STATE OF NEW MEXICO
NEW MEXICO OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC

CASE NO. 24683

APPLICANTS' PREHEARING STATEMENT

Pursuant to 19.15.3.11.B NMAC and the Hearing Officer's Amended Prehearing Procedural Order in this matter, Applicants Western Environmental Law Center (WELC"), Citizens Caring for the Future, Conservation Voters New Mexico Education Fund, Diné C.A.R.E., Earthworks, Naeva, New Mexico Interfaith Power and Light, San Juan Citizens Alliance, Sierra Club, and WildEarth Guardians hereby submit their Prehearing Statement in this matter with the following information:

1. The person's name and its attorney's name: WELC represents all parties in the proceeding, identified above.
2. The names of all witnesses the person will call to testify: Applicants will present:
    a. Thomas Alexander, Principal, Alexander Engineering, LLC;
    a. Peter Morgan, J.D., Legal and Policy Director, Center for Asset Retirement Accountability;
    b. Dwayne Purvis, P.E., Founder and Principal Advisor, Purvis Energy Advisors; and
    c. Adam Peltz, J.D., Director and Senior Attorney, Environmental Defense Fund.
3. All witnesses' full direct testimony, their qualifications including a description of their education and experience, and the approximate time to present a summary of the witness's direct testimony: All witnesses' full direct testimony and qualifications are set forth in this Prehearing Statement as follows:

a. Direct testimony of Thomas Alexander is Applicants' Exhibit 3 and his resume is Applicants' Exhibit 2; the approximate time for a summary of his testimony is one hour.

b. Direct testimony of Peter Morgan, J.D., is Applicants' Exhibit 15 and his resume is Applicants' Exhibit 14; the approximate time for a summary of his testimony is one hour.

c. Direct testimony of Dwayne Purvis, P.E., is Applicants' Exhibit 30 and his curriculum vitae is Applicants' Exhibit 29; the approximate time for a summary of his testimony is one hour.

d. Direct Testimony of Adam Peltz, J.D., is Applicants' Exhibit 58 and his resume is Applicants' Exhibit 57; the approximate time for a summary of his testimony is one hour.

4. Any proposed modifications to the proposed rule change with reasons for adopting the modifications: Applicants' proposed modifications are set forth in Applicants' Exhibit 1 and their reasons for adopting the modifications are set forth in their exhibits, a list of which appears below.

5. All exhibits the person plans to offer as direct exhibits in the hearing: Applicants' list of exhibits is set forth below and the exhibits are attached (except for Applicants' Exhibit 55, which is an Excel spreadsheet which has been uploaded to the shared WELC folder in the ENMRD CentreStack platform for this proceeding). Applicants provide a Bates stamp number for each exhibit to facilitate accessing the exhibits.

Exhibit No.	**Exhibit**	**Bates Stamp No.**
1		0001
1-A	Apps' Proposed 19.15.2 NMAC	0002
1-B	Apps' Proposed 19.15.5 NMAC	0015
1-C	Apps' Proposed 19.15.8 NMAC	0021
1-D	Apps' Proposed 19.15.9 NMAC	0026
1-E	Apps' Proposed 19.15.25 NMAC	0031
2	Tom Alexander Resume	0037
3	Direct Testimony of Tom Alexander	0041
4	LFC, Policy Spotlight: Orphaned Wells (June 24, 2025)	0101
5	OCD Redline Proposals (Feb. 12, 2025)	0149

6	Correspondence among counsel re negotiations	0220
7	Graphic: OCD inactive well search list (7-3-25)	0240
8	Graphic: number of wells inactive by minimum time inactive	0242
9	Graphic: number of operators with inactive wells by minimum time inactive	0244
10	Graphic: compliance status of operators with inactive wells over time	0246
11	Graphic: wells in approved or expired TA status	0248
12	Form C-103 and samples of C-103's requesting temporary abandonment	0250
13	Graphic: length of time before deactivated wells return to activity & Graphic: percent of wells ever returning to activity	0282
14	Peter Morgan Resume	0285
15	Direct Testimony of Peter Morgan	0287
16	NM LFC, FIR for H.B. 481	0383
17	EMNRD, ORF Report FY19	0387
18	EMNRD, ORF Report FY20	0392
19	EMNRD, ORF Report FY21	0397
20	EMNRD, ORF Report FY22	0401
21	EMNRD, ORF Report FY23	0406
22	EMNRD, ORF Report FY24	0410
23	EMNRD, App. for Initial Grant Funding	0422
24	Lattanzio, CRS Report	0454
25	Jackson et al. Report	0531
26	El Hachem & Kang Report	0555
27	Proville et al. Report	0575
28	IOGCC Regulatory Strategies Report	0590
29	Dwayne Purvis Curriculum Vitae	0675
30	Direct Testimony of Dwayne Purvis	0687
31	Graphic: Plugged and unplugged wells	0778
32	Graphic: Subdivisions of unplugged wells	0780
33	Graphic: History of daily production by basin	0782
34	Graphic: Total decommissioning and reclamation costs	0784
35	Graphic: Relative contribution of companies	0786
36	Graphic: Relative contribution of companies by portfolio	0788
37	Graphic: Relative contribution of companies by production	0790
38	Graphic: Concept of holdback	0792
39	Graphic: Cost to downhole plug orphan wells over time	0794
40	Graphic: Production and activity of wells	0796
41	Graphic: Number of wells by category	0798
42	Graphic: Number of wells by category in stripper context	0800
43	Graphic: Economic limit of production	0802
44	Graphic: Proportion of wells shut-in meeting new definitions	0804

45	Graphic: Permian horizontal well production and age	0806
46	Graphic: Permian vertical well production and age	0808
47	Graphic: Permian vertical well production and age comparison with wells permanently shut-in	0810
48	Graphic: San Juan horizontal well production and age	0812
49	Graphic: San Juan vertical well production and age	0814
50	Graphic: San Juan vertical well production and age comparison with wells permanently shut-in	0816
51	Graphic: Size of well portfolios orphaned	0818
52	Graphic: Effect of marginal and inactive well threshold	0820
53	Graphic: Comparison of oil field inflation to CPI	0822
54	SPE, Economic Yardsticks	0824
55	OCD Master Orphan Well List (7-2-25)[1]	0835
56	Adam Peltz Resume	0836
57	Direct Testimony of Adam Peltz	0839
58	Selected excerpts from Change Research polling results (2025 New Mexico Landscape: Energy & Climate, Nov. 22 – Dec. 5, 2024)	0917
59	Graphic: New Mexico oil production, 2010 - 2024	0919
60	Graphic: Average depth of new wells drilled, 1980 - 2020	0921
61	Graphic: Wells in Expired TA status over time	0923
62	Graphic: TA status wells, by time since last production	0925
63	Graphic: Projected bonding amount, by marginal/inactive well % groups	0927
64	Graphic: Proposed bonding amounts vs potential plugging liability, by operator	0933
65	Table: List of wells individually producing more than all marginal wells, 2024	0935
66	Table: comparisons of operators by marginal and inactive well %	0937
67	Graphic: Operators by % of wells marginal or inactive	0939
68	Graphic: Operator annual revenue vs. cost of plugging marginal and inactive wells	0941
69	Graphic: Shut-downs & reactivations annually, 2011-2023	0943
70	Table: All Temporary Abandonment status wells, by time since initial entry into TA status	0945
71	Table: Temporary Abandonment status wells, by time since last production	0947

[1]Ex. 55 is an Excel spreadsheet that is filed in the shared WELC folder in EMNRD CentreStack.

Respectfully submitted,

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Certificate of Service

I certify that on August 8, 2025, I served by a copy of this pleading by filing a copy in the shared WELC folder in the EMNRD CentreStack platform and notifying the following via email:

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EXHIBIT 1

EXHIBIT 1-A

APPLICANTS' PROPOSED REVISED AMENDMENTS TO 19.15.2 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 2 GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS

19.15.2.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.2.1 NMAC - Rp, 19.15.1.1 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.2 SCOPE: 19.15.2 NMAC applies to persons or entities engaged in oil and gas development and production within New Mexico and to 19.15.2 NMAC through 19.15.39 NMAC.
[19.15.2.2 NMAC - Rp, 19.15.1.2 NMAC, 12/1/2008]

19.15.2.3 STATUTORY AUTHORITY: 19.15.2 NMAC is adopted pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978, which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash because of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[19.15.2.3 NMAC - Rp, 19.15.1.3 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.4 DURATION: Permanent.
[19.15.2.4 NMAC - Rp, 19.15.1.4 NMAC, 12/1/2008]

19.15.2.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.2.5 NMAC - Rp, 19.15.1.5 NMAC, 12/1/2008]

19.15.2.6 OBJECTIVE: To set forth general provisions and definitions pertaining to the authority of the oil conservation division and the oil conservation commission pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978.
[19.15.2.6 NMAC - Rp, 19.15.1.6 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.7 DEFINITIONS: These definitions apply to 19.15.2 NMAC through 19.15.39 NMAC.

A. Definitions beginning with the letter "A".

(1) **"Abate"** means to investigate, contain, remove or mitigate water pollution.

(2) **"Abatement"** means the investigation, containment, removal or other mitigation of water pollution.

(3) **"Abatement plan"** means a description of operational, monitoring, contingency and closure requirements and conditions for water pollution's prevention, investigation and abatement.

(4) **"Act" or "Oil and Gas Act"** means Chapter 70, Article 2 NMSA 1978, as it may be modified or amended.

(5) **"Adjoining spacing units"** mean those existing or prospective spacing units in the same pool that are touching at a point or line on the subject spacing unit.

(6) **"Adjusted allowable"** means the allowable production a well or proration unit receives after all adjustments are made.

(7) **"AFE"** means authorization for expenditure.

(8) **"Affected persons"** means the following persons owning interests in a spacing unit or other identified tract:

(a) the operator, as shown in division records, of a well on the tract, or, if the tract is included in a division-approved or federal unit, the designated unit operator;

(b) in the absence of an operator, or with respect to an application wherein the operator of the spacing unit or identified tract is the applicant, each working interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant files the application;

(c) as to any tract or interest therein that is not subject to an existing oil and gas lease, each mineral interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant filed the application; and

(d) if the United States or state of New Mexico owns the mineral estate in the spacing unit or identified tract or any part thereof, the BLM or state land office, as applicable; or

(e) if the mineral estate in the spacing unit or identified tract or any part thereof is tribal land, the BLM, the United States department of the interior, bureau of Indian affairs, and the relevant tribe.

(9) "Allocated pool" means a pool in which the total oil or gas production is restricted and is allocated to various wells in the pool in accordance with proration schedules.

(10) "Allowable production" means that number of barrels of oil or cubic feet of gas the division authorizes to be produced from an allocated pool.

(11) "APD" means application for permit to drill.

(12) "API" means the American petroleum institute.

(13) "Approved temporary abandonment," "temporary abandonment," or "temporarily abandoned status" means the status of a well that is inactive, has been approved in accordance with 19.15.25.13 NMAC and complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

(14) "Aquifer" means a geological formation, group of formations or a part of a formation that can yield a significant amount of water to a well or spring.

(15) "ASTM" means ASTM International - an international standards developing organization that develops and publishes voluntary technical standards for a wide range of materials, products, systems and services.

B. Definitions beginning with the letter "B".

(1) "Back allowable" means the authorization for production of an underproduction resulting from pipeline proration.

(2) "Background" means, for purposes of ground water abatement plans only, the amount of ground water contaminants naturally occurring from undisturbed geologic sources or water contaminants occurring from a source other than the responsible person's facility. This definition does not prevent the director from requiring abatement of commingled plumes of pollution, does not prevent responsible persons from seeking contribution or other legal or equitable relief from other persons and does not preclude the director from exercising enforcement authority under any applicable statute, rule or common law.

(3) "Barrel" means 42 United States gallons measured at 60 degrees fahrenheit and atmospheric pressure at the sea level.

(4) "Barrel of oil" means 42 United States gallons of oil, after deductions for the full amount of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) "Barrel of oil equivalent" is determined by converting the volume of gas the well produced to barrels of oil by using a ratio of 6,000 cubic feet to one barrel of oil.

~~(5)~~**(6) "Below-grade tank"** means a vessel, excluding sumps and pressurized pipeline drip traps, where a portion of the tank's sidewalls is below the surrounding ground surface's elevation. Below-grade tank does not include an above ground storage tank that is located above or at the surrounding ground surface's elevation and is surrounded by berms.

(7) "Beneficial purposes" or "beneficial use" means an oil or gas well that is being used in a productive or beneficial manner such as production, injection or monitoring, and does not include use of a well for speculative purposes.

~~(6)~~**(8) "Berm"** means an embankment or ridge constructed to prevent the movement of liquids, sludge, solids or other materials.

~~(7)~~**(9) "Biopile",** also known as biocell, bioheap, biomound or compost pile, means a pile of contaminated soils used to reduce concentrations of petroleum constituents in excavated soils through biodegradation. This technology involves heaping contaminated soils into piles or "cells" and stimulating aerobic microbial activity within the soils through the aeration or addition of minerals, nutrients and moisture.

~~(8)~~**(10) "BLM"** means the United States department of the interior, bureau of land management.

~~(9)~~**(11) "Bottom hole pressure"** means the gauge pressure in psi under conditions existing at or near the producing horizon.

~~(10)~~**(12) "Bradenhead gas well"** means a well producing gas through wellhead connections from a gas reservoir that has been successfully cased off from an underlying oil or gas reservoir.

~~(11)~~**(13) "BS&W"** means basic sediments and water.

~~(12)~~**(14) "BTEX"** means benzene, toluene, ethylbenzene and xylene.

C. Definitions beginning with the letter "C".

(1) "Carbon dioxide gas" means noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks.

(2) "Casinghead gas" means a gas or vapor or both gas and vapor indigenous to and produced from a pool the division classifies as an oil pool. This also includes gas-cap gas produced from such an oil pool.

(3) "Certified mail" or "certified mail, return receipt requested" means United States Postal Service Certified Mail or equivalent service that provides tracking and signature receipt, including Federal Express, United Parcel Service, or similar courier services.

(4) "Cm/sec" means centimeters per second.

(5) "CPD" means central point delivery.

(6) "Combination multiple completion" means a multiple completion in which two or more common sources of supply are produced through a combination of two or more conventional diameter casing strings cemented in a common well bore, or a combination of small diameter and conventional diameter casing strings cemented in a common well bore, the conventional diameter strings of which might or might not be a conventional multiple completion.

(7) "Commission" means the oil conservation commission.

(8) "Commission clerk" means the division employee the director designates to provide staff support to the commission and accept filings in rulemaking or adjudicatory cases before the commission.

(9) "Common purchaser for gas" means a person now or hereafter engaged in purchasing from one or more producers gas produced from gas wells within each common source of supply from which it purchases.

(10) "Common purchaser for oil" means every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines.

(11) "Common source of supply". See pool.

(12) "Condensate" means the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

(13) "Contiguous" means acreage joined by more than one common point, that is, the common boundary is at least one side of a governmental quarter-quarter section.

(14) "Conventional completion" means a well completion in which the production string of casing has an outside diameter exceeding 2.875 inches.

(15) "Conventional multiple completion" means a completion in which two or more common sources of supply are produced through one or more strings of tubing installed within a single casing string, with the production from each common source of supply completely segregated by means of packers.

(16) "Correlative rights" means the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste the owner's just and equitable share of the oil or gas in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas under the property bears to the total recoverable oil or gas in the pool, and for the purpose to use the owner's just and equitable share of the reservoir energy.

(17) "Cubic feet of gas or cubic foot of gas" means that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 psi (15.025 psi absolute), at a standard base temperature of 60 degrees fahrenheit.

D. Definitions beginning with the letter "D".

(1) "Deep pool" means a common source of supply that is situated 5000 feet or more below the surface.

(2) "Depth bracket allowable" means the basic oil allowable the division assigns a pool and based on its depth, unit size or special pool orders, which, when multiplied by the market demand percentage factor in effect, determines the pool's top proration unit allowable.

(3) "Director" means the director of the New Mexico energy, minerals and natural resources department, oil conservation division.

(4) "Division" means the New Mexico energy, minerals and natural resources department, oil conservation division.

(5) "Division clerk" means the division employee the director designates to accept filings in adjudicatory cases before the division.

(6) "Downstream facility" means a facility associated with the transportation (including gathering) or processing of gas or oil (including a refinery, gas plant, compressor station or crude oil pump station); brine production; or the oil field service industry.

(7) "DRO" means diesel range organics.

E. Definitions beginning with the letter "E".

(1) "EC" means electrical conductivity.

(2) "Enhanced oil recovery project" means the use or the expanded use of a process for the

displacement of oil from an oil well or division-designated pool other than a primary recovery process, including but not limited to the use of a pressure maintenance process; a water flooding process; an immiscible, miscible, chemical, thermal or biological process; or any other related process.

(3) "EOR project" means an enhanced oil recovery project.

(4) "EPA" means the United States environmental protection agency.

(5) "Exempted aquifer" means an aquifer that does not currently serve as a source of drinking water, and that cannot now and will not in the foreseeable future serve as a source of drinking water because:

(a) it is hydrocarbon producing;

(b) it is situated at a depth or location that makes the recovery of water for drinking water purposes economically or technologically impractical; or

(c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(6) "Exempt waste" means oil field waste exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(7) "Existing spacing unit" means a spacing unit containing a producing well.

(8) "Expired temporary abandonment" or **"expired temporary abandonment status"** means the status of a well that is inactive and has been approved for temporary abandoned status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

F. Definitions beginning with the letter "F".

(1) "Facility" means a structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock or activity of any kind, whether stationary or mobile.

(2) "Field" means the general area that at least one pool underlies or appears to underlie; and also includes the underground reservoir or reservoirs containing oil or gas. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools.

(3) "Fresh water" to be protected includes the water in lakes and playas (regardless of quality, unless the water exceeds 10,000 mg/l TDS and it can be shown that degradation of the particular water body will not adversely affect hydrologically connected fresh ground water), the surface waters of streams regardless of the water quality within a given reach, and underground waters containing 10,000 mg/l or less of TDS except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use that contamination of such waters would impair.

G. Definitions beginning with the letter "G".

(1) "Gas", also known as natural gas, means a combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool the division has classified as a gas pool.

(2) "Gas lift" means a method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

(3) "Gas-oil ratio" means the ratio of the casinghead gas produced in standard cubic feet to the number of barrels of oil concurrently produced during any stated period.

(4) "Gas-oil ratio adjustment" means the reduction in allowable of a high gas oil ratio unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

(5) "Gas transportation facility" means a pipeline in operation serving gas wells for the transportation of gas, or some other device or equipment in like operation where the gas produced from gas wells connected with the pipeline or other device or equipment can be transported or used for consumption.

(6) "Gas well" means a well producing gas from a gas pool, or a well with a gas-oil ratio exceeding 100,000 cubic feet of gas per barrel of oil producing from an oil pool.

(7) "Geomembrane" means an impermeable polymeric sheet material that is impervious to liquid and gas if it maintains its integrity and is used as an integral part of an engineered structure designed to limit the movement of liquid or gas in a system.

(8) "Geotextile" means a sheet material that is less impervious to liquid than a geomembrane but more resistant to penetration damage, and is used as part of an engineered structure or system to serve as a filter to prevent the movement of soil fines into a drainage system, to provide planar flow for drainage, to serve as a cushion to protect geomembranes or to provide structural support.

(9) "GRO" means gasoline range organics.

(10) "Ground water" means interstitial water that occurs in saturated earth material and can enter a well in sufficient amounts to be used as a water supply.

(11) "Ground water sensitive area" means an area the division specifically designates after

evaluation of technical evidence where ground water exists that would likely exceed WQCC standards if contaminants were introduced into the environment.

H. Definitions beginning with the letter "H".

(1) "Hardship gas well" means a gas well where underground waste occurs if the well is shut-in or curtailed below its minimum sustainable flow rate.

(2) "Hazard to public health" exists when water that is used or is reasonably expected to be used in the future as a human drinking water supply exceeds at the time and place of the use, one or more of the numerical standards of Subsection A of 20.6.2.3103 NMAC, or the naturally occurring concentrations, whichever is higher, or if a toxic pollutant as defined at Subsection WW of 20.6.2.7 NMAC affecting human health is present in the water. In determining whether a release would cause a hazard to public health to exist, the director investigates and considers the purification and dilution reasonably expected to occur from the time and place of release to the time and place of withdrawal for use as human drinking water.

(3) "Hazardous waste" means non-exempt waste that exceeds the minimum standards for waste hazardous by characteristics established in RCRA regulations, 40 CFR 261.21-261.24, or listed hazardous waste as defined in 40 CFR, part 261, subpart D, as amended.

(4) "HDPE" means high-density polyethylene.

(5) "High gas-oil ratio proration unit" means a unit with at least one producing oil well with a gas-oil ratio exceeding the limiting gas-oil ratio for the pool in which the unit is located.

(6) "H2S" means hydrogen sulfide.

I. Definitions beginning with the letter **"I"**.

(1) "Illegal gas" means gas produced from a gas well exceeding the division-determined allowable.

(2) "Illegal oil" means oil produced exceeding the allowable the division fixes.

(3) "Illegal product" means a product of illegal gas or illegal oil.

(4) "Inactive well" means a well that is not being used for beneficial purposes such as production, injection or monitoring and that is not being drilled, completed, repaired or worked over.

(5) "Injection well" means a well used for the injection of air, gas, water or other fluids into an underground stratum.

J. Definitions beginning with the letter "J". [RESERVED]

K. Definitions beginning with the letter "K". "Knowingly and willfully", for assessing civil penalties, means the voluntary or conscious performance of an act that is prohibited or the voluntary or conscious failure to perform an act or duty that is required. It does not include performances or failures to perform that are honest mistakes or merely inadvertent. It includes, but does not require, performances or failures to perform that result from a criminal or evil intent or from a specific intent to violate the law. The conduct's knowing and willful nature may be established by plain indifference to or reckless disregard of the requirements of statutes, rules, orders or permits. A consistent pattern or performance or failure to perform also may be sufficient to establish the conduct's knowing and willful nature, where such consistent pattern is neither the result of honest mistakes nor mere inadvertency. Conduct that is otherwise regarded as being knowing and willful is rendered neither accidental nor mitigated in character by the belief that the conduct is reasonable or legal.

L. Definitions beginning with the letter "L".

(1) "Limiting gas-oil ratio" means the gas-oil ratio the division assigns to a particular oil pool to limit the volumes of casinghead gas that may be produced from the various oil producing units within that particular pool.

(2) "Liner" means a continuous, low-permeability layer constructed of natural or human-made materials that restricts the migration of liquid oil field wastes, gases or leachate.

(3) "LLDPE" means linear low-density polyethylene.

(4) "Load oil" means oil or liquid hydrocarbon that has been used in remedial operation in an oil or gas well.

(5) "Log" means a systematic detailed and correct record of formations encountered in drilling a well.

M. Definitions beginning with the letter "M".

(1) "Marginal unit" means a proration unit that is incapable of producing top proration unit allowable for the pool in which it is located.

(2) "Marginal well" means an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period.

~~(2)~~**(3) "Market demand percentage factor"** means that percentage factor of one hundred percent or less as the division determines at an oil allowable hearing, which, when multiplied by the depth bracket allowable applicable to each pool, determines that pool's top proration unit allowable.

~~(3)~~**(4) "MCF"** means 1000 cubic feet.

~~(4)~~**(5) "MCFD"** means 1000 cubic feet per day.

~~(5)~~**(6) "MCFGPD"** means 1000 cubic feet of gas per day.

~~(6)~~**(7) "Measured depth"** means the total length of the well bore.

~~(7)~~**(8) "Mg/l"** means milligrams per liter.

~~(8)~~**(9) "Mg/kg"** means milligrams per kilogram.

~~(9)~~**(10) "Mineral estate"** is the most complete ownership of oil and gas recognized in law and includes the mineral interests and the royalty interests.

~~(10)~~**(11) "Mineral interest owner"** means a working interest owner, or an owner of a right to explore for and develop oil and gas that is not subject to an existing oil and gas lease.

~~(11)~~**(12) "Minimum allowable"** means the minimum amount of production from an oil or gas well that may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste.

~~(12)~~**(13) "Miscellaneous hydrocarbons"** means tank bottoms occurring at pipeline stations; oil storage terminals or refineries; pipeline break oil; catchings collected in traps, drips or scrubbers by gasoline plant operators in the plants or in the gathering lines serving the plants; the catchings collected in private, community or commercial salt water disposal systems; or other liquid hydrocarbon that is not lease crude or condensate.

N. Definitions beginning with the letter "N".

(1) "Non-aqueous phase liquid" means an interstitial body of liquid oil, petroleum product, petrochemical or organic solvent, including an emulsion containing such material.

(2) "Non-exempt waste" means oil field waste not exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(3) "Non-hazardous waste" means non-exempt oil field waste that is not hazardous waste.

(4) "Non-marginal unit" means a proration unit that can produce the top proration unit allowable for the pool in which it is located, and to which the division assigns a top proration unit allowable.

(5) "NORM" means the naturally occurring radioactive materials regulated by 20.3.14 NMAC.

O. Definitions beginning with the letter "O".

(1) "Official gas-oil ratio test" means the periodic gas-oil ratio test the operator performs pursuant to division order by the method and in the manner the division prescribes.

(2) "Oil" means petroleum hydrocarbon produced from a well in the liquid phase and that existed in a liquid phase in the reservoir. This definition includes crude oil or crude petroleum oil.

(3) "Oil field waste" means non-domestic waste resulting from the exploration, development, production or storage of oil or gas pursuant to Paragraph (21) of Subsection B of Section 70-2-12 NMSA 1978 and the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil pursuant to Paragraph (22) of Subsection B of Section 70-2-12 NMSA 1978, including waste generated from oil field remediation or abatement activity regardless of the date of release. Oil field waste does not include waste not generally associated with oil and gas industry operations such as tires, appliances or ordinary garbage or refuse unless generated at a division-regulated facility, and does not include sewage, regardless of the source.

(4) "Oil well" means a well capable of producing oil and that is not a gas well as defined in Paragraph (6) of Subsection G of 19.15.2.7 NMAC.

(5) "Operator" means a person who, duly authorized, manages a lease's development or a producing property's operation, or who manages a facility's operation.

(6) "Overproduction" means the amount of oil or gas produced during a proration period exceeding the amount authorized on the proration schedule.

(7) "Owner" means the person who has the right to drill into and to produce from a pool, and to appropriate the production either for the person or for the person and another.

P. Definitions beginning with the letter "P".

(1) "Penalized unit" means a proration unit to which, because of an excessive gas-oil ratio,

the division assigns an allowable that is less than top proration unit allowable for the pool in which it is located and also less than the ability of the well or wells on the unit to produce.

(2) "Person" means an individual or entity including partnerships, corporations, associations, responsible business or association agents or officers, the state or a political subdivision of the state or an agency, department or instrumentality of the United States and of its officers, agents or employees.

(3) "Pit" means a surface or sub-surface impoundment, man-made or natural depression or diked area on the surface. Excluded from this definition are berms constructed around tanks or other facilities solely for safety, secondary containment and storm water or run-on control.

(4) "Playa lake" means a level or nearly level area that occupies the lowest part of a completely closed basin and that is covered with water at irregular intervals, forming a temporary lake.

(5) "Pool" means an underground reservoir containing a common accumulation of oil or gas. Each zone of a general structure, which zone is completely separated from other zones in the structure, is covered by the word pool as used in 19.15.2 NMAC through 19.15.39 NMAC. "Pool" is synonymous with "common source of supply" and with "common reservoir".

(6) "Potential" means a well's properly determined capacity to produce oil or gas under division-prescribed conditions.

(7) "Ppm" means parts per million by volume.

(8) "PQL" means practical quantitation limit.

(9) "Pressure maintenance" means the injection of gas or other fluid into a reservoir, either to maintain the reservoir's existing pressure or to retard the reservoir pressure's natural decline.

(10) "Produced water" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

(11) "Producer" means the owner of a well or wells capable of producing oil or gas or both in paying quantities.

(12) "Product" means a commodity or thing made or manufactured from oil or gas, and derivatives of oil or gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzene, wash oil, lubricating oil and blends or mixtures of oil or gas or a derivative thereof.

(13) "Proration day" consists of 24 consecutive hours that begin at 7:00 a.m. and end at 7:00 a.m. on the following day.

(14) "Proration month" means the calendar month that begins at 7:00 a.m. on the first day of the month and ends at 7:00 a.m. on the first day of the next succeeding month.

(15) "Proration period" means for oil the proration month and for gas the 12-month period that begins at 7:00 a.m. on January 1 of each year and ends at 7:00 a.m. on January 1 of the succeeding year or other period designated by general or special order of the division.

(16) "Proration schedule" means the division orders authorizing the production, purchase and transportation of oil, casinghead gas and gas from the various units of oil or of gas in allocated pools.

(17) "Proration unit" means the area in a pool that can be effectively and efficiently drained by one well as determined by the division or commission (see Subsection B of Section 70-2-17 NMSA 1978) as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool.

(18) "Prospective spacing unit" means a hypothetical spacing unit that does not yet have a producing well.

(19) "PVC" means poly vinyl chloride.

(20) "Psi" means pounds per square inch.

Q. Definitions beginning with the letter "Q". [RESERVED]

R. Definitions beginning with the letter "R".

(1) "RCRA" means the federal Resource Recovery and Conservation Act.

(2) "Recomplete" means the subsequent completion of a well in a different pool from the pool in which it was originally completed.

(3) "Regulated NORM" means NORM contained in oil-field soils, equipment, sludges or other materials related to oil-field operations or processes exceeding the radiation levels specified in 20.3.14.1403 NMAC.

(4) "Release" means breaks, leaks, spills, releases, fires or blowouts involving oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and gases to the environment.

(5) "Remediation plan" means a written description of a program to address unauthorized

releases. The plan may include appropriate information, including assessment data, health risk demonstrations and corrective action or actions. The plan may also include an alternative proposing no action beyond the spill report's submittal.

(6) **"Responsible person"** means the owner or operator who shall complete a division-approved corrective action for pollution from releases.

(7) **"Rules"** means the rules enacted pursuant to the Oil and Gas Act, 19.15.2 to 19.15.39 NMAC, as they may be modified or amended.

(8) **"Royalty interest owner"** means the owner of an interest in oil and gas that does not presently entitle the owner to explore, drill or otherwise develop those minerals, including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing.

(9) **"Run-on"** means rainwater, leachate or other liquid that drains from other land onto any part of a division-approved facility.

S. **Definitions beginning with the letter "S"**.

(1) **"SAR"** means the sodium adsorption ratio.

(2) **"Secondary recovery"** means a method of recovering quantities of oil or gas from a reservoir which quantities would not be recoverable by ordinary primary depletion methods.

(3) **"Sediment oil"** means tank bottoms and other accumulations of liquid hydrocarbons on an oil and gas lease, which hydrocarbons are not merchantable through normal channels.

(4) **"Shallow pool"** means a pool that has a depth range from zero to 5000 feet.

(5) **"Shut-in"** means the status of a production well or an injection well that is temporarily closed, whether by closing a valve or disconnection or other physical means.

(6) **"Shut-in pressure"** means the gauge pressure noted at the wellhead when the well is completely shut-in, not to be confused with bottom hole pressure.

(7) **"Significant modification of an abatement plan"** means a change in the abatement technology used excluding design and operational parameters, or relocation of twenty-five percent or more of the compliance sampling stations, for a single medium, as designated pursuant to Subparagraph (d) of Paragraph (2) of Subsection D of 19.15.30.13 NMAC.

(8) **"Soil"** means earth, sediments or other unconsolidated accumulations of solid particles produced by the physical and chemical disintegration of rocks, and that may or may not contain organic matter.

(9) **"Spacing unit"** means the area allocated to a well under a well spacing order or rule. Under the Oil and Gas Act, Paragraph (10) of Subsection B of Section 70-2-12 NMSA 1978, the commission may fix spacing units without first creating proration units. See *Rutter & Wilbanks corp. v. oil conservation comm'n*, 87 NM 286 (1975). This is the area designated on form C-102.

(10) **"Subsurface water"** means ground water and water in the vadose zone that may become ground water or surface water in the reasonably foreseeable future or that vegetation may use.

(11) **"Surface waste management facility"** means a facility that receives oil field waste for collection, disposal, evaporation, remediation, reclamation, treatment or storage except:

(a) a facility that utilizes underground injection wells subject to division regulation pursuant to the federal Safe Drinking Water Act, and does not manage oil field wastes on the ground in pits, ponds, below-grade tanks or land application units;

(b) a facility permitted pursuant to the New Mexico environmental improvement board rules or WQCC rules;

(c) a temporary pit as defined in 19.15.17 NMAC;

(d) a below-grade tank or pit that receives oil field waste from a single well, permitted pursuant to 19.15.37 NMAC, regardless of the capacity or volume of oil field waste received;

(e) a facility located at an oil and gas production facility and used for temporary storage of oil field waste generated on-site from normal operations, if the facility does not pose a threat to fresh water, public health, safety or the environment;

(f) a remediation conducted in accordance with a division-approved abatement plan pursuant to 19.15.30 NMAC, a corrective action pursuant to 19.15.29 NMAC or a corrective action of a non-reportable release;

(g) a facility operating pursuant to a division emergency order;

(h) a site or facility where the operator is conducting emergency response operations to abate an immediate threat to fresh water, public health, safety or the environment or as the division has specifically directed or approved; or

(i) a facility that receives only exempt oil field waste, receives less than 50 barrels of liquid water per day (averaged over a 30-day period), has a capacity to hold 500 barrels of liquids or less and is permitted pursuant to 19.15.17 NMAC.

T. Definitions beginning with the letter "T".

(1) "Tank bottoms" means that accumulation of hydrocarbon material and other substances that settles naturally below oil in tanks and receptacles that are used in oil's handling and storing, and which accumulation contains more than two percent of BS&W; provided, however, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet to the tank.

(2) "TDS" means total dissolved solids.

~~**(3) "Temporary abandonment" or "temporarily abandoned status"** means the status of a well that is inactive.~~

~~(4)~~**(3) "Top proration unit allowable for gas"** means the maximum number of cubic feet of gas, for the proration period, the division allocates to a gas producing unit in an allocated gas pool.

~~(5)~~**(4) "Top proration unit allowable for oil"** means the maximum number of barrels for oil daily for each calendar month the division allocates on a proration unit basis in a pool to non-marginal units. The division shall determine the top proration unit allowable for a pool by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect.

~~(6)~~**(5) "TPH"** means total petroleum hydrocarbons.

~~(7)~~**(6) "Treating plant"** means a plant constructed for wholly or partially or being used wholly or partially for reclaiming, treating, processing or in any manner making tank bottoms or other waste oil marketable.

~~(8)~~**(7) "Tribal lands"** means those lands for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe. This includes reservations, pueblo land grants, tribal trust lands and individual trust allotments.

~~(9)~~**(8) "Tribal leases"** means those leases of minerals or interests in or rights to minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(10)~~**(9) "Tribal minerals"** means those minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(11)~~**(10) "True vertical depth"** means the difference in elevation between the ground level at the surface location of the well and the deepest point in the well bore.

~~(12)~~**(11) "Tubingless completion"** means a well completion in which the production string of casing has an outside diameter of 2.875 inches or less.

~~(13)~~**(12) "Tubingless multiple completion"** means completion in which two or more common sources of supply are produced through an equal number of casing strings cemented in a common well bore, each such string of casing having an outside diameter of 2.875 inches or less, with the production from each common source of supply completely segregated by cement.

U. Definitions beginning with the letter "U".

(1) "Underground source of drinking water" means an aquifer that supplies water for human consumption or that contains ground water having a TDS concentration of 10,000 mg/l or less and that is not an exempted aquifer.

(2) "Underproduction" means the amount of oil or the amount of gas during a proration period by which a given proration unit failed to produce an amount equal to that the division authorizes in the proration schedule.

(3) "Unit of proration for gas" consists of such multiples of 40 acres as may be prescribed by division-issued special pool orders.

(4) "Unit of proration for oil" consists of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by division-issued special pool orders.

(5) "Unorthodox well location" means a location that does not conform to the spacing requirements division rules establish.

(6) "Unstable area" means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity of some or all a division-approved facility's structural components. Examples of unstable areas are areas of poor foundation conditions, areas susceptible to mass earth movements and karst terrain areas where karst topography is developed because of dissolution of limestone, dolomite or other soluble rock. Characteristic physiographic features of karst terrain include sinkholes, sinking streams, caves, large springs and blind valleys.

(7) "Upstream facility" means a facility or operation associated with the exploration, development, production or storage of oil or gas that is not a downstream facility.

V. Definitions beginning with the letter "V". "Vadose zone" means unsaturated earth material below the land surface and above ground water, or in between bodies of ground water.

W. Definitions beginning with the letter "W".

(1) **"Waste",** in addition to its ordinary meaning, includes:

(a) underground waste as those words are generally understood in the oil and gas business, and to embrace the inefficient, excessive or improper use or dissipation of the reservoir energy, including gas energy and water drive, of a pool, and the locating, spacing, drilling, equipping, operating or producing of a well or wells in a manner to reduce or tend to reduce the total quantity of oil or gas ultimately recovered from a pool, and the use of inefficient underground storage of gas;

(b) surface waste as those words are generally understood in the oil and gas business, and to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of gas of any type or in any form, or oil, or a product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing a well or wells, or incident to or resulting from the use of inefficient storage or from the production of oil or gas, in excess of the reasonable market demand;

(c) oil production in this state in excess of the reasonable market demand for the oil; the excess production causes or results in waste that the Oil and Gas Act prohibits; reasonable market demand as used herein with respect to oil means the demand for the oil, for reasonable current requirements for current consumption and use within or outside of the state, together with the demand of amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of oil or the products thereof, or both the oil and products;

(d) the non-ratable purchase or taking of oil in this state; the non-ratable taking and purchasing causes or results in waste, as defined in Subparagraphs (a), (b) and (c) of Paragraph (1) of Subsection W of 19.15.2.7 NMAC and causes waste by violating the Oil and Gas Act, Section 70-2-16 NMSA 1978;

(e) the production in this state of gas from a gas well or wells, or from a gas pool, in excess of the reasonable market demand from such source for gas of the type produced or in excess of the capacity of gas transportation facilities for such type of gas; the words "reasonable market demand", as used herein with respect to gas, shall be construed to mean the demand for gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of gas or products thereof, or both the gas and products.

(2) **"Water"** means all water including water situated wholly or partly within or bordering upon the state, whether surface or subsurface, public or private, except private waters that do not combine with other surface or subsurface water.

(3) **"Water contaminant"** means a substance that could alter if released or spilled water's physical, chemical, biological or radiological qualities. Water contaminant does not mean source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954.

(4) **"Watercourse"** means a river, creek, arroyo, canyon, draw or wash or other channel having definite banks and bed with visible evidence of the occasional flow of water.

(5) **"Water pollution"** means introducing or permitting the introduction into water, either directly or indirectly, of one or more water contaminants in such quantity and of such duration as may with reasonable probability injure human health, animal or plant life or property, or to unreasonably interfere with the public welfare or property use.

(6) **"Well blowout"** means a loss of control over and subsequent eruption of a drilling or workover well or the rupture of the casing, casinghead or wellhead of an oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquid, from the well.

(7) **"Well bore"** means the interior surface of a cased or open hole through which drilling, production or injection operations are conducted.

(8) **"Wellhead protection area"** means the area within 200 horizontal feet of a private, domestic fresh water well or spring used by less than five households for domestic or stock watering purposes or within 1000 horizontal feet of any other fresh water well or spring. Wellhead protection areas does not include areas around water wells drilled after an existing oil or gas waste storage, treatment or disposal site was established.

(9) **"Wetlands"** means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions in New Mexico. This definition does not include constructed wetlands used for wastewater treatment purposes.

(10) **"Working interest owner"** means the owner of an operating interest under an oil and gas lease who has the exclusive right to exploit the oil and gas minerals. Working interests are cost bearing.

(11) **"WQCC"** means the New Mexico water quality control commission.

[19.15.2.7 NMAC - Rp, 19.15.1.7 NMAC, 12/1/2008; A, 3/31/2015; A, 6/30/2016; A, 6/26/2018; A, 1/15/2019; A, 10/13/2020; A, 8/23/2022]

19.15.2.8 GENERAL OPERATIONS/WASTE PROHIBITED:

A. The production or handling of oil or gas of any type or in any form or the handling of oil or gas products in a manner, under conditions or in an amount as to constitute or result in waste is prohibited.

B. Operators, contractors, drillers, carriers, gas distributors, service companies, pipe pulling and salvaging contractors, treating plant operators or other persons shall conduct their operations in or related to the drilling, equipping, operating, producing, plugging and abandonment of oil, gas, injection, disposal and storage wells or other facilities in a manner that prevents waste of oil and gas, the contamination of fresh waters and shall not wastefully utilize oil or gas or allow either to leak or escape from a natural reservoir or from wells, tanks, containers, pipe or other storage, conduit or operating equipment.

[19.15.2.8 NMAC - Rp, 19.15.1.13 NMAC, 12/1/2008]

19.15.2.9 ORDERS: The division or commission may issue orders, including division or commission special pool orders when required and the orders shall prevail against rules if in conflict with them.

[19.15.2.9 NMAC - Rp, 19.15.1.11 NMAC, 12/1/2008]

19.15.2.10 ONLINE APPLICATION AND SUBMITTALS:

A. The division shall establish online application and submittal procedures on the division's website for the electronic filing of all forms, applications and other written documents and information with the division.

B. All applications that require the payment of a fee, as provided in Section 70-2-39 NMSA 1978, shall include the fee payment with the application.

C. A person whose filing is made untimely due to a technical failure of the division's web-based online application process may request an extension of time. Technical failures not originating with the division's process, such as problems with the filer's equipment, software, or telecommunications facility will not constitute a basis for relief.

[19.15.2.10 NMAC - N, 8/23/2022]

19.15.2.11 EMERGENCY ORDERS AND RULES:

A. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, in the event the division or commission finds an emergency exists that requires an order's or rule's issuance without a hearing, the emergency rule or order shall have the same validity as if the division or commission held a hearing before the division or commission after due notice. The emergency rule or order shall remain in force no longer than 15 days from its effective date.

B. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, if the division or commission finds an emergency exists, the division or commission may conduct a hearing on an application within less than 30 days after party files an application and the director may set the notice period at the director's discretion.

[19.15.2.11 NMAC - Rp, 19.15.14.1225 NMAC, 12/1/2008]

19.15.2.12 FILING AND NOTIFICATION: All requirements in the rules:

A. to file a form or application with the division or commission, including documents required to be filed with district offices or the Santa Fe office, shall be accomplished by using the applicable online process on the division's website,

B. to otherwise notify, advise, contact, or report to the division, including to any unit of the division (such as a bureau or office) or any division official (such as the director or a bureau chief), may be accomplished by electronic mail or as otherwise provided on the division's website; the division shall provide contact instructions on the division's website, and

C. to file an original financial assurance instrument with the division as provided in 19.15.8 NMAC shall require delivery to the Santa Fe office unless otherwise directed by the division.

[19.15.2.12 NMAC - Rp, 19.15.15.1304 NMAC, 12/1/2008; 19.15.2.12 NMAC - Rp, 19.15.2.12 NMAC, 8/23/2022]

19.15.2.13 COMPUTATION OF TIME: In computing a period of time prescribed by the Oil and Gas Act, the rules or an order, the division and commission shall comply with the Uniform Statute and Rule Construction Act, Section 12-2A-7 NMSA 1978.

[19.15.2.13 NMAC - Rp, 19.15.14.1226 NMAC, 12/1/2008; A, 8/23/2022]

19.15.2.14 MEETINGS BY TELECONFERENCE: Pursuant to Section 10-15-1 NMSA 1978, commission members may participate in commission meetings and hearings by conference telephone or other

similar communications equipment when it is otherwise difficult or impossible for members to attend the meeting or hearing in person. Each member participating by conference telephone or other similar communications equipment shall be identified when speaking. Participants shall be able to hear each other at the same time. Members of the public hearing attending the meetings or hearing shall be able to hear commission members who speak during the meeting or hearing.
[19.15.2.14 NMAC - Rp, 19.15.1.20 NMAC, 12/1/2008]

19.15.2.15 AUTHORITY TO COOPERATE WITH OTHER AGENCIES: The division may from time to time enter into arrangements with state and federal governmental agencies, industry committees and individuals with respect to special projects, services and studies relating to oil and gas conservation and the associated protection of fresh waters.
[19.15.2.15 NMAC - Rp, 19.15.1.17 NMAC, 12/1/2008]

19.15.2.16 DUTIES AND AUTHORITY OF DIVISION PERSONNEL: Division personnel have the authority and duty to enforce division rules. Upon a showing by an operator that changes are necessary to avoid waste or protect public health or the environment, division personnel may allow minor deviations from approved field operational plans such as drilling and plugging plans. The operator shall file a Form C-103 as a notice of intention showing the change of plans within two business days of the approval.
[19.15.2.16 NMAC - Rp, 19.15.15.1303, 12/1/2008; A, 8/23/2022]

19.15.2.17 ORGANIZATIONAL UNITS: When necessary to assist in the administration of the Oil and Gas Act, the director may divide the state into districts or other organizational units as appropriate. Upon establishment of, or revisions to, such units, the director shall provide or amend a map on the division's website with the boundaries of the units. Contact information for the units, including any assigned personnel, shall be maintained on the division's website.
[19.15.2.17 NMAC - Rp, 19.15.15.1301 NMAC, 12/1/2008; 19.15.2.17 NMAC - Rp, 19.15.2.17 NMAC, 8/23/2022]

19.15.2.18 RENUMBERING OR REORGANIZATION OF RULES: When the commission approves reorganization or renumbering of division rules, either through amendment or repeal and replacement, persons with permits, orders or agreements that reference rules that have been reorganized or renumbered shall comply with the rules as reorganized or renumbered.
[19.15.2.18 NMAC - N, 12/1/2008]

HISTORY of 19.15.2 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001); 19.15.14 NMAC, Procedure (filed 09/16/2005); and 19.15.15 NMAC, Administration (filed 07/12/2004) all repealed 12/1/2008.

NMAC History:
Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 1-7, 11, 13, 17, & 20) (filed 04/27/2001); 19.15.14 NMAC, Procedure (Sections 1225 and 1226) (filed 09/16/2005); and 19.15.15 NMAC, Administration (Sections 1301 and 1303) (filed 07/12/2004) were replaced by 19.15.2 NMAC, General Provisions for Oil and Gas Operations, effective 12/1/2008.

EXHIBIT 1-B

APPLICANTS' PROPOSED REVISED AMENDMENTS TO 19.15.5 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 5 ENFORCEMENT AND COMPLIANCE

19.15.5.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.5.1 NMAC - N, 12/1/2008]

19.15.5.2 SCOPE: 19.15.5 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.5.2 NMAC - N, 12/1/2008]

19.15.5.3 STATUTORY AUTHORITY: 19.15.5 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12, Section 70-2-31 and Section 70-2-31.1 NMSA 1978.
[19.15.5.3 NMAC – N, 12/1/2008, A, 2/25/2020]

19.15.5.4 DURATION: Permanent.
[19.15.5.4 NMAC - N, 12/1/2008]

19.15.5.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.5.5 NMAC - N, 12/1/2008]

19.15.5.6 OBJECTIVE: To establish a process to ensure compliance with the Oil and Gas Act, division rules and division and commission orders.
[19.15.5.6 NMAC - N, 12/1/2008]

19.15.5.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.5.8 ENFORCEMENT OF STATUTES AND RULES: The division is charged with the duty and obligation of enforcing the state's rules and statutes relating to the conservation of oil and gas, including the prevention of waste and the protection of correlative rights, and the protection of public health and the environment. An owner or operator shall obtain information pertaining to the regulation of oil and gas before beginning operations.
[19.15.5.8 NMAC - Rp, 19.15.1.12 NMAC, 12/1/2008, A, 2/25/2020]

19.15.5.9 COMPLIANCE:

A. An operator is in compliance with Subsection A of 19.15.5.9 NMAC if the operator:

(1) currently meets the financial assurance requirements of 19.15.8 NMAC;

(2) is not subject to a division or commission order, issued after notice and hearing, finding the operator to be in violation of an order requiring corrective action;

(3) does not have a penalty assessment that is unpaid more than 30 days after issuance of the order assessing the penalty; ~~and~~

(4) currently meets the requirements of 19.15.25.8 NMAC; and ~~has no more than the following number of wells out of compliance with 19.15.25.8 NMAC that are not subject to an agreed compliance or final order setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met:~~

~~**(a)** two wells or fifty percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;~~

~~**(b)** five wells if the operator operates between 101 and 500 wells;~~

~~**(c)** seven wells if the operator operates between 501 and 1000 wells; and~~

~~**(d)** 10 wells if the operator operates more than 1000 wells.~~

(5) currently meets the requirements of 19.15.27.A.8 NMAC.

B. Inactive wells.

(1) The division shall make available on its website, and update daily, an "inactive well list" listing each well, by operator, that according to division records:

(a) shows no production or injection for past 15 months;

(b) does not have its well bore plugged in accordance with 19.15.25.9 NMAC

through 19.15.25.11 NMAC;

(c) is not in approved temporary abandonment in accordance with 19.15.25.12 NMAC through 19.15.25.14 NMAC; and

(d) is not subject to an agreed compliance or final order setting a schedule for bringing the well into compliance with 19.15.25.8 NMAC.

(2) A well inactive for more than 13~~15~~ months creates a rebuttable presumption that the well is out of compliance with 19.15.25.8 NMAC.

C. Financial assurance. The division shall make available on its website and update weekly the status of operators' financial assurance that 19.15.8 NMAC requires, according to division records.

[19.15.5.9 NMAC - Rp, 19.15.1.40 NMAC, 12/1/2008; A, 11/30/2016, A, 2/25/2020]

19.15.5.10 ENFORCEMENT:

A. General. Whenever the division determines that a person violated or is violating the Oil and Gas Act or a provision of any rule, order, permit or authorization issued pursuant to the Oil and Gas Act, the division may seek a sanction by:

(1) issuing a temporary cessation order if it determines that the alleged violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The temporary cessation order shall remain in place until the earlier of when the division determines that the alleged violation is abated or 30 days, unless a hearing is held before the division and a new order is issued;

(2) issuing a notice of violation; or

(3) commencing a civil action in district court.

B. Sanctions. The division may seek one or more of the following sanctions:

(1) a civil penalty;

(2) modification, suspension, cancellation or termination of a permit or authorization;

(3) plugging and abandonment of a well;

(4) remediation and restoration of a well location and associated facilities, including the removal of surface and subsurface equipment and other materials;

(5) remediation and restoration of a location affected by a spill or release;

(6) forfeiture of financial assurance;

(7) shutting in a well or wells; and

(8) any other remedy authorized by law.

C. Notice of violation.

(1) A notice of violation issued by the division shall state with reasonable specificity:

(a) the identity of the alleged violator;

(b) the nature and factual and legal basis of the alleged violation, including the provision of the Oil and Gas Act or rule, order, permit or authorization allegedly violated;

(c) whether compliance is required immediately or within a specified time period;

(d) the sanction(s) available for the alleged violation, the sanction(s) proposed by the division, and a statement that the division will take into consideration the violators good faith efforts to comply with the applicable requirements;

(e) the availability of a process for informal review and resolution of the alleged violation, and the procedure to initiate the informal review process, including the contact information of the appropriate division employee;

(f) a statement that if the notice of violation is not informally resolved within 30 days of service, the division will hold a hearing, but that the hearing shall not prohibit the parties from negotiating and settling the notice of violation at any time; and

(g) the date of the hearing, which shall be no later than 90 days after the date of the notice of violation.

(2) The division shall serve the notice of violation on the alleged violator by certified mail, and may provide the notice of violation by electronic mail if possible.

(3) If during the informal review the division and the alleged violator agree to resolve the alleged violation, they shall incorporate their agreement into a stipulated final order signed by both parties. The stipulated final order shall state that the alleged violator admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives the alleged violator's right of review by the commission.

(4) If the division and the alleged violator fail to enter a stipulated final order within 30 days

of service, the division shall hold a hearing at the division's principal office.

D. Civil penalties. A civil penalty assessed by the division shall account for the seriousness of the violation, good faith efforts to comply with the applicable requirement, history of noncompliance under the Oil and Gas Act and other relevant factors. The civil penalty assessed by the division shall not exceed $2,500 per day of noncompliance for each alleged violation, unless the alleged violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond the time specified in the notice of violation or stipulated final order, whereupon the civil penalty may not exceed $10,000 per day of noncompliance for each alleged violation, provided that the civil penalty assessed by the division for an alleged violation shall not exceed $200,000.

E. Adjudicatory procedures. These adjudicatory procedures shall apply to hearings on temporary cessation orders and notices of violation before the division, and the provisions of 19.15.4 NMAC shall not apply.

(1) General provisions.

(a) Designation of parties. The parties shall be the division and the person served with a notice of violation or order, referred to herein as "respondent".

(b) Representation. Respondent may appear and participate in a hearing either pro se or through counsel, provided that a collective entity, including a corporation, partnership, unincorporated association, political subdivision or governmental agency shall appear only through counsel or a duly authorized officer or member.

(c) Rule applicability. In the absence of a specific provision in this section, the hearing examiner may apply the New Mexico rules of civil procedure and evidence.

(d) Computation of time. In computing any period of time under 19.15.5.10 NMAC the day of the event from which the designated period begins to run shall not be included, and the last day of the computed period shall be included, unless it is a Saturday, Sunday or legal state holiday, in which case the time is extended until the next day which is not a Saturday, Sunday or legal state holiday. Whenever a party must act within a prescribed period after service, and service is by first class mail only, three days is added to the prescribed period.

(e) Extensions of time. The hearing examiner may grant an extension of time to file a document or continue a hearing upon timely motion upon consent of the parties, or for good cause shown after consideration of prejudice to the other party and undue delay to the hearing.

(f) Filing of documents. A party shall file the original of each document and serve a copy on the other party, accompanied by a certificate of service identifying the method and address used to complete service.

(g) Service of documents. A party shall serve each document on the other party or its counsel, as applicable, by personal service or first class mail, or by electronic mail if the parties agree.

(h) Form of documents. Unless otherwise ordered, all documents, except exhibits, shall be on 8 1/2 x 11-inch white paper, shall contain the caption of the notice of violation or temporary cessation order on the first page and shall be signed by the party or its counsel, as applicable.

(2) Pre-hearing procedures.

(a) Docketing. At the expiration of the 30 day period for informal resolution of a notice of violation, when a party appeals a final order under Subsection E of 19.15.5.10 NMAC, or when the division gives notice that it intends to extend a temporary cessation order, the division shall docket the notice of violation or order for hearing, identify the factual basis for the alleged violation and proposed sanction(s), and serve a notice of docketing on respondent.

(b) Answer. No later than 10 days after service of the notice of docketing, respondent shall file an answer stating its objection, if any, and the factual and legal basis for such objection, to each alleged violation and proposed sanction in the notice of violation or order.

(c) Hearing examiner. The hearing examiner shall have the authority to take all measures necessary to conduct a fair, impartial and efficient adjudication of issues, and to maintain order and avoid undue delay, including the authority to conduct pre-hearing conferences and hearings, rule on procedural and evidentiary motions, govern the examination of witnesses and the admission of evidence, issue orders and prepare a recommended decision. After the division issues the notice of violation, the hearing examiner shall not discuss ex parte the merits of the proceeding with the division or the respondent.

(d) Pre-hearing conference. The hearing examiner may hold a pre-hearing conference to narrow the issues, eliminate or resolve preliminary matters and encourage settlement, and may issue a pre-hearing order on procedural and evidentiary matters, including a schedule for the filing of motions and testimony, stipulations regarding alleged violations and requested relief, including proposed civil penalties or

elements thereof, and any other matter necessary for the efficient conduct of the hearing.

(e) Pre-hearing statements. No later than seven calendar days before the hearing, a party who intends to present evidence at the hearing shall file and serve a statement that contains the following information:

(i) the name, address, employment and qualifications, including education and work history, of each witness;

(ii) a statement identifying the opinions and factual assertions supporting each witness' testimony;

(iii) the exhibits and other evidence to be presented by each witness; and

(iv) procedural matters that are to be resolved prior to the hearing.

(f) Enforcement. The hearing examiner may enforce the requirements of 19.15.5.10 NMAC by any appropriate means, including the exclusion of testimony, exhibits and other evidence.

(g) Motions.

(i) General. All motions, except motions made orally during the hearing, shall be in writing, specify the grounds for the motion, state the relief sought, indicate whether the motion is opposed or unopposed and be served on the other party.

(ii) Unopposed motions. An unopposed motion shall state that concurrence of the other party was obtained and shall be accompanied by a proposed order approved by the parties.

(iii) Opposed motions. An opposed motion shall state either that concurrence was sought and not obtained, or the reason that concurrence was not sought.

(iv) Response. No later than 10 days after service of an opposed motion, the opposing party may file a response. Failure to file a response shall be deemed a waiver of any objection to the granting of the motion.

(v) Reply. No later than 10 days after service of a response to an opposed motion, the moving party may file a reply.

(vi) Decision. The hearing examiner shall decide all motions without a hearing, unless otherwise ordered by the hearing examiner sua sponte or upon written request of a party.

(h) Shortening Deadlines. On the written request of the alleged violator showing good cause, the hearing examiner may shorten the deadlines specified in Paragraph (2) of Subsection E of 19.15.10 NMAC to conduct the hearing on the division's application for a temporary cessation order as expeditiously as possible. If the division opposes the request to shorten deadlines, the procedures for opposed motions set forth in Subparagraph (g) of Paragraph (2) of Subsection G of 19.15.5.10 NMAC shall not apply and the hearing examiner shall decide the request, with or without hearing, as quickly as practicable.

(3) Hearing procedures.

(a) General. The hearing examiner shall admit all evidence, unless he or she determines that the evidence is irrelevant, immaterial, unduly repetitious or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded by the New Mexico rules of evidence is not admissible.

(b) Witness examination. Witnesses shall be examined orally and under oath or affirmation, provided that the parties may stipulate to the admission of the testimony of a witness, or part thereof. Parties shall have the right to cross-examine a witness, provided that the hearing examiner may limit cross-examination that is unduly repetitious, harassing or beyond the scope of the direct testimony.

(c) Exhibits. A party shall label each exhibit used during the hearing or offered into evidence with a designation identifying the party, the witness using or offering the exhibit and a serial number.

(d) Burden of persuasion. The division has the burden of going forward with the evidence and of proving by a preponderance of the evidence the facts relied upon to show the alleged violation occurred and that the proposed civil penalty is appropriate. Following the establishment of a prima facie case, respondent shall have the burden of going forward with any adverse evidence or defense to the allegations.

(4) Post-hearing procedures.

(a) Transcript. The hearing shall be transcribed verbatim. Respondent may order a copy of the transcript from the reporter at its own expense.

(b) Recommended decision. The hearing examiner shall prepare a recommended decision for review by the director.

(c) Final order. The director shall file a final order addressing the material issues of fact and law and may assess a sanction for each alleged violation, which shall be served on the division and the respondent.

F. Commission review. No later than 30 days after the director serves the final order, a party may file a notice of appeal with the commission and shall serve the notice of appeal on the other party. The commission shall schedule a hearing on the appeal and notify the parties of the date and time of the hearing. The commission shall conduct a de novo review, provided however, that the parties may stipulate to the issues to be heard and to the admission of all or part of the record before the division. The commission shall conduct the hearing in accordance with the adjudicatory procedures in Paragraph (1), Subparagraphs (c) through (g) of Paragraph (2), Paragraph (3) and Subparagraph (a) of Paragraph (4) of Subsection E of 19.15.5.10 NMAC.

G. Rehearings. A party may file an application for rehearing with the commission pursuant to Section 70-2-25 NMSA 1978.

H. Payment of civil penalty. Respondent shall pay the full amount of the civil penalty assessed in the final order (i) no later than 30 days after the director serves the final order, or (ii) if respondent files a notice of appeal to the commission or the district court pursuant to Section 70-2-25 NMSA 1978, no later than 30 days after the commission or the district court files a final order or the appeal is withdrawn.

I. Resolution after commencement of hearing. If the parties agree to resolve a notice of violation at any time after the commencement of a hearing, they shall file a stipulated final order signed by both parties. The stipulated final order shall state that respondent admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives respondent's right of review by the commission or the court, as applicable.

J. Publication. On or about October 1 of each year, the division shall publish a list identifying the temporary cessation orders and notices of violation issued during the preceding year, along with the civil penalty paid, if any.

K. Reservation. Nothing in 19.15.5.10 NMAC precludes the division from bringing any other action and seeking any relief allowed by the Oil and Gas Act.

[19.15.5.10 NMAC – Rp, 19.15.5.10 NMAC, 2/25/2020]

19.15.5.11 **ENFORCEABILITY OF PERMITS AND ADMINISTRATIVE ORDERS:** A person who conducts an activity pursuant to a permit, administrative order or other written authorization or approval from the division shall comply with every term, condition and provision of the permit, administrative order, authorization or approval.

[19.15.5.11 NMAC - Rp, 19.15.1.41 NMAC, 12/1/2008]

HISTORY of 19.15.5 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001) and 19.15.14 NMAC, Procedure (filed 09/16/2005) repealed 12/1/2008.

NMAC History:

Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 12, 40 & 41) (filed 04/27/2001) and 19.15.14 NMAC, Procedure (Section 1227) (filed 09/16/2005), were replaced by 19.15.5 NMAC, Enforcement and Compliance, effective 12/1/2008.

EXHIBIT 1-C

APPLICANTS' PROPOSED REVISED AMENDMENTS TO 19.15.8 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 8 FINANCIAL ASSURANCE

19.15.8.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.8.1 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.2 SCOPE: 19.15.8 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.8.2 NMAC - N, 12/1/2008]

19.15.8.3 STATUTORY AUTHORITY: 19.15.8 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12 and Section 70-2-14 NMSA 1978.
[19.15.8.3 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.4 DURATION: Permanent.
[19.15.8.4 NMAC - N, 12/1/2008]

19.15.8.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.8.5 NMAC - N, 12/1/2008]

19.15.8.6 OBJECTIVE: To establish financial assurance requirements for persons, firms, corporations or associations who have drilled or acquired, are drilling or propose to drill or acquire an oil, gas or injection or other service well to furnish financial assurance acceptable to the division.
[19.15.8.6 NMAC - N, 12/1/2008]

19.15.8.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.8.8 GENERAL REQUIREMENTS FOR FINANCIAL ASSURANCE:

A. The operator shall file financial assurance documents with the division's Santa Fe office and obtain approvals and releases of financial assurance from that office.

B. Financial assurance documents shall be on forms prescribed by or otherwise acceptable to the division.

C. The division may require proof that the individual signing for an entity on a financial assurance document or an amendment to a financial assurance document has the authority to obligate that entity.

D. Any time an operator changes the corporate surety, financial institution or amount of financial assurance, the operator shall file updated financial assurance documents on forms prescribed by the division. Notwithstanding the foregoing, if an operator makes other changes to its financial assurance documents, the division may require the operator to file updated financial assurance documents on forms prescribed by the division.
[19.15.8.8 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.9 CATEGORIES AND AMOUNTS OF FINANCIAL ASSURANCE FOR WELL PLUGGING:

A. Applicability. An operator who has drilled or acquired, is drilling or proposes to drill or acquire an oil, gas or injection or other service well within this state shall furnish a financial assurance acceptable to the division in accordance with 19.15.8.9 NMAC and in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico conditioned that the well be plugged and abandoned and the location restored and remediated in compliance with commission rules, unless the well is covered by federally required financial assurance. The division shall not approve, and the operator shall not proceed with any proposed drilling or acquisition until the operator has furnished the required financial assurance.

B. A financial assurance shall be conditioned for well plugging and abandonment and location restoration and remediation only, and not to secure payment for damages to livestock, range, crops or tangible improvements or any other purpose.

C. Active wells. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsections D and E of 19.15.8.9 NMAC in one of the following categories:

(1) a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance in the amount of $250,000 ~~following amounts~~ covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC.~~:~~

~~**(a)** $50,000 for one to 10 wells;~~
~~**(b)** $75,000 for 11 to 50 wells;~~
~~**(c)** $125,000 for 51 to 100 wells; and~~
~~**(d)** $250,000 for more than 100 wells.~~

D. Marginal wells and inactive wells. Notwithstanding the provisions in Subsection C(2) in this Section:

(1) As of the [effective date of amendments] a transferee operator shall provide a one well plugging financial assurance of $150,000 for each marginal well prior to transfer.

(2) Beginning January 1, 2028, an operator shall provide a one well plugging financial assurance for each marginal well.

(3) An operator with 15 percent or more of their wells in marginal or inactive well status, or a combination thereof, shall provide a one well plugging financial assurance in the amount of $150,000 for each well registered to the operator until the percentage of the operator's marginal and inactive wells is decreased below 15 percent.

(4) An operator may furnish all necessary one well plugging financial assurance in the form of a single instrument.

E.~~D.~~ Inactive wells and wells in approved and expired temporarily abandoned status. An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories:

(1) a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E~~D~~ of 19.15.8.9 NMAC.~~:~~

~~**(e)** $150,000 for one to five wells;~~
~~**(f)** $300,000 for six to 10 wells;~~
~~**(g)** $500,000 for 11 to 25 wells; and~~
~~**(h)** $1,000,000 for more than 25 wells.~~

F.~~D.~~ Operators who have on file with the division a blanket plugging financial assurance that does not cover additional wells shall file additional one ~~single~~ well plugging ~~bond~~ financial assurance for any wells not covered by the existing blanket plugging financial assurance ~~bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978.~~or, in the alternative, may file a replacement blanket bond.~~

G. On January 1, 2028 and on January 1 of each successive year, the division may adjust the financial assurance amounts provided by Subsections C(1), D, E and F of this Section by multiplying the financial assurance as of January 1, 2027 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2026; provided that any financial assurance shall not be adjusted below the minimum amounts required in Subsections C(1), D, E and F of this Section as a result of a decrease in the consumer price index. By November 1, 2027 and by November 1 of each successive year, the division shall post on its website the financial assurance requirements in Subsection A through E of this Section for the next year. As used in this subsection, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a 12 month period ending September 30.

[19.15.8.9 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015; A, 1/15/2019]

19.15.8.10 ADDITIONAL REQUIREMENTS FOR CASH AND SURETY BONDS:

A. Surety bonds shall be issued by a reputable corporate surety authorized by the office of the superintendent of insurance to do business in the state. The surety shall be listed on U.S. department of the treasury circular 570.

B. The operator shall deposit cash representing the full amount of the bond in an account in a

federally-insured financial institution located within the state, such account to be held in trust for the division. Authorized representatives of the operator and the depository institution shall execute a document evidencing the cash bond's terms and conditions. The operator shall file the document with the division prior to the bond's effective date. If the operator's financial status or reliability is unknown to the director, the director may require the filing of a financial statement or such other information as may be necessary to evaluate the operator's ability to fulfill the bond's conditions. From time to time, any accrued interest over and above the bond's face amount may be paid to the operator.
[19.15.8.10 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.11 ADDITIONAL REQUIREMENTS FOR LETTERS OF CREDIT:

A. The division may accept irrevocable letters of credit issued by national or state-chartered banking associations.

B. Letters of credit shall be irrevocable for a term of not less than five years, unless the applicant shows good cause for a shorter time period.

C. Letters of credit shall provide for automatic renewal for successive, like terms upon expiration, unless the issuer has notified the division in writing of non-renewal at least 30 days prior to expiration.

D. The division may forfeit and collect a letter of credit if not replaced by an approved financial assurance at least 30 days before the expiration date.

E. Authorized representatives of the operator and the depository institution shall execute a document evidencing the letter of credit's terms and conditions.
[19.15.8.11 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.12 RELEASE OF FINANCIAL ASSURANCE:

A. The division shall release a financial assurance document upon the operator's or surety's written request if all wells drilled or acquired under that financial assurance have been plugged and abandoned and the location restored and remediated and released pursuant to 19.15.25.9 NMAC through 19.15.25.11 NMAC, or have been covered by another financial assurance the division has approved.

B. Transfer of a property or a change of operator does not of itself release a financial assurance. The division shall not approve a request for change of operator for a well until the new operator has the required financial assurance in place and is otherwise in compliance with the requirements of 19.15.5.9 NMAC and 19.15.9.9 NMAC.
[19.15.8.12 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.13 FORFEITURE OF FINANCIAL ASSURANCE:

A. Upon the operator's failure to properly plug and abandon and restore and remediate the location of a well or wells a financial assurance covers, the division shall give notice to the operator and surety, if applicable, and hold a hearing as to whether the well or wells should be plugged and abandoned and the location restored and remediated in accordance with a division-approved plugging program. If it is determined at the hearing that the operator has failed to plug and abandon the well and restore and remediate the location as provided for in the financial assurance or division rules, the director shall issue an order directing the well to be plugged or abandoned and the location restored and remediated in a time certain. Such an order may also direct the forfeiture of the financial assurance upon the failure or refusal of the operator, surety or other responsible party to properly plug and abandon the well and restore and remediate the location.

B. If the financial assurance's proceeds exceed the costs the division incurred plugging and abandoning the well and restoring and remediating the location the financial assurance covers, the division shall return the excess to the surety or the operator, as appropriate.

C. If the financial assurance's proceeds are not sufficient to cover all the costs the division incurred in plugging and abandoning the well and restoring and remediating the location, the division may seek indemnification from the operator as provided in Subsection E of Section 70-2-14 NMSA 1978.

D. The division shall deposit forfeitures and funds collected pursuant to a judgment in a suit for indemnification in the oil and gas reclamation fund.
[19.15.9.13 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.14 EFFECTIVE DATES.

A. 19.15.8 NMAC applies to wells drilled or acquired after December 15, 2005.

B. As to all other wells, 19.15.8 NMAC is effective January 1, 2008.

C. The 2018 amendments to 19.15.8.9 NMAC apply to applications for permits to drill, deepen or plug back and applications for approved temporary abandonment filed on or after January 15, 2019, and for all other

wells on April 15, 2019.
[19.15.8.14 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 1/15/2019]

19.15.8.15 ADDITIONAL REQUIREMENTS FOR PLUGGING INSURANCE POLICIES:

A. The plugging insurance policy must be issued by a company authorized by the office of the superintendent of insurance to do business in New Mexico.

B. The policy shall name a specific well and name the state of New Mexico as the owner of the policy and contingent beneficiary.

C. The policy shall name a primary beneficiary who agrees to plug the specified wellbore.

D. The policy shall be fully prepaid and cannot be canceled or surrendered.

E. The policy shall continue in effect until the specified wellbore has been plugged.

F. The policy shall provide that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with division rules in effect at the time of plugging.

G. The policy shall provide benefits that are not less than an amount equal to the one-well financial assurance required by division rules. If, subsequent to an operator obtaining an insurance policy, the one-well financial assurance requirement applicable to the operator's well covered by said policy increases, either because the well is deepened or the division's rules are amended, the operator will meet the additional financial assurance requirement by complying with one of the requirements below.

(1) The operator's existing policy benefit equals or exceeds the revised requirement.

(2) The operator obtains and files with the division within 30 days an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement.

19.15.8.16 The operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit and files said financial assurance with the division within 30 days. [19.15.8.15 NMAC - N, 6/30/2015]

19.15.8.17 DUTY TO REPORT: Any operator who filed for bankruptcy shall provide notice to the division, in writing, through the processes provided for under the rules of the United States bankruptcy court. [19.15.8.16 NMAC - N, 6/30/2015]

HISTORY of 19.15.8 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/2008.

NMAC History:
That applicable portion of 19.15.3 NMAC, Drilling (Section 101) (filed 10/29/2001) was replaced by 19.15.8 NMAC, Financial Assurance, effective 12/1/2008.

EXHIBIT 1-D

APPLICANTS' PROPOSED REVISED AMENDMENTS TO 19.15.9 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 9 WELL OPERATOR PROVISIONS

19.15.9.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.9.1 NMAC - N, 12/1/08]

19.15.9.2 SCOPE: 19.15.9 NMAC applies to persons or entities operating oil or gas wells within New Mexico.
[19.15.9.2 NMAC - N, 12/1/08]

19.15.9.3 STATUTORY AUTHORITY: 19.15.9 NMAC is adopted pursuant to the Oil and Gas Act, NMSA 1978, Section 70-2-6, Section 70-2-11 and Section 70-2-12.
[19.15.9.3 NMAC - N, 12/1/08]

19.15.9.4 DURATION: Permanent.
[19.15.9.4 NMAC - N, 12/1/08]

19.15.9.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section. [19.15.9.5 NMAC - N, 12/1/08]

19.15.9.6 OBJECTIVE: To require an operator of a well or wells to register with the division prior to commencing operations and to require the reporting of a change of operator or a change of name to the division. [19.15.9.6 NMAC - N, 12/1/08]

19.15.9.7 DEFINITIONS:[RESERVED]
[See 19.15.2 NMAC for definitions.]
[19.15.9.7 NMAC - N, 12/1/08]

19.15.9.8 OPERATOR REGISTRATION:

A. Prior to commencing operations, an operator of a well or wells in New Mexico shall register with the division as an operator. Applicants shall provide the following to the financial assurance administrator in the division's Santa Fe office:

(1) an oil and gas registration identification (OGRID) number obtained from the division, the state land office or the taxation and revenue department;

(2) a current address of record to be used for notice and a current emergency contact name and telephone number for each district in which the operator operates wells; and

(3) the financial assurance 19.15.8 NMAC requires.

B. Prior to commencing operations, an operator shall provide to the division a certification by an officer, director, or partner that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC.

~~B.~~**C.** The division may deny registration as an operator if:

(1) the applicant is not in compliance with Subsection A of 19.15.5.9 NMAC;

(2) the applicant is out of compliance with federal and state oil and gas laws and regulations in each state in which the applicant does business;

(~~2~~3) an officer, director, partner in the applicant or person with an interest in the applicant exceeding 25 percent, is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(~~3~~4) the applicant is or was within the past five years an officer, director, partner or person

with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; or

(45) the applicant is a corporation, ~~or~~ limited liability company, or limited partnership and is not registered or is not in good standing with the New Mexico secretary of state ~~public regulation commission~~ to do business in New Mexico.~~; or~~

~~**(5)** the applicant is a limited partnership and is not registered with the New Mexico secretary of state to do business in New Mexico.~~

~~C.~~D. An operator shall inform the division of its current address of record and emergency contact names and telephone numbers by submitting changes in writing to the division's financial assurance administrator in the division's Santa Fe office within 30 days of the change.

~~D.~~E. ~~The division may require an~~ An operator shall ~~or applicant to~~ certify compliance annually of ~~identify~~ its current and past officers, directors and partners and its current and past ownership interest in other operators consistent with 19.15.9.8.C(2) and (3) NMAC.

[19.15.9.8 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.9 CHANGE OF OPERATOR:

A. A change of operator occurs when the entity responsible for a well or a group of wells changes. A change of operator may result from a sale, assignment by a court, a change in operating agreement or other transaction. Under a change of operator, wells are moved from the OGRID number of the operator of record with the division to the new operator's OGRID number.

B. The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an officer, director, or partner of the new operator that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a plugging and abandonment plan; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator. The plugging and abandonment plan shall be certified by an officer, director, or partner of the new operator and shall demonstrate that the new operator has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells to be transferred in light of all the operator's assets and liabilities. The division may request the operator to provide additional information including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics report, records of the operator's historical costs for decommissioning activities, estimate of the operator's decommissioning obligations, and history of inactive wells and returning wells to production.

C. The director of the director's designee may deny a change of operator if:

(1) the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC; ~~or~~

~~**(2)** the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order.~~

(2) the new operator is out of compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business;

(3) any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(4) the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(5) the applicant is a corporation, limited liability company, or limited partnership and is not registered or is not in good standing with the New Mexico secretary of state to do business in New Mexico; or

(6) the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

D. In determining whether to grant or deny a change of operator when the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC, the director or the director's designee shall consider such factors as whether the non-compliance with Subsection A of 19.15.5.9 NMAC is caused by the operator not meeting the financial assurance requirements of 19.15.8 NMAC, being subject to a division or commission order finding the operator to be in violation of an order requiring corrective action, having a penalty assessment that has been unpaid for more than 70 days since the issuance of the order assessing the penalty or having ~~more than the allowed number of~~ wells out of compliance with 19.15.25.8 NMAC. If the non-compliance is caused by the operator having ~~more than the allowed number of~~ wells not in compliance with 19.15.25.8 NMAC, the director or director's designee shall consider the number of wells not in compliance, the length of time the wells have been out of compliance and the operator's efforts to bring the wells into compliance.

E. No well, facility or site that is out of compliance with Subsection A of 19.15.5.9 NMAC, 19.15.29 NMAC, or 19.15.30 NMAC shall be transferred unless, prior to transfer, the current operator brings the associated well, facility or site into compliance or the new operator submits a schedule of compliance approved by the division.

[19.15.9.9 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.10 CHANGE OF NAME:

A. A change of operator name occurs when the name of the entity responsible for a well or wells changes but the entity does not change. For a change of name, the OGRID number remains the same, but division records are changed to reflect the new operator name.

B. An operator shall apply for a change of name by filing a form C-146 using the division's web-based online application and supplying documentary proof that the change is a name change and not a change of operator. If the operator is a corporation, limited liability company or limited partnership, the name must be registered with the public regulation commission or the New Mexico secretary of state, as applicable. The division shall not approve a change of name until the state land office and the taxation and revenue department have cleared the change of name on the OGRID.

[19.15.9.10 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.11 EXAMPLES OF CHANGE OF OPERATOR AND CHANGE OF NAME:

A. Mr. Smith, a sole proprietor, operates five wells under the name "Smith oil company". Mr. Smith changes the name of his company to "Smith production company". The name of the entity operating the wells has changed, but the entity has not changed. Mr. Smith should apply for a change of name.

B. Mr. Smith incorporates his business, changing from the sole proprietorship, "Smith production company", to a corporation: "Smith production company, inc.". The entity responsible for the wells has changed, and Mr. Smith and "Smith production company, inc." should apply for a change of operator.

C. Smith production company, inc., a New Mexico operator, merges with XYZ, inc., which does not operate in New Mexico. At the surviving entity's election, this transaction may be treated as a change of name from Smith production company, to XYZ, inc., maintaining the existing OGRID, or as a change of operator, with a new OGRID.

D. Two New Mexico operators, Smith production company, inc. and Jones production company, inc., merge. The surviving corporation is Jones production company, inc. A different entity now operates the wells Smith production company, formerly operated, and the wells must be placed under that entity's OGRID. Jones production company, inc. and Smith production company, inc. should apply for a change of operator as to the wells Smith production company, inc. operated.

[19.15.9.11 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

HISTORY of 19.15.9 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/08.

NMAC History:
That applicable portion of 19.15.3 NMAC, Drilling (Section 100) (filed 11/30/2005) was replaced by 19.15.9 NMAC, Well Operator Provisions, effective 12/1/08.

EXHIBIT 1-E

APPLICANTS' PROPOSED REVISED AMENDMENTS TO 19.15.25 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 25 PLUGGING AND ABANDONMENT OF WELLS

19.15.25.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.25.1 NMAC - Rp, 19.15.4.1 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.2 SCOPE: 19.15.25 NMAC applies to persons that operate oil or gas wells within New Mexico.
[19.15.25.2 NMAC - Rp, 19.15.4.2 NMAC, 12/1/2008]

19.15.25.3 STATUTORY AUTHORITY: 19.15.25 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-12 NMSA 1978, which authorizes the division to require dry or abandoned wells to be plugged so as to confine oil, gas or water in the strata in which they are found and to prevent them from escaping into other strata.
[19.15.25.3 NMAC - Rp, 19.15.4.3 NMAC, 12/1/2008]

19.15.25.4 DURATION: Permanent.
[19.15.25.4 NMAC - Rp, 19.15.4.4 NMAC, 12/1/2008]

19.15.25.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of asection.
[19.15.25.5 NMAC - Rp, 19.15.4.5 NMAC, 12/1/2008]

19.15.25.6 OBJECTIVE: To establish requirements for properly abandoning and plugging wells drilled for oil or gas or service wells including seismic, core, exploration or injection wells or placing the wells in temporary abandonment in order to protect public health, fresh water and the environment.
[19.15.25.6 NMAC - Rp, 19.15.4.6 NMAC, 12/1/2008]

19.15.25.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.25.8 WELLS TO BE PROPERLY ABANDONED:

A. The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.

B. The operator shall either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within ~~90~~ 30 days after:

(1) a 60 day period following suspension of drilling operations;

(2) a determination that a well is no longer usable for beneficial purposes; or

(3) a period of one year in which a well has been ~~continuously~~ inactive.

[19.15.25.8 NMAC - Rp, 19.15.4.201 NMAC, 12/1/2008]

19.15.25.9 PRESUMPTIONS OF NO BENEFICIAL USE:

A. For oil and gas production wells, there is a rebuttable presumption that a well is not capable of beneficial use if, in a consecutive 12 month period, the well has not produced for at least 90 days and has not produced at least 90 barrels of oil equivalent.

B. For injection or salt water disposal wells, there is a rebuttable presumption that a well is not capable of beneficial use if, in a consecutive 12 month period, the well has not injected at least 90 days and at least 100 barrels of fluid.

C. The rebuttable presumptions in this Section do not apply to wells that have been drilled but not completed for less than 18 months and wells that have been completed but have not produced for less than 18 months.

D. Within 30 calendar days after notice of a preliminary determination from the division that a well or wells are not being used for beneficial purposes, a well operator may submit an application for administrative review of such determination through the division's electronic permitting portal. The division shall issue a final determination based on the application and information available in division records. The final determination may be appealed pursuant to 19.15.4 NMAC. Applications to demonstrate beneficial use of a well or wells shall include:

(1) Documentation demonstrating that the well is reasonably projected to produce in paying quantities; and

(2) Documentation demonstrating that the operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all reasonably anticipated plugging and environmental liabilities of the well or wells and associated production facilities, not inclusive of any financial assurance associated with the well or wells; and

(3) Other relevant information requested by the division including a plugging and abandonment plan as described in 19.15.9.9.B NMAC.

19.15.25.9~~10~~ NOTICE OF PLUGGING:

A. The operator shall file notice of intention to plug with the division on form C-103 prior to commencing plugging operations. The notice shall provide all the information 19.15.7.14 NMAC requires including operator and well identification and proposed procedures for plugging the well.

B. In addition, the operator shall provide a well bore diagram showing the proposed plugging procedure.

C. The operator shall notify the division 24 hours prior to commencing plugging operations. In the case of a newly drilled dry hole, the operator may obtain verbal approval from the appropriate district supervisor or the district supervisor's representative of the plugging method and time operations are to begin. The operator shall file written notice in accordance with 19.15.25.11 NMAC with the division within 10 days after the district supervisor has given verbal approval.

[19.15.25.9 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.~~10~~11PLUGGING:

A. Before an operator abandons a well, the operator shall plug the well in a manner that permanently confines all oil, gas and water in the separate strata in which they are originally found. The operator may accomplish this by using mud-laden fluid, cement and plugs singly or in combination as approved by the division on the notice of intention to plug.

B. The operator shall mark the exact location of plugged and abandoned wells with a steel marker not less than four inches in diameter set in cement and extending at least four feet above mean ground level. The operator name, lease name and well number and location, including unit letter, section, township and range, shall be welded, stamped or otherwise permanently engraved into the marker's metal. A person shall not build permanent structures preventing access to the wellhead over a plugged and abandoned well without the division's written approval. A person shall not remove a plugged and abandonment marker without the division's written approval.

C. The operator may use below-ground plugged and abandonment markers only with the division's written approval when an above-ground marker would interfere with agricultural endeavors. The below-ground marker shall have a steel plate welded onto the abandoned well's surface or conductor pipe and shall be at least three feet below the ground surface and of sufficient size so that all the information 19.15.16.8 NMAC requires can be stenciled into the steel or welded onto the steel plate's surface. The division may require a re-survey of the well location.

D. As soon as practical, but no later than one year after the completion of plugging operations, the operator shall:

(1) level the location;

(2) remove deadmen and other junk; and

(3) take other measures necessary or required by the division to restore the location to a safe and clean condition.

E. The operator shall close all pits and below-grade tanks pursuant to 19.15.17 NMAC.

F. Upon completion of plugging and clean up restoration operations as required, the operator shall contact the appropriate division district office to arrange for an inspection of the well and location.

[19.15.25.10 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.~~11~~12 REPORTS FOR PLUGGING AND ABANDOMENT:

A. The operator shall file form C-105 as provided in 19.15.7.16 NMAC.

B. Within 30 days after completing required restoration work, the operator shall file with the division a record of the work done on form C-103 as provided in 19.15.7.14 NMAC.

C. The division shall not approve the record of plugging or release a bond until the operator has filed necessary reports and the division has inspected and approved the location.

[19.15.25.11 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.~~12~~13 APPROVED TEMPORARY ABANDONMENT:

A. The division may place a well in approved temporary abandonment for a period of up to five

years upon a demonstration from the operator that the well will be used for beneficial use within the approved period of temporary abandonment. The operator's demonstration shall include an explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future including supporting technical and economic data, a plan that describes the ultimate disposition of the well, the time frame for that disposition, and any other information the division determines appropriate, including a current and complete well bore diagram; geological evidence; geophysical data; well casing information; waste removal and disposition; production engineering; geophysical logs, e.g., cement bond logs, caliper logs, and casing inspection logs; and health, safety, and environmental information. If the division denies a request, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

B. Prior to the expiration of an approved temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves, permanently plug and abandon the well and restore and remediate the location, or apply ~~for a new approval to temporarily abandon the well~~ to the division to extend temporary abandonment status pursuant to the procedures for adjudicatory proceedings in 19.15.4 NMAC, except that in any such adjudicatory proceeding any interested person may intervene under 19.15.4.11.A NMAC. To continue in temporary abandonment, the operator must demonstrate to the division that the well will be returned to beneficial use within the requested period of temporary abandonment. The request shall include documentation demonstrating why the well should remain in temporary abandonment; documentation demonstrating why the well was not brought back to beneficial use or plugged and abandoned during the period of temporary abandonment; documentation demonstrating how the well will be put to beneficial use in the future and supporting technical and economic data; a plan that describes the ultimate disposition of the well, the time frame for that disposition; and a health and safety plan demonstrating the well's casing and cementing meet the requirements of Subsections B and C of Section 19.15.25.13 NMAC and the operator has adequate monitoring procedures in place to ensure such requirements will be met. An extended term shall not exceed two additional years, upon which time the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

C. An operator is limited to placing the following numbers of wells in approved temporary abandonment:

~~A.~~(1) one well, if the operator operates between one and five wells; or

~~B.~~(2) one-third of all wells (rounded to the nearest whole number), if the operator operates more than five wells.

D. Implementation schedule for existing wells.

(1) Inactive wells. Wells that have been inactive for less than three years are eligible for temporary abandonment status. Wells that have been inactive for three or more years are not eligible for temporary abandonment status.

(2) Wells in approved temporary abandoned status. Any operator of a well in temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status in accordance with Subsection B of this Section prior to the date temporary abandonment status terminates. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(3) Wells in expired temporary abandoned status. Any operator of a well in expired temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status in accordance with Subsection B of this Section. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

E. The timeframes Subsections A and B in this Section shall be implemented consistent with any applicable federal requirements.

[19.15.25.12 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.~~13~~14 REQUEST FOR APPROVAL AND PERMIT FOR APPROVED TEMPORARY ABANDONMENT:

A. An operator seeking approval for approved temporary abandonment shall submit the request on form C-103 ~~a notice of intent~~ to seek approved temporary abandonment for the well setting forth the demonstration required in 19.15.25.12 NMAC and describing the proposed temporary abandonment procedure the operator will use. The operator shall not commence work until the division has approved the request. The operator shall give 24 hours' notice to the appropriate division district office before beginning work.

B. The division shall not approve a permit for approved temporary abandonment until the operator

furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:

(1) damage to the producing zone;

(2) noncontainment of well bore fluids to the atmosphere or migration of hydrocarbons or water;

(3) the contamination of fresh water or other natural resources; and

(4) the leakage of a substance at the surface.

C. The operator shall demonstrate both internal and external mechanical integrity pursuant to Subsection A of 19.15.25.14 NMAC.

D. Upon successful completion of the work on the temporarily abandoned well, the operator shall submit a request for approved temporary abandonment to the appropriate division district office on form C-103 together with other information Subsection E of 19.15.7.14 NMAC requires.

E. The division shall not approve a permit for approved temporary abandonment until the operator provides financial assurance for the well that complies with Subsection D of 19.15.8.9 NMAC.

F. The division shall specify the permit's expiration date., ~~which shall be not more than five years from the date of approval.~~

[19.15.25.13 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.~~14~~15 DEMONSTRATING MECHANICAL INTEGRITY:

A. An operator may use the following methods of demonstrating internal casing integrity for wells to be placed in approved temporary abandonment:

(1) the operator may set a cast iron bridge plug within 100 feet of uppermost perforations or production casing shoe, load the casing with inert fluid and pressure test to 500 psi surface pressure with a pressure drop of not more than 10 percent over a 30 minute period;

(2) the operator may run a retrievable bridge plug or packer to within 100 feet of uppermost perforations or production casing shoe, and test the well to 500 psi surface pressure for 30 minutes with a pressure drop of not greater than 10 percent over a 30 minute period; or

(3) the operator may demonstrate that the well has been completed for less than five years ~~and has not been connected to a pipeline~~.

(4) Any isolation device used to test mechanical integrity pursuant to Subsection A of this Section shall remain in place for the duration of the temporary abandonment.

(5) The operator shall perform a caliper log and casing integrity log.

B. During the testing described in Paragraphs (1) and (2) of Subsection A of 19.15.25.14 NMAC the operator shall:

(1) open all casing valves during the internal pressure tests and report a flow or pressure ~~change~~ occurring immediately before, during or immediately after the 30 minute pressure test;

(2) top off the casing with inert fluid prior to leaving the location;

(3) report flow during the test in Paragraph (2) of Subsection A of 19.15.25.14 NMAC to the appropriate division district office prior to completion of the temporary abandonment operations; the division may require remediation of the flow prior to approving the well's temporary abandonment.

C. An operator may use any method approved by the EPA in 40 C.F.R. section 146.8(c) to demonstrate external casing and cement integrity for wells to be placed in approved temporary abandonment.

D. The division shall not accept mechanical integrity tests or logs conducted more than 12 months prior to submittal.

E. The operator shall record mechanical integrity tests on a chart recorder with a maximum two hour clock and maximum 1000 pound spring, which has been calibrated within the six months prior to conducting the test. Witnesses to the test shall sign the chart. The operator shall submit the chart, caliper log, and casing integrity log with form C-103 requesting approved temporary abandonment.

F. The division may approve other testing methods the operator proposes if the operator demonstrates that the test satisfies the requirements of Subsection B of 19.15.25.13 NMAC.

[19.15.25.14 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008]

19.15.25.~~15~~16 WELLS TO BE USED FOR FRESH WATER:

A. When a well to be plugged may safely be used as a fresh water well and the landowner agrees to take over the well for that purpose, the operator does not need to plug the well above the sealing plug set below the fresh water formation.

B. The operator shall comply with other requirements contained in 19.15.25.9 NMAC through

19.15.25.11 NMAC regarding plugging, including surface restoration and reporting requirements.

C. Upon completion of plugging operations, the operator shall file with the division a written agreement signed by the landowner whereby the landowner agrees to assume responsibility for the well. Upon the filing of this agreement and division approval of well abandonment operations, the operator is no longer responsible for the well, and the division may release bonds on the well.

[19.15.25.15 NMAC - Rp, 19.15.4.204 NMAC, 12/1/2008]

HISTORY of 19.15.25 NMAC:

History of Repealed Material: 19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) repealed 12/1/2008.

NMAC History:

19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) was replaced by 19.15.25 NMAC, Plugging and Abandonment of Wells, effective 12/1/2008.

EXHIBIT 2

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EDUCATION

* **University of Denver, Denver, Colorado**
  Master of Arts, Environmental Policy and Management, completed all coursework, 1994

* **South Dakota School of Mines and Technology, Rapid City, South Dakota**
  Master of Science, Mining Engineering, 1981
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  Post-graduate work in chemistry and genetics, 1973

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  Bachelor of Arts, Psychology, 1973
  Athletic Scholarship (golf), 1969-1973

* **Oil & Gas Industry Courses**, including but not limited to reservoir, economics, production, drilling, safety, cementing, directional wells, hydraulic stimulation, conformance, facilities, pressure analysis.

RELEVANT WORK EXPERIENCE

Over 39 years of comprehensive technical, operational and HSE experience in the oil and gas industry; recognized as an industry expert in unconventional resource development.
Assisted in development of leading edge regulatory frameworks within Southwestern Energy, New Brunswick and North Carolina.
Exceptional understanding of varying social, economic, regulatory, and political interests.
Excellent experienced communicator with multiple levels of understanding.
Very comfortable with all forms of media, live and otherwise.
Demonstrated composure in the most difficult public relations situations.
Adept at building consensus amongst multiple stakeholders.

EMPLOYMENT HISTORY

July 2016-present **Alexander Engineering, LLC – Principal**
Consultant on oil and gas industry operations and regulatory matters. Work includes:

Environmental Defense Fund – Technical/Regulatory Consultant (July 2016-present)
Assisting with several key projects involving underground natural gas storage, flaring/venting, conventional regulation reviews, underground gas storage in China, IOGCC regulatory project, Illinois and Oklahoma gas storage regulation comment, white paper covering HSE Management Systems, Risk Management, Emergency Response Planning, policy, process, procedure, corporate culture and water management. Additional projects include methane emission reduction in related regulatory updates in Colorado and New Mexico with EDF and several partner organizations.

I participated in a nearly 2 year long project representing EDF to update (American Petroleum Institute Recommended Practice) API RP 1170 (cavern storage of natural gas) and API 1170 (depleted reservoir and aquifer storage of natural gas) in 2 work groups focusing on risk management and HSE (health, safety and environment). The work accomplished a great deal toward better organization, flow, utilization of key HSE management system principles, KPI's, goals and objectives, audit functions, and the

use of ALARP or a related system of quantifying and ranking risk assessment and management thereof.

Current projects (2024) include review and comment on upcoming PHMSA safe transport of CO2 via pipeline regulations, a new API RP (API RP 11CO2) on pipeline transport of CO2 and continued defense of the recent EPA rules related to methane emission reduction and management. Finally, I am currently engaged with the Western Environmental Law Center to pursue New Mexico regulation improvements and updates primarily regarding oil and gas well temporary abandonment, plugging and abandonment, and financial assurance.

Independent Energy Standards Corporation - Consultant (Jan. 2017-Mar. 2018)
Assisted in the development of rubrics to evaluate companies' HSE management systems, risk management programs, corporate culture, emergency response plans, upstream engineering and operations. Assisted as well in developing an HSE management system for IES itself. Helped evaluate IES clients in underground natural gas storage operations and upstream independent oil and gas operations in the mid-continent.

Oct. 2012-Apr. 2016 **Southwestern Energy Company – Vice President Health Safety & Environment**
Managed staff of over 60 HSE professionals assisting full breadth of company operations. Worked closely with federal and state government and regulatory agencies to insure safe and responsible development of company's oil and natural gas assets. Led team efforts that reduced company and contractor injury rates by over 50%. Managed all aspects of the cultural conversion to behavior based safety. Retired April 1, 2016.

May 2010-Sept. 2012 **SWN Resources Canada – General Manager, New Brunswick, Canada**
Managed company's initial international exploration project covering 2.5 million acres. Worked closely with provincial government, regulators, First Nations, and the public on a daily basis. Delivered well over 100 presentations and consultations, including numerous media events (live television, radio, scrums, and print). Served on Board of Directors of the Canadian Society of Unconventional Resources. Served on Board of Atlantica Centre for Energy, and was Treasurer for newly-formed New Brunswick Oil and Natural Gas Association.

Mar. 2007-Apr. 2010 **Southwestern Energy Company, Houston, Texas – Fayetteville Shale Completion Manager**
Managed a team of up to 75 professionals and was responsible for the completion of over 1200 horizontal wells. Annual completion budgets were in excess of $500,000,000. Team coordinated activity with drilling, geology, geophysics, land, and production. Shared technical and operational expertise at numerous industry conferences. Served on initial committee that ultimately developed our Model Regulatory Framework.

Apr. 2004-Feb. 2007 **Southwestern Energy Company – Team Lead Fayetteville Shale Project**
Promoted to Team Lead for Fayetteville Shale Project and managed multidisciplinary staff. Responsible for drilling, completion, and production of some 50 vertical and 90 horizontal wells during the initial phases of the project.

Jan. 2001-Mar. 2004 **Southwestern Energy Company, Fayetteville, Arkansas – Staff and Senior Staff Production Engineer**
Reviewed well performance of over 200 wells. Prepared commingling of 90 to 100 wells and identified 40-50 candidates for artificial lift. Directed the field work to accomplish

these installations and comminglings. Identified over 30 stimulation candidates, designed the refracs and supervised their execution. Responsible for the completion design and execution of over 20 new wells each year.

Dec. 1997-Nov. 2000 **New Prospect Company, Fort Smith, Arkansas – Production/Reservoir Engineer**
Responsible for all production and reservoir aspects of over 200 wells, Consulted to Southwestern Energy 12/1998 – 12/2000 regarding production, operations, and artificial lift.

Nov. 1996-Nov. 1997 **Oil and Gas Consulting Engineer, Fort Smith, Arkansas**

June 1994-Nov. 1996 **Revere Corporation, Fort Smith, Arkansas – Operations/Engineering Manager**
Designed and executed all drilling, completion, and production, including artificial lift, recompletions, workovers, and safety and environmental concerns. Supervised and trained field and office personnel, provided expert testimony at state and local levels.

Sep. 1989-Jun. 1994 **Habersham Energy Company, Englewood, Colorado – Vice President Operations**
Managed all phases of an independent operating oil and gas company. Supervised 8 employees, served on board of directors, executed the annual budget.

Jul. 1998-Sept. 1989 **Southwest Operating, Incorporated, Tyler, Texas – President**
Acquired and invested in producing oil and gas properties.

Aug.1984-Jul. 1988 **Altair Energy Corporation, Tyler, Texas – Senior Vice President Operations**
Involved in all phases of drilling, production, property acquisition and divestiture.

Aug. 1981-Aug. 1984 **Schlumberger Offshore Services, Houston, Texas – Field and Sales Engineer**
Performed petrophysical logging services for offshore oil and gas companies. Involved personnel supervision, equipment logistics, nuclear sources and explosives control, log interpretation, electronic equipment maintenance, calibration, trouble-shooting and repairs. Sold logging products, petrophysical evaluations, and new technologies.

Mar. 1975-Jun. 1981 **United States Air Force – B-52H Navigator and Radar Navigator**
SAC B-52H crew member. Consistently rated top in class and operations in all phases of performance and training. Honorably discharged with the rank of Captain.

EXHIBIT 3

STATE OF NEW MEXICO
NEW MEXICO OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC **CASE NO. 24683**

DIRECT TESTIMONY OF THOMAS M. ALEXANDER

Table of Contents

BACKGROUND AND QUALIFICATIONS ……2

SUMMARY OF OPINIONS ……..10

OVERVIEW OF THE ORPHAN WELL PROBLEM ……..….15

BACKGROUND OF REVISED APPLICATION ……..…….19

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS ……...……...21

19.15.8 NMAC - FINANCIAL ASSURANCE ……..…...25

19.15.9 NMAC – WELL OPERATOR PROVISIONS ……28

19.15.25 NMAC – PLUGGING AND ABANDONMENT OF WELLS ……..…29

19.15.25.9 NMAC – Presumptions of No Beneficial Use ……..….41

19.15.25.13 NMAC – Approved Temporary Abandonment ……..…..46

19.15.25.14 NMAC – Request for Approval and Permit for Approved Temporary Abandonment ……..……55

19.15.25.15 NMAC – Demonstrating Mechanical Integrity ……56

BACKGROUND AND QUALIFICATIONS

Q: Please state your name.

A: Thomas Alexander.

Q: What is your current employment?

A: Since 2016, I have been a principal of Alexander Engineering, Inc., a consulting firm focused on oil and gas operations. In addition to serving as an expert for Applicants in this proceeding, I have been retained by the Environmental Defense Fund ("EDF") and Independent Energy Standards Corporation. I describe some of my consulting work below.

Q: What is your educational background?

A: I earned a Bachelor of Arts in Psychology from Wake Forest University (1973) followed by post-graduate work in chemistry and genetics at Duke University (1973). I earned a Master of Science, Mining Engineering (1981) and a Bachelor of Science, Mining Engineering (1981) from South Dakota School of Mines and Technology and completed the course work for a Master of Arts, Environmental Policy and Management at the University of Denver (1994). Throughout my work experience in oil and gas I have taken industry-related courses focused on and not limited to oil and gas well production, drilling, completion techniques, rock mechanics, economics, health, safety and environmental engineering, artificial lift, gas reservoir engineering, risk management, nodal analysis and well cementing.

Q: Would you please describe your work experience.

A: My work experience after earning my degree from Wake Forest University and completing some post graduate work at Duke University began with serving over 6 years in the United States Air Force. I completed Officer Training School and was trained as a navigator and radar navigator in the B-52H heavy bomber. While this work is not directly related to the issues

at hand, it is worth mentioning because it taught and trained me to be an exceptional officer and leader in addition to requiring high levels of responsibility and accountability.

I was honorably discharged in June 1981 and began my oil and gas career with Schlumberger Offshore (dba SLB), a multinational oilfield services company, out of Houston, Texas. There I ran logging operations on offshore drilling rigs (jack-ups and semisubmersibles) for two years followed by conducting sales and interpretation services (petrophysics) for major integrated oil and gas companies such as Shell PLC, Exxon Mobil Corp., and Chevron Corp.

Following Schlumberger, I worked for Altair Energy in Tyler, Texas. We were a small operator that drilled some 12 to 15 wells per year and operated close to 200 wells mainly in east and central Texas, Mississippi, and Louisiana. My technical responsibilities were primarily in completion and production engineering. I spent a great deal of time in the field supervising completions, workovers, plugging, well economic evaluations and acquisitions, and promotion of drilling ventures.

In 1989 I began work for a small operator, Habersham Energy, in Denver, Colorado with operations mainly in Colorado, Nebraska, and Wyoming. I was the Chief Operating Officer and worked there nearly five years when I went to Fort Smith, Arkansas to fill a similar role with Revere Corporation. Our operations were all in the Arkansas side of the Arkoma Basin, a dry gas region with multiple pay horizons that offered many challenges in completion and production engineering. I also served a short time in Fort Smith with Oxley Petroleum which involved a great deal of field work in eastern Oklahoma ranging from completions, production, artificial lift, site restoration, plugging, site restoration, and various other well site supervisory roles.

In December 1999 I went to work for Southwestern Energy Co. (“SWN”) (now combined with Chesapeake Energy Corp. as Expand Energy Corp., one of the largest natural gas producers

in the U.S.) as a consultant with an initial task of evaluating some 30 properties on Ft. Chaffee, in Arkansas, for recompletion potential, production upgrade, and possibility for plugging and abandonment ("P&A"). That project developed into a fulltime position a year later as a staff production and completion engineer. We operated over 300 wells in Arkansas and I spent several years reviewing the entire portfolio for artificial lift (plunger lift), recompletion, hydraulic fracturing, and comingling. The project was a great success and led to my promotion to Team Lead to evaluate the Fayetteville Shale in the Arkoma Basin of Arkansas as a potential economic target.

We successfully tested the Fayetteville Shale, named the venture Desoto, which ultimately led to the drilling of some 4,500 wells. I served not only as the discovery Team Lead and completion engineer but also as the West Desoto Manager and then Completion Division Manager. We were eventually drilling and completing approximately 450 wells per year and in my capacity I was closely involved not only with completions but coordinating with drilling, infrastructure development, midstream buildout, geology, geophysics, land acquisition, staffing, and health, safety and environment ("HSE"). To say the Fayetteville Shale was a success is an understatement. As a company we all spent a great deal of time and energy working with local, county, and state officials to ensure landowner concerns were addressed and rights were preserved. Our engagement with the Arkansas Oil and Gas Commission was enormous as we were setting new standards and methods of looking at well spacing and proper regulation of activities of approximately 4,500 wells, most of which were horizontal. We developed our own sand mine east of Little Rock and also constructed built-for-purpose drilling rigs.

In 2010, I was promoted to General Manager of SWN Canada. I led the exploration efforts in New Brunswick, Canada for the Frederickbrook Shale for over two years and then

returned to Houston to lead the HSE Division, and retired in April 2016.

After retirement I formed a consultancy, Alexander Engineering, Inc., in 2016 and began work as a consultant with EDF. I have provided technical expertise on issues such as underground gas storage, flaring, venting, and conventional and unconventional regulations. I assisted EDF in review and proposed amendments for the New Mexico Oil Conservation Commission's ("Commission") Methane Waste Rule in 2021 and the New Mexico Environmental Improvement Board's Ozone Precursor Rule in 2022, and testified as an expert on behalf of EDF during both rulemaking hearings. I also worked with EDF on proposed rules to prohibit routine venting and flaring before the Colorado Oil and Gas Conservation Commission (now the Colorado Energy and Carbon Management Commission). I assisted EDF in contributions to the Interstate Oil and Gas Compact Commission and Energy Resources, Research and Technology Committee and on two American Petroleum Institute work groups focused on updating two recommended practices for underground gas storage. Recently I completed a project with the American Petroleum Institute and major pipeline companies to construct a new recommended practice on the operation of carbon dioxide ("CO_2") pipelines. My primary work on these projects focused on risk management, health, safety and environment, security, and training

I have consulted for Independent Energy Standards Corporation, a company that provides independent ratings and analytics services, and assisted in development of rubrics to evaluate companies' HSE management systems, risk management programs, corporate culture, emergency response plans, upstream engineering, and operations.

Most recently I have been engaged by the Western Environmental Law Center on behalf of Applicants in this rulemaking proceeding to advise and testify on requirements for authorizing

temporary abandonment of wells, timelines for plugging and abandoning inactive wells, and adequate financial assurance.

Throughout most of my career in oil and gas, I have operated in basins that are highly populated with small operators with wells that are in large part on the tail end of their producing life cycle. These include the East Texas, Arkoma, Denver-Julesburg, and Appalachian Basins. I have observed hundreds of wells in these areas that are literally on their last legs and in many cases saw them abandoned and left for the state to manage. In some cases we were on the purchasing end of well sets that had end of life wells that we subsequently plugged. And unfortunately the bonds intended to "secure" these properties were not anywhere near enough to cover the expense. That bonds are insufficient to cover liabilities is a well known fact across all producing states. In particular, during my 17+ years with SWN, we took our corporate responsibilities very seriously. We were exceedingly careful to respect the rights of landowners and the regulatory requirements of the state and not drag our feet to timely plug and abandon, remove surface equipment, and restore locations in order to meet or exceed regulations and expectations. Indeed, as Manager of our HSE Division, we developed a company-wide motto: "We don't follow or exceed all regulations because we have to, we follow or exceed them because we want to." That was a corporate cultural shift I was very proud of leading.

Q: What is your experience making determinations when and how to plug inactive and unproductive oil and gas wells and remediating well sites?

A: One word: EXTENSIVE. The first part of the question as to when a well should be plugged is generally straightforward and is a coordinated effort among a variety of disciplines that at least include geology, geophysics, engineering (including drilling, completion, production, reservoir, and facility), field operations, land management, regulatory, HSE,

measurement, sales, and management. I was repeatedly involved in these processes in the East Texas Basin, Wilcox Basin in Mississippi and Louisiana, Hardeman Basin of Texas, Denver-Julesburg Basin in Colorado, and the Arkoma Basin in Arkansas and Oklahoma as well as other areas with the operators I worked for, for over 32 years.

There are basically three cases to consider. The first case involves decisions to be made once a well has been drilled. At a minimum, logs, cores, drill stem tests, reservoir characteristics, and encountered geology are to be evaluated to decide if the drilling venture has encountered enough economic pay to justify completing the well for production and sales. Like many engineers, I have been involved in the decision to P&A a well at this point rather than proceeding to completion.

The second case occurs when a new well has been drilled and the completion attempt has not yielded enough production to warrant moving forward with the expense to equip the well for production and sales. Once again, I've participated in all these facets and coordinated efforts that at times have resulted in the decision to plug the well at that point.

A third case involves evaluating a producing property that is nearing or has reached its economic limit. I was in the position as a production engineer to be constantly evaluating well performance and recommending a variety of procedures based upon where the well was in relation to its economic limit or point of expected ultimate recovery or EUR. While a large part of my career was completion and production engineering, I did spend a significant amount of time in reservoir engineering and was and am very familiar with fundamental techniques that are used to determine a well's remaining life. I have performed many evaluations using decline curve analysis, volumetric calculations, and pressure depletion analysis on a wide range of reservoirs and producing horizons.

The basic process is straightforward. As a production engineer I was constantly reviewing well performance and would zero in on properties that were either underperforming (as a result of mechanical issues, scale, paraffin, or other issues) or appeared to be nearing their economic limit. At that point the exercise was to closely review decline curves, pressures, and volumetrics to ascertain if there was potentially a downhole mechanical problem, for example, or if the well was indeed a candidate for P&A. Other disciplines would of course be engaged such as geology, land management (lease terms and restoration requirements in the lease as stipulated by the landowner), and regulatory and field operations to wrap up the analysis and prepare a plan for final disposition. Partners would have to be notified and paperwork filed with the regulator to receive a permit to P&A.

As to how to P&A a well, each state has clearly defined rules how to P&A wells in all configurations and I would work closely with our regulatory professionals to ensure the procedure I prepared was fully in compliance. I prepared many authorities for expenditures to P&A wells and dispose of equipment as either junk or for reuse or sale and finally to restore the site to near original condition. Qualified contractors were needed to be engaged to perform all the required work in the field in a safe and efficient manner. These would include at a minimum a workover rig with adequate blowout prevention, cementers, fluids, tanks, field supervision, downhole plugs as required, dozers, and trucking; the list could go on. Often, a representative from the state regulator would be present for all or part of the operation to ensure compliance with the regulations, plugging permit, and use of sound engineering and operational procedures. Getting cement plugs properly placed with well-engineered cement is one of the most important aspects of plugging a well properly.

Site remediation is, of course, a critical part of the whole process. Often the lease

agreement would have specific provisions to be followed to ensure the site was restored to as close to the original condition as possible. I was involved with sites that had severe saltwater or hydrocarbon contamination that required special measures. In all cases we did whatever was necessary to meet or exceed regulator and landowner requirements and expectations. So, evaluation, planning, and execution of every phase is as important as the next and we always took the process and result seriously.

Yes, it's a somewhat involved process but one that a prudent engineer working with other various disciplines -- geologist, landman, or manager -- is familiar with and dedicated to performing properly as a prudent operator. I was involved with all these functions and processes hundreds of times in over three decades of engineering operations both in the office and the field.

Q: Is Applicants' Exhibit 2 an accurate copy of your resume?

A: Yes.

Q: What documents have you reviewed in preparing your testimony?

A: I reviewed various materials including:

- Mary Kang, et al., *Environmental risks and opportunities of orphaned oil and gas wells in the United States*, Environmental Research Letters, vol. 18, no. 7, June 20, 2023;
- New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025 [Apps' Ex. 4];
- Nikki Way, et al., *Landowners' Primer: What You Need to Know About Unreclaimed Oil and Gas Wells*, Pembina Institute, Nov. 21, 2019, https://www.pembina.org/pub/landowners-primer-what-you-need-know-about-unreclaimed-oil-gas-wells;
- Mark Jaffe, *Colorado towns take new approach to force oil and gas company to plug old wells***,** The Colorado Sun, updated June 11, 2025; https://coloradosun.com/2025/06/10/kpk-dacono-frederick-idle-oil-gas-wells/;
- Zachary R. Mider, et al., *An Empire of Dying Wells*, Bloomberg, Oct. 21, 2021, https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/;
- Jerry Redfern, *It's Settled: New Mexico to Bankroll Plugging of Oil Wells for Texas Company*, Capital & Main, Dec. 21, 2023, https://capitalandmain.com/its-settled-new-mexico-to-bankroll-plugging-of-oil-wells-for-texas-company;
- Jack Hansen, EDF, Energy and Public Lands in the West, A Wave of Orphaned Wells in

Texas? (not published);
- Aaron Wolfe et al., EDF, Louisiana's Inactive Wells Steps Toward Improved Management, Economics Discussion Paper Series, July 2024 (not published);
- Missi Currier, New Mexico's Oil and Gas Industry Leads on Well Plugging—Let's Keep It That Way, June 19, 2025, https://www.nmoga.org/new_mexico_s_oil_and_gas_industry_leads_on_well_plugging_l et_s_keep_it_that_way;
- Various Commission rules including 19.15.2 NMAC, 19.15.5 NMAC, 19.15.8 NMAC, 19.15.9 NMAC, 19.15.25 NMAC;
- Oil Conservation Division ("OCD") public records including OCD's inactive well list and operator C-103's;
- OnePetro, Society of Petroleum Engineer's E&P Glossary;
- *Wheeler and LeMaster Oil and Gas Co. v. Henley*, 398 S.W. 2d 475, 477 (Ky. Ct. App. 1965); and
- Change Research. 2025 New Mexico Landscape November 22 – December 5, 2024 (not published).

SUMMARY OF OPINIONS

Q: Can you please summarize the opinions you will give in your testimony?

A: At the outset, I'd like to underscore for the Commission that the general purpose of the rules proposed by Applicants is to protect the State against those operators who are most at-risk. The proposals focus on those operators who are operating at the very margins, those wells that are producing so little that they are not paying in sufficient quantities to fund future liabilities for plugging and abandonment and site remediation. The proposals before the Commission will not guard against every oil and gas bankruptcy or every well operating at the edge of profitability. But the proposals are designed to protect the State, its taxpayers, surrounding communities, and the environment against the most serious risks while nonetheless allowing small operators who operate prudently and responsibly to continue to operate profitably.

Regarding **19.15.2 NMAC - Definitions:** There are several definitions that have been amended or added to support the rule changes that Applicants propose. They are "temporarily abandoned status," "barrel of oil equivalent," "beneficial purpose/use," "expired temporary abandoned status," and "marginal well." The definition changes proposed are industry standard

and/or required for clarity regarding the proposed rule changes, and I support them all.

Regarding **19.15.5 NMAC - Enforcement and Compliance:** The two changes proposed are straightforward additions regarding compliance with key regulations -- plugging and abandonment requirements at 19.15.25.8 NMAC and venting and flaring requirements at 19.15.27.8.A NMAC -- that are required to be in compliance for purposes of 19.15.5.9.A NMAC. I am fully in support of requiring compliance with these two critically important regulatory provisions in order for operators to be in compliance for purposes of 19.15.5.9.A NMAC.[1] There is no justification for allowing even a handful of wells to be out of compliance with P&A and venting and flaring requirements.

Regarding **19.15.8 NMAC - Financial Assurance:** This is a complex but necessary set of proposed changes to the financial assurance rules. It is widely recognized that the financial assurance provisions across the country are sorely deficient and New Mexico is no exception. The New Mexico Legislative Finance Committee ("LFC") recently issued a report on the orphan well problem in New Mexico: Policy Spotlight: Orphaned Wells (June 24, 2025), attached as Applicants' Exhibit 4. LFC recognizes New Mexico's financial assurance requirements are inadequate, finding that: "The gap between actual plugging costs and the required financial assurance weakens the incentive for operators to plug their own wells, especially older, low-value wells where cleanup costs are high. As a result, operators are more likely to walk away from those wells, leaving OCD to manage the most complex and least desirable sites." LFC Policy Spotlight: Orphan Wells at 24.

[1] Section 19.15.5.9.A NMAC lists criteria for a compliance determination for purposes of certain regulatory actions in the rules. These include OCD's determinations: (1) whether to release financial assurances under 19.15.8.12 NMAC, (2) whether to approve or deny an application for operator registration under 19.15.9.8.B NMAC, and (3) whether to approve or deny an application for change of operator under 19.15.9.9.C NMAC.

There are estimates that some 800,000 wells are in orphan status and that doesn't even include wells whose locations are not even known or those that are in peril of becoming orphaned. In LFC's report, LFC finds that:

- OCD has plugging authority for roughly 700 wells on state and private lands,
- OCD will likely will need to plug an additional 1,400 inactive wells for which OCD does not have plugging authority, and
- There are more than 3,000 wells on state or private land producing extremely small quantities of oil and gas whose expected cleanup costs exceed their predicted future revenues, increasing their risk of being orphaned.

LFC Policy Spotlight: Orphaned Wells at 1. The LFC concludes that:

> . . . it would be prudent for the state to reduce its future liability for orphaned wells, which could be accomplished through a variety of mechanisms, including revising its financial assurance system to incentivize operators to plug wells before they become fully inactive.

Id. LFC finds that over the past 20 years, OCD has plugged approximately 1,000 orphaned wells or five percent of all wells plugged in the state. *Id.* Five percent is far too many wells left by operators for the State to plug and remediate. Clearly states and taxpayers are unfortunately and unnecessarily bearing the brunt of imprudent operators that take advantage of wholly insufficient financial protections provided in law and regulations. I am in full support of the proposed changes.

Some in industry will argue that some operators will not be able to comply with these additional bonding requirements that would protect the state and the public from bearing the financial responsibility of plugging orphaned wells and restoring the land and water resources but that these operators should nonetheless be allowed to continue to operate. My opinion is solidly that this class of operator has no business remaining in business if the operator cannot

"pay" for adequate financial assurance and these wells should be managed by an operator who is capable of completing proper P&A and site remediation.

Regarding **19.15.9 NMAC - Well Operator Provisions:** The essential elements of the proposed rule changes are that operators, and their officers, directors, partners, and 25% owners, must be in compliance with rules and regulations, not just in New Mexico, but in other jurisdictions in which they operate in order for operators to register in New Mexico and to change operator. There are other auxiliary provisions Applicants propose that support this general idea as well. The idea is one of common sense in that any operator out of compliance in other jurisdictions or within New Mexico presents a greater risk to the State than an operator in compliance, and that OCD should be able to take account of an operator's current compliance and compliance history when approving an operator registration or well transfer. OCD should have the discretion to determine whether an operator should be allowed to continue in that status and then potentially compound any out of compliance injury to the State. I am in full agreement with these new provisions as additional protection for the State and people of New Mexico.

Regarding **19.15.25 NMAC - Plugging and Abandonments of Wells:** There are three key ideas that are the basis of these proposed rule changes. First is the concept of beneficial use. Current Commission rules allow a well to be placed in temporary abandonment ("TA") status without any showing that the well has future beneficial use. *See* 19.15.25.8.B, -12.A NMAC. So, when applying for TA status or to extend TA, operators do not have to provide any justification why a well should be placed in TA status instead of simply being properly plugged and abandoned. In so doing TA status is granted in essentially five year increments. As these five year periods come to a close, if TA status is requested again[2], there is no to little substantive

[2] There are many wells in New Mexico that are in expired TA status, that is, the operator does

reason and granted. There is literally no end to it in the Commission's current regulations. If a well has no present or future beneficial use, there is no good reason not to P&A the well. Applicants propose rules that require a showing of future beneficial use, like the vast majority of oil and gas states.

I have reviewed regulations from as many as 15 producing states governing TA requirements for TA or idle wells and P&A. There are a number of ways states approach the issues on what approvals are needed for TA, the periods of time for TA, and physical maintenance and reporting requirements. However, there are common elements such as:

1. Wells must pass a mechanical integrity test for TA and often the test must be witnessed.
2. There must be a demonstration of future utility or beneficial use to be approved for TA.
3. TA periods vary from one year to 10 years and extensions must often be accompanied by future utility or beneficial use demonstrations.
4. Routine physical maintenance and reporting can include but is not limited to fluid level tests, casing pressure tests, and plugs set over perforated intervals.
5. While there are no set "drop dead dates" for TA wells, operators must justify extended TA status or a P&A order will be issued.

A second important piece of the new proposal is that wells should not be allowed to linger indefinitely in TA status, as the Commission's rules now allow. After remaining in TA status year after year, a well becomes less and less likely to go back into production or to be used for another beneficial purpose. Applicants propose that, after eight years of inactivity, a well

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not renew TA status in accordance with Commission rules, which I discuss below.

must be plugged and abandoned or put back into productive use. The data from New Mexico inactive wells supports this proposal. After eight years of inactivity, very few wells – approximately **0.5%**, go back into use. As such, Applicants' proposal to P&A after eight years of inactivity is more than reasonable.

Third, Applicants have adopted a proposal from OCD to identify wells that are technically active but in reality no longer have real beneficial use. If an oil and gas production well hasn't produced for at least 90 days and hasn't produced at least 90 barrels of oil equivalent in 12 consecutive months, the well is presumed not to have beneficial use. These wells comprise **2.9% of the total well population** in New Mexico or **approximately 1,700 wells** and represent **0.003% of total statewide production**. The operator has an opportunity to rebut the presumption and demonstrate to OCD that the well has use. The same mechanism is proposed for injection and salt water disposal wells that haven't injected for at least 90 days and injected less than 100 barrels of fluid in 12 consecutive months. These presumptions are based on New Mexico data showing these wells are unlikely to be productive.

LFC concludes that, "Reforms that prioritize operator-led cleanup can limit the state's financial exposure." LFC, Policy Spotlight: Orphan Wells at 2. I agree. The proposals to limit the time within which inactive wells are allowed to linger without a showing of beneficial use will limit the state's financial exposure. I am in full support of these new proposals regarding TA status, and note that LFC finds that "many of the changes" proposed by Applicants in this rulemaking "align with the recommendations" in its report. LFC Policy Spotlight: Orphan Wells at 32.

OVERVIEW OF THE ORPHAN WELL PROBLEM

Q: Mr. Alexander, are current oil and gas regulations nationally and in New Mexico

generally adequate to ensure appropriate and timely plugging of oil and gas wells?

A: In a word…no. The problems that New Mexico and other jurisdictions across the country face are well documented and have been problems for some time now. If regulations had been adequate and properly enforced there would not be as many as 800,000 orphan wells nationally. It's that simple.

Consider the typical life cycle of a well, wells, or a field. The initial completion results in an economic well followed by development with adequate production to be a viable investment. With time, production naturally declines and the profitability falls to a point where the operator elects for a variety of reasons to sell to another operator, but all too often the purchasing operator is smaller and less financially capable of handling the end state. This cycle often repeats itself until the set of wells is operated by someone who has nowhere near the financial wherewithal to finalize operations and plug and abandon the well, wells, or field. So, the state regulator winds up with the entire mess in their lap to handle as the operator has either walked off or gone bankrupt. There are thousands upon thousands of decaying "monuments" -- oil and gas equipment rotting and rusting, half covered with vines and brush -- scattered over the countryside of many oil and gas states that loudly testify to the inadequacy of regulations. Very similar variations of this happen over and over and have for decades.

Add to this that all too often state regulations governing financial assurance have not been updated for years or are completely inadequate to cover the cost of decommissioning wells or entire fields. Case in point: I recall plugging 5,000 to 6,000 foot gas wells in the Arkoma for $30,000 +/- not too many years ago but due to the cost of services and materials increasing, this same type of wells could cost multiple times that nowadays and the financial assurance behind the process is woefully inadequate. New Mexico amended its financial assurance provisions in

the Oil and Gas Act in 2018, but the amendment limiting blanket bonds for an operator's active wells to $250,000 was sorely inadequate at the time and certainly is now when the average cost to OCD to plug and abandon one well exceeds $150,000.

There are a number of other issues worth noting surrounding this issue. The magnitude of the problem is simply overwhelming state regulatory agencies in the sense they are not adequately staffed or funded to carry out the regulations in place in an efficient and cost effective manner. The staff is frequently stuck with only being able to pursue the most flagrant issues and leaving many of the one-offs alone, again to the eventual detriment of the state. State legislators are often reticent to do the right thing, updating requirements and funding, fearing they would lose money and votes in their next election. Therefore, the problems don't get properly addressed. New Mexico is no exception.

Another glaring problem is the very small operator that has a longtime business with only the prospect of continuing to operate their well set is mostly at the mercy of the price of oil and gas and declining production. These entities are problematic because any increase in fees, bonding requirements or other cost of business perturbations might put them out of business. A vote to the detriment of this type of operators can result in a loss of a vote in an election; this is simply a fact of political life.

My position on this set of problems is straightforward. No one has the right to operate any business, be it oil and gas or other. Also, certainly no one has the right to operate an oil and gas property knowing full well someday the State and its taxpayers will be stuck with final disposition of their wells.[3] Moreover, in regard to oil and gas, if a well's net income is not

[3] I understand that, in New Mexico, the Reclamation Fund is funded through a tax on oil and gas operations. However, that public money spent on plugging and abandoning wells of operators that have abandoned their responsibilities could have been spent on other worthy and necessary

sufficient to prudently operate and protect health, safety and the environment plus be able to pay for reasonable financial assurance, that well should no longer be operated. Period.

Another variant to this is the operator who claims (whether true or not) a well's life will continue well into the future, so much so that the present value of the cost to plug the well is negligible and the estimate of the property's value is inappropriately high. In my opinion, using "tools" such as out of context present value and unreasonable engineering evaluations boils down to essentially a ponzi scheme. Make no mistake about it, someday, someone will have to fork over hundreds of thousands of dollars to plug a well and clean up the well site. It's a matter of "pay me now or pay me later."

There is an insightful Bloomberg article entitled "An Empire of Dying Wells."[4] Reporters investigated the situation with Diversified Energy Co. ("Diversified") out of West Virginia that operates 69,000+/- wells, the largest owner of wells in the country at that time. Many of the wells made little to no income but yet are portrayed as economically viable entities. Diversified is playing off inadequate regulations to keep its decrepit collection of – quite candidly – junk, going. It is staggering to think about what will eventually become of this whole thing. Apparently Diversified is trying to expand to Texas, Oklahoma and Louisiana. "Coming to a theater near you" is an appropriate phrase I think. I'm not suggesting Diversified will target New Mexico (but you never know) but I am saying New Mexico has in place a regulatory framework that can allow this type of giant mess to develop.

The settlement between the State of New Mexico and Ridgeway Arizona Oil Corp. ("Ridgeway") is a prime example. It became clear to OCD that Ridgeway, operating in New

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public programs.

[4] Zachary R. Mider, et al., *An Empire of Dying Wells*, Bloomberg, Oct. 21, 2021, https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/.

Mexico, was not going to be able to fund the projected liabilities for plugging and abandonment and remediation of almost 300 of its wells.[5] In the settlement, the State agreed to plug 299 "of the company's moribund, nonproducing oil wells" while the company agreed to reimburse the State $30,000 a month until the bill is repaid. At a potential cost to P&A and remediate in excess of $30 million, repaying could take more than 83 years.[6] What is the likelihood that a company that cannot plug, abandon, and remediate its wells today will be operating eight decades from now?

LFC finds that there are "thousands of inactive and low-producing wells . . . at risk of being orphaned" and concludes that, "In New Mexico, the goal should be to structure policies that motivate operators to plug wells before they become OCD's responsibility, leveraging the industry's capacity to do the work faster and likely at a lower cost." LFC Policy Spotlight: Orphan Wells at 15, 32. I agree. It is imperative to enact new rules that give the State the regulatory tools necessary to prudently manage New Mexico's portfolio of oil and gas properties in order to secure the State against the liabilities posed by the operators most at-risk. In my opinion, having worked for over three decades for oil and gas companies big and small, the proposed rules go a long way toward accomplishing that goal.

BACKGROUND OF REVISED APPLICATION

Q: Before we dive into Applicants' specific proposals, can you give please Commission members some background on the development of Applicants' proposals and how we got to the Revised Application?

[5] Jerry Redfern, *It's Settled: New Mexico to Bankroll Plugging of Oil Wells for Texas Company*, Capital & Main, Dec. 21, 2023, https://capitalandmain.com/its-settled-new-mexico-to-bankroll-plugging-of-oil-wells-for-texas-company.

[6] *Id.*

A: Sure. I began working with Applicants' attorneys in the summer of 2023 on proposals to amend the Commission's plugging and abandonment rules in 19.15.25 NMAC and financial assurance rules in 19.15.8 NMAC. Between then and when Applicants filed their original Application in June 2024, Applicants' counsel met with OCD staff and State Land Office staff to discuss proposals. I was part of some of the meetings with OCD staff.

Just prior to filing the original Application, Applicants' counsel reached out to the New Mexico Oil and Gas Association and the Independent Petroleum Association of New Mexico to let them know they would be presently filing an application for rule making and that they would like to work with those industry groups on the proposals after filing.

After filing in June 2024, Applicants' counsel worked to meet with OCD and industry counsel to discuss the proposals in their Application. The parties scheduled four meetings in October 2024. Just prior to the meetings, industry counsel said they could only attend the first meeting. I attended that meeting. During the second meeting, which one industry lawyer did attend, OCD staff stated they were working on alternative proposals that they wanted to present to the parties prior to the end of the year.

Because of resource constraints, OCD was not able to provide its proposals to the parties until February 12, 2025. In its February 12, 2025 proposals, attached as Applicants' Exhibit 5, OCD invited the parties to meet to discuss proposals in April 2025. Applicants' counsel responded they would like to meet with the parties. As far as I know, industry counsel did not respond.

After OCD sent its alternate proposals, Applicants' counsel and their experts, including myself, met with OCD staff on a number of occasions to discuss OCD's proposals. The result of those discussions was that Applicants adopted all OCD's major proposals relating to posting

more adequate financial assurance and to timely plugging and abandonment of wells. These include OCD's proposal to require "marginal wells" to post a single well financial assurance of $150,000, the proposal to require operators with more than 15% of their wells in marginal or inactive status to post financial assurance for all their wells equal to an average of $150,000 per well, and the proposal to establish the rebuttal presumptions of no beneficial use. Applicants made other changes as well in response to OCD concerns and suggestions and filed their Revised Application April 25, 2025. Applicants' Exhibit 6, which are email exchanges between counsel, reflects this course of events.

One party, OXY USA, Inc. ("Oxy"), did respond to Applicants' counsel's overtures to discuss Applicants' proposals to find common ground. Applicants' counsel and OXY's counsel and representatives met during the summer of 2024 and again in July 2025 and, in August 2025, we met with OCD counsel and staff and OXY counsel and representatives. Those were constructive discussions, and we were able to reach agreement on certain provisions where OXY proposed changes. I appreciated the opportunity to talk and listen to OXY's concerns.

In my experience in other states, particularly in Colorado, these types of discussions can be quite productive and can lead to agreement among the various parties on some issues or at least a narrowing of disagreement on some issues. I do believe it is regrettable that the other industry parties did not sit down with OCD staff and Applicants' counsel to seriously discuss the proposals on the table.

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS

Q: Let's turn to Applicants' proposed amendments to Commission rules. Beginning with 19.15.2 NMAC – General Provisions for Oil and Gas Operators, Applicants propose to combine the current definitions for "approved temporary abandonment" at 19.15.2.7.A(13)

NMAC and "temporary abandonment" or "temporarily abandoned status" at 19.15.2.7.T(3) NMAC. What are Applicants' proposals?

A: Applicants propose to revise the definition of "approved temporary abandonment" to include "temporary abandonment" and "temporarily abandoned status" and to delete the definition for the latter two terms as follows:

> **19.15.2.7.A(13) "Approved temporary abandonment," "temporary abandonment," or "temporarily abandonment status"** means the status of a well that is inactive, has been approved in accordance with 19.15.25.13 NMAC and complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.
>
> ~~**19.15.2.7.T(3) "Temporary abandonment" or "temporarily abandoned status"** means the status of a well that is inactive.~~

Q: What is the basis of these proposals?

A: The terms "approved temporary abandonment," "temporary abandonment," and "temporarily abandonment status" are used interchangeably throughout the Commission's rules to refer to wells that are authorized to be in temporary abandonment and that authorization has not expired.[7] Additionally, the current definition for "temporary abandonment" and "temporarily abandonment status" – which "means the status of the well is inactive" is not entirely accurate. Those wells are not only inactive (as defined in 19.15.2.7.I(4) NMAC) but have gone through the approval process in the Commission's rules at 19.15.25.13 NMAC to be placed in temporary abandonment. It therefore makes sense to combine the definitions into one.

Q: Along those same lines, Applicants have proposed a new definition for "expired

[7] *See, e.g.*, 19.15.8.9.D NMAC; 19.15.8.14.C NMAC; 19.15.7.14.A(1)(d), -B(2)(d) NMAC; 19.15.25.8.A, -B NMAC; 19.15.25.12 NMAC; 19.15.25.13.A-E NMAC; 19.15.25.14.A, -C, -E NMAC (using "approved temporary abandonment"); 19.15.7.14.E NMAC; 19.15.25.6 NMAC; 19.15.25.14.B(3) NMAC (using "temporary abandonment"); 19.15.8.9.D NMAC (using "temporarily abandoned status"); 19.15.39.10.B(8) NMAC (using "approved temporary abandonment status").

temporary abandonment" and "expired temporary abandonment status" at 19.15.2.7.E(8) NMAC, correct?

A: Yes, Applicants propose:

> **19.15.2.7.E(8) "Expired temporary abandonment"** or **"expired temporary abandonment status"** means the status of a well that is inactive and has been approved for temporary abandoned status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

Q: What is the basis for this definition?

A: Applicants propose to use these terms in certain proposals of theirs for financial assurance in 19.15.8 NMAC, specifically requiring increased financial assurance for this category of well, and for plugging and abandonment in 19.15.25 NMAC. Therefore, Applicants propose a definition for these terms. These wells are defined as wells that had been approved for temporary abandonment, but no longer qualify for that status because they no longer meet the Commission's regulatory requirements. Generally, these are wells where the term of temporary abandonment has not been renewed by the operator as required by Commission rules.

Q: Applicants propose a new definition for "barrel of oil equivalent" at 19.15.2.7.B(5) NMAC, correct?

A: Yes, Applicants propose:

> **19.15.2.7.B(5) "Barrel of oil equivalent"** is determined by converting the volume of gas the well produced to barrels of oil by using a ratio of 6,000 cubic feet to one barrel of oil.

Applicants propose a new definition for "barrel of oil equivalent" because that term is used in new proposals of theirs in 19.15.2.7.M(2) NMAC, defining "marginal well," and in 19.15.25.9 NMAC, setting forth the criteria to establish "presumptions of no beneficial use." I will discuss those presumptions later in my testimony. One "barrel of oil equivalent" is defined as 6,000

cubic feet of gas, which is the standard measurement to convert one barrel of oil to the equivalent volume of gas. This is an industry standard approximation to allow comparisons of gas production to oil and a thorough definition to support our proposal can be found in a number of petroleum engineering texts but the easy reference is the Society of Petroleum Engineer's E&P Glossary.[8]

Q: Applicants propose a definition for "beneficial purposes" and "beneficial use" at 19.15.2.7.B(7) NMAC, correct?

A: Yes, Applicants propose:

> **19.15.2.7.B(7)** "Beneficial purposes" or "beneficial use" means an oil or gas well that is being used in a productive or beneficial manner such as production, injection or monitoring, and does not include use of a well for speculative purposes.

Q: What is the basis for this definition?

A: The Commission's rules currently use these terms, which are important terms, but there is no definition. See, e.g., 19.15.2.7.I(4) NMAC; 19.15.25.8.B(2) NMAC; 19.15.25.12 NMAC; 19.15.27.8.F(1), -G(3)(a), - NMAC; 19.15.27.9.D(5), -D(5)(1), -D(7) NMAC; 19.15.28.8.E(1), -8.F(2)(d) NMAC. Applicants also propose using the term "beneficial use" in a new provision in 19.15.25.9 NMAC creating presumptions of no beneficial use that, if not rebutted, requires an operator to plug and abandon a well.

The proposed definition is consistent with the current definition of "inactive well" at 19.15.2.7.I(4) NMAC and clarifies that beneficial use does not include use of a well for speculative purposes. It's important to clarify that speculative use is not sufficient to extend

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[8] OnePetro, Society of Petroleum Engineer's E&P Glossary ("Barrel of oil equivalent: A method of equating the energy produced by a hydrocarbon gas to a standard oil measurement. One barrel of oil has about the same heat producing capacity as 6,000 ft^3 of gas at standard conditions."), https://onepetro.org/pages/glossary.

unproductive status of any well. Beneficial use can include any number of activities, such as production, monitoring, and injection. However, if a well is inactive and is being held for speculative purposes, that is, "based on a guess and not on information,"[9] the well should be plugged and abandoned.

An example of speculative purpose comes to mind from the early 1990's. I was a consultant to the City and County of Denver in their case against operators with production where the new Denver International Airport was to be built. All of the production was primary oil production in the Denver-Julesburg Basin. The operator hired consultants that presented a case of multimillions in value for the speculative potential of secondary and tertiary recovery of oil from the producing horizons. Their case did not succeed and the value of the field was deemed to be substantially less than the speculative claim. I also saw numerous cases in the Arkoma Basin, a dry gas region, where operators would "hold" 640 acre units claiming one well would drain the unit when the reservoir mechanics and properties clearly showed otherwise. This practice impeded timely development of resources. *See Wheeler and LeMaster Oil and Gas Co. v. Henley*, 398 S.W. 2d 475, 477 (Ky. Ct. App. 1965) (court recognizes a strong policy against an oil and gas lessee holding land for an unreasonable length of time simply for speculative purposes).

19.15.8 NMAC - FINANCIAL ASSURANCE

Q: Mr. Alexander, Applicants' other witnesses (Peter Morgan, Legal and Policy Director, Center for Asset Retirement Accountability; Adam Peltz, Director and Senior Attorney, EDF; and Dwayne Purvis, Founder and Principal Advisor, Purvis Energy

[9] Definition of "speculative"; Cambridge Dictionary, https://dictionary.cambridge.org/us/dictionary/english/speculative.

Advisors) are providing testimony in support of Applicants' specific proposals related to financial assurance in 19.15.8 NMAC, but can you give the Commission your general opinion why the current Commission rules are inadequate to address the risks of orphan wells and the why it is necessary to increase financial assurance to better reflect the actual costs of plugging and abandonment for at-risk wells.

A: It is no secret that inadequate financial assurance for oil and gas properties is a serious problem spread across all oil and gas producing states and places the public at great risk throughout the country. The lack of adequate financial assurance in the current rule framework in New Mexico threatens to only increase the problem that wells will eventually be left to the State to decommission and clean up the environment. The proposals Applicants set forth are an attempt to head off a foreseeable problem and protect safety, health, and environment now and in the future as well as prudently protect natural resources. Let me expand.

I have previously testified to the typical life cycle of wells and fields. To summarize, oil and gas properties begin their life in a productive manner, providing reasonable rates of return to the operator and investor. As production declines wells and fields eventually get sold to smaller and smaller operators that are less and less capable of properly operating the properties to include the financial wherewithal to handle the end state -- properly plugging and cleaning up well sites. LFC recognizes that "wells below certain production thresholds are unlikely to generate sufficient revenues in their remaining lifespan to be able to fund their own plugging and reclamation, putting those wells at greater risk of being orphaned." LFC Policy Spotlight: Orphan Wells at 20. This cycle has repeated itself for decades all over the country and the situation cannot be argued. Add to this cycle, inadequate financial safety nets through proper bonding and you have the real problem: wells and fields are abandoned by the operators or

operators go bankrupt with plugging and clean up left to state regulators and yes, the taxpayers, to foot the bill and do the work, and that is simply not right.

All too often legislatures do not give the regulator the resources to staff adequately and thus compliance with existing regulations falls short with the regulator only attacking the biggest problems leaving an increasing accumulation of problem wells. All too often legislatures do not give regulators the funding to timely plug abandoned wells and the wells sit idle, at risk, until funds are available putting the public and environment at risk. All too often legislative representatives avoid passing laws pointed toward these issues. All too often regulators have been reticent to write and adopt effective regulations in an effort to avoid having small, financially incapable operators go out of business. I will repeat that if wells and operators can't pay the toll to operate prudently, they should not operate and the wells should be plugged.

There will be arguments against the provisions proposed that fall into this category of wells and operators. My opinion is clearly that it is better to adopt appropriate regulations now, absorb the cost of the small percentage of operators and wells being eliminated, but in so doing protect the future of the current economically viable producing properties. If operators are going to go out of business, better now (while wells may still have some residual value) than waiting later at the risk of the public and environment and the wells will have no value in the ground or on the surface. Indeed, waiting will only make matters worse; guaranteed.

The last time New Mexico updated its financial assurance regulations at 19.15.8 NMAC was 2019. The amendments put in place at that time were inadequate and, with the price of materials and services always increasing, the value of financial assurance provided then is less adequate now. As LFC observed: "Current financial incentives are poorly aligned to encourage operators to properly plug and abandon their wells because requirements for financial assurance

per well are less than the typical plugging cost . . . .” LFC Policy Spotlight: Orphan Wells at 32.

There is simply no rational reason to defend keeping the regulations as is. Doing so will wind up giving the citizens of New Mexico a terrible, burgeoning financial, safety, and environmental burden and waste precious natural resources in the future to clean-up a huge problem.

19.15.9 NMAC – WELL OPERATOR PROVISIONS

Q: Similarly Mr. Alexander, Mr. Morgan is providing testimony in support of Applicants' specific proposals to protect against registering risky operators and risky transfers of wells in 19.15.9 NMAC, but can you give your general opinion why it is important to assess risk at the point of transfer of wells and put into place a regulatory framework that protects against those risks?

A: The proposed provisions to which you refer are in 19.15.9.8 NMAC and 19.15.9.9 NMAC regarding operator registration and change of operator. It's really straightforward in that it is only common sense that the State would require operators to be in good standing not only with New Mexico laws and regulations but wherever they conduct business. Why would the State not want to assess the risks of operators with red flags, such as being out of compliance in New Mexico or anywhere? Also, in the situation of well transfer, it's appropriate to require the proposed new operator demonstrate they are capable of operating prudently and have a plan for taking on future known financial responsibilities for the well's, wells' or fields' end state. Again, not to allow the State to assess risk to the State through a review of an operator's compliance history and, for well transfers, the financial capability of a new operator to decommission the wells they are taking on is necessarily turning a blind eye to potential risks to the State, surrounding communities, and the environment. Requiring these risk assessments on the front

end will help prevent damage to the State on the back end.

LFC highlights a transfer of wells in 2010 to Canyon E&P ("Canyon"), which is when Canyon purchased many of its 277 wells. LFC Policy Spotlight: Orphan Wells at 31. The wells were depleted of conventional oil resources and Canyon intended to initiate secondary recovery, but went bankrupt in 2015. OCD began plugging Canyon's wells in 2016. A decade later OCD has plugged and remediated 25 wells, plugged but not remediated 171 wells, and not plugged 32 wells, some of which have been idle for 30 years. And OCD has spent millions of dollars more for plugging and remediation than the financial assurance posted by Canyon. *Id.* OCD needs regulatory tools to more effectively scrutinize transfers to transferee operators who may not have the financial wherewithal to decommission the wells they are taking on. Applicants' proposed amendments to protect the State against high risk transfers helps address the current regulatory gaps.

19.15.25 NMAC – PLUGGING AND ABANDONMENT OF WELLS

Q: Before we discuss Applicants' specific proposals for plugging and abandonment at 19.15.25 NMAC, can you discuss why it's important to timely plug and abandon unproductive wells?

A: Certainly. Timely plugging and abandonment, including site restoration, is important for a number of reasons.

I would place public safety at the top of the list. I think everyone will agree that well sites are a form of "attractive nuisance" and can definitely pose a public risk. I have personally been involved with a case (in Colorado) wherein great injury happened to a young man that decided to climb onto a pumping unit, fell in between the weights and crank case, and severely injured himself. Abandoned well sites can pose an even greater risk as they are often not well maintained

or monitored and are in many ways are “out of sight, out of mind,” an accident waiting to happen. Also, many well sites have leaks at the wellhead or various pieces of surface equipment, albeit small, that can pose a fire or explosion hazard. It’s worth mentioning that even though a well may not be in a producing state, the processes of corrosion still marches on, thus increasing the possibility of leaks or a massive and serious failure of valves or tubulars leading to blowouts or a sort. From a safety standpoint, it makes no sense not to plug and abandon an unproductive well. This is expanded in greater detail later in the section outlining the proposed temporary abandonment rules.

Next, unattended, non-productive wells, potentially pose issues regarding public health and environmental risk. Often the wells that have become unproductive are old to very old and have been managed with old technology and operating techniques. As mentioned above, corrosion is an ever present issue. As wells age, there are distinct possibilities that leaks, casing failures, plug failures, cement sheath failures will occur thus endangering ground water and the air. This can become especially problematic if the produced fluids contain corrosive and harmful elements such as hydrogen sulfide or H_2S, CO_2 or concentrations of volatile organic compounds. The LFC recognizes the risks of inactive, unplugged wells, finding that:

> Oil and gas wells, by design, tap into subsurface reservoirs that are often more than a mile deep. When active production ceases, the wells can become pathways for hazardous substances to escape, including gases like methane and hydrogen sulfide and fluids like produced water and residual hydrocarbons. Those leaking gases and fluids can contaminate groundwater, endanger nearby homes, and impede future development of oil and gas resources.

LFC Policy Spotlight: Orphan Wells at 4. I discuss this in greater detail in the following section on the proposed revisions to temporary abandonments rules.

Next, consider regulatory compliance. It is true there are many wells in New Mexico that are simply out of compliance for a number of reasons. The topic I will later address concerning

temporary abandonment is a good example. Why are there so many wells in the state that have expired temporary abandonment status or have been inactive for years without ever having obtained temporary abandonment status in the first place? That's not an acceptable situation. Not meeting regulatory compliance wastes time and money. Wells that should be plugged timely are in that same classification of wasting resources.

Closely tied to regulatory compliance is the issue of financial responsibility. Properly plugging wells in a timely manner is part of managing oil and gas wells prudently at the end of their life cycle. Neglecting plugging obligations can, and does, lead to significant future costs for plugging and environmental restoration, especially if the well becomes orphaned in which case the state is on the hook . . . again.

In summary, timely plugging of unproductive wells is essential to safeguard the public and environment, and the regulator must be given the regulations and resources for enforcement to keep New Mexico safe, healthy, and pursuing responsible resource management.

Q: OCD maintains a list of inactive wells, correct?

A: Yes. This list is on OCD's website[10] and is updated daily.

Q: What information is on that list?

A: The list has all wells that have been inactive for at least 15 months and are not plugged. The list has various pieces of information including the well's operator and API number and location; the date of last production; the surface owner; whether it's in approved or expired temporary abandonment status or whether it's ever been placed in the TA status in the first place; whether the lease is a state, federal, or private lease; and whether it's an oil, gas, or injection

[10] The list, which is updated daily, can be found at https://wwwapps.emnrd.nm.gov/OCD/OCDPermitting/Reporting/Compliance/InactiveWells.aspx.

well. It can be sorted to include or exclude wells in approved temporary abandonment status and wells under an agreed compliance order.

Q: Can you give the Commission a snapshot of information from a recent review of OCD's inactive well list?

A: Yes. OCD's July 3, 2024 inactive well list showed the following:[11]

OCD INACTIVE WELL SEARCH LIST (15+ Months inactive)
3-Jul-25

Well Type	No. of Wells	% of total inactive wells	No. of Operators	%
Total well count (from Inactive Well search output – appears to represent wells other than Plugged & Released, Cancelled, and Never Drilled statuses)	74,582		Not included in search	
Total inactive wells (15+ months)	3,765	100%	350	100%
Total approved TA wells* on Inactive Well Search list	419	11%	89	25%
Total expired TA wells*	155	4%	67	19%
Total wells under ACOI**	99	3%	3	1%
Wells listed with unusual status (Drilled, New, or Plugged) – *excluded from total below*	13	< 0.5%	11	3%
Total inactive wells apparently out of compliance ***** (Inactive wells without ACOI coverage or non-expired TA status)***	3,234	86%	346	99%

* The approved and expired TA status wells listed on OCD Inactive Well Search is only a subset of all wells labeled by OCD as having TA status, per OCD's Well History datafiles, and per a July 3rd search of OCD's Well Permitting Search for all TA wells.
** ACOI (Inactive Well Agreed Compliance Order) coverage was determined by the difference between wells included on 2 back-to-back queries of OCD's Inactive Well Search for wells 15+ months inactive— one set to include ACOI wells and one set to exclude them. Wells absent from the "Exclude ACOI" version of the list are presumed to have a compliance order in place.
*** Some wells with an ACOI are also listed in expired TA status, so this total is slightly less than the sum of the preceding rows.

Apps' Ex. 7

This chart, Applicants' Exhibit 7, shows that on that day there were 3,765 inactive wells, 419 of which were in approved TA status, 155 in expired TA status, and 3,234 that were out of compliance. So, only a small percentage of inactive wells were in approved temporary status, **11%**, while the vast majority of inactive wells were out of compliance with Commission rules, **86%.** These data also show that there are many operators in New Mexico avoiding plugging wells on a timely basis. As LFC put it, ". . . virtually all wells on the inactive list are eligible for

[11] Applicants' expert Dwayne Purvis, P.E., working with EDF data management staff, has helped develop and/or review the graphics in my testimony, attached as exhibits.

enforcement action . . . .” LFC Policy Spotlight: Orphan Wells at 18.

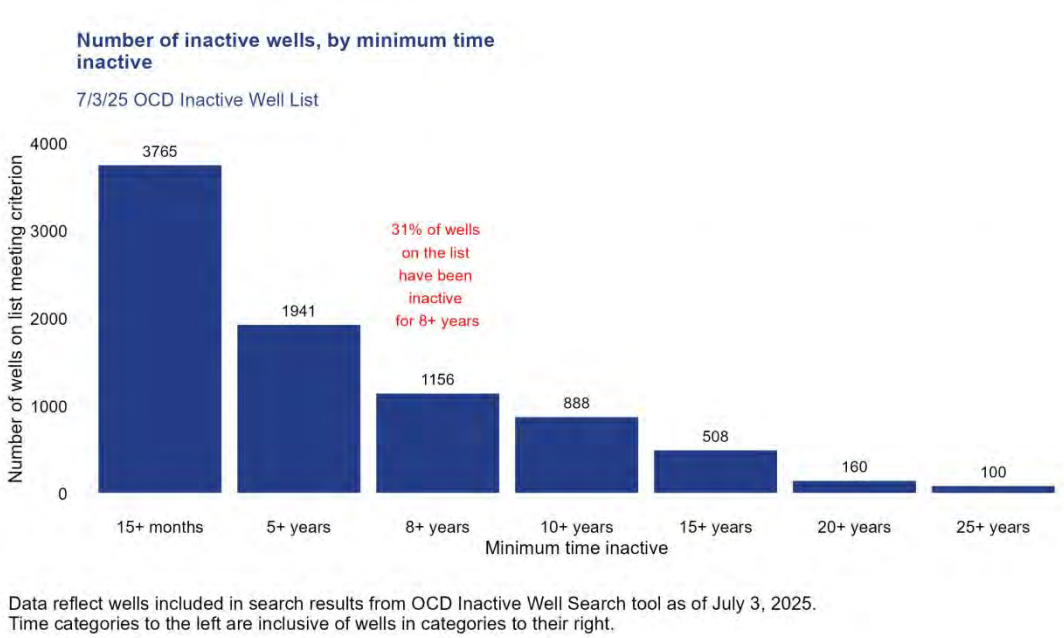
So, on July 3, 2025, there were **3,234 inactive wells** in New Mexico that were out of compliance with Commission rules. Why have they not been put back on production? Why have they not been put to some beneficial use? Why has the operator not at a minimum placed its inactive wells in approved TA status? In short, there are over 3,200 wells in the state grossly out of compliance.[12]

I think we can all agree that this is an unacceptable situation and may likely place the public and environment at risk for a number of reasons. I will state over and over that oil and gas wells, inactive or active, have an inherent risk associated with them. Even the most stringent measures cannot mitigate all risk associated with oil and gas properties. These risks include financial assurance risk, leak risk (surface waters, air, fire and explosion), spill risk (water and air), corrosion risk (leading to unexpected leaks and spills on the surface and underground), and vandalism risk (almost an unlimited menu).

Moreover, inactive wells are likely on an operator’s back burner in terms of attention which means the array of risks are going to be elevated. Requiring more adequate financial assurance for these wells, as proposed by Applicants, not only better insures the State in case of abandonment but gives operators greater incentive properly plug and abandon the well or put it back to use.

[12] These wells are out of compliance with the requirements to plug and abandon or place a well in approved temporary abandonment in 19.15.25.8 and -12 NMAC. Not all these wells may be out of compliance for purpose of the compliance determination in 19.15.5.9 NMAC.

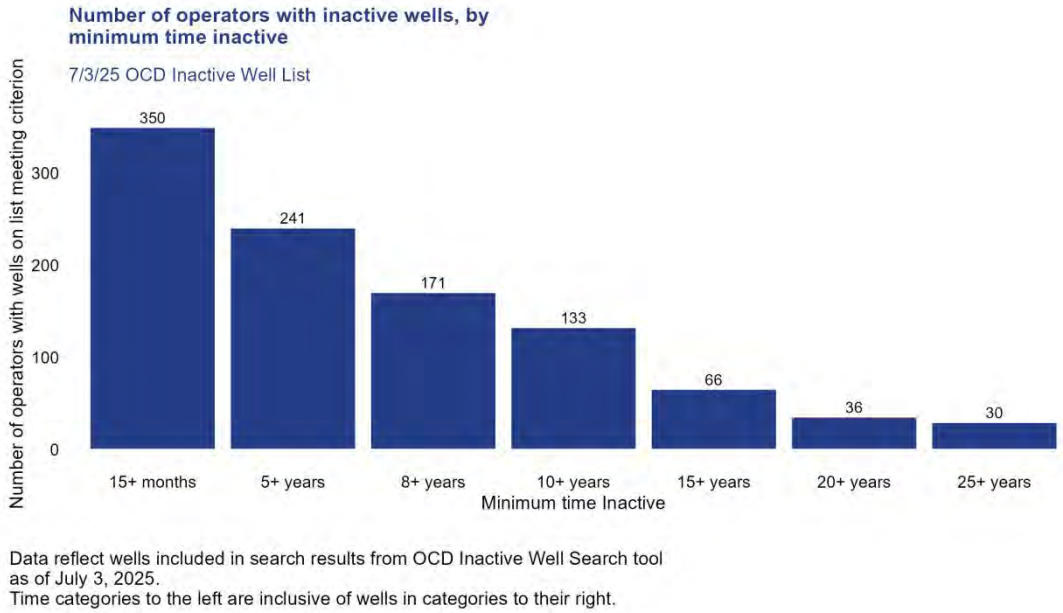
In addition, many inactive wells have been inactive for a long time:



Apps' Ex. 8

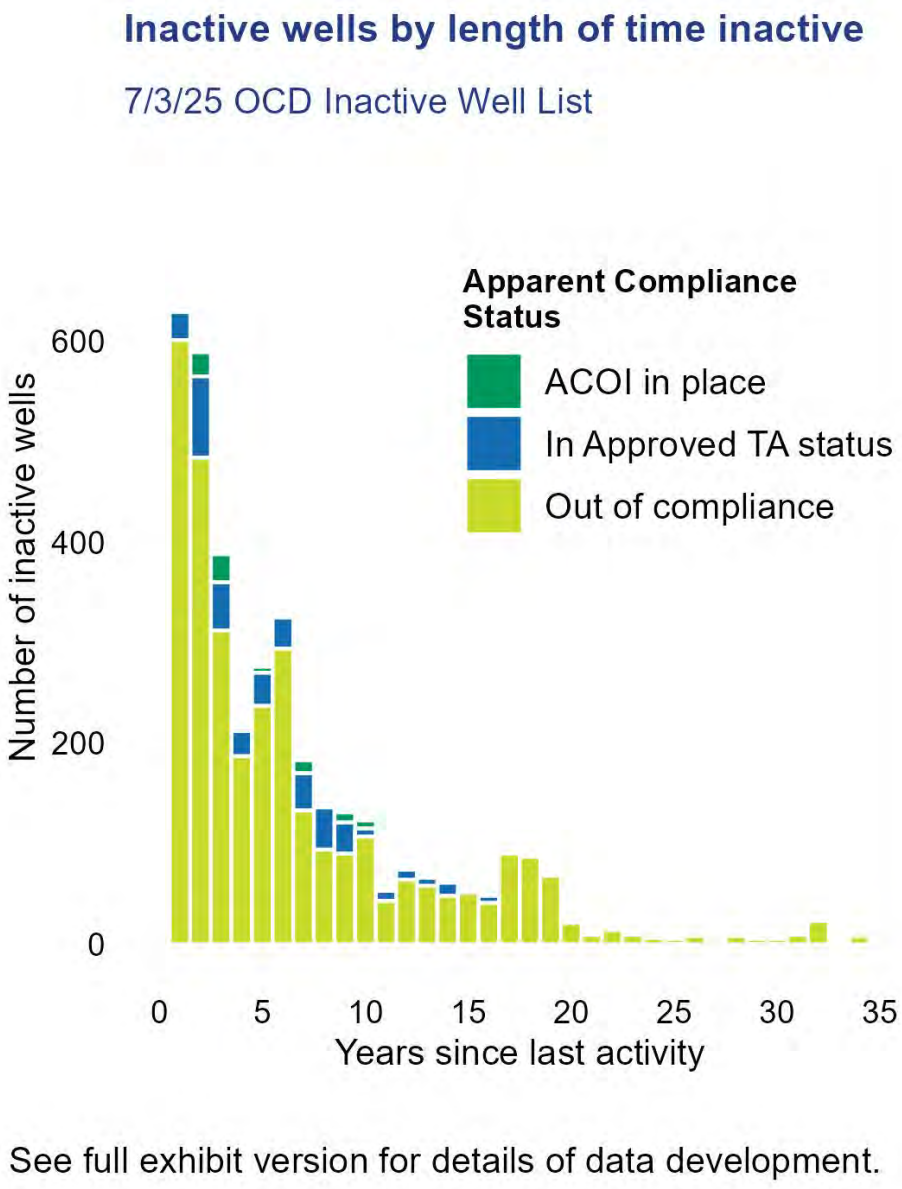
The data speak for themselves. Too many wells are lingering too long in inactive status, as shown by Applicants' Exhibit 8 above. For example, there are almost 900 wells that have not produced for 10 years.

And there are many operators responsible for inactive wells. For example, there are over 130 operators responsible for wells that have been inactive for over 10 years, as shown by Applicants' Exhibit 9:



Apps' Ex. 9

During all periods of inactivity, there is an astoundingly high degree of noncompliance. But after 10 years of inactivity, exceedingly few wells remain in compliance with Commission rules, as shown by Applicants' Exhibit 10:



Apps' Ex. 10

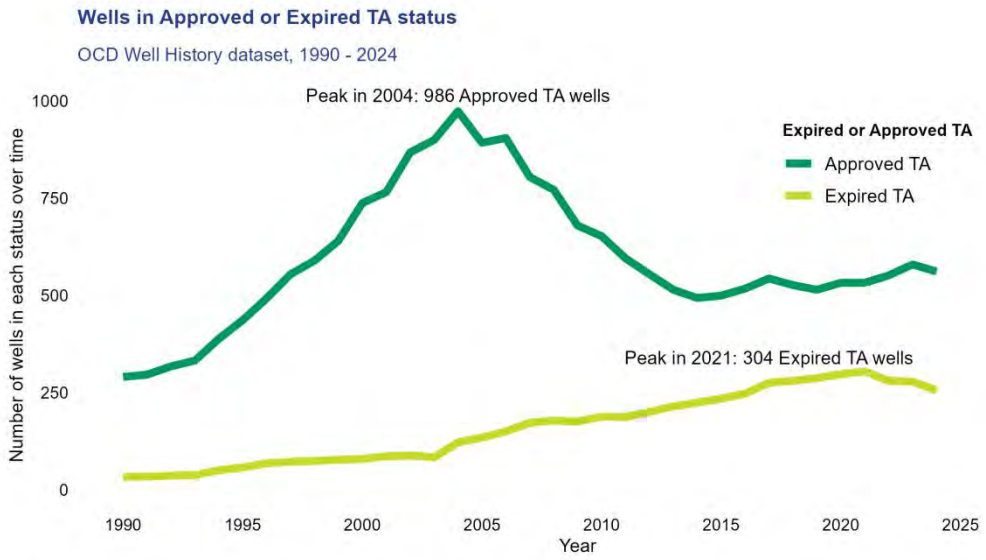
Is there a sound justification why most of these inactive wells should not be plugged and abandoned? The longer a well is inactive, depending upon the operator's financial health, the greater the risk of becoming orphaned, leaving communities and the state to wrestle with the

consequences.

A recent article in The Colorado Sun[13] highlighted the fallout for communities. The Towns of Frederick and Dacono in Weld County are using new legal authority to petition the Colorado Energy and Carbon Management Commission to order the operator K.P. Kaufman Co., Inc. to plug and abandon 45 wells. The towns contend the wells are no longer "used or useful" pose a threat to public health, safety and welfare. While the operator objects, the point is clear: lengthy inactivity not only poses health, environmental and safety threats to the public but renders the surface unusable for more productive endeavors.

Q: Are the numbers of expired TA wells increasing over time?

A; Unfortunately, yes. As shown by the graph below, Applicants' Exhibit 11.



Wells reported in Approved or Expired TA status by OCD Well History dataset, current as of 7/11/25.

Apps' Ex. 11

[13] Mark Jaffe, *Colorado towns take new approach to force oil and gas company to plug old wells*, The Colorado Sun, updated June 11, 2025, https://coloradosun.com/2025/06/10/kpk-dacono-frederick-idle-oil-gas-wells/.

Over time the number of wells in expired TA has steadily increased, from below 50 wells in 1990 to more than 250 wells in 2024. The upward trend of non-compliance is disturbing. Instead of renewing TA status – and renewing the protections and safeguards TA requires – more and more operators are simply not obeying the rules and allowing their wells to linger, out of compliance, in expired TA status. Over time, the mechanical integrity of these wells can be compromised and, again, these wells present a risk to nearby communities and the environment. Clearly, the financial assurance currently required for inactive wells and expired TA wells is not sufficient to incentivize operators to come into compliance with the Commission's rules.

Q: What do the data show with respect to the numbers of wells in approved TA over time?

A: Looking again at Applicants' Exhibit 11, the data show that since 2016 the number of TA approved wells has remained steady; those numbers unfortunately have not decreased over the last 10 years or so

Q: Under the Commission's current rules, what demonstration must an operator make to place an inactive well into temporary abandonment instead of plug and abandon the well?

A: Essentially none. Under the current rules, if a well has not produced for one year, the operator has 90 days either to plug and abandon the well or place the inactive well in temporary abandonment. 19.15.25.8.B(3) NMAC. To place an inactive well in temporary abandonment status, the operator does not have to make any showing that the inactive well will be returned to beneficial use or provide a reason why the inactive well should not be properly plugged and abandoned. The current rules provide:

> An operator seeking approval for approved temporary abandonment shall submit on form C-103 a notice of intent to seek approved temporary abandonment for the

well describing the proposed temporary abandonment procedure the operator will use.

19.15.25.13.A NMAC. The C-103 form is a multi-purpose form that does not require the operator to make any demonstration that a well for which they apply for TA status will be returned to beneficial use or provide a reason why the inactive well should not be plugged and abandoned. Attached as Applicants' Exhibit 12 is a copy of OCD's current C-103 form and 30 examples of operator notices of intent to place a well in temporary abandonment from OCD's Permitting website.[14] . You will notice the Form C-103 has essentially three parts. The first part (items 1-11) are simply administrative details about the well. The second part (items 12 -13) identifies the proposed intention with a description (at a high level) of the procedure to be executed. The third part (at the bottom) is simply a signature block for the operator's designated authority/representative and OCD's approval. Notice there is no request for even a modest justification of the request for TA, or any other of the possible intended actions. The C-103's available on the website range from 2021 to 2025. Applicants' Exhibit 12 includes 30 C-103's seeking initial approval for TA status or seeking renewal of TA status for those years. The 30 forms included were selected in a random fashion, 6 forms for each year from 2021 through 2025. There is a smorgasbord of responses about requesting TA status, be it an initial request or a request for an extension. While there are some forms wherein the operator gave somewhat of a reason why the TA status was being requested, there is never any technical, geological, economical or administrative data and justification to support the request whatsoever. While an operator must demonstrate the mechanical integrity of the well and take other measures to secure

[14] *See* https://wwwapps.emnrd.nm.gov/OCD/OCDPermitting/Operators/Search/OperatorSearch.aspx.

the well for TA status, 19.15.25.10, -14, -15 NMAC, Commission rules require no justification for placing the well in temporary abandonment in the first place.

Similarly, an operator can extend the temporary abandonment for five years and another five years and another five years and so on – there is no time limit -- and current rules require no showing the well will ever be put into production or other beneficial use or why the inactive wells should not be plugged and abandoned. See 19.15.25.12 NMAC.

Q: You testified earlier that other oil and gas producing states require operators to demonstrate that inactive wells will be put to beneficial use in the future or, if not, plug and abandon the wells?

A: Yes, that's correct. **Q: Turning to the Applicants' specific proposals for 19.15.25 NMAC, what amendments do Applicants propose for 19.15.25.8 NMAC?**

A: Applicants propose:

> **19.15.28.8 WELLS TO BE PROPERLY ABANDONED:**
>
> **A.** The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.
>
> **B.** The operator shall either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within ~~90~~ 30 days after:
>
> **(1)** a 60 day period following suspension of drilling operations;
>
> **(2)** a determination that a well is no longer usable for beneficial purposes; or
>
> **(3)** a period of one year in which a well has been ~~continuously~~ inactive.

Q: What is the basis for the amendments?

A: First, the proposed amendments clarify that an operator must apply to OCD to be placed in temporary abandonment status.

Second, Applicants propose to shorten the time period within which an operator must apply for temporary abandonment or plug and abandon the inactive well. The well has already

been inactive for 12 months. The operator has had sufficient time to assess what should be done with the well, that is, apply to place it in temporary abandonment or plug and abandon it. There is no need to give the operator an additional three months, which represents delay and potential risk.

Third, Applicants propose deleting the word "continuously" from the one year period of time for inactivity. This proposal is based on two reasons: First, according to OCD staff, some operators game the system with inactive wells. They have the wells come back into production for a short period of time during the 12 months of inactivity but without intending to actually put the well back into production. According to the Commission's rules, a well is inactive if "it is not being used for beneficial purposes . . . ." 19.15.2.7.I(4) NMAC. Adding the word "continuously" to the requirement for plugging or temporary abandonment distorts the definition of "inactive well" and gives operators an opportunity to avoid either plugging or requesting temporary abandonment when a well is in fact "inactive."

Second, deleting the word "continuously" is consistent with Applicants' proposal to establish rebuttal presumptions for no beneficial use in newly proposed 19.15.25.9 NMAC. Those presumptions are based on the number of days in production or number of days injecting within 12 months and do not require "continuous" inactivity over 12 months to determine a well is inactive.

19.15.25.9 NMAC – Presumptions of No Beneficial Use

Q: What is Applicants' proposal to establish presumptions for no beneficial use?

A: OCD initially proposed establishing rebuttal presumptions for no beneficial use in its February 12, 2025 Redline Proposals. *See* Apps' Ex. 5. Applicants adopted OCD's proposal and propose the following language:

19.15.25.9 PRESUMPTIONS OF NO BENEFICIAL USE:

A. For oil and gas production wells, there is a rebuttable presumption that a well is not capable of beneficial use if, in a consecutive 12 month period, the well has not produced for at least 90 days and has not produced at least 90 barrels of oil equivalent.

B. For injection or salt water disposal wells, there is a rebuttable presumption that a well is not capable of beneficial use if, in a consecutive 12 month period, the well has not injected at least 90 days and at least 100 barrels of fluid.

C. The rebuttable presumptions in this Section do not apply to wells that have been drilled but not completed for less than 18 months and wells that have been completed but have not produced for less than 18 months.

D. Within 30 calendar days after notice of a preliminary determination from the division that a well or wells are not being used for beneficial purposes, a well operator may submit an application for administrative review of such determination through the division's electronic permitting portal. The division shall issue a final determination based on the application and information available in division records. The final determination may be appealed pursuant to 19.15.4 NMAC. Applications to demonstrate beneficial use of a well or wells shall include:

(1) Documentation demonstrating that the well is reasonably projected to produce in paying quantities; and

(2) Documentation demonstrating that the operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all reasonably anticipated plugging and environmental liabilities of the well or wells and associated production facilities, not inclusive of any financial assurance associated with the well or wells; and

(3) Other relevant information requested by the division including a plugging and abandonment plan as described in 19.15.9.9.B NMAC.

Q: What is the basis for this proposal?

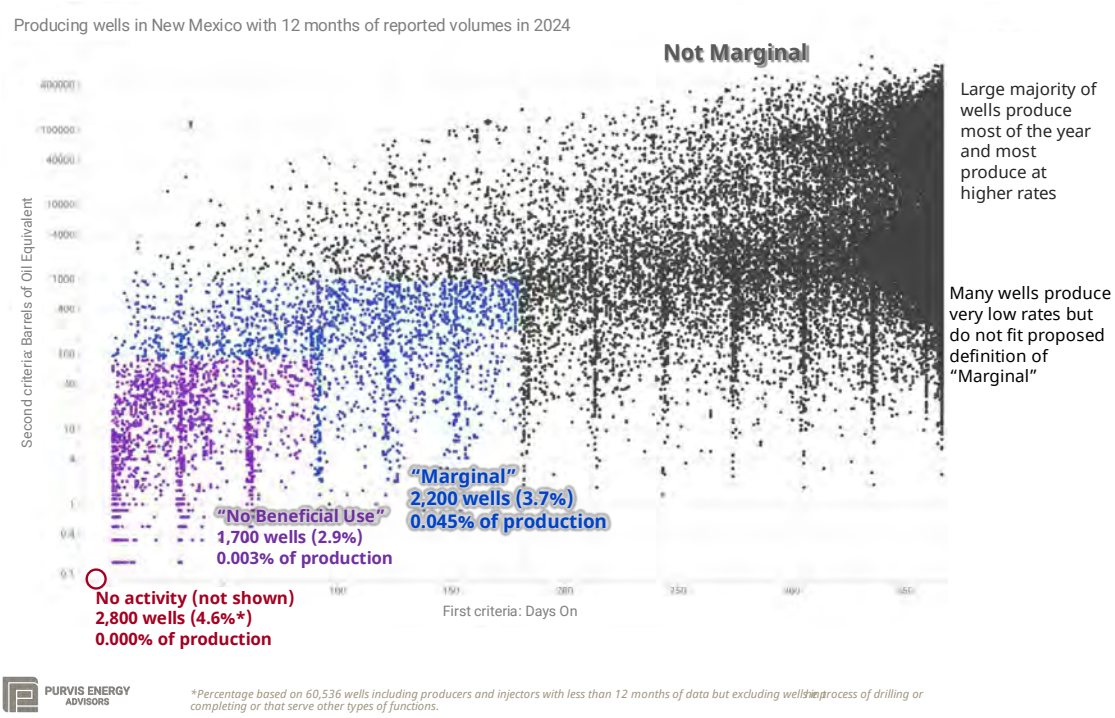
A: First, as mentioned, this set of proposals setting forth presumptions of beneficial use is from OCD and I do agree with them all. Also, as stated in the subsection, these are rebuttal presumptions, meaning that the operator has a full opportunity to provide evidence that the well or wells are of beneficial use. Also, the structure set forth is these proposals triggers an administrative assessment of beneficial use before the well entirely cease production. As to each proposal:

Subsection A. In this proposal a well is deemed of no beneficial use if in a consecutive

12 month period it has not produced at least 90 days and made at least 90 BOE. That amounts to roughly **0.25 BOE per day** which in almost all circumstances, after tax, royalties, and operating expense, is hardly economic. The administrative review is not directed at prudent stripper well operators but those who are problematic based on OCD staff experience. A point of comparison is the recent LFC report on orphan wells. *See* Apps' Ex. 4. In its analysis, LFC deemed wells at or below **2 BOE per day** problematic and observed that with this level of production the average well is plugged and abandoned. *Id.* at 4, 21. OCD's proposed presumption, which is rebuttable, is more than reasonable.

Mr. Purvis has run an analysis on the production wells that would be presumed to have no beneficial use (as well as those that would be categorized as "marginal wells" for purposes of financial assurance at 19.15.8 NMAC). As Mr. Purvis' scatter chart, Applicants' Exhibit 40, below shows, only a small subset of production wells meet the criteria for a presumption of no beneficial use:

Applicants' Exhibit 40: Production vs days of activity of wells in New Mexico during 2024.



Only **2.9% of the state's active wells, or 1,700 wells,** would be presumed to have no beneficial use, accounting for only **0.003% of production** in the state. The proposal -- establishing rebuttal presumptions -- targets the very lowest producing wells, is modest. OCD should have the authority to scrutinize wells that are operating at the edge of solvency in order to prevent the State from taking on more orphaned wells. Indeed, LFC recognizes that the "potential liability for extremely low-producing wells greatly exceeds potential tax contributions. While wells can continue producing in very low quantities for extended periods of time, the financial risk those wells pose to the state far exceeds potential tax revenues." LFC Policy Spotlight: Orphan Wells at 22.

Subsection B. A similar approach is taken for injection wells or salt water disposal wells

in that very minimal activity as described: in a consecutive 12 month period, OCD administrative review is triggered when injection has occurred less than 90 days and less than 100 barrels of fluid have been injected. Such an injection well is barely operating and the operator has the opportunity to demonstrate the well nonetheless has beneficial use. Once again, the purpose is to intervene in problematic situations and assess whether operators should plug and abandon the well before that responsibility falls to the State.

Subsection C. Here the rebuttal presumption does not apply to wells that have been drilled but not completed for less than 18 months as well as to wells that have been completed but have not produced for less than 18 months. In my experience in the Fayetteville Shale development wherein we drilled, completed, and produced approximately 4,500 wells, it was common practice to drill a number of wells at a time on a pad or pads and come back later to complete the wells back to back to back in step with the availability of a sales line in the midstream infrastructure. This was often a complicated set of logistics and services; therefore, it's plausible that an 18 month window is needed and should be granted. I am in favor of the proposal.

Subsection D. This subsection sets forth the administrative procedures for a determination of no beneficial use. In subsections D(1) – (3), the operator is given notice of OCD's preliminary determination that a well does not have beneficial use, given ample opportunity to offer evidence and proof the well or wells are indeed of beneficial use given their low production on injection levels. The information required to be submitted to OCD is relevant to a determination of beneficial use and entirely appropriate. The operator must document that a well is or will be producing in "paying quantities," which means producing more revenue than costs plus accounting for plugging and reclamation costs) in order to be of beneficial use. And

the operator must demonstrate that it has the financial wherewithal to conduct necessary site remediation. The financial assurance associated with the well is not included in that analysis because the financial assurance required under the Oil and Gas Act and Commission rules does not include site remediation. However, if decommissioning a well is left to the State, the State is responsible for that cost, which can range in the tens and hundreds of thousands of dollars. It is also entirely appropriate that OCD may request and be given all relevant information to make an informed decision.

Because Applicants propose to add a new Section 9, the remainder of the sections in 19.15.25 NMAC are re-numbered accordingly.

19.15.25.13 NMAC – Approved Temporary Abandonment

Q: What amendments do Applicants propose to 19.15.25.12 NMAC – Approved Temporary Abandonment, renumbered to 19.15.25.13 NMAC?

A: In general, Applicants propose two fundamental changes to this section. First, Applicants propose that, to be approved for temporary abandonment status, operators demonstrate that an inactive well will be used for beneficial purposes in the future. As already discussed, current Commission rules do not require any demonstration of future beneficial use to place a well in TA status. *See* 19.15.13.A NMAC. However, if an inactive well has no future use, there is no reason the well should not be immediately plugged and abandoned. Placing a well in temporary abandonment with no evidence for beneficial use just delays the inevitable and creates a risk that the well will become orphaned and the State will become responsible for plugging, abandonment, and site remediation.

Second, Applicants propose a limit on the time within which temporarily abandoned wells must be plugged and abandoned. There is no time limit in Commission rules now, and

wells may stay in temporary abandonment indefinitely, which makes no sense and is not in the best interest of preserving resources or the safety of the public and environment. Applicants propose that a well may remain inactive for eight years. This includes one year of inactivity before being placed in temporary abandonment, five years for an initial administrative approval from OCD to be placed in temporary abandonment, and two years for a second approval from OCD after a public hearing to be placed in temporary abandonment. After eight years, the well must be plugged and abandoned or returned to beneficial use.

Specifically, Applicants propose the following amendments for proposed 19.15.25.13.A NMAC:

> **19.15.25.~~12~~13 APPROVED TEMPORARY ABANDONMENT:**
>
> **A.** The division may place a well in approved temporary abandonment for a period of up to five years upon a demonstration from the operator that the well will be used for beneficial use within the approved period of temporary abandonment. The operator's demonstration shall include an explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future including supporting technical and economic data, a plan that describes the ultimate disposition of the well, the time frame for that disposition, and any other information the division determines appropriate, including a current and complete well bore diagram; geological evidence; geophysical data; well casing information; waste removal and disposition; production engineering; geophysical logs, e.g., cement bond logs, caliper logs, and casing inspection logs; and health, safety, and environmental information. If the division denies a request, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

Q: What is the basis for these amendments?

A: As discussed above, I have reviewed form C-103's on OCD's Permitting website and representative samples are included as Applicants' Exhibit 12. As you can see the C-103's provide little or no justification for requesting TA status and no demonstration that the well will ever return to productive use. This is unacceptable for a number of reasons including considerations of environmental protection, safety, health, and landowner rights, and the

increased risk that the well will become orphaned. The proposed amendments are simple and require the operator not to just claim the well will be returned to "beneficial use" but to demonstrate how and when the well will be returned to beneficial use. To make this demonstration, the proposal requires the operator to provide relevant data, analysis and reasoning so that OCD can assess whether the well is likely to be put to use in the future or whether it should be plugged and abandoned now because the operator cannot adequately demonstrate future use. The proposal includes a list of common technical and economic data and administrative information any operator would have and use to justify investment in oil and gas projects. Indeed there is no information requested that isn't mostly available or easily attained. Some of this data may already have been submitted to OCD during the course of the well's life but it should be the responsibility of the operator to consolidate and present the information needed to justify the request in a straightforward and logical manner. It should not be OCD's responsibility to cobble together what information may be on file to hopefully discover a justification.

Q: What additional amendments do Applicants propose to newly proposed 19.15.25.13.A NMAC?

A: Applicants propose adding a new subsection B as follows:

> **B.** Prior to the expiration of an approved temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves, permanently plug and abandon the well and restore and remediate the location, or apply ~~for a new approval to temporarily abandon the well~~ to the division to extend temporary abandonment status pursuant to the procedures for adjudicatory proceedings in 19.15.4 NMAC, except that in any such adjudicatory proceeding any interested person may intervene under 19.15.4.11.A NMAC. To continue in temporary abandonment, the operator must demonstrate to the division that the well will be returned to beneficial use within the requested period of temporary abandonment. The request shall include documentation demonstrating why the well should remain in temporary abandonment; documentation demonstrating why the well was not brought back to beneficial use or plugged and abandoned during the period of temporary abandonment; documentation demonstrating how

the well will be put to beneficial use in the future and supporting technical and economic data; a plan that describes the ultimate disposition of the well, the time frame for that disposition; and a health and safety plan demonstrating the well's casing and cementing meet the requirements of Subsections B and C of Section 19.15.25.13 NMAC and the operator has adequate monitoring procedures in place to ensure such requirements will be met. An extended term shall not exceed two additional years, upon which time the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

Q: What is the basis for this proposal?

A: This section of the TA proposal pertains to the period following a five year temporary abandonment, and allows an operator to request an additional two years to remain in TA status pursuant to a public hearing before OCD.

To extend TA status for an additional two years, the operator must provide the same technical, economic, and administrative information to demonstrate the well has future beneficial use initially required and (1) an explanation why the well was not put back into beneficial use during the previous five years of temporary abandonment and (2) a health and safety plan. Requiring an explanation why the well was not put back into use makes sense: the operator should be able to explain to OCD and interested parties why its original plan to bring the well back into to use did not come to fruition and why the operator believes the well will be put into use over the next two years. The health and safety plan must demonstrate that the well's casing and cementing meet current Commission requirements for mechanical integrity and that there are adequate monitoring procedures in place to ensure such requirements will be met.

TA properties offer many opportunities for harm due to mechanical failure, intentional or unintentional interaction by peripheral operations or activities, and neglected infrastructure. To this end also, the operator should be required to demonstrate the mechanical integrity of critical well elements such as cement sheath and casings/tubing, plus methods that will be deployed to

monitor the status of same for the remainder of the requested time spent in TA status. To be clear, it is naïve to think that a TA well is eternally safe and static

The proposed amendments to extend TA status include an opportunity for interested parties to participate in a public hearing process before OCD. The justification for this is several fold. First, hearing from interested parties may provide additional information and valuable insight and perspectives that will assist OCD in understanding potential impacts of TA to develop the best informed basis for a decision to permit continued TA status
or not. Second, allowing public participation at critical points and decisions will provide greater transparency and accountability in the decision process. Third, public participation can add local concerns or expertise that may otherwise not be part of the OCD decision making process.

Q: Current Commission rules at 19.15.25.13 and -14 NMAC require mechanical integrity testing and other protections in order for an inactive well to be placed in temporary abandonment and prior to each renewal. Why are these requirements not sufficiently protective to allow wells to remain in TA status indefinitely?

A: The current rule falls well short of providing necessary protections for the environment and public for a number of reasons. It is, of course, good that a mechanical integrity test ("MIT") is conducted to provide evidence at that moment of the test. Applicants proposed several amendments to 19.15.25.13 and -14 NMAC to provide better protection that I discuss below.

However, during the course of the five year temporary abandonment period, during which no further MIT or robust monitoring is required[15], there are opportunities for undetected corrosion to express itself via leaks underground. Also, if the perforated interval is protected only

[15] The Methane Waste Rule requires at least monthly audio, visual and olfactory inspections for methane leaks on inactive and TA wells. 19.15.27.8.E(5)(c)(ii) NMAC.

by a weighted completion fluid, there is opportunity for fluid exchange or offset operator activity that could render the back pressure insufficient to contain the well properly. This means that wells can emit methane and pollutants that can harm human health, and leak fluids onto the surface and into the ground contaminating the soil and potentially contaminating ground and surface water.

Further, wells that are in TA frequently are not tended on a regular basis, thus opening up opportunities for decay of seals and valves that can lead to leaks, fires, and possible explosions. There is always the possibility of vandalism which can be a very serious opportunity for injury or death. I have seen this happen in my experience as an operator in Colorado and Arkansas. Many operators and jurisdictions require scheduled monitoring and in particular checking pressures on the tubing and backside to spot any unusual pressure buildups or fall offs. The list could go on.

Q: What other amendments do Applicants propose to proposed 19.15.25.13 NMAC?

A: There is a new Subsection C, which is non-substantive and re-numbers the rules, as follows:

> **C.** An operator is limited to placing the following numbers of wells in approved temporary abandonment:
> ~~**A.**~~**(1)** one well, if the operator operates between one and five wells; or
> ~~**B.**~~**(2)** one-third of all wells (rounded to the nearest whole number), if the operator operates more than five wells.

There is a new Subsection D, which is an implementation schedule for the new rules, which provides:

> **D. Implementation schedule for existing wells.**
> **(1) Inactive wells.** Wells that have been inactive for less than three years are eligible for temporary abandonment status. Wells that have been inactive for three or more years are not eligible for temporary abandonment status.
> **(2) Wells in approved temporary abandoned status.** Any operator of a well in temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status

in accordance with Subsection B of this Section prior to the date temporary abandonment status terminates. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(3) Wells in expired temporary abandoned status. Any operator of a well in expired temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status in accordance with Subsection B of this Section. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

Q: What is the basis for this proposal?

A: The proposed implementation schedule is composed of three categories: inactive wells (that are not in approved or expired TA status), wells in approved temporary abandonment, and wells in expired temporary abandonment.

Inactive wells: In this proposed section, wells that have been inactive for less than three years and are not in approved TA status are eligible to apply for TA status. Wells that have been inactive for three years or more and are not in TA status are not eligible for TA status. OCD staff proposed the three-year cutoff, based on their experience with operators and wells that have been inactive, and Applicants have adopted this proposal.

On July 3, 2025, there were **3,234 wells** on OCD's inactive well list that had been inactive between 15 months and three years and that were not in approved TA status or subject to an Agreed-to Compliance Order. While these wells are clearly out of compliance with Commission rules, because their period of inactivity is not excessive and there is some likelihood the wells can be put to beneficial use, Applicants propose that they may still be allowed to make the required demonstration that the well will be put to beneficial use in the future. If the operator cannot make that demonstration, the well must be plugged.

Wells that have been inactive more than three years and that are not approved for TA

status are also clearly out of compliance with Commission rules and the time period of non-compliance is getting to be more excessive. Those wells are less likely to ever come back into productive use, and should be plugged and abandoned. As shown by data I present below, with each successive year of inactivity, the likelihood of a well coming back on line decreases.

Wells in approved temporary abandonment: Wells in approved temporary abandonment are in compliance with Commission rules and this is a simple go forward provision. The well(s) may remain in TA status for the remainder of its five year TA period at which time the operator may turn the well(s) to beneficial use, P&A, or apply to extend the TA status under the provisions set for in proposed Subsection B of 19.15.25.13 NMAC above. There are approximately 419 wells in this status. There provision is straightforward.

Wells in expired temporary abandonment: There are currently 155 wells in this status. These wells have already been in TA status for at least five years and certainly the operator has a good idea what the realistic destiny of these wells is. I would also point out that the operators of these wells, just as the ones with out of compliance inactive wells, have operated with indifference to current regulations and are out of compliance. Therefore, in this provision the operator can either submit for a two year extension according to proposed Subsection B of 19.15.25.13 NMAC, return to beneficial use or permanently plug the well(s) and restore the locations. This proposal is quite generous.

Q: What is the basis for newly proposed 19.15.25.13.E NMAC?

A: That provision provides:

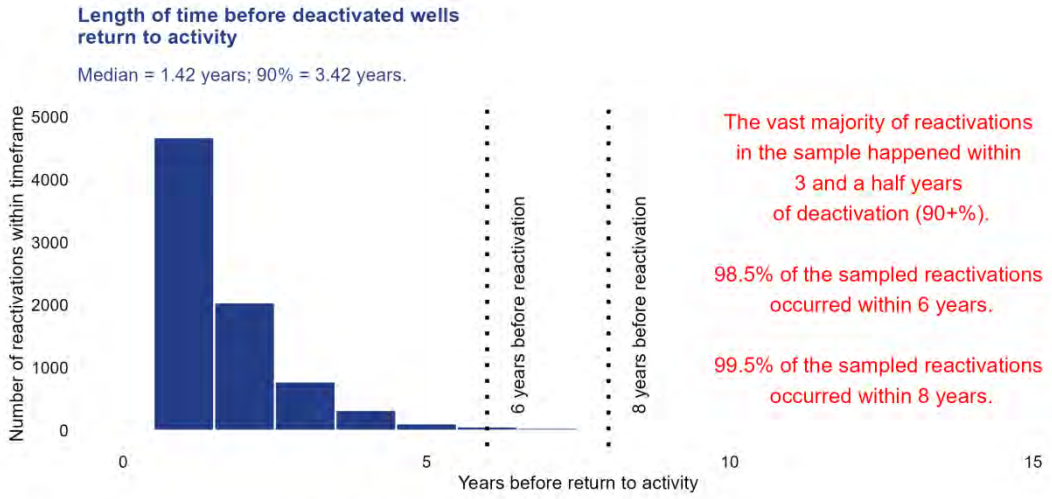
> **E.** The timeframes in Subsections A and B in this Section shall be implemented consistent with any applicable federal requirements.

This provision was added at the suggestion of OCD to ensure that these state requirements do not conflict with federal requirements for plugging and abandonment for federal wells. OCD

coordinates with the U.S. Bureau of Land Management on requirements to plug and abandon wells that are subject to federal regulation.

Q: As you observed, Applicants' proposal allows wells to remain inactive for eight years and then the well must be plugged or put back into use. There is a one year period of inactivity prior to applying for temporary abandonment, a five year period of temporary abandonment, and a two year extended period of temporary abandonment after a public hearing. What is the basis for these time frames?

A: The critical time periods in the proposal are (1) after a well has been inactive six years, a hearing before OCD is required for the well to continue in TA status and (2) after a well has been inactive eight years, the well must be plugged or go back into use. The data support these timeframes, as shown by the graphic below, which is Applicants' Exhibit 13.



Apps' Ex. 13

The graphic above shows the timeframes on which a sample of New Mexico inactive wells

reactivated after their last activity, after at least 12 months inactive. At the six year point, when a hearing before OCD is required to continue in TA status, all but a small percentage of wells – **1.5%** -- had already reactivated. And, after eight years of inactivity, when P&A is required if the well does not go back into use, all but **0.5%** of wells had already returned production. These data demonstrate that the chance of wells going back into use after eight years is almost non-existent, as almost all wells return to activity far sooner if they are going to do so at all. Applicants' proposal to require wells that have been inactive for eight years to be plugged or go back into use is entirely reasonable based on New Mexico data.

19.15.25.14 NMAC – Request for Approval and Permit for Approved Temporary Abandonment

Q: What amendments do Applicants propose for existing 19.15.25.13 NMAC, renumbered to 19.15.25.14 NMAC?

A: Applicants propose:

19.15.25.~~13~~14 REQUEST FOR APPROVAL AND PERMIT FOR APPROVED TEMPORARY ABANDONMENT:

A. An operator seeking approval for approved temporary abandonment shall submit the request on form C-103 ~~a notice of intent~~ to seek approved temporary abandonment for the well setting forth the demonstration required in 19.15.25.12 NMAC and describing the proposed temporary abandonment procedure the operator will use. The operator shall not commence work until the division has approved the request. The operator shall give 24 hours' notice to the appropriate division district office before beginning work.

B. The division shall not approve a permit for approved temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:

(1) damage to the producing zone;

(2) noncontainment of well bore fluids to the atmosphere or migration of hydrocarbons or water;

(3) the contamination of fresh water or other natural resources; and

(4) the leakage of a substance at the surface.

C. The operator shall demonstrate both internal and external mechanical integrity pursuant to Subsection A of 19.15.25.14 NMAC.

D. Upon successful completion of the work on the temporarily

abandoned well, the operator shall submit a request for approved temporary abandonment to the appropriate division district office on form C-103 together with other information Subsection E of 19.15.7.14 NMAC requires.

E. The division shall not approve a permit for approved temporary abandonment until the operator provides financial assurance for the well that complies with Subsection D of 19.15.8.9 NMAC.

F. The division shall specify the permit's expiration date~~, which shall be not more than five years from the date of approval.~~

Q: What is the basis for these amendments?

A: In Subsection A, the amendments clarify that an operator must request approval for TA status and must set forth the demonstration required in 19.15.25.13.A NMAC on a form C-103.

In proposed Subsection B(2), Applicants propose that proof be given to OCD that the well's mechanical integrity is sufficient to prevent wellbore fluids from contaminating the atmosphere. This provision is in addition to current provisions to protect the producing zone, migration of hydrocarbons or water, contamination of freshwater or other natural resources or leakage of a substance to the surface. The measures an operator is required to take to place a well in TA status should already ensure no emissions to the atmosphere, and therefore this addition clarifies and makes more complete the environmental protections in place for TA wells.

The proposed amendment in Subsection F – deleting the reference to a five year permit term – is necessary to be consistent with Applicants' proposal for a two-year extension of TA status, after an initial five year period of TA, pursuant to a public hearing before OCD.

19.15.25.15 NMAC – Demonstrating Mechanical Integrity

Q: What amendments do Applicants propose for existing 19.15.25.14 NMAC, renumbered to 19.15.25.15 NMAC?

A: Applicants propose:

19.15.25.~~14~~.15 DEMONSTRATING MECHANICAL INTEGRITY:

A. An operator may use the following methods of demonstrating internal casing integrity for wells to be placed in approved temporary abandonment:

(1) the operator may set a cast iron bridge plug within 100 feet of uppermost perforations or production casing shoe, load the casing with inert fluid and pressure test to 500 psi surface pressure with a pressure drop of not more than 10 percent over a 30 minute period;

(2) the operator may run a retrievable bridge plug or packer to within 100 feet of uppermost perforations or production casing shoe, and test the well to 500 psi surface pressure for 30 minutes with a pressure drop of not greater than 10 percent over a 30 minute period; or

(3) the operator may demonstrate that the well has been completed for less than five years ~~and has not been connected to a pipeline~~.

(4) Any isolation device used to test mechanical integrity pursuant to Subsection A of this Section shall remain in place for the duration of the temporary abandonment.

(5) The operator shall perform a caliper log and casing integrity log.

(B) During the testing described in Paragraphs (1) and (2) of Subsection A of 19.15.25.14 NMAC the operator shall:

(1) open all casing valves during the internal pressure tests and report a flow or pressure ~~change~~ occurring immediately before, during or immediately after the 30 minute pressure test;

(2) top off the casing with inert fluid prior to leaving the location;

(3) report flow during the test in Paragraph (2) of Subsection A of 19.15.25.14 NMAC to the appropriate division district office prior to completion of the temporary abandonment operations; the division may require remediation of the flow prior to approving the well's temporary abandonment.

(C) An operator may use any method approved by the EPA in 40 C.F.R. section 146.8(c) to demonstrate external casing and cement integrity for wells to be placed in approved temporary abandonment.

(D) The division shall not accept mechanical integrity tests or logs conducted more than 12 months prior to submittal.

(E) The operator shall record mechanical integrity tests on a chart recorder with a maximum two hour clock and maximum 1000 pound spring, which has been calibrated within the six months prior to conducting the test. Witnesses to the test shall sign the chart. The operator shall submit the chart, caliper log, and casing integrity log with form C-103 requesting approved temporary abandonment.

(F) The division may approve other testing methods the operator proposes if the operator demonstrates that the test satisfies the requirements of Subsection B of 19.15.25.13 NMAC.

Q: What is the basis for these proposed amendments?

A: The Commission's current rules requiring a demonstration of mechanical integrity in order for wells to be placed in TA status are well done. Applicants propose several additional

safety measures be applied to wells that are going to be in TA status. The proposed provisions twice require running and submitting a caliper log and casing integrity log. Simply stated, these two logs are designed to evaluate the state of the casing especially with regard to any corrosion that may be in process. This is especially critical in wells that have corrosive elements in their produced fluids and gases. Actually, the operator should want to know if the casing is competent and if there is a corrosion issue, so that any problem can be addressed before there is a major issue (such as catastrophic failure) leading to a potential blowout underground causing contamination of nearby zones or potentially worse. OCD recommended these logs be required now before permitting a well into TA status and I completely agree.

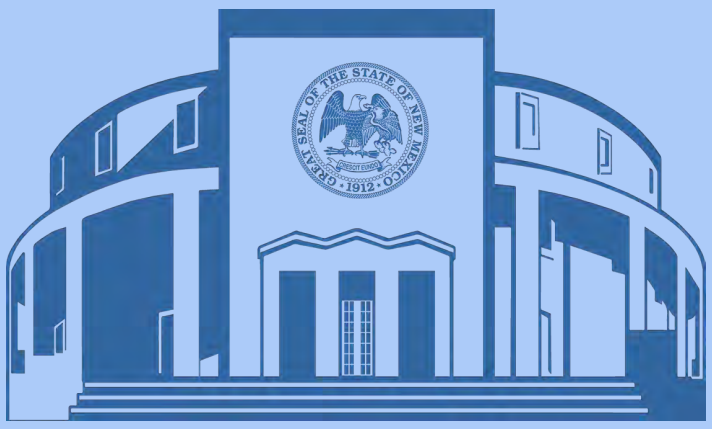
Applicants next propose that any device, cast iron bridge plus or retrievable plug for example, that is used to test a well's mechanical integrity be left in place during the time the well is in TA status. This adds another layer of protection to a well. Obviously the devices are simple to install and retrieve and would be used anyway in the mechanical integrity test, so keeping them in place makes sense. Wells left in TA status with the wellhead shut-in sounds safe enough but the downhole environment in anything but static, especially if corrosion is an issue. Plugging of intervals that have been perforated and have residual pressure is the prudent thing to do to have an additional barrier to protect from downhole contamination and help safeguard environment and personnel safety in case of an unexpected failure. None of these proposed provisions is expensive, nor do they require any special expertise to execute. If the operator or well(s) can't absorb the cost and execution of these safety measures, there is a larger problem and perhaps the prudent course is to proceed with P&A.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Tom Alexander August 5, 2025
Tom Alexander Date

EXHIBIT 4

Policy Spotlight: Orphaned Wells



June 24, 2025

Apps' Ex. 4

Legislative Finance Committee

Representative Nathan P. Small, Chair
Senator George K. Muñoz, Vice Chair
Representative Jack Chatfield
Representative Meredith A. Dixon
Representative Rebecca Dow
Representative Susan K. Herrera
Representative Derrick J. Lente
Representative Joseph Sanchez
Representative Harlan Vincent
Senator Pete Campos
Senator Roberto “Bobby” J. Gonzales
Senator Steve D. Lanier
Senator Benny Shendo Jr.
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Contents

Summary **1**

New Mexico faces significant and growing financial liabilities for oil and gas well cleanup. 1

Background **4**

New Mexico has long recognized the importance of plugging wells at their end of their lives, but there is no consensus on when that is. 4

Since the 1970s, the state has stepped in to plug oil and gas wells when the operator does not. 7

OCD spent $46.4 million between FY19 and FY24 on plugging and reclamation of 360 wells and their associated infrastructure. 12

Current Orphaned Wells Will Cost the State More Than $200 Million; Future Liability Very Likely Exceeds $700 Million **14**

Plugging and reclaiming the well sites and associated infrastructure OCD currently has responsibility for will likely cost between $200 million and $400 million. 15

OCD expects to plug and reclaim most wells on its inactive well list, which would cost close to $500 million. 18

In addition to fully inactive wells, thousands of extremely low-producing wells have minimal revenues and hundreds of millions of dollars in outstanding cleanup liabilities. 20

Reforms That Prioritize Operator-Led Cleanup can Limit the State's Financial Exposure **24**

OCD struggles to control both the cost and quality of state-contracted plugging. 24

Despite recent increases, financial assurance posted by operators is typically insufficient to cover the costs of plugging and remediating orphaned well sites. 31

Regulators in other states and countries reduce their liability for plugging and remediating orphaned wells through various mechanisms. 32

Appendix A. EMNRD Report Card Updates on Orphaned Well Plugging **38**

Appendix B. Other State Financial Assurance Amounts **40**

Appendix C. History of the Oil and Gas Conservation Tax and the Oil and Gas Reclamation Fund **41**

Appendix D. Texas Plugging Costs **42**

Appendix E. OCD Well Plugging Prioritization System **43**

Appendix F. OCD Organizational Structure **44**

Summary

New Mexico faces significant and growing financial liabilities for oil and gas well cleanup.

Properly plugging and decommissioning wells at the end of their productive lives is important to protect health and safety, the environment, and future resource development.

New Mexico has more than 60 thousand oil and gas wells that will eventually need to be plugged. Properly plugging and decommissioning those wells at the end of their productive lives is important to protect health and safety, the environment, and future resource development.

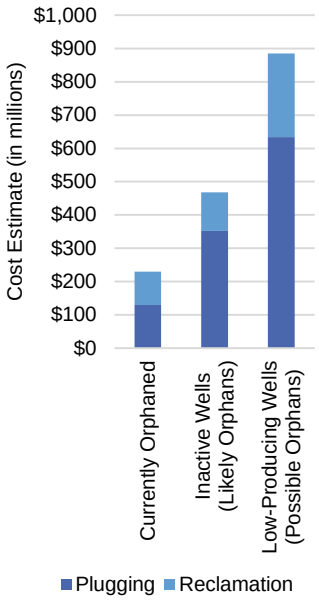
While operators plug most wells in New Mexico, the Oil Conservation Division (OCD) of the Energy, Minerals and Natural Resources Department (EMNRD) can intervene to plug wells that operators leave inactive and unplugged without authorization. In the past 20 years, OCD has plugged approximately 1,000 of those "orphaned" wells, or 5 percent of all wells plugged in the state. However, the number of wells the division is authorized to plug has consistently outpaced its plugging efforts.

Currently, OCD has plugging authority for roughly 700 wells on state and private ("fee") lands. The state likely will need to plug an additional 1,400 inactive wells for which OCD has not yet pursued plugging authority. On top of that, there are more than 3,000 wells on state or private land producing extremely small quantities of oil and gas whose expected cleanup costs far exceed their predicted future revenues, increasing their risk of being orphaned.

At recent state-contracted rates, plugging, remediating and reclaiming currently orphaned wells and their associated infrastructure will likely take close to a decade and cost more than $208 million. Plugging and reclaiming the other 1,400 inactive wells on state and private land could cost more than $468 million. Should additional extremely low-producing wells be orphaned by their operators, the costs for plugging and reclaiming them could approach $1 billion. Altogether, the state's current and near-future liability for well plugging and site remediation is estimated at $700 million to $1.6 billion.

Recent federal grants have increased OCD's plugging capacity, but the division is still unable to plug wells at a rate that would allow it to clear its existing orphaned well list in a timely fashion, even without accounting for additional wells that are likely to become orphaned. The division has also struggled to control the costs of plugging and reclamation. Given that, it would be prudent for the state to reduce its future liability for orphaned wells, which could be accomplished through a variety of mechanisms, including revising its financial assurance system to incentivize operators to plug wells before they become fully inactive.

Chart 1. Liability Estimates for Plugging and Reclamation



*Note: Only wells on state or private lands; categories are mutually exclusive; plugging based on actual depth, $43.85/foot, gas wells costing 9 percent more than oil wells; reclamation at $83 thousand per well site.

Source: LFC

Project Objectives

- Assess the current scope of the orphaned well problem in New Mexico, including the environmental, economic, and health and safety impacts.
- Evaluate the adequacy of the state's current regulatory framework for preventing wells from becoming orphaned, and the efficacy of its current efforts to plug and abandon orphaned wells.
- Estimate the state's potential future liability for orphaned wells and accompanying infrastructure.

Key Findings

- Current orphaned wells will cost the state more than $200 million; future liability very likely exceeds $700 million.
- Reforms that prioritize operator-led cleanup can limit the state's financial exposure.

Key Recommendations

The Legislature should consider:

- Amending statute to define "orphaned" and "abandoned" wells, aligning the definitions with their common use in the oil and gas industry and clarifying that "orphaned" wells are oil and gas wells for which the state has pursued and received plugging authority;
- Amending Section 70-2-14 NMSA 1978 to specify that wells producing below certain thresholds set in rule require additional financial assurance;
- Amending Section 70-2-14 NMSA 1978 to allow an operator to meet its financial assurance obligations by fully funding a third-party trust or escrow up to OCD's site- or operator-specific estimated plugging and remediation costs; and
- Amending statute to clarify OCD's authority to review and disallow the transfer of wells should the division determine, through processes outlined in rule, the purchaser is unlikely to be able to fulfill its asset retirement obligations.

The Energy, Minerals and Natural Resources Department should:

- Promulgate rules defining "low-producing" wells (such as wells producing less than 750 BOE annually or ~ 2 BOE per day);
- Promulgate rules to expand the definition of "inactive" wells to include consistently ultra-low producing wells (such as wells that produce less than 180 BOE annually or ~0.5 BOE per day for more than three years);
- Promulgate rules specifying that low-producing wells require individual well financial assurance, posted within two months of

notice, and clarifying that their transfer is contingent on regulatory approval;

- Publish a list of orphaned wells monthly, including both wells the state has already plugged and those it is planning to plug and the costs associated with their plugging and reclamation, to ensure transparent tracking of state expenditures on orphaned wells; and
- Ensure the presence of a "company man" for all state-contracted well plugging who is responsible for filing daily reports on the activities undertaken by the contractor, the materials used, and the estimated plugging cost.

Background

New Mexico has been an oil and gas producing state for more than a century. During that time, companies have drilled at least 121 thousand oil and gas wells in the state, mostly in the northwest (San Juan Basin) and southeast (Permian Basin). Wells must be plugged at the end of their productive lives to protect the environment, health and safety, and future resource production. For wells still producing any volume of oil or gas, the state typically leaves it to operators to decide when the well should be plugged—in recent years, the average well produced roughly two barrels of oil equivalent a day in the year before it was plugged. However, if a well becomes fully inactive for more than a year, the Oil Conservation Division (OCD) of the Energy, Minerals and Natural Resources Department (EMNRD) can require an operator to plug the well or pursue authority to plug it itself to mitigate potential risks. Since the 1970s, OCD has largely paid for state-contracted plugging using money from the oil and gas reclamation fund, which receives a portion of the oil conservation tax. Since 2022, the state has also received $55.5 million in multiyear federal grants to address unplugged orphaned wells on state and private lands.

New Mexico has long recognized the importance of plugging wells at their end of their lives, but there is no consensus on when that is.

Oil and gas wells, by design, tap into subsurface reservoirs that are often more than a mile deep. When active production ceases, the wells can become pathways for hazardous substances to escape, including gases like methane and hydrogen sulfide and fluids like produced water and residual hydrocarbons. Those leaking gases and fluids can contaminate groundwater, endanger nearby homes, and impede future development of oil and gas resources. Modern plugging involves using cement to seal off oil, gas, and water-bearing formations to prevent leaks to the surface or adjacent strata, while site remediation and reclamation involve removing contaminated soil and disposing of surface infrastructure. Since the 1930s, New Mexico has required operators to plug wells at the end of their productive life.

Plugging wells mitigates the risk of a variety of hazards, including groundwater contamination. In the early 20th century, most states started requiring companies to plug oil and gas wells that were no longer producing or otherwise inactive with the goal of oil conservation because unplugged wells can lead to pressure drops or water intrusions that impede oil recovery. However, over time, regulators also recognized the importance of plugging for conservation of other resources, including groundwater. Improperly sealed wells can act as a conduit for fluids and gases to migrate into underground aquifers. A 2011 study by the Groundwater Protection Council, an organization whose members are state groundwater regulators, found inactive and unplugged wells were responsible for 22 percent of oil-

Terms and Definitions

Many terms used in the oil and gas industry are inconsistently defined. For example, "abandoned well" means different things in different parts of New Mexico statute. For this report, the following definitions apply, unless otherwise specified:

Orphaned well
A well for which the state has received plugging authority, either through a settlement agreement, order, or intergovernmental agreement.

Abandoned well
A well that has been properly plugged, either by the state or its operator.

Inactive well
A well that has not produced or injected for at least 15 months.

Plugging
Placing cement plugs at specific depths inside the wellbore to prevent migration of fluids and gas.

Remediation
Removal or treatment of contaminated soil and groundwater.

Reclamation
Removing infrastructure and returning the land to a condition as close to its original state as possible.

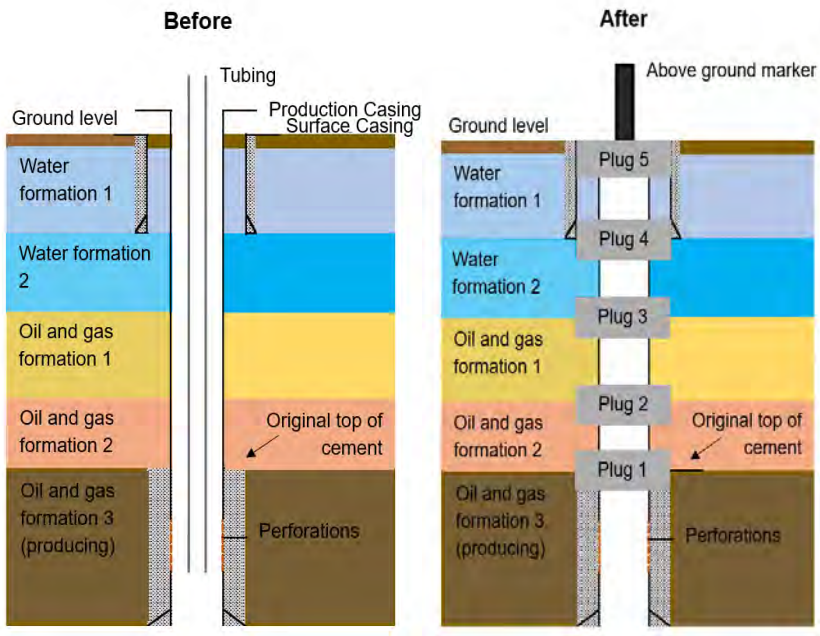
Produced water
Water that is brought to the surface alongside the oil and gas produced from a well. Produced water is also called "saltwater" because it typically contains high levels of salts, hydrocarbons, and other contaminants.

Barrel of oil equivalent (BOE)
A standardized unit that combines oil and gas into a single measure; one barrel of crude oil or 6,000 cubic feet of natural gas (6 mcf) equals one BOE

and gas-related groundwater contamination incidents in Ohio and 14 percent in Texas over a 16-year study period. Improperly plugged or unplugged wells have also been implicated in surface contamination incidents, including recently near the Texas-New Mexico border, where the wells have served as conduits for large leaks of produced water and hydrocarbons. Unplugged or improperly plugged wells can also leak gases, including hydrogen sulfide, which is toxic and highly corrosive, and methane, which is both a potent greenhouse gas and explosive. The federal Environmental Protection Agency estimates annual methane emissions from the nation's inactive and unplugged oil and gas wells are comparable to adding an additional 2 million gas-powered cars to the road. Although rare, methane leaks from oil and gas wells have also caused buildings to explode.

OCD regulations for plugging require placing cement at various depths inside the wellbore. Cement is the primary material used in oil and gas wells to prevent fluid and gas migration. When a well is constructed, companies anchor the steel casing that lines the well in place by filling sections of the space between the casing and the surrounding rock formation with cement. Similarly, when a well is plugged, cement is used to both seal off the producing formation and any hydrocarbon- and water-bearing formations above it. OCD may also require other types of mechanical barriers to be set inside the wellbore. The location of plugged wells must be marked with a 4-inch-wide, 4-foot-tall steel post, unless OCD grants a waiver to place the marker below ground.

Figure 1. Well Plugging



Source: OCD

Rising Incidence of State-Contracted Emergency Well Plugging in Texas

In November 2024, Texas' oil and gas regulator, the Texas Railroad Commission (RRC), requested an additional $100 million appropriation for FY26-27 for well plugging, saying, "Emergent issues have developed that have made [the initial $234 million request] insufficient to protect groundwater and the environment." While the request did not cite any specific incidents, RRC has reported responding to a number of well emergencies in the region of west Texas bordering New Mexico in recent years. For example, in December 2023, an unplugged well on a ranch in west Texas began leaking produced water at 14,000 gallons an hour. The water eventually covered more than 300 acres and pooled to as deep as a foot. Testing found the water contained 10 times the EPA's allowable amount of benzene, a chemical found in crude oil that is a known carcinogen. With no existing operator associated with the well, RRC paid $2.5 million to plug the well and clean up the spill.

After a well is plugged, OCD may require remediation and reclamation of the well site. During active production, wells may leak oil, produced water, or drilling fluids, either from the well itself or from associated pits and tanks. When spills occur, operators are required to remediate the site promptly. However, a second round of remediation is often necessary at the end of a well's life to ensure the site is clean before closure. Remediation focuses on removing polluted soil and, if necessary, addressing impacts to surface water or groundwater. When remediation is necessary, OCD regulations require the top 4 feet of soil be free of contamination, usually achieved through excavation and replacement of the affected soil. Reclamation is usually characterized as restoring the land to its prior physical and ecological condition. Prior to well closure, OCD requires operators to level the site, remove equipment and debris, and close pits and tanks. OCD does not have a requirement for the operator to restore native vegetation or remove roads. The State Land Office (SLO) has its own requirements for reclaiming well sites on state trust land, which include erosion prevention, removal of infrastructure and roads, and revegetation.

Figure 2. Remediation and Reclamation



Remediation involves cleaning up surface and groundwater contamination, as at the Chaves County site on the left. Reclamation involves leveling the site and removing any equipment, as at the Eddy County site on the right.

Source: LFC files

Roughly half of wells drilled in New Mexico have already been plugged, although not always to modern standards. Of the roughly 121 thousand wells drilled in New Mexico, OCD records compiled by the energy analytics firm Enverus show at least 54 thousand have been plugged. Sixty-four percent of those wells have a plugging date, indicating there is an administrative record associated with their abandonment. The remaining wells in "plugged and abandoned" status have either blank or placeholder plugging dates. According to OCD, placeholder dates may mean they were plugged prior to modern recordkeeping or they remain unplugged. For wells plugged prior to the 1990s, the plugs may not meet modern plugging standards. While most modern plugging techniques were well-understood by the 1990s, the American Petroleum Institute, which publishes technical standards for the industry, did not release a manual of recommended practices for wellbore plugging and abandonment until 2021.

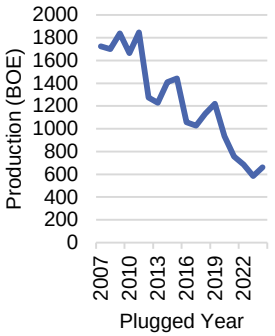
Figure 3. Modern Plugging Rig



Source: LFC Files

For wells producing any volume of oil or gas, OCD has historically left it to the discretion of operators to decide when to plug and reclaim the well. While state statute authorizes OCD to "require dry or abandoned wells to be plugged" to prevent oil, gas, or water from migrating between underground formations, neither "dry" nor "abandoned" is defined. In regulation, OCD requires operators to plug a well that is "no longer useable for beneficial purposes; or a period of one year in which a well has been continuously inactive." "Beneficial purpose" is not defined, leaving operators with considerable discretion to decide when a well producing in any quantity has reached the end of its useful life. Operators may weigh different variables in their decision-making, including oil and gas prices, produced-water disposal costs, the potential for reworking the well to increase production, and the opportunity to drill new wells nearby, which often requires plugging older wells. In recent years, the average well produced roughly two barrels of oil equivalent (BOE) a day in the year before it was plugged, a decline from the mid-2000s. When wells stop producing altogether for an extended period, they become "inactive," and must be either plugged, approved for temporary abandonment, or returned to production within a year.

Chart 2. Average Production in Year Prior to Plugging
n = 13,134



Source: Enverus

Since the 1970s, the state has stepped in to plug oil and gas wells when the operator does not.

When a well becomes inactive and is not plugged by its operator, OCD can pursue authority to plug the well itself. Once it receives that authority, OCD contracts with a plugging company. The division pays those contractors using funds from several sources, including forfeited financial assurances, the oil and gas reclamation fund, and, recently, federal grant funding through the Infrastructure, Investment and Jobs Act (IIJA). Since FY19, OCD's contractual services spending has grown more than 2,000 percent, primarily as a result of plugging and reclamation of orphaned wells and their associated infrastructure. Most of that money has come from federal grants.

Plugging and reclamation account for a growing majority of OCD's spending. OCD has broad authority to regulate oil and gas activity in New Mexico. Its statutory responsibilities include conducting inspections, overseeing drilling operations, and ensuring wells are properly plugged at the end of their productive life. State law also requires OCD to collect financial assurance from operators before drilling begins, to help insulate the state from future plugging and reclamation liability. As New Mexico has grown into the second-largest oil-producing state in the country, behind only Texas, OCD has also expanded, in both budget and personnel, although it remains relatively small compared to regulators in other oil- and gas-producing states. OCD regularly reports challenges with recruitment and retention, which has contributed to the division consistently underspending its budget. In recent years, plugging and reclamation of orphaned wells and their associated infrastructure have become a major part of OCD's budget and responsibilities; contractual services spending, which

In recent years, plugging and reclamation of orphaned wells and their associated infrastructure have become a major part of OCD's budget and responsibilities.

is primarily for addressing orphaned wells, has far exceeded any other spending category in the division's budget in recent years.

Table 1. OCD Sources and Uses
(in thousands)

	FY19	FY20	FY21	FY22	FY23	FY24	FY25 (budgeted)	FY26 (allocated)
Sources								
General Fund Transfers	$5,020.9	$5,835.3	$6,203.1	$6,451.1	$7,163.1	$8,836.6	$10,374.6	$10,439.3
Other Transfers	$0.0	$0.0	$3.5	$88.1	$348.8	$394.9	$0.0	$0.0
Federal Revenues	$673.8	$510.7	$214.7	$325.7	$10,093.6	$15,913.9	$25,930.2	$30,861.5
Other Revenues	$3,040.8	$4,523.6	$5,333.2	$19,384.6	$30,353.4	$24,698.8	$21,475	$25,192.8
Fund Balance	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$722.1	$0.0
Total Sources	$8,735.5	$10,869.6	$11,754.5	$26,249.5	$47,958.9	$49,844.2	$58,501.9	$66,493.6
Uses								
Personal Services and Employee Benefits	$4,305.3	$4,303.7	$4,891.2	$5,291.0	$6,548.1	$7,173.7	$9759.9	$9,759.9
Contractual Services	**$1,711.6**	**$1,415.3**	**$3,136.8**	**$10,607.9**	**$13,219.0**	**$28,546.7**	**$44,990.9**	**$52,983.9**
Other	$716.5	$1,244.5	$911.3	$1,503.3	$2,228.4	$2,368.6	$3,451.4	$3,450.1
Other Financing Uses	$119.9	$132.0	$123.9	$91.8	$0.0	$144.8	$299.7	$299.7
Total Uses	$6,853.3	$7,095.5	$9,063.2	$17,494.0	$21,995.5	$38,233.8	$58,501.9	$66,493.6

Source: LFC files

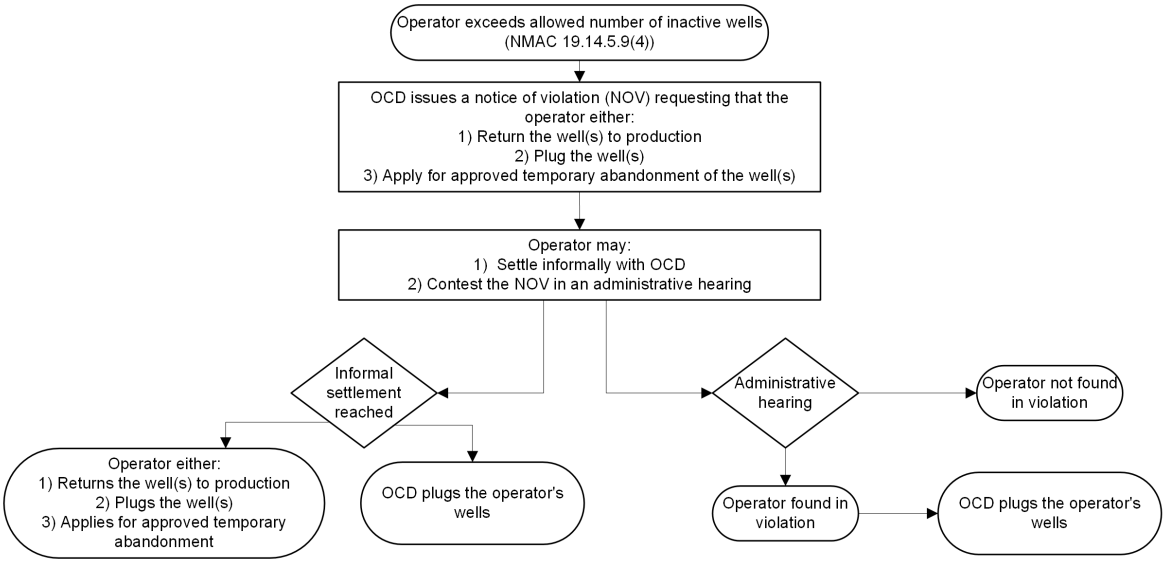
OCD typically pursues plugging authority for a well only when the operator is unresponsive to enforcement action. OCD can issue a notice of violation (NOV) to any operator that has more inactive wells than they are allowed under NMAC 19.15.5.9 A(4). Inactive wells are any production in 15 months and which are not plugged or approved for tem NOV, OCD offers operators the option to informally resolve the situation via ("agreed compliance order") prior to a formal administrative law hearing. Op an informal agreement with OCD may contest the NOV in an administrative much like a civil trial. In practice, many operators simply do not respond to i a default judgment in OCD's favor at hearing. Following the hearing, if the c violation of the law, OCD's director may issue an order directing the operato days or have them plugged by the state (Figure 4). OCD can also plug wells government and tribal governments as requested, using either state funding, 1978, or through intergovernmental cost-sharing agreements.

Table 2. Number of Allowed Inactive Wells

Size of Operation	Number of Wells
100 wells or less	Two or fifty percent, whichever is less
101 to 500 wells	Five or less
501 to 1000 wells	Seven or less
More than 1000 wells	10 or less

Source: NMAC 19.15.5.9

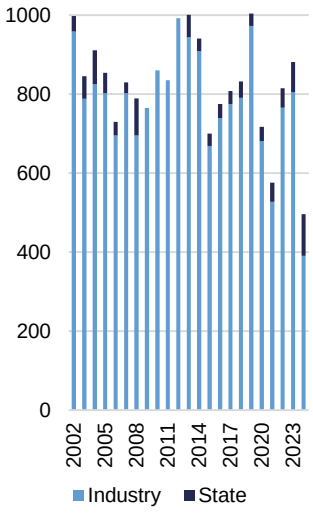
Figure 4. How Wells are "Orphaned" in New Mexico



Source: LFC

OCD has not kept detailed records of state-contracted plugging, but the division has plugged at least 967 wells since 2002, or approximately 5 percent of all wells plugged in New Mexico during the same period. Historically, OCD has not kept robust records of the wells it has plugged, making it difficult to evaluate trends in state-contracted well plugging over time. However, the division began reporting the number of orphaned wells plugged during a fiscal year as part of its budget performance measures starting in 2002. According to those records, OCD has plugged at least 967 wells since then, although the actual number is likely higher because reporting was not required for fiscal years 2009-2012. That equates to approximately 51 wells per year and 5 percent of all wells plugged in the state since 2002. However, OCD has always had a plugging backlog, meaning the percentage of state-plugged wells would be higher if OCD were able to plug all wells it had the authority to plug in any given year. In past performance reports to LFC, OCD has cited a number of reasons for delays in plugging, including contractor availability, funding shortfalls, weather conditions, well conditions, and delays in procurement contracting (see Appendix A).

Chart 3. Wells Plugged by Year
FY02-FY24



Note: OCD was not required to report to the LFC on state-contracted well plugging between FY09 and FY12.

Source: OCD, LFC Report Cards

Statute requires operators to provide financial assurance to OCD before drilling to insulate the state from well plugging and reclamation liability, but the maximum allowable amounts do not cover actual costs. Financial assurance requirements for oil and gas operations in New Mexico are set partly in statute and partly in rule. Section 70-2-14 NMSA 1978 requires operators to post financial assurance before they can drill or

produce a well, in an amount "sufficient to reasonably pay the cost of plugging the wells covered." However, the statute caps total financial assurance at $250 thousand per operator for all active wells, even though plugging a single well can often exceed $100 thousand, and most operators in the state have more than five wells. The statute also requires higher bonding amounts for wells in "temporarily abandoned status," although that term is not defined. In practice, for the purposes of financial assurance, OCD considers wells "temporarily abandoned" when they have reported no production for more than two years or when operators apply for official permission to shut-in a well temporarily. In rule, OCD sets the maximum financial assurance for temporarily abandoned wells at $1 million, which reflects their higher risk of being orphaned. According to a study examining 40 years of oil production in California, the chance a dormant well will resume production is 50-50 after just 10 months of dormancy and 25 percent after five years of dormancy. (See Appendix B for other states' minimum and maximum financial assurance amounts).

Even if OCD plugs an operator's well or wells, its financial assurance remains intact unless the division actively pursues forfeiture. Operators can use one of several financial instruments to fulfill the state's financial assurance requirements. Surety bonds, typically issued by specialized surety companies, are the most commonly used type of financial assurance. They are paid for with annual premiums and secured by varying amounts of collateral; typical premium rates are 1 to 5 percent of the total bond amount annually. Regulations state OCD will not approve the transfer of a well to a new operator until appropriate financial assurance is in place. Once a new operator provides the required financial assurance, the previous operator can request release of its own bond or policy. When OCD plugs an operator's wells, it can seek forfeiture of the financial assurance. In the case of a surety bond, OCD must file a claim with the surety company that is the third-party guarantor. The surety will then initiate an investigation to determine the validity of both the bond and the claim. Investigations can be lengthy and may involve site visits and requesting evidence from OCD. At the end of the process, if the surety company finds the claim is valid, it will try to get the operator to pay and, only failing that, pay the claim itself. If the operator is bankrupt or the surety disputes the validity of the bond, the process can be complicated and involve litigation. In most cases, the funds recovered through forfeiture fall short of the actual cleanup cost. Although OCD is authorized by statute to sue operators for the remaining balance, it has not done so.

Table 3. Estimated Annual Premiums for Surety Bonds

Premium Rate	100+ Active Wells	25+ Temporarily Abandoned Wells
2%	$5,000	$20,000
4%	$10,000	$40,000

Source: LFC files

Financial Assurance Tiers for Wells on Private and State Lands

Active wells

- One well: $25 thousand plus $2 per foot depth.
- One to 10 wells: $50 thousand.
- 11 to 50 wells: $75 thousand.
- 51 to 100 wells: $125 thousand.
- More than 100 wells: $250 thousand.

Temporarily abandoned wells

- One well: $25 thousand plus $2 per foot depth.
- One to five wells: $150 thousand.
- Six to 10 wells: $300 thousand.
- 11 to 25 wells: $500 thousand.
- More than 25 wells: $1 million.

Source: NMAC 19.15.8.9

Allowable Types of Financial Assurance

Surety bond
A three-party agreement in which a surety company guarantees the operator will fulfill its plugging and reclamation obligations.

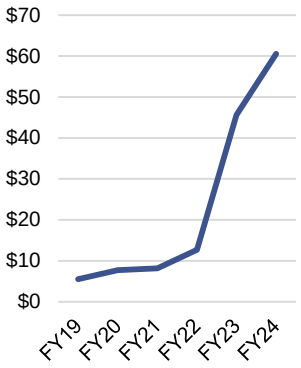
Cash bond
A cash deposit held by the state to guarantee the operator fulfills its obligations.

Irrevocable letter of credit
A financial guarantee issued by a bank, ensuring payment to the state under specified conditions and with appropriate documentation.

Insurance policy
A two-party contract in which an operator pays a premium in exchange for an insurer guaranteeing a defined well cleanup benefit.

Historically, OCD has used the oil and gas reclamation fund to pay for plugging orphaned wells; as of April 2025, the fund's balance was $66.7 million. The Legislature established the oil and gas reclamation fund in 1977 as a nonreverting fund "for use by the oil conservation division in carrying out the provisions of the Oil and Gas Act." Among the currently enumerated purposes of the fund is ensuring the proper plugging and reclamation of "abandoned oil and gas wells and associated facilities" (Section 70-2-38 NMSA 1978). While the statute does not define "abandoned," the fund has historically been used primarily for plugging and reclamation of wells and associated infrastructure without a locatable or financially viable operator. At the time of its creation, the fund received 0.01 percent of oil and gas conservation tax revenues. Today, the reclamation fund receives 10.5 percent of conservation tax proceeds when the price of West Texas Intermediate crude oil is less than $70 and 19.7 percent when it is above $70. Those distributions represent the highest percentages of the conservation tax the reclamation fund has received since the fund was created (see Appendix C). The remainder of the oil and gas conservation tax goes to the general fund. The reclamation fund also receives financial assurances the state has forfeited from oil and gas producers that fail to meet their reclamation obligations, but those are a minor contributor. The fund's balance grew 998 percent between the end of FY19 and the end of FY24, to $65 million, because of high oil and gas prices and production. Despite those record balances, the state has made minimal expenditures from the fund in the last two years, instead using federal grants to pay for plugging orphaned wells.

Chart 4. Oil Reclamation Fund Balance
(in millions)



Source: LFC cash balance

Table 4. Reclamation Fund Sources and Uses
(in thousands)

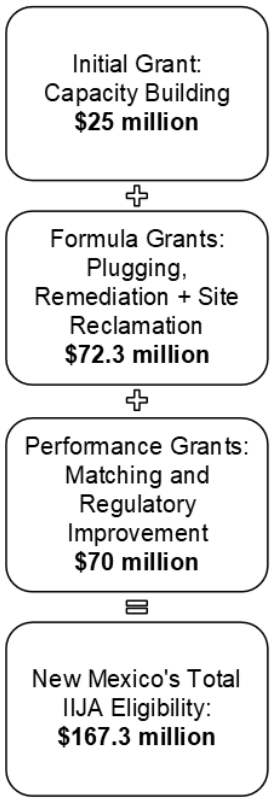
	FY19	FY20	FY21	FY22	FY23
Beginning Cash Balance July	**$4,226.4**	**$6,322.7**	**$7,777.7**	**$9,073.2**	**$26,995.0**
Oil and Gas Conservation Tax Revenue	$3,529.5	$3,340.3	$4,656.3	$22,222.6	$26,933.7
Bond Forfeitures, Salvage, and Reimbursement Recoveries	$88.5	$0.00	$0.00	$161.3	$0.00
Total Revenue	$3,617.9	$3,340.3	$4,656.3	$22,383.9	$26,933.7
Total Expenses Directly from Fund	$1,521.6	$1,885.4	$3,361.3	$4,462.1	$3,030.7
Ending Cash Balance June	**$6,322.7**	**$7,777.7**	**$9,072.7**	**$26,995.0**	**$50,898.1**

Source: OCD

Since 2022, New Mexico has received $55.5 million in federal grants to identify and plug orphaned oil and gas wells and is eligible for up to $111.8 million more. The federal Infrastructure Investment and Jobs Act, (IIJA) or bipartisan infrastructure law, signed into law in 2021, allocated more than $4 billion toward identifying, plugging, and remediating orphaned wells on state, federal, and tribal lands. The law specifies that for the purposes of wells on state and private lands, the term orphaned "has the

meaning given the term by the applicable state." Under IIJA, states became eligible for three types of grants: an initial grant, formula grants, and performance grants. The initial grant was intended to strengthen states' existing well-plugging programs. New Mexico received an initial grant of $25 million. The formula grants provide additional financial assistance for plugging and reclamation on state and private lands. New Mexico is eligible for up to $72.3 million in formula grants; it received $25 million in 2024. Finally, performance grants are intended to reward states for meeting specific targets; matching performance grants of up to $30 million are available to cover the cost of any spending on orphaned well plugging in a single fiscal year that exceeds historic state averages, while regulatory improvement performance grants provide up to $40 million to states that improve their standards and procedures around well-plugging and strengthen their regulatory frameworks to avoid future orphaned well liability. New Mexico received a $5.5 million performance matching grant in January 2025 based on the average of its spending on well plugging between 2010 and 2019. A federal review of grants briefly paused funding in early 2025, but it has since resumed.

Figure 5. New Mexico's IIJA Funding Eligibility



Source: Orphaned Well Program Office

OCD spent $46.4 million between FY19 and FY24 on plugging and reclamation of 360 wells and their associated infrastructure.

With federal funding to plug and remediate orphaned wells, OCD has recently increased its yearly plugging rate from 30 to 50 wells a year to over 100 in FY24. Historically, OCD has not consistently or systematically tracked the costs incurred by the state for plugging and reclamation, complicating the assessment of long-term trends in spending on orphaned wells. However, at a high level, OCD has spent more in the last five years on plugging and reclamation than it did in the previous 10. As spending has increased, the costs for plugging and remediation have also risen dramatically.

Plugging costs are highly site-specific but depth, type of well, and other variables typically affect costs. Numerous studies have found the cost of plugging can vary widely between different well sites. However, a 2021 study of more than 19 thousand wells across several states found certain factors to be predictive of increased costs, including well depth, well age, and the elevation of the well site. Additionally, the study found gas wells were, on average, 9 percent more expensive to plug than oil wells because of additional time and equipment often needed to stop the flow of natural gas during plugging operations. In testing those findings on recent well plugging costs in New Mexico, the relationships between plugging costs and depth and plugging costs and well type hold true; deeper wells were more expensive to plug and gas wells were more expensive than oil wells. (In FY24, the average gas well cost 101 percent more to plug than the average oil well, but the sample size was only 10 wells). Wells at higher elevations, however, were not more expensive in FY24 than lower elevations, and older wells were not significantly more expensive than more

Scan the QR code for an interactive map of wells plugged by the state

recently drilled wells. New Mexico's current financial assurance regulations account for the increased cost of depth in requirements for single well bonds, but not all-well or blanket bonds, and do not differentiate between oil and gas wells.

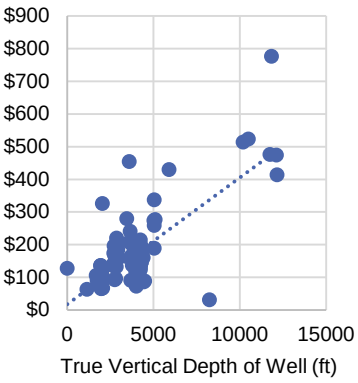
The average per-well cost of state-contracted plugging has risen nearly 450 percent since FY19 and the average per-foot cost has risen 270 percent, more than eight times the rate of overall oilfield inflation. OCD does not systematically track the cost of well plugging, but LFC analysis of available invoices from FY19 onward shows the per-well cost of state-contracted plugging rose 443 percent between FY19 to FY24, from an average of $30 thousand to $163 thousand. In FY24, costs ranged from $31 thousand to $778 thousand. Because deeper wells, which take more time and require more cement, are typically more expensive to plug, many cost comparisons use cost-per-foot instead of a per-well average. Since FY19, per-foot costs for state-contracted plugging have risen roughly 270 percent. In FY24, the average per-foot cost of state-contracted plugging in New Mexico was $43.85. The Texas Railroad Commission (RRC) has reported comparable costs for state-contracted plugging in RRC District 8, a region that borders New Mexico. However, RRC attributes those high costs primarily to complex emergency plugging incidents in District 8. While New Mexico has had a handful of emergency plugging incidents, its costs for nonemergency plugging are similarly high (see Appendix D for more on Texas' plugging costs).

Table 5. FY24 Average Cost to Plug by Well Type

Well Type	# of wells	Average Cost
Overall Average	106	$163,000
Oil	81	$150,634
Gas	10	$303,063
Injection	13	$120,634
Salt Water Disposal	2	$259,965

Source: OCD, SHARE

Chart 5. FY24 Cost of Plugging by Depth of Well
(in thousands)



Source: OCD, SHARE

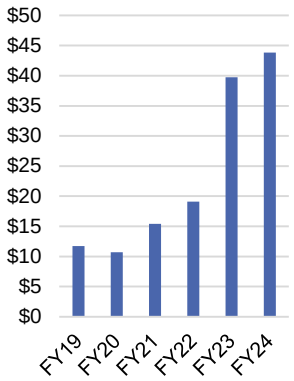
Table 6. OCD Reclamation and Remediation Costs for Orphaned Tank Batteries
FY23-25

Cato San Andres Tank Battery #6	$ 623,024.02
Double L Queen Tank Battery	$ 5,151,041.47
Hal J Rasmussen Tank Battery	$ 7,607,260.24
Total	**$13,381,325.73**

*Note, all totals are as of May 1, 2025

Source: SHARE

Chart 6. Average Per-Foot Cost for State-Contracted Plugging
FY19-24



Source: LFC analysis of OCD and SHARE data

While OCD spent more overall on well plugging between FY19 and FY24, per-project costs were highest for remediation and reclamation of infrastructure associated with oil and gas production, not well plugging itself. In FY23, OCD began remediation and reclamation work on three tank batteries—groups of tanks typically used to collect, separate, and store crude oil and produced water—in Lea and Chaves countries. The tank batteries were previously owned and operated by Canyon E&P Company, Cano Petro of New Mexico, and Hal J Rasmussen Operating, and all three were selected for remediation because of suspected or confirmed leaks of petroleum hydrocarbons. Two of the three projects are ongoing, but the most expensive project to date has been the Hal J Rasmussen site, known as the Reed Estate #001 tank battery. A site assessment conducted prior to remediation efforts found soil with

hydrocarbon levels 10 times the state limit and chloride levels double the state limit. However, the most recent leak at the site was more than a decade ago and there is no evidence spills at the site have contaminated groundwater or a nearby playa (seasonal lake). Similarly, a contamination delineation assessment of the Double L Queen Tank battery (Canyon E&P) found evidence of hydrocarbon and chloride contamination above state thresholds from past leaks, but no evidence the spills had impacted groundwater resources or caused any additional health or safety issues. At the third site, known as the Cato San Andres tank battery #6 (Cano Petro), OCD documents do not indicate that similar soil sampling or groundwater assessment have occurred to date, but photographs submitted to the division by the contractor responsible for cleanup show pools of standing oil at the site. In a 2021 report for the New Mexico State Land Office, Vertex Resources estimated the decommissioning and reclamation costs of a storage tank site at $9.5 million, based principally on an assumption of a large site surface area and the need to remove substantial volumes of contaminated soil. Invoices from the tank battery sites show that removal of contaminated soil is by far the largest line-item expense.

Figure 6. Orphaned Tank Batteries



Double L Queen tank battery in Chaves county



Cato San Andres tank battery #6 in Chaves county

Source: Envirotech/Frontier Development

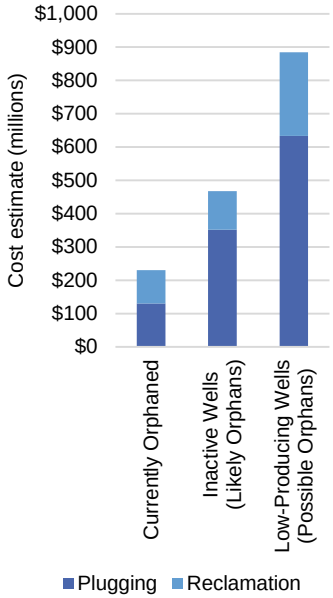
Current Orphaned Wells Will Cost the State More Than $200 Million; Future Liability Very Likely Exceeds $700 Million

New Mexico does not define "orphaned well" in statute or rule, resulting in different estimates of both the number of orphaned wells and the resulting state liability, depending on the context and source. For this report, orphaned wells are those for which OCD has already pursued and received plugging authority, either through a settlement agreement or administrative hearings, because those represent the most immediate and certain costs. However, in addition to wells the state already has legal authority to plug, thousands of inactive and low-producing wells are at risk of being orphaned, potentially increasing the state's liability by many orders of magnitude. OCD considers a well "inactive" if it has not reported production in 15 months. OCD does not currently have the authority to plug approximately 1,400 inactive wells on state or private land that it considers likely to be orphaned. In addition to those inactive wells, thousands of wells produce extremely low volumes of oil and gas—less than a barrel of oil equivalent per day. For many of those wells, the expected cost of cleanup far exceeds predicted future revenues, increasing their risk of being orphaned. Altogether, the state's current and near-future liability for well plugging and site remediation is estimated to be between $700 million and $1.6 billion.

Plugging and reclaiming the well sites and associated infrastructure OCD currently has responsibility for will likely cost between $200 million and $400 million.

Based on internal OCD data, the division is currently responsible for plugging close to 1,000 orphaned wells, including roughly 700 on state or private land. At recent rates, plugging those wells will take close to a decade, not including well site remediation and reclamation. OCD is also responsible for remediation and reclamation of an additional 500 well sites and 18 infrastructure sites, including a number of tank batteries. In total, plugging, remediation and reclamation of all currently orphaned wells and infrastructure on state and private land is estimated to cost a minimum of $208 million, and likely more.

Chart 7. Liability Estimates for Plugging and Reclamation



*Note: Only wells on state or private lands; categories are mutually exclusive; plugging based on actual depth, $43.85/foot, gas wells costing 9 percent more than oil wells; reclamation at $83 thousand per well site.

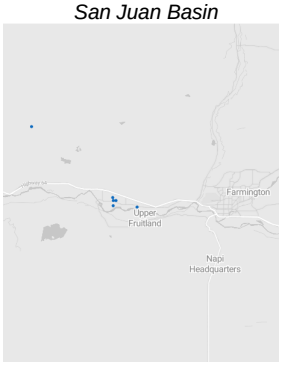
Source: LFC analysis

Scan the QR code for an interactive map of current, likely, and possible orphaned wells

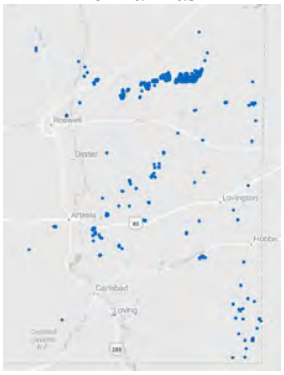
The term "orphaned well" is not defined in either statute or rule, complicating efforts to estimate the state's liability. While orphaned wells are commonly understood in the oil and gas industry to mean wells that have no viable operator and, therefore, have become the responsibility of the state or federal government, New Mexico does not define the term anywhere in statute or rule, and OCD does not use the term consistently. Public estimates of the number of orphaned wells in New Mexico vary widely, depending on how the term is defined. In some contexts, OCD cites around 700 orphaned wells; in others, it references 1,700 or more than 3,000. The disparity results from whether OCD includes only wells the state has pursued and received permission to plug or also those it does not currently have legal authority to plug but believes it will have to plug in the future. It also depends on whether the count refers only to state and private (fee) wells or also includes federal and tribal wells. While limiting the definition to only wells OCD currently has plugging authority for runs the risk of obscuring the magnitude of the state's liability, it is important to distinguish between certain liability and expected liability. For that reason, this report considers those categories separately. Also, while OCD contracts for well plugging on state, private, tribal, and federal land under different circumstances, state funds are primarily used for plugging wells on state and private land[1], so those wells are the focus of this analysis.

Figure 7. Maps of Orphaned Wells in New Mexico

San Juan Basin



Permian Basin



OCD does not publish a list of wells the state has plugged or is planning to plug and does not track them consistently in internal documents. As a result of requirements associated with federal IIJA grant funding, OCD has recently begun compiling an internal list of wells the state has plugged or plans to plug, along with associated infrastructure requiring cleanup. That list represents the most comprehensive effort to understand the scope of state-contracted well plugging. However, the list is not publicly available and is frequently inconsistent with publicly available data. However, because it is the only available data source that tracks wells for which OCD has received plugging authority, LFC staff used the list to determine the number of currently orphaned wells in New Mexico and refined the number by removing incorrectly labeled data. Wells were included if they did not have a plugged date and if they were located on state or private land.

At current rates, plugging the 702 wells the state is currently responsible for will likely cost more than $130 million and take close to a decade. According to OCD's internal list, OCD currently has plugging authority for 702 wells that have yet to be plugged on state and private land. Based on the average per-foot cost for state-contracted well plugging in

[1] Per *Section 70-2-37 NMSA* 1978, OCD does have authority to plug wells on federal land using the reclamation fund; however, most orphaned wells on federal land are plugged using federal money. Additionally, OCD does not have authority to plug wells on tribal land without a request from the corresponding tribal government. Therefore, this analysis of state liability only includes wells with state or private surface ownership; it excludes orphaned, inactive, and low-producing wells with federal surface ownership and private or state mineral ownership, which are rare.

FY24 ($43.85) it will cost OCD over $130 million just to plug those wells. That figure is based on actual well depths and an estimate that gas wells cost 9 percent more to plug than oil wells, although, as noted above, recent actual costs for plugging gas wells have been 101 percent higher than oil wells. If that trend holds, the total cost could be closer to $141 million for those 702 wells. Saltwater disposal wells could also be more expensive to plug based on previous OCD spending, and there are currently 11 of those wells on OCD's plugging list. However, the state has plugged too few in recent years to draw clear conclusions. If the state's per-foot plugging costs could be brought closer to those of other states, like Texas's FY24 average of $15.60 statewide, or back to OCD's average of $19.10 in FY22, plugging currently orphaned wells could be closer to $46 million to $57 million. The state holds $5.6 million in financial assurance associated with currently orphaned wells or their operators, meaning most of the funding for plugging the wells is likely to come from federal IIJA grants or the reclamation fund. If FY24 plugging rates of approximately 100 wells per year are maintained, it would take OCD seven years to plug its current orphan well population. However, these estimates do not include the added time and cost of site remediation.

Table 7. Orphaned Well Plugging Cost Estimates

Estimate	Per-foot Cost	Oil and Other Wells (in millions)	Gas Wells (9% increase) (in millions)	Total Cost (in millions)
NM FY24 Average	$43.85	$118.7	$12.1	$130.8
NM FY24 Median	$40.30	$109.1	$11.1	$120.2
NM FY22 Average	$19.10	$51.7	$5.3	$57.0
Texas Statewide FY24 Average	$15.60	$42.2	$4.3	$46.5

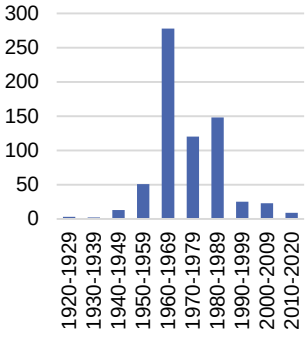
Source: OCD, SHARE, Enverus

In addition to plugging, OCD is currently responsible for remediation and reclamation of roughly 1,200 well sites; the estimated cost is $48 million to $100 million. In addition to the 702 unplugged wells, 499 wells plugged by the state between 2013 and 2024 are awaiting environmental remediation and reclamation. OCD records show the division has only remediated and reclaimed five of the wells it has plugged since 2013. That work cost a total of $205 thousand, including performance bond premiums paid by contractors but reimbursed by OCD The average per-site cost was approximately $40 thousand. All those projects were completed in FY24 for wells plugged in FY18. At $40 thousand per site, remediation of all roughly 1,200 well sites the state currently has authority for would cost an estimated $48 million. OCD has inspected 121 well sites to date and has estimated the cost of remediation and reclamation for those sites at $2.8 million, or an average of $23 thousand per site. However, based on past averages and other studies, that estimate is likely low. The 2021 Vertex Resources study for the State Land Office estimated well site remediation and reclamation at $83 thousand per-site, on average, which would put the total at $100 million, not including cleanup of infrastructure associated with the well sites, like tank batteries.

Ridgeway Arizona Settlement Agreement

Among the orphaned wells OCD is currently plugging are a number of wells owned by Ridgeway Arizona Oil Corporation, an active operator. In 2023, OCD reached a settlement agreement with Ridgeway Arizona to plug 299 of the company's wells, Under the terms of the agreement, the state is paying upfront to plug the wells, with Ridgeway Arizona reimbursing the state "at a rate of $2.00 per gross barrel of oil sold by Operator," with a minimum payment of $30 thousand per month. According to OCD contracts, the state paid $1.3 million to plug six of Ridgeway's inactive wells in FY24, for an average cost of $210 thousand per well. If future costs are similar, the total for the remaining inactive Ridgeway wells could exceed $60 million. Paying $30 thousand per month, it would take Ridgeway Arizona 170 years to make the state whole in that scenario.

Chart 8. Orphaned Wells by Year Drilled



Note: Does not include orphaned wells missing a drilling date (30 out of the 700)

Source: OCD

OCD is also responsible for decommissioning, remediation, and reclamation of 18 infrastructure sites; the estimated cost is $30 million to $140 million. The infrastructure sites include both tank batteries and a waterflood facility, which are facilities that treat, store, and pump (usually produced) water for injection into oil and gas wells to increase reservoir pressure and boost oil recovery. As noted above, the cost for remediation and reclamation of tank batteries has varied widely in the past. The three already-commenced projects have collectively cost the state $13.4 million since FY23, and two are ongoing. Two of the tank battery sites listed for future reclamation are considered "highest" priority by OCD, although no public documents indicate how the division arrived at that assessment. OCD has not yet had to reclaim a waterflood facility, and its public database lacks information about the facility, making it difficult to estimate the potential costs associated with its decommissioning and reclamation. Given that the only completed tank battery project cost OCD $5.2 million and a nearing-completion project has already cost $7.6 million, a very conservative estimate for the remaining 15 tank batteries would be $30 million, at $2 million per site. On the high end, using the $9.5 million estimate from the Vertex Resources report, the costs could be more than $140 million.

OCD expects to plug and reclaim most wells on its inactive well list, which would cost close to $500 million.

OCD rules require it to keep a publicly available "inactive well list" that is updated daily. The list records wells that have reported no production or injection for 15 months, a period encompassing both the 12 months of inactivity that renders a well out of compliance with the Oil and Gas Act and a 90-day grace period for the operator to remedy the problem and report production. Inactive wells become orphaned wells when OCD issues a notice of violation (NOV), and the operator fails to bring its inactive wells into compliance. While virtually all wells on the inactive list are eligible for enforcement action, OCD has historically prioritized issuing NOVs to operators with large numbers of inactive wells. However, the division considers the entire inactive well list likely orphans. In its application for federal IIJA funding, OCD estimated New Mexico has 1,700 orphaned wells, a number encompassing all inactive wells on state and private land, including wells for which OCD has not yet pursued plugging authority.

Table 8. April 2025 Inactive Well Count by Surface Owner

Surface Owner	Inactive Wells
State	749
Private/ Fee	1307
Federal	955
Tribal	336

Source: OCD Inactive well list

Twenty-nine percent of operators are out of compliance with the Oil and Gas Act because they have too many inactive wells. Under administrative code, an operator is allowed to have a certain number of wells that are nonproducing and unplugged for more than a year while remaining in compliance with the Oil and Gas Act, depending on the size of its overall well portfolio. About 60 percent of the 576 oil and gas companies operating in the state have at least one well that has not produced anything in the past 15 months; 29 percent of all operators are out of compliance with the Oil and Gas Act because they hold too many inactive wells. Of those out of compliance, 121 companies have no wells that have produced any oil or gas in the last 15 months; they collectively hold 1,034 inactive, unplugged wells. About 70 percent of those operators could be considered very small, with five wells or less.

Table 9. Years Since Last Production for Inactive Wells

Years since last production	Number of inactive wells
1 to 5	928
6 to 10	283
11 to 20	140
21 to 40	47
More than 40	3

Source: OCD

Table 10. Operators Out of Compliance Due to Inactive Well Counts

Size of Operation	# of inactive wells to be out of compliance	# of operators out of compliance
100 wells or less	Two or fifty percent, whichever is more	139
101 to 500 wells	Six or more	20
501 to 1,000 wells	Eight or more	7
More than 1,000 wells	11 or more	1

Note: As of March 2025.

Source: OCD Inactive Well List

Currently, the state does not have plugging authority for 1,400 wells on state or private land that appear on the inactive well list; they could cost the state $468 million to plug and reclaim. The inactive well list is updated daily and is not archived, making it difficult to track trends in the data over time, but past presentations and reports from OCD indicate the overall number of inactive wells has been increasing. A 2008 LFC report card for EMNRD indicates roughly 2,000 wells were inactive at the time. In 2021, OCD reported the state had over 3,000 inactive wells, similar to the number of inactive wells on the list when it was exported for analysis in this report in April 2025. Of those, roughly 2,000 are on state and private land and 1,400 are not currently orphaned. Plugging those 1,400 inactive wells would cost $352 million at the FY24 per-foot average of $43.85, assuming gas wells cost 9 percent more. However, if gas-well costs follow recent trends, the total would be closer to $416 million. Site remediation would cost an additional $116 million based on Vertex's per-site estimate of $83 thousand. OCD currently holds $66 million in financial assurance associated with the operators of those wells, although not all of that would likely be available for plugging and reclamation. At the rate OCD plugged orphaned wells in FY24, about 100 wells, it would take the division over 30 years to plug all the wells on the inactive well list. About 14 percent of the remaining wells on the inactive well list have not produced or injected in the last decade.

Table 11. Estimated Costs to Plug Remaining Inactive Wells
(in millions)

Per- foot Estimate	Total Cost (9% more for gas wells)	Total Cost (101% more for gas wells)
NM FY24 Average ($43.85)	$352.5	$416.4
NM FY24 Median ($40.30)	$323.9	$382.7
NM FY22 Average ($19.10)	$153.5	$181.4
Texas Statewide FY24 Average ($15.60)	$125.4	$148.1

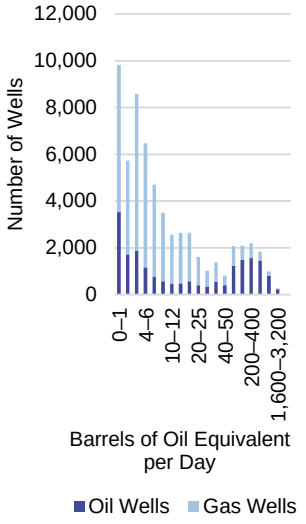
Source: OCD Inactive Well List, SHARE, Enverus

In addition to fully inactive wells, thousands of extremely low-producing wells have minimal revenues and hundreds of millions of dollars in outstanding cleanup liabilities.

New Mexico oil and gas production has climbed precipitously in recent years, driven by a small subset of very high-volume unconventional wells in the Permian Basin. Meanwhile, a growing majority of wells in the state are "stripper" wells, nearing the end of their productive lives. While low-producing wells can generate significant revenues for both operators and the state, wells below certain production thresholds are unlikely to generate sufficient revenues in their remaining lifespan to be able to fund their own plugging and reclamation, putting those wells at greater risk of being orphaned.

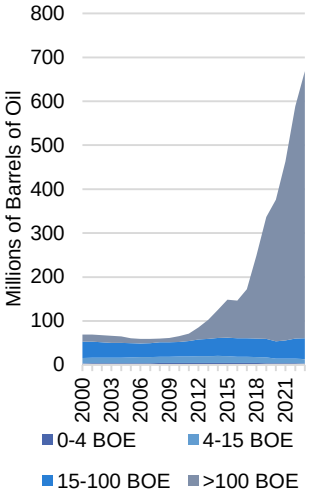
Wells producing extremely low volumes pose a financial risk to the state because they may not generate sufficient revenues to fund their own end-of-life plugging and abandonment. Stripper wells are defined in Section 7-29B-3 NMSA 1978 as an oil well producing less than 10 barrels of oil a day, a gas well that produces less than 60 thousand cubic feet of gas a day or an oil and gas well that produces less than 10 barrels of oil equivalent (BOE) per day. The federal government uses the term to refer to wells that produce less than 15 BOE a day. According to production data from the energy analytics firm Enverus compiled by the federal Energy Information Administration, 64 percent of active wells in New Mexico produced 10 BOE a day or less in 2023. Those 38,817 stripper wells accounted for 1 percent of the state's oil production and 7 percent of its natural gas production in 2023 and generated roughly $890 million in revenue based on average commodity prices. However, most of those revenues are attributable to wells producing at the higher end of the range, with just $48.8 million, or an average of $5 thousand per well attributable to the 9,824 wells that produced 1 BOE a day or less in 2023. Revenues for those ultra-low producing wells likely vary widely, depending on the oil/gas ratio of the well (oil-heavy wells are more profitable), pipeline availability, and location, among other things. However, even at the high end, those wells are unlikely to be generating sufficient revenues to finance their own end-of-life plugging and abandonment. While companies with diversified well portfolios may be able to fund plugging and abandonment out of revenues from other wells, companies with concentrated portfolios of ultra-low-producing wells may struggle to meet their end-of-life asset retirement obligations.

Chart 9. New Mexico Oil and Gas Wells by Production Volume, 2023



Source: EIA (Enverus)

Chart 10. New Mexico Oil Production by Well Production Volume, 2000-2023

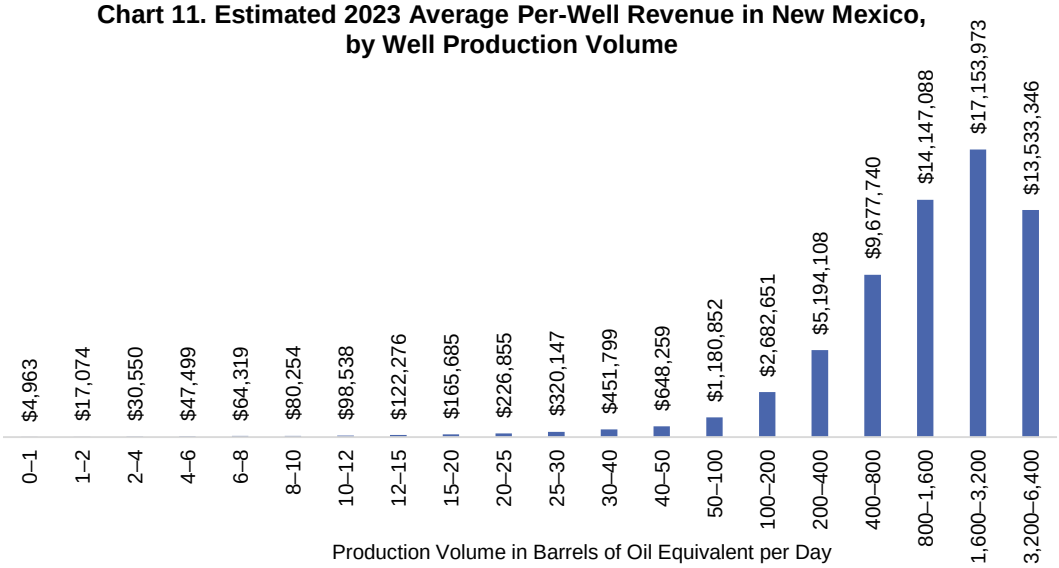


Source: EIA (Enverus)

There is no specific threshold at which a well becomes uneconomic, but production of less than 2 BOE a day may be an appropriate threshold for additional regulatory scrutiny. Determining the specific point when a well becomes uneconomic—i.e., when a well's liability surpasses the value of its potential future production—is challenging for several reasons, but principally because of fluctuating prices for oil and gas. For example, a well producing 2 BOE per day might be profitable at $100 per barrel but uneconomic at $50 per barrel. However, as noted previously, in New Mexico, the average well plugged in recent years produced approximately 2 BOE per day in the year prior to abandonment. Because most wells are plugged by the industry, that suggests operators may find it uneconomic to maintain production from wells producing less than 2 BOE a day—roughly 750 BOE a year. In Colorado, wells producing less than two barrels of oil or 10 mcf of gas per day are considered "low-producing" and are subject to additional scrutiny because of their risk of being orphaned. New Mexico should consider adopting a similar standard. In 2023, 15,558 wells produced less than 750 BOE. Of those, 9,016 produced less than 750 BOE a year from 2021 to 2023 and are not currently on the state's orphaned or inactive lists, including 4,969 on state or private land. Given when industry plugs wells and Colorado's regulations, that group of persistently low-producing wells likely represents those most at risk of being orphaned in the future.

In Colorado, wells producing less than two barrels of oil or 10 mcf of gas per day are considered "low-producing" and are subject to additional scrutiny because of their risk of being orphaned.

Chart 11. Estimated 2023 Average Per-Well Revenue in New Mexico, by Well Production Volume

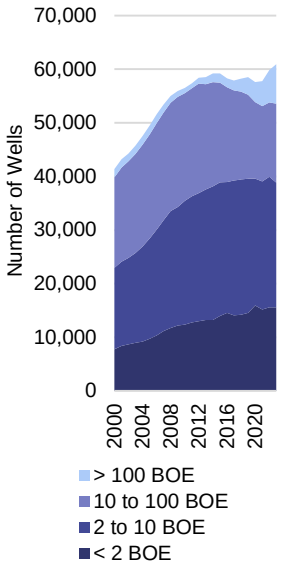


*Note: Estimates are based on EIA's 2023 average WTI price of $77.58/barrel and Henry Hub spot price of $2.53/MMBtu. EIA classified wells based on peak production, without accounting for well downtime, so for categories with a small sample size (11 wells produced 3,200 boe +/day), well downtime has a large effect on overall production volumes, and per-well revenue estimates.

Source: LFC analysis of EIA (Enverus) data.

The roughly 3,000 wells on state and private land in New Mexico that have produced less than 1 BOE per day over multiple years are likely at the end of their lives. Wells may temporarily dip into ultra-low production levels for a variety of reasons. However, wells that consistently produce less than 365 barrels of oil equivalent a year (1 BOE a day) are likely at the end of their productive lives, given the average production of wells in the year before they are plugged. More than 5,000 oil and gas wells in New Mexico fall into that category based on annual production data for 2021, 2022, and 2023. (This analysis excludes enhanced oil recovery injection wells and saltwater disposal wells, which also require plugging at the end of their lives.) While some of those wells are currently on the inactive list, a majority are not. Of the wells not on the inactive list, 3,024 are located on state or private land, meaning they could become the responsibility of the state if their operators fail to plug them. Seventy percent of those wells are oil wells while 30 percent are gas wells, and they are of widely varying vintages, with some of the wells drilled more than a century ago, according to OCD records, and others drilled as recently as 2020. Most were drilled between 1950 and 2010. The vast majority of the wells—87 percent—are owned by private companies whose financial health is difficult for regulators to assess. New Mexico should consider updating its definition of "inactive" to include wells producing fractions of a barrel a day for multiple years, to minimize the incentive for operators to delay plugging of wells.

Chart 12. New Mexico Oil and Gas Wells by Production Volume 2000-2023



Source: EIA (Enverus) data

Potential liability for extremely low-producing wells greatly exceeds potential tax contributions. While wells can continue producing in very low quantities for extended periods of time, the financial risk those wells pose to the state far exceeds potential tax revenues. At an 8 percent effective tax rate on oil and gas, the 3,024 wells producing 365 BOE a year would generate a maximum of $6 million in tax revenue annually with West Texas Intermediate crude oil at $70 per barrel. The 1,828 wells producing 180 BOE would generate a maximum of $1.8 million in tax revenue annually under the same scenario. At current state-contracted plugging and reclamation costs, using actual depth and assuming gas wells cost 9 percent more to plug than oil wells, plugging and reclaiming those wells would cost $531 million to $885 million.

Table 12. Estimated Plugging Costs for Wells Producing <365 BOE Annually Between 2021 and 2023

	Number of Wells	Estimated Plugging Cost
< 90 BOE	1,135	$235,000,000
<180 BOE	1,828	$379,000,000
<365 BOE	3,024	$634,000,000

*Note: Only currently active wells on state or fee land; categories are inclusive; plugging estimate based on actual depth, $43.85/foot, and gas wells costing 9% more than oil wells

Source: LFC Analysis of OCD data

Recommendations

The Legislature should consider:

- Amending statute to define "orphaned" and "abandoned" wells, aligning the definitions with their common use in the oil and gas industry and clarifying that "orphaned" wells are oil and gas wells for which the state has pursued and received plugging authority.

The Energy, Minerals and Natural Resources Department should:

- Archive and publish a quarterly inactive well list to enable longitudinal analysis and better cost estimating.
- Create a system that formally reminds operators of stripper wells of state statute and rule requiring them to plug and properly abandon their wells;
- Promulgate rules defining "low-producing" wells (such as wells producing less than 750 BOE annually or ~ 2 BOE per day); and
- Promulgate rules to expand the definition of "inactive well" to include consistently ultra-low producing wells (such as wells that produce less than 180 BOE annually or ~0.5 BOE per day for more than three years).

Reforms That Prioritize Operator-Led Cleanup can Limit the State's Financial Exposure

Requiring financial assurance is currently the state's primary tool to discourage operators from orphaning wells, but in practice, it is insufficient. Even when OCD can successfully forfeit an operator's financial assurance, the amount recovered is typically far below the actual costs of plugging and reclamation. The gap between actual plugging costs and the required financial assurance weakens the incentive for operators to plug their own wells, especially older, low-value wells where cleanup costs are high. As a result, operators are more likely to walk away from those wells, leaving OCD to manage the most complex and least desirable sites. Managing those projects has proven difficult: OCD was not designed to act as a large-scale plugging contractor and has struggled to control costs and ensure consistent quality. To reduce future liabilities and discourage a reliance on state-contracted plugging, the Legislature should consider regulatory mechanisms beyond financial assurance that would better align incentives and keep well closure in the hands of the industry, which is generally better equipped to do the work efficiently and cost-effectively.

OCD struggles to control both the cost and quality of state-contracted plugging.

As noted in earlier in this report, per-foot and per-well costs for state-contracted plugging have increased sharply in recent years. There are a number of possible explanations for that increase. Oil field inflation has increased industry costs across the board. Also, with increased funding, OCD has taken on a backlog of plugging and remediation work that involves more complicated and expensive wells and associated infrastructure. However, OCD's lack of systematic cost-tracking mechanisms and its procurement process have also likely contributed to the rapid increase in New Mexico's per-foot plugging costs, which are higher on average than neighboring states. Since FY19, OCD has managed well plugging and reclamation through four separate statewide price agreements (SPAs), each amended multiple times. Instead of issuing contracts for individual projects, OCD uses SPAs as rate sheets, allowing contractors to bill for work based on pre-approved unit prices. That approach has resulted in limited price competition and inconsistent cost control, with multiple projects requiring change orders exceeding $1 million. Plugging designs and costs have also varied widely across sites with similar characteristics, suggesting gaps in both quality oversight and financial accountability.

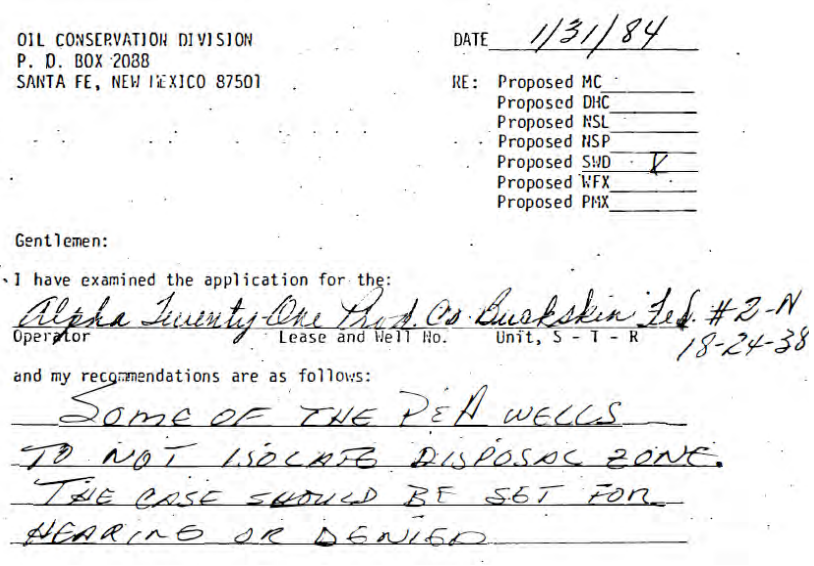
OCD Contracting Procedure for Standard Well Plugging Operation:

1. OCD requests and receives a plugging price estimate from a vendor on the statewide price agreement.
2. OCD issues a purchase order (PO) to the vendor.
3. The vendor designs a plugging plan and wellbore diagram based on available information.
4. The vendor submits a sundry notice to OCD for review and approval.
5. OCD reviews the sundry and may add additional conditions of approval, depending on the well.
6. The vendor plugs the well and submits a plugging and abandonment report for the OCD well file.
7. The vendor invoices OCD with line items for each per-unit charge, by day.

Source: OCD

Records associated with orphaned wells may be missing or incomplete, making it more difficult to anticipate problems that might arise during plugging. Operators are required to file paperwork with OCD about various well operations, including drilling, well completions, and well conversions. Many of those records are digital or have been digitized and are available as PDFs on OCD's website. However, those public well files usually contain far less detail than the files available to operators themselves when they purchase a well. Older wells also often have incomplete OCD well files, resulting in situations where OCD's plugging contractors encounter unanticipated problems as they commence plugging. Those problems can result in orphaned wells being more expensive and dangerous to plug than wells plugged by the industry.

Figure 9: Incomplete Well File



OIL CONSERVATION DIVISION
P. O. BOX 2088
SANTA FE, NEW MEXICO 87501

DATE 1/31/84

RE: Proposed MC
Proposed DHC
Proposed NSL
Proposed NSP
Proposed SWD X
Proposed WFX
Proposed PMX

Gentlemen:

I have examined the application for the:

Alpha Twenty-One Prod. Co. Buckskin Fed. #2-N 18-24-38
Operator Lease and Well No. Unit, S - T - R

and my recommendations are as follows:

SOME OF THE P&A WELLS
TO NOT ISOLATE DISPOSAL ZONE.
THE CASE SHOULD BE SET FOR
HEARING OR DENIED

The OCD file for the Buckskin Federal #002 well contains a document from 1984 indicating OCD had concerns at the time about converting the well to a saltwater disposal well. The file does not contain information about how those concerns were resolved, but it was ultimately converted. Plugging the well cost the state $5.2 million.

Source: OCD

OCD does not have a comprehensive monitoring system for regularly assessing the relative risk of a well. As a condition of the federal IIJA grants, OCD is required to measure the amount of methane a well is emitting pre- and post-plugging, the state's first attempt at monitoring leaks from orphaned wells. While methane is just one type of potential leak, it can indicate larger problems with the well that may not be otherwise easily detectable, making it a powerful diagnostic tool. To date, OCD has sampled 172 wells pre-plugging, most of which have since been plugged. Thirty-eight percent of the wells had no detectable methane leakage, and another 35 percent were leaking in very low quantities. However, 27 percent were leaking more than the IIJA reporting threshold of 1 gram per hour. Leaking wells are supposed to be considered the top plugging priority in OCD's prioritization framework, which combines field observations with other

Figure 8. Corroded Production Tubing



When pluggers pulled the production tubing from this well prior to plugging, they found it was full of holes, likely caused by either prolonged contact with saltwater or hydrogen sulfide. Holes can cause the tubing to part or split as it is removed from the hole, which then necessitates expensive fishing operations.

Source: LFC files

Table 13. Pre-Plugging Methane Emissions

Emissions Rate (g/hr)	Count of Wells
0	66
< 1	60
1-100	37
100-1,000	4
1,000 +	5

Source: OCD

data to assign wells a plugging priority (see Appendix E for more on the scoring system). OCD has scored 271 or 39 percent of the 702 currently orphaned wells. Despite measured methane leaks at some of those sites, OCD has not assigned any of the currently orphaned wells to its top priority category. Also, OCD's priority rankings are time-sensitive, meaning low-priority wells may become high priority in the future. Factors like whether a well is inside a municipal boundary and the type of well are unlikely to change over time, but development can encroach on wells, and inactive and unmaintained wells are more likely to develop integrity issues that could lead to leaks or other problems. Roughly 80 percent of the 702 currently orphaned wells have not produced oil or gas in the last five years. Given that OCD has been able to plug roughly 100 wells a year in recent years, the lowest-priority wells on its list may not be plugged for close to a decade. Unmaintained and unplugged wells are more likely to develop integrity issues, which not only can pose an environmental and safety hazard but has the potential to make the wells more expensive and difficult to eventually plug. To reduce the risk of currently low-priority wells becoming safety or environmental emergencies, OCD should develop a system for consistently monitoring orphaned wells awaiting plugging.

Table 14. Statewide Purchase Agreements for Plugging and Reclamation

SPA	Start Date	End Date	Amendments	Spending Authorized Through SPA
60-521-16-05813	12/1/2016	12/1/2020	4	$4,971,170
10-00000-20-00038	10/1/2020	10/1/2022	2	$6,707,646
10-52100-21-06041	6/1/2021	6/1/2023	1	$3,049,040
30-00000-22-00001	2/1/2023	(ongoing)	9	$48,438,853

Source: LFC Analysis of SHARE data

Frequent changes to the statewide price agreements obscure pricing and make it difficult to pinpoint specific cost drivers. A statewide purchase price agreement (SPA) is a contract with one or more vendors to provide specific goods or services at a predetermined price for a set period. In theory, SPAs can allow the state to leverage its purchase power for discounts on bulk goods or services, but past LFC evaluations have found agencies often use them to make direct purchases that might be provided more economically through separate contracts. However, agencies often favor SPAs because they allow for faster procurement, without the need for individual bids. . OCD has used SPAs, administered for agencies by the State Purchasing Division of the General Services Department (GSD), for all of its plugging and remediation work in recent years, and the division says this allows it to respond quickly to emergency plugging situations. However, the division's use of SPAs reduces pricing transparency and cost control. Because of frequent changes to the invoiceable line items covered by the SPAs, it is extremely difficult to track changes to the costs of goods

and services over time. For example, cement retainers and cast iron bridge plugs—both used to help place cement plugs in the wellbore—have been categorized differently across the last four SPAs. Some agreements list them separately, others group them together, and the latest agreement includes different bid options based on whether they are set via tubing or wireline. However, where comparable, costs for the same goods and services have in many cases doubled or even tripled since FY19. Analyzing a single contractor's invoices from 2023 shows that prices for identical line items increased by more than 20 percent between March and November of that year, at a time when the producer price index for oilfield services, a measure of inflation, was declining. For example, the cost of a "supervisor/cementer" rose from $500 per day to $750 per day, "backhoe services with operator" increased from $100 per hour to $150 per hour, and the price for a "wireline unit on location" jumped from $500 to $2,000.

Figure 10. Vendor Costs for Specific Line Items within the Statewide Purchase Price Agreement

			(AO)	$1,730.00
			(AS)	$5,100.00
61		Each	Wireline set CIBP, 7.625", includes setting tool rental	
			(AB)	$3,500.00
			(AE)	$2,850.00
			(AL)	$5,000.00
			(AO)	$2,345.00
			(AS)	$5,600.00
62		Each	Tubing set CIBP, 7.625", includes setting tool rental	
			(AB)	$3,800.00
			(AE)	$5,250.00
			(AL)	$5,000.00
			(AO)	$1,925.00

Source: GSD

Without internal cost estimates or requirements to select the lowest bid, OCD may be paying more for plugging and reclamation than necessary. In the latest statewide purchase agreement, GSD requested vendor "bids" or rate proposals on 156 items and services related to the plugging, remediation and restoration of orphaned oil and gas wells and facilities. That process is similar to what Colorado requests as part of its "main service agreement" and Texas as part of its "request for qualifications." The items and services in the SPA range from the per-item cost of sacks of Class B cement to the discount a vendor will offer if it provides items not covered by the SPA. Companies were not required to submit bids on all items, but only on the items and services they intended to provide. A total of 31 vendors were awarded under the agreement, ranging from oilfield service companies to environmental consulting firms. According to the terms of the SPA, awarded vendors effectively form a "pre-approved" vendor list.

OCD is not required to contract for the lowest rate proposed under the agreement but can choose the contractor it believes is best suited to a

particular job. Texas and Colorado follow similar models, but both states then issue separate, detailed contracts for specific plugging projects. Colorado's contract includes a per-unit, line-item breakdown of the estimated cost. In Texas, the Railroad Commission can negotiate the details of the contract. Before issuing a purchase order, OCD does not negotiate or develop its own internal price estimates for plugging and remediation work but instead relies on the approved vendors to submit estimates. Plugging costs frequently exceed estimates, with 236 recently plugged wells costing $10.4 million more than originally budgeted. While some of those cost overruns may be unavoidable, requiring more detailed information from contractors upfront and having more structured processes for internally estimating costs could save the state hundreds of thousands of dollars if they help reduce project totals by even a fraction of a percent.

OCD has approved multiple change orders exceeding $1 million on projects contracted through the statewide purchase price agreement. Change orders are used to adjust the total authorized by a purchase order to accommodate alterations in scope, timeline, or cost. It is considered procurement best practice to limit change orders and for any change order involving significant increases or decreases to include supporting documentation and an estimate of the projected total cost. OCD frequently issues multiple change orders for plugging and reclamation projects, and often the justification for the change order is "additional work was required." In many cases, the division also issues change orders after receiving invoices for total amounts higher than the initial purchase order, which, while not prohibited, is considered a poor procurement practice.

Ballooning Costs as a Result of Plugging Problems

The most expensive well OCD plugged in FY24 was the BRC Madera #001 well (API 30-015-22372), a gas well drilled in 1977. The well is between an RV park and a residential neighborhood on the south side of Carlsbad and prior to plugging was leaking significant quantities of methane. OCD's contractor began plugging the well on August 23, 2023. According to a plugging summary filed with OCD, the contractor encountered a number of issues during plugging, including problems with cementing that resulted in the company having to drill out cement plugs it had previously set before replacing them, extending the time and equipment needed to completely plug the well. While the original cost estimate was $250 thousand, it ultimately cost $778 thousand to plug the well.

Table 15. Change Orders for Plugging the Buckskin Federal #002 Well (API: 30-025-27024)

Date	Event	Plugging	Bond Premiums	NM GRT	Total Authorized
7/5/2024	Purchase Order Issued for Plugging 2 Wells (Buckskin #001 and #002)	$ 372,031.37	$ 18,601.57	$ 20,508.23	$ 411,141.17
Undated	Change Order Issued	$ 1,183,069.91	$ (6,267.33)	$ 61,802.00	$ 1,649,745.75
1/29/2025	Change Order Issued	$ 1,157,000.00		$ 83,159.38	$ 2,889,905.13
2/21/2025	Change Order Issued	$ 2,750,000.00		$ 342,617.63	$ 5,982,522.76

*Note: The values associated with NM GRT in the latter two change orders do not correspond to a line item in the original purchase order but are assumed to be for NM GRT. The total is listed incorrectly in the 02/21/2025 change order but is correct in the table.

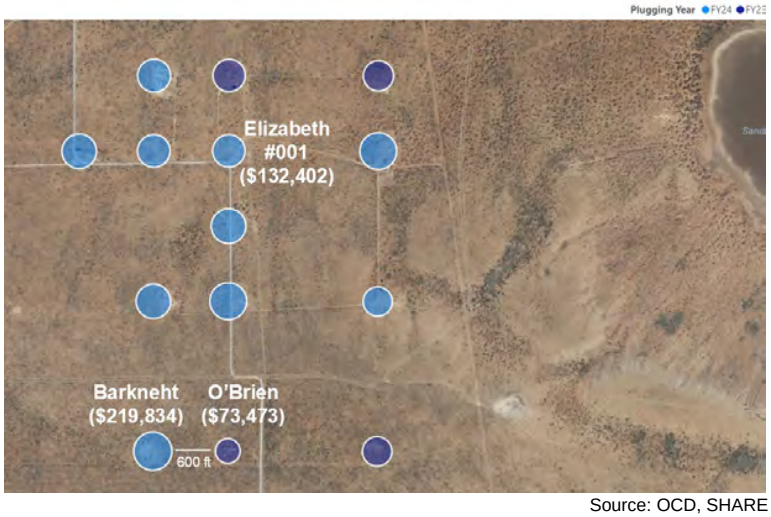
Source: SHARE

OCD has paid at least $1.3 million between FY23 and FY25 to reimburse contractors for performance bond premiums but has no guidelines for nonperformance. The purpose of a performance bond is to ensure that only qualified, financially stable contractors take on public projects and that the contractor fulfills the obligations outlined in their contract. The terms of the most recent state purchase price agreement

governing plugging and reclamation work specify that companies are required to obtain performance bonds covering 50 percent of the project total for any project estimated to cost more than $25 thousand. The agreement also specifies that the state will pay "the premium cost for the performance bond without markup." Section 13-4-18 NMSA 1978 requires contractors to provide performance bonding for public works construction contracts valued at $25 thousand or more. Public works contracts are defined as "a contract for construction, construction management, architectural, landscape architectural, engineering, surveying or interior design services." While performance bonds can theoretically help insulate the state from liability associated with incomplete or poorly executed work, OCD has no record of ever pulling a contractor's performance bond and does not specify under what circumstances it would do so in the statewide purchase price agreement. Nevertheless, according to invoices, OCD has paid at least $1.3 million in bond premiums between FY23 and FY25. Some states do not require performance bonding for plugging and reclamation projects. The Colorado Department of Natural Resources only requires performance bonds for federally funded projects but not state projects; the Texas Railroad Commission's contract management guide notes that performance bonds are "discouraged unless there is a compelling need or statutory requirement."

Plugging costs and designs vary widely between sites with similar characteristics, suggesting inadequate quality and financial controls. Examining a set of 12 oil wells plugged between March and November 2023 within a half-mile radius by the same contractor, total plugging costs ranged from $73 thousand to $220 thousand (Figure 13). The wells are largely identical in their depth, design and age. For example, the lowest and highest cost wells are 600 feet apart and were drilled in the same year, to the same depth (Table 15). While the final plugging design is also almost identical (Figure 11 and Figure 12), the OCD plugging report for the Barkneht well indicates the contractor had trouble with cementing

Figure 13. Plugging Cost Variation Within an Oil Field



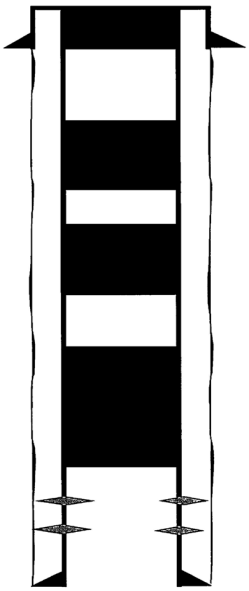
Source: OCD, SHARE

Figure 11. Plugged Wellbore Diagram: Barkneht #001 $219,834



Source: OCD

Figure 12. Plugged Wellbore Diagram: O'Brien Lightcap 7 #001 $73,473



Source: OCD

equipment that resulted in needing to drill out a previously-set plug, and that it had to pump much more cement to cover the same vertical distance because of cement loss to the surrounding rock formation. The contractor ran a cement bond log—a tool used to determine how well cement is bonded to the casing and surrounding formation—prior to plugging the Barkneht well, but not the O'Brien, and used a device called a cement retainer below the first plug on the Barkneht, but not on the O'Brien. OCD attributes the differences in plugging costs and procedures to differences in the conditions encountered downhole, as well as staff turnover. While downhole conditions do vary across wells, differences of the magnitude observed in this small group of wells suggest OCD has inadequate financial and quality controls.

Table 16. Adjacent Well Plugging Comparison

Well Name	O'Brien Lightcap	Barkneht
API	30-005-60815	30-005-60817
Date Drilled	12/2/1980	12/15/1980
Well Depth	2860	2861
Well Type	Oil	Oil
Date Plugged	3/18/2023	10/12/2023
Plugs Placed	4	4
Days to Plug	5	9
Purchase Order Estimated Cost	$78,974.00	$150,000.00
Actual Plugging Cost	$ 73,472.95	$ 219,834.41

Source: OCD, SHARE

Having a designated agency representative on site for state-contracted plugging, as is done by the industry and other states, could result in significant cost savings and would ensure plugging standards are followed. It is common practice for the industry to have a representative on site during well-plugging operations, often called a "company man." The representative might either be a direct employee of the company or a contracted third party, but the job is to be an on-site supervisor, sending frequent updates to the operator on actions taken to plug the well, materials used, and any issues that arise. The practice ensures all plugging standards are followed and that billing is accurate. Eight states require a representative of the regulator to be on site for well plugging, including Texas and Colorado, but New Mexico does not. While different states have different reasons for requiring a representative of the regulator on site during plugging operations, the practice has both potential quality and cost-saving benefits. Improperly plugged wells may leak, requiring re-plugging, which is time-consuming and expensive, so it is in the state's interest to ensure wells are plugged properly the first time. There is also the potential for cost savings from more accurate invoicing. At the anticipated total cost for plugging all wells currently under OCD's purview, a 1 percent cost savings would translate to $1.3 million, which would cover the cost of OCD hiring a third-party contractor to be the division's representative at state-contracted plugging operations.

OCD Plugging Oversight

Although many staff at OCD play some role in the state's well-plugging efforts, only one person currently provides dedicated oversight of state-contracted plugging. That petroleum engineer in the engineering special projects group reviews contractor-provided plugging plans and diagrams and communicates with the plugging contractors over the phone about problems that arise, as well as any modifications to the plugging plan. However, the engineer is not in the field and must rely on accurate reporting from the contractors. Field oversight is handled by a rotating group of inspectors, who visit plugging sites as their broader duties allow but who are typically not present for any extended period of time at a site. Using IIJA funding, OCD is currently attempting to hire a new staff member whose sole focus would be on-the-ground oversight of plugging operations, but the division has struggled with recruitment and retention (see Appendix F for OCD's organization structure).

Despite recent increases, financial assurance posted by operators is typically insufficient to cover the costs of plugging and remediating orphaned well sites.

In 2015, the Legislature amended statute to create separate financial assurance requirements for "temporarily abandoned" wells, and in 2018, it increased the maximum amount of financial assurance that can be required for active wells from $50 thousand to $250 thousand. The result has been operators posting an additional $53 million for temporarily abandoned wells and increased overall financial assurance. However, the financial assurance posted by some operators remains as low as $105 per well, with only one operator in the state having more per-well financial assurance than the current average cost of state-contracted plugging.

Operators have posted a total of $117 million in financial assurance with OCD, but that translates to less than $1,000 per well for some operators. OCD records show the division currently holds unreleased financial assurance from 1,580 operators totaling $117 million. There are currently 576 operators in New Mexico with unplugged wells. Of the financial assurance that has not been released by OCD, $17 million is associated with operators that OCD records show no longer have any unplugged wells in the state. The largest amount held by OCD for a single operator with active wells is $1.5 million, or $20 thousand per well. The median financial assurance held by OCD for an individual operator with active wells is $75 thousand, or an average of $7,000 per well. However, some operators have much lower per-well financial assurance; more than three dozen operators have less than $1,000 per well in posted assurance, and the company with the least has just $105 per well. Because financial assurance is tied to specific operators, the per-well financial assurance amount is much more significant than the statewide total; OCD can only access funds from the individual operator whose wells it has plugged.

According to OCD records, the state has successfully redeemed a total of $870 thousand in financial assurances since 2000, which represents just a fraction of the costs of state-contracted well plugging over the same time period. As noted previously, OCD does not have a comprehensive record of the wells it has plugged historically, making it difficult to evaluate how much financial assurance should have been available to OCD for plugging. However, according to OCD records, the state has successfully "redeemed" $869,863 in financial assurance since 2000 from 15 different operators backed by 10 banks or sureties. OCD has not successfully redeemed any financial assurance since 2018; available data does not indicate whether the division has pursued forfeiture in the interim. Of the financial assurance that has been forfeited since 2000 (the furthest extent of OCD records), roughly a third ($304 thousand) came from a single operator, Canyon E&P, which orphaned 227 wells in 2015 (see sidebar). There are 34 operators on OCD's orphaned well list with wells on state or private land that are being or have been plugged by the division.

Canyon E&P: Insufficient and Unforfeited Financial Assurance

Canyon E&P, a foreign limited liability company, purchased many of its 227 wells in 2010 from an operator going through bankruptcy proceedings with the stated intent of using waterflooding to restore production from the wells, which had been depleted of conventional oil resources. However, the waterflooding never commenced and Canyon E&P also went bankrupt.

In 2015, OCD issued the company a notice of violation (NOV), noting that none of the company's wells had reported production for two years and many of its wells had not produced for much longer, putting the company out of compliance with the Oil and Gas Act. After an administrative law hearing, the OCD director issued an order compelling Canyon E&P to plug the wells within 30 days, or barring that, giving OCD the authority to plug them itself. OCD began plugging the wells shortly thereafter, in the first quarter of fiscal year 2016.

At the time OCD began plugging Canyon E&P's wells, the state held **$957 thousand** in financial assurance from the operator. It has successfully forfeited **$304 thousand**, while **$644 thousand** is listed as unredeemed, without a release date. While OCD does not have records that would allow for analysis of the total amount spent by the state on plugging Canyon E&P's wells, since FY18, it has been at least **$10 million**.

A decade later, the division has fully plugged and remediated 25 of Canyon E&P's wells, plugged but not remediated an additional 171, and **32 remain unplugged and unremediated.** Those unplugged wells have been sitting idle for at least 11 years, and in some cases as long as 30 years.

Together, those operators have $5.8 million in unredeemed financial assurance, but the totals for individual operators vary widely, from $16 thousand to more than $1 million. The administrative burden of pursuing small amounts of financial assurance could be seen as outweighing the value, but not pursuing forfeiture may communicate that there are no consequences for orphaning wells.

While statute authorizes OCD to sue operators for indemnification of costs associated with state-contracted plugging, the division has no record of ever having done so. Section 70-14 NMSA 1978 allows OCD to sue operators to recover plugging costs paid out of the reclamation fund. However, there is no record of OCD ever bringing suit against an operator to recover costs incurred by the state through the plugging of its wells. The State Land Office (SLO) brought suit against an operator in 2016 for recovery of damages associated with spills and unpaid fees. In 2020, a judge ruled in SLO's favor and ordered the operator to pay $2.4 million, with interest. In 2023, the company filed for Chapter 11 bankruptcy and in 2024, for Chapter 7. Despite the judgement, the state has not recovered any money beyond the operator's original financial assurance.

Regulators in other states and countries reduce their liability for plugging and remediating orphaned wells through various mechanisms.

Current financial incentives are poorly aligned to encourage operators to properly plug and abandon their wells because requirements for financial assurance per well are less than the typical plugging cost, and OCD does not consistently seek forfeiture of financial assurance. Regulators in other states and countries have attempted to address that misalignment of incentives through a variety of mechanisms, including increasing financial assurance requirements, assigning liability to prior operators or interest holders, and preventing the transfer of wells to operators that cannot demonstrate they have the financial resources to plug them. More direct approaches include requiring operators to set aside future cleanup money in site- or operator-specific trust or escrow accounts and to plug a certain percentage of their inactive wells regularly. Many of these policy approaches have only been implemented in recent years, making it too early to fully assess their long-term effectiveness, and each comes with tradeoffs in terms of administrative burden, enforceability, and industry impact. EMNRD is currently beginning a rulemaking process based on a third-party petition that would make changes to the financial assurance requirements, among other things. While many of the changes align with the recommendations of this report, they are constrained by the current statutory framework and, as a result, have the potential to simply replicate its existing problems. In New Mexico, the goal should be to structure policies that motivate operators to plug wells before they become OCD's responsibility, leveraging the industry's capacity to do the work faster and likely at a lower cost.

Table 17. Policy Options for Reducing Orphan Well Liability

Policy	Description	Arguments For	Arguments Against	Implementing Jurisdictions
Increased financial assurance	Increase required financial assurance amounts to reflect actual plugging costs, including requiring single well financial assurance for inactive and low producing wells.	Increases the money available to the state for orphaned well plugging; matches an operator or well's risk profile to its required financial assurance.	Bonds or letters of credit can be difficult to obtain and cost operators money that goes towards neither production nor plugging; it can be difficult for the state to forfeit surety bonds.	Colorado Proposed NM rules
Trailing liability	The regulator can hold prior operators, lease holders, or working interest owners responsible for well plugging and remediation if the current operator is unable to pay.	Allows the state to hold operators that profited from the well responsible for cleanup; encourages self-policing among operators and may minimize the transfer of wells to risky operators.	Trailing liability can be difficult to enforce and can result in costly legal battles.	California Louisiana Department of the Interior
Licensing	The regulator can assess various aspects of a company (past compliance, financial standing, plugging liability, well portfolio, etc.) to determine if a company should operate in the state and/or if it can buy wells from other operators.	Prevents operators that do not have the capital to plug wells, have many inactive wells, or are facing large plugging liabilities from obtaining more wells that could become the responsibility of the state.	Depending on the level of detail requested from operators, the administrative burden could be significant.	Alberta <Canada> Texas
Site- or operator-specific trusts	Operators are required to pay into a trust or escrow account up to a site- or operator-specific estimated cleanup cost. The payments can be structured to build over time at defined rates or be tethered to production, so those profiting the most pay the most.	Ensures the state has enough money to plug and remediate wells should they be orphaned and puts all the money spent by the operators on FA towards cleanup. Disincentivizes orphaning because liability is effectively pre-paid.	Between estimating the necessary assurance and tracking many hundreds or thousands of accounts, the administrative burden could be significant. This option also ties up operator capital.	Louisiana Colorado

Source: LFC files

In 2022, Colorado adopted new rules requiring additional financial assurance with the goal of aligning an operator's risk profile with its required financial assurance. In 2019, the Colorado General Assembly passed Senate Bill 19-181, which restructured the Oil and Gas Conservation Commission into the Energy and Carbon Management Commission (ECMC) and directed it to adopt rules ensuring every operator is financially capable of meeting statutory obligations, including plugging, remediation, and reclamation (C.R.S. § 34-60-106(13)). The resulting rules, which went into effect in 2022, require all operators to submit a financial assurance plan, reviewed annually by ECMC. In its rulemaking, the commission determined lower production is a proxy for higher orphaning risk, and as a result, the required financial assurance plans are tethered to an operator's average annual production and its corporate structure (e.g., public or private). Operators with lower average production are assigned to plans that require greater financial assurance. Operators on those plans must also make defined annual contributions to a third-party trust fund until their full financial assurance obligation is met. Operators receive credit toward their financial assurance requirements for wells they plug and abandon. As of June 2024, more than one-third of operators had not submitted a financial assurance plan, and another 10 percent had submitted plans that were deemed insufficient. The rules have also been criticized for offering too many compliance pathways, increasing ECMC's administrative burden and potentially creating loopholes. However, it remains to be seen whether they

ultimately achieve the goal of reducing the number of orphaned wells in the state.

Similar to Colorado, proposed New Mexico rules would require operators to submit a plugging and abandonment plan prior to purchasing wells and for OCD to collect more financial assurance from operators with lower production. The rulemaking proposal, case number 24683 submitted by the Western Environmental Law Center, would make changes to OCD's current rules regarding inactive wells, financial assurance and well plugging. Among the suggestions are requiring operators to submit plugging plans when wells are transferred that demonstrate the purchaser has sufficient resources to plug the wells it is purchasing, requiring single well financial assurance for wells that produce less than 1,000 BOE annually and for less than 180 days, and requiring operators with well portfolios composed of more than 15 percent inactive or low-producing wells to provide single-well financial assurance for all of their wells. The proposal also recommends treating wells that produce less than 90 barrels and for less than 90 days in a year as presumptively of "no beneficial use," meaning they would need to be plugged. This report recommends defining "low-producing" wells and requiring additional financial assurances for them. It further recommends expanding the definition of "inactive" wells to include wells that produce fractions of a barrel of oil equivalent a day. This report also suggests additional mechanisms be made available to fulfill financial assurance requirements that would allow operators to set aside money over time for plugging and reclamation costs. Careful consideration should be afforded in the rulemaking process to ensuring the changes do not result in operators orphaning additional wells.

California uses trailing liability to hold previous operators responsible for properly plugging and abandoning wells if the current operator does not meet its obligations. Since 1996, California administrative code (Cal. PRC. Section 3237) has stated that the current operator of a deserted well is responsible for properly plugging wells and decommissioning production facilities. However, if the regulator determines the current operator does not have the financial resources to fully cover the cost of plugging and cleanup, the immediately preceding operator is responsible for the cost. The regulator can continue to look to previous operators until an operator is found that is determined to have the resources to plug and abandon the well. That includes mineral interest owners that may have leased the working interest in a well to another person. Known as "trailing liability," the rule is meant to disincentivize operators from transferring wells to companies they believe will not have the capital to properly plug and abandon the well, therefore keeping it from being orphaned to the state. The federal Department of the Interior has also had regulations that create trailing liability for offshore oil and gas platform decommissioning since the 1950s. However, it has never used those rules to pursue a prior operator in part because complex corporate structures can limit the ability of regulators to pursue compensation using trailing liability.

While OCD is limited in its ability to hold previous operators responsible for well plugging and reclamation, the State Land Office (SLO) can hold lessees responsible for the cleanup of well sites on state land if the operator cannot afford or refuses to do it themselves. On New Mexico state trust lands, the lessee and the operator of a well are often not the same because the entity that holds the lease from SLO may assign operational responsibilities to another company. In March 2020, SLO created an accountability and enforcement program focused on ensuring leaseholders comply with the terms of their lease agreements, including proper plugging and reclamation. SLO staff began tracking inactive wells and reaching out to lessees to plug and remediate those sites. In several cases, SLO has sued to compel lessees, and a recent New Mexico Court of Appeals decision concluded prior oil and gas lessees can be held responsible for cleanup necessitated by their activities on state trust lands. According to the agency, the program has resulted in the industry plugging 650 wells that may otherwise have been orphaned. At the current per-well average of $163 thousand, that translates to nearly $106 million in potential cost savings for plugging alone. SLO also claims increased enforcement has led to operators and lessees doing a better job of tracking and managing their inactive and marginal wells before the agency gets involved, but it is difficult to validate those claims. OCD records indicate a similar number of wells have been plugged annually in recent years as have been plugged historically, but it is possible those wells would not have been plugged otherwise.

The Alberta (Canada) Energy Regulator can deny the transfer of wells to operators that cannot afford to plug them. The Alberta Energy Regulator (AER) oversees all oil and gas production in Alberta, including licensing of oil and gas operators in the province. AER conducts an annual licensee assessment with the goal of understanding the ability of licensees to meet their regulatory obligations, including plugging and abandoning their wells. Factors considered in determining whether the applicant poses an unreasonable risk and should be denied a license include the compliance history of all actors within the applicant's company (including its directors, officers, and shareholders in the province and elsewhere), compliance history of actors previously associated with the applicant, financial health of the applicant and associated entities, outstanding debts to AER or others, cancelation or reductions in insurance coverage, and any unspecified factor AER considers appropriate in the circumstances. This process applies to the company's initial license to operate as well as whether it is allowed to purchase additional wells from other operators. Texas similarly requires operator assessments, though the information required is far less comprehensive than the financial and operational assessments used in Alberta. If OCD were able to review and deny or approve well transfers from one operator to another based on both companies' compliance history and available capital, the division could potentially prevent the transfer of wells to companies that do not have the financial resources to properly plug and abandon wells, therefore reducing the likelihood of orphaning.

Alberta Licensee Capability Assessment Considerations

- Financial health;
- Estimated total magnitude of liability (active and inactive), including plugging, remediation, and reclamation;
- Remaining lifespan of mineral resources and infrastructure and the extent to which existing operations fund current and future liabilities;
- Management and maintenance of regulated infrastructure and sites, including compliance with operational requirements;
- Rate of closure activities and spending and pace of inactive liability growth; and
- Compliance with administrative regulatory requirements, including the management of debts, fees, and levies.

Source: Alberta Energy Regulator

A site-specific trust account, like those offered in Louisiana and required for certain operators in Colorado, can be used as a supplement or alternative to the current financial assurance system. Bonds, particularly surety bonds, have long been the primary regulatory mechanism for ensuring proper plugging and abandonment of wells. However, changes to the surety bond market have made those more difficult for some operators to obtain. As a result, regulators in some states have created a mechanism for companies to set aside money directly for cleanup through site-specific trusts or escrow accounts, up to an estimated maximum. In Louisiana, operators have the option of fulfilling their financial assurance requirements though a site-specific trust when they transfer a well to another operator. Typically, an operator will do that to avoid being held liable for plugging and remediation costs if the new operator fails to pay (because Louisiana also has trailing liability). The amount required for Louisiana's site-specific trust accounts is determined through an estimate of actual plugging costs, which must be updated when the well is transferred. A 2024 legislative program evaluation recommended Louisiana encourage the use of site-specific trusts by requiring them when new wells are permitted. In Colorado, certain low-producing operators are required to contribute to a sinking fund or third-party trust at a specified rate annually. Those funds are not tied to individual wells but to the operator itself to minimize the administrative burden on regulatory staff. Other models for escrow or trust accounts include tethering contributions to the account to production, with different tiers for the stage of a well's life. Those can be structured to ensure the operator who profits from the most from the well also pay towards the liability, or to require accelerated contributions later in a well's life. One advantage of trusts over sureties is that all the money paid into the account ultimately goes toward plugging and reclamation, not to a bank or insurance company through premiums. If structured properly, the trusts also ensure the state has sufficient financial assurance to cover the costs of plugging and remediating the site should it be orphaned.

Recommendations

The Legislature should consider:

- Amending statute to require the Oil Conservation Division of the Energy, Minerals and Natural Resources Department to annually provide a report to the Legislature detailing all costs associated with state-contracted plugging and remediation, not only costs associated with use of the reclamation fund, including information about average cost-per-foot for plugging and cost-per-acre for remediation;
- Amending Section 70-2-14 NMSA 1978 to specify that wells producing below certain thresholds set in rule require additional financial assurance;
- Amending Section 70-2-14 NMSA 1978 to allow an operator to meet its financial assurance obligations by fully funding a third-

party trust or escrow up to OCD's site- or operator-specific estimated plugging and remediation costs; and

- Amending statute to grant the Oil Conservation Division the authority to review and disallow the transfer of wells should the division determine, through processes outlined in rule, that the purchaser is unlikely to be able to fulfill its asset retirement obligations.

The Energy, Minerals and Natural Resources Department should:

- Promulgate rules specifying that low-producing wells require individual well financial assurance, posted within two months of notice, and clarifying that the transfer is contingent on regulatory approval;
- Publish a list of orphaned wells monthly, including both wells the state has already plugged and those it is planning to plug, including the costs associated with plugging and reclamation, to ensure transparent tracking of state expenditures on orphaned wells;
- Develop internal estimates for the cost of plugging and reclaiming individual wells and associated infrastructure;
- Develop individual contracts for plugging projects, in addition to the statewide purchase price agreement, that specify the scope of work, the estimated cost, the procedures for obtaining a change order and the circumstances under which OCD will pull a contractor's performance bond;
- Reopen its statewide purchase agreement for plugging and remediation work to solicit additional bids from plugging contractors by September 2025;
- Ensure the presence of a "company man" for all state-contracted well plugging who is responsible for filing daily reports on the activities undertaken by the contractor, the materials used, and the estimated plugging cost;
- Develop a risk-based monitoring system to track leaks from wells awaiting plugging, as well as plugged and abandoned wells, and provide annual reports on the number of previously plugged wells that are leaking, what they are leaking, and how much; and
- Complete the prioritization scoring of all currently orphaned wells and complete assessments for new orphaned wells within 90 days of the state assuming plugging authority.

Appendix A. EMNRD Report Card Updates on Orphaned Well Plugging

Fiscal Year	LFC/OCD Comments
2007	"The program area managed 12 site remediation projects in FY07 costing approximately $3 million and exhausting reclamation funds available for this purpose. It should be noted that some of these projects, while expensive, were determined to be critical to reclamation efforts."
2012	"In FY12, the OCD spent only $3 million, or 30 percent, of the oil and gas reclamation fund to plug wells and to conduct site assessments, monitoring and maintenance activities. The agency reports no wells were plugged for the first quarter of FY13 because a vendor on price agreement went out of business and the price agreement expired."
2013	"Well plugging activity increased in FY13, with a cumulative, annual total of 57 wells plugged, decreasing the number of outstanding wells to be plugged by almost 50 percent. Additionally, the program generated $100 thousand in revenue for the oil and gas reclamation fund from the sale of salvage equipment at the plugging sites."
2014	"The program is currently working with a group of contractors to properly plug a significant number of wells resulting from the business failure of the former Xeric Oil and Gas Corp. There are 45 such wells located southwest of Hobbs, ten of which were plugged in the first quarter of FY14."
2015	"The program is currently working with a group of contractors to properly plug a significant number of wells resulting from the business failure of the former Xeric Oil and Gas Corp. The hearing process for two sets of wells was completed and the wells are now approved for plugging. The division has five plugging contractors under contract. All five are currently doing work for other clients and will begin plugging wells for the Oil Conservation Division as soon as possible."
2016	"The agency is on track to meet the annual target for plugging abandoned oil and gas wells. However, agency and LFC projections show a rapidly decreasing oil reclamation fund balance through FY17 due to a long list of wells authorized for plugging – which is expected to grow in the near future due to oil producer bankruptcies – and increased use of the fund to support agency operations. At the same time the fund is being tapped at a higher rate, revenues are projected to decline as the oil and gas industry weathers the downturn. As of May 2016, the cash balance of the oil reclamation fund is $9.3 million, but agency staff reports an unobligated balance of only $395 thousand and projects a reduction in fund revenues. The average cost of plugging a well is $30 thousand to $40 thousand."
2017	"OCD had been waiting on General Services Department approval of a new four year plugging contract, which stopped activity in the second quarter. However, 10 wells were plugged in the third quarter and improved weather conditions should allow the agency to meet the annual target of 30 wells plugged."
2018	Q1: "No wells were plugged in the first quarter, which the OCD attributes to wet weather in the southeast which limited access to well locations. OCDs performance on this measure will also likely be hindered by funding; the oil reclamation fund, which is used to pay for plugging activities, will likely be exhausted by the close of FY20." Q2: "OCD plugged 12 wells in the second quarter and is on pace to meet the target. Performance on this measure may improve as a result of the Legislature increasing general fund appropriations for EMNRD by $3 million to offset use of the reclamation fund. EMNRD anticipates plugging 60 wells in calendar year 2018. The State Land Office estimates there are 600 unplugged, abandoned wells on state trust lands."
2019	"Despite plugging 41 abandoned oil and gas wells in FY18, the agency requested a target of only 27 in FY19, which it met. OCD reports that 208 abandoned or orphaned wells are currently approved for plugging."
2021	Q1: "Due mainly to timing conflicts with OCD's well-plugging contractor, the target for wells plugged was not met in FY20." Q4: "OCD had a new procurement agreement for FY21 that allowed for additional approved well-plugging contractors, which substantially increased the number of wells plugged in FY21 relative to the past three fiscal years. The division was just one well short of meeting its annual target."

Comments Continued

2022	Q2: "Orphan well-plugging was slow in the first two quarters of FY22 and OCD is unlikely to meet its annual target. Program staff report the recent well sites have been in worse than usual condition with defective casing and casing collapses causing additional rig time and cementing to properly remediate the wells. The increased time and materials required, plus the effects of inflation, have significantly increased cost of well-plugging to roughly $70.5 thousand per well." Q3: "OCD has recently been focusing its well-plugging efforts on a large oil field containing old, poorly maintained orphan well sites that require additional time and resources to remediate. Furthermore, program staff report low availability of equipment and crews has also contributed to the slow pace of well-plugging. Wells such as these with defective casing and casing collapses are more expensive and take longer to complete, but pose the greatest risk to groundwater. OCD has spent just over $1 million on plugging costs for 16 wells so far in FY22." Q4: OCD has recently been focusing its well-plugging efforts on a large oil field containing old, poorly maintained orphan well sites that require additional time and resources to remediate. Since 2015, OCD has plugged 234 wells on state and private land. In FY22 OCD has spent $1.6 million in recurring funds, and $1.8 in other state funds on well plugging. OCD secured the services of four rigs and intends to plug more wells using monies from the reclamation fund and a sizeable grant from the federal government. Plugging cost per well have doubled from FY21 to FY22."
2023	"OCD received a $25 million initial federal grant to fund plugging and remediation at 200 well sites over 24 months under the federal Infrastructure Investment and Jobs Act's Orphan Well Program. ENMRD's 2022 annual report estimated more than 1,700 abandoned wells are located on state-owned or private land. The division expects to receive an additional $75 million over the next four years for expenditure through 2030. As required by the grant, the division successfully obligated 90 percent of the initial funding to 145 plugging projects. The Division anticipates plugging the remaining balance of those initial grant funds by September 2023. However, the "wells properly plugged" metric counts only completed plugging projects. The division currently has three contract plugging crews working concurrently and correctly predicted a significant increase in well-plugging activity between the second and third quarters once it completed steps to ramp up the program. OCD has set an internal target of plugging approximately 200 wells by October 2023, well above its target of 50 for the year; however, crew availability remains a challenge."
2024	"Ten wells were plugged during the fourth quarter of FY24, bringing the total for the fiscal year to 105. Five plugging rigs were contracted and are working simultaneously. Plugging activity increased due to funding from the federal Infrastructure Investment and Jobs Act and continued state support from the oil reclamation fund. With still over 2,000 orphaned wells identified in New Mexico, the agency's ability to complete these plugging projects at an increased pace will be critical to protecting public health and safety."
2025	"Nine abandoned and orphaned wells were plugged during the first quarter of FY25. The lower-than-average number was due to new requirements for pre-clearance of well site regarding compliance with the Endangered Species Act and the National Historic Preservation Act. Once new clearance requirements are finalized, well plugging will return to a more consistent rate. The division also, per the request of the Federal Indian Minerals office, has begun plugging on Navajo-allotted land. With still over 2,000 orphaned wells identified in New Mexico, the agency's ability to complete these plugging projects at an increased pace will be critical to protecting public health and safety."

Source: LFC

Appendix B. Other State Financial Assurance Amounts

While most states require oil and gas operators to provide upfront financial assurance for well plugging, the amounts and variables considered vary widely. In 2023, the Ground Water Protection Council published a summary report featuring different states' approaches to financial assurance for oil and gas well plugging and remediation. Among the states, Alaska has the highest blanket or all-well bond maximum at $30 million, while Pennsylvania has the lowest blanket bond at $25 thousand for all wells. New Mexico is one of four states where the maximum blanket bond is capped at $250,000 in statute. Eleven states consider the depth of the proposed well in the amount of financial assurance required, increasing the amount as the well depth increases. However, many of these states, including New Mexico, only consider well depth in the financial assurance amount required for a single well while the blanket bonds for more than one well do not consider depth. Only four states vary their blanket bond amounts depending on the depth of the well: for example, in Kansas there are blanket bond amounts for all wells less than 2,000 feet in depth and higher blanket amounts for wells more than 2,000 feet in depth. Additionally, some states consider factors like location of the well, mineral type, and status of the well.

Financial Assurance Amounts in Select States

State	Minimum	Maximum	Do amounts consider well depth?
Alaska	$400,000	$30,000,000	No
Colorado	$12,000	$6,000,000	No
New York	$2,500	$2,000,000	Yes*
Louisiana	$6,000	$500,000	Yes
New Mexico	**$25,000**	**$250,000**	**Yes**
Texas	$25,000	$250,000	Yes
Michigan	$20,000	$250,000	Yes*
West Virginia	$5,000	$250,000	No
Utah	$1,500	$120,000	Yes*
South Dakota	$50,000	$100,000	No
Mississippi	$20,000	$100,000	Yes
Nebraska	$10,000	$100,000	No
Alabama	$5,000	$100,000	Yes
Arkansas	$3,000	$100,000	No
Illinois	$1,500	$100,000	Yes
Montana	$1,500	$50,000	Yes
Kansas	$7,500	$45,000	Yes*
Indiana	$2,500	$45,000	No
Pennsylvania	$2,500	$25,000	No

Note: New York, Michigan, Utah, and Kansas regulate blanket bond amounts based on the depth of the wells while the other only consider depth in the amount for a single well.

Source: Ground Water Protection Council

Appendix C. History of the Oil and Gas Conservation Tax and the Oil and Gas Reclamation Fund

- Laws 1959, Chapter 53, Section 7: Oil conservation tax created at a rate of 0.14 percent on oil and gas products severed and sold. The revenue went to the oil conservation fund, which was used by the Oil Conservation Commission (OCC) to enforce the Oil and Gas Act (as is currently the function of OCD).

- Laws 1975, Chapter 289, Section 15: The oil conservation tax rate was increased to .18 percent.

- Laws 1977, Chapter 237, Section 5 and 6; Chapter 234, Section 4: The Legislature amended statute so most of the conservation tax revenue still went to the conservation fund, but 0.01 percent was deposited in the newly created oil and gas reclamation fund specifically for the OCC to plug and remediate abandoned well sites. The laws also tied the conservation tax rate to the balance in the reclamation fund; being 0.19 percent when the fund balance was under $1 million, and 0.18 percent when the balance was over $1 million.

- Laws 1989, Chapter 130, Sections 1 and 6: The Legislature changed the allocation of the conservation tax, increasing the share directed to the reclamation fund to 5.3 percent, with 87.7 percent going to the conservation fund, and 7 percent to the general fund.

- Laws 1991, Chapter 9, Section 16: The Legislature repealed the conservation fund, instead sending all conservation tax not sent to the reclamation fund to the general fund; the percent directed to the reclamation fund remained the same, at 5.3 percent.

- Laws 2010, Chapter 98, Sections 1 and 2: The Legislature untethered the conservation tax rate from the balance of the reclamation fund and instead tied it to the price of oil. When the price of West Texas Intermediate is less than $70 per barrel, the tax is 0.19 percent and the reclamation fund receives 10.5 percent of the tax revenue and the remainder goes to the general fund. When the price is over $70 per barrel, the tax is 0.24 percent and the reclamation fund receives 19.7 percent of the revenue.

Appendix D. Texas Plugging Costs

District	Calculated average per-foot cost												
	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024
01	$3.95	$3.03	$5.98	$10.47	$8.52	$6.85	$6.65	$7.68	$8.21	$7.88	$11.14	$12.31	$11.53	$9.49	$11.15
02	$3.96	$4.84	$4.84[2]	$14.27	$10.74	$10.74[4]	$8.36	$8.36[5]	$8.30	$8.81	$15.70	$13.57	$7.97	$8.48	$11.77
03	$8.36	$6.07	$8.73	$12.13	$8.71	$10.59	$10.96	$5.22	$6.04	$7.51	$13.93	$15.58	$10.40	$30.19	$21.60
04	$4.31	$5.60	$7.72	$13.96	$15.77	$6.49	$6.38	$7.56	$9.42	$9.35	$8.32	$8.16	$8.66	$10.35	$16.37
05	$3.87	$4.35	$6.10	$7.85	$14.45	$10.96	$7.45	$5.28	$5.02	$31.73	$6.40	$8.29	$6.62	$10.20	$9.92
06	$8.99	$7.64	$6.42	$4.90	$5.94	$5.94[4]	$8.30	$11.00	$6.84	$7.69	$7.93	$6.49	$8.81	$15.75	$15.05
6E	$3.74	$5.63	$5.63[2]	$8.45	$7.16	$6.25	$6.11	$5.96	$6.40	$7.63	$6.79	$7.54	$8.34	$12.46	$11.90
7B	$3.90	$5.70	$5.39	$6.48	$6.76	$7.77	$5.93	$6.23	$6.23	$7.19	$11.27	$7.42	$10.09	$9.57	$10.62
7C	$7.34	$12.93	$10.56	$6.29	$4.52	$10.26	$7.53	$7.85	$7.21	$8.09	$9.63	$9.30	$6.43	$11.14	$10.95
08	$8.56	$6.52	$12.31	$12.68	$17.37	$6.80	$11.57	$14.15	$13.28	$10.29	$17.88	$17.23	$27.38	$30.75	$46.48
8A	$4.28	$4.28[1]	$4.28[2]	$4.28[3]	$9.02	$9.02[4]	$6.54	$6.54[5]	$6.54[6]	$10.62	$12.16	$17.54	$12.74	$17.09	$14.27
09	$2.60	$2.73	$3.38	$3.96	$4.21	$4.92	$2.88	$2.97	$3.04	$4.27	$4.37	$4.46	$4.61	$6.39	$5.96
10	$6.25	$5.85	$5.63	$14.50	$7.48	$17.17	$9.05	$6.85	$5.44	$8.13	$9.69	$10.94	$9.81	$16.45	$16.39

Notes: Cost is calculated based on actual costs incurred by the Railroad Commission for plugging wells in the previous fiscal year.
(1) No State Funded plugging operations were completed in District 8A during FY 2011. The per-foot cost from FY 2010 was continued.
(2) No State Funded plugging operations were completed in Districts 02, 6E or 8A during FY 2012. The per-foot cost from FY 2011 was continued.
(3) No State Funded plugging operations were completed in Districts 8A during FY 2013. The per-foot cost from FY 2012 was continued.
(4) No State Funded plugging operations were completed in Districts 02, 06, and 8A during FY 2015. The per-foot cost from FY 2014 was continued.
(5) No State Funded plugging operations were completed in Districts 02 and 8A during FY 2017. The per-foot cost from FY 2016 was continued.
(6) No State Funded plugging operations were completed in Districts 8A during FY 2018. The per-foot cost from FY 2017 was continued.

Appendix E. OCD Well Plugging Prioritization System

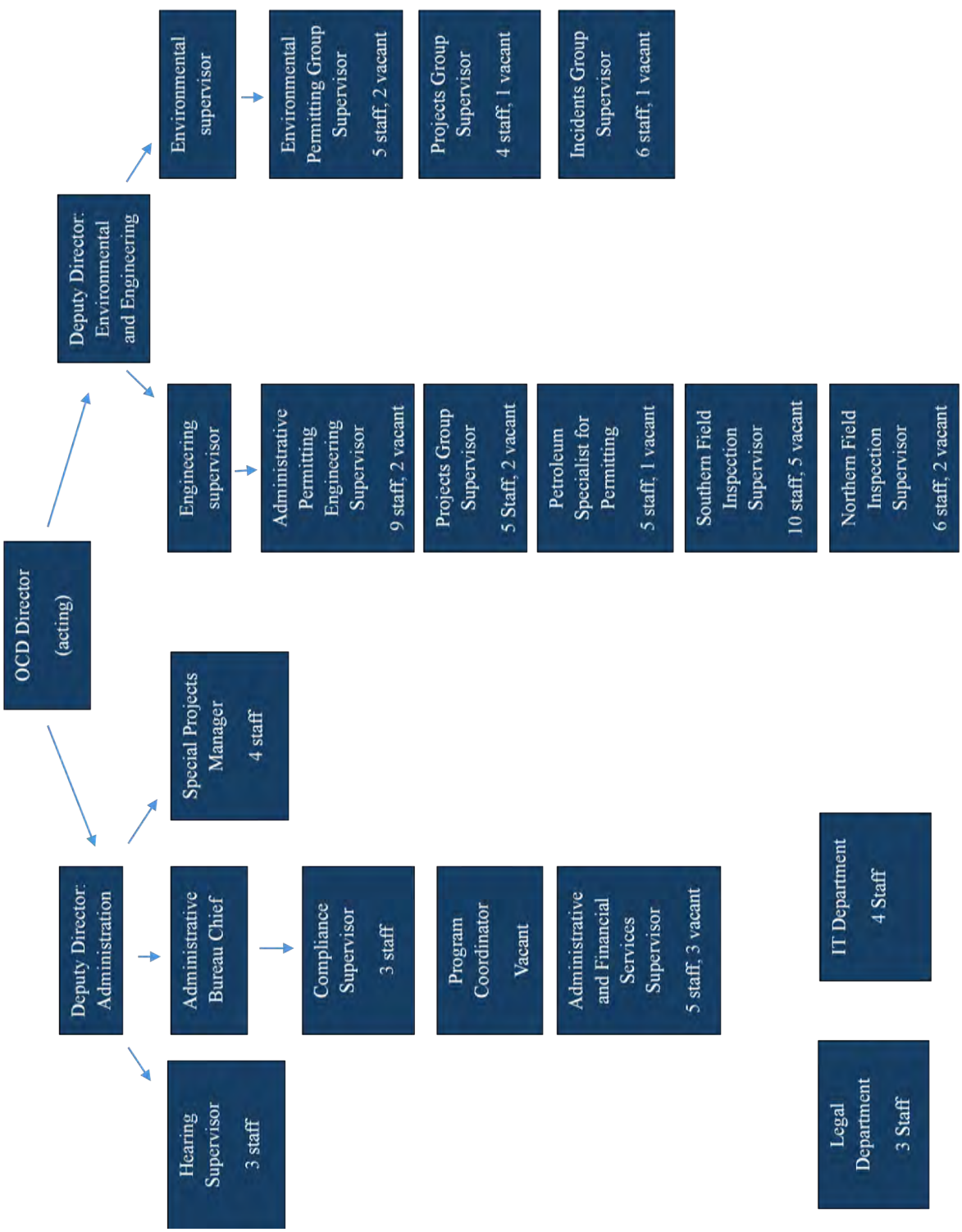
Each well is scored on 21 different criteria, with different weights assigned to each criterion. Wells that are actively leaking are automatically deemed highest priority, but other criteria that may boost a well's overall score include if it is within 300 feet of an occupied structure, if it is within a municipal boundary, if the well is a saltwater disposal well, if it has known defective casing, and if it has no well head control. After wells that are actively leaking, wells with a score over 100 are considered the second-highest priority, scores of 50-100 are third, and wells with a score lower than 50 are the last priority to plug.

OCD Plugging Prioritization Ranking Criteria

Factor	Maximum Weight	Weighting Criteria
Active leaks	Highest priority	
Within 300 ft of an occupied structure	10	Yes/No
Within a municipal boundary	10	Yes/No
Disposal well?	10	Yes/No
Mechanical integrity testing history/ known defective casing	10	Yes/ No; unrepaired failure
No Wellhead control	10	Well with gas or casing above 12" =10, well without gas =7
No surface casing or water protection casing	9	Yes/No
Well has abnormally high pressure	8	Yes/No
Located within an agricultural area	8	Yes/No
Age of well >25 years	7	Yes/No
Bradenhead pressure >10	7	Yes/No
Date of las production or injection >10	7	Yes/No
Within one mile of other orphan wells needing plugging	6	Yes/No
Within 200 ft of a water supply well	5	Yes/No
Proximity to karst geology	5	High karst =5, medium karst =3, low karst =0
Hydrogen sulfide	5	Yes/No
Naturally occurring radioactive material	5	Yes/No
Citizen complaints	5	Yes/No
Areas within ½ mile of injection/disposal	4	Yes/No
Private surface	3	Yes/No
Other	10	TBD, level dependent on issue discovered.

Source: OCD

Appendix F. OCD Organizational Structure



Source: OCD

Note: As of March 2025

EXHIBIT 5

Tannis Fox

From: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>
Sent: Wednesday, February 12, 2025 4:03 PM
To: Tannis Fox; Kyle Tisdel; Morgan O'Grady; Matt Nykiel; Michael Feldewert (MFeldewert@hollandhart.com); Adam Rankin; Paula M. Vance; Trevino, Christy, EMNRD; Moander, Chris, EMNRD; jennifer@bradfutelaw.com; matthias@bradfutelaw.com; Jordan Kessler; Andrew Cloutier; atripp@hinkelawfirm.com; Miguel Suazo; Miguel Suazo; James Martin; JParrot@bwenergylaw.com
Subject: OCC 24683_OCD Redline Proposal
Attachments: 24683_OCD Redline Proposal_final draft 2.12.25.docx; 24683_OCD Redline Proposal_clean draft 2.12.25.docx

Good afternoon counselors,

Please find the long-awaited OCD redline proposal. The 'final draft' document includes OCD's proposals in blue, over WELC's original redline. The 'clean draft' document condenses WELC's proposal and OCD's proposal into one redline, assuming all OCD changes were adopted for a revised petition.

Housekeeping note – some combination of the original formatting and my Microsoft office products combined forces to generate some very interesting formatting challenges. I've spent significant time trying to get this into a form that can facilitate substantive discussions. As we consider any changes, I think it will be necessary to start a clean version. Considering our original schedule, I wanted to circulate this as soon as possible.

OCD edits summarized:

1. Wells are 'tiered' into roughly three categories, as proxies for levels of risk:
    a. Normal 'active' wells. These wells are eligible for blanket FA as set forth in 70-2-14. Most wells fall into this category.
    b. "Marginal wells." These wells represent a greater risk of abandonment and are proposed to be ineligible for blanket FA. These wells, or well portfolios substantially comprised of marginal wells, must be covered by single well FA by a date to be determined or upon transfer.
    c. Wells that are no longer usable for beneficial purposes. Wells producing less than 90 BOE or for 90 days in the prior year are presumed to be no longer usable for beneficial purposes. This category triggers an administrative review of an operator's ability to cover the liability for plugging activities. Operators will be able to demonstrate that well(s) can continue production and do not pose an undue risk of abandonment to the state. Essentially, these changes trigger an analysis of operator asset retirement plans prior to a 12-month period of inactivity, at which time enforcement actions typically only result in adding abandoned wells to OCD's orphan plugging program.
2. Proposed to strike the 19.15.5.9 NMAC inactive well threshold exceptions. All wells would need to be either compliant or place in approved temporary abandonment.
3. Various other edits for consistency.

I expect many questions and we are interested in discussing the proposed changes at future stakeholder engagement meetings.

Thank you,

Jesse K. Tremaine
Legal Director, Oil Conservation Division
Office of General Counsel
New Mexico Energy, Minerals & Natural Resources Department
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OCD REDLINE DRAFT

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 2 GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS

19.15.2.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.2.1 NMAC - Rp, 19.15.1.1 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.2 SCOPE: 19.15.2 NMAC applies to persons or entities engaged in oil and gas development and production within New Mexico and to 19.15.2 NMAC through 19.15.39 NMAC.
[19.15.2.2 NMAC - Rp, 19.15.1.2 NMAC, 12/1/2008]

19.15.2.3 STATUTORY AUTHORITY: 19.15.2 NMAC is adopted pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978, which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash because of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[19.15.2.3 NMAC - Rp, 19.15.1.3 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.4 DURATION: Permanent.
[19.15.2.4 NMAC - Rp, 19.15.1.4 NMAC, 12/1/2008]

19.15.2.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.2.5 NMAC - Rp, 19.15.1.5 NMAC, 12/1/2008]

19.15.2.6 OBJECTIVE: To set forth general provisions and definitions pertaining to the authority of the oil conservation division and the oil conservation commission pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978.
[19.15.2.6 NMAC - Rp, 19.15.1.6 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.7 DEFINITIONS: These definitions apply to 19.15.2 NMAC through 19.15.39 NMAC.

A. Definitions beginning with the letter "A".

(1) **"Abate"** means to investigate, contain, remove or mitigate water pollution.

(2) **"Abatement"** means the investigation, containment, removal or other mitigation of water pollution.

(3) **"Abatement plan"** means a description of operational, monitoring, contingency and closure requirements and conditions for water pollution's prevention, investigation and abatement.

(4) **"Act" or "Oil and Gas Act"** means Chapter 70, Article 2 NMSA 1978, as it may be modified or amended.

(5) **"Adjoining spacing units"** mean those existing or prospective spacing units in the same pool that are touching at a point or line on the subject spacing unit.

(6) **"Adjusted allowable"** means the allowable production a well or proration unit receives after all adjustments are made.

(7) **"AFE"** means authorization for expenditure.

(8) **"Affected persons"** means the following persons owning interests in a spacing unit or other identified tract:

(a) the operator, as shown in division records, of a well on the tract, or, if the tract is included in a division-approved or federal unit, the designated unit operator;

(b) in the absence of an operator, or with respect to an application wherein the operator of the spacing unit or identified tract is the applicant, each working interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant files the application;

(c) as to any tract or interest therein that is not subject to an existing oil and gas lease, each mineral interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant filed the application; and

(d) if the United States or state of New Mexico owns the mineral estate inthe spacing unit or identified tract or any part thereof, the BLM or state land office, as applicable;or

(e) if the mineral estate in the spacing unit or identified tract or any part thereof is tribal land, the BLM, the United States department of the interior, bureau of Indian affairs, and the relevant tribe.

(9) "Allocated pool" means a pool in which the total oil or gas production is restricted and is allocated to various wells in the pool in accordance with proration schedules.

(10) "Allowable production" means that number of barrels of oil or cubic feet of gas the division authorizes to be produced from an allocated pool.

(11) "APD" means application for permit to drill.

(12) "API" means the American petroleum institute.

(13) "Approved temporary abandonment", "temporary abandonment", or "temporary abandonment status" means the status of a well that is inactive, has been approved in accordance with 19.15.25.13 NMAC and complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

(14) "Aquifer" means a geological formation, group of formations or a part of a formation that can yield a significant amount of water to a well or spring.

(15) "Asset retirement obligation" means an obligation associated with the retirement of a tangible long-lived asset.

~~(15)~~**(16) "ASTM"** means ASTM International - an international standards developing organization that develops and publishes voluntary technical standards for a wide range of materials, products, systems and services.

B. Definitions beginning with the letter "B".

(1) "Back allowable" means the authorization for production of an underproduction resulting from pipeline proration.

(2) "Background" means, for purposes of ground water abatement plans only, the amount of ground water contaminants naturally occurring from undisturbed geologic sources or water contaminants occurring from a source other than the responsible person's facility. This definition does not prevent the director from requiring abatement of commingled plumes of pollution, does not prevent responsible persons from seeking contribution or other legal or equitable relief from other persons and does not preclude the director from exercising enforcement authority under any applicable statute, rule or common law.

(3) "Barrel" means 42 United States gallons measured at 60 degrees fahrenheit and atmospheric pressure at the sea level.

(4) "Barrel of oil" means 42 United States gallons of oil, after deductions for the full amount of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) "Below-grade tank" means a vessel, excluding sumps and pressurized pipeline drip traps, where a portion of the tank's sidewalls is below the surrounding ground surface's elevation. Below-grade tank does not include an above ground storage tank that is located above or at the surrounding ground surface's elevation and is surrounded by berms.

(6) "Beneficial purposes" or "beneficial use" ~~means productive use of an oil or gas well, and includes but is not limited to use of a well for primary production of oil or gas, secondary or tertiary production of oil, injection for secondary and tertiary production of oil, injection for reservoir pressure maintenance, monitoring, and disposal of wastewater. "Beneficial purposes" and "beneficial use" does not include use of an oil or gas well for speculative purposes.~~means the well is being used in a productive or beneficial manner.

a. For the purposes of oil and gas production, wells and well or operator compliance under 19.15.25.8 and 19.15.5.9 NMAC, there is a presumption that wells are not capable of beneficial use if, in the prior 12-month period, any well has not produced:
   i. for at least 90 days, and
   ii. at least 90 barrel of oil equivalent or at a volume that the operator is able to demonstrate that the well produces in paying quantities.

b. For injection or salt water disposal wells, beneficial use requires that wells must inject at least 90 days and at least 100 bbls in any consecutive 12-month period.

c. Wells that have been drilled but not completed and wells that have been completed for less than 18 months are exempt from the beneficial purposes thresholds in this section.

~~(6)~~**(7) "Berm"** means an embankment or ridge constructed to prevent the movement of liquids, sludge, solids or other materials.

~~(7)~~**(8) "Biopile",** also known as biocell, bioheap, biomound or compost pile, means a pile of contaminated soils used to reduce concentrations of petroleum constituents in excavated soils through biodegradation. This technology involves heaping contaminated soils into piles or "cells" and stimulating aerobic microbial activity within the soils through the aeration or addition of minerals, nutrients and moisture.

~~(8)~~**(9) "BLM"** means the United States department of the interior, bureau of land management.

~~(9)~~(10) **"Bottom hole pressure"** means the gauge pressure in psi under conditions existing at or near the producing horizon.

~~(10)~~(11) **"Bradenhead gas well"** means a well producing gas through wellhead connections from a gas reservoir that has been successfully cased off from an underlying oil or gas reservoir.

~~(11)~~(12) **"BS&W"** means basic sediments and water.

~~(12)~~(13) **"BTEX"** means benzene, toluene, ethylbenzene and xylene.

C. **Definitions beginning with the letter "C".**

(1) **"Carbon dioxide gas"** means noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks.

(2) **"Casinghead gas"** means a gas or vapor or both gas and vapor indigenous to and produced from a pool the division classifies as an oil pool. This also includes gas-cap gas produced from such an oil pool.

(3) **"Certified mail" or "certified mail, return receipt requested"** means United States Postal Service Certified Mail or equivalent service that provides tracking and signature receipt, including Federal Express, United Parcel Service, or similar courier services.

(4) **"Cm/sec"** means centimeters per second.

(5) **"CPD"** means central point delivery.

(6) **"Combination multiple completion"** means a multiple completion in which two or more common sources of supply are produced through a combination of two or more conventional diameter casing strings cemented in a common well bore, or a combination of small diameter and conventional diameter casing strings cemented in a common well bore, the conventional diameter strings of which might or might not be a conventional multiple completion.

(7) **"Commission"** means the oil conservation commission.

(8) **"Commission clerk"** means the division employee the director designates to provide staff support to the commission and accept filings in rulemaking or adjudicatory cases before the commission.

(9) **"Common purchaser for gas"** means a person now or hereafter engaged in purchasing from one or more producers gas produced from gas wells within each common source of supply from which it purchases.

(10) **"Common purchaser for oil"** means every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines.

(11) **"Common source of supply"**. See pool.

(12) **"Condensate"** means the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

(13) **"Contiguous"** means acreage joined by more than one common point, that is, the common boundary is at least one side of a governmental quarter-quarter section.

(14) **"Conventional completion"** means a well completion in which the production string of casing has an outside diameter exceeding 2.875 inches.

(15) **"Conventional multiple completion"** means a completion in which two or more common sources of supply are produced through one or more strings of tubing installed within a single casing string, with the production from each common source of supply completely segregated by means of packers.

(16) **"Correlative rights"** means the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste the owner's just and equitable share of the oil or gas in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas under the property bears to the total recoverable oil or gas in the pool, and for the purpose to use the owner's just and equitable share of the reservoir energy.

(17) **"Cubic feet of gas or cubic foot of gas"** means that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 psi (15.025 psi absolute), at a standard base temperature of 60 degrees fahrenheit.

D. **Definitions beginning with the letter "D".**

(1) **"Deep pool"** means a common source of supply that is situated 5000 feet or more below the surface.

(2) **"Depth bracket allowable"** means the basic oil allowable the division assigns a pool and based on its depth, unit size or special pool orders, which, when multiplied by the market demand percentage factor in effect, determines the pool's top proration unit allowable.

(3) **"Director"** means the director of the New Mexico energy, minerals and natural resources department, oil conservation division.

(4) **"Division"** means the New Mexico energy, minerals and natural resources department,

oil conservation division.

(5) "Division clerk" means the division employee the director designates to accept filings in adjudicatory cases before the division.

(6) "Downstream facility" means a facility associated with the transportation (including gathering) or processing of gas or oil (including a refinery, gas plant, compressor station or crude oil pump station); brine production; or the oil field service industry.

(7) "DRO" means diesel range organics.

E. Definitions beginning with the letter "E".

(1) "EC" means electrical conductivity.

(2) "Enhanced oil recovery project" means the use or the expanded use of a process for thedisplacement of oil from an oil well or division-designated pool other than a primary recovery process, including but not limited to the use of a pressure maintenance process; a water flooding process; an immiscible, miscible, chemical, thermal or biological process; or any other related process.

(3) "EOR project" means an enhanced oil recovery project.

(4) "EPA" means the United States environmental protection agency.

(5) "Exempted aquifer" means an aquifer that does not currently serve as a source of drinking water, and that cannot now and will not in the foreseeable future serve as a source of drinking water because:

(a) it is hydrocarbon producing;

(b) it is situated at a depth or location that makes the recovery of water for drinking water purposes economically or technologically impractical; or

(c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(6) "Exempt waste" means oil field waste exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(7) "Existing spacing unit" means a spacing unit containing a producing well.

(8) "Expired temporary abandonment" or "expired temporary abandonment status" means the status of a well that is inactive and has been approved for temporary abandoned status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

F. Definitions beginning with the letter "F".

(1) "Facility" means a structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock or activity of any kind, whether stationary or mobile.

(2) "Field" means the general area that at least one pool underlies or appears to underlie; and also includes the underground reservoir or reservoirs containing oil or gas. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools.

(3) "Fresh water" to be protected includes the water in lakes and playas (regardless of quality, unless the water exceeds 10,000 mg/l TDS and it can be shown that degradation of the particular water body will not adversely affect hydrologically connected fresh ground water), the surface waters of streams regardless of the water quality within a given reach, and underground waters containing 10,000 mg/l or less of TDS except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use that contamination of such waters would impair.

G. Definitions beginning with the letter "G".

(1) "Gas", also known as natural gas, means a combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool the division has classified as a gas pool.

(2) "Gas lift" means a method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

(3) "Gas-oil ratio" means the ratio of the casinghead gas produced in standard cubic feet to the number of barrels of oil concurrently produced during any stated period.

(4) "Gas-oil ratio adjustment" means the reduction in allowable of a high gas oil ratio unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

(5) "Gas transportation facility" means a pipeline in operation serving gas wells for the transportation of gas, or some other device or equipment in like operation where the gas produced from gas wells connected with the pipeline or other device or equipment can be transported or used for consumption.

(6) "Gas well" means a well producing gas from a gas pool, or a well with a gas-oil ratio exceeding 100,000 cubic feet of gas per barrel of oil producing from an oil pool.

(7) **"Geomembrane"** means an impermeable polymeric sheet material that is impervious to liquid and gas if it maintains its integrity and is used as an integral part of an engineered structure designed to limit the movement of liquid or gas in a system.

(8) **"Geotextile"** means a sheet material that is less impervious to liquid than a geomembrane but more resistant to penetration damage, and is used as part of an engineered structure or system to serve as a filter to prevent the movement of soil fines into a drainage system, to provide planar flow for drainage, to serve as a cushion to protect geomembranes or to provide structural support.

(9) **"GRO"** means gasoline range organics.

(10) **"Ground water"** means interstitial water that occurs in saturated earth material and can enter a well in sufficient amounts to be used as a water supply.

(11) **"Ground water sensitive area"** means an area the division specifically designates after evaluation of technical evidence where ground water exists that would likely exceed WQCC standards if contaminants were introduced into the environment.

H. Definitions beginning with the letter "H".

(1) **"Hardship gas well"** means a gas well where underground waste occurs if the well is shut-in or curtailed below its minimum sustainable flow rate.

(2) **"Hazard to public health"** exists when water that is used or is reasonably expected to be used in the future as a human drinking water supply exceeds at the time and place of the use, one or more of the numerical standards of Subsection A of 20.6.2.3103 NMAC, or the naturally occurring concentrations, whichever is higher, or if a toxic pollutant as defined at Subsection WW of 20.6.2.7 NMAC affecting human health is present in the water. In determining whether a release would cause a hazard to public health to exist, the director investigates and considers the purification and dilution reasonably expected to occur from the time and place of release to the time and place of withdrawal for use as human drinking water.

(3) **"Hazardous waste"** means non-exempt waste that exceeds the minimum standards for waste hazardous by characteristics established in RCRA regulations, 40 CFR 261.21-261.24, or listed hazardous waste as defined in 40 CFR, part 261, subpart D, as amended.

(4) **"HDPE"** means high-density polyethylene.

(5) **"High gas-oil ratio proration unit"** means a unit with at least one producing oil well with a gas-oil ratio exceeding the limiting gas-oil ratio for the pool in which the unit is located.

(6) **"H2S"** means hydrogen sulfide.

I. Definitions beginning with the letter **"I".**

(1) **"Illegal gas"** means gas produced from a gas well exceeding the division-determined allowable.

(2) **"Illegal oil"** means oil produced exceeding the allowable the division fixes.

(3) **"Illegal product"** means a product of illegal gas or illegal oil.

(4) **"Inactive well"** means a well that is not being used for beneficial purposes such as production, injection or monitoring and that is not being drilled, completed, repaired or worked over.

(5) **"Injection well"** means a well used for the injection of air, gas, water or other fluids into an underground stratum.

J. Definitions beginning with the letter "J". [RESERVED]

K. Definitions beginning with the letter "K". "Knowingly and willfully", for assessing civil penalties, means the voluntary or conscious performance of an act that is prohibited or the voluntary or conscious failure to perform an act or duty that is required. It does not include performances or failures to perform that are honest mistakes or merely inadvertent. It includes, but does not require, performances or failures to perform that result from a criminal or evil intent or from a specific intent to violate the law. The conduct's knowing and willful nature may be established by plain indifference to or reckless disregard of the requirements of statutes, rules, orders or permits. A consistent pattern or performance or failure to perform also may be sufficient to establish the conduct's knowing and willful nature, where such consistent pattern is neither the result of honest mistakes nor mere inadvertency. Conduct that is otherwise regarded as being knowing and willful is rendered neither accidental nor mitigated in character by the belief that the conduct is reasonable or legal.

L. Definitions beginning with the letter "L".

(1) **"Limiting gas-oil ratio"** means the gas-oil ratio the division assigns to a particular oil pool to limit the volumes of casinghead gas that may be produced from the various oil producing units within that particular pool.

(2) **"Liner"** means a continuous, low-permeability layer constructed of natural or human-made materials that restricts the migration of liquid oil field wastes, gases or leachate.

(3) **"LLDPE"** means linear low-density polyethylene.

(4) **"Load oil"** means oil or liquid hydrocarbon that has been used in remedial operation in

an oil or gas well.

(5) **"Log"** means a systematic detailed and correct record of formations encountered in drilling a well.

M. Definitions beginning with the letter "M".

(1) **"Marginal unit"** means a proration unit that is incapable of producing top proration unit allowable for the pool in which it is located.

(2) "Marginal Well" means an oil or gas well that:

(a) produced less than 180 days and less than 1000 barrel of oil equivalent over the prior 12 month period, or

(b) produced less than 1000 barrel of oil equivalent.

(3) **"Market demand percentage factor"** means that percentage factor of one hundred percent or less as the division determines at an oil allowable hearing, which, when multiplied by the depth bracket allowable applicable to each pool, determines that pool's top proration unit allowable.

(4) **"MCF"** means 1000 cubic feet.

(5) **"MCFD"** means 1000 cubic feet per day.

(6) **"MCFGPD"** means 1000 cubic feet of gas per day.

(7) **"Measured depth"** means the total length of the well bore.

(8) **"Mg/l"** means milligrams per liter.

(9) **"Mg/kg"** means milligrams per kilogram.

(10) **"Mineral estate"** is the most complete ownership of oil and gas recognized in law and includes the mineral interests and the royalty interests.

(11) **"Mineral interest owner"** means a working interest owner, or an owner of a right to explore for and develop oil and gas that is not subject to an existing oil and gas lease.

(12) **"Minimum allowable"** means the minimum amount of production from an oil or gas well that may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste.

(13) **"Miscellaneous hydrocarbons"** means tank bottoms occurring at pipeline stations; oil storage terminals or refineries; pipeline break oil; catchings collected in traps, drips or scrubbers by gasoline plant operators in the plants or in the gathering lines serving the plants; the catchings collected in private, community or commercial salt water disposal systems; or other liquid hydrocarbon that is not lease crude or condensate.

N. Definitions beginning with the letter "N".

(1) **"Non-aqueous phase liquid"** means an interstitial body of liquid oil, petroleum product, petrochemical or organic solvent, including an emulsion containing such material.

(2) **"Non-exempt waste"** means oil field waste not exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(3) **"Non-hazardous waste"** means non-exempt oil field waste that is not hazardous waste.

(4) **"Non-marginal unit"** means a proration unit that can produce the top proration unit allowable for the pool in which it is located, and to which the division assigns a top proration unit allowable.

(5) **"NORM"** means the naturally occurring radioactive materials regulated by 20.3.14 NMAC.

O. Definitions beginning with the letter "O".

(1) **"Official gas-oil ratio test"** means the periodic gas-oil ratio test the operator performs pursuant to division order by the method and in the manner the division prescribes.

(2) **"Oil"** means petroleum hydrocarbon produced from a well in the liquid phase and that existed in a liquid phase in the reservoir. This definition includes crude oil or crude petroleum oil.

(3) **"Oil field waste"** means non-domestic waste resulting from the exploration, development, production or storage of oil or gas pursuant to Paragraph (21) of Subsection B of Section 70-2-12 NMSA 1978 and the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil pursuant to Paragraph (22) of Subsection B of Section 70-2-12 NMSA 1978, including waste generated from oil field remediation or abatement activity regardless of the date of release. Oil field waste does not include waste not generally associated with oil and gas industry operations such as tires, appliances or ordinary garbage or refuse unless generated at a division-regulated facility, and does not include sewage, regardless of the source.

(4) **"Oil well"** means a well capable of producing oil and that is not a gas well as defined in Paragraph (6) of Subsection G of 19.15.2.7 NMAC.

(5) **"Operator"** means a person who, duly authorized, manages a lease's development or a producing property's operation, or who manages a facility's operation.

(6) **"Overproduction"** means the amount of oil or gas produced during a proration period

exceeding the amount authorized on the proration schedule.

(7) **"Owner"** means the person who has the right to drill into and to produce from a pool, and to appropriate the production either for the person or for the person and another.

P. Definitions beginning with the letter "P".

(1) **"Penalized unit"** means a proration unit to which, because of an excessive gas-oil ratio, the division assigns an allowable that is less than top proration unit allowable for the pool in which it is located and also less than the ability of the well or wells on the unit to produce.

(2) **"Person"** means an individual or entity including partnerships, corporations, associations, responsible business or association agents or officers, the state or a political subdivision of the state or an agency, department or instrumentality of the United States and of its officers, agents or employees.

(3) **"Pit"** means a surface or sub-surface impoundment, man-made or natural depression or diked area on the surface. Excluded from this definition are berms constructed around tanks or other facilities solely for safety, secondary containment and storm water or run-on control.

(4) **"Playa lake"** means a level or nearly level area that occupies the lowest part of a completely closed basin and that is covered with water at irregular intervals, forming a temporary lake.

(5) **"Pool"** means an underground reservoir containing a common accumulation of oil or gas. Each zone of a general structure, which zone is completely separated from other zones in the structure, is covered by the word pool as used in 19.15.2 NMAC through 19.15.39 NMAC. "Pool" is synonymous with "common source of supply" and with "common reservoir".

(6) **"Potential"** means a well's properly determined capacity to produce oil or gas under division-prescribed conditions.

(7) **"Ppm"** means parts per million by volume.

(8) **"PQL"** means practical quantitation limit.

(9) **"Pressure maintenance"** means the injection of gas or other fluid into a reservoir, either to maintain the reservoir's existing pressure or to retard the reservoir pressure's natural decline.

(10) **"Produced water"** means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

(11) **"Producer"** means the owner of a well or wells capable of producing oil or gas or both in paying quantities.

(12) **"Product"** means a commodity or thing made or manufactured from oil or gas, and derivatives of oil or gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzene, wash oil, lubricating oil and blends or mixtures of oil or gas or a derivative thereof.

(13) **"Proration day"** consists of 24 consecutive hours that begin at 7:00 a.m. and end at7:00 a.m. on the following day.

(14) **"Proration month"** means the calendar month that begins at 7:00 a.m. on the first day of the month and ends at 7:00 a.m. on the first day of the next succeeding month.

(15) **"Proration period"** means for oil the proration month and for gas the 12-month period that begins at 7:00 a.m. on January 1 of each year and ends at 7:00 a.m. on January 1 of the succeeding year or other period designated by general or special order of the division.

(16) **"Proration schedule"** means the division orders authorizing the production,purchase and transportation of oil, casinghead gas and gas from the various units of oil or of gas in allocated pools.

(17) **"Proration unit"** means the area in a pool that can be effectively and efficiently drained by one well as determined by the division or commission (see Subsection B of Section 70-2-17 NMSA 1978) as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool.

(18) **"Prospective spacing unit"** means a hypothetical spacing unit that does not yet havea producing well.

(19) **"PVC"** means poly vinyl chloride.

(20) **"Psi"** means pounds per square inch.

Q. Definitions beginning with the letter "Q". [RESERVED]

R. Definitions beginning with the letter "R".

(1) **"RCRA"** means the federal Resource Recovery and Conservation Act.

(2) **"Recomplete"** means the subsequent completion of a well in a different pool from the pool in which it was originally completed.

(3) **"Regulated NORM"** means NORM contained in oil-field soils, equipment, sludges or other materials related to oil-field operations or processes exceeding the radiation levels specified in 20.3.14.1403 NMAC.

(4) **"Release"** means breaks, leaks, spills, releases, fires or blowouts involving oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and gases to the environment.

(5) **"Remediation plan"** means a written description of a program to address unauthorized releases. The plan may include appropriate information, including assessment data, health risk demonstrations and corrective action or actions. The plan may also include an alternative proposing no action beyond the spill report's submittal.

(6) **"Responsible person"** means the owner or operator who shall complete a division-approved corrective action for pollution from releases.

(7) **"Rules"** means the rules enacted pursuant to the Oil and Gas Act, 19.15.2 to 19.15.39 NMAC, as they may be modified or amended.

(8) **"Royalty interest owner"** means the owner of an interest in oil and gas that does not presently entitle the owner to explore, drill or otherwise develop those minerals, including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing.

(9) **"Run-on"** means rainwater, leachate or other liquid that drains from other land onto any part of a division-approved facility.

S. **Definitions beginning with the letter "S".**

(1) **"SAR"** means the sodium adsorption ratio.

(2) **"Secondary recovery"** means a method of recovering quantities of oil or gas from a reservoir which quantities would not be recoverable by ordinary primary depletion methods.

(3) **"Sediment oil"** means tank bottoms and other accumulations of liquid hydrocarbons on an oil and gas lease, which hydrocarbons are not merchantable through normal channels.

(4) **"Shallow pool"** means a pool that has a depth range from zero to 5000 feet.

(5) **"Shut-in"** means the status of a production well or an injection well that is temporarily closed, whether by closing a valve or disconnection or other physical means.

(6) **"Shut-in pressure"** means the gauge pressure noted at the wellhead when the well is completely shut-in, not to be confused with bottom hole pressure.

(7) **"Significant modification of an abatement plan"** means a change in the abatement technology used excluding design and operational parameters, or relocation of twenty-five percent or more of the compliance sampling stations, for a single medium, as designated pursuant to Subparagraph (d) of Paragraph (2) of Subsection D of 19.15.30.13 NMAC.

(8) **"Soil"** means earth, sediments or other unconsolidated accumulations of solid particles produced by the physical and chemical disintegration of rocks, and that may or may not contain organic matter.

(9) **"Spacing unit"** means the area allocated to a well under a well spacing order or rule. Under the Oil and Gas Act, Paragraph (10) of Subsection B of Section 70-2-12 NMSA 1978, the commission may fix spacing units without first creating proration units. See *Rutter & Wilbanks corp. v. oil conservation comm'n*, 87 NM 286 (1975). This is the area designated on form C-102.

(10) **"Subsurface water"** means ground water and water in the vadose zone that may become ground water or surface water in the reasonably foreseeable future or that vegetation may use.

(11) **"Surface waste management facility"** means a facility that receives oil field waste for collection, disposal, evaporation, remediation, reclamation, treatment or storage except:

(a) a facility that utilizes underground injection wells subject to division regulation pursuant to the federal Safe Drinking Water Act, and does not manage oil field wastes on the ground in pits, ponds, below-grade tanks or land application units;

(b) a facility permitted pursuant to the New Mexico environmental improvement board rules or WQCC rules;

(c) a temporary pit as defined in 19.15.17 NMAC;

(d) a below-grade tank or pit that receives oil field waste from a single well, permitted pursuant to 19.15.37 NMAC, regardless of the capacity or volume of oil field waste received;

(e) a facility located at an oil and gas production facility and used for temporary storage of oil field waste generated on-site from normal operations, if the facility does not pose a threat to fresh water, public health, safety or the environment;

(f) a remediation conducted in accordance with a division-approved abatement plan pursuant to 19.15.30 NMAC, a corrective action pursuant to 19.15.29 NMAC or a corrective action of a non-reportable release;

(g) a facility operating pursuant to a division emergency order;

(h) a site or facility where the operator is conducting emergency response operations to abate an immediate threat to fresh water, public health, safety or the environment or as the division has

specifically directed or approved; or

(i) a facility that receives only exempt oil field waste, receives less than 50 barrels of liquid water per day (averaged over a 30-day period), has a capacity to hold 500 barrels of liquids or less and is permitted pursuant to 19.15.17 NMAC.

T. Definitions beginning with the letter "T".

(1) "Tank bottoms" means that accumulation of hydrocarbon material and other substances that settles naturally below oil in tanks and receptacles that are used in oil's handling and storing, and which accumulation contains more than two percent of BS&W; provided, however, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet to the tank.

(2) "TDS" means total dissolved solids.

~~**(3) "Temporary abandonment" or "temporarily abandoned status"** means the status of a well that is inactive.~~

~~(4)~~**(3) "Top proration unit allowable for gas"** means the maximum number of cubic feet of gas, for the proration period, the division allocates to a gas producing unit in an allocated gas pool.

~~(5)~~**(4) "Top proration unit allowable for oil"** means the maximum number of barrels for oil daily for each calendar month the division allocates on a proration unit basis in a pool to non-marginal units. The division shall determine the top proration unit allowable for a pool by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect.

~~(6)~~**(5) "TPH"** means total petroleum hydrocarbons.

~~(7)~~**(6) "Treating plant"** means a plant constructed for wholly or partially or being used wholly or partially for reclaiming, treating, processing or in any manner making tank bottoms or other waste oil marketable.

~~(8)~~**(7) "Tribal lands"** means those lands for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe. This includes reservations, pueblo land grants, tribal trust lands and individual trust allotments.

~~(9)~~**(8) "Tribal leases"** means those leases of minerals or interests in or rights to minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(10)~~**(9) "Tribal minerals"** means those minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(11)~~**(10) "True vertical depth"** means the difference in elevation between the ground level at the surface location of the well and the deepest point in the well bore.

~~(12)~~**(11) "Tubingless completion"** means a well completion in which the production string of casing has an outside diameter of 2.875 inches or less.

~~(13)~~**(12) "Tubingless multiple completion"** means completion in which two or more common sources of supply are produced through an equal number of casing strings cemented in a common well bore, each such string of casing having an outside diameter of 2.875 inches or less, with the production from each common source of supply completely segregated by cement.

U. Definitions beginning with the letter "U".

(1) "Underground source of drinking water" means an aquifer that supplies water for human consumption or that contains ground water having a TDS concentration of 10,000 mg/l or less and that is not an exempted aquifer.

(2) "Underproduction" means the amount of oil or the amount of gas during a proration period by which a given proration unit failed to produce an amount equal to that the division authorizes in the proration schedule.

(3) "Unit of proration for gas" consists of such multiples of 40 acres as may be prescribed by division-issued special pool orders.

(4) "Unit of proration for oil" consists of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by division-issued special pool orders.

(5) "Unorthodox well location" means a location that does not conform to the spacing requirements division rules establish.

(6) "Unstable area" means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity of some or all a division-approved facility's structural components. Examples of unstable areas are areas of poor foundation conditions, areas susceptible to mass earth movements and karst terrain areas where karst topography is developed because of dissolution of limestone, dolomite or other soluble rock. Characteristic physiographic features of karst terrain include sinkholes, sinking streams, caves, large springs and blind valleys.

(7) "Upstream facility" means a facility or operation associated with the exploration, development, production or storage of oil or gas that is not a downstream facility.

V. Definitions beginning with the letter "V". "Vadose zone" means unsaturated earth material below the land surface and above ground water, or in between bodies of ground water.

W. Definitions beginning with the letter "W".

(1) "Waste", in addition to its ordinary meaning, includes:

(a) underground waste as those words are generally understood in the oil and gasbusiness, and to embrace the inefficient, excessive or improper use or dissipation of the reservoir energy, including gas energy and water drive, of a pool, and the locating, spacing, drilling, equipping, operating or producing of a well or wells in a manner to reduce or tend to reduce the total quantity of oil or gas ultimately recovered from a pool, and the use of inefficient underground storage of gas;

(b) surface waste as those words are generally understood in the oil and gas business, and to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of gas of any type or in any form, or oil, or a product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing a well or wells, or incident to or resulting from the use of inefficient storage or from the production of oil or gas, in excess of the reasonablemarketdemand;

(c) oil production in this state in excess of the reasonable market demand for the oil; the excess production causes or results in waste that the Oil and Gas Act prohibits; reasonable market demand as used herein with respect to oil means the demand for the oil, for reasonable current requirements for current consumption and use within or outside of the state, together with the demand of amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of oil or the products thereof, or both the oil and products;

(d) the non-ratable purchase or taking of oil in this state; the non-ratable taking and purchasing causes or results in waste, as defined in Subparagraphs (a), (b) and (c) of Paragraph (1) of Subsection W of 19.15.2.7 NMAC and causes waste by violating the Oil and Gas Act, Section 70-2-16 NMSA 1978;

(e) the production in this state of gas from a gas well or wells, or from a gas pool, in excess of the reasonable market demand from such source for gas of the type produced or in excess of the capacity of gas transportation facilities for such type of gas; the words "reasonable market demand", as used herein with respect to gas, shall be construed to mean the demand for gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of gas or products thereof, or both the gas and products.

(2) "Water" means all water including water situated wholly or partly within or bordering upon the state, whether surface or subsurface, public or private, except private waters that do not combine with other surface or subsurface water.

(3) "Water contaminant" means a substance that could alter if released or spilled water's physical, chemical, biological or radiological qualities. Water contaminant does not mean source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954.

(4) "Watercourse" means a river, creek, arroyo, canyon, draw or wash or other channel having definite banks and bed with visible evidence of the occasional flow of water.

(5) "Water pollution" means introducing or permitting the introduction into water, either directly or indirectly, of one or more water contaminants in such quantity and of such duration as may with reasonable probability injure human health, animal or plant life or property, or to unreasonably interfere with the public welfare or property use.

(6) "Well blowout" means a loss of control over and subsequent eruption of a drilling or workover well or the rupture of the casing, casinghead or wellhead of an oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquid, from thewell.

(7) "Well bore" means the interior surface of a cased or open hole through which drilling, production or injection operations are conducted.

(8) "Wellhead protection area" means the area within 200 horizontal feet of a private, domestic fresh water well or spring used by less than five households for domestic or stock watering purposes or within 1000 horizontal feet of any other fresh water well or spring. Wellhead protection areas does not include areas around water wells drilled after an existing oil or gas waste storage, treatment or disposal site wasestablished.

(9) "Wetlands" means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions in New Mexico. This definition does not include constructed wetlands used for wastewater treatment purposes.

(10) "Working interest owner" means the owner of an operating interest under an oil and gas lease who has the exclusive right to exploit the oil and gas minerals. Working interests are costbearing.

(11) "WQCC" means the New Mexico water quality control commission.

[19.15.2.7 NMAC - Rp, 19.15.1.7 NMAC, 12/1/2008; A, 3/31/2015; A, 6/30/2016; A, 6/26/2018; A, 1/15/2019; A, 19.15.2 NMAC

10/13/2020; A, 8/23/2022]

19.15.2.8 GENERAL OPERATIONS/WASTE PROHIBITED:

A. The production or handling of oil or gas of any type or in any form or the handling of oil or gas products in a manner, under conditions or in an amount as to constitute or result in waste is prohibited.

B. Operators, contractors, drillers, carriers, gas distributors, service companies, pipe pulling and salvaging contractors, treating plant operators or other persons shall conduct their operations in or related to the drilling, equipping, operating, producing, plugging and abandonment of oil, gas, injection, disposal and storage wells or other facilities in a manner that prevents waste of oil and gas, the contamination of fresh waters and shall not wastefully utilize oil or gas or allow either to leak or escape from a natural reservoir or from wells, tanks, containers, pipe or other storage, conduit or operating equipment.
[19.15.2.8 NMAC - Rp, 19.15.1.13 NMAC, 12/1/2008]

19.15.2.9 ORDERS: The division or commission may issue orders, including division or commission special pool orders when required and the orders shall prevail against rules if in conflict with them.
[19.15.2.9 NMAC - Rp, 19.15.1.11 NMAC, 12/1/2008]

19.15.2.10 ONLINE APPLICATION AND SUBMITTALS:

A. The division shall establish online application and submittal procedures on the division's website for the electronic filing of all forms, applications and other written documents and information with the division.

B. All applications that require the payment of a fee, as provided in Section 70-2-39 NMSA 1978, shall include the fee payment with the application.

C. A person whose filing is made untimely due to a technical failure of the division's web-based online application process may request an extension of time. Technical failures not originating with the division's process, such as problems with the filer's equipment, software, or telecommunications facility will not constitute a basis for relief.
[19.15.2.10 NMAC - N, 8/23/2022]

19.15.2.11 EMERGENCY ORDERS AND RULES:

A. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, in the event the division or commission finds an emergency exists that requires an order's or rule's issuance without a hearing, the emergency rule or order shall have the same validity as if the division or commission held a hearing before the division or commission after due notice. The emergency rule or order shall remain in force no longer than 15 days from its effective date.

B. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, if the division or commission finds an emergency exists, the division or commission may conduct a hearing on an application within less than 30 days after party files an application and the director may set the notice period at the director's discretion.
[19.15.2.11 NMAC - Rp, 19.15.14.1225 NMAC, 12/1/2008]

19.15.2.12 FILING AND NOTIFICATION: All requirements in the rules:

A. to file a form or application with the division or commission, including documents required to be filed with district offices or the Santa Fe office, shall be accomplished by using the applicable online process on the division's website,

B. to otherwise notify, advise, contact, or report to the division, including to any unit of the division (such as a bureau or office) or any division official (such as the director or a bureau chief), may be accomplished by electronic mail or as otherwise provided on the division's website; the division shall provide contact instructions on the division's website, and

C. to file an original financial assurance instrument with the division as provided in 19.15.8 NMAC shall require delivery to the Santa Fe office unless otherwise directed by the division.
[19.15.2.12 NMAC - Rp, 19.15.15.1304 NMAC, 12/1/2008; 19.15.2.12 NMAC - Rp, 19.15.2.12 NMAC, 8/23/2022]

19.15.2.13 COMPUTATION OF TIME: In computing a period of time prescribed by the Oil and Gas Act, the rules or an order, the division and commission shall comply with the Uniform Statute and Rule Construction Act, Section 12-2A-7 NMSA 1978.
[19.15.2.13 NMAC - Rp, 19.15.14.1226 NMAC, 12/1/2008; A, 8/23/2022]

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC

19.15.2.14 MEETINGS BY TELECONFERENCE: Pursuant to Section 10-15-1 NMSA 1978, commission members may participate in commission meetings and hearings by conference telephone or other similar communications equipment when it is otherwise difficult or impossible for members to attend the meeting or hearing in person. Each member participating by conference telephone or other similar communications equipment shall be identified when speaking. Participants shall be able to hear each other at the same time. Members of the public hearing attending the meetings or hearing shall be able to hear commission members who speak during the meeting or hearing.
[19.15.2.14 NMAC - Rp, 19.15.1.20 NMAC, 12/1/2008]

19.15.2.15 AUTHORITY TO COOPERATE WITH OTHER AGENCIES: The division may from time to time enter into arrangements with state and federal governmental agencies, industry committees and individuals with respect to special projects, services and studies relating to oil and gas conservation and the associated protection of fresh waters.
[19.15.2.15 NMAC - Rp, 19.15.1.17 NMAC, 12/1/2008]

19.15.2.16 DUTIES AND AUTHORITY OF DIVISION PERSONNEL: Division personnel have the authority and duty to enforce division rules. Upon a showing by an operator that changes are necessary to avoid waste or protect public health or the environment, division personnel may allow minor deviations from approved field operational plans such as drilling and plugging plans. The operator shall file a Form C-103 as a notice of intention showing the change of plans within two business days of the approval.
[19.15.2.16 NMAC - Rp, 19.15.15.1303, 12/1/2008; A, 8/23/2022]

19.15.2.17 ORGANIZATIONAL UNITS: When necessary to assist in the administration of the Oil and Gas Act, the director may divide the state into districts or other organizational units as appropriate. Upon establishment of, or revisions to, such units, the director shall provide or amend a map on the division's website with the boundaries of the units. Contact information for the units, including any assigned personnel, shall be maintained on the division's website.
[19.15.2.17 NMAC - Rp, 19.15.15.1301 NMAC, 12/1/2008; 19.15.2.17 NMAC - Rp, 19.15.2.17 NMAC, 8/23/2022]

19.15.2.18 RENUMBERING OR REORGANIZATION OF RULES: When the commission approves reorganization or renumbering of division rules, either through amendment or repeal and replacement, persons with permits, orders or agreements that reference rules that have been reorganized or renumbered shall comply with the rules as reorganized or renumbered.
[19.15.2.18 NMAC - N, 12/1/2008]

HISTORY of 19.15.2 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001); 19.15.14 NMAC, Procedure (filed 09/16/2005); and 19.15.15 NMAC, Administration (filed 07/12/2004) all repealed 12/1/2008.

NMAC History:
Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 1-7, 11, 13, 17, & 20) (filed 04/27/2001); 19.15.14 NMAC, Procedure (Sections 1225 and 1226) (filed 09/16/2005); and 19.15.15 NMAC, Administration (Sections 1301 and 1303) (filed 07/12/2004) were replaced by 19.15.2 NMAC, General Provisions for Oil and Gas Operations, effective 12/1/2008.

EXHIBIT 1-B

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.5 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 5 ENFORCEMENT AND COMPLIANCE

19.15.5.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.5.1 NMAC - N, 12/1/2008]

19.15.5.2 SCOPE: 19.15.5 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.5.2 NMAC - N, 12/1/2008]

19.15.5.3 STATUTORY AUTHORITY: 19.15.5 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12, Section 70-2-31 and Section 70-2-31.1 NMSA 1978.
[19.15.5.3 NMAC – N, 12/1/2008, A, 2/25/2020]

19.15.5.4 DURATION: Permanent.
[19.15.5.4 NMAC - N, 12/1/2008]

19.15.5.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.5.5 NMAC - N, 12/1/2008]

19.15.5.6 OBJECTIVE: To establish a process to ensure compliance with the Oil and Gas Act, division rules and division and commission orders.
[19.15.5.6 NMAC - N, 12/1/2008]

19.15.5.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.5.8 ENFORCEMENT OF STATUTES AND RULES: The division is charged with the duty and obligation of enforcing the state's rules and statutes relating to the conservation of oil and gas, including the prevention of waste and the protection of correlative rights, and the protection of public health and the environment. An owner or operator shall obtain information pertaining to the regulation of oil and gas before beginning operations.
[19.15.5.8 NMAC - Rp, 19.15.1.12 NMAC, 12/1/2008, A, 2/25/2020]

19.15.5.9 COMPLIANCE:

A. An operator is in compliance with Subsection A of 19.15.5.9 NMAC if the operator:

(1) currently meets the financial assurance requirements of 19.15.8 NMAC;

(2) is not subject to a division or commission order, issued after notice and hearing, finding the operator to be in violation of an order requiring corrective action;

(3) does not have a penalty assessment that is unpaid more than 30 days after issuance of the order assessing the penalty; ~~and~~

(4) currently meets the waste prevention requirements in 19.15.27.A(3) ~~and 28 NMAC; and~~

~~**(4)**~~**(5)** ~~has no more than the following number of wells out of compliance with 19.15.25.8 NMAC that are not subject to an agreed compliance or final order setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met:~~

~~**(a)** two wells or fifty percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;~~

~~**(b)** five wells if the operator operates between 101 and 500 wells;~~

~~**(c)** seven wells if the operator operates between 501 and 1000 wells; and~~

~~**(d)** 10 wells if the operator operates more than 1000 wells.~~

B. Inactive wells.

(1) The division shall make available on its website, and update daily, an "inactive well list" listing each well, by operator, that according to division records:

(a) shows no production or injection for past 15 months;

(b) does not have its well bore plugged in accordance with 19.15.25.9 NMAC

through 19.15.25.11 NMAC;

(c) is not in approved temporary abandonment in accordance with 19.15.25.12 NMAC through 19.15.25.14 NMAC; and

(d) is not subject to an agreed compliance or final order setting a schedule for bringing the well into compliance with 19.15.25.8 NMAC.

(2) A well inactive for more than 15 months creates a rebuttable presumption that the well is out of compliance with 19.15.25.8 NMAC.

C. Financial assurance. The division shall make available on its website and update weekly the status of operators' financial assurance that 19.15.8 NMAC requires, according to division records.

[19.15.5.9 NMAC - Rp, 19.15.1.40 NMAC, 12/1/2008; A, 11/30/2016, A, 2/25/2020]

D. Presumptions of no beneficial use: Registered well operators may, within 30 calendar days after notice of a determination or administrative presumption that a well is no longer useable for beneficial purposes, submit an application for administrative review of such beneficial use determination through the division permitting system or any successor online operator portal. The division shall issue a final determination based on the content of the application and information available in division records. The final determination may be subject to appeal pursuant to 19.15.4 NMAC. Applications to demonstrate beneficial use of well(s) must include:

(1) Documentation that the well may be reasonably projected to continue producing in paying quantities; and,

(2) The operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all plugging and known environmental liabilities of the well(s) and associated production facilities, not inclusive of any financial assurance associated with the well(s); and,

(3) Other information as may be reasonably required by the division.

19.15.5.10 ENFORCEMENT:

A. General. Whenever the division determines that a person violated or is violating the Oil and Gas Act or a provision of any rule, order, permit or authorization issued pursuant to the Oil and Gas Act, the division may seek a sanction by:

(1) issuing a temporary cessation order if it determines that the alleged violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The temporary cessation order shall remain in place until the earlier of when the division determines that the alleged violation is abated or 30 days, unless a hearing is held before the division and a new order is issued;

(2) issuing a notice of violation; or

(3) commencing a civil action in district court.

B. Sanctions. The division may seek one or more of the following sanctions:

(1) a civil penalty;

(2) modification, suspension, cancellation or termination of a permit or authorization;

(3) plugging and abandonment of a well;

(4) remediation and restoration of a well location and associated facilities, including the removal of surface and subsurface equipment and other materials;

(5) remediation and restoration of a location affected by a spill or release;

(6) forfeiture of financial assurance;

(7) shutting in a well or wells; and

(8) any other remedy authorized by law.

C. Notice of violation.

(1) A notice of violation issued by the division shall state with reasonable specificity:

(a) the identity of the alleged violator;

(b) the nature and factual and legal basis of the alleged violation, including the provision of the Oil and Gas Act or rule, order, permit or authorization allegedly violated;

(c) whether compliance is required immediately or within a specified time period;

(d) the sanction(s) available for the alleged violation, the sanction(s) proposed by the division, and a statement that the division will take into consideration the violators good faith efforts to comply with the applicable requirements;

(e) the availability of a process for informal review and resolution of the alleged violation, and the procedure to initiate the informal review process, including the contact information of the appropriate division employee;

(f) a statement that if the notice of violation is not informally resolved within 30 days of service, the division will hold a hearing, but that the hearing shall not prohibit the parties from negotiating and settling the notice of violation at any time; and

(g) the date of the hearing, which shall be no later than 90 days after the date of the notice of violation.

(2) The division shall serve the notice of violation on the alleged violator by certified mail, and may provide the notice of violation by electronic mail if possible.

(3) If during the informal review the division and the alleged violator agree to resolve the alleged violation, they shall incorporate their agreement into a stipulated final order signed by both parties. The stipulated final order shall state that the alleged violator admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives the alleged violator's right of review by the commission.

(4) If the division and the alleged violator fail to enter a stipulated final order within 30 days of service, the division shall hold a hearing at the division's principal office.

D. Civil penalties. A civil penalty assessed by the division shall account for the seriousness of the violation, good faith efforts to comply with the applicable requirement, history of noncompliance under the Oil and Gas Act and other relevant factors. The civil penalty assessed by the division shall not exceed $2,500 per day of noncompliance for each alleged violation, unless the alleged violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond the time specified in the notice of violation or stipulated final order, whereupon the civil penalty may not exceed $10,000 per day of noncompliance for each alleged violation, provided that the civil penalty assessed by the division for an alleged violation shall not exceed $200,000.

E. Adjudicatory procedures. These adjudicatory procedures shall apply to hearings on temporary cessation orders and notices of violation before the division, and the provisions of 19.15.4 NMAC shall not apply.

(1) General provisions.

(a) Designation of parties. The parties shall be the division and the person served with a notice of violation or order, referred to herein as "respondent".

(b) Representation. Respondent may appear and participate in a hearing either pro se or through counsel, provided that a collective entity, including a corporation, partnership, unincorporated association, political subdivision or governmental agency shall appear only through counsel or a duly authorized officer or member.

(c) Rule applicability. In the absence of a specific provision in this section, the hearing examiner may apply the New Mexico rules of civil procedure and evidence.

(d) Computation of time. In computing any period of time under 19.15.5.10 NMAC the day of the event from which the designated period begins to run shall not be included, and the last day of the computed period shall be included, unless it is a Saturday, Sunday or legal state holiday, in which case the time is extended until the next day which is not a Saturday, Sunday or legal state holiday. Whenever a party must act within a prescribed period after service, and service is by first class mail only, three days is added to the prescribed period.

(e) Extensions of time. The hearing examiner may grant an extension of time to file a document or continue a hearing upon timely motion upon consent of the parties, or for good cause shown after consideration of prejudice to the other party and undue delay to the hearing.

(f) Filing of documents. A party shall file the original of each document and serve a copy on the other party, accompanied by a certificate of service identifying the method and address used to complete service.

(g) Service of documents. A party shall serve each document on the other party or its counsel, as applicable, by personal service or first class mail, or by electronic mail if the parties agree.

(h) Form of documents. Unless otherwise ordered, all documents, except exhibits, shall be on 8 1/2 x 11-inch white paper, shall contain the caption of the notice of violation or temporary cessation order on the first page and shall be signed by the party or its counsel, as applicable.

(2) Pre-hearing procedures.

(a) Docketing. At the expiration of the 30 day period for informal resolution of a notice of violation, when a party appeals a final order under Subsection E of 19.15.5.10 NMAC, or when the division gives notice that it intends to extend a temporary cessation order, the division shall docket the notice of violation or order for hearing, identify the factual basis for the alleged violation and proposed sanction(s), and serve a notice of docketing on respondent.

(b) Answer. No later than 10 days after service of the notice of docketing, respondent shall file an answer stating its objection, if any, and the factual and legal basis for such objection, to each alleged violation and proposed sanction in the notice of violation or order.

(c) Hearing examiner. The hearing examiner shall have the authority to take all measures necessary to conduct a fair, impartial and efficient adjudication of issues, and to maintain order and avoid

undue delay, including the authority to conduct pre-hearing conferences and hearings, rule on procedural and evidentiary motions, govern the examination of witnesses and the admission of evidence, issue orders and prepare a recommended decision. After the division issues the notice of violation, the hearing examiner shall not discuss ex parte the merits of the proceeding with the division or the respondent.

(d) Pre-hearing conference. The hearing examiner may hold a pre-hearing conference to narrow the issues, eliminate or resolve preliminary matters and encourage settlement, and may issue a pre-hearing order on procedural and evidentiary matters, including a schedule for the filing of motions and testimony, stipulations regarding alleged violations and requested relief, including proposed civil penalties or

lements thereof, and any other matter necessary for the efficient conduct of the hearing.

(e) Pre-hearing statements. No later than seven calendar days before the hearing, a party who intends to present evidence at the hearing shall file and serve a statement that contains the following information:

(i) name, address, employment and qualifications, including education and work history, of each witness;

(ii) a statement identifying the opinions and factual assertions supporting each witness' testimony;

(iii) the exhibits and other evidence to be presented by each witness; and

(iv) procedural matters that are to be resolved prior to the hearing.

(f) Enforcement. The hearing examiner may enforce the requirements of 19.15.5.10 NMAC by any appropriate means, including the exclusion of testimony, exhibits and other evidence.

(g) Motions.

(i) General. All motions, except motions made orally during the hearing, shall be in writing, specify the grounds for the motion, state the relief sought, indicate whether the motion is opposed or unopposed and be served on the other party.

(ii) Unopposed motions. An unopposed motion shall state that concurrence of the other party was obtained and shall be accompanied by a proposed order approved by the parties.

(iii) Opposed motions. An opposed motion shall state either that concurrence was sought and not obtained, or the reason that concurrence was not sought.

(iv) Response. No later than 10 days after service of an opposed motion, the opposing party may file a response. Failure to file a response shall be deemed a waiver of any objection to the granting of the motion.

(v) Reply. No later than 10 days after service of a response to an opposed motion, the moving party may file a reply.

(vi) Decision. The hearing examiner shall decide all motions without a hearing, unless otherwise ordered by the hearing examiner sua sponte or upon written request of a party.

(h) Shortening Deadlines. On the written request of the alleged violator showing good cause, the hearing examiner may shorten the deadlines specified in Paragraph (2) of Subsection E of 19.15.10 NMAC to conduct the hearing on the division's application for a temporary cessation order as expeditiously as possible. If the division opposes the request to shorten deadlines, the procedures for opposed motions set forth in Subparagraph (g) of Paragraph (2) of Subsection G of 19.15.5.10 NMAC shall not apply and the hearing examiner shall decide the request, with or without hearing, as quickly as practicable.

(3) Hearing procedures.

(a) General. The hearing examiner shall admit all evidence, unless he or she determines that the evidence is irrelevant, immaterial, unduly repetitious or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded by the New Mexico rules of evidence is not admissible.

(b) Witness examination. Witnesses shall be examined orally and under oath or affirmation, provided that the parties may stipulate to the admission of the testimony of a witness, or part thereof. Parties shall have the right to cross-examine a witness, provided that the hearing examiner may limit cross-examination that is unduly repetitious, harassing or beyond the scope of the direct testimony.

(c) Exhibits. A party shall label each exhibit used during the hearing or offered into evidence with a designation identifying the party, the witness using or offering the exhibit and a serial number.

(d) Burden of persuasion. The division has the burden of going forward with the evidence and of proving by a preponderance of the evidence the facts relied upon to show the alleged violation occurred and that the proposed civil penalty is appropriate. Following the establishment of a prima facie case, respondent shall have the burden of going forward with any adverse evidence or defense to the allegations.

(4) Post-hearing procedures.

(a) Transcript. The hearing shall be transcribed verbatim. Respondent may order

a copy of the transcript from the reporter at its own expense.

(b) Recommended decision. The hearing examiner shall prepare a recommended decision for review by the director.

(c) Final order. The director shall file a final order addressing the material issues of fact and law and may assess a sanction for each alleged violation, which shall be served on the division and the respondent.

F. Commission review. No later than 30 days after the director serves the final order, a party may file a notice of appeal with the commission and shall serve the notice of appeal on the other party. The commission shall schedule a hearing on the appeal and notify the parties of the date and time of the hearing. The commission shall conduct a de novo review, provided however, that the parties may stipulate to the issues to be heard and to the admission of all or part of the record before the division. The commission shall conduct the hearing in accordance with the adjudicatory procedures in Paragraph (1), Subparagraphs (c) through (g) of Paragraph (2), Paragraph (3) and Subparagraph (a) of Paragraph (4) of Subsection E of 19.15.5.10 NMAC.

G. Rehearings. A party may file an application for rehearing with the commission pursuant to Section 70-2-25 NMSA 1978.

H. Payment of civil penalty. Respondent shall pay the full amount of the civil penalty assessed in the final order (i) no later than 30 days after the director serves the final order, or (ii) if respondent files a notice of appeal to the commission or the district court pursuant to Section 70-2-25 NMSA 1978, no later than 30 days after the commission or the district court files a final order or the appeal is withdrawn.

I. Resolution after commencement of hearing. If the parties agree to resolve a notice of violation at any time after the commencement of a hearing, they shall file a stipulated final order signed by both parties. The stipulated final order shall state that respondent admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives respondent's right of review by the commission or the court, as applicable.

J. Publication. On or about October 1 of each year, the division shall publish a list identifying the temporary cessation orders and notices of violation issued during the preceding year, along with the civil penalty paid, if any.

K. Reservation. Nothing in 19.15.5.10 NMAC precludes the division from bringing any other action and seeking any relief allowed by the Oil and Gas Act.

[19.15.5.10 NMAC – Rp, 19.15.5.10 NMAC, 2/25/2020]

19.15.5.11 **ENFORCEABILITY OF PERMITS AND ADMINISTRATIVE ORDERS:** A person who conducts an activity pursuant to a permit, administrative order or other written authorization or approval from the division shall comply with every term, condition and provision of the permit, administrative order, authorization or approval.

[19.15.5.11 NMAC - Rp, 19.15.1.41 NMAC, 12/1/2008]

HISTORY of 19.15.5 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001) and 19.15.14 NMAC, Procedure (filed 09/16/2005) repealed 12/1/2008.

NMAC History:

Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 12, 40 & 41) (filed 04/27/2001) and 19.15.14 NMAC, Procedure (Section 1227) (filed 09/16/2005), were replaced by 19.15.5 NMAC, Enforcement and Compliance, effective 12/1/2008.

EXHIBIT 1-C

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.8 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 8 FINANCIAL ASSURANCE

19.15.8.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.8.1 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.2 SCOPE: 19.15.8 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.8.2 NMAC - N, 12/1/2008]

19.15.8.3 STATUTORY AUTHORITY: 19.15.8 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12 and Section 70-2-14 NMSA 1978.
[19.15.8.3 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.4 DURATION: Permanent.
[19.15.8.4 NMAC - N, 12/1/2008]

19.15.8.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.8.5 NMAC - N, 12/1/2008]

19.15.8.6 OBJECTIVE: To establish financial assurance requirements for persons, firms, corporations or associations who have drilled or acquired, are drilling or propose to drill or acquire an oil, gas or injection or other service well to furnish financial assurance acceptable to the division.
[19.15.8.6 NMAC - N, 12/1/2008]

19.15.8.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.8.8 GENERAL REQUIREMENTS FOR FINANCIAL ASSURANCE:

A. The operator shall file financial assurance documents with the division's Santa Fe office and obtain approvals and releases of financial assurance from that office.

B. Financial assurance documents shall be on forms prescribed by or otherwise acceptable to the division.

C. The division may require proof that the individual signing for an entity on a financial assurance document or an amendment to a financial assurance document has the authority to obligate that entity.

D. Any time an operator changes the corporate surety, financial institution or amount of financial assurance, the operator shall file updated financial assurance documents on forms prescribed by the division. Notwithstanding the foregoing, if an operator makes other changes to its financial assurance documents, the division may require the operator to file updated financial assurance documents on forms prescribed by the division.
[19.15.8.8 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.9 CATEGORIES AND AMOUNTS OF FINANCIAL ASSURANCE FOR WELL PLUGGING:

A. Applicability. An operator who has drilled or acquired, is drilling or proposes to drill or acquire an oil, gas or injection or other service well within this state shall furnish a financial assurance acceptable to the division in accordance with 19.15.8.9 NMAC and in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico conditioned that the well be plugged and abandoned and the location restored and remediated in compliance with commission rules, unless the well is covered by federally required financial assurance. The division shall not approve, and the operator shall not proceed with, any proposed drilling or acquisition until the operator has furnished the appropriate financial assurance.

B. A financial assurance shall be conditioned for well plugging and abandonment and location restoration and remediation only, and not to secure payment for damages to livestock, range, crops or tangible improvements or any other purpose.

C. Active wells. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsection D of 19.15.8.9 NMAC in one ofthe following categories:

(1) a one well financial assurance in the amount of $150,000 per well , to be adjusted for inflation pursuant to Subsection G of 19.15.8.9 NMAC. ~~25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells~~; or

(2) a blanket plugging financial assurance in the amount of $250,000 ~~following amounts~~ covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC~~, to be adjusted for inflation pursuant to Subsection G of 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978~~:

~~**(a)** $50,000 for one to 10 wells; $200,000 for one to five wells; and~~

~~**(b)** $75,000 for 11 to 50 wells; $250,000 for six or more wells.;~~

~~**(c)** $125,000 for 51 to 100 wells; and~~

~~**(d)** $250,000 for more than 100 wells.~~

(3) Notwithstanding the foregoing, an operator shall provide a ~~one~~ single well financial assurance in the amount of $150,000 for each well in each of the following categories:

~~**(a)** **Stripper well properties prior to change of operator.** Every "stripper well property" as defined in Subsection M of 19.15.6.7 NMAC, prior to a change of operator for that stripper well property pursuant to 19.15.9.9 NMAC. The division shall not approve a request for change of operator for a stripper well property until the required financial assurance is in place~~.

~~**(b)**~~ (a) Marginal wells. Every marginal well, prior to (--, 2030) or prior to any well transfer must have single well financial assurance in place.

~~**(c)**~~ (b) An operator who has over 15% of their wells in Marginal or Inactive well status prior to XXXX (five years) or at the time of well transfer, must single well bond all their wells until the percentage of marginal wells registered to the operator is decreased to less than 15%. ~~these total production across all wells in New Mexico is equal to or less than 1,000 barrels of oil equivalent per day average during the calendar year, or for whom all of the operator's inactive wells, wells in approved and expired temporarily abandonment status, and stripper well properties in New Mexico total 15 percent or more of the operator's total wells in the state. The determination whether an operator meets either criterion in this category shall be made as of December 31 of each year, and any change in the amount of financial assurance required under this subparagraph shall be in place as of March 1 of the following year.~~

D. Inactive wells, wells in approved temporarily abandoned status, and wells in expired temporarily abandoned status. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC that ~~have been~~ are inactive, in approved temporarily abandoned status ~~for more than two years~~ or expired temporarily abandoned status, or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories, to be adjusted for inflation pursuant to Subsection G of 19.15.8.9 NMAC:

(1) a one well financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance amounting to an average of $150,000 per well covering all wells of the operator subject to Subsection D of 19.15.8.9 NMAC:.

~~**(a)** $150,000 for one to five wells;~~

~~**(b)** $300,000 for six to 10 wells;~~

~~**(c)** $500,000 for 11 to 25 wells; and~~

~~**(d)** $1,000,000 for more than 25 wells.~~

E. Operators who have on file with the division a blanket financial assurance that does not cover additional wells shall file additional single well bond financial assurance for any wells not covered by the existing blanket bond ~~or, in the alternative, may file a replacement blanket bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978.

F. As used in this Section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a twelve-month period ending September 30.

G. On January 1, 2027 and on January 1 of each successive year, the division may adjust the financial assurance amounts provided by Subsections A through F of this Section by multiplying the financial assurance as of January 1, 2026 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2025; provided that the financial assurances shall not be adjusted below the minimum amounts provided in Subsection A through F of this Section as a result of a decrease in the consumer price index. By November 1, 2026 and by November 1 of each

successive year, the division shall post on its website the financial assurance requirements in Subsection A through E of this Section for the next year.

[19.15.8.9 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015; A, 1/15/2019]

19.15.8.10 ADDITIONAL REQUIREMENTS FOR CASH AND SURETY BONDS:

A. Surety bonds shall be issued by a reputable corporate surety authorized by the office of the superintendent of insurance to do business in the state. The surety shall be listed on U.S. Department of the Treasury circular 570.

B. The operator shall deposit cash representing the full amount of the bond in an account in a federally-insured financial institution located within the state, such account to be held in trust for the division. Authorized representatives of the operator and the depository institution shall execute a document evidencing the cash bond's terms and conditions. The operator shall file the document with the division prior to the bond's effective date. If the operator's financial status or reliability is unknown to the director, the director may require the filing of a financial statement or such other information as may be necessary to evaluate the operator's ability to fulfill the bond's conditions. From time to time, any accrued interest over and above the bond's face amount may be paid to the operator.

[19.15.8.10 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.11 ADDITIONAL REQUIREMENTS FOR LETTERS OF CREDIT:

A. The division may accept irrevocable letters of credit issued by national or state-chartered banking associations.

B. Letters of credit shall be irrevocable for a term of not less than five years, unless the applicant shows good cause for a shorter time period.

C. Letters of credit shall provide for automatic renewal for successive, like terms upon expiration, unless the issuer has notified the division in writing of non-renewal at least 30 days prior to expiration.

D. The division may forfeit and collect a letter of credit if not replaced by an approved financial assurance at least 30 days before the expiration date.

E. Authorized representatives of the operator and the depository institution shall execute a document evidencing the letter of credit's terms and conditions.

[19.15.8.11 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.12 RELEASE OF FINANCIAL ASSURANCE:

A. The division shall release a financial assurance document upon the operator's or surety's written request if all wells drilled or acquired under that financial assurance have been plugged and abandoned and the location restored and remediated and released pursuant to 19.15.25.9 NMAC through 19.15.25.11 NMAC, or have been covered by another financial assurance the division has approved.

B. Transfer of a property or a change of operator does not of itself release a financial assurance. The division shall not approve a request for change of operator for a well until the new operator has the required financial assurance in place and is otherwise in compliance with all requirements of 19.15.5.9 NMAC and 19.15.9.9 NMAC.

[19.15.8.12 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.13 FORFEITURE OF FINANCIAL ASSURANCE:

A. Upon the operator's failure to properly plug and abandon and restore and remediate the location of a well or wells a financial assurance covers, the division shall give notice to the operator and surety, if applicable, and hold a hearing as to whether the well or wells should be plugged and abandoned and the location restored and remediated in accordance with a division-approved plugging program. If it is determined at the hearing that the operator has failed to plug and abandon the well and restore and remediate the location as provided for in the financial assurance or division rules, the director shall issue an order directing the well to be plugged or abandoned and the location restored and remediated in a time certain. Such an order may also direct the forfeiture of the financial assurance upon the failure or refusal of the operator, surety or other responsible party to properly plug and abandon the well and restore and remediate the location.

B. If the financial assurance's proceeds exceed the costs the division incurred plugging and abandoning the well and restoring and remediating the location the financial assurance covers, the division shall return the excess to the surety or the operator, as appropriate.

C. If the financial assurance's proceeds are not sufficient to cover all the costs the division incurred in plugging and abandoning the well and restoring and remediating the location, the division may seek indemnification from the operator as provided in Subsection E of Section 70-2-14 NMSA 1978.

D. The division shall deposit forfeitures and funds collected pursuant to a judgment in a suit for indemnification in the oil and gas reclamation fund.

[19.15.9.13 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.14 EFFECTIVE DATES.

A. 19.15.8 NMAC applies to wells drilled or acquired after December 15, 2005.

B. As to all other wells, 19.15.8 NMAC is effective January 1, 2008.

C. The 2018 amendments to 19.15.8.9 NMAC apply to applications for permits to drill, deepen or plug back and applications for approved temporary abandonment filed on or after January 15, 2019, and for all other wells on April 15, 2019.

[19.15.8.14 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 1/15/2019]

19.15.8.15 ADDITIONAL REQUIREMENTS FOR PLUGGING INSURANCE POLICIES:

A. The plugging insurance policy must be issued by a company authorized by the office of the superintendent of insurance to do business in New Mexico.

B. The policy shall name a specific well and name the state of New Mexico as the owner of the policy and contingent beneficiary.

C. The policy shall name a primary beneficiary who agrees to plug the specified wellbore.

D. The policy shall be fully prepaid and cannot be canceled or surrendered.

E. The policy shall continue in effect until the specified wellbore has been plugged.

F. The policy shall provide that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with division rules in effect at the time of plugging.

G. The policy shall provide benefits that are not less than an amount equal to the one-well financial assurance required by division rules. If, subsequent to an operator obtaining an insurance policy, the one-well financial assurance requirement applicable to the operator's well covered by said policy increases, either because the well is deepened or the division's rules are amended, the operator will meet the additional financial assurance requirement by complying with one of the requirements below.

(1) The operator's existing policy benefit equals or exceeds the revised requirement.

(2) The operator obtains and files with the division within 30 days an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement.

(3) The operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit and files said financial assurance with the division within 30 days.

[19.15.8.15 NMAC - N, 6/30/2015]

19.15.8.16 DUTY TO REPORT: Any operator who filed for bankruptcy shall provide notice to the division, in writing, through the processes provided for under the rules of the United States bankruptcy court.

[19.15.8.16 NMAC - N, 6/30/2015]

HISTORY of 19.15.8 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/2008.

NMAC History:

That applicable portion of 19.15.3 NMAC, Drilling (Section 101) (filed 10/29/2001) was replaced by 19.15.8 NMAC, Financial Assurance, effective 12/1/2008.

EXHIBIT 1-D

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.9 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 9 WELL OPERATOR PROVISIONS

19.15.9.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.9.1 NMAC - N, 12/1/08]

19.15.9.2 SCOPE: 19.15.9 NMAC applies to persons or entities operating oil or gas wells within New Mexico.
[19.15.9.2 NMAC - N, 12/1/08]

19.15.9.3 STATUTORY AUTHORITY: 19.15.9 NMAC is adopted pursuant to the Oil and Gas Act, NMSA 1978, Section 70-2-6, Section 70-2-11 and Section 70-2-12.
[19.15.9.3 NMAC - N, 12/1/08]

19.15.9.4 DURATION: Permanent.
[19.15.9.4 NMAC - N, 12/1/08]

19.15.9.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.9.5 NMAC - N, 12/1/08]

19.15.9.6 OBJECTIVE: To require an operator of a well or wells to register with the division prior to commencing operations and to require the reporting of a change of operator or a change of name to the division.
[19.15.9.6 NMAC - N, 12/1/08]

19.15.9.7 DEFINITIONS: [RESERVED]
[See 19.15.2 NMAC for definitions.]
[19.15.9.7 NMAC - N, 12/1/08]

19.15.9.8 OPERATOR REGISTRATION:

A. Prior to commencing operations, an operator of a well or wells in New Mexico shall register with the division as an operator. Applicants shall provide the following to the financial assurance administrator in the division's Santa Fe office:

(1) an oil and gas registration identification (OGRID) number obtained from the division, the state land office or the taxation and revenue department;

(2) a current address of record to be used for notice and a current emergency contact name and telephone number for each district in which the operator operates wells; and

(3) the financial assurance 19.15.8 NMAC requires.

B. The division may deny registration as an operator if:

(1) the applicant is not in compliance with Subsection A of 19.15.5.9 NMAC;

(2) an officer, director, partner in the applicant or person with an interest in the applicant exceeding 25 percent, is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(3) the applicant is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(4) the applicant is a corporation, ~~or~~ limited liability company, or limited partnership and is not registered and in good standing with the New Mexico secretary of state ~~public regulation commission~~ to do business in New Mexico.~~; or~~

~~**(5)** the applicant is a limited partnership and is not registered with the New Mexico secretary of state to do business in New Mexico.~~

C. An operator shall inform the division of its current address of record and emergency contact names and telephone numbers by submitting changes in writing to the division's financial assurance administrator in the division's Santa Fe office within 30 days of the change.

D. The division may require an operator or applicant to identify its current and past officers, directors and partners and its current and past ownership interest in other operators.

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.9 NMAC

[19.15.9.8 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.9 CHANGE OF OPERATOR:

A. A change of operator occurs when the entity responsible for a well or a group of wells changes. A change of operator may result from a sale, assignment by a court, a change in operating agreement or other transaction. Under a change of operator, wells are moved from the OGRID number of the operator of record with the division to the new operator's OGRID number.

B. The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a disclosure of the new operator's aggregate asset retirement obligations, as defined in 19.15.2.7 NMAC, across its operations; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator.

C. The director of the director's designee may deny a change of operator if:

(1) the new operator or operator of record is not in compliance with Subsection A of 19.15.5.9 NMAC; ~~or~~

(2) the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order;~~.~~

(3) any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(4) the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(5) the applicant is a corporation, limited liability company, or limited partnership and is not registered and in good standing with the New Mexico secretary of state to do business in New Mexico; or

(6) the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

D. In determining whether to grant or deny a change of operator based on Paragraphs 1, 2, 3, and 4 of Subsection C ~~when the new operator is not in compliance with Subsection A~~ of 19.15.5.9 NMAC, the director or the director's designee shall consider such factors as whether the non-compliance with Subsection A of 19.15.5.9 NMAC is caused by the operator not meeting the financial assurance requirements of 19.15.8 NMAC, being subject to a division or commission order finding the operator to be in violation of an order requiring corrective action, having a penalty assessment that has been unpaid for more than 70 days since the issuance of the order assessing the penalty or having more than the allowed number of wells out of compliance with 19.15.25.8 NMAC. If the non-compliance is caused by the operator having more than the allowed number of wells not in compliance with 19.15.25.8 NMAC, the director or director's designee shall consider the number of wells not in compliance, the length of time the wells have been out of compliance and the operator's efforts to bring the wells into compliance.

[19.15.9.9 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.10 CHANGE OF NAME:

A. A change of operator name occurs when the name of the entity responsible for a well or wells

changes but the entity does not change. For a change of name, the OGRID number remains the same, but division records are changed to reflect the new operator name.

B. An operator shall apply for a change of name by filing a form C-146 using the division's web-based online application and supplying documentary proof that the change is a name change and not a change of operator. If the operator is a corporation, limited liability company or limited partnership, the name must be registered with the public regulation commission or the New Mexico secretary of state, as applicable. The division shall not approve a change of name until the state land office and the taxation and revenue department have cleared the change of name on the OGRID.

[19.15.9.10 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.11 EXAMPLES OF CHANGE OF OPERATOR AND CHANGE OF NAME:

A. Mr. Smith, a sole proprietor, operates five wells under the name "Smith oil company". Mr. Smith changes the name of his company to "Smith production company". The name of the entity operating the wells has changed, but the entity has not changed. Mr. Smith should apply for a change of name.

B. Mr. Smith incorporates his business, changing from the sole proprietorship, "Smith production company", to a corporation: "Smith production company, inc.". The entity responsible for the wells has changed, and Mr. Smith and "Smith production company, inc." should apply for a change of operator.

C. Smith production company, inc., a New Mexico operator, merges with XYZ, inc., which does not operate in New Mexico. At the surviving entity's election, this transaction may be treated as a change of name from Smith production company, to XYZ, inc., maintaining the existing OGRID, or as a change of operator, with a new OGRID.

D. Two New Mexico operators, Smith production company, inc. and Jones production company, inc., merge. The surviving corporation is Jones production company, inc. A different entity now operates the wells Smith production company, formerly operated, and the wells must be placed under that entity's OGRID. Jones production company, inc. and Smith production company, inc. should apply for a change of operator as to the wells Smith production company, inc. operated.

[19.15.9.11 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

HISTORY of 19.15.9 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/08.

NMAC History:

That applicable portion of 19.15.3 NMAC, Drilling (Section 100) (filed 11/30/2005) was replaced by 19.15.9 NMAC, Well Operator Provisions, effective 12/1/08.

EXHIBIT 1-E

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.25 NMAC

TITLE 19 NATURAL RESOURCES ANDWILDLIFE
CHAPTER 15 OIL AND GAS
PART 25 PLUGGING AND ABANDONMENT OF WELLS

19.15.25.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.25.1 NMAC - Rp, 19.15.4.1 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.2 SCOPE: 19.15.25 NMAC applies to persons that operate oil or gas wells within New Mexico.
[19.15.25.2 NMAC - Rp, 19.15.4.2 NMAC, 12/1/2008]

19.15.25.3 STATUTORY AUTHORITY: 19.15.25 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-12 NMSA 1978, which authorizes the division to require dry or abandoned wells to be plugged so as to confine oil, gas or water in the strata in which they are found and to prevent them from escaping into other strata.
[19.15.25.3 NMAC - Rp, 19.15.4.3 NMAC, 12/1/2008]

19.15.25.4 DURATION: Permanent.
[19.15.25.4 NMAC - Rp, 19.15.4.4 NMAC, 12/1/2008]

19.15.25.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end ofasection.
[19.15.25.5 NMAC - Rp, 19.15.4.5 NMAC, 12/1/2008]

19.15.25.6 OBJECTIVE: To establish requirements for properly abandoning and plugging wells drilled for oil or gas or service wells including seismic, core, exploration or injection wells or placing the wells in temporary abandonment in order to protect public health, fresh water and the environment.
[19.15.25.6 NMAC - Rp, 19.15.4.6 NMAC, 12/1/2008]

19.15.25.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.25.8 WELLS TO BE PROPERLY ABANDONED:

A. The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.

B. The operator shall either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within ~~90~~ 30 days after:

(1) a 60 day period following suspension of drilling operations; or

(2) a determination or administrative presumption that a well is no longer usable for beneficial purposes; or

(3) a period of one year in which a well has been ~~continuously~~ inactive.

[19.15.25.8 NMAC - Rp, 19.15.4.201 NMAC, 12/1/2008]

19.15.25.9 NOTICE OF PLUGGING:

A. The operator shall file notice of intention to plug with the division on form C-103 prior to commencing plugging operations. The notice shall provide all the information 19.15.7.14 NMAC requires including operator and well identification and proposed procedures for plugging the well.

B. In addition, the operator shall provide a well bore diagram showing the proposed plugging procedure.

C. The operator shall notify the division 24 hours prior to commencing plugging operations. In the case of a newly drilled dry hole, the operator may obtain verbal approval from the appropriate district supervisor or the district supervisor's representative of the plugging method and time operations are to begin. The operator shall file written notice in accordance with 19.15.25.11 NMAC with the division within 10 days after the district supervisor has given verbal approval.
[19.15.25.9 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.10 PLUGGING:

A. Before an operator abandons a well, the operator shall plug the well in a manner that permanently confines all oil, gas and water in the separate strata in which they are originally found. The operator may accomplish this by using mud-laden fluid, cement and plugs singly or in combination as approved by the division on 19.15.25 NMAC

the notice of intention to plug.

B. The operator shall mark the exact location of plugged and abandoned wells with a steel marker not less than four inches in diameter set in cement and extending at least four feet above mean ground level. The operator name, lease name and well number and location, including unit letter, section, township and range, shall be welded, stamped or otherwise permanently engraved into the marker's metal. A person shall not build permanent structures preventing access to the wellhead over a plugged and abandoned well without the division's written approval. A person shall not remove a plugged and abandonment marker without the division's written approval.

C. The operator may use below-ground plugged and abandonment markers only with the division's written approval when an above-ground marker would interfere with agricultural endeavors. The below-ground marker shall have a steel plate welded onto the abandoned well's surface or conductor pipe and shall be at least three feet below the ground surface and of sufficient size so that all the information 19.15.16.8 NMAC requires can be stenciled into the steel or welded onto the steel plate's surface. The division may require a re-survey of the well location.

D. As soon as practical, but no later than one year after the completion of plugging operations, the operator shall:

(1) level the location;

(2) remove deadmen and other junk; and

(3) take other measures necessary or required by the division to restore the location to a safe and clean condition.

E. The operator shall close all pits and below-grade tanks pursuant to 19.15.17 NMAC.

F. Upon completion of plugging and clean up restoration operations as required, the operator shall contact the appropriate division district office to arrange for an inspection of the well and location.

[19.15.25.10 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.11 REPORTS FOR PLUGGING AND ABANDOMENT:

A. The operator shall file form C-105 as provided in 19.15.7.16 NMAC.

B. Within 30 days after completing required restoration work, the operator shall file with the division a record of the work done on form C-103 as provided in 19.15.7.14 NMAC.

C. The division shall not approve the record of plugging or release a bond until the operator has filed necessary reports and the division has inspected and approved the location.

[19.15.25.11 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.12 APPROVED TEMPORARY ABANDONMENT:

A. The division may place a well in approved temporary abandonment for a period of up to ~~five~~ two years upon a demonstration from the operator that the well will be used for beneficial use within the approved period of temporary abandonment. The operator's demonstration shall include a detailed explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future including supporting technical and economic data, a detailed plan that describes the ultimate disposition of the well, the time frame for that disposition, and any other information the division determines appropriate, including a current and complete well bore diagram; geological evidence; geophysical data; well casing information; waste removal and disposition; production and reservoir engineering; leasing status; geophysical logs, e.g., cement bond logs, caliper logs, and casing inspection logs; and health, safety, and environmental information. The division shall approve, approve with conditions, or deny a request. Such conditions may include conditions to protect human health and the environment. If the division denies a request, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

B. Prior to the expiration of an approved temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves, permanently plug and abandon the well and restore and remediate the location, or apply for a new approval to temporarily abandon the well for a period of up to one year upon the same terms and conditions required in Subsection A of this Section. The division shall approve, approve with conditions, or deny a request. Such conditions may include conditions to protect human health and the environment. If the division denies a request, the operator shall permanently plug and abandon the well and restore and remediate the location. An operator may apply for additional one year extensions for approved temporary abandoned status, upon the same terms and conditions as required in Subsection A of this Section, except that a well may not remain in temporary abandonment more than five years unless the commission approves an extension pursuant to Subsection C of this Section. Unless an operator has timely renewed a temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

C. Prior to the expiration of five years in temporary abandonment, an operator may apply to the commission to extend temporary abandonment status pursuant to the procedures for adjudicatory proceedings in 19.15.4 NMAC. In any such adjudicatory proceeding, any interested person may intervene pursuant to 19.15.4.11 NMAC. To continue in temporary abandonment, the operator must demonstrate to the commission that the well will be returned to beneficial use within the requested period of temporary abandonment. The request shall include a detailed explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future and supporting technical and economic data, a detailed plan that describes the ultimate disposition of the well, the time frame for that disposition, and a health and safety plan demonstrating the well's casing and cementing meet the requirements of Subsections B and C of Section 13 of 19.15.25 NMAC and the operator has adequate monitoring procedures in place to ensure such requirements will be met. The commission shall approve, approve with conditions, or deny a request to extend the temporary abandonment. Such conditions may include conditions to protect human health and the environment. An extended term shall not exceed two additional years, upon which time the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

D. An operator is limited to placing the following numbers of wells in approved temporary abandonment:

~~A.~~(1) one well, if the operator operates between one and five wells; or

~~B.~~(2) one-third of all wells (rounded to the nearest whole number), if the operator operates more than five wells.

E. **Implementation schedule for existing wells.**

(1) **Active wells.** This Section applies to active wells to wells as of [effective date of amendments].

(2) **Inactive wells.**

(a) This Section applies to wells that have been inactive for less than two years as of [effective date of amendments].

(b) Operators of wells that have been inactive between two years and less than three years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up two years, may apply to the division for a one year extension of temporary abandonment one time, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(c) Operators of wells that have been inactive between three years and less than four years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up two years with no opportunity for an extension, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(d) Operators of wells that have been inactive between four years and less than five years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up one year with no opportunity for an extension, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(e) Operators of wells that have been inactive five years or more as of [effective date of amendments] ~~shall~~ may apply to the commission for approved temporary abandonment for up two years in accordance with this Section.

(f) Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(2) **Wells in temporary abandoned status.** Any operator of a well in temporary abandoned status as of [effective date of amendments] shall apply to the commission to extend temporary abandonment status in accordance with this Section prior to the date temporary abandonment status terminates. Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(3) **Wells in expired temporary abandoned status.** Any operator of a well in expired temporary abandoned status as of [effective date of amendments] shall apply to the commission to extend temporary abandonment status in accordance with this Section. Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

[19.15.25.12 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.13 REQUEST FOR APPROVAL AND PERMIT FOR APPROVED TEMPORARY ABANDONMENT:

A. An operator seeking approval for approved temporary abandonment shall submit the request on form C-103 ~~a notice of intent~~ to seek approved temporary abandonment for the well setting forth the demonstration required in 19.15.25.12 NMAC and describing the proposed temporary abandonment procedure the operator will use. The operator shall not commence work until the division has approved the request. The operator shall give 24 hours' notice to the appropriate division district office before beginning work.

B. The division shall not approve a permit for approved temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:

(1) damage to the producing zone;

(2) emissions to the air or migration of hydrocarbons or water;

(3) the contamination of fresh water or other natural resources; and

(4) the leakage of a substance at the surface.

C. The operator shall demonstrate both internal and external mechanical integrity pursuant to Subsection A of 19.15.25.14 NMAC.

D. Upon successful completion of the work on the temporarily abandoned well, the operator shall submit a request for approved temporary abandonment to the appropriate division district office on form C-103 together with other information Subsection E of 19.15.7.14 NMAC requires.

E. The division shall not approve a permit for approved temporary abandonment until the operator provides financial assurance for the well that complies with Subsection D of 19.15.8.9 NMAC.

F. The division shall specify the permit's expiration date., ~~which shall be not more than five years from the date of approval.~~

[19.15.25.13 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.14 DEMONSTRATING MECHANICAL INTEGRITY:

A. An operator may use the following methods of demonstrating internal casing integrity for wells to be placed in approved temporary abandonment:

(1) the operator may set a cast iron bridge plug within 100 feet of uppermost perforations or production casing shoe, load the casing with inert fluid and pressure test to 500 psi surface pressure with a pressure drop of not more than 10 percent over a 30 minute period;

(2) the operator may run a retrievable bridge plug or packer to within 100 feet of uppermost perforations or production casing shoe, and test the well to 500 psi surface pressure for 30 minutes with a pressure drop of not greater than 10 percent over a 30 minute period; or

(3) the operator may demonstrate that the well has been completed for less than five years ~~and has not been connected to a pipeline~~.

B. During the testing described in Paragraphs (1) and (2) of Subsection A of 19.15.25.14 NMAC the operator shall:

(1) open all casing valves during the internal pressure tests and report a flow or pressure change occurring immediately before, during or immediately after the 30 minute pressure test;

(2) top off the casing with inert fluid prior to leaving the location;

(3) report flow during the test in Paragraph (2) of Subsection A of 19.15.25.14 NMAC to the appropriate division district office prior to completion of the temporary abandonment operations; the division may require remediation of the flow prior to approving the well's temporary abandonment.

C. An operator may use any method approved by the EPA in 40 C.F.R. section 146.8(c) to demonstrate external casing and cement integrity for wells to be placed in approved temporary abandonment.

D. The division shall not accept mechanical integrity tests or logs conducted more than 12 months prior to submittal.

E. The operator shall record mechanical integrity tests on a chart recorder with a maximum two hour clock and maximum 1000 pound spring, which has been calibrated within the six months prior to conducting the test. Witnesses to the test shall sign the chart. The operator shall submit the chart with form C-103 requesting approved temporary abandonment.

F. The division may approve other testing methods the operator proposes if the operator demonstrates that the test satisfies the requirements of Subsection B of 19.15.25.13 NMAC.

G. Beginning [effective date of amendments], the operator shall conduct the testing required in this Section, and shall submit the chart required in Subsection E of this Section to the division.

[19.15.25.14 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008]

19.15.25.15 WELLS TO BE USED FOR FRESH WATER:

A. When a well to be plugged may safely be used as a fresh water well and the landowner agrees to take over the well for that purpose, the operator does not need to plug the well above the sealing plug set below the fresh water formation.

B. The operator shall comply with other requirements contained in 19.15.25.9 NMAC through 19.15.25.11 NMAC regarding plugging, including surface restoration and reporting requirements.

C. Upon completion of plugging operations, the operator shall file with the division a written agreement signed by the landowner whereby the landowner agrees to assume responsibility for the well. Upon the filing of this agreement and division approval of well abandonment operations, the operator is no longer responsible for the well, and the division may release bonds on the well.

[19.15.25.15 NMAC - Rp, 19.15.4.204 NMAC, 12/1/2008]

HISTORY of 19.15.25 NMAC:

History of Repealed Material: 19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) repealed 12/1/2008.

NMAC History:

19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) was replaced by 19.15.25 NMAC, Plugging and Abandonment of Wells, effective 12/1/2008.

OCD CLEAN DRAFT

Apps' Ex. 5

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 2 GENERAL PROVISIONS FOR OIL AND GAS OPERATIONS

19.15.2.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.2.1 NMAC - Rp, 19.15.1.1 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.2 SCOPE: 19.15.2 NMAC applies to persons or entities engaged in oil and gas development and production within New Mexico and to 19.15.2 NMAC through 19.15.39 NMAC.
[19.15.2.2 NMAC - Rp, 19.15.1.2 NMAC, 12/1/2008]

19.15.2.3 STATUTORY AUTHORITY: 19.15.2 NMAC is adopted pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978, which grants the oil conservation division jurisdiction and authority over all matters relating to the conservation of oil and gas, the prevention of waste of oil and gas and of potash because of oil and gas operations, the protection of correlative rights and the disposition of wastes resulting from oil and gas operations.
[19.15.2.3 NMAC - Rp, 19.15.1.3 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.4 DURATION: Permanent.
[19.15.2.4 NMAC - Rp, 19.15.1.4 NMAC, 12/1/2008]

19.15.2.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.2.5 NMAC - Rp, 19.15.1.5 NMAC, 12/1/2008]

19.15.2.6 OBJECTIVE: To set forth general provisions and definitions pertaining to the authority of the oil conservation division and the oil conservation commission pursuant to the Oil and Gas Act, Sections 70-2-1 through 70-2-38 NMSA 1978.
[19.15.2.6 NMAC - Rp, 19.15.1.6 NMAC, 12/1/2008; A, 6/26/2018]

19.15.2.7 DEFINITIONS: These definitions apply to 19.15.2 NMAC through 19.15.39 NMAC.

A. Definitions beginning with the letter "A".

(1) **"Abate"** means to investigate, contain, remove or mitigate water pollution.

(2) **"Abatement"** means the investigation, containment, removal or other mitigation of water pollution.

(3) **"Abatement plan"** means a description of operational, monitoring, contingency and closure requirements and conditions for water pollution's prevention, investigation and abatement.

(4) **"Act" or "Oil and Gas Act"** means Chapter 70, Article 2 NMSA 1978, as it may be modified or amended.

(5) **"Adjoining spacing units"** mean those existing or prospective spacing units in the same pool that are touching at a point or line on the subject spacing unit.

(6) **"Adjusted allowable"** means the allowable production a well or proration unit receives after all adjustments are made.

(7) **"AFE"** means authorization for expenditure.

(8) **"Affected persons"** means the following persons owning interests in a spacing unit or other identified tract:

(a) the operator, as shown in division records, of a well on the tract, or, if the tract is included in a division-approved or federal unit, the designated unit operator;

(b) in the absence of an operator, or with respect to an application wherein the operator of the spacing unit or identified tract is the applicant, each working interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant files the application;

(c) as to any tract or interest therein that is not subject to an existing oil and gas lease, each mineral interest owner whose interest is evidenced by a written conveyance document either of record or known to the applicant as of the date the applicant filed the application; and

(d) if the United States or state of New Mexico owns the mineral estate in the spacing unit or identified tract or any part thereof, the BLM or state land office, as applicable; or

(e) if the mineral estate in the spacing unit or identified tract or any part thereof is tribal land, the BLM, the United States department of the interior, bureau of Indian affairs, and the relevant tribe.

(9) "Allocated pool" means a pool in which the total oil or gas production is restricted and is allocated to various wells in the pool in accordance with proration schedules.

(10) "Allowable production" means that number of barrels of oil or cubic feet of gas the division authorizes to be produced from an allocated pool.

(11) "APD" means application for permit to drill.

(12) "API" means the American petroleum institute.

(13) "Approved temporary abandonment", "temporary abandonment", or "temporary abandonment status" means the status of a well that is inactive, has been approved in accordance with 19.15.25.13 NMAC and complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

(14) "Aquifer" means a geological formation, group of formations or a part of a formation that can yield a significant amount of water to a well or spring.

(15) "Asset retirement obligation" means an obligation associated with the retirement of a tangible long-lived asset.

~~(15)~~**(16) "ASTM"** means ASTM International - an international standards developing organization that develops and publishes voluntary technical standards for a wide range of materials, products, systems and services.

B. Definitions beginning with the letter "B".

(1) "Back allowable" means the authorization for production of an underproduction resulting from pipeline proration.

(2) "Background" means, for purposes of ground water abatement plans only, the amount of ground water contaminants naturally occurring from undisturbed geologic sources or water contaminants occurring from a source other than the responsible person's facility. This definition does not prevent the director from requiring abatement of commingled plumes of pollution, does not prevent responsible persons from seeking contribution or other legal or equitable relief from other persons and does not preclude the director from exercising enforcement authority under any applicable statute, rule or common law.

(3) "Barrel" means 42 United States gallons measured at 60 degrees fahrenheit and atmospheric pressure at the sea level.

(4) "Barrel of oil" means 42 United States gallons of oil, after deductions for the full amount of basic sediment, water and other impurities present, ascertained by centrifugal or other recognized and customary test.

(5) "Below-grade tank" means a vessel, excluding sumps and pressurized pipeline drip traps, where a portion of the tank's sidewalls is below the surrounding ground surface's elevation. Below-grade tank does not include an above ground storage tank that is located above or at the surrounding ground surface's elevation and is surrounded by berms.

(6) "Beneficial purposes" or "beneficial use" means the well is being used in a productive or beneficial manner.

a. For the purposes of oil and gas production, wells and well or operator compliance under 19.15.25.8 and 19.15.5.9 NMAC, there is a presumption that wells are not capable of beneficial use if, in the prior 12-month period, any well has not produced:
   i. for at least 90 days, and
   ii. at least 90 barrel of oil equivalent or at a volume that the operator is able to demonstrate that the well produces in paying quantities.

b. For injection or salt water disposal wells, beneficial use requires that wells must inject at least 90 days and at least 100 bbls in any consecutive 12-month period.

c. Wells that have been drilled but not completed and wells that have been completed for less than 18 months are exempt from the beneficial purposes thresholds in this section.

~~(6)~~**(7) "Berm"** means an embankment or ridge constructed to prevent the movement of liquids, sludge, solids or other materials.

~~(7)~~**(8) "Biopile",** also known as biocell, bioheap, biomound or compost pile, means a pile of contaminated soils used to reduce concentrations of petroleum constituents in excavated soils through biodegradation. This technology involves heaping contaminated soils into piles or "cells" and stimulating aerobic microbial activity within the soils through the aeration or addition of minerals, nutrients and moisture.

~~(8)~~**(9) "BLM"** means the United States department of the interior, bureau of land management.

~~(9)~~**(10) "Bottom hole pressure"** means the gauge pressure in psi under conditions existing at or near the producing horizon.

~~(10)~~**(11) "Bradenhead gas well"** means a well producing gas through wellhead connections from

a gas reservoir that has been successfully cased off from an underlying oil or gas reservoir.

~~(11)~~(12) **"BS&W"** means basic sediments and water.

~~(12)~~(13) **"BTEX"** means benzene, toluene, ethylbenzene and xylene.

C. **Definitions beginning with the letter "C".**

(1) **"Carbon dioxide gas"** means noncombustible gas composed chiefly of carbon dioxide occurring naturally in underground rocks.

(2) **"Casinghead gas"** means a gas or vapor or both gas and vapor indigenous to and produced from a pool the division classifies as an oil pool. This also includes gas-cap gas produced from such an oil pool.

(3) **"Certified mail" or "certified mail, return receipt requested"** means United States Postal Service Certified Mail or equivalent service that provides tracking and signature receipt, including Federal Express, United Parcel Service, or similar courier services.

(4) **"Cm/sec"** means centimeters per second.

(5) **"CPD"** means central point delivery.

(6) **"Combination multiple completion"** means a multiple completion in which two or more common sources of supply are produced through a combination of two or more conventional diameter casing strings cemented in a common well bore, or a combination of small diameter and conventional diameter casing strings cemented in a common well bore, the conventional diameter strings of which might or might not be a conventional multiple completion.

(7) **"Commission"** means the oil conservation commission.

(8) **"Commission clerk"** means the division employee the director designates to provide staff support to the commission and accept filings in rulemaking or adjudicatory cases before the commission.

(9) **"Common purchaser for gas"** means a person now or hereafter engaged in purchasing from one or more producers gas produced from gas wells within each common source of supply from which it purchases.

(10) **"Common purchaser for oil"** means every person now engaged or hereafter engaging in the business of purchasing oil to be transported through pipelines.

(11) **"Common source of supply"**. See pool.

(12) **"Condensate"** means the liquid recovered at the surface that results from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing in a gaseous phase in the reservoir.

(13) **"Contiguous"** means acreage joined by more than one common point, that is, the common boundary is at least one side of a governmental quarter-quarter section.

(14) **"Conventional completion"** means a well completion in which the production string of casing has an outside diameter exceeding 2.875 inches.

(15) **"Conventional multiple completion"** means a completion in which two or more common sources of supply are produced through one or more strings of tubing installed within a single casing string, with the production from each common source of supply completely segregated by means of packers.

(16) **"Correlative rights"** means the opportunity afforded, as far as it is practicable to do so, to the owner of each property in a pool to produce without waste the owner's just and equitable share of the oil or gas in the pool, being an amount, so far as can be practically determined, and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas under the property bears to the total recoverable oil or gas in the pool, and for the purpose to use the owner's just and equitable share of the reservoir energy.

(17) **"Cubic feet of gas or cubic foot of gas"** means that volume of gas contained in one cubic foot of space and computed at a base pressure of 10 ounces per square inch above the average barometric pressure of 14.4 psi (15.025 psi absolute), at a standard base temperature of 60 degrees fahrenheit.

D. **Definitions beginning with the letter "D".**

(1) **"Deep pool"** means a common source of supply that is situated 5000 feet or more below the surface.

(2) **"Depth bracket allowable"** means the basic oil allowable the division assigns a pool and based on its depth, unit size or special pool orders, which, when multiplied by the market demand percentage factor in effect, determines the pool's top proration unit allowable.

(3) **"Director"** means the director of the New Mexico energy, minerals and natural resources department, oil conservation division.

(4) **"Division"** means the New Mexico energy, minerals and natural resources department, oil conservation division.

(5) **"Division clerk"** means the division employee the director designates to accept filings in adjudicatory cases before the division.

(6) **"Downstream facility"** means a facility associated with the transportation (including gathering) or processing of gas or oil (including a refinery, gas plant, compressor station or crude oil pump station); brine production; or the oil field service industry.

(7) **"DRO"** means diesel range organics.

E. **Definitions beginning with the letter "E".**

(1) **"EC"** means electrical conductivity.

(2) **"Enhanced oil recovery project"** means the use or the expanded use of a process for thedisplacement of oil from an oil well or division-designated pool other than a primary recovery process, including but not limited to the use of a pressure maintenance process; a water flooding process; an immiscible, miscible, chemical, thermal or biological process; or any other related process.

(3) **"EOR project"** means an enhanced oil recovery project.

(4) **"EPA"** means the United States environmental protection agency.

(5) **"Exempted aquifer"** means an aquifer that does not currently serve as a source of drinking water, and that cannot now and will not in the foreseeable future serve as a source of drinking water because:

(a) it is hydrocarbon producing;

(b) it is situated at a depth or location that makes the recovery of water for drinking water purposes economically or technologically impractical; or

(c) it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption.

(6) **"Exempt waste"** means oil field waste exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(7) **"Existing spacing unit"** means a spacing unit containing a producing well.

(8) **"Expired temporary abandonment" or "expired temporary abandonment status"** means the status of a well that is inactive and has been approved for temporary abandoned status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

F. **Definitions beginning with the letter "F".**

(1) **"Facility"** means a structure, installation, operation, storage tank, transmission line, access road, motor vehicle, rolling stock or activity of any kind, whether stationary or mobile.

(2) **"Field"** means the general area that at least one pool underlies or appears to underlie; and also includes the underground reservoir or reservoirs containing oil or gas. The words field and pool mean the same thing when only one underground reservoir is involved; however, field unlike pool may relate to two or more pools.

(3) **"Fresh water"** to be protected includes the water in lakes and playas (regardless of quality, unless the water exceeds 10,000 mg/l TDS and it can be shown that degradation of the particular water body will not adversely affect hydrologically connected fresh ground water), the surface waters of streams regardless of the water quality within a given reach, and underground waters containing 10,000 mg/l or less of TDS except for which, after notice and hearing, it is found there is no present or reasonably foreseeable beneficial use that contamination of such waters would impair.

G. **Definitions beginning with the letter "G".**

(1) **"Gas"**, also known as natural gas, means a combustible vapor composed chiefly of hydrocarbons occurring naturally in a pool the division has classified as a gas pool.

(2) **"Gas lift"** means a method of lifting liquid to the surface by injecting gas into a well from which oil production is obtained.

(3) **"Gas-oil ratio"** means the ratio of the casinghead gas produced in standard cubic feet to the number of barrels of oil concurrently produced during any stated period.

(4) **"Gas-oil ratio adjustment"** means the reduction in allowable of a high gas oil ratio unit to conform with the production permitted by the limiting gas-oil ratio for the particular pool during a particular proration period.

(5) **"Gas transportation facility"** means a pipeline in operation serving gas wells for the transportation of gas, or some other device or equipment in like operation where the gas produced from gas wells connected with the pipeline or other device or equipment can be transported or used for consumption.

(6) **"Gas well"** means a well producing gas from a gas pool, or a well with a gas-oil ratio exceeding 100,000 cubic feet of gas per barrel of oil producing from an oil pool.

(7) **"Geomembrane"** means an impermeable polymeric sheet material that is impervious to liquid and gas if it maintains its integrity and is used as an integral part of an engineered structure designed to limit the movement of liquid or gas in a system.

(8) **"Geotextile"** means a sheet material that is less impervious to liquid than a geomembrane but more resistant to penetration damage, and is used as part of an engineered structure or system to serve as a filter to prevent the movement of soil fines into a drainage system, to provide planar flow for drainage, to serve as a cushion to protect geomembranes or to provide structural support.

(9) **"GRO"** means gasoline range organics.

(10) **"Ground water"** means interstitial water that occurs in saturated earth material and can enter a well in sufficient amounts to be used as a water supply.

(11) **"Ground water sensitive area"** means an area the division specifically designates after evaluation of technical evidence where ground water exists that would likely exceed WQCC standards if contaminants were introduced into the environment.

H. **Definitions beginning with the letter "H".**

(1) **"Hardship gas well"** means a gas well where underground waste occurs if the well is shut-in or curtailed below its minimum sustainable flow rate.

(2) **"Hazard to public health"** exists when water that is used or is reasonably expected to be used in the future as a human drinking water supply exceeds at the time and place of the use, one or more of the numerical standards of Subsection A of 20.6.2.3103 NMAC, or the naturally occurring concentrations, whichever is higher, or if a toxic pollutant as defined at Subsection WW of 20.6.2.7 NMAC affecting human health is present in the water. In determining whether a release would cause a hazard to public health to exist, the director investigates and considers the purification and dilution reasonably expected to occur from the time and place of release to the time and place of withdrawal for use as human drinking water.

(3) **"Hazardous waste"** means non-exempt waste that exceeds the minimum standards for waste hazardous by characteristics established in RCRA regulations, 40 CFR 261.21-261.24, or listed hazardous waste as defined in 40 CFR, part 261, subpart D, as amended.

(4) **"HDPE"** means high-density polyethylene.

(5) **"High gas-oil ratio proration unit"** means a unit with at least one producing oil well with a gas-oil ratio exceeding the limiting gas-oil ratio for the pool in which the unit is located.

(6) **"H2S"** means hydrogen sulfide.

I. Definitions beginning with the letter **"I".**

(1) **"Illegal gas"** means gas produced from a gas well exceeding the division-determined allowable.

(2) **"Illegal oil"** means oil produced exceeding the allowable the division fixes.

(3) **"Illegal product"** means a product of illegal gas or illegal oil.

(4) **"Inactive well"** means a well that is not being used for beneficial purposes such as production, injection or monitoring and that is not being drilled, completed, repaired or worked over.

(5) **"Injection well"** means a well used for the injection of air, gas, water or other fluids into an underground stratum.

J. **Definitions beginning with the letter "J". [RESERVED]**

K. **Definitions beginning with the letter "K". "Knowingly and willfully"**, for assessing civil penalties, means the voluntary or conscious performance of an act that is prohibited or the voluntary or conscious failure to perform an act or duty that is required. It does not include performances or failures to perform that are honest mistakes or merely inadvertent. It includes, but does not require, performances or failures to perform that result from a criminal or evil intent or from a specific intent to violate the law. The conduct's knowing and willful nature may be established by plain indifference to or reckless disregard of the requirements of statutes, rules, orders or permits. A consistent pattern or performance or failure to perform also may be sufficient to establish the conduct's knowing and willful nature, where such consistent pattern is neither the result of honest mistakes nor mere inadvertency. Conduct that is otherwise regarded as being knowing and willful is rendered neither accidental nor mitigated in character by the belief that the conduct is reasonable or legal.

L. **Definitions beginning with the letter "L".**

(1) **"Limiting gas-oil ratio"** means the gas-oil ratio the division assigns to a particular oil pool to limit the volumes of casinghead gas that may be produced from the various oil producing units within that particular pool.

(2) **"Liner"** means a continuous, low-permeability layer constructed of natural or human-made materials that restricts the migration of liquid oil field wastes, gases or leachate.

(3) **"LLDPE"** means linear low-density polyethylene.

(4) **"Load oil"** means oil or liquid hydrocarbon that has been used in remedial operation in

an oil or gas well.

(5) "Log" means a systematic detailed and correct record of formations encountered in drilling a well.

M. Definitions beginning with the letter "M".

(1) "Marginal unit" means a proration unit that is incapable of producing top proration unit allowable for the pool in which it is located.

(2) "Marginal Well" means an oil or gas well that:

(a) produced less than 180 days and less than 1000 barrel of oil equivalent over the prior 12 month period, or

(b) produced less than 1000 barrel of oil equivalent.

(3) "Market demand percentage factor" means that percentage factor of one hundred percent or less as the division determines at an oil allowable hearing, which, when multiplied by the depth bracket allowable applicable to each pool, determines that pool's top proration unit allowable.

(4) "MCF" means 1000 cubic feet.

(5) "MCFD" means 1000 cubic feet per day.

(6) "MCFGPD" means 1000 cubic feet of gas per day.

(7) "Measured depth" means the total length of the well bore.

(8) "Mg/l" means milligrams per liter.

(9) "Mg/kg" means milligrams per kilogram.

(10) "Mineral estate" is the most complete ownership of oil and gas recognized in law and includes the mineral interests and the royalty interests.

(11) "Mineral interest owner" means a working interest owner, or an owner of a right to explore for and develop oil and gas that is not subject to an existing oil and gas lease.

(12) "Minimum allowable" means the minimum amount of production from an oil or gas well that may be advisable from time to time to the end that production will repay reasonable lifting cost and thus prevent premature abandonment and resulting waste.

(13) "Miscellaneous hydrocarbons" means tank bottoms occurring at pipeline stations; oil storage terminals or refineries; pipeline break oil; catchings collected in traps, drips or scrubbers by gasoline plant operators in the plants or in the gathering lines serving the plants; the catchings collected in private, community or commercial salt water disposal systems; or other liquid hydrocarbon that is not lease crude or condensate.

N. Definitions beginning with the letter "N".

(1) "Non-aqueous phase liquid" means an interstitial body of liquid oil, petroleum product, petrochemical or organic solvent, including an emulsion containing such material.

(2) "Non-exempt waste" means oil field waste not exempted from regulation as hazardous waste pursuant to Subtitle C of RCRA and applicable regulations.

(3) "Non-hazardous waste" means non-exempt oil field waste that is not hazardous waste.

(4) "Non-marginal unit" means a proration unit that can produce the top proration unit allowable for the pool in which it is located, and to which the division assigns a top proration unit allowable.

(5) "NORM" means the naturally occurring radioactive materials regulated by 20.3.14 NMAC.

O. Definitions beginning with the letter "O".

(1) "Official gas-oil ratio test" means the periodic gas-oil ratio test the operator performs pursuant to division order by the method and in the manner the division prescribes.

(2) "Oil" means petroleum hydrocarbon produced from a well in the liquid phase and that existed in a liquid phase in the reservoir. This definition includes crude oil or crude petroleum oil.

(3) "Oil field waste" means non-domestic waste resulting from the exploration, development, production or storage of oil or gas pursuant to Paragraph (21) of Subsection B of Section 70-2-12 NMSA 1978 and the oil field service industry, the transportation of crude oil or natural gas, the treatment of natural gas or the refinement of crude oil pursuant to Paragraph (22) of Subsection B of Section 70-2-12 NMSA 1978, including waste generated from oil field remediation or abatement activity regardless of the date of release. Oil field waste does not include waste not generally associated with oil and gas industry operations such as tires, appliances or ordinary garbage or refuse unless generated at a division-regulated facility, and does not include sewage, regardless of the source.

(4) "Oil well" means a well capable of producing oil and that is not a gas well as defined in Paragraph (6) of Subsection G of 19.15.2.7 NMAC.

(5) "Operator" means a person who, duly authorized, manages a lease's development or a producing property's operation, or who manages a facility's operation.

(6) "Overproduction" means the amount of oil or gas produced during a proration period

exceeding the amount authorized on the proration schedule.

(7) **"Owner"** means the person who has the right to drill into and to produce from a pool, and to appropriate the production either for the person or for the person and another.

P. Definitions beginning with the letter "P".

(1) **"Penalized unit"** means a proration unit to which, because of an excessive gas-oil ratio, the division assigns an allowable that is less than top proration unit allowable for the pool in which it is located and also less than the ability of the well or wells on the unit to produce.

(2) **"Person"** means an individual or entity including partnerships, corporations, associations, responsible business or association agents or officers, the state or a political subdivision of the state or an agency, department or instrumentality of the United States and of its officers, agents or employees.

(3) **"Pit"** means a surface or sub-surface impoundment, man-made or natural depression or diked area on the surface. Excluded from this definition are berms constructed around tanks or other facilities solely for safety, secondary containment and storm water or run-on control.

(4) **"Playa lake"** means a level or nearly level area that occupies the lowest part of a completely closed basin and that is covered with water at irregular intervals, forming a temporary lake.

(5) **"Pool"** means an underground reservoir containing a common accumulation of oil or gas. Each zone of a general structure, which zone is completely separated from other zones in the structure, is covered by the word pool as used in 19.15.2 NMAC through 19.15.39 NMAC. "Pool" is synonymous with "common source of supply" and with "common reservoir".

(6) **"Potential"** means a well's properly determined capacity to produce oil or gas under division-prescribed conditions.

(7) **"Ppm"** means parts per million by volume.

(8) **"PQL"** means practical quantitation limit.

(9) **"Pressure maintenance"** means the injection of gas or other fluid into a reservoir, either to maintain the reservoir's existing pressure or to retard the reservoir pressure's natural decline.

(10) **"Produced water"** means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

(11) **"Producer"** means the owner of a well or wells capable of producing oil or gas or both in paying quantities.

(12) **"Product"** means a commodity or thing made or manufactured from oil or gas, and derivatives of oil or gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, treated crude oil, fuel oil, residuum, gas oil, naphtha, distillate, gasoline, kerosene, benzene, wash oil, lubricating oil and blends or mixtures of oil or gas or a derivative thereof.

(13) **"Proration day"** consists of 24 consecutive hours that begin at 7:00 a.m. and end at 7:00 a.m. on the following day.

(14) **"Proration month"** means the calendar month that begins at 7:00 a.m. on the first day of the month and ends at 7:00 a.m. on the first day of the next succeeding month.

(15) **"Proration period"** means for oil the proration month and for gas the 12-month period that begins at 7:00 a.m. on January 1 of each year and ends at 7:00 a.m. on January 1 of the succeeding year or other period designated by general or special order of the division.

(16) **"Proration schedule"** means the division orders authorizing the production, purchase and transportation of oil, casinghead gas and gas from the various units of oil or of gas in allocated pools.

(17) **"Proration unit"** means the area in a pool that can be effectively and efficiently drained by one well as determined by the division or commission (see Subsection B of Section 70-2-17 NMSA 1978) as well as the area assigned to an individual well for the purposes of allocating allowable production pursuant to a prorationing order for the pool.

(18) **"Prospective spacing unit"** means a hypothetical spacing unit that does not yet have a producing well.

(19) **"PVC"** means poly vinyl chloride.

(20) **"Psi"** means pounds per square inch.

Q. Definitions beginning with the letter "Q". [RESERVED]

R. Definitions beginning with the letter "R".

(1) **"RCRA"** means the federal Resource Recovery and Conservation Act.

(2) **"Recomplete"** means the subsequent completion of a well in a different pool from the pool in which it was originally completed.

(3) **"Regulated NORM"** means NORM contained in oil-field soils, equipment, sludges or other materials related to oil-field operations or processes exceeding the radiation levels specified in 20.3.14.1403 NMAC.

(4) **"Release"** means breaks, leaks, spills, releases, fires or blowouts involving oil, produced water, condensate, drilling fluids, completion fluids or other chemical or contaminant or mixture thereof, including oil field wastes and gases to the environment.

(5) **"Remediation plan"** means a written description of a program to address unauthorized releases. The plan may include appropriate information, including assessment data, health risk demonstrations and corrective action or actions. The plan may also include an alternative proposing no action beyond the spill report's submittal.

(6) **"Responsible person"** means the owner or operator who shall complete a division-approved corrective action for pollution from releases.

(7) **"Rules"** means the rules enacted pursuant to the Oil and Gas Act, 19.15.2 to 19.15.39 NMAC, as they may be modified or amended.

(8) **"Royalty interest owner"** means the owner of an interest in oil and gas that does not presently entitle the owner to explore, drill or otherwise develop those minerals, including lessors, royalty interest owners and overriding royalty interest owners. Royalty interests are non-cost bearing.

(9) **"Run-on"** means rainwater, leachate or other liquid that drains from other land onto any part of a division-approved facility.

S. **Definitions beginning with the letter "S".**

(1) **"SAR"** means the sodium adsorption ratio.

(2) **"Secondary recovery"** means a method of recovering quantities of oil or gas from a reservoir which quantities would not be recoverable by ordinary primary depletion methods.

(3) **"Sediment oil"** means tank bottoms and other accumulations of liquid hydrocarbons on an oil and gas lease, which hydrocarbons are not merchantable through normal channels.

(4) **"Shallow pool"** means a pool that has a depth range from zero to 5000 feet.

(5) **"Shut-in"** means the status of a production well or an injection well that is temporarily closed, whether by closing a valve or disconnection or other physical means.

(6) **"Shut-in pressure"** means the gauge pressure noted at the wellhead when the well is completely shut-in, not to be confused with bottom hole pressure.

(7) **"Significant modification of an abatement plan"** means a change in the abatement technology used excluding design and operational parameters, or relocation of twenty-five percent or more of the compliance sampling stations, for a single medium, as designated pursuant to Subparagraph (d) of Paragraph (2) of Subsection D of 19.15.30.13 NMAC.

(8) **"Soil"** means earth, sediments or other unconsolidated accumulations of solid particles produced by the physical and chemical disintegration of rocks, and that may or may not contain organic matter.

(9) **"Spacing unit"** means the area allocated to a well under a well spacing order or rule. Under the Oil and Gas Act, Paragraph (10) of Subsection B of Section 70-2-12 NMSA 1978, the commission may fix spacing units without first creating proration units. See *Rutter & Wilbanks corp. v. oil conservation comm'n*, 87 NM 286 (1975). This is the area designated on form C-102.

(10) **"Subsurface water"** means ground water and water in the vadose zone that may become ground water or surface water in the reasonably foreseeable future or that vegetation may use.

(11) **"Surface waste management facility"** means a facility that receives oil field waste for collection, disposal, evaporation, remediation, reclamation, treatment or storage except:

(a) a facility that utilizes underground injection wells subject to division regulation pursuant to the federal Safe Drinking Water Act, and does not manage oil field wastes on the ground in pits, ponds, below-grade tanks or land application units;

(b) a facility permitted pursuant to the New Mexico environmental improvement board rules or WQCC rules;

(c) a temporary pit as defined in 19.15.17 NMAC;

(d) a below-grade tank or pit that receives oil field waste from a single well, permitted pursuant to 19.15.37 NMAC, regardless of the capacity or volume of oil field waste received;

(e) a facility located at an oil and gas production facility and used for temporary storage of oil field waste generated on-site from normal operations, if the facility does not pose a threat to fresh water, public health, safety or the environment;

(f) a remediation conducted in accordance with a division-approved abatement plan pursuant to 19.15.30 NMAC, a corrective action pursuant to 19.15.29 NMAC or a corrective action of a non-reportable release;

(g) a facility operating pursuant to a division emergency order;

(h) a site or facility where the operator is conducting emergency response operations to abate an immediate threat to fresh water, public health, safety or the environment or as the division has

specifically directed or approved; or

(i) a facility that receives only exempt oil field waste, receives less than 50 barrels of liquid water per day (averaged over a 30-day period), has a capacity to hold 500 barrels of liquids or less and is permitted pursuant to 19.15.17 NMAC.

T. Definitions beginning with the letter "T".

(1) "Tank bottoms" means that accumulation of hydrocarbon material and other substances that settles naturally below oil in tanks and receptacles that are used in oil's handling and storing, and which accumulation contains more than two percent of BS&W; provided, however, that with respect to lease production and for lease storage tanks, a tank bottom shall be limited to that volume of the tank in which it is contained that lies below the bottom of the pipeline outlet to the tank.

(2) "TDS" means total dissolved solids.

~~(3) "Temporary abandonment" or "temporarily abandoned status" means the status of a well that is inactive.~~

~~(4)~~(3) **"Top proration unit allowable for gas"** means the maximum number of cubic feet of gas, for the proration period, the division allocates to a gas producing unit in an allocated gas pool.

~~(5)~~(4) **"Top proration unit allowable for oil"** means the maximum number of barrels for oil daily for each calendar month the division allocates on a proration unit basis in a pool to non-marginal units. The division shall determine the top proration unit allowable for a pool by multiplying the applicable depth bracket allowable by the market demand percentage factor in effect.

~~(6)~~(5) **"TPH"** means total petroleum hydrocarbons.

~~(7)~~(6) **"Treating plant"** means a plant constructed for wholly or partially or being used wholly or partially for reclaiming, treating, processing or in any manner making tank bottoms or other waste oil marketable.

~~(8)~~(7) **"Tribal lands"** means those lands for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe. This includes reservations, pueblo land grants, tribal trust lands and individual trust allotments.

~~(9)~~(8) **"Tribal leases"** means those leases of minerals or interests in or rights to minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(10)~~(9) **"Tribal minerals"** means those minerals for which the United States government has a trust responsibility to a native American tribe or a member of a native American tribe.

~~(11)~~(10) **"True vertical depth"** means the difference in elevation between the ground level at the surface location of the well and the deepest point in the well bore.

~~(12)~~(11) **"Tubingless completion"** means a well completion in which the production string of casing has an outside diameter of 2.875 inches or less.

~~(13)~~(12) **"Tubingless multiple completion"** means completion in which two or more common sources of supply are produced through an equal number of casing strings cemented in a common well bore, each such string of casing having an outside diameter of 2.875 inches or less, with the production from each common source of supply completely segregated by cement.

U. Definitions beginning with the letter "U".

(1) "Underground source of drinking water" means an aquifer that supplies water for human consumption or that contains ground water having a TDS concentration of 10,000 mg/l or less and that is not an exempted aquifer.

(2) "Underproduction" means the amount of oil or the amount of gas during a proration period by which a given proration unit failed to produce an amount equal to that the division authorizes in the proration schedule.

(3) "Unit of proration for gas" consists of such multiples of 40 acres as may be prescribed by division-issued special pool orders.

(4) "Unit of proration for oil" consists of one 40-acre tract or such multiples of 40-acre tracts as may be prescribed by division-issued special pool orders.

(5) "Unorthodox well location" means a location that does not conform to the spacing requirements division rules establish.

(6) "Unstable area" means a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity of some or all a division-approved facility's structural components. Examples of unstable areas are areas of poor foundation conditions, areas susceptible to mass earth movements and karst terrain areas where karst topography is developed because of dissolution of limestone, dolomite or other soluble rock. Characteristic physiographic features of karst terrain include sinkholes, sinking streams, caves, large springs and blind valleys.

(7) "Upstream facility" means a facility or operation associated with the exploration, development, production or storage of oil or gas that is not a downstream facility.

V. Definitions beginning with the letter "V". "Vadose zone" means unsaturated earth material below the land surface and above ground water, or in between bodies of ground water.

W. Definitions beginning with the letter "W".

(1) "Waste", in addition to its ordinary meaning, includes:

(a) underground waste as those words are generally understood in the oil and gasbusiness, and to embrace the inefficient, excessive or improper use or dissipation of the reservoir energy, including gas energy and water drive, of a pool, and the locating, spacing, drilling, equipping, operating or producing of a well or wells in a manner to reduce or tend to reduce the total quantity of oil or gas ultimately recovered from a pool, and the use of inefficient underground storage of gas;

(b) surface waste as those words are generally understood in the oil and gas business, and to embrace the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of gas of any type or in any form, or oil, or a product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating or producing a well or wells, or incident to or resulting from the use of inefficient storage or from the production of oil or gas, in excess of the reasonablemarketdemand;

(c) oil production in this state in excess of the reasonable market demand for the oil; the excess production causes or results in waste that the Oil and Gas Act prohibits; reasonable market demand as used herein with respect to oil means the demand for the oil, for reasonable current requirements for current consumption and use within or outside of the state, together with the demand of amounts as are reasonably necessary for building up or maintaining reasonable storage reserves of oil or the products thereof, or both the oil and products;

(d) the non-ratable purchase or taking of oil in this state; the non-ratable taking and purchasing causes or results in waste, as defined in Subparagraphs (a), (b) and (c) of Paragraph (1) of Subsection W of 19.15.2.7 NMAC and causes waste by violating the Oil and Gas Act, Section 70-2-16 NMSA 1978;

(e) the production in this state of gas from a gas well or wells, or from a gas pool, in excess of the reasonable market demand from such source for gas of the type produced or in excess of the capacity of gas transportation facilities for such type of gas; the words "reasonable market demand", as used herein with respect to gas, shall be construed to mean the demand for gas for reasonable current requirements, for current consumption and for use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of gas or products thereof, or both the gas and products.

(2) "Water" means all water including water situated wholly or partly within or bordering upon the state, whether surface or subsurface, public or private, except private waters that do not combine with other surface or subsurface water.

(3) "Water contaminant" means a substance that could alter if released or spilled water's physical, chemical, biological or radiological qualities. Water contaminant does not mean source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954.

(4) "Watercourse" means a river, creek, arroyo, canyon, draw or wash or other channel having definite banks and bed with visible evidence of the occasional flow of water.

(5) "Water pollution" means introducing or permitting the introduction into water, either directly or indirectly, of one or more water contaminants in such quantity and of such duration as may with reasonable probability injure human health, animal or plant life or property, or to unreasonably interfere with the public welfare or property use.

(6) "Well blowout" means a loss of control over and subsequent eruption of a drilling or workover well or the rupture of the casing, casinghead or wellhead of an oil or gas well or injection or disposal well, whether active or inactive, accompanied by the sudden emission of fluids, gaseous or liquid, from the well.

(7) "Well bore" means the interior surface of a cased or open hole through which drilling, production or injection operations are conducted.

(8) "Wellhead protection area" means the area within 200 horizontal feet of a private, domestic fresh water well or spring used by less than five households for domestic or stock watering purposes or within 1000 horizontal feet of any other fresh water well or spring. Wellhead protection areas does not include areas around water wells drilled after an existing oil or gas waste storage, treatment or disposal site wasestablished.

(9) "Wetlands" means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions in New Mexico. This definition does not include constructed wetlands used for wastewater treatment purposes.

(10) "Working interest owner" means the owner of an operating interest under an oil and gas lease who has the exclusive right to exploit the oil and gas minerals. Working interests are costbearing.

(11) "WQCC" means the New Mexico water quality control commission.

[19.15.2.7 NMAC - Rp, 19.15.1.7 NMAC, 12/1/2008; A, 3/31/2015; A, 6/30/2016; A, 6/26/2018; A, 1/15/2019; A, 19.15.2 NMAC

10/13/2020; A, 8/23/2022]

19.15.2.8 GENERAL OPERATIONS/WASTE PROHIBITED:

A. The production or handling of oil or gas of any type or in any form or the handling of oil or gas products in a manner, under conditions or in an amount as to constitute or result in waste is prohibited.

B. Operators, contractors, drillers, carriers, gas distributors, service companies, pipe pulling and salvaging contractors, treating plant operators or other persons shall conduct their operations in or related to the drilling, equipping, operating, producing, plugging and abandonment of oil, gas, injection, disposal and storage wells or other facilities in a manner that prevents waste of oil and gas, the contamination of fresh waters and shall not wastefully utilize oil or gas or allow either to leak or escape from a natural reservoir or from wells, tanks, containers, pipe or other storage, conduit or operating equipment.

[19.15.2.8 NMAC - Rp, 19.15.1.13 NMAC, 12/1/2008]

19.15.2.9 ORDERS: The division or commission may issue orders, including division or commission special pool orders when required and the orders shall prevail against rules if in conflict with them.

[19.15.2.9 NMAC - Rp, 19.15.1.11 NMAC, 12/1/2008]

19.15.2.10 ONLINE APPLICATION AND SUBMITTALS:

A. The division shall establish online application and submittal procedures on the division's website for the electronic filing of all forms, applications and other written documents and information with the division.

B. All applications that require the payment of a fee, as provided in Section 70-2-39 NMSA 1978, shall include the fee payment with the application.

C. A person whose filing is made untimely due to a technical failure of the division's web-based online application process may request an extension of time. Technical failures not originating with the division's process, such as problems with the filer's equipment, software, or telecommunications facility will not constitute a basis for relief.

[19.15.2.10 NMAC - N, 8/23/2022]

19.15.2.11 EMERGENCY ORDERS AND RULES:

A. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, in the event the division or commission finds an emergency exists that requires an order's or rule's issuance without a hearing, the emergency rule or order shall have the same validity as if the division or commission held a hearing before the division or commission after due notice. The emergency rule or order shall remain in force no longer than 15 days from its effective date.

B. Notwithstanding other provisions of 19.15.2 NMAC through 19.15.39 NMAC, if the division or commission finds an emergency exists, the division or commission may conduct a hearing on an application within less than 30 days after party files an application and the director may set the notice period at the director's discretion.

[19.15.2.11 NMAC - Rp, 19.15.14.1225 NMAC, 12/1/2008]

19.15.2.12 FILING AND NOTIFICATION: All requirements in the rules:

A. to file a form or application with the division or commission, including documents required to be filed with district offices or the Santa Fe office, shall be accomplished by using the applicable online process on the division's website,

B. to otherwise notify, advise, contact, or report to the division, including to any unit of the division (such as a bureau or office) or any division official (such as the director or a bureau chief), may be accomplished by electronic mail or as otherwise provided on the division's website; the division shall provide contact instructions on the division's website, and

C. to file an original financial assurance instrument with the division as provided in 19.15.8 NMAC shall require delivery to the Santa Fe office unless otherwise directed by the division.

[19.15.2.12 NMAC - Rp, 19.15.15.1304 NMAC, 12/1/2008; 19.15.2.12 NMAC - Rp, 19.15.2.12 NMAC, 8/23/2022]

19.15.2.13 COMPUTATION OF TIME: In computing a period of time prescribed by the Oil and Gas Act, the rules or an order, the division and commission shall comply with the Uniform Statute and Rule Construction Act, Section 12-2A-7 NMSA 1978.

[19.15.2.13 NMAC - Rp, 19.15.14.1226 NMAC, 12/1/2008; A, 8/23/2022]

19.15.2.14 MEETINGS BY TELECONFERENCE: Pursuant to Section 10-15-1 NMSA 1978, commission members may participate in commission meetings and hearings by conference telephone or other similar communications equipment when it is otherwise difficult or impossible for members to attend the meeting or hearing in person. Each member participating by conference telephone or other similar communications equipment shall be identified when speaking. Participants shall be able to hear each other at the same time. Members of the public hearing attending the meetings or hearing shall be able to hear commission members who speak during the meeting or hearing.
[19.15.2.14 NMAC - Rp, 19.15.1.20 NMAC, 12/1/2008]

19.15.2.15 AUTHORITY TO COOPERATE WITH OTHER AGENCIES: The division may from time to time enter into arrangements with state and federal governmental agencies, industry committees and individuals with respect to special projects, services and studies relating to oil and gas conservation and the associated protection of fresh waters.
[19.15.2.15 NMAC - Rp, 19.15.1.17 NMAC, 12/1/2008]

19.15.2.16 DUTIES AND AUTHORITY OF DIVISION PERSONNEL: Division personnel have the authority and duty to enforce division rules. Upon a showing by an operator that changes are necessary to avoid waste or protect public health or the environment, division personnel may allow minor deviations from approved field operational plans such as drilling and plugging plans. The operator shall file a Form C-103 as a notice of intention showing the change of plans within two business days of the approval.
[19.15.2.16 NMAC - Rp, 19.15.15.1303, 12/1/2008; A, 8/23/2022]

19.15.2.17 ORGANIZATIONAL UNITS: When necessary to assist in the administration of the Oil and Gas Act, the director may divide the state into districts or other organizational units as appropriate. Upon establishment of, or revisions to, such units, the director shall provide or amend a map on the division's website with the boundaries of the units. Contact information for the units, including any assigned personnel, shall be maintained on the division's website.
[19.15.2.17 NMAC - Rp, 19.15.15.1301 NMAC, 12/1/2008; 19.15.2.17 NMAC - Rp, 19.15.2.17 NMAC, 8/23/2022]

19.15.2.18 RENUMBERING OR REORGANIZATION OF RULES: When the commission approves reorganization or renumbering of division rules, either through amendment or repeal and replacement, persons with permits, orders or agreements that reference rules that have been reorganized or renumbered shall comply with the rules as reorganized or renumbered.
[19.15.2.18 NMAC - N, 12/1/2008]

HISTORY of 19.15.2 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001); 19.15.14 NMAC, Procedure (filed 09/16/2005); and 19.15.15 NMAC, Administration (filed 07/12/2004) all repealed 12/1/2008.

NMAC History:
Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 1-7, 11, 13, 17, & 20) (filed 04/27/2001); 19.15.14 NMAC, Procedure (Sections 1225 and 1226) (filed 09/16/2005); and 19.15.15 NMAC, Administration (Sections 1301 and 1303) (filed 07/12/2004) were replaced by 19.15.2 NMAC, General Provisions for Oil and Gas Operations, effective 12/1/2008.

EXHIBIT 1-B

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.5 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 5 ENFORCEMENT AND COMPLIANCE

19.15.5.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.5.1 NMAC - N, 12/1/2008]

19.15.5.2 SCOPE: 19.15.5 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.5.2 NMAC - N, 12/1/2008]

19.15.5.3 STATUTORY AUTHORITY: 19.15.5 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12, Section 70-2-31 and Section 70-2-31.1 NMSA 1978.
[19.15.5.3 NMAC – N, 12/1/2008, A, 2/25/2020]

19.15.5.4 DURATION: Permanent.
[19.15.5.4 NMAC - N, 12/1/2008]

19.15.5.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.5.5 NMAC - N, 12/1/2008]

19.15.5.6 OBJECTIVE: To establish a process to ensure compliance with the Oil and Gas Act, division rules and division and commission orders.
[19.15.5.6 NMAC - N, 12/1/2008]

19.15.5.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.5.8 ENFORCEMENT OF STATUTES AND RULES: The division is charged with the duty and obligation of enforcing the state's rules and statutes relating to the conservation of oil and gas, including the prevention of waste and the protection of correlative rights, and the protection of public health and the environment. An owner or operator shall obtain information pertaining to the regulation of oil and gas before beginning operations.
[19.15.5.8 NMAC - Rp, 19.15.1.12 NMAC, 12/1/2008, A, 2/25/2020]

19.15.5.9 COMPLIANCE:

A. An operator is in compliance with Subsection A of 19.15.5.9 NMAC if the operator:

(1) currently meets the financial assurance requirements of 19.15.8 NMAC;

(2) is not subject to a division or commission order, issued after notice and hearing, finding the operator to be in violation of an order requiring corrective action;

(3) does not have a penalty assessment that is unpaid more than 30 days after issuance of the order assessing the penalty; ~~and~~

(4) currently meets the waste prevention requirements in 19.15.27.A(3) ~~and 28 NMAC; and~~

~~**(4)**~~**(5)** ~~has no more than the following number of wells out of compliance with 19.15.25.8 NMAC that are not subject to an agreed compliance or final order setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met:~~

~~**(a)** two wells or fifty percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;~~

~~**(b)** five wells if the operator operates between 101 and 500 wells;~~

~~**(c)** seven wells if the operator operates between 501 and 1000 wells; and~~

~~**(d)** 10 wells if the operator operates more than 1000 wells.~~

B. Inactive wells.

(1) The division shall make available on its website, and update daily, an "inactive well list" listing each well, by operator, that according to division records:

(a) shows no production or injection for past 15 months;

(b) does not have its well bore plugged in accordance with 19.15.25.9 NMAC

through 19.15.25.11 NMAC;

(c) is not in approved temporary abandonment in accordance with 19.15.25.12 NMAC through 19.15.25.14 NMAC; and

(d) is not subject to an agreed compliance or final order setting a schedule for bringing the well into compliance with 19.15.25.8 NMAC.

(2) A well inactive for more than 15 months creates a rebuttable presumption that the well is out of compliance with 19.15.25.8 NMAC.

C. Financial assurance. The division shall make available on its website and update weekly the status of operators' financial assurance that 19.15.8 NMAC requires, according to division records.

[19.15.5.9 NMAC - Rp, 19.15.1.40 NMAC, 12/1/2008; A, 11/30/2016, A, 2/25/2020]

D. Presumptions of no beneficial use: Registered well operators may, within 30 calendar days after notice of a determination or administrative presumption that a well is no longer useable for beneficial purposes, submit an application for administrative review of such beneficial use determination through the division permitting system or any successor online operator portal. The division shall issue a final determination based on the content of the application and information available in division records. The final determination may be subject to appeal pursuant to 19.15.4 NMAC. Applications to demonstrate beneficial use of well(s) must include:

(1) Documentation that the well may be reasonably projected to continue producing in paying quantities; and,

(2) The operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all plugging and known environmental liabilities of the well(s) and associated production facilities, not inclusive of any financial assurance associated with the well(s); and,

(3) Other information as may be reasonably required by the division.

19.15.5.10 ENFORCEMENT:

A. General. Whenever the division determines that a person violated or is violating the Oil and Gas Act or a provision of any rule, order, permit or authorization issued pursuant to the Oil and Gas Act, the division may seek a sanction by:

(1) issuing a temporary cessation order if it determines that the alleged violation is causing or will cause an imminent danger to public health or safety or a significant imminent environmental harm. The temporary cessation order shall remain in place until the earlier of when the division determines that the alleged violation is abated or 30 days, unless a hearing is held before the division and a new order is issued;

(2) issuing a notice of violation; or

(3) commencing a civil action in district court.

B. Sanctions. The division may seek one or more of the following sanctions:

(1) a civil penalty;

(2) modification, suspension, cancellation or termination of a permit or authorization;

(3) plugging and abandonment of a well;

(4) remediation and restoration of a well location and associated facilities, including the removal of surface and subsurface equipment and other materials;

(5) remediation and restoration of a location affected by a spill or release;

(6) forfeiture of financial assurance;

(7) shutting in a well or wells; and

(8) any other remedy authorized by law.

C. Notice of violation.

(1) A notice of violation issued by the division shall state with reasonable specificity:

(a) the identity of the alleged violator;

(b) the nature and factual and legal basis of the alleged violation, including the provision of the Oil and Gas Act or rule, order, permit or authorization allegedly violated;

(c) whether compliance is required immediately or within a specified time period;

(d) the sanction(s) available for the alleged violation, the sanction(s) proposed by the division, and a statement that the division will take into consideration the violators good faith efforts to comply with the applicable requirements;

(e) the availability of a process for informal review and resolution of the alleged violation, and the procedure to initiate the informal review process, including the contact information of the appropriate division employee;

(f) a statement that if the notice of violation is not informally resolved within 30 days of service, the division will hold a hearing, but that the hearing shall not prohibit the parties from negotiating and settling the notice of violation at any time; and

(g) the date of the hearing, which shall be no later than 90 days after the date of the notice of violation.

(2) The division shall serve the notice of violation on the alleged violator by certified mail, and may provide the notice of violation by electronic mail if possible.

(3) If during the informal review the division and the alleged violator agree to resolve the alleged violation, they shall incorporate their agreement into a stipulated final order signed by both parties. The stipulated final order shall state that the alleged violator admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives the alleged violator's right of review by the commission.

(4) If the division and the alleged violator fail to enter a stipulated final order within 30 days of service, the division shall hold a hearing at the division's principal office.

D. Civil penalties. A civil penalty assessed by the division shall account for the seriousness of the violation, good faith efforts to comply with the applicable requirement, history of noncompliance under the Oil and Gas Act and other relevant factors. The civil penalty assessed by the division shall not exceed $2,500 per day of noncompliance for each alleged violation, unless the alleged violation presents a risk either to the health or safety of the public or of causing significant environmental harm, or unless the noncompliance continues beyond the time specified in the notice of violation or stipulated final order, whereupon the civil penalty may not exceed $10,000 per day of noncompliance for each alleged violation, provided that the civil penalty assessed by the division for an alleged violation shall not exceed $200,000.

E. Adjudicatory procedures. These adjudicatory procedures shall apply to hearings on temporary cessation orders and notices of violation before the division, and the provisions of 19.15.4 NMAC shall not apply.

(1) General provisions.

(a) Designation of parties. The parties shall be the division and the person served with a notice of violation or order, referred to herein as "respondent".

(b) Representation. Respondent may appear and participate in a hearing either pro se or through counsel, provided that a collective entity, including a corporation, partnership, unincorporated association, political subdivision or governmental agency shall appear only through counsel or a duly authorized officer or member.

(c) Rule applicability. In the absence of a specific provision in this section, the hearing examiner may apply the New Mexico rules of civil procedure and evidence.

(d) Computation of time. In computing any period of time under 19.15.5.10 NMAC the day of the event from which the designated period begins to run shall not be included, and the last day of the computed period shall be included, unless it is a Saturday, Sunday or legal state holiday, in which case the time is extended until the next day which is not a Saturday, Sunday or legal state holiday. Whenever a party must act within a prescribed period after service, and service is by first class mail only, three days is added to the prescribed period.

(e) Extensions of time. The hearing examiner may grant an extension of time to file a document or continue a hearing upon timely motion upon consent of the parties, or for good cause shown after consideration of prejudice to the other party and undue delay to the hearing.

(f) Filing of documents. A party shall file the original of each document and serve a copy on the other party, accompanied by a certificate of service identifying the method and address used to complete service.

(g) Service of documents. A party shall serve each document on the other party or its counsel, as applicable, by personal service or first class mail, or by electronic mail if the parties agree.

(h) Form of documents. Unless otherwise ordered, all documents, except exhibits, shall be on 8 1/2 x 11-inch white paper, shall contain the caption of the notice of violation or temporary cessation order on the first page and shall be signed by the party or its counsel, as applicable.

(2) Pre-hearing procedures.

(a) Docketing. At the expiration of the 30 day period for informal resolution of a notice of violation, when a party appeals a final order under Subsection E of 19.15.5.10 NMAC, or when the division gives notice that it intends to extend a temporary cessation order, the division shall docket the notice of violation or order for hearing, identify the factual basis for the alleged violation and proposed sanction(s), and serve a notice of docketing on respondent.

(b) Answer. No later than 10 days after service of the notice of docketing, respondent shall file an answer stating its objection, if any, and the factual and legal basis for such objection, to each alleged violation and proposed sanction in the notice of violation or order.

(c) Hearing examiner. The hearing examiner shall have the authority to take all measures necessary to conduct a fair, impartial and efficient adjudication of issues, and to maintain order and avoid

undue delay, including the authority to conduct pre-hearing conferences and hearings, rule on procedural and evidentiary motions, govern the examination of witnesses and the admission of evidence, issue orders and prepare a recommended decision. After the division issues the notice of violation, the hearing examiner shall not discuss ex parte the merits of the proceeding with the division or the respondent.

(d) Pre-hearing conference. The hearing examiner may hold a pre-hearing conference to narrow the issues, eliminate or resolve preliminary matters and encourage settlement, and may issue a pre-hearing order on procedural and evidentiary matters, including a schedule for the filing of motions and testimony, stipulations regarding alleged violations and requested relief, including proposed civil penalties or

lements thereof, and any other matter necessary for the efficient conduct of the hearing.

(e) Pre-hearing statements. No later than seven calendar days before the hearing, a party who intends to present evidence at the hearing shall file and serve a statement that contains the following information:

(i) name, address, employment and qualifications, including education and work history, of each witness;

(ii) a statement identifying the opinions and factual assertions supporting each witness' testimony;

(iii) the exhibits and other evidence to be presented by each witness; and

(iv) procedural matters that are to be resolved prior to the hearing.

(f) Enforcement. The hearing examiner may enforce the requirements of 19.15.5.10 NMAC by any appropriate means, including the exclusion of testimony, exhibits and other evidence.

(g) Motions.

(i) General. All motions, except motions made orally during the hearing, shall be in writing, specify the grounds for the motion, state the relief sought, indicate whether the motion is opposed or unopposed and be served on the other party.

(ii) Unopposed motions. An unopposed motion shall state that concurrence of the other party was obtained and shall be accompanied by a proposed order approved by the parties.

(iii) Opposed motions. An opposed motion shall state either that concurrence was sought and not obtained, or the reason that concurrence was not sought.

(iv) Response. No later than 10 days after service of an opposed motion, the opposing party may file a response. Failure to file a response shall be deemed a waiver of any objection to the granting of the motion.

(v) Reply. No later than 10 days after service of a response to an opposed motion, the moving party may file a reply.

(vi) Decision. The hearing examiner shall decide all motions without a hearing, unless otherwise ordered by the hearing examiner sua sponte or upon written request of a party.

(h) Shortening Deadlines. On the written request of the alleged violator showing good cause, the hearing examiner may shorten the deadlines specified in Paragraph (2) of Subsection E of 19.15.10 NMAC to conduct the hearing on the division's application for a temporary cessation order as expeditiously as possible. If the division opposes the request to shorten deadlines, the procedures for opposed motions set forth in Subparagraph (g) of Paragraph (2) of Subsection G of 19.15.5.10 NMAC shall not apply and the hearing examiner shall decide the request, with or without hearing, as quickly as practicable.

(3) Hearing procedures.

(a) General. The hearing examiner shall admit all evidence, unless he or she determines that the evidence is irrelevant, immaterial, unduly repetitious or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded by the New Mexico rules of evidence is not admissible.

(b) Witness examination. Witnesses shall be examined orally and under oath or affirmation, provided that the parties may stipulate to the admission of the testimony of a witness, or part thereof. Parties shall have the right to cross-examine a witness, provided that the hearing examiner may limit cross-examination that is unduly repetitious, harassing or beyond the scope of the direct testimony.

(c) Exhibits. A party shall label each exhibit used during the hearing or offered into evidence with a designation identifying the party, the witness using or offering the exhibit and a serial number.

(d) Burden of persuasion. The division has the burden of going forward with the evidence and of proving by a preponderance of the evidence the facts relied upon to show the alleged violation occurred and that the proposed civil penalty is appropriate. Following the establishment of a prima facie case, respondent shall have the burden of going forward with any adverse evidence or defense to the allegations.

(4) Post-hearing procedures.

(a) Transcript. The hearing shall be transcribed verbatim. Respondent may order

a copy of the transcript from the reporter at its own expense.

(b) Recommended decision. The hearing examiner shall prepare a recommended decision for review by the director.

(c) Final order. The director shall file a final order addressing the material issues of fact and law and may assess a sanction for each alleged violation, which shall be served on the division and the respondent.

F. Commission review. No later than 30 days after the director serves the final order, a party may file a notice of appeal with the commission and shall serve the notice of appeal on the other party. The commission shall schedule a hearing on the appeal and notify the parties of the date and time of the hearing. The commission shall conduct a de novo review, provided however, that the parties may stipulate to the issues to be heard and to the admission of all or part of the record before the division. The commission shall conduct the hearing in accordance with the adjudicatory procedures in Paragraph (1), Subparagraphs (c) through (g) of Paragraph (2), Paragraph (3) and Subparagraph (a) of Paragraph (4) of Subsection E of 19.15.5.10 NMAC.

G. Rehearings. A party may file an application for rehearing with the commission pursuant to Section 70-2-25 NMSA 1978.

H. Payment of civil penalty. Respondent shall pay the full amount of the civil penalty assessed in the final order (i) no later than 30 days after the director serves the final order, or (ii) if respondent files a notice of appeal to the commission or the district court pursuant to Section 70-2-25 NMSA 1978, no later than 30 days after the commission or the district court files a final order or the appeal is withdrawn.

I. Resolution after commencement of hearing. If the parties agree to resolve a notice of violation at any time after the commencement of a hearing, they shall file a stipulated final order signed by both parties. The stipulated final order shall state that respondent admits the division's jurisdiction to file the notice of violation, consents to the specified relief, including the civil penalty, if any, and waives respondent's right of review by the commission or the court, as applicable.

J. Publication. On or about October 1 of each year, the division shall publish a list identifying the temporary cessation orders and notices of violation issued during the preceding year, along with the civil penalty paid, if any.

K. Reservation. Nothing in 19.15.5.10 NMAC precludes the division from bringing any other action and seeking any relief allowed by the Oil and Gas Act.

[19.15.5.10 NMAC – Rp, 19.15.5.10 NMAC, 2/25/2020]

19.15.5.11 **ENFORCEABILITY OF PERMITS AND ADMINISTRATIVE ORDERS:** A person who conducts an activity pursuant to a permit, administrative order or other written authorization or approval from the division shall comply with every term, condition and provision of the permit, administrative order, authorization or approval.

[19.15.5.11 NMAC - Rp, 19.15.1.41 NMAC, 12/1/2008]

HISTORY of 19.15.5 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001) and 19.15.14 NMAC, Procedure (filed 09/16/2005) repealed 12/1/2008.

NMAC History:

Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 12, 40 & 41) (filed 04/27/2001) and 19.15.14 NMAC, Procedure (Section 1227) (filed 09/16/2005), were replaced by 19.15.5 NMAC, Enforcement and Compliance, effective 12/1/2008.

EXHIBIT 1-C

Apps' Ex. 5

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.8 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 8 FINANCIAL ASSURANCE

19.15.8.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.8.1 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.2 SCOPE: 19.15.8 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.8.2 NMAC - N, 12/1/2008]

19.15.8.3 STATUTORY AUTHORITY: 19.15.8 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11, Section 70-2-12 and Section 70-2-14 NMSA 1978.
[19.15.8.3 NMAC - N, 12/1/2008; A, 1/15/2019]

19.15.8.4 DURATION: Permanent.
[19.15.8.4 NMAC - N, 12/1/2008]

19.15.8.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.8.5 NMAC - N, 12/1/2008]

19.15.8.6 OBJECTIVE: To establish financial assurance requirements for persons, firms, corporations or associations who have drilled or acquired, are drilling or propose to drill or acquire an oil, gas or injection or other service well to furnish financial assurance acceptable to the division.
[19.15.8.6 NMAC - N, 12/1/2008]

19.15.8.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.8.8 GENERAL REQUIREMENTS FOR FINANCIAL ASSURANCE:

A. The operator shall file financial assurance documents with the division's Santa Fe office and obtain approvals and releases of financial assurance from that office.

B. Financial assurance documents shall be on forms prescribed by or otherwise acceptable to the division.

C. The division may require proof that the individual signing for an entity on a financial assurance document or an amendment to a financial assurance document has the authority to obligate that entity.

D. Any time an operator changes the corporate surety, financial institution or amount of financial assurance, the operator shall file updated financial assurance documents on forms prescribed by the division. Notwithstanding the foregoing, if an operator makes other changes to its financial assurance documents, the division may require the operator to file updated financial assurance documents on forms prescribed by the division.
[19.15.8.8 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.9 CATEGORIES AND AMOUNTS OF FINANCIAL ASSURANCE FOR WELL PLUGGING:

A. Applicability. An operator who has drilled or acquired, is drilling or proposes to drill or acquire an oil, gas or injection or other service well within this state shall furnish a financial assurance acceptable to the division in accordance with 19.15.8.9 NMAC and in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico conditioned that the well be plugged and abandoned and the location restored and remediated in compliance with commission rules, unless the well is covered by federally required financial assurance. The division shall not approve, and the operator shall not proceed with, any proposed drilling or acquisition until the operator has furnished the appropriate financial assurance.

B. A financial assurance shall be conditioned for well plugging and abandonment and location restoration and remediation only, and not to secure payment for damages to livestock, range, crops or tangible improvements or any other purpose.

C. Active wells. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsection D of 19.15.8.9 NMAC in one ofthe following categories:

(1) a one well financial assurance in the amount of $150,000 per well , to be adjusted for inflation pursuant to Subsection G of 19.15.8.9 NMAC. ~~25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells~~; or

(2) a blanket plugging financial assurance in the amount of $250,000 covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC;

~~**(a)** $50,000 for one to 10 wells; $200,000 for one to five wells; and~~

~~**(b)** $75,000 for 11 to 50 wells; $250,000 for six or more wells.;~~

~~**(c)** $125,000 for 51 to 100 wells; and~~

~~**(d)** $250,000 for more than 100 wells.~~

(3) Notwithstanding the foregoing, an operator shall provide a ~~one~~ single well financial assurance in the amount of $150,000 for each well in each of the following categories:

~~**(a)**~~ (a) Marginal wells. Every marginal well, prior to (--, 2030) or prior to any well transfer must have single well financial assurance in place.

~~**(b)**~~ (b) An operator who has over 15% of their wells in Marginal or Inactive well status prior to XXXX (five years) or at the time of well transfer, must single well bond all their wells until the percentage of marginal wells registered to the operator is decreased to less than 15%.

D. Inactive wells, wells in approved temporarily abandoned status, and wells in expired temporarily abandoned status. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC that ~~have been~~ are inactive, in approved temporarily abandoned status ~~for more than two years~~ or expired temporarily abandoned status, or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories, to be adjusted for inflation pursuant to Subsection G of 19.15.8.9 NMAC:

(1) a one well financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance amounting to an average of $150,000 per well covering all wells of the operator subject to Subsection D of 19.15.8.9 NMAC:.

~~**(a)** $150,000 for one to five wells;~~

~~**(b)** $300,000 for six to 10 wells;~~

~~**(c)** $500,000 for 11 to 25 wells; and~~

~~**(d)** $1,000,000 for more than 25 wells.~~

E. Operators who have on file with the division a blanket financial assurance that does not cover additional wells shall file additional single well bond financial assurance for any wells not covered by the existing blanket bond ~~or, in the alternative, may file a replacement blanket bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978.

F. As used in this Section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a twelve-month period ending September 30.

G. On January 1, 2027 and on January 1 of each successive year, the division may adjust the financial assurance amounts provided by Subsections A through F of this Section by multiplying the financial assurance as of January 1, 2026 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2025; provided that the financial assurances shall not be adjusted below the minimum amounts provided in Subsection A through F of this Section as a result of a decrease in the consumer price index. By November 1, 2026 and by November 1 of each successive year, the division shall post on its website the financial assurance requirements in Subsection A through E of this Section for the next year.

[19.15.8.9 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015; A, 1/15/2019]

19.15.8.10 ADDITIONAL REQUIREMENTS FOR CASH AND SURETY BONDS:

A. Surety bonds shall be issued by a reputable corporate surety authorized by the office of the superintendent of insurance to do business in the state. The surety shall be listed on U.S. Department of the Treasury circular 570.

B. The operator shall deposit cash representing the full amount of the bond in an account in a

federally-insured financial institution located within the state, such account to be held in trust for the division. Authorized representatives of the operator and the depository institution shall execute a document evidencing the cash bond's terms and conditions. The operator shall file the document with the division prior to the bond's effective date. If the operator's financial status or reliability is unknown to the director, the director may require the filing of a financial statement or such other information as may be necessary to evaluate the operator's ability to fulfill the bond's conditions. From time to time, any accrued interest over and above the bond's face amount may be paid to the operator.
[19.15.8.10 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.11 ADDITIONAL REQUIREMENTS FOR LETTERS OF CREDIT:

A. The division may accept irrevocable letters of credit issued by national or state-chartered banking associations.

B. Letters of credit shall be irrevocable for a term of not less than five years, unless the applicant shows good cause for a shorter time period.

C. Letters of credit shall provide for automatic renewal for successive, like terms upon expiration, unless the issuer has notified the division in writing of non-renewal at least 30 days prior to expiration.

D. The division may forfeit and collect a letter of credit if not replaced by an approved financial assurance at least 30 days before the expiration date.

E. Authorized representatives of the operator and the depository institution shall execute a document evidencing the letter of credit's terms and conditions.
[19.15.8.11 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 6/30/2015]

19.15.8.12 RELEASE OF FINANCIAL ASSURANCE:

A. The division shall release a financial assurance document upon the operator's or surety's written request if all wells drilled or acquired under that financial assurance have been plugged and abandoned and the location restored and remediated and released pursuant to 19.15.25.9 NMAC through 19.15.25.11 NMAC, or have been covered by another financial assurance the division has approved.

B. Transfer of a property or a change of operator does not of itself release a financial assurance. The division shall not approve a request for change of operator for a well until the new operator has the required financial assurance in place and is otherwise in compliance with all requirements of 19.15.5.9 NMAC and 19.15.9.9 NMAC.

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[19.15.8.12 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.13 FORFEITURE OF FINANCIAL ASSURANCE:

A. Upon the operator's failure to properly plug and abandon and restore and remediate the location of a well or wells a financial assurance covers, the division shall give notice to the operator and surety, if applicable, and hold a hearing as to whether the well or wells should be plugged and abandoned and the location restored and remediated in accordance with a division-approved plugging program. If it is determined at the hearing that the operator has failed to plug and abandon the well and restore and remediate the location as provided for in the financial assurance or division rules, the director shall issue an order directing the well to be plugged or abandoned and the location restored and remediated in a time certain. Such an order may also direct the forfeiture of the financial assurance upon the failure or refusal of the operator, surety or other responsible party to properly plug and abandon the well and restore and remediate the location.

B. If the financial assurance's proceeds exceed the costs the division incurred plugging and abandoning the well and restoring and remediating the location the financial assurance covers, the division shall return the excess to the surety or the operator, as appropriate.

C. If the financial assurance's proceeds are not sufficient to cover all the costs the division incurred in plugging and abandoning the well and restoring and remediating the location, the division may seek indemnification from the operator as provided in Subsection E of Section 70-2-14 NMSA 1978.

D. The division shall deposit forfeitures and funds collected pursuant to a judgment in a suit for indemnification in the oil and gas reclamation fund.

[19.15.9.13 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008]

19.15.8.14 EFFECTIVE DATES.

A. 19.15.8 NMAC applies to wells drilled or acquired after December 15, 2005.

B. As to all other wells, 19.15.8 NMAC is effective January 1, 2008.

C. The 2018 amendments to 19.15.8.9 NMAC apply to applications for permits to drill, deepen or plug back and applications for approved temporary abandonment filed on or after January 15, 2019, and for all other wells on April 15, 2019.

[19.15.8.14 NMAC - Rp, 19.15.3.101 NMAC, 12/1/2008; A, 1/15/2019]

19.15.8.15 ADDITIONAL REQUIREMENTS FOR PLUGGING INSURANCE POLICIES:

A. The plugging insurance policy must be issued by a company authorized by the office of the superintendent of insurance to do business in New Mexico.

B. The policy shall name a specific well and name the state of New Mexico as the owner of the policy and contingent beneficiary.

C. The policy shall name a primary beneficiary who agrees to plug the specified wellbore.

D. The policy shall be fully prepaid and cannot be canceled or surrendered.

E. The policy shall continue in effect until the specified wellbore has been plugged.

F. The policy shall provide that benefits will be paid when, but not before, the specified wellbore has been plugged in accordance with division rules in effect at the time of plugging.

G. The policy shall provide benefits that are not less than an amount equal to the one-well financial assurance required by division rules. If, subsequent to an operator obtaining an insurance policy, the one-well financial assurance requirement applicable to the operator's well covered by said policy increases, either because the well is deepened or the division's rules are amended, the operator will meet the additional financial assurance requirement by complying with one of the requirements below.

(1) The operator's existing policy benefit equals or exceeds the revised requirement.

(2) The operator obtains and files with the division within 30 days an amendment increasing the policy benefit by the amount of the increase in the applicable financial assurance requirement.

(3) The operator obtains financial assurance equal to the amount, if any, by which the revised requirement exceeds the policy benefit and files said financial assurance with the division within 30 days.

[19.15.8.15 NMAC - N, 6/30/2015]

19.15.8.16 DUTY TO REPORT: Any operator who filed for bankruptcy shall provide notice to the division, in writing, through the processes provided for under the rules of the United States bankruptcy court.

[19.15.8.16 NMAC - N, 6/30/2015]

HISTORY of 19.15.8 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/2008.

NMAC History:

That applicable portion of 19.15.3 NMAC, Drilling (Section 101) (filed 10/29/2001) was replaced by 19.15.8 NMAC, Financial Assurance, effective 12/1/2008.

EXHIBIT 1-D

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.9 NMAC

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 9 WELL OPERATOR PROVISIONS

19.15.9.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.9.1 NMAC - N, 12/1/08]

19.15.9.2 SCOPE: 19.15.9 NMAC applies to persons or entities operating oil or gas wells within New Mexico.
[19.15.9.2 NMAC - N, 12/1/08]

19.15.9.3 STATUTORY AUTHORITY: 19.15.9 NMAC is adopted pursuant to the Oil and Gas Act, NMSA 1978, Section 70-2-6, Section 70-2-11 and Section 70-2-12.
[19.15.9.3 NMAC - N, 12/1/08]

19.15.9.4 DURATION: Permanent.
[19.15.9.4 NMAC - N, 12/1/08]

19.15.9.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.9.5 NMAC - N, 12/1/08]

19.15.9.6 OBJECTIVE: To require an operator of a well or wells to register with the division prior to commencing operations and to require the reporting of a change of operator or a change of name to the division.
[19.15.9.6 NMAC - N, 12/1/08]

19.15.9.7 DEFINITIONS: [RESERVED]
[See 19.15.2 NMAC for definitions.]
[19.15.9.7 NMAC - N, 12/1/08]

19.15.9.8 OPERATOR REGISTRATION:

A. Prior to commencing operations, an operator of a well or wells in New Mexico shall register with the division as an operator. Applicants shall provide the following to the financial assurance administrator in the division's Santa Fe office:

(1) an oil and gas registration identification (OGRID) number obtained from the division, the state land office or the taxation and revenue department;

(2) a current address of record to be used for notice and a current emergency contact name and telephone number for each district in which the operator operates wells; and

(3) the financial assurance 19.15.8 NMAC requires.

B. The division may deny registration as an operator if:

(1) the applicant is not in compliance with Subsection A of 19.15.5.9 NMAC;

(2) an officer, director, partner in the applicant or person with an interest in the applicant exceeding 25 percent, is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(3) the applicant is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(4) the applicant is a corporation, ~~or~~ limited liability company, or limited partnership and is not registered and in good standing with the New Mexico secretary of state ~~public regulation commission~~ to do business in New Mexico.~~; or~~

~~(5) the applicant is a limited partnership and is not registered with the New Mexico secretary of state to do business in New Mexico.~~

C. An operator shall inform the division of its current address of record and emergency contact names and telephone numbers by submitting changes in writing to the division's financial assurance administrator in the division's Santa Fe office within 30 days of the change.

D. The division may require an operator or applicant to identify its current and past officers, directors and partners and its current and past ownership interest in other operators.

[19.15.9.8 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.9 CHANGE OF OPERATOR:

A. A change of operator occurs when the entity responsible for a well or a group of wells changes. A change of operator may result from a sale, assignment by a court, a change in operating agreement or other transaction. Under a change of operator, wells are moved from the OGRID number of the operator of record with the division to the new operator's OGRID number.

B. The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a disclosure of the new operator's aggregate asset retirement obligations, as defined in 19.15.2.7 NMAC, across its operations; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator.

C. The director of the director's designee may deny a change of operator if:

(1) the new operator or operator of record is not in compliance with Subsection A of 19.15.5.9 NMAC; ~~or~~

(2) the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order;~~.~~

(3) any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(4) the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;

(5) the applicant is a corporation, limited liability company, or limited partnership and is not registered and in good standing with the New Mexico secretary of state to do business in New Mexico; or

(6) the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

D. In determining whether to grant or deny a change of operator based on Paragraphs 1, 2, 3, and 4 of Subsection C ~~when the new operator is not in compliance with Subsection A~~ of 19.15.5.9 NMAC, the director or the director's designee shall consider such factors as whether the non-compliance with Subsection A of 19.15.5.9 NMAC is caused by the operator not meeting the financial assurance requirements of 19.15.8 NMAC, being subject to a division or commission order finding the operator to be in violation of an order requiring corrective action, having a penalty assessment that has been unpaid for more than 70 days since the issuance of the order assessing the penalty or having more than the allowed number of wells out of compliance with 19.15.25.8 NMAC. If the non-compliance is caused by the operator having more than the allowed number of wells not in compliance with 19.15.25.8 NMAC, the director or director's designee shall consider the number of wells not in compliance, the length of time the wells have been out of compliance and the operator's efforts to bring the wells into compliance.

[19.15.9.9 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.10 CHANGE OF NAME:

A. A change of operator name occurs when the name of the entity responsible for a well or wells

changes but the entity does not change. For a change of name, the OGRID number remains the same, but division records are changed to reflect the new operator name.

B. An operator shall apply for a change of name by filing a form C-146 using the division's web-based online application and supplying documentary proof that the change is a name change and not a change of operator. If the operator is a corporation, limited liability company or limited partnership, the name must be registered with the public regulation commission or the New Mexico secretary of state, as applicable. The division shall not approve a change of name until the state land office and the taxation and revenue department have cleared the change of name on the OGRID.

[19.15.9.10 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

19.15.9.11 EXAMPLES OF CHANGE OF OPERATOR AND CHANGE OF NAME:

A. Mr. Smith, a sole proprietor, operates five wells under the name "Smith oil company". Mr. Smith changes the name of his company to "Smith production company". The name of the entity operating the wells has changed, but the entity has not changed. Mr. Smith should apply for a change of name.

B. Mr. Smith incorporates his business, changing from the sole proprietorship, "Smith production company", to a corporation: "Smith production company, inc.". The entity responsible for the wells has changed, and Mr. Smith and "Smith production company, inc." should apply for a change of operator.

C. Smith production company, inc., a New Mexico operator, merges with XYZ, inc., which does not operate in New Mexico. At the surviving entity's election, this transaction may be treated as a change of name from Smith production company, to XYZ, inc., maintaining the existing OGRID, or as a change of operator, with a new OGRID.

D. Two New Mexico operators, Smith production company, inc. and Jones production company, inc., merge. The surviving corporation is Jones production company, inc. A different entity now operates the wells Smith production company, formerly operated, and the wells must be placed under that entity's OGRID. Jones production company, inc. and Smith production company, inc. should apply for a change of operator as to the wells Smith production company, inc. operated.

[19.15.9.11 NMAC - Rp, 19.15.3.100 NMAC, 12/1/08]

HISTORY of 19.15.9 NMAC:

History of Repealed Material: 19.15.3 NMAC, Drilling (filed 10/29/2001) repealed 12/1/08.

NMAC History:

That applicable portion of 19.15.3 NMAC, Drilling (Section 100) (filed 11/30/2005) was replaced by 19.15.9 NMAC, Well Operator Provisions, effective 12/1/08.

EXHIBIT 1-E

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.25 NMAC

TITLE 19 NATURAL RESOURCES ANDWILDLIFE
CHAPTER 15 OIL AND GAS
PART 25 PLUGGING AND ABANDONMENT OF WELLS

19.15.25.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.25.1 NMAC - Rp, 19.15.4.1 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.2 SCOPE: 19.15.25 NMAC applies to persons that operate oil or gas wells within New Mexico.
[19.15.25.2 NMAC - Rp, 19.15.4.2 NMAC, 12/1/2008]

19.15.25.3 STATUTORY AUTHORITY: 19.15.25 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-12 NMSA 1978, which authorizes the division to require dry or abandoned wells to be plugged so as to confine oil, gas or water in the strata in which they are found and to prevent them from escaping into other strata.
[19.15.25.3 NMAC - Rp, 19.15.4.3 NMAC, 12/1/2008]

19.15.25.4 DURATION: Permanent.
[19.15.25.4 NMAC - Rp, 19.15.4.4 NMAC, 12/1/2008]

19.15.25.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end ofasection.
[19.15.25.5 NMAC - Rp, 19.15.4.5 NMAC, 12/1/2008]

19.15.25.6 OBJECTIVE: To establish requirements for properly abandoning and plugging wells drilled for oil or gas or service wells including seismic, core, exploration or injection wells or placing the wells in temporary abandonment in order to protect public health, fresh water and the environment.
[19.15.25.6 NMAC - Rp, 19.15.4.6 NMAC, 12/1/2008]

19.15.25.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.25.8 WELLS TO BE PROPERLY ABANDONED:

A. The operator of wells drilled for oil or gas or services wells including seismic, core, exploration or injection wells, whether cased or uncased, shall plug the wells as Subsection B of 19.15.25.8 NMAC requires.

B. The operator shall either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment in accordance with 19.15.25 NMAC within ~~90~~ 30 days after:

(1) a 60 day period following suspension of drilling operations; or

(2) a determination or administrative presumption that a well is no longer usable for beneficial purposes; or

(3) a period of one year in which a well has been ~~continuously~~ inactive.

[19.15.25.8 NMAC - Rp, 19.15.4.201 NMAC, 12/1/2008]

19.15.25.9 NOTICE OF PLUGGING:

A. The operator shall file notice of intention to plug with the division on form C-103 prior to commencing plugging operations. The notice shall provide all the information 19.15.7.14 NMAC requires including operator and well identification and proposed procedures for plugging the well.

B. In addition, the operator shall provide a well bore diagram showing the proposed plugging procedure.

C. The operator shall notify the division 24 hours prior to commencing plugging operations. In the case of a newly drilled dry hole, the operator may obtain verbal approval from the appropriate district supervisor or the district supervisor's representative of the plugging method and time operations are to begin. The operator shall file written notice in accordance with 19.15.25.11 NMAC with the division within 10 days after the district supervisor has given verbal approval.
[19.15.25.9 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.10 PLUGGING:

A. Before an operator abandons a well, the operator shall plug the well in a manner that permanently confines all oil, gas and water in the separate strata in which they are originally found. The operator may accomplish this by using mud-laden fluid, cement and plugs singly or in combination as approved by the division on

the notice of intention to plug.

B. The operator shall mark the exact location of plugged and abandoned wells with a steel marker not less than four inches in diameter set in cement and extending at least four feet above mean ground level. The operator name, lease name and well number and location, including unit letter, section, township and range, shall be welded, stamped or otherwise permanently engraved into the marker's metal. A person shall not build permanent structures preventing access to the wellhead over a plugged and abandoned well without the division's written approval. A person shall not remove a plugged and abandonment marker without the division's written approval.

C. The operator may use below-ground plugged and abandonment markers only with the division's written approval when an above-ground marker would interfere with agricultural endeavors. The below-ground marker shall have a steel plate welded onto the abandoned well's surface or conductor pipe and shall be at least three feet below the ground surface and of sufficient size so that all the information 19.15.16.8 NMAC requires can be stenciled into the steel or welded onto the steel plate's surface. The division may require a re-survey of the well location.

D. As soon as practical, but no later than one year after the completion of plugging operations, the operator shall:

(1) level the location;

(2) remove deadmen and other junk; and

(3) take other measures necessary or required by the division to restore the location to a safe and clean condition.

E. The operator shall close all pits and below-grade tanks pursuant to 19.15.17 NMAC.

F. Upon completion of plugging and clean up restoration operations as required, the operator shall contact the appropriate division district office to arrange for an inspection of the well and location.

[19.15.25.10 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.11 REPORTS FOR PLUGGING AND ABANDOMENT:

A. The operator shall file form C-105 as provided in 19.15.7.16 NMAC.

B. Within 30 days after completing required restoration work, the operator shall file with the division a record of the work done on form C-103 as provided in 19.15.7.14 NMAC.

C. The division shall not approve the record of plugging or release a bond until the operator has filed necessary reports and the division has inspected and approved the location.

[19.15.25.11 NMAC - Rp, 19.15.4.202 NMAC, 12/1/2008]

19.15.25.12 APPROVED TEMPORARY ABANDONMENT:

A. The division may place a well in approved temporary abandonment for a period of up to ~~five~~ two years upon a demonstration from the operator that the well will be used for beneficial use within the approved period of temporary abandonment. The operator's demonstration shall include a detailed explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future including supporting technical and economic data, a detailed plan that describes the ultimate disposition of the well, the time frame for that disposition, and any other information the division determines appropriate, including a current and complete well bore diagram; geological evidence; geophysical data; well casing information; waste removal and disposition; production and reservoir engineering; leasing status; geophysical logs, e.g., cement bond logs, caliper logs, and casing inspection logs; and health, safety, and environmental information. The division shall approve, approve with conditions, or deny a request. Such conditions may include conditions to protect human health and the environment. If the division denies a request, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

B. Prior to the expiration of an approved temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves, permanently plug and abandon the well and restore and remediate the location, or apply for a new approval to temporarily abandon the well for a period of up to one year upon the same terms and conditions required in Subsection A of this Section. The division shall approve, approve with conditions, or deny a request. Such conditions may include conditions to protect human health and the environment. If the division denies a request, the operator shall permanently plug and abandon the well and restore and remediate the location. An operator may apply for additional one year extensions for approved temporary abandoned status, upon the same terms and conditions as required in Subsection A of this Section, except that a well may not remain in temporary abandonment more than five years unless the commission approves an extension pursuant to Subsection C of this Section. Unless an operator has timely renewed a temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

C. Prior to the expiration of five years in temporary abandonment, an operator may apply to the commission to extend temporary abandonment status pursuant to the procedures for adjudicatory proceedings in 19.15.4 NMAC. In any such adjudicatory proceeding, any interested person may intervene pursuant to 19.15.4.11 NMAC. To continue in temporary abandonment, the operator must demonstrate to the commission that the well will be returned to beneficial use within the requested period of temporary abandonment. The request shall include a detailed explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future and supporting technical and economic data, a detailed plan that describes the ultimate disposition of the well, the time frame for that disposition, and a health and safety plan demonstrating the well's casing and cementing meet the requirements of Subsections B and C of Section 13 of 19.15.25 NMAC and the operator has adequate monitoring procedures in place to ensure such requirements will be met. The commission shall approve, approve with conditions, or deny a request to extend the temporary abandonment. Such conditions may include conditions to protect human health and the environment. An extended term shall not exceed two additional years, upon which time the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

D. An operator is limited to placing the following numbers of wells in approved temporary abandonment:

~~A.~~(1) one well, if the operator operates between one and five wells; or

~~B.~~(2) one-third of all wells (rounded to the nearest whole number), if the operator operates more than five wells.

E. **Implementation schedule for existing wells.**

(1) **Active wells.** This Section applies to active wells to wells as of [effective date of amendments].

(2) **Inactive wells.**

(a) This Section applies to wells that have been inactive for less than two years as of [effective date of amendments].

(b) Operators of wells that have been inactive between two years and less than three years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up two years, may apply to the division for a one year extension of temporary abandonment one time, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(c) Operators of wells that have been inactive between three years and less than four years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up two years with no opportunity for an extension, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(d) Operators of wells that have been inactive between four years and less than five years as of [effective date of amendments] may apply to the division for approved temporary abandonment for up one year with no opportunity for an extension, and thereafter may apply to the commission for an extension up two years, all in accordance with this Section.

(e) Operators of wells that have been inactive five years or more as of [effective date of amendments] may apply to the commission for approved temporary abandonment for up two years in accordance with this Section.

(f) Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(2) **Wells in temporary abandoned status.** Any operator of a well in temporary abandoned status as of [effective date of amendments] shall apply to the commission to extend temporary abandonment status in accordance with this Section prior to the date temporary abandonment status terminates. Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(3) **Wells in expired temporary abandoned status.** Any operator of a well in expired temporary abandoned status as of [effective date of amendments] shall apply to the commission to extend temporary abandonment status in accordance with this Section. Unless an operator of an inactive well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

[19.15.25.12 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.13 REQUEST FOR APPROVAL AND PERMIT FOR APPROVED TEMPORARY ABANDONMENT:

A. An operator seeking approval for approved temporary abandonment shall submit the request on form C-103 ~~a notice of intent~~ to seek approved temporary abandonment for the well setting forth the demonstration required in 19.15.25.12 NMAC and describing the proposed temporary abandonment procedure the operator will use. The operator shall not commence work until the division has approved the request. The operator shall give 24 hours' notice to the appropriate division district office before beginning work.

B. The division shall not approve a permit for approved temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:

(1) damage to the producing zone;

(2) emissions to the air or migration of hydrocarbons or water;

(3) the contamination of fresh water or other natural resources; and

(4) the leakage of a substance at the surface.

C. The operator shall demonstrate both internal and external mechanical integrity pursuant to Subsection A of 19.15.25.14 NMAC.

D. Upon successful completion of the work on the temporarily abandoned well, the operator shall submit a request for approved temporary abandonment to the appropriate division district office on form C-103 together with other information Subsection E of 19.15.7.14 NMAC requires.

E. The division shall not approve a permit for approved temporary abandonment until the operator provides financial assurance for the well that complies with Subsection D of 19.15.8.9 NMAC.

F. The division shall specify the permit's expiration date., ~~which shall be not more than five years from the date of approval.~~

[19.15.25.13 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008; A, 1/15/2019]

19.15.25.14 DEMONSTRATING MECHANICAL INTEGRITY:

A. An operator may use the following methods of demonstrating internal casing integrity for wells to be placed in approved temporary abandonment:

(1) the operator may set a cast iron bridge plug within 100 feet of uppermost perforations or production casing shoe, load the casing with inert fluid and pressure test to 500 psi surface pressure with a pressure drop of not more than 10 percent over a 30 minute period;

(2) the operator may run a retrievable bridge plug or packer to within 100 feet of uppermost perforations or production casing shoe, and test the well to 500 psi surface pressure for 30 minutes with a pressure drop of not greater than 10 percent over a 30 minute period; or

(3) the operator may demonstrate that the well has been completed for less than five years ~~and has not been connected to a pipeline~~.

B. During the testing described in Paragraphs (1) and (2) of Subsection A of 19.15.25.14 NMAC the operator shall:

(1) open all casing valves during the internal pressure tests and report a flow or pressure change occurring immediately before, during or immediately after the 30 minute pressure test;

(2) top off the casing with inert fluid prior to leaving the location;

(3) report flow during the test in Paragraph (2) of Subsection A of 19.15.25.14 NMAC to the appropriate division district office prior to completion of the temporary abandonment operations; the division may require remediation of the flow prior to approving the well's temporary abandonment.

C. An operator may use any method approved by the EPA in 40 C.F.R. section 146.8(c) to demonstrate external casing and cement integrity for wells to be placed in approved temporary abandonment.

D. The division shall not accept mechanical integrity tests or logs conducted more than 12 months prior to submittal.

E. The operator shall record mechanical integrity tests on a chart recorder with a maximum two hour clock and maximum 1000 pound spring, which has been calibrated within the six months prior to conducting the test. Witnesses to the test shall sign the chart. The operator shall submit the chart with form C-103 requesting approved temporary abandonment.

F. The division may approve other testing methods the operator proposes if the operator demonstrates that the test satisfies the requirements of Subsection B of 19.15.25.13 NMAC.

G. Beginning [effective date of amendments], the operator shall conduct the testing required in this Section, and shall submit the chart required in Subsection E of this Section to the division.

[19.15.25.14 NMAC - Rp, 19.15.4.203 NMAC, 12/1/2008]

19.15.25.15 WELLS TO BE USED FOR FRESH WATER:

A. When a well to be plugged may safely be used as a fresh water well and the landowner agrees to take over the well for that purpose, the operator does not need to plug the well above the sealing plug set below the fresh water formation.

B. The operator shall comply with other requirements contained in 19.15.25.9 NMAC through 19.15.25.11 NMAC regarding plugging, including surface restoration and reporting requirements.

C. Upon completion of plugging operations, the operator shall file with the division a written agreement signed by the landowner whereby the landowner agrees to assume responsibility for the well. Upon the filing of this agreement and division approval of well abandonment operations, the operator is no longer responsible for the well, and the division may release bonds on the well.

[19.15.25.15 NMAC - Rp, 19.15.4.204 NMAC, 12/1/2008]

HISTORY of 19.15.25 NMAC:

History of Repealed Material: 19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) repealed 12/1/2008.

NMAC History:

19.15.4 NMAC, Plugging and Abandonment of Wells (filed 11/29/2001) was replaced by 19.15.25 NMAC, Plugging and Abandonment of Wells, effective 12/1/2008.

EXHIBIT 6

AUG. 23-SEPT. 5, 2024

Apps' Ex. 6

Tannis Fox

From: Tannis Fox
Sent: Thursday, September 5, 2024 12:58 PM
To: Tremaine, Jesse, EMNRD; Andrew Cloutier; Jaclyn McLean; Trevino, Christy, EMNRD; Michael Feldewert (MFeldewert@hollandhart.com); Miguel Suazo
Cc: Morgan O'Grady; Ally Beasley; Kyle Tisdel
Subject: RE: OCC No. 24683 - Doodle poll for discussions/negotiations

Hello again. One other point for our negotiations: if other parties have proposed revisions to our proposed amendments, other proposed language, or proposed concepts, could you please forward those to the parties by **Monday, October 7**? It would be helpful to have other parties' alternative proposals prior to discussions/negotiations.

I'm going send a meeting invite to everyone for the negotiation dates below to make sure the dates/times are on our calendars. (And OCD can send round the virtual link at some point.)

Thanks much.
Tannis

Tannis Fox | Senior Attorney | *she/ella*
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From: Tannis Fox
Sent: Wednesday, September 4, 2024 12:20 PM
To: 'Tremaine, Jesse, EMNRD' <JesseK.Tremaine@emnrd.nm.gov>; 'Andrew Cloutier' <ACloutier@hinklelawfirm.com>; 'Jaclyn McLean' <JMcLean@hinklelawfirm.com>; 'Trevino, Christy, EMNRD' <Christy.Trevino@emnrd.nm.gov>; 'Michael Feldewert (MFeldewert@hollandhart.com)' <MFeldewert@hollandhart.com>; 'Miguel Suazo' <msuazo@bwenergylaw.com>
Cc: Morgan O'Grady <ogrady@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Kyle Tisdel <tisdel@westernlaw.org>
Subject: RE: OCC No. 24683 - Doodle poll for discussions/negotiations
Importance: High

Hello all. I think we have an extra day/time for discussions/negotiations that works for everyone: **Wed. Oct. 23, 1-3 pm MST**. Thanks for everyone's diligence in filling out the Doodle poll. I believe we now have firm dates for discussions/negotiations, **all times in MST**:

Financial assurance discussions:
Wed. 10/16 10-12
Wed. 10/23 1-3

Inactive wells discussions:
Tues. 10/22 10-12

Thur. 10/24 10-12

Jesse, because we will convene at ENMRD offices and use your video conferencing – thank you again for that -- does it make sense for you to send out invites to everyone for participating virtually so that these meeting days/times get on everyone's calendars?

Thanks all.
Tannis

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From: Tannis Fox
Sent: Thursday, August 29, 2024 1:40 PM
To: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Miguel Suazo <msuazo@bwenergylaw.com>
Cc: Morgan O'Grady <ogrady@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Kyle Tisdel <tisdel@westernlaw.org>
Subject: OCC No. 24683 - Doodle poll for discussions/negotiations

Hello all. If everyone could please fill out the Doodle poll by noon tomorrow, I can see whether we have an additional day/time we can schedule for discussions/negotiations. If you didn't get the poll, please LMK. And, to access the poll, please follow the directions I gave below.

Thx much.

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Ok, due to user error, the Doodle poll I sent is not letting you complete it. However, if you click "Review response," then on the Doodle page that opens, click "Change your response," you can respond to the poll (even though you hadn't responded before). Thx!

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From: Miguel Suazo <msuazo@bwenergylaw.com>
Sent: Wednesday, August 28, 2024 2:49 PM
To: Tannis Fox <fox@westernlaw.org>; Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Morgan O'Grady <ogrady@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Kyle Tisdel <tisdel@westernlaw.org>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Subject: RE: [EXTERNAL] RE: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

I am in Denver those days. I suggest we send a Survey Monkey or something like that.

Miguel Suazo | Shareholder
Beatty & Wozniak, P.C.
505.946.2090 | Direct

Confidentiality: This Beatty & Wozniak, P.C. email, its attachments and data ("email") are intended to be Confidential and may contain Attorney-Client Communications or Work Product. If you are not the intended recipient or may have received this message in error, notify the sender immediately and permanently delete the email and all copies thereof from any drives or storage media and destroy any printouts. Any unauthorized use or distribution of any of the information in this email is **Strictly Prohibited**.

From: Tannis Fox <fox@westernlaw.org>
Sent: Wednesday, August 28, 2024 2:42 PM
To: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Miguel Suazo <msuazo@bwenergylaw.com>; Morgan O'Grady <ogrady@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Kyle Tisdel <tisdel@westernlaw.org>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Subject: RE: [EXTERNAL] RE: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

CAUTION: EXTERNAL SOURCE

Hello all. When I said that I should not be coordinating scheduling, I meant it. I have an all-day meeting Oct. 15 that I must attend. Would you all be available **Oct. 17 or 18** to meet instead? Thank you, and apologies for missing that meeting when I looked at my calendar.

Tannis

Tannis Fox | Senior Attorney | *she/ella*
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From: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>
Sent: Wednesday, August 28, 2024 11:43 AM
To: Tannis Fox <fox@westernlaw.org>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Miguel Suazo <msuazo@bwenergylaw.com>; Morgan O'Grady <ogrady@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Kyle Tisdel <tisdel@westernlaw.org>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Trevino, Christy, EMNRD

<Christy.Trevino@emnrd.nm.gov>
Subject: FW: [EXTERNAL] RE: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

Please see attached for reference in OCC Case 24683.

Jesse K. Tremaine
Legal Director, Oil Conservation Division
Office of General Counsel
New Mexico Energy, Minerals & Natural Resources Department
1220 South St. Francis Dr., Santa Fe, NM 87505
Cell: (505) 231-9312
E-mail: JesseK.Tremaine@emnrd.nm.gov

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From: Daniel Rubin <DRubin@nmdoj.gov>
Sent: Friday, August 23, 2024 2:57 PM
To: Rubin, Daniel <drubin@nmag.gov>; Tim Davis <tdavis@wildearthguardians.org>; Hearings, OCC, EMNRD <OCC.Hearings@emnrd.nm.gov>; Apodaca, Sheila, EMNRD <Sheila.Apodaca@emnrd.nm.gov>
Cc: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Moander, Chris, EMNRD <Chris.Moander@emnrd.nm.gov>; Samantha Ruscavage-Barz <sruscavagebarz@wildearthguardians.org>; Michael Feldewert <MFeldewert@hollandhart.com>; Adam Rankin <agrankin@hollandhart.com>; Julia Broggi <jbroggi@hollandhart.com>; Paula M. Vance <pmvance@hollandhart.com>; Deana M. Bennett <deana.bennett@modrall.com>; Cristina A. Mulcahy <CAMulcahy@hollandhart.com>
Subject: [EXTERNAL] RE: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

You don't often get email from drubin@nmdoj.gov. Learn why this is important

CAUTION: This email originated outside of our organization. Exercise caution prior to clicking on links or opening attachments.

Dear all,

To ensure compliance with the minimum due process required for rulemakings pursuant to 1.24.25.13 NMAC, I have edited the notice to only require prefiling of technical testimony. The proposed pre-filing requirements for offering an amendment to the rule (to the extent not of a technical nature) or to cross-examine appear to conflict with the ability to freely provide public comment and to cross-examine at the discretion of the commission or hearing officer, as provided in para. D of that rule. The Rule may draw an implicit distinction between public comment and technical testimony. However, proposing rule amendments and CX are clearly part of the right to provide public comment by just showing up and stating one's name, relevant affiliation and being recognized.

Thank you for your understanding.

Daniel Ross Rubin
Assistant Attorney General
Government Counsel & Accountability
State of New Mexico Department of Justice
505-537-4477
drubin@nmag.gov

From: Daniel Rubin <drubin@nmag.gov>
Sent: Friday, August 23, 2024 2:00 PM
To: Tim Davis <tdavis@wildearthguardians.org>; Hearings, OCC, EMNRD <OCC.Hearings@emnrd.nm.gov>; sheila.apodaca@emnrd.nm.gov
Cc: jessek.tremaine@state.nm.us; Moander, Chris, EMNRD <Chris.Moander@emnrd.nm.gov>; Samantha Ruscavage-Barz <sruscavagebarz@wildearthguardians.org>; Michael Feldewert <MFeldewert@hollandhart.com>; Adam Rankin <agrankin@hollandhart.com>; Julia Broggi <jbroggi@hollandhart.com>; Paula M. Vance <pmvance@hollandhart.com>; Deana M. Bennett <deana.bennett@modrall.com>; Cristina A. Mulcahy <CAMulcahy@hollandhart.com>
Subject: RE: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

Thank you Tim. OCC staff will proceed with providing this amended rule to the public in conformity with the State Rules Act.

Daniel Ross Rubin
Assistant Attorney General
Government Counsel & Accountability
State of New Mexico Department of Justice
505-537-4477
drubin@nmag.gov

From: Tim Davis <tdavis@wildearthguardians.org>
Sent: Friday, August 23, 2024 1:44 PM
To: Hearings, OCC, EMNRD <OCC.Hearings@emnrd.nm.gov>; sheila.apodaca@emnrd.nm.gov
Cc: jessek.tremaine@state.nm.us; Moander, Chris, EMNRD <Chris.Moander@emnrd.nm.gov>; Samantha Ruscavage-Barz <sruscavagebarz@wildearthguardians.org>; Michael Feldewert <MFeldewert@hollandhart.com>; Adam Rankin <agrankin@hollandhart.com>; Julia Broggi <jbroggi@hollandhart.com>; Paula M. Vance <pmvance@hollandhart.com>; Deana M. Bennett <deana.bennett@modrall.com>; Cristina A. Mulcahy <CAMulcahy@hollandhart.com>; Daniel Rubin <drubin@nmag.gov>
Subject: OCC 23580 - WildEarth Guardians Amended Application for Rulemaking

Good afternoon Ms. Apodaca:

Attached for filing is WildEarth Guardians' Amended Application for Rulemaking in OCC Case No. 23580. I am also attaching a Word version of the proposed legal notice so you have it in an editable form.

Pursuant to 19.15.3.8(B) NMAC, I am also mailing a copy of the Amended Application for Rulemaking to the Commission Clerk.

- Tim

--



TIM DAVIS
Staff Attorney
he/him

wildearthguardians.org



OCT. 8-11, 2024

Apps' Ex. 6

Tannis Fox

From: Tannis Fox
Sent: Friday, October 11, 2024 1:56 PM
To: Miguel Suazo; Andrew Cloutier; Michael Feldewert; Jaclyn McLean; Tremaine, Jesse, EMNRD; Trevino, Christy, EMNRD
Cc: Kyle Tisdel; Ally Beasley; Morgan O'Grady; Sophia Graham
Subject: RE: OCC No. 24683 negotiations/discussions

Hi Miguel. If NMOGA and IPANM prefer to collapse the four meetings into one, we can do that. Please know Applicants remain open to good faith negotiations after meeting next week. Miguel, on Wednesday Christy sent out invites for the Oct. 16 meeting and the other three meetings for anyone to attend virtually through Teams.

Tannis

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From: Miguel Suazo <msuazo@bwenergylaw.com>
Sent: Friday, October 11, 2024 1:27 PM
To: Tannis Fox <fox@westernlaw.org>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Michael Feldewert <MFeldewert@hollandhart.com>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Cc: Kyle Tisdel <tisdel@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>; Sophia Graham <sgraham@bwenergylaw.com>
Subject: RE: OCC No. 24683 negotiations/discussions

Hi Tannis,

Thank you for your email. After conferring with IPANM, we would like to propose discussing both the financial assurance and inactive well matters during the scheduled meeting on October 16th. Unfortunately, we now have conflicts with the other dates currently on the schedule.

Additionally, neither IPANM nor NMOGA have finalized positions at this time, as we are still working to fully understand the details of your proposed changes and OCD's perspective on the amendments they are considering before filing.

I also wanted to note that I will need to fly to Denver on the afternoon of October 16th, so I will be attending remotely. Given the circumstances, it would be ideal if we could hold the meeting via Teams.

Thank you.

Miguel Suazo | Shareholder
Beatty & Wozniak, P.C.

505.946.2090 | Direct

Confidentiality: This Beatty & Wozniak, P.C. email, its attachments and data ("email") are intended to be Confidential and may contain Attorney-Client Communications or Work Product. If you are not the intended recipient or may have received this message in error, notify the sender immediately and permanently delete the email and all copies thereof from any drives or storage media and destroy any printouts. Any unauthorized use or distribution of any of the information in this email is **Strictly Prohibited**.

From: Tannis Fox <fox@westernlaw.org>
Sent: Tuesday, October 8, 2024 2:26 PM
To: Miguel Suazo <msuazo@bwenergylaw.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Michael Feldewert <MFeldewert@hollandhart.com>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Cc: Kyle Tisdel <tisdel@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>
Subject: OCC No. 24683 negotiations/discussions

CAUTION: EXTERNAL SOURCE

Hello all.

We are looking forward to our upcoming negotiations/discussions on Applicants' application for rulemaking.

- As a reminder, the negotiations are scheduled for:

Wed., 10/16, 10am-12pm MT: financial assurance
Tu., 10/22, 10am-12pm MT: inactive wells
Wed., 10/23, 1-3pm MT: financial assurance
Th., 10/24, 10am-12pm MT: inactive wells

Everyone should have already received a calendar invite from me for the four meetings to save the dates/times. Jesse/OCD will circulate an invite to attend virtually since we will be using their offices and virtual platform for the meetings. Thanks OCD!

- We've put together draft agendas for the initial meetings for financial assurance and inactive wells, which are set forth below. Please let us know if you have any additions or changes or a different approach how to structure the discussions:

    - **Initial financial assurance meeting 10/16**
        - **Introductions**
        - **Brief presentation from Applicants on scope and purpose of proposal**
        - **Discussion of concepts:**
            - **Increasing financial assurance for active wells**
                - Increasing single well bond for active wells to $150K
                - Increasing blanket bonds for active wells ($200k for 1-5 wells and $250K for >6 wells)
            - **Increasing financial assurance for operations at greater risk**
                - Stripper wells upon transfer
                - Inactive wells, wells in approved and expired TA status
            - **Authorizing increases to financial assurance based on CPI**

- **Compliance with additional requirements to release FA** [we may want to discuss these proposals in detail in second financial assurance meeting]
    - Methane waste rules
    - Proposed transfer provisions
- **Proposals/redlines from other parties**

- **Initial inactive wells meeting 10/22**
    - **Introductions**
    - **Presentation from Applicants on scope and purpose of proposal**
    - **Discussion of concepts:**
        - **Require a showing that well will be used for beneficial use in future prior to temporary abandonment (TA) approval**
            - Beneficial use is defined
            - Showing requires a plan for ultimate disposition of well and time frame
            - OCD may approve, approve with conditions, deny
            - Initial approval is up to 2 years, and can be renewed annually 3 more times
            - Prior to expiration of 5 years, operator can request to continue in TA status, but must do so through adjudicatory proceeding before OCC
                - A health and safety plan must be submitted
                - OCC can approve for additional 2 years
        - **An implementation schedule is established**
            - New provisions apply immediately to active wells
            - Inactive wells implementation schedule allows wells to be in approved TA status up to 7 years
            - Approved TA wells implementation schedule requires wells to stay in TA status for 5 year period, and then apply to OCC for 2 more years
            - Expired TA wells implementation schedule allows TA to continue up to 7 years
        - **Other proposals:**
            - Modify definition of approved TA and add definition for expired TA; shorten time to apply for TA status for inactive well to 30 days; deletes showing that well not be usable for beneficial use; and deletes "continuously" to modify "inactive"
        - **Proposals/redlines from other parties**

- While we listed proposals/redlines from other parties at the end of each meeting, we anticipate hearing and would like to hear proposals, language changes, etc. from other parties throughout the discussions.

- In that regard, if any parties have proposals or redlines they would like to circulate prior to the meetings, those would be helpful to the discussions.

- Can parties please identify who will attend the meetings on their behalves? In addition to Kyle, Ally, Morgan, and me, we will have in attendance virtually Adam Peltz of EDF, Peter Morgan of Center for Asset Retirement Accountability (formerly of Sierra Club), and Tom Alexander, a consultant (and, for those who participated in the methane waste rule hearing, Tom provided testimony in that rulemaking).

Please let us know if you have questions. We look forward to meeting and hope discussions are productive.

Tannis

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DEC. 10, 2024

Tannis Fox

From:	Tannis Fox
Sent:	Tuesday, December 10, 2024 1:48 PM
To:	Tremaine, Jesse, EMNRD; Trevino, Christy, EMNRD; Michael Feldewert; acloutier@hinklelawfirm.com; Jaclyn McLean; Miguel Suazo
Cc:	Kyle Tisdel; Morgan O'Grady
Subject:	No. OCC 24683

Hello all. Since we last met in October, we had understood that OCD would propose amendments to our rulemaking petition. Jesse had targeted November to get the parties OCD proposals, but OCD staff has been stretched thin, and we do not have their proposals at this date. For our part, petitioners would like to review OCD's proposals, discuss them with our experts, and discuss them with OCD and industry parties prior to filing testimony to see if we can reach common ground or at least narrow differences among the parties.

Toward that end and given the current timing, we propose to postpone the schedule the parties agreed to and the OCC approved by approximately two months in order to give the parties the opportunity to meet and discuss OCD's proposals in the new year. This would postpone the date for filing direct testimony and exhibits to around March 28, filing rebuttal testimony and exhibits to around May 9, and beginning the hearing around June 23.

We would like to hear your reaction to this approach and to be able to file a joint proposal with the OCC. We do not want to put the commission in the position of having to decide on a disputed hearing schedule; we think the parties should work this out. The OCC meets twice before our first filing deadline of January 31, 2025, on December 12 and January 16. December 12 may be a little too quick to jointly file for a postponement, but we would like to at least work out a proposal that everyone agrees to by the end of this week. We can meet by Zoom if you would like to discuss.

Thank you for your attention to this matter, and we look forward to hearing from you.
Tannis

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MAR. 14-20, 2025

Apps' Ex. 6

Tannis Fox

From: Tannis Fox
Sent: Thursday, March 20, 2025 11:12 AM
To: Tremaine, Jesse, EMNRD; Trevino, Christy, EMNRD; Michael Feldewert (MFeldewert@hollandhart.com); Adam Rankin; Paula M. Vance; Andrew Cloutier; Kyle Tisdel; Morgan O'Grady; Miguel Suazo; James Martin; James Parrot; Jennifer Bradfute; Matthias Sayer; Jordan Kessler; Matt Nykiel; atripp@hinklelawfirm.com
Subject: RE: [EXTERNAL] Revised Notice of Hearing for OCC No. 24683

Hello all. It's good to have a hearing date. I wanted to reiterate what I said during the status conference today regarding the interim dates between now and the hearing, and that is we are flexible as to dates for filing direct and rebuttal testimony, and welcome other parties' proposals in that regard.

Also, we support meeting again among the parties to discuss OCD's redline and are available during the dates in early April that Jesse has suggested, if other parties are also interested in meeting.

Thanks.
Tannis

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Western Environmental Law Center
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505.629.0732 | fox@westernlaw.org
www.westernlaw.org | *Defending the West*

From: Tannis Fox <fox@westernlaw.org>
Sent: Tuesday, March 18, 2025 10:58 AM
To: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Adam Rankin <AGRankin@hollandhart.com>; Paula M. Vance <PMVance@hollandhart.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Kyle Tisdel <tisdel@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>; Miguel Suazo <msuazo@bwenergylaw.com>; James Martin <jmartin@bwenergylaw.com>; James Parrot <JParrot@bwenergylaw.com>; Jennifer Bradfute <jennifer@bradfutelaw.com>; Matthias Sayer <matthias@bradfutelaw.com>; Jordan Kessler <Jordan_Kessler@eogresources.com>; Matt Nykiel <nykiel@westernlaw.org>; atripp@hinklelawfirm.com
Subject: RE: [EXTERNAL] Revised Notice of Hearing for OCC No. 24683

Hello all. Thank you, Jesse, for proposing dates for stakeholder meetings and a hearing schedule. The proposed dates work for Applicants. We believe the evidentiary hearing should conclude before the holiday season gets going, and therefore we think beginning the hearing mid-October is near the outside date of when the hearing should begin. We look forward to hearing from the other parties.

Thanks,
Tannis

Tannis Fox | Senior Attorney | *she/ella*
Western Environmental Law Center

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505.629.0732 | fox@westernlaw.org
www.westernlaw.org | *Defending the West*

From: Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>
Sent: Friday, March 14, 2025 12:38 PM
To: Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>; Tannis Fox <fox@westernlaw.org>; Michael Feldewert (MFeldewert@hollandhart.com) <MFeldewert@hollandhart.com>; Adam Rankin <AGRankin@hollandhart.com>; Paula M. Vance <PMVance@hollandhart.com>; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Kyle Tisdel <tisdel@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>; Miguel Suazo <msuazo@bwenergylaw.com>; James Martin <jmartin@bwenergylaw.com>; James Parrot <JParrot@bwenergylaw.com>; Jennifer Bradfute <jennifer@bradfutelaw.com>; Matthias Sayer <matthias@bradfutelaw.com>; Jordan Kessler <Jordan_Kessler@eogresources.com>; Matt Nykiel <nykiel@westernlaw.org>; atripp@hinklelawfirm.com
Subject: RE: [EXTERNAL] Revised Notice of Hearing for OCC No. 24683

Greetings,

Please find the attached draft third amended notice of hearing. We are circulating this for discussion and request the parties prepare to discuss the proposed dates at the status conference on March 20th. I understand that there are a lot of moving pieces and the session is wrapping up. Ideally, we can discuss at least the date range for a proposed hearing, as that is usually of greatest concern for the Commission.

Based on prior meetings, I expect the Commission to request a revised notice submission to follow the 3/20 meeting. Because the Commission scheduled the Goodnight/Empire contested case to resume in April, it's not clear whether they will want to schedule another status conference for this matter in April. Other matters are being scheduled for May. I believe that delaying scheduling decisions to the May meeting will compress the schedule – OCD would prefer that we set a date to submit a revised joint notice earlier in April.

We propose the following schedule, picking up after session wraps:

- Stakeholder meetings: 4/1, 2, 7, 8 or 9
    - OCC picks back up with Goodnight/Empire in the middle of April, so we have availability just before or just after.
- Revised petition submission ~ 4/25
- Direct Testimony ~6/13
- Rebuttal Testimony ~8/15
- Hrg 2+ weeks beginning 10/14

OCD would love to hear any feedback in advance of the status conference. If we can agree on reasonable hearing dates, I think it will be easier to work backwards and identify other deadlines that work for all parties.

Please reach out with any questions,

Jesse K. Tremaine
Legal Director, Oil Conservation Division
Office of General Counsel
New Mexico Energy, Minerals & Natural Resources Department

1220 South St. Francis Dr., Santa Fe, NM 87505
Cell: (505) 231-9312
E-mail: JesseK.Tremaine@emnrd.nm.gov

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From: Michael Feldewert <MFeldewert@hollandhart.com>
Sent: Wednesday, September 4, 2024 9:46 AM
To: fox@westernlaw.org; Andrew Cloutier <ACloutier@hinklelawfirm.com>; Miguel Suazo <msuazo@bwenergylaw.com>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Cc: Kyle Tisdel <tisdel@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>
Subject: [EXTERNAL] Revised Notice of Hearing for OCC No. 24683

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Tannis: Thanks for the edits, and they are acceptable to Oxy.

Michael Feldewert
Partner, Holland & Hart LLP
mfeldewert@hollandhart.com | **T:** 505-988-4421

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From: Tannis Fox <fox@westernlaw.org>
Sent: Friday, August 30, 2024 1:00 PM
To: Andrew Cloutier <ACloutier@hinklelawfirm.com>; Miguel Suazo <msuazo@bwenergylaw.com>; Michael Feldewert <MFeldewert@hollandhart.com>; Jaclyn McLean <JMcLean@hinklelawfirm.com>; Tremaine, Jesse, EMNRD <JesseK.Tremaine@emnrd.nm.gov>; Trevino, Christy, EMNRD <Christy.Trevino@emnrd.nm.gov>
Cc: Kyle Tisdel <tisdel@westernlaw.org>; Ally Beasley <beasley@westernlaw.org>; Morgan O'Grady <ogrady@westernlaw.org>
Subject: OCC No. 24683 - Notice of Hearing

External Email

Hello all. Thank you for meeting this week to discuss the Notice of Hearing. We thought it was productive. Attached is a revised notice based on our discussions and the notice of hearing from the PFAS rule making

edited by Commission counsel. The attached Second Amended Notice represents a redline/strikeout from the Amended Notice we filed.

- I've highlighted material we did not discuss, some of which is taken from the PFAS rule making notice from Dan.
- After thinking about it more, I thought we might build in another week of time between the filing of rebuttal and the hearing because of the workload during that period and, therefore, left the dates for filing direct (Jan. 31) and rebuttal (Mar. 7) the same to give us an extra week during that period.
- We slightly modified that public comment on the first day is at 1:00 and 4:00 (instead of 9:00 and 4:00) because I remembered that Felicia (if she is the hearing officer) prefers not to start the hearing on the first day with public comment, but likes to first get the hearing going with the administrative body and parties, and first take public comment after lunch.
- Minor point, but the various notices of hearing I've reviewed have differing emails and phone numbers for the Commission Clerk. I asked Sheila what she prefers and, based on that, am using her Sheila.apodaca@emnrd.nm.gov email and 505-669-8358 telephone number for public inquiries to her and occ.hearings@emnrd.nm.gov for filings. (This is how the PFAS notice handles that contact information.)

We hope this proposed notice is acceptable to all, and that we can tell the Commission all parties agree to it (or at least there's no objection). Would you please let us know by **COB next Thursday, September 5** if you can concur/not object because we would like to file an amended notice next Friday, September 6.

Thanks very much.

Have nice and hopefully long weekend.
Tannis

Tannis Fox | Senior Attorney | *she/ella*
Western Environmental Law Center
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EXHIBIT 7

OCD INACTIVE WELL SEARCH LIST (15+ Months inactive)
3-Jul-25

Well Subset	No. of wells	% of total inactive wells	No. of associated operators	%
Total well count (from Inactive Well search output – appears to represent wells other than Plugged & Released, Cancelled, and Never Drilled statuses)	**74,582**		**Not included in search**	
Total inactive wells (15+ months)	**3,765**	**100%**	**350**	**100%**
Total approved TA wells* on Inactive Well Search list	419	11%	89	25%
Total expired TA wells* on Inactive Well Search list	155	4%	67	19%
Total wells under ACOI** on Inactive Well Search list	99	3%	3	1%
Wells on Inactive Well Search list with unusual status (Drilled, New, or Plugged) - *excluded from total below*	13	< 0.5%	11	3%
Total inactive wells apparently out of compliance **** (Inactive wells without ACOI coverage or non-expired TA status)***	**3,234**	**86%**	**346**	**99%**

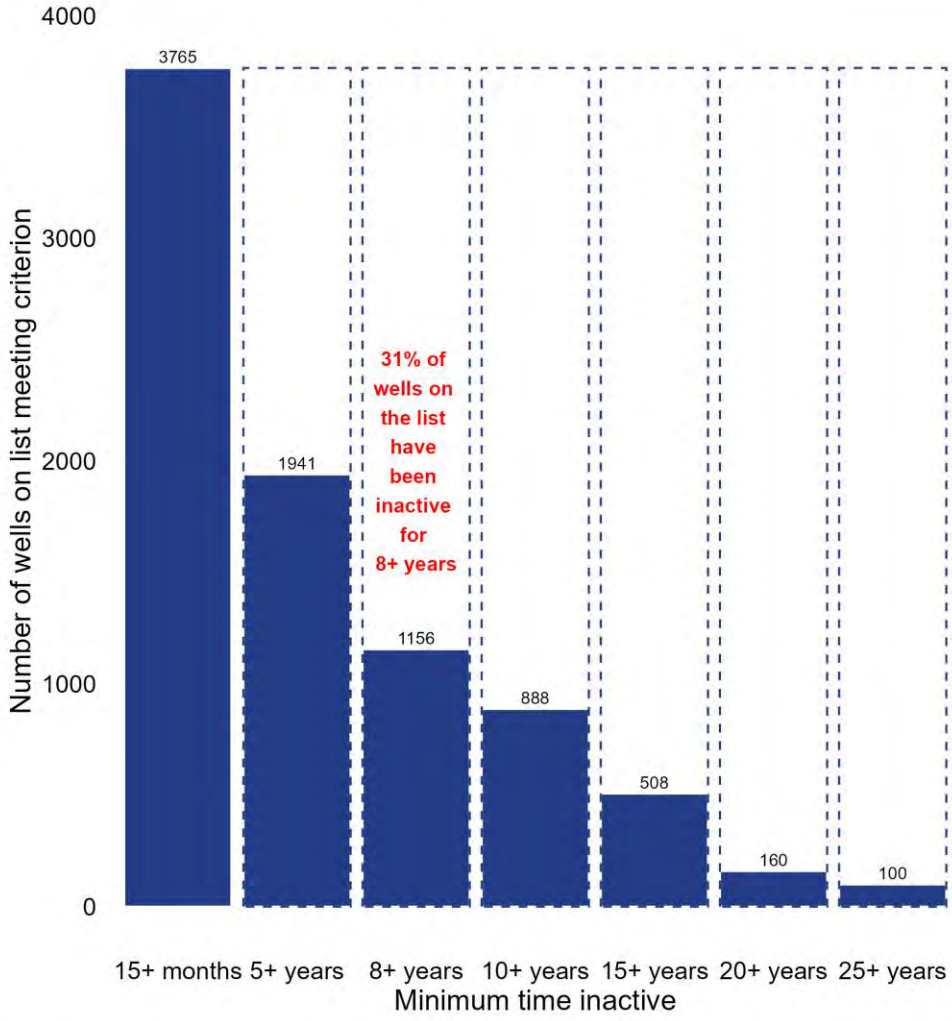
* The approved and expired TA status wells listed on OCD Inactive Well Search is only a subset of all wells labeled by OCD as having TA status, per OCD's Well History datafiles, and per a July 3rd search of OCD's Well Permitting Search for all TA wells.
** ACOI (Inactive Well Agreed Compliance Order) coverage was determined by the difference between wells included on 2 back-to-back queries of OCD's Inactive Well Search for wells 15+ months inactive— one set to include ACOI wells and one set to exclude them. Wells absent from the "Exclude ACOI" version of the list are presumed to have a compliance order in place.
*** Some wells with an ACOI are also listed in expired TA status, so this total is slightly less than the sum of the preceding rows.

Apps' Ex. 7

EXHIBIT 8

Number of inactive wells, by minimum time inactive

7/3/25 OCD Inactive Well List



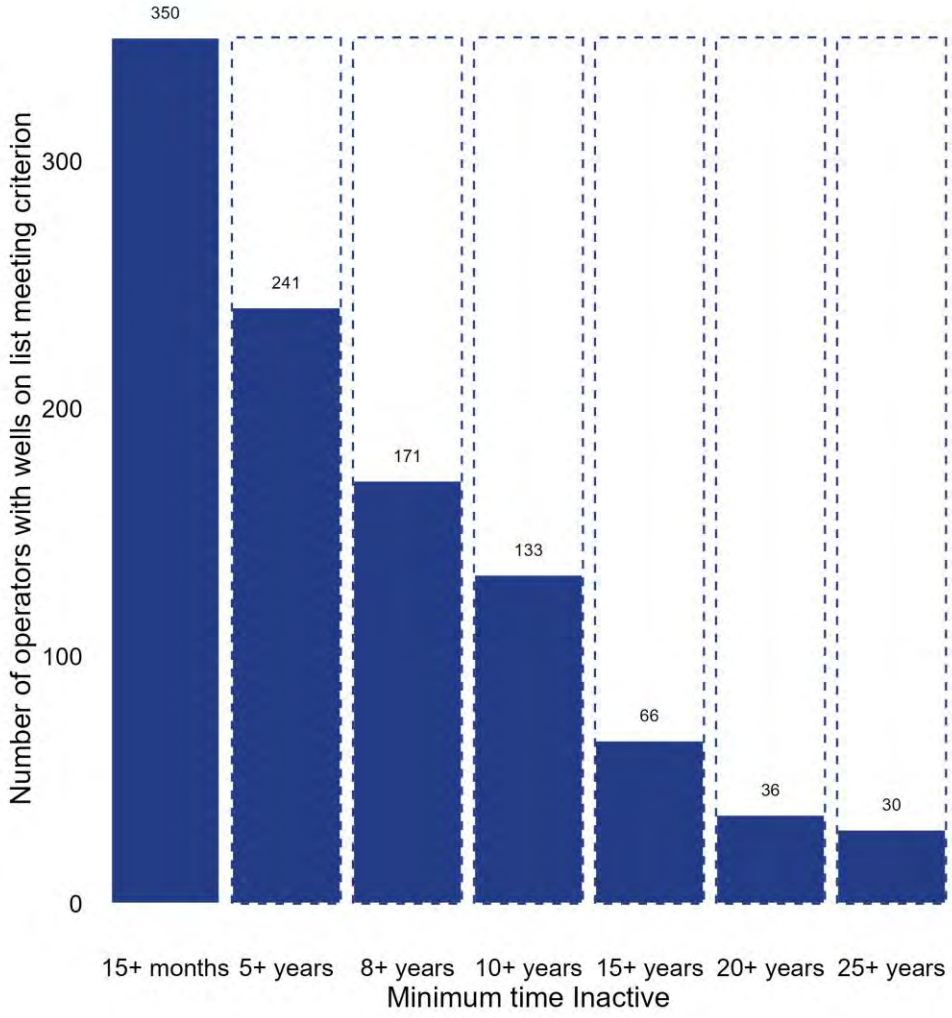
Data reflect wells included in search results from OCD Inactive Well Search tool as of July 3, 2025.
Time categories to the left are inclusive of wells in categories to their right.

Apps' Ex. 8

EXHIBIT 9

Number of operators with inactive wells, by minimum time inactive

7/3/25 OCD Inactive Well List



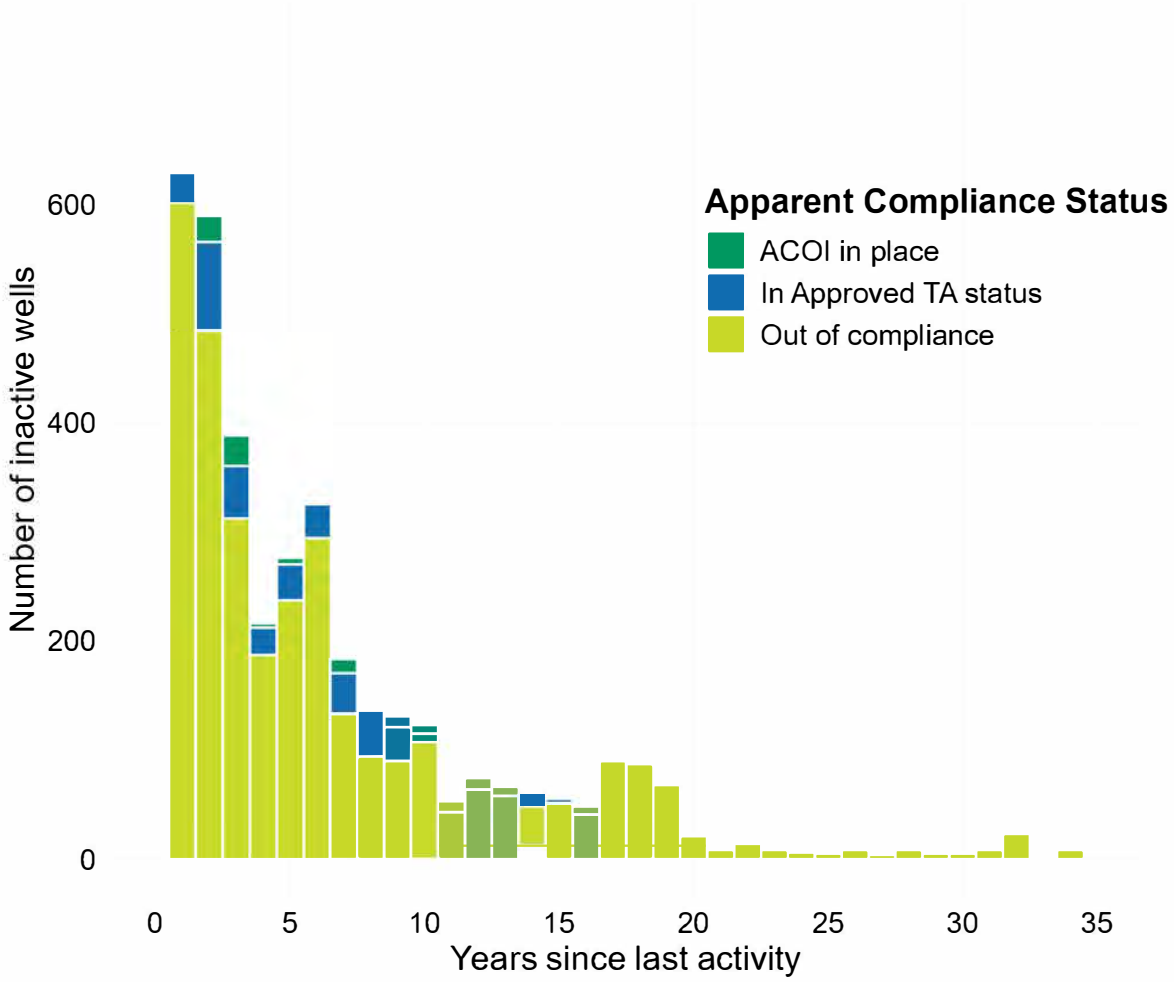
Data reflect wells included in search results from OCD Inactive Well Search tool as of July 3, 2025.
Time categories to the left are inclusive of wells in categories to their right.

Apps' Ex. 9

EXHIBIT 10

Inactive wells by length of time inactive

7/3/25 OCD Inactive Well List



Histogram data reflect wells included in search results from OCD Inactive Well Search tool as of July 3, 2025.

'Years since last activity' reflects full years since last reported production date, for wells inactive 15 or more months.

'ACOI in place' refers to the existence of an Agreed-To Compliance Order for the inactive well.

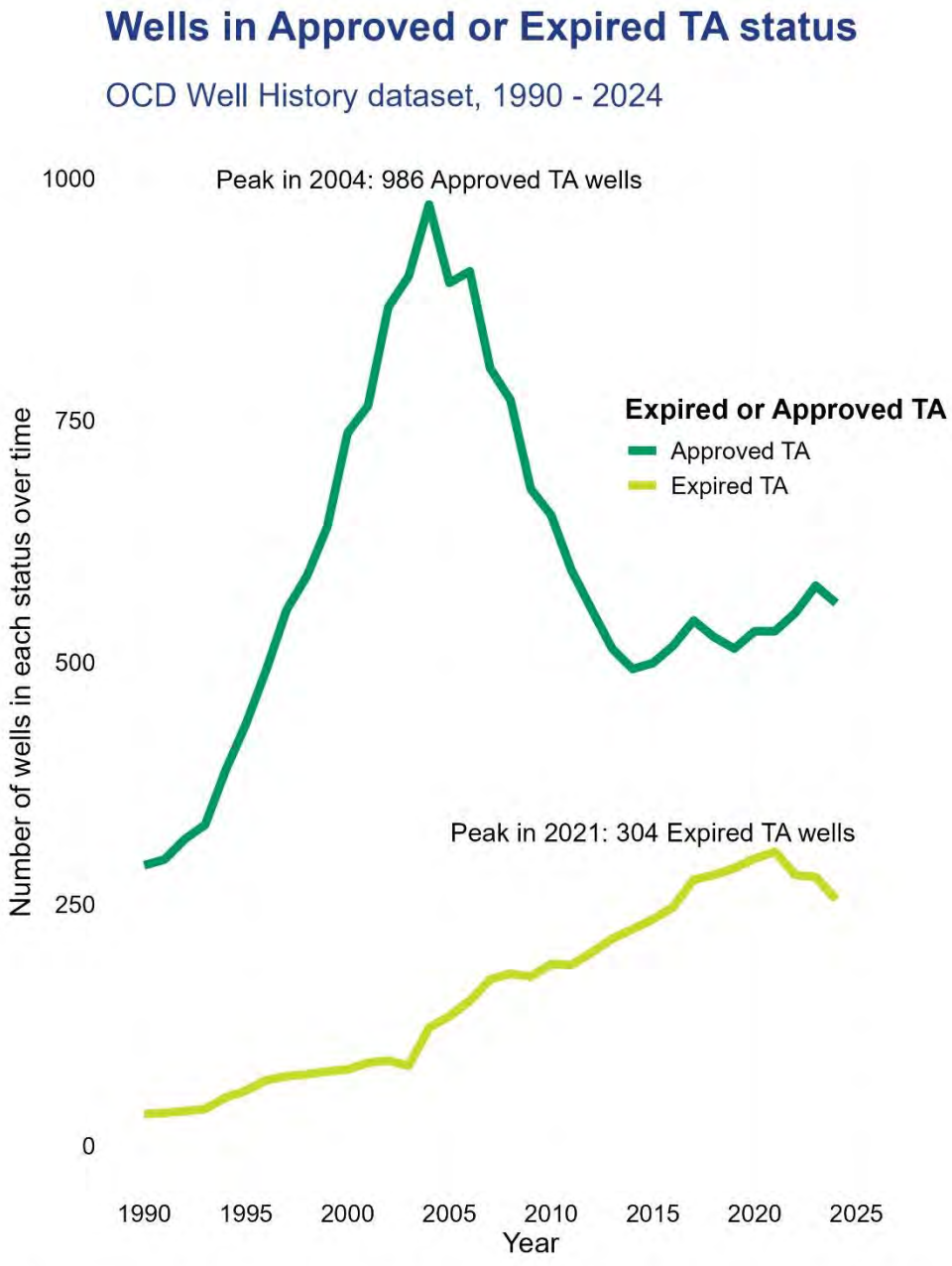
Wells with an ACOI were identified by presence in search results with or without 'Exclude Wells Under ACOI' option.

'Out of compliance' indicates wells for which no current TA status or ACOI were evident.

Expiration of TA status was determined by listed TA expiration date, relative to July 3, 2025.

Apps' Ex. 10

EXHIBIT 11



Wells reported in Approved or Expired TA status by OCD Well History dataset, current as of 7/11/25.

Apps' Ex. 11

EXHIBIT 12

Santa Fe Main Office
Phone: (505) 476-3441
General Information
Phone: (505) 629-6116

Online Phone Directory Visit:
https://www.emnrd.nm.gov/ocd/contact-us/

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO.	
5. Indicate Type of Lease STATE ☐ FEE ☐	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name
1. Type of Well: Oil Well ☐ Gas Well ☐ Other	8. Well Number
2. Name of Operator	9. OGRID Number
3. Address of Operator	10. Pool name or Wildcat
4. Well Location Unit Letter_____ : _____ feet from the _____ line and _____ feet from the _____ line Section Township Range NMPM County	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE_____ TITLE_____ DATE_____

Type or print name _____ E-mail address: _____ PHONE: _____

For State Use Only

APPROVED BY:_____ TITLE_____ DATE_____

Conditions of Approval (if any):

Apps' Ex. 12

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Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

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Revised July 18, 2013

WELL API NO. 30-015-20971

5. Indicate Type of Lease STATE ☐ FEE ☒

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: Saik

1. Type of Well: Oil Well ☐ Gas Well ☒ Other

8. Well Number: 001

2. Name of Operator: American Energy Resources LLC

9. OGRID Number: 372991

3. Address of Operator: P.O. Box 114 Hagerman, NM 88232

10. Pool name or Wildcat: Carlsbad Wolfcamp, East

4. Well Location
Unit Letter B : 990 feet from the N line and 1980 feet from the E line
Section 17 Township 22S Range 27E NMPM County Eddy

11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3122' GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Proposed TA Procedure:
1. Release Packer and POOH with 2-3/8 tubing and packer
2. Set CIBP at 9334', Pressure test. Dump bail 9sx Class H Cmt, tag
3. Circulate packer fluid into wellbore

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE _____ TITLE Representative DATE 3/18/2025

Type or print name Jonathan Samaniego E-mail address: energy.jrs@gmail.com PHONE: (575)499-7330

For State Use Only

APPROVED BY: _____ TITLE _____ DATE _____

Conditions of Approval (if any):

Apps' Ex. 12

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Phone: (505) 476-3441
General Information
Phone: (505) 629-6116

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https://www.emnrd.nm.gov/ocd/contact-us/

State of New Mexico
Energy, Minerals and Natural Resources

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1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
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WELL API NO. 30-025-05043	
5. Indicate Type of Lease STATE ☐ FEE ☒	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name: Wingerd
1. Type of Well: Oil Well ☒ Gas Well ☐ Other	8. Well Number 10
2. Name of Operator: Fasken Oil and Ranch, Ltd	9. OGRID Number 151416
3. Address of Operator: 6101 Holiday Hill Road, Midland, TX 79707	10. Pool name or Wildcat: Gladiola Devonian
4. Well Location: Unit Letter J : 2310 feet from the South line and 1650 feet from the East line; Section 24 Township 12S Range 37E NMPM County Lea	
11. Elevation (*Show whether DR, RKB, RT, GR, etc.*) 3886 KB	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☒	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: ☐		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Fasken Oil and Ranch, Ltd Temporarily Abandoned as wellbore was in bad shape.

See attached drilling report procedure.

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Viola Vasquez TITLE Regulatory Analyst DATE 03-11-2025

Type or print name Viola Vasquez E-mail address: violav@forl.com PHONE: 432-687-1777

For State Use Only

APPROVED BY: TITLE DATE

Conditions of Approval (if any):

Apps' Ex. 12

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Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-37277

5. Indicate Type of Lease STATE ☑ FEE ☐

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: JALMAT FIELD YATES SAND UNIT

1. Type of Well: Oil Well ☑ Gas Well ☐ Other

8. Well Number 216

2. Name of Operator: Breitburn Operating LP

9. OGRID Number: 370080

3. Address of Operator: 1000 Main Street Ste 2900 Houston, TX 77002

10. Pool name or Wildcat

4. Well Location
Unit Letter E : 2540 feet from the North line and 140 feet from the West line
Section 24 Township 22S Range 35E NMPM County

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3581

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

BOLP is requesting the approval of the attached TA plan.

Notify OCD 24 hours prior to running MIT so test may be witnessed

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Nicole Lee TITLE Regulatory Lead DATE 5/16/2025

Type or print name Nicole Lee E-mail address: nicole.lee@mavresources.com PHONE: 713-437-8097

For State Use Only

APPROVED BY: [signature] TITLE Staff Manager DATE 6/26/25

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

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Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
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Santa Fe, NM 87505

Form C-103
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WELL API NO. 30-015-32564

5. Indicate Type of Lease STATE ☒ FEE ☐

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
COYOTE STATE

1. Type of Well: Oil Well ☒ Gas Well ☐ Other

8. Well Number 6

2. Name of Operator
Extex Operating Company

9. OGRID Number 330423

3. Address of Operator
5065 Westheimer Road, Suite 625

10. Pool name or Wildcat
MALJAMAR; GB-SA

4. Well Location
Unit Letter H : 2310 feet from the NORTH line and 990 feet from the EAST line
Section 36 Township 17S Range 31E NMPM County EDDY

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*
3835' GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER: REQUEST TO EXTEND TA WITH MIT TEST	☒			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Extex requests the current TA status be extended while commodities recover in the immediate area.

Last TA Status Approved until 1/29/2029

well must be on production or P&A by 1/29/29

Spud Date: 12/4/24 Rig Release Date: 12/4/24

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Bryce Mueller TITLE Production Engineer DATE 1/24/25

Type or print name Bryce Mueller E-mail address: bmueller@extex.net PHONE: 817-944-7406

For State Use Only

APPROVED BY: TITLE Staff Manager DATE 1/29/29

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-045-22975
	5. Indicate Type of Lease STATE ☐ FEE ☐
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Atlantic B
1. Type of Well: Oil Well ☐ Gas Well ☑ Other	8. Well Number 8A
2. Name of Operator SIMCOE LLC	9. OGRID Number
3. Address of Operator 1199 Main Ave, Suite 101, Durango, CO 81301	10. Pool name or Wildcat Blanco M.V.
4. Well Location Unit Letter C : 1030 feet from the North line and 1150 feet from the West line Section 3 Township 30N Range 10W NMPM San Juan County	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 6,296', GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:			☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Proposed start date: 4/29/2025

1 Run casing scrapper
2 Set CIBP @ 4,439'
3 Test casing to 560 psi for 30 min
4 RDMO

The Atlantic B LS 008A does not penetrate any Federal or Indian lease. As such, the BLM cannot approve or deny any TA request for the well.

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Christy Kost TITLE Regulatory Analyst DATE 4/28/2025

Type or print name Christy Kost E-mail address: christy.kost@ikavenergy.com PHONE: 970-822-8931

For State Use Only

APPROVED BY: TITLE DATE

Conditions of Approval (if any):

Apps' Ex. 12

Santa Fe Main Office
Phone: (505) 476-3441
General Information
Phone: (505) 629-6116

Online Phone Directory Visit:
https://www.emnrd.nm.gov/ocd/contact-us

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-015-33581	
5. Indicate Type of Lease STATE ☒ FEE ☐	
6. State Oil & Gas Lease No. 308899	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☒ Gas Well ☐ Other	7. Lease Name or Unit Agreement Name RED LAKE 36 C STATE
	8. Well Number 001
2. Name of Operator APACHE CORPORATION	9. OGRID Number 873
3. Address of Operator 303 VETERANS AIRPARK LANE, SUITE 1000, MIDLAND, TX 79705	10. Pool name or Wildcat RED LAKE; GLORIETA-YESO, NORTHEAST (96836)
4. Well Location Unit Letter C : 990 feet from the N line and 2310 feet from the W line Section 36 Township 17S Range 27E NMPM County EDDY	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3570 GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: TA RENEWAL ☒		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

APACHE CORPORATION REQUESTS AN EXTENSION OF THE STATUS OF TEMPORARY ABANDONMENT FOR THIS WELL. APACHE PLANS TO PERFORM AN MIT ON THIS WELL IN FEBRUARY. PROPER NOTIFICATION WILL BE SENT PRIOR TO PERFORMING THE OFFICIAL TEST.

THE WELL WE SOON BE TAKEN OVER BY HILCORP WHO PLANS TO EVALUATE THE WELLBORE AND MAKE A DECISION TO PERMANENTLY PLUG OR RETURN TO PRODUCTION. CURRENT WBD ATTACHED.

Spud Date: 10/21/2004 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE alicia fulton TITLE Reg Tech DATE 2/18/2025

Type or print name Alicia Fulton E-mail address: alicia.fulton@apachecorp.com PHONE: 432-818-1000

For State Use Only

APPROVED BY: TITLE DATE

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-04889
	5. Indicate Type of Lease STATE ☒ FEE ☐
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☐ Gas Well ☒ Other	7. Lease Name or Unit Agreement Name Arnott Ramsay NCT D
	8. Well Number 8
2. Name of Operator Empire Petroleum Corporation – New Mexico	9. OGRID Number 330679
3. Address of Operator 2200 S. Utica Place Suite 150, Tulsa, Oklahoma 74114	10. Pool name or Wildcat Eunice; Seven Rivers-Queen, South; 33820
4. Well Location Unit Letter N : 660 feet from the South line and 1980 feet from the West line Section 33 Township 21S Range 36E NMPM County Lea	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3574' GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

1. MIRU WOR.
2. Unseat pump and POOH with rods.
3. Scan tubing OOH.
4. RIH bit and scraper to 3710'.
5. RIH with CIBP and set at 3696'.
6. Dump 4 sks of class C cement on top of CIBP.
7. RIH with CIBP and set at 3328'.
8. Dump 4 sks of class C cement on top of CIBP.
9. Circulate packer fluid.
10. Perform MIT and submit to NMOCD.
11. RDMO WOR.
12. Notify NMOCD.
13. TA well.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Nathan Sandel TITLE Production Engineer DATE 10/18/2023

Type or print name Nathan Sandel E-mail address: nsandel@empirepetrocorp.com PHONE: 918-404-4202

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 1/1/24
Conditions of Approv

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-40063	
5. Indicate Type of Lease STATE [X] FEE [ ]	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name NEW MEXICO R NCT-4
1. Type of Well: Oil Well [X] Gas Well [ ] Other	8. Well Number 006
2. Name of Operator MORNINGSTAR OPERATING LLC	9. OGRID Number 330132
3. Address of Operator 400 W 7TH ST, FORT WORTH, TX 76102	10. Pool name or Wildcat
4. Well Location Unit Letter D : 375 feet from the N line and 470 feet from the W line Section 07 Township 18S Range 35E NMPM County LEA	
11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3982 GL	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	[ ]	PLUG AND ABANDON	[ ]	REMEDIAL WORK	[ ]	ALTERING CASING	[ ]
TEMPORARILY ABANDON	[X]	CHANGE PLANS	[ ]	COMMENCE DRILLING OPNS.	[ ]	P AND A	[ ]
PULL OR ALTER CASING	[ ]	MULTIPLE COMPL	[ ]	CASING/CEMENT JOB	[ ]		
DOWNHOLE COMMINGLE	[ ]						
CLOSED-LOOP SYSTEM	[ ]						
OTHER:	[ ]			OTHER:	[ ]		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

MorningStar requests approval to TA:

1. MIRU
2. POOH w/ rods & pump. POOH w/ production tubing.
3. RIH w/ bit to 5,500'. POOH.
4. Set 5-1/2" CIBP at 5,500'. Dump bail 35' of cmt on top.
5. Pressure test plug & casing to 550 psi.
6. Notify NMOCD of intent to run MIT and proceed as directed.
7. RDMO.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Connie Blaylock TITLE Regulatory Analyst DATE 02/09/2024

Type or print name Connie Blaylock E-mail address: cblaylock@txoenergy.com PHONE: 817-334-7882

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 2/20/24

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-35344

5. Indicate Type of Lease STATE ☐ FEE ☑

6. State Oil & Gas Lease No. 312268

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: Cooper G

1. Type of Well: Oil Well ☑ Gas Well ☐ Other

8. Well Number 001

2. Name of Operator: Petroleum Exploration Company LTD, Limited P

9. OGRID Number 013300

3. Address of Operator: P O Box 548 BreckenRidge, Texas 76424

10. Pool name or Wildcat: Jalmat (Yates)

4. Well Location
Unit Letter N : 660 feet from the South line and 1980 feet from the West line
Section 11 Township 24S Range 36E NMPM County Lea

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3354.0 GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:			☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Set CIBP @ appx. 2987-3037' to cover open perfs at 3087-3795', Drop 2 sacks 35' cement to cover CIBP, Fill backside with 2% KCL, Rig up Kill truck and run MIT to 500 PSI, Chart and record.

Would like to start work on 5-10-24

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Kevin Breckel TITLE Production Foreman DATE 5-6-24

Type or print name Kevin Breckel E-mail address: kbreckel@petexltd.com PHONE: 2545590881

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 5/7/24

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO.
30-025-31610

5. Indicate Type of Lease
STATE ☐ FEE ☒

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
Arrowhead Grayburg Unit

1. Type of Well: Oil Well ☒ Gas Well ☐ Other

8. Well Number
234

2. Name of Operator
Empire Petroleum Corporation – New Mexico

9. OGRID Number 330679

3. Address of Operator
2200 S. Utica Place Suite 150, Tulsa, Oklahoma 74114

10. Pool name or Wildcat
Arrowhead; Grayburg

4. Well Location
Unit Letter L : 1880 feet from the South line and 750 feet from the West line
Section 18 Township 22S Range 37E NMPM County Lea

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*
3434' GE

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

1. MIRU WOR
2. Unseat the ESP and scan tubing OOH.
3. RIH with bit and scraper to 3600'. POOH.
4. RIH with CIBP and set at 3558'.
5. Dump 4 sks of cement on top.
6. Pressure test.
7. Remediate casing integrity issues if any.
8. Circulate packer fluid.
9. Notify NMOCD of MIT.
10. Perform MIT and submit paperwork.
11. RDMO WOR.
12. TA well.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Nathan Sandel TITLE Production Engineer DATE 02/13/2024

Type or print name Nathan Sandel E-mail address: nsandel@empirepetrocorp.com PHONE: 918-404-4202

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 2/14/24

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO.
30-025-10355

5. Indicate Type of Lease
STATE ☒ FEE ☐

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

1. Type of Well: Oil Well ☒ Gas Well ☐ Other

7. Lease Name or Unit Agreement Name
Arrowhead Grayburg Unit

8. Well Number
231

2. Name of Operator
Empire Petroleum Corporation – New Mexico

9. OGRID Number 330679

3. Address of Operator
2200 S. Utica Place Suite 150, Tulsa, Oklahoma 74114

10. Pool name or Wildcat
Arrowhead; Grayburg

4. Well Location
Unit Letter I : 1980 feet from the South line and 660 feet from the East line
Section 18 Township 22S Range 37E NMPM County Lea

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

1. MIRU WOR
2. Release TAC and scan tubing OOH.
3. RIH with bit and scraper to 3400'. POOH.
4. RIH with CIBP and set at 3380'.
5. Dump 4 sks of cement on top.
6. Pressure test.
7. Remediate casing integrity issues if any.
8. Circulate packer fluid.
9. Notify NMOCD of MIT.
10. Perform MIT and submit paperwork.
11. RDMO WOR.
12. TA well.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Nathan Sandel TITLE Production Engineer DATE 02/12/2024

Type or print name Nathan Sandel E-mail address: nsandel@empirepetrocorp.com PHONE: 918-404-4202

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 2/14/24

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-015-35222
	5. Indicate Type of Lease STATE ☑ FEE ☐
	6. State Oil & Gas Lease No. 308898
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Red Lake 36 A STATE
1. Type of Well: Oil Well ☑ Gas Well ☐ Other	8. Well Number 4
2. Name of Operator Apache Corporation	9. OGRID Number 873
3. Address of Operator 303 Veterans Airpark Lane, Suite 1000 Midland, TX 79705	10. Pool name or Wildcat RED LAKE GLORIETA-YESO NE (96836)
4. Well Location Unit Letter A : 330 feet from the N line and 465 feet from the E line Section 36 Township 17S Range 27E NMPM County EDDY	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3568

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

APACHE REQUEST TO TA THE CURRENT WELLBORE -CORRECTED PROCEDURES

Disconnect, isolate, lock-out surface mechanical and electrical equipment.
POOH all equipment. Run Ring Gauge
Set CIBP @ 3220' - test plug 500psi/30min
Set CIBP @ 3100' DB 35' cmt - WOC & tag - test plug 500psi/30min
Set CIBP @ 1,992 ft.
Dump bail 35 ft of cement on top of CIBP.
Tag Cement – notify NMOCD ready to conduct MIT.
Circulate pkr fluid.
24 hr prior notification to NMOCD

TA status may be granted after a successful MIT test is performed. Contact the OCD to schedule the test so it may be witnessed.

Conduct MIT, increase pressure within prod csg up to 500 psig, and hold for 30min. Pressure must stablize for last 15 minutes

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE alicia fulton TITLE Reg Analyst DATE 4/22/2024

Type or print name Alicia Fulton E-mail address: alicia.fulton@apachecorp.com PHONE: (432) 818-1088

For State Use Only

APPROVED BY: TITLE Staff Manager DATE 4/23/24
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised August 1, 2011

WELL API NO. 30-025-27469	
5. Indicate Type of Lease STATE FEE X	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well Gas Well X Other	7. Lease Name or Unit Agreement Name NORTH ROCK LAKE
	8. Well Number 001
2. Name of Operator EARTHSTONE OPERATING, LLC	9. OGRID Number 372137
3. Address of Operator 1400 WOODLOCH FOREST DR., SUITE 300, THE WOODLANDS, TX 77380	10. Pool name or Wildcat UNDES. MORROW
4. Well Location Unit Letter G : 1980 feet from the NORTH line and 1980 feet from the EAST line Section 16 Township 22S Range 35E NMPM LEA County	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3,526' – GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON X	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER: ☐		OTHER: WELL TEMPORARILY ABANDONED 09/25/2022	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

EARTHSTONE OPERATING, LLC RESPECTFULLY REQUEST TO TEMPORARILY ABANDON THE NORTH ROCK LAKE #001 IN ORDER TO EVALUATE THE FUTURE ECONOMIC POTENTIAL OF SAID WELLBORE

PROCEDURE DESCRIPTION:

1) POOH W/ 2-3/8" TBG. X PKR. @ 12,581'
2) SET 7" CIBP @ 12,654'; DUMP BAIL 35' CLASS "H" CMT. @ 12,654'-12,619'
3) CIRC. WELL W/ PKR. FLUID X PRES. TEST 7" CSG. TO 750# X HOLD
4) MIT WILL BE CONDUCTED UPON COMPLETION OF T/A; OCD WILL BE NOTIFIED PRIOR TO MIT

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE [signature] TITLE: AGENT DATE: 04/05/2023

Type or print name: DAVID A. EYLER E-mail address: DEYLER@MILAGRO-RES.COM PHONE: 432.687.3033

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 4/12/23

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-07148
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name V V Wallace
1. Type of Well: Oil Well ☒ Gas Well ☐ Other	8. Well Number 3
2. Name of Operator: Special Energy Corp	9. OGRID Number 138008
3. Address of Operator P.O. BOX Drawer 369, Stillwater, OK 74076	10. Pool name or Wildcat Gladiola; Devonian
4. Well Location Unit Letter G : 1980 feet from the North line and 1988 feet from the East line Section 06 Township 12S Range 38E NMPM County Lea	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3876 GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Nitro Oil & Gas is requesting approval to extend the temporary abandonment status of the V V Wallace #003.

We will perform a mechanical integrity test to meet the requirements to TA.

After approved TA expiration, NOG will plug well in accordance with NMOCD standards.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Bob Koricanek TITLE Manager, Nitro Oil & Gas LLC DATE 04/17/2023

Type or print name Bob Koricanek E-mail address: operations@nitro-og.com PHONE: 979-587-4837

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 4/18/23
Conditions of Appro

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
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1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-045-34144	
5. Indicate Type of Lease STATE ☐ FEE ☐	
6. State Oil & Gas Lease No. E-3707-5	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name NEBU
1. Type of Well: Oil Well ☐ Gas Well ☑ Other	8. Well Number 346
2. Name of Operator SIMCOE LLC	9. OGRID Number 6137
3. Address of Operator 1199 Main Ave, Durango, CO 81301	10. Pool name or Wildcat Basin Dakota
4. Well Location Unit Letter P : 1240 feet from the South line and 1205 feet from the East line	
Section 36 Township 31N Range 8W NMPM San Juan County	
11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 6414' GR	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

MIRU service unit. Pull rodstring/pump/tubing if present in well. RIH cast iron bridge plug and set at 7900'. Top off casing with 2% KCl w/ biocide and corrosion inhibitor. Pressure test casing to 500 psi for 30 min. Pressure shall not decrease more than 50 psi over the 30 min period. Open casing valves to check for flow or pressure change. Test shall be recorded using a chart recorder with a maximum two hour clock and 1000 pound spring, calibrated within six months prior to MIT of casing. Submit chart, C-103, and wellbore diagram showing well details and plug set depth. Air gap and blind flange production flow lines. After a period not to exceed 5 years after the temporary abandoment has been completed, a workover rig will remove the cast iron bridge plug and monitor pressure buildup of the well for a two week period to determine if the well will return to a production status. If the decision is made to not produce the well, a request for plugging and abandonment will be submitted. If the decision is made to produce the well, all necessary flow and production lines will be reinstalled for a flow ready status up to and including any removed flowmeters and well ties. Surface facilitlies will be placed for production puroposes.

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Christy Kost TITLE Regulatory Analyst DATE 10/30/2023

Type or print name Christy Kost E-mail address: christy.kost@ikavenergy.com PHONE: 970-822-8931

For State Use Only

APPROVED BY: Monica Kuehling TITLE Deputy Oil and Gs Inspector DATE 11/3/2023

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-50227
	5. Indicate Type of Lease STATE ☒ FEE ☐
	6. State Oil & Gas Lease No. VB-2968-0000
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☒ Gas Well ☐ Other	7. Lease Name or Unit Agreement Name TEAGUE 16 STATE
	8. Well Number 002
2. Name of Operator SCO PERMIAN, LLC	9. OGRID Number 330782
3. Address of Operator 5728 NW 132ND ST., OKLAHOMA CITY, OK 73142	10. Pool name or Wildcat LANGLIE MATTIX; 7 RVRS-Q-
4. Well Location Unit Letter: K 2310 feet from the SOUTH line and 2310 feet from the WEST line Section 16 Township 23 S Range 37 E NMPM LEA County	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3305' GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☒	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: ☐		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

NOTE change to procedure

Will isolate San Andres by setting CIBP @ 4075' and topping with 25 sx cement.
See attached diagram.

5 sx

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE BWood TITLE CONSULTANT DATE 4-14-23

Type or print name BRIAN WOOD E-mail address: brian@permitswest.com PHONE: 505 466-8120

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 5/3/23
Conditions of Approval

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. **30-025-11099**
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.) 1. Type of Well: Oil Well ☒ Gas Well ☐ Other	7. Lease Name or Unit Agreement Name **Langlie Mattix**
	8. Well Number **#3**
2. Name of Operator **Walsh & Watts Inc**	9. OGRID Number **24558**
3. Address of Operator **155 Walsh Drive Aledo, TX 76008**	10. Pool name or Wildcat **Langlie Mattix; 7 Rvrs-Qn-GB**
4. Well Location Unit Letter **M** : **660** feet from the **S** line and **660** feet from the **W** line Section **14** Township **24S** Range **37E** NMPM County **Lea**	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:			☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Filing a C-103 to request TA status for this well.
CIBP to-be set over the perfs, SWD needs and future use.

TA status may be granted after a successful MIT test is performed. Contact the OCD to schedule the test so it may be witnessed.

Set 4 1/2" CIBP @ 3311'. Spot 25 sx cmt @ 3311-2961'.

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Alexandra Fleming TITLE Regulatory Tech DATE 12/07/2023

Type or print name Alexandra Fleming E-mail address: afleming@walshwatts.com PHONE: 469-428-3381

For State Use Only

APPROVED BY: TITLE Staff Manager DATE 12/8/23
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-015-39401

5. Indicate Type of Lease STATE ☑ FEE ☐

6. State Oil & Gas Lease No. B0-9603-0025

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: EMPIRE ABO UNIT [309164]

1. Type of Well: Oil Well ☑ Gas Well ☐ Other

8. Well Number 417

2. Name of Operator: Apache Corporation

9. OGRID Number 873

3. Address of Operator: 303 Veterans Airpark Lane, Suite 1000 Midland, TX 79705

10. Pool name or Wildcat: Empire; Abo (22040)

4. Well Location
Unit Letter P : 1110 feet from the FSL line and 630 feet from the FEL line
Section 36 Township 17S Range 27E NMPM County EDDY

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3671 GL

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☐	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER: ta extension	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Apache is requesting a 1-year TA extension on the above mentioned well. Current TA expires 3/6/2024.

The request for the extension We are evaluating the geology for additional production potential in zones uphole.

procedures
contact OCD 24 hours prior to running MIT

Attached current WBD.

TA status may be granted after a successful MIT test is performed. Contact the OCD to schedule the test so it may be witnessed.

Spud Date: 1/19/2012 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE alicia fulton TITLE Sr. Reg Analyst DATE 11/16/2023

Type or print name Alicia Fulton E-mail address: alicia.fulton@apachecorp.com PHONE: (432) 818-1088

For State Use Only

APPROVED BY: [signature] TITLE Staff Manager DATE 12/1/23
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-015-49780
5. Indicate Type of Lease STATE ☒ FEE ☐
6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: Anchorage State
1. Type of Well: Oil Well ☒ Gas Well ☐ Other
8. Well Number 1
2. Name of Operator: Mack Energy Corporation
9. OGRID Number 013837
3. Address of Operator: P.O. Box 960 Artesia, NM 88211-0960
10. Pool name or Wildcat: WC 16S27W32; San Andres
4. Well Location
Unit Letter D : 180 feet from the North line and 330 feet from the West line
Section 32 Township 16S Range 27E NMPM County Eddy
11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3436'

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Mack Energy Coporation is requesting approval to T&A the Anchorage State 1.
The T&A plan for the Anchorage 1 is as follows:
Set plug #1 from 2664' - 2564' with 35 sx Class C
Set plug #2 from1400' - 300' with 420 sx Class H WOC & Tag
Will pressure test to 500# for 30 min after cmt has set up.

TA status may be granted after a successful MIT test is performed. Contact the OCD to schedule the test so it may be witnessed.

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Delilah Flores TITLE Regulatory Technician I DATE 12/5/2022

Type or print name Delilah Flores E-mail address: delilah@mec.com PHONE: 575-748-1288

For State Use Only

APPROVED BY: TITLE Staff Manager DATE
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-015-21394
	5. Indicate Type of Lease STATE ☑ FEE ☐
	6. State Oil & Gas Lease No. BO-2071-0034
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Empire Abo Unit (309164)
1. Type of Well: Oil Well ☑ Gas Well ☐ Other	8. Well Number 331
2. Name of Operator Apache Corporation	9. OGRID Number 873
3. Address of Operator 303 Veterans Airpark Lane, Suite 1000 Midland, TX 79705	10. Pool name or Wildcat Empire; Abo (22040)
4. Well Location Unit Letter E : 2576 feet from the NORTH line and 1250 feet from the West line Section 34 Township 17S Range 28E NMPM County Eddy	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:			☐

Notify OCD 24 hrs. prior to any work done

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Apache would like to perform the following work.

TA WELLBORE

PROCEDURES AND CURRENT AND PROPOSED WBD ATTACHED

SEE CHANGES TO PROCEDURE

Spud Date: 11/22/1974 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE alicia fulton TITLE Regulatory Analyst DATE 3/31/2022

Type or print name Alicia Fulton E-mail address: alicia.fulton@apachecorp.com PHONE: (432) 818-1088

For State Use Only

APPROVED BY: [redacted] TITLE STAFF MANAGER DATE 4/1/2022

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-25-31131	
5. Indicate Type of Lease STATE [X] FEE [ ]	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name: VACUUM GLORIETA WEST UNIT
1. Type of Well: Oil Well [X] Gas Well [ ] Other	8. Well Number 115H
2. Name of Operator: MORNINGSTAR OPERATING LLC	9. OGRID Number 330132
3. Address of Operator: 400 W 7TH ST, FORT WORTH, TX 76102	10. Pool name or Wildcat
4. Well Location: Unit Letter A : 604 feet from the N line and 856 feet from the E line; Section 01 Township 18S Range 34E NMPM County LEA	
11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3986' GL	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	[ ]	PLUG AND ABANDON	[ ]	REMEDIAL WORK	[ ]	ALTERING CASING	[ ]
TEMPORARILY ABANDON	[X]	CHANGE PLANS	[ ]	COMMENCE DRILLING OPNS.	[ ]	P AND A	[ ]
PULL OR ALTER CASING	[ ]	MULTIPLE COMPL	[ ]	CASING/CEMENT JOB	[ ]		
DOWNHOLE COMMINGLE	[ ]						
CLOSED-LOOP SYSTEM	[ ]						
OTHER:	[ ]			OTHER:	[ ]		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

1) MIRU pulling unit and spool truck.
2) POOH w/tubing and ESP.
3) RIH w/bit and scraper to 5810'. POOH.
4) MIRU wireline. Set CIBP @ 5800. Dump bail 35' cement on top.
5) Pressure test plug and casing.
6) Circulate hole w/pkr fluid.
7) Notify NMOCD of intent to run MIT and proceed as directed.
8) RDMO.

Current and Proposed WBDs attached.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: 3/28/1991 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Connie Blaylock TITLE Regulatory Analyst DATE 10/25/2022

Type or print name Connie Blaylock E-mail address: cblaylock@mspartners.com PHONE: 817-334-7882

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 10/27/22
Conditions of Approv

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-025-27493
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name BYARS
1. Type of Well: Oil Well ☒ Gas Well ☐ Other	8. Well Number 1
2. Name of Operator: Special Energy Corp	9. OGRID Number 138008
3. Address of Operator P.O. BOX Drawer 369, Stillwater, OK 74076	10. Pool name or Wildcat Gladiola; Devonian (27740)
4. Well Location Unit Letter A : 660 feet from the North line and 660 feet from the East line Section 8 Township 12S Range 38E NMPM County Lea	
	11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3862'GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Nitro Oil & Gas is requesting approval to extend the temporary abandonment status of the Byars #1.

We will perform a mechanical integrity test to meet the requirements to TA.

After approved TA expiration, NOG will plug well in accordance with NMOCD standards.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Bob Koricanek TITLE Manager, Nitro Oil & Gas LLC DATE 11/9/22

Type or print name Bob Koricanek E-mail address: operations@nitro-og.com PHONE: 979-587-4837

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 11/23/22
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

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1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

	WELL API NO. 30-045-07228
	5. Indicate Type of Lease STATE [X] FEE [ ]
	6. State Oil & Gas Lease No. I149IND8471 Navajo Minerals
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Gallegos Canyon Unit
1. Type of Well: Oil Well [ ] Gas Well [x] Other	8. Well Number 176
2. Name of Operator SIMCOE LLC	9. OGRID Number 329736
3. Address of Operator 1199 Main Avenue, Ste 101, Durango, CO 81301	10. Pool name or Wildcat Basin Dakota(Prorated Gas); Basin Mancos
4. Well Location Unit Letter C : 800 feet from the NORTH line and 2180 feet from the WEST line Section 25 Township 28N Range 13W NMPM County San Juan	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	[ ]	PLUG AND ABANDON	[ ]	REMEDIAL WORK	[ ]	ALTERING CASING	[ ]
TEMPORARILY ABANDON	[x]	CHANGE PLANS	[ ]	COMMENCE DRILLING OPNS.	[ ]	P AND A	[ ]
PULL OR ALTER CASING	[ ]	MULTIPLE COMPL	[ ]	CASING/CEMENT JOB	[ ]		
DOWNHOLE COMMINGLE	[ ]						
CLOSED-LOOP SYSTEM	[ ]						
OTHER:	[ ]			OTHER:			[ ]

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Simcoe is requesting the TA for this well for a 12-month period, beginning on 11/11/2021. The expiration date will be 11/10/2022. This well may have future recompletion or production potential. There is other production in the agreement, since there are over 150 wells in the Gallegos Canyon Unit DK Participating Agreement.

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Gina Doerner TITLE Regulatory Analyst DATE 5/6/2022

Type or print name Gina Doerner E-mail address: gina.doerner@ikavenergy.com PHONE: 970-852-0082

For State Use Only

APPROVED BY: Monica Kuehling TITLE Deputy Oil and Gas Inspector DATE 6/10/2022

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-38894	
5. Indicate Type of Lease STATE ☑ FEE ☐	
6. State Oil & Gas Lease No.	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name Northeast Drinkard Unit (NEDU) [22503]
1. Type of Well: Oil Well ☑ Gas Well ☐ Other	8. Well Number 151
2. Name of Operator Apache Corporation	9. OGRID Number 873
3. Address of Operator 303 Veterans Airpark Lane, Suite 1000 Midland, TX 79705	10. Pool name or Wildcat Eunice; B-T-D, North [22900]
4. Well Location Unit Letter A : 330 feet from the North line and 330 feet from the East line Section 02 Township 21S Range 37E NMPM County Lea	
11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3536'	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Apache requesting to TA wellbore:

1. Set CIBP via WL between 5836'-5934'
2. Dump bail 35' of cmt on top of CIBP
3. Notify OCD 24hrs advance notice run MIT.

Current and proposed wellbore diagram attached.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: 08/12/2008 Rig Release Date: 08/23/2008

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Sorina L Flores TITLE Sr. Regulatory Analyst DATE 11/17/2021

Type or print name Sorina L Flores E-mail address: sorina.flores@apachecorp.com PHONE: 432-818-1167

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 2/15/22

Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-11055	
5. Indicate Type of Lease STATE ☐ FEE ☑	
6. State Oil & Gas Lease No. 330337	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name: Myers Langlie Mattix Unit
1. Type of Well: Oil Well ☑ Gas Well ☐ Other	8. Well Number 217
2. Name of Operator: J R Oil, Ltd. Co.	9. OGRID Number 256073
3. Address of Operator: PO Box 2975, Hobbs, NM 88241	10. Pool name or Wildcat: Langlie Mattix; 7R-Q-GB [37240]
4. Well Location: Unit Letter H : 1,650 feet from the N line and 330 feet from the E line; Section 8 Township 24S Range 37E NMPM County Lea	
11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3,276' GL	

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☒	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: ☐		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

J R Oil respectfully requests permission to extend approved TA status pending successful MIT.

Original TA status approved Jan. 8, 2018

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: | Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE [signature] TITLE Engineer DATE 12/17/2021

Type or print name Ian Petersen E-mail address: ian@ddpetro.com PHONE: (432) 634-4922

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 12/20/21

Conditions of Approval (if any):

575-263-6633

Apps' Ex. 12

Submit 3 Copies To Appropriate District Office
District I
1625 N. French Dr., Hobbs, NM 88240
District II
1301 W. Grand Ave., Artesia, NM 88210
District III
1000 Rio Brazos Rd., Aztec, NM 87410
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
May 27, 2004

WELL API NO. 30-025-35866
5. Indicate Type of Lease STATE ☐ FEE x
6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: W.D. Grimes (NCT-A)
8. Well Number: #26
1. Type of Well: Oil Well ☐ Gas Well ☐ Other
2. Name of Operator: Texland Petroleum-Hobbs, LLC
9. OGRID Number: 113315
3. Address of Operator: 777 Main Street, Suite 3200, Fort Worth, Texas 76021
10. Pool name or Wildcat: Hobbs, Upper Blinebry
4. Well Location
Unit Letter D : 585 feet from the North line and 900 feet from the West line
Section 32 Township 18S Range 38E NMPM Lea County
11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3638'

Pit or Below-grade Tank Application ☐ or Closure ☐
Pit type ____ Depth to Groundwater ____ Distance from nearest fresh water well ____ Distance from nearest surface water ____
Pit Liner Thickness: ____ mil Below-Grade Tank: Volume ____ bbls: Construction Material ____

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
OTHER: Request to extend TA Status ☐		OTHER: ☐	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 1103. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

TA Status expired 7/3/2021
CIBP was set @ 5587'

See attached Well Bore Schematic

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

I hereby certify that the information above is true and complete to the best of my knowledge and belief. I further certify that any pit or below-grade tank has been/will be constructed or closed according to NMOCD guidelines ☐, a general permit ☐ or an (attached) alternative OCD-approved plan ☐.

SIGNATURE Vickie Smith TITLE Regulatory Analyst DATE 12/8/21

Type or print name Vickie Smith E-mail address: vsmith@texpetro.com Telephone No. 575-433-8395

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 12/20/21
Conditions of Approval (if any):
575-263-6633

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II – (575) 748-1283
811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

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Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
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Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-025-20830
5. Indicate Type of Lease STATE [X] FEE [ ]
6. State Oil & Gas Lease No. B-1399

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: Vacuum Glorieta East Unit Tract 5
1. Type of Well: Oil Well [X] Gas Well [ ] Other
8. Well Number 002
2. Name of Operator: ConocoPhillips Company
9. OGRID Number 217817
3. Address of Operator: 600 West Illinois Ave; Midland, TX 79701
10. Pool name or Wildcat: Vacuum; Glorieta
4. Well Location
Unit Letter I : 1980 feet from the South line and 660 feet from the East line
Section 29 Township 17S Range 35E NMPM Lea County
11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	[ ]	PLUG AND ABANDON	[ ]	REMEDIAL WORK	[ ]	ALTERING CASING	[ ]
TEMPORARILY ABANDON	[X]	CHANGE PLANS	[ ]	COMMENCE DRILLING OPNS.	[ ]	P AND A	[ ]
PULL OR ALTER CASING	[ ]	MULTIPLE COMPL	[ ]	CASING/CEMENT JOB	[ ]		
DOWNHOLE COMMINGLE	[ ]						
CLOSED-LOOP SYSTEM	[ ]						
OTHER:	[ ]			OTHER:	[ ]		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

ConocoPhillips Company respectfully requests to temporarily abandon this well following casing repair. We proposed to cancel the previously proposed permanent abandonment to evaluate options for using this well. The procedure is below and schematics are attached.

- MIRU WSU. ND WH, NU BOP.
- TOOH w/ tubing and ESP.
- PU bit and scraper. RIH to ~6,075'
- PU bridge plug and packer. Set bridge plug @ 6,070'. Hunt for leak.
- Isolate leak and establish injection rate.
- Set 2nd RBP @ TBD location.
- Repair casing leak by cement squeeze if deeper than 20' or surface cut and replace if shallower than 20'.
- Load casing and pressure test to 550 psi.
- Contact NMOCD to witness MIT and bradenhead test.
- Run MIT at 550 psi for 30 minutes.
- Turn well over to operations. RDMO.

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Susan Maunder TITLE Senior Regulatory Coordinator DATE 10/07/2021

Type or print name Susan B. Maunder E-mail address: Susan.B.Maunder@conocophillips.com PHONE: 432-269-4378

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 10/8/21
Conditions of Approval (if any):

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I- (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
District II- (575) 748-1283
1301 W. Grand Ave., Artesia, NM 8821 0
District III- (505) 334-6178
1 000 Rio Brazos Rd., Aztec, NM 8741 0
District IV- (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-005-64361

5. Indicate Type of Lease STATE ☒ FEE ☐

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR, USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: White State

1. Type of Well: Oil Well ☒ Gas Well ☐ Other

8. Well Number 5

2. Name of Operator: Mack Energy Corporation

9. OGRID Number 013837

3. Address of Operator: P.O. Box 960 Artesia, NM 88210

10. Pool Name or Wildcat: WC 16S28E3;San Andres

4. Well Location
Unit Letter P 740 feet from the South line and 330 feet from the East line
Section 35 Township 15S Range 27E NMPM County Chaves

11. Elevation (Show *whether DR, RKB, RT, GR etc.*) 3586' GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIALWORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:			☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Mack Energy is requesting approval to T&A the White State #5.
The T&A plan for the White State #5 is as follows:
Set plug #1 from 2,700' up to 1,875' Cement volume is 290sx Class C, 1.32 yield, 14.8 ppg.
Set plug #2 from 1,875' to 1,100' (86' inside intermediate casing. Intermediate casing is set at 1,186'. Cement volume is 420sx Class C, .94 yield, 17.5 ppg.
Cap well with B1 Bonnet. Rig down drilling rig.
Will pressure test to 500# for 30 minutes after cement has set up.

Spud Date: Rig Release Date:

I hereby certify that the information above is true slid complete to the best of my knowledge and belief.

SIGNATURE Jerry W Sherrell TITLE Production Supervisor DATE 6/24/21

Type or print name Jerry W. Sherrell E-mail address: jerrys@mec.com PHONE: 575-748-1288

For State Use Only

APPROVED BY: John Garcia TITLE Petroleum Engineer DATE 6/25/2021

Conditions of Approval (if any):

Must preform MIT in accordance with 19.15.25.13 - 14
Notify OCD District 24hrs prior to running the MIT test.

Apps' Ex. 12

Submit 1 Copy To Appropriate District Office
District I – (575) 393-6161
1625 N. French Dr., Hobbs, NM 88240
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811 S. First St., Artesia, NM 88210
District III – (505) 334-6178
1000 Rio Brazos Rd., Aztec, NM 87410
District IV – (505) 476-3460
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO.
30-025-26954

5. Indicate Type of Lease
STATE ☒ FEE ☐

6. State Oil & Gas Lease No.

SUNDRY NOTICES AND REPORTS ON WELLS
(DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name
Bobbi State Waterflood Unit

1. Type of Well: Oil Well ☒ Gas Well ☒ Other TA'd

8. Well Number 3

2. Name of Operator
Sundown Energy LP

9. OGRID Number 232611

3. Address of Operator
16400 Dallas Pkwy, Ste 100, Dallas, TX 72248

10. Pool name or Wildcat
Arkansas Junction; San Andres, West

4. Well Location
Unit Letter N : 330 feet from the SOUTH line and 2310 feet from the WEST line
Section 20 Township 18S Range 36E NMPM County LEA

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*
3835' GR

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☒	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☒	REQUEST TA EXTENSION		OTHER:			☐

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

We request an extension for the Temporarily Abandonment of this well to maintain for future utilization in the Bobbi WFU. A MIT would be run if approved.

NEED CURRENT WELL BORE DIAGRAM
Will need to submit plan for intentions for well
This is last TA extension

Condition of Approval: notify OCD Hobbs office 24 hours prior of running MIT Test & Chart

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Christi Gregory TITLE Production Analyst DATE 06/29/2021

Type or print name Christi Gregory E-mail address: cgregory@elandenergy.com PHONE: 214-368-6100 x2160

For State Use Only

APPROVED BY: Kerry Fortner TITLE Compliance Officer A DATE 10/8/21

Conditions of Approval (if any):

Apps' Ex. 12

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District I – (575) 393-6161
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District III – (505) 334-6178
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Energy, Minerals and Natural Resources

OIL CONSERVATION DIVISION
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Santa Fe, NM 87505

Form C-103
Revised July 18, 2013

WELL API NO. 30-015-46528	
5. Indicate Type of Lease STATE ☑ FEE ☐	
6. State Oil & Gas Lease No. 326768	
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name PALMILLO 20 STATE COM
1. Type of Well: Oil Well ☑ Gas Well ☐ Other	8. Well Number 365H
2. Name of Operator Apache Corporation	9. OGRID Number 873
3. Address of Operator 303 Veterans Airpark Lane, Suite 1000 Midland, TX 79705	10. Pool name or Wildcat WINCHESTER;BONE SPRING WEST
4. Well Location Unit Letter E : 1905 feet from the N line and 370 feet from the W line Section 21 Township 19S Range 28E NMPM County EDDY	
	11. Elevation *(Show whether DR, RKB, RT, GR, etc.)* 3459

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	☐	PLUG AND ABANDON	☐	REMEDIAL WORK	☐	ALTERING CASING	☐
TEMPORARILY ABANDON	☑	CHANGE PLANS	☐	COMMENCE DRILLING OPNS.	☐	P AND A	☐
PULL OR ALTER CASING	☐	MULTIPLE COMPL	☐	CASING/CEMENT JOB	☐		
DOWNHOLE COMMINGLE	☐						
CLOSED-LOOP SYSTEM	☐						
OTHER:	☐			OTHER:	☐		

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

Apache is requesting a 2yr extension to current TA approval set to expire 10/2021. Due to economic and market conditions, wells will not be drilled in 2021. Expecting to finish drilling well as market conditions improve.

Composite bridge plug at 189', MIT to 600 psi after notification to NMOCD, T&A cap on Cameron wellhead with a gauge to monitor backside pressure.

Surface csg set at 334' (TD) w/400 sx Cl C cmt. Plan is to complete well at a later date.

Current WBD is attached.

Spud Date: 8/24/2021 Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Sorina L Flores TITLE Sr Regulatory Analyst DATE 8/24/2021

Type or print name Sorina L Flores E-mail address: sorina.flores@apachecorp.com PHONE: 432-818-1167

For State Use Only

APPROVED BY: John Garcia TITLE Petroleum Engineer DATE 10/7/2021

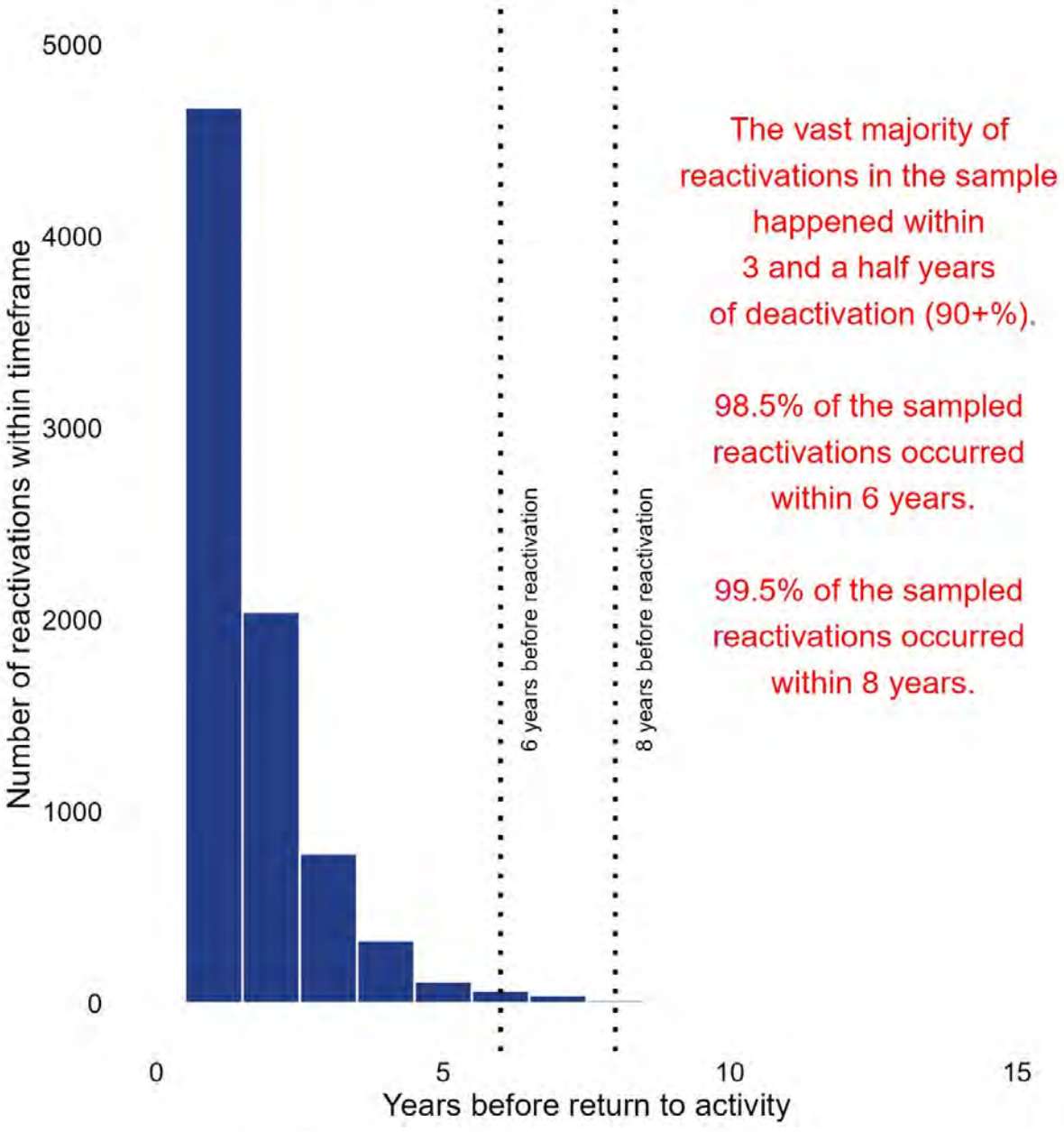
Conditions of Approval (if any): TA status approved until 10/7/2021

Apps' Ex. 12

EXHIBIT 13

Length of time before deactivated wells return to activity

Median = 1.42 years; 90% = 3.42 years.



The vast majority of reactivations in the sample happened within 3 and a half years of deactivation (90+%).

98.5% of the sampled reactivations occurred within 6 years.

99.5% of the sampled reactivations occurred within 8 years.

Histogram of length of time inactive prior to return to activity, across sample of wells that reactivated following 12+ months of no production.

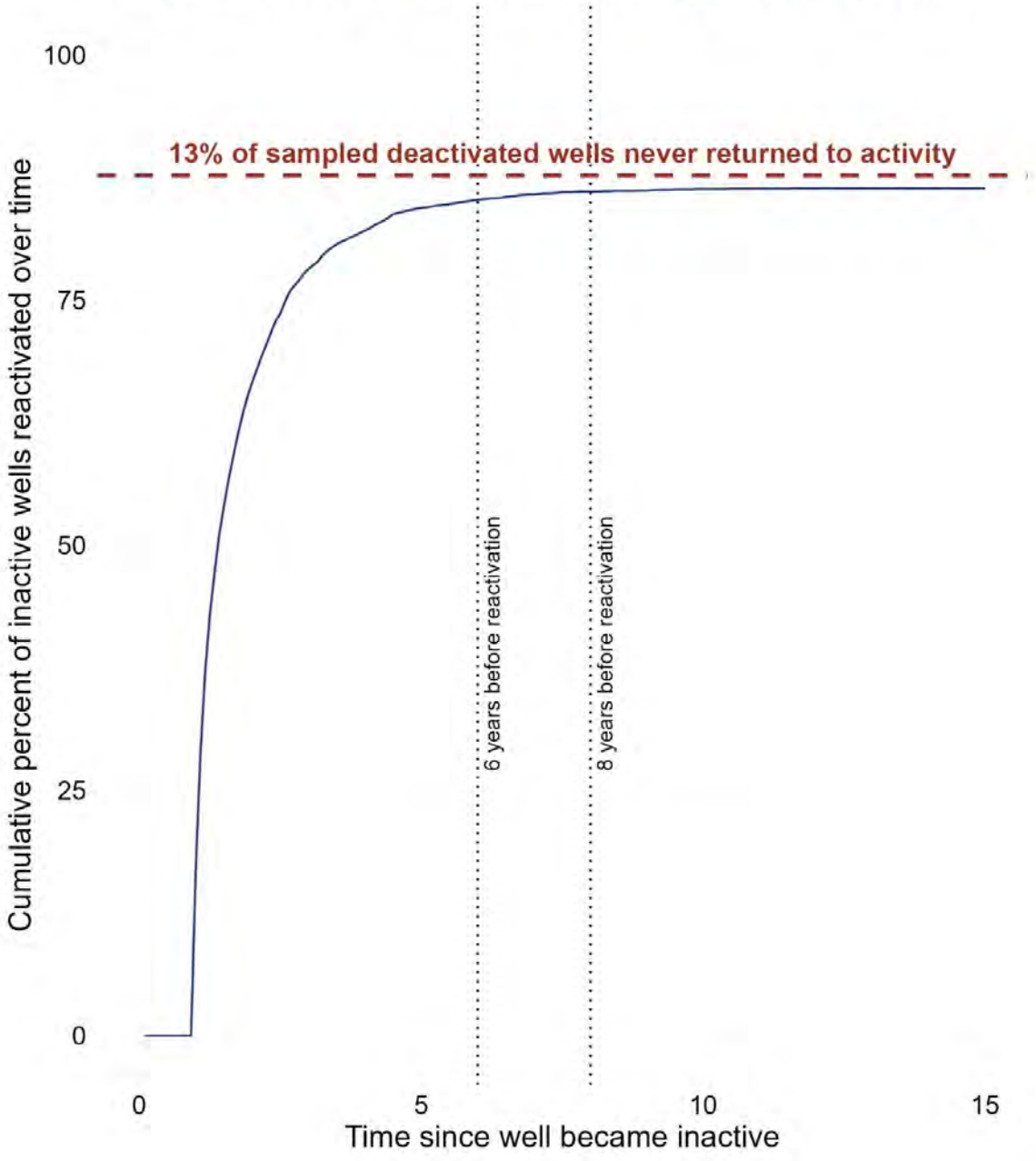
Based on analysis of production data from 2010-2024, for wells spudded prior to 2017.

Applicant's Exhibit 13

Apps' Ex. 13

Percent of wells ever returning to activity

Cumulative wells returning to activity, as a percent of all wells inactive for 12+ months during sample window



Based on analysis of production data from 2010-2024, for sample of wells spudded prior to 2017, beginning with first period of activity after 2010.

Applicant's Exhibit 13

Apps' Ex. 13

EXHIBIT 14

PETER M. MORGAN
peter@thecara.org

EMPLOYMENT

CENTER FOR ASSET RETIREMENT ACCOUNTABILITY (CARA), Denver, CO
Legal and Policy Director, September 2024-Present

- Develop policy and legal solutions to address well plugging and other aspects of extractive industry decommissioning.

THE SIERRA CLUB, Environmental Law Program
Senior Attorney, January 2017–September 2024, Denver, CO

- Led Sierra Club's work to secure the timely clean-up of coal mines and oil and gas wells

Staff Attorney, July 2010–December 2016, Denver, CO
Law Fellow, September 2008–June 2010, San Francisco, CA

THE SUPREME COURT OF ALASKA, Justice Walter Carpeneti, Juneau, AK
Law Clerk, August 2007–August 2008

THE NATURAL CAPITAL PROJECT, Stanford, CA
Postdoctoral Policy Fellow, Hawaii Site, January 2007–August 2007

THE NATURE CONSERVANCY, Martha's Vineyard, MA
Program Manager, Massachusetts Islands Program, 2002–2003
Office Manager, Massachusetts Islands Program, 2001–2002

EDUCATION

STANFORD LAW SCHOOL, Stanford, CA
J.D., *January 2007*

STANFORD UNIVERSITY, Stanford, CA
M.S., Interdisciplinary Graduate Program in Environment and Resources, *January 2007*

MIDDLEBURY COLLEGE, Middlebury, VT
B.A., *magna cum laude*, *phi beta kappa*, with High Honors in American Literature, *May 2001*

TESTIMONY AND SPEAKING APPEARANCES

Witness, U.S. House of Representatives, Natural Resources Committee, Hearing on Examining the Biden Administration's Abandoned Mine Lands and Active Mining Programs, November 2023
Panelist, *US Coal in the 21st Century: Bankruptcy, Ownership and Financing*, Columbia University Law School, September 2016

MEDIA ENGAGEMENT

Quoted on issues related to fossil fuel clean-up and decommissioning in the *New York Times, Washington Post, Wall St. Journal, Science, Slate, Greenwire*.
Letters to the editor published in the *New Yorker* and the *Atlantic Monthly*.

EXHIBIT 15

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC **CASE NO. 24683**

DIRECT TESTIMONY OF PETER MORGAN

Table of Contents

BACKGROUND AND QUALIFICATIONS ……2

SUMMARY OF OPINIONS……3

OVERVIEW OF THE ORPHAN WELL PROBLEM……..5

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS……...8

19.15.5 NMAC – ENFORCEMENT AND COMPLIANCE……10

19.15.8 NMAC – FINANCIAL ASSURANCE……..14

General Overview……14

Current New Mexico Requirements……...37

Applicants' Proposed Amendments……...39

19.15.9 NMAC – WELL OPERATOR PROVISIONS……68

List of References……92

BACKGROUND AND QUALIFICATIONS

Q: Please state your name.

A: Peter Morgan.

Q: Where are you employed and what is your position?

A: I am Legal and Policy Director for the Center for Asset Retirement Accountability (CARA). I helped found CARA in September 2024. CARA's mission is to address the national problem of unplugged oil and gas wells, including through regulatory solutions. This work involves understanding existing regulatory requirements at the federal and state level, identifying gaps and flaws with those requirements that lead to the creation of additional orphaned wells, and proposing solutions to address those gaps and flaws.

Q: What is your educational background?

A: I have a Bachelor of Arts from Middlebury College. I have a J.D. from Stanford Law School and a Master of Science degree from Stanford's Emmet Interdisciplinary Program in Environment and Resources.

Q: Can you briefly describe your work background?

A: Prior to my current position with CARA, I worked for 16 years as an attorney for the Sierra Club. My work at Sierra Club focused on issues around the operation and cleanup of fossil fuel extraction facilities nationwide, with a concentration on oil and gas operations and coal mines. Through this work I have expertise in understanding state and federal regulatory requirements for financial assurance from oil and gas operators for plugging and abandonment and site remediation, the strengths and weaknesses in these regulatory schemes, oil and gas operators' failure to comply with regulatory requirements and best practices, and the fiscal, environmental, and public health problems resulting from orphaned and abandoned wells across

the nation, including in New Mexico.

I testified before Congress at a 2023 hearing of the U.S. House of Representatives Natural Resources Committee's Subcommittee on Energy and Mineral Resources on the need for improved regulations to strengthen financial assurances, restrict transfer of obligations, and address other issues related to cleaning up fossil fuel extraction sites. I have drafted and submitted multiple sets of comments to federal authorities including the U.S. Bureau of Land Management regarding best regulatory practices to ensure prompt cleanup of fossil fuel extraction infrastructure and to avoid the creation of orphaned infrastructure.

Q: Is Applicants' Exhibit 14 an accurate copy of your resume?

A: Yes.

Q: In preparing your testimony, what sources did you review?

A: I reviewed Applicants' Application and Revised Application, including the proposed amendments to Parts 2, 5, 8, and 9 of Title 19, Chapter 15 of the New Mexico Administrative Code, and Notice of Errata. In addition, I reviewed various materials that are included as references at the end of my testimony.

Q: Have you reviewed other states' regulatory requirements for financial assurances?

A: I have, and where appropriate I reference those requirements in my testimony.

Q: Have you reviewed other states' regulatory requirements governing the transfer of oil and gas wells?

A: I have, and where appropriate I reference those requirements in my testimony.

SUMMARY OF OPINIONS

Q: Can you summarize the opinions you will provide in your testimony?

A: Yes. I will provide testimony and opinions on the Applicants' proposed amendments to

19.15.2 NMAC, 19.15.5 NMAC, 19.15.8 NMAC, and 19.15.9 NMAC. Specifically, I will cover the following areas:

First, a definition for "marginal well" should be added to 19.15.2 NMAC to identify wells at greatest risk of being orphaned, based on their duration and amount of production. These wells are good candidates for increased financial assurance.

Second, 19.15.5 NMAC should be amended to better incentivize the prompt plugging of wells. Currently, the rule allows an operator to maintain a certain number of wells out of compliance with plugging requirements at any given time. Operators should instead either promptly plug wells once they stop producing, or demonstrate that the wells are likely to be returned to service or otherwise be put to beneficial use in the future.

Third, 19.15.8 NMAC should be amended to better reflect the average costs of plugging and deter operators from orphaning wells. In particular, I recommend the increase in plugging financial assurance for certain categories of high risk wells to better meet the statutory requirement that one-well financial assurance be set at an amount sufficient to reasonably pay the well's plugging costs. NMSA 1978, § 70-2-14(A). I also recommend a new provision that would allow the agency to increase financial assurance annually to match inflation.

Fourth, and finally, 19.15.9 NMAC should be amended to ensure an adequate review of financial assurance at the point of a well's transfer. High risk wells are often transferred to less financially capable operators and the risk of a well becoming orphaned increases. Specifically, I recommend placing conditions at the point of a well's transfer, such as a certification that a new operator is in compliance with the law and a requirement that wells either be brought into compliance prior to transfer or a plan be drawn up, to ensure they are in compliance after transfer.

Overall, my recommendations are intended to help prevent wells being orphaned without adequate financial assurance in place to provide for their plugging. My goal is to encourage the timely plugging of wells by operators and ensure the agency has access to adequate resources to plug any wells that have been orphaned.

OVERVIEW OF THE ORPHAN WELL PROBLEM

Q: Mr. Morgan, are current oil and gas regulations nationally and in New Mexico adequate to ensure appropriate and timely plugging of oil and gas wells?

A: No. Unfortunately, most states' regulations allow oil and gas operators to delay and avoid meeting their asset retirement obligations. The result is that landowners and communities must contend with unplugged inactive wells, many of which leak or pose other threats to human health and the environment. When operators go out of business without completing plugging, the responsibility and associated costs get passed on to the state and the state's taxpayers. Because financial assurances for well plugging are set at levels far below the actual costs, states must use funds from other sources to pay for the plugging. This both delays plugging and prevents those funds from being used for other beneficial purposes. Meanwhile, the oil and gas industry continues to enjoy substantial profits.

In New Mexico, rather than use a portion of those profits to pay to plug wells once they are no longer economic, operators often take advantage of the state's weak regulatory provisions to transfer the wells, and their associated cleanup obligations, to less-resourced operators who are much more likely to go out of business and pass the cleanup costs on to the public.

The New Mexico Legislative Finance Committee issued a report on orphan wells and their attendant risks on June 24, 2025: Policy Spotlight: Orphaned Wells, attached as Applicants' Exhibit 4. According to the report, there are currently between 700 and 2,100 non-producing

wells in New Mexico that will not be plugged by their operator and will instead need to be plugged by the State. The actual figure is almost certainly at the higher end of that range. Although New Mexico does not have a statutory or regulatory definition for the term, these can be understood to be "orphaned wells." In general usage, orphaned wells are wells for which there is no longer a viable operator capable of completing the plugging. The responsibility to plug orphaned wells falls to the state. The New Mexico Legislative Finance Committee reports that there are approximately 700 wells for which OCD has already secured plugging authority, and an additional 1,400 inactive wells that "[t]he state likely will need to plug," but for which OCD has not yet pursued plugging authority.[1] These figures are consistent with the number of orphaned wells OCD reported to the U.S. Department of the Interior in the State's initial December 2021 notice of intent to apply for federal orphaned well grant funding, and with OCD's approach to calculating that total.[2] In the notice of intent, OCD stated that "New Mexico has 1741 known orphaned sites," and specified that "New Mexico rules do not use the term orphan wells, instead such wells are a subset of inactive wells under state rules."[3]

The Legislative Finance Committee also reports that, based on its review of OCD invoices, the average cost for OCD to plug a well in fiscal year 2024 was $163,000.[4] It will therefore cost the state between $114 million and $342 million just to plug this existing inventory of orphaned wells. As of April 2025, New Mexico's Reclamation Fund contained just

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[1] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 1.

[2] State of New Mexico Energy, Minerals, and Natural Resources Department, Notice of Intent to Apply for Formula Grant Funding, (Dec. 22, 2021).

[3] *Id*.

[4] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 13; *see also* Apps' Ex. 16, New Mexico Legislative Finance Committee, Fiscal Impact Report for H.B. 481, 57th Leg. (NM 2025), https://www.nmlegis.gov/Sessions/25%20Regular/firs/HB0481.PDF.

$66.7 million.[5]

These figures do not include the additional tens of thousands of wells almost certain to be orphaned in the coming years. Orphaned wells are a subset of the total number of unplugged inactive wells. Of the approximately 110,000 wells that have been drilled for oil and gas in New Mexico, approximately 63,000 are currently unplugged and will eventually need to be plugged.[6] Of these, approximately 3,765 wells were on the OCD Inactive Well List as of July 3, 2025.[7] In addition, according to the Legislative Finance Committee, "there are more than 3,000 wells on state or private land producing extremely small quantities of oil and gas whose expected cleanup costs far exceed their predicted future revenues, increasing their risk of being orphaned."[8] These low-producing wells are at high risk of orphaning, particularly when transferred to under-resourced operators, including operators who already hold a large number of inactive and low-producing wells.

Current New Mexico regulations contribute to and precipitate this present and growing orphaned well crisis in three ways. First, the current regulations allow operators to delay and avoid plugging by allowing wells to be placed in temporary abandonment status without any demonstration that the wells have future beneficial use.

Second, because current financial assurance requirements are set far below actual plugging costs, the rules do not provide an incentive to operators to plug wells in a timely manner in order to be released from financial assurance obligations. And the lack of adequate

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[5] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 11.
[6] Apps' Ex. 32, Subdivisions of unplugged wells in NM.
[7] Apps' Ex. 7, OCD Inactive Well Search List (7/3/25).
[8] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 11.

financial assurances means that when the wells are orphaned, essentially all the plugging costs must be borne by the state.

Third, the current regulations facilitate and encourage the practice of transferring inactive and low-producing wells away from the operators who profited from their earlier production. OCD lacks the information and authority to take meaningful action to scrutinize and reject proposals to transfer inactive and low-producing wells to under-resourced operators most likely to orphan those wells rather than plug them.

Applicants' proposed amendments address all these issues.

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS

Q: Mr. Morgan, beginning with 19.15.2 NMAC – General Provisions for Oil and Gas Operators, Applicants propose to add a new definition for "marginal well" at 19.15.2.7.M(2) NMAC. What is the purpose of this new definition?

A: Marginal wells represent a category of well that is at greater risk of becoming orphaned and, therefore, Applicants propose increased financial assurance for these at-risk wells. The proposed definition for "marginal well" is:

> **19.15.2.7.M(2) "Marginal well"** means an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period.

OCD initially proposed a definition for "marginal well" in its February 12, 2025, Redline Proposal (Apps' Ex. 5) to all parties in this proceeding and proposed increased financial assurance amounts for these wells in 19.15.8 NMAC. Applicants adopted OCD's proposal.

Marginal wells pose a significant risk of being orphaned because the revenue they will produce over their remaining production may be less than the cost of plugging and remediating the well. This creates a powerful incentive for operators, particularly new operators who did not

enjoy the original profitable period of higher production, to avoid these cleanup costs.

The proposed definition of "marginal well" includes components related to both the amount of production (less than 1,000 BOE ("barrel of oil equivalent") in 12 months, or approximately 2.7 BOE per day) and the number of days the well produces (180 days within consecutive 12 months). Each component is critical. The total amount of production relates directly to the revenue generated by that well. The number of days producing is also important, because operators can manipulate well production to make wells appear artificially productive, but only over short periods of time, giving a false impression that a well is economic when it is not. Requiring wells with "active" status to produce at least half the time prevents operators from manipulating production in this way.

According to the analysis of Dwayne Purvis, P.E., one of Applicants' experts, 3,900 wells would qualify as "marginal," representing 6.6% of the well population and 0.048% of total production in the state. *See* Apps' Ex. 40. Operators in "marginal" status are producing an average of 2.7 BOE per day or less over 12 months and are operating less than half of the year.

In its orphan well report, the Legislative Finance Committee recognized that, at a point of low production, a well's liability surpasses the value of its potential future production.[9] It also found that, in New Mexico, the average well plugged in recent years produced approximately 2 BOE per day in the year prior to abandonment. The Legislative Finance Committee recommended that the Energy, Minerals and Natural Resource Department ("EMNRD") promulgate rules for low-producing wells, such as those producing approximately 2.0 BOE per day, and require single well financial assurance for those low producing wells.[10] Applicants'

[9] *Id.* at 21.
[10] *Id.* at 2-3.

proposal to establish a category of marginal wells and require full cost bonding for those at-risk wells is consistent with recommendations of the Legislative Finance Committee.

19.15.5 NMAC – ENFORCEMENT AND COMPLIANCE

Q: Turning to 19.15.5 NMAC – Enforcement and Compliance, Applicants propose to amend 19.15.5.9.A NMAC. What is the purpose of 19.15.5.9.A NMAC?

A: Section 19.15.5.9.A NMAC lists criteria for a compliance determination for purposes of certain regulatory actions in the rules. These regulatory actions include OCD's determinations:

- Whether to release financial assurances under 19.15.8.12 NMAC,
- Whether to approve or deny an application for operator registration under 19.15.9.8.B NMAC, and
- Whether to approve or deny an application for change of operator under existing 19.15.9.9.C NMAC.[11]

Q: What amendments do Applicants propose to Section 19.15.5.9.A NMAC?

A: Applicants propose the following:

> **9. COMPLIANCE:**
> **A.** An operator is in compliance with Subsection A of 19.15.5.9 NMAC if the operator:
> **(1)** currently meets the financial assurance requirements of 19.15.8 NMAC;
> **(2)** is not subject to a division or commission order, issued after notice and hearing, finding the operator to be in violation of an order requiring corrective action;
> **(3)** does not have a penalty assessment that is unpaid more than 30 days after issuance of the order assessing the penalty; ~~and~~
> **(4)** currently meets the requirements of 19.15.25.8 NMAC; and ~~has no more than the following number of wells out of compliance with 19.15.25.8 NMAC that are not subject to an agreed compliance or final order~~

[11] Other regulatory actions that require a compliance determination under 19.15.5.9.A NMAC are whether to approve or deny a permit to drill, deepen, or plug back a well under 19.15.14.10.A NMAC; whether to grant a permit for injection of fluid into reservoirs under 19.15.26.8.A(2) NMAC; and whether to approve an application for an exploration and development plan or an application to amend, renew, or replace an existing exploration and development plan, or revoke such a plan, under 19.15.39.9.J NMAC (providing special provisions for Santa Fe County and the Galisteo Basin).

~~setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met:~~

~~**(a)** two wells or fifty percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;~~

~~**(b)** five wells if the operator operates between 101 and 500 wells;~~

~~**(c)** seven wells if the operator operates between 501 and 1000 wells; and~~

~~**(d)** 10 wells if the operator operates more than 1000 wells.~~

(5) currently meets the requirements of 19.15.27.8.A NMAC.

The proposed amendments would modify the compliance criteria at 19.15.5.9.A in two ways. First, the proposed amendments would eliminate existing language at 19.15.5.9.A(4) allowing operators to maintain a specified number of wells, scaled to the number of wells in the operator's total inventory, out of compliance with the well plugging requirements specified at 19.15.25.8. Second, the proposed amendments would add an additional criterion at 19.15.5.9.A(5) requiring operators to "meet[] the requirements of 19.15.27.8.A NMAC," which regulates venting and flaring of natural gas at wells.

Q: As you identified, currently 19.15.5.9.A NMAC allows an operator to have a certain number of wells out of compliance with 19.15.25.8 NMAC but the operator is nonetheless in compliance for purposes of 19.15.5.9.A NMAC. How would Applicants' proposed change affect operators?

A. Currently, under the existing regulations, 19.15.5.9.A(4) authorizes operators to maintain a specified number of wells "out of compliance with 19.15.25.8 NMAC that are not subject to an agreed compliance or final order setting a schedule for bringing the wells into compliance with 19.15.25.8 NMAC and imposing sanctions if the schedule is not met." Section 19.15.25.8 NMAC is the regulatory provision requiring wells to be properly plugged and abandoned. The number of wells that may be out of compliance under the existing regulation depends on the total number of wells in the operator's inventory, ranging from two wells for operators with 100 or

fewer wells, to 10 wells for operators with more than 1,000 wells. The proposed amendment eliminates these allowances, instead providing that to be in compliance with 19.15.5.9.A NMAC, an operator must "currently meet[] the requirements of 19.15.25.8 NMAC." In other words, the proposed amendment holds all operators to the requirement that they promptly plug their wells once they stop producing.

The proposed amendment does not leave operators without recourse for a well that may be returned to service or otherwise used for a beneficial purpose in the future. The existing regulation at 19.15.25.8 NMAC already allows an operator to secure designated "temporary abandonment" status for such a well.

Q: Why do Applicants propose eliminating the current language allowing an operator to have wells out of compliance with 19.15.25.8 NMAC? The current regulation allows only a small number of wells to be out of compliance.

The proposed amendment, eliminating the provision allowing an operator to maintain a specified number of wells out of compliance with plugging and abandonment requirements, is necessary for two reasons.

First, a functional oil and gas regulatory program must provide clear guidance to operators, landowners, regulators, and the public regarding the point at which an oil or gas well must be plugged. New Mexico's regulations at 19.15.25.8 NMAC provide that type of clear, brightline guidance. But that clarity is significantly compromised by the current language at 19.15.5.9.A(4) NMAC allowing operators to maintain wells out of compliance with plugging requirements. The proposed amendment restores the needed clarity by requiring that all wells must be promptly plugged when plugging obligations are triggered.

Second, the allowances provided under the current regulation facilitate the transfer of

inactive wells with overdue plugging obligations. These wells are incapable of generating any additional revenue, and must be seen as pure liabilities. The current regulations allow operators to maintain these wells in an unplugged status and then transfer them to a new operator. The proposed amendments disrupt this practice by encouraging operators to use the revenue and profits generated by the wells' operation toward promptly satisfying plugging and abandonment obligations.

Q: Do the proposed amendments include changes to any other sections to reflect the elimination of the unplugged well allowances at 19.15.5.9.A(4) NMAC?

Yes. The proposed amendments would also modify section 19.15.9.9.D NMAC to delete the phrase "more than the allowed number of" from the phrases "having more than the allowed number of wells out of compliance with 19.15.25.8 NMAC" and "having more than the allowed number of wells not in compliance with 19.15.25.8 NMAC."

These proposed omissions from 19.15.9.9.D NMAC maintain regulatory consistency, and are discussed below in the section on 19.15.9 NMAC – Well Operator Provisions.

Q: Why do Applicants propose adding compliance with 19.15.27.8.A NMAC to the requirements in 19.15.5.9.A NMAC?

A: Among the proposed amendments to the "Compliance" provisions of 19.15.5.9 NMAC is the addition of subsection A(5), which reads: "An operator is in compliance with Subsection A of 19.15.5.9 NMAC if the operator: . . . (5) currently meets the requirements of 19.15.27.8.A NMAC."

Section 19.15.27.8.A NMAC sets forth the Commission's general prohibition on venting and flaring of natural gas and incorporates exceptions to the prohibition set forth in 19.15.27.8.B, -C, and -D NMAC. Section 19.15.27 NMAC, commonly referred to as the "Methane Waste

Rule," was promulgated in 2021, after promulgation of 19.15.5.9.A NMAC. By including an express reference to these obligations of operators regarding venting and flaring among the "compliance" provisions of 19.15.5.9 NMAC, the proposed amendments highlight the importance of compliance with limitations on venting and flaring, which wastes natural gas and contributes to air pollution. The general prohibition against venting and flaring methane waste is one of the Commission's most important rules. Not only does the rule prevent waste of the resource, a fundamental goal of the Oil and Gas Act, NMSA 1978, § 70-2-2, it reduces emissions of methane, one of the most potent greenhouse gases and one of the most significant contributors to climate change.[12]

Furthermore, operators who regularly vent and flare natural gas in violation of 19.15.27.8 NMAC may also lack capacity to properly operate and plug their wells, and the inclusion of the reference to 19.15.27.8 NMAC in the compliance provisions of 19.15.5.9 NMAC provides OCD with the opportunity to address these operational deficiencies and to determine whether the operator has the resources and ability to assume additional well operating and plugging obligations.

19.15.8 NMAC – FINANCIAL ASSURANCE

General Overview

Q: Mr. Morgan, before you discuss Applicants' specific proposals to amend 19.15.8 – Financial Assurance, could you please discuss the role of financial assurance in general and the problems that arise when financial assurance is not adequate. So, let's begin with why adequate financial assurance is important component of effective oil and gas regulations?

[12] *See* Press Release, Office of the Governor Michelle Lujan Grisham, *Independent study shows New Mexico's emissions from oil and gas are HALF those of Texas' industry*, (Nov. 14, 2023),

A: Before an oil or gas well is even drilled, it is known that one day it will stop producing in economic quantities and must be plugged. This is because oil and gas wells provide access to a finite resource.[13] Once that finite resource is exhausted, the well loses any private or societal value and must be properly decommissioned "to reduce risks to health and the environment and to turn the land over to alternative uses."[14]

The nature of oil and gas operations is that the obligation to plug comes due at the point when the well has stopped generating revenue. At the same time, plugging and decommissioning is expensive and represents a pure cost with no potential to produce additional revenue.[15] The economics of this reality dramatically increases the likelihood that an operator will go out of business or otherwise walk away from its obligations before completing plugging. At that point, even if the regulator were to sue the operator, the operator would be effectively "judgment-proof," with no assets left for the regulator to claim.[16] This risk increases the more inactive wells an operator holds.

Regulators can address this dynamic by requiring operators to post financial assurances—prior to drilling or acquiring a well—sufficient to cover the costs of plugging, or at least sufficient to shift the incentives so that operators prioritize well plugging.[17]

Financial assurance requirements for resource extractors provide a mechanism for

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[13] J. Weber et al., Identifying the End: Minimum Production Thresholds for Natural Gas Wells, University of Pittsburgh Graduate School of Public and International Affairs Working Paper No. 21-500 at p. 4 (May 27, 2021).

[14] *Id.* at p. 1.

[15] *Id.* at p. i.

[16] David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97 at p. 191, Oct. 2, 2000.

[17] *Id.* at p. 191 ("An approach to the judgment-proof problem is to require collateral (such as a bond), thus providing the agent with a direct monetary incentive to comply with the regulations. If the agent fails to perform, the forfeited collateral is used to remedy the performance failure.").

ensuring ultimate compliance with decommissioning requirements.[18] The operator posts the financial assurance, which is only released when plugging and decommissioning is successfully completed.[19] If plugging is not successfully completed, the operator forfeits the financial assurance and the proceeds are used by the state to pay a third party to complete the plugging.[20]

Effective financial assurance programs facilitate timely and effective decommissioning in three primary ways.

First, the financial assurance "assures that some resources will be available for reclamation if the firm fails to clean up the site."[21] This financial backstop is particularly important in industries such as oil and gas extraction that are subject to "boom-and-bust cycles" that "can lead operators to drill wells when prices for oil and gas are high but can contribute to bankruptcies when prices are low."[22] In such cases, a prudent regulator requires financial assurances in order to insulate itself from the risks inherent to the industry.

Second, maintaining the financial assurance imposes an ongoing cost on the operator that is only released once plugging is complete, thereby creating an incentive for the operator to complete the plugging as soon as the well is no longer economic. Financial assurances such as surety bonds "can impose liquidity constraints on firms" and "can tie up a firm's operating capital,"[23] such that the operator will be motivated to seek release sooner than later. In addition to imposing collateral requirements, surety bond providers also charge annual premiums and

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[18] *Id.* at p. 189.
[19] *Id.*
[20] *Id.*
[21] *Id.*
[22] U.S. Gov't Accountability Office, Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells, GAO-19-615 at p. 1 (Sept. 2019).
[23] David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97, Oct. 2, 2000, at p. 191.

other regular fees. The desire to free up capital and avoid these ongoing costs should offset an operator's desire to avoid or delay the cost of plugging.

Third, financial assurance requirements shift risk away from the state and onto a third party such as a surety bond provider, with the third party conducting its own analysis of an operator's reliability and likelihood of default.[24] Financial assurance providers will screen operators and set premiums and other fees based on "observable indicators" of factors including "regulatory compliance."[25] "Insurers are able to continuously monitor firms' assets, production, and environmental liabilities over time. If the firm accumulates many non-producing wells or its net assets begin to decrease, the insurer can raise premiums. This prevents firms from accumulating unsustainable plugging or other environmental costs over time and eventually declaring bankruptcy."[26]

Q: Under the current regulations, what percentage of plugging costs for orphaned wells are covered by forfeited financial assurances in New Mexico?

A: Almost none.

The proceeds from forfeited financial assurances (as well as any funds recovered directly from responsible operators) are deposited into the Oil and Gas Reclamation Fund.[27] OCD provides annual reports on its administration of the Reclamation Fund to the EMNRD Secretary, the Governor, and the Legislature.[28] An analysis of annual reports for fiscal years 2019 through

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[24] *Id.* at 189-90 ("The use of a third party further reduces public exposure by increasing the number of parties potentially liable for the cleanup. Moreover, the third party assumes an enforcement role, which encourages contractual or regulatory compliance.").
[25] Judson Boomhower, Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk, American Economic Review Vol. 109, No. 2 at p. 401, Feb. 2019.
[26] *Id.* at p. 418 (noting that "Insurers in this market described this type of monitoring in interviews").
[27] NMSA 1978, § 70-2-14(B); NMSA 1978, § 10-2-38(B).
[28] NMSA 1978, § 70-2-38(C).

2024 reveals that although OCD expended $15,554,119.99 plugging 193 wells, it recovered only $249,723 from financial assurance forfeitures, salvage, and recovery from operators.[29] That works out to only **1.6%** of total plugging costs recovered by the state. In three of the five years analyzed, OCD recovered $0 from financial assurance forfeitures, salvage, and recovery from operators. The Legislative Finance Committee found in its recent report on orphan wells that "OCD has not successfully redeemed any financial assurance since 2018."[30]

- Total expended on well plugging for fiscal year 2019 through 2023: $15,554,119.99
- Total recovered from bond forfeitures, salvage and reimbursement: $249,723
    - Difference: $15,304,396.99
    - Percentage: 1.6%

[29] Apps' Ex. 17, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2019, (Dec. 27, 2019); Apps' Ex. 18, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2020, (Dec. 31, 2020); Apps' Ex. 19, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2021, (Dec. 20, 2021); Apps' Ex. 20, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2022, (Dec. 27, 2022); Apps' Ex. 21, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2023, (Jan. 23, 2024); Apps' Ex. 22, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2024, (July 1, 2025).

[30] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 31.

Wells Plugged and Costs Recovered

Year	Wells Plugged	Plugging Costs Recovered
2019	39	$88,000
2020	19	$0
2021	49	$0
2022	27	$161,250
2023	13	$0
2024	46	$0
Total:	193	$1,291 per well

This dramatic gap—between funds expended to plug these wells and funds collected from financial assurances (and the operators)—is attributable to two factors. First, the amount of financial assurance required from operators is far too low. Second, OCD generally does not pursue bond forfeiture. These factors are related, because the low amounts recoverable via bond forfeiture may lead OCD to conclude that it is not worth the time and effort required to complete bond forfeiture. OCD has recognized this dynamic: "If OCD is required to plug and abandon the sites because the operator is unable or unwilling to, OCD has the authority to forfeit any applicable financial assurance once plugging work is complete. The financial assurance helps the state to offset the cost of plugging and abandonment operations; however, because of statutory limits on financial assurance the amounts available for forfeiture are typical [sic] below plugging costs."[31]

Q: Why is it important to maintain policies that promote prompt plugging of non-producing oil and gas wells?

[31] Apps' Ex. 23, State of New Mexico Energy, Minerals, and Natural Resources Department, State of New Mexico Application for Initial Grant Funding for Orphan Well Plugging under the Infrastructure Investment and Jobs Act (May 13, 2022) at p. 22 (emphasis added).

A: Unplugged oil and gas wells harm New Mexico's communities and economy. Plugging these wells as soon as they are no longer economic to operate prevents air and water pollution, and the associated human health impacts, and allows the land on which the wells are located to be returned to other productive uses. Plugging wells is expensive, so oil and gas operators have a strong financial incentive to delay and avoid those costs for as long as possible. New Mexico therefore needs effective policies that hold operators accountable and ensure wells are plugged promptly.

OCD has recognized the community and environmental benefits that come from plugging wells, noting that:

> The plugging of orphaned wells and the remediation and reclamation of abandoned facilities provides a myriad of public benefits. Local and regional air quality is improved due to a reduction in the emissions of hydrocarbons and hydrogen sulfide. Water pollution is abated and potential risks to groundwater and surface water are reduced. Wildlife habitat is restored.[32]

Q. Please elaborate on the air, water, and human health impacts resulting from unplugged wells.

A. Unplugged oil and gas wells can leak numerous harmful pollutants into the air and water. Pollutants may escape when the well casings or wellheads of unplugged wells rust or crack, which can happen through improper maintenance, subsidence, or from other causes.[33] Oil and gas wells can emit air pollutants including methane, nitrogen oxides, sulfur dioxide, and

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[32] State of New Mexico Energy, Minerals, and Natural Resources Department, Work Plan/Proposal for Formula Phase 2 Grant Funds, (Dec. 13, 2024).

[33] American Geosciences Institute, Abandoned Wells: What Happens to Oil and Gas Wells When They Are No Longer Productive? (June 2018); Bill Analysis for A.B. 2729, 2016 Stat. Assembly, 2015-2016 Sess. (Ca. 2016), http://www.leginfo.ca.gov/pub/15-16/bill/asm/ab_2701-2750/ab_2729_cfa_20160819_202107_asm_floor.html.

hazardous air toxics like benzene, toluene, ethylbenzene, and xylene.[34] These pollutants "are known or suspected to cause cancer or other serious health effects, such as reproductive diseases, or birth defects."[35] Researchers have observed "increased concentrations of PM2.5, CO, NO2, O3, and VOCs at distances up to 4 km downwind of wells."[36]

Methane leaks are a particular concern from unplugged wells.[37] At very high concentrations, methane can pose an asphyxiation and explosion risk, particularly when accumulated in basements or well pits.[38] Methane is also a potent greenhouse gas driving global climate change. Methane's heat-trapping effects are up to 80 times more powerful than carbon dioxide, depending on the timeframe.[39] The U.S. Environmental Protection Agency estimates

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[34] Apps' Ex. 24, Richard K. Lattanzio, Cong. Research Serv., R42833, Air Quality Issues in Natural Gas Systems (2013), https://www.congress.gov/crs_external_products/R/PDF/R42833/R42833.9.pdf; Gregg P. Macey et al., Air Concentrations of Volatile Compounds Near Oil and Gas Production: A Community-Based Exploratory Study, Envtl. Health 14, 1–18 (2014), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4216869/.

[35] Apps' Ex. 24, Lattanzio, Cong. Research Serv., R42833, Air Quality Issues in Natural Gas Systems (2013), https://www.congress.gov/crs_external_products/R/PDF/R42833/R42833.9.pdf.

[36] Gonzales et al., Upstream oil and gas production and ambient air pollution in California, Science of the Total Environment 806 (2022), https://www.sciencedirect.com/science/article/pii/S0048969721053754?via%3Dihub.

[37] Josh Woda et al., Methane concentrations in streams reveal gas leak discharges in regions of oil, gas, and coal development, 737 Science of the Total Environment 140105 (2020), https://www.sciencedirect.com/science/article/abs/pii/S0048969720336251?fr=RR-2&ref=pdf_download&rr=7f521def4fba2bc4; Mary Kang et al., Direct Measurements of Methane Emissions from Abandoned Oil and Gas Wells in Pennsylvania, Proceedings of the National Academy of Sciences 111(51): 18173–18177 (2014); Nicholas J. Gianoutsos et al., Geologic sources and well integrity impact methane emissions from orphaned and abandoned oil and gas wells, Science of The Total Environment, Elsevier (Feb. 20, 2024), https://www.sciencedirect.com/science/article/pii/S0048969723082141.

[38] Apps' Ex. 25, R.E. Jackson et al., Groundwater Protection and Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research, Groundwater 51(4): 488–510, at p. 492 (2013).

[39] Apps' Ex. 26, Khalil El Hachem & Mary Kang, Reducing Oil and Gas Leakage, Environ. Research: Infrastructure & Sustainability, Environ. Res.: Infrastruct. Sustain. 3012002 (2023), https://iopscience.iop.org/article/10.1088/2634-4505/acbced/pdf.

that an average low- or non-producing oil well leaks 1.8 tons of methane into the atmosphere each year.[40]

Leaking wells can also pollute groundwater and surface water, including contaminating drinking water sources.[41] Oil and gas wellbores pass through shallower strata that may contain groundwater used for drinking or other purposes.[42] Unplugged, non-producing wells can facilitate the migration of pollutants from deeper hydrocarbon-producing strata into this groundwater or up to the surface.[43]

Applicants' expert Tom Alexander testifies that even wells in approved temporary abandonment status that have met mechanical integrity testing requirements and other protective requirements in Oil Conservation Commission (Commission) rules can nonetheless emit and leak pollutants to the air, land, and water because equipment can fail over time.[44]

The communities most likely to be exposed to pollutants from unplugged oil and gas wells include historically marginalized groups.[45] This includes communities in northwest New

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[40] U.S. Environmental Protection Agency, Oil and Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Background Technical Support Document for the Proposed Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Sept. 2018) at p. 36.

[41] Apps' Ex. 25, Jackson et al., Groundwater Protection and Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research, Groundwater 51(4): 488–510 (2013) at pp. 496-99.

[42] Richard J. Davies, Oil and gas wells and their integrity: implications for shale and unconventional resource exploitation, Marine and Petroleum Geology 56: 239–254 (2014) at pp. 239-40.

[43] D.G. Calvert, & Dwight K. Smith, Issues and techniques of plugging and abandonment of oil and gas wells, SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers (1994), at p. 3; George Everette King & Randy L. Valencia, Environmental risk and well integrity of plugged and abandoned wells, SPE Annual Technical Conference and Exhibition, Society of Petroleum Engineers, (2014) at pp. 2, 5-6.

[44] *See* Apps' Ex. 3, Alexander Dir. Test.

[45] Apps' Ex. 27, Jeremy Proville et al, The demographic characteristics of populations living near oil and gas wells in the USA, 44 Population & Env t (2022), https://link.springer.com/article/10.1007/s11111-022-00403-2.

Mexico living in close proximity to a high density of wells.[46] Proximity to oil and gas wells is associated with a range of negative health outcomes, including increased risk of cancer, birth defects, and cardiac and pulmonary impairment.[47]

Q. How does timely plugging of wells reduce the impacts those wells have on air, water, and human health?

Plugging abates emissions from wells. Wells that are plugged have roughly 100 times lower average emissions than wells that are unplugged.[48]

Prompt plugging is important because the longer a non-producing well sits idle, the more opportunity there is for air, land and water pollution. Wells that already leak will produce more pollution, and non-leaking wells may deteriorate to the point where they begin to leak.

Delays in plugging impose multiple direct and indirect costs on New Mexico:

> It means delaying alternative uses of the land such as agriculture, forestry, or residential development. It also means continuing to allow the pollution that the well may currently generate. In addition, delaying reclamation raises the probability that the operator falls into financial distress and is unable to pay for decommissioning, in which case the liability for the well falls to the state and its taxpayers.[49]

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[46] *Id*. at pp. 1, 11.

[47] Gregg P. Macey et al., Air Concentrations of Volatile Compounds Near Oil and Gas Production: A Community-Based Exploratory Study, Envtl. Health 14, 1–18 (2014), https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4216869/; Lisa M. McKenzie et al., Childhood hematologic cancer and residential proximity to oil and gas development, PLOS One. (2017), https://journals.plos.org/plosone/article?id=10.1371/journal.pone.0170423; Lisa M. McKenzie et al., Congenital heart defects and intensity of oil and gas well site activities in early pregnancy, Environ Int. 2019 Nov;132:104949 (2019), https://pubmed.ncbi.nlm.nih.gov/31327466/; V.D. Balise et al., Systematic review of the association between oil and natural gas extraction processes and human reproduction, Fertil Steril. 2016 Sep 15;106(4):795-819, https://pmc.ncbi.nlm.nih.gov/articles/PMC7528095/.

[48] U.S. Environmental Protection Agency, Inventory of US Greenhouse Gas Emissions and Sinks 1990-2018 at 3-102 (2020), https://www.epa.gov/sites/default/files/2020-04/documents/us-ghg-inventory-2020-main-text.pdf.

[49] J. Weber et al., Identifying the End: Minimum Production Thresholds for Natural Gas Wells, University of Pittsburgh Graduate School of Public and International Affairs Working Paper No. 21-500 (May 27, 2021) at pp. 7-8.

Without express regulatory intervention, oil and gas operators have an incentive to seek to avoid or delay plugging for as long as possible.

> Oil and gas well operators have a strong incentive to delay decommissioning wells. Every year of delay benefits the operator financially because of the return earned from alternative uses of the funds (their opportunity cost). Decommissioning involves expenditures that yield no revenue. Delay, on the other hand, allows the operator to earn a return on its funds, whether that is in drilling another well, paying down debt, or any number of alternatives.[50]

Unless required by regulation to timely plug their wells, operators may delay plugging for as long as possible. Once a well is inactive, it is unlikely to return to service, and the longer a well is inactive the less likely it is to ever be reactivated, even following a rise in oil and gas prices.[51] An economic study modeling the dynamics influencing operator decisions to plug or reactivate oil and gas wells found that even a dramatic increase in commodity prices—raising the price by four times—only "decreases the probability of inactivity by 18%."[52] The authors of that study concluded that "the probability of choosing to leave a well inactive does not decrease proportionately with an increase in price or an increase in recoverable reserves. In order to see a substantial reduction in the number of inactive wells a dramatic improvement in extraction technology and wellhead price would be needed."[53] A New Mexico-specific analysis of well reactivations found that some inactive wells reactivate when prices increases, but not all, noting that "[i]ncreased numbers of deactivations are seen in the year of each event, with a smaller increase in reactivations lagging after (correlated to rising prices)."[54] Of the New Mexico wells

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[50] *Id*. at p. 7.
[51] Lucija Muehlenbachs, Idle Oil Wells: Half Empty or Half Full?, Association for Energy Economics Article No. 2190 (March 25, 2009).
[52] *Id.*
[53] *Id.*
[54] Apps' Ex. 55, Peltz Dir. Test.

studied that were ever reactivated, two-thirds of the reactivations took place within two years of the well becoming inactive.[55] Wells that are inactive for longer are less likely to be reactivated. Such wells should be plugged, at the operators' expense.

Q: Why isn't it sufficient to rely on the existing regulatory requirements that require operators to plug non-producing wells or wells that are serving no beneficial purpose?

A: The significant costs of plugging and remediating wells come due for operators at the end of the productive and economic life of the well. That means the operator is compelled to make a significant financial outlay at a time when that well has stopped generating any new revenue. This creates a powerful incentive for the operator to avoid that cost. Financial assurance requirements address this dynamic by requiring operators to absorb some of the costs during the time when the well is productive, including by paying bond premiums and dedicating assets as bond collateral. Because those costs persist even after the well has stopped producing, operators have a strong incentive to prioritize prompt plugging.

Q: Why can't OCD compel operators to plug wells or sue them to recover the costs?

A: By the time an operator has defaulted on its plugging obligations, it may no longer have assets with any value, and may be actually or functionally insolvent. By their very nature, plugging obligations come due when the associated well has stopped producing and stopped generating revenue. If an operator successfully avoided plugging all its wells until they all stopped producing, or production dropped below marginal levels, then that operator would not have a source of funds to cover plugging costs. This risk is even greater for operators who acquire low-producing wells from other operators.

Even if OCD pursues an enforcement action against such an operator and prevails, there

[55] *Id.*

may be nothing left for OCD to recover. This situation becomes even more complicated if the operator files for bankruptcy, because the bankruptcy code imposes a rigid system of priority for creditors, and OCD's claims are likely to be treated as a lower priority compared to other creditors, particularly those with secured claims. OCD is then left with only the value of whatever financial assurances it secured from the operator, minus the costs of forfeiting and collecting those financial assurances.

For these reasons, OCD cannot wait until operations have ceased and obligations have come due, as would be the case if OCD merely sought to enforce plugging requirements. OCD must be able to protect the state's interests—and those of its citizens—by requiring adequate financial assurances up front and creating incentives for operators to plug wells with no beneficial use sooner rather than later.

Q: Does inadequate financial assurance impact regulators' decision making?

A: Yes. When financial assurance amounts are set too low, this can impact regulators' decision making in two ways.

First, regulators may conclude that it is not worth the expense and staff time to forfeit financial assurances following operator default. Forfeiting a financial assurance such as a surety bond or letter of credit requires OCD to file a legal action against the issuer of that financial assurance, and the issuer may contest the action. As described earlier in this testimony, this is playing out directly in New Mexico, with OCD recovering less than 3% of actual plugging costs. This doesn't just mean that there are less resources available to OCD. The lack of bond forfeiture can also skew the criteria that financial assurance providers use to evaluate bonding risk and set premium amounts. This, in turn, means that operators who would otherwise be flagged as a high risk for default and bond forfeiture are treated the same as other operators. This disadvantages

operators who comply with well plugging obligations and other operating requirements because it deprives them of the financial benefit of their good behavior.

In addition, when financial assurances are set too low, regulators may become wary of taking any form of enforcement action, including enforcing plugging requirements, out of fear that such actions will push operators toward bankruptcy. When financial assurances are adequate, regulators are free to enforce regulations without concern that an operator could respond by filing for bankruptcy. Because, under such a scenario, plugging costs are covered either by the operator or the financial assurance, regulators should be agnostic as to the risk of default. But when financial assurances are set too low, regulators cannot help but factor in the potential consequences of an enforcement action.

The reality is that in most cases this is a false choice: the operator is already functionally insolvent, and is going to go out of business and default on its plugging and compliance obligations regardless. In such circumstances, regulators' hesitation to take action merely perpetuates the fiction that the operator was ever going to plug the wells.

Q: How much does it cost OCD to plug a well in New Mexico?

A: According to OCD data, the current average cost to plug a well in New Mexico is $163,000, though OCD has reported average costs as high as $180,000 per well.

The Legislative Finance Committee, reviewing invoices for OCD-directed plugging, has reported the average plugging cost for fiscal year 2024 as $163,000. The Fiscal Impact Report prepared by the Legislative Finance Committee for House Bill 481, attached as Applicants' Exhibit 16, in the 2025 legislative session stated that "OCD costs for plugging in FY24 averaged $163 thousand per well," with the caveat that "plugging costs can vary widely based on well depth, age, type, and contractor availability. Environmental remediation for spills and cleanup of

infrastructure associated with wells (tank batteries, gathering lines, etc.) can cost considerably more than plugging."[56] And in the Legislative Finance Committee's recent report on orphan wells, it stated the average cost to OCD for plugging a well in FY24 was $163,000.[57]

Other calculations of well plugging costs in New Mexico have resulted in similar—or higher—figures. In its 2021 notice of intent to apply to the U.S. Department of the Interior (DOI) for Orphaned Well Plugging Program grants, OCD reported that it estimated spending $290,611,502 to plug and remediate 1,741 orphaned wells identified in the state.[58] That works out to an average of $166,922.17 per well. In its 2024 Phase 2 Work Plan Proposal, OCD reported "recent average plugging costs of $180K per well."[59] That updated estimate was informed by several years of implementation of the initial orphaned well plugging program.

Q: How do these actual plugging costs compare to the financial assurance levels in New Mexico's current regulations?

A: Currently, financial assurance amounts in New Mexico fall far below the average cost to plug a well.

Under the existing regulations, single well financial assurances are expressed in terms of the depth of the well, as "$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well."[60] For even a 10,000 foot well, that would equal only $45,000 in

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[56] Apps' Ex. 16, New Mexico Legislative Finance Committee, Fiscal Impact Report for H.B. 481, at 2., Feb. 26, 2025, 57th Leg. (NM 2025), https://www.nmlegis.gov/Sessions/25%20Regular/firs/HB0481.PDF.

[57] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 13, 35.

[58] State of New Mexico Energy, Minerals, and Natural Resources Department, Notice of Intent to Apply for Formula Grant Funding, (Dec. 22, 2021).

[59] State of New Mexico Energy, Minerals, and Natural Resources Department, Work Plan/Proposal for Formula Phase 2 Grant Funds, (Dec. 13, 2024).

[60] 19.15.8.9 NMAC.

financial assurance, less than a third of the actual average plugging cost.

The current blanket bonding provisions allow for significantly lower financial assurance amounts. The currently allowable blanket bond for an operator with 100 active wells is $125,000, working out to just $1,250 per well.[61] If an operator with 100 wells were to default and orphan its wells, the shortfall between the bonded amount and the well-plugging cost (using OCD's per well average of $163,000) would be $16,175,000.

Other assessments of the adequacy of New Mexico's financial assurance system have similarly found a staggering gap between bonded amounts and actual plugging costs. The April 2021 Center for Applied Research report, commissioned by the New Mexico State Land Office, identified a gap of over $8 billion between the total funds available through financial assurance held by the state and the estimated total costs of well plugging and infrastructure cleanup (including pipeline decommissioning).[62]

Not at all surprisingly, OCD has acknowledged that "because of statutory limits on financial assurance the amounts available for forfeiture are typical [sic] below plugging costs."[63] In discussing a scenario where four operators orphaned a total of 100 wells, OCD stated that:

> "[g]iven the usage of so called 'blanket bonds' covering the entirety of an operator's wells, the expected forfeiture of financial assurance for the four operators might yield at most $400K. The revenue obtained from the salvage of equipment and materials rarely exceeds the cost of deconstruction, decontamination, and transportation so OCD does not expect it to offset plugging

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[61] 19.15.8.9 NMAC.

[62] Center for Applied Research, An Analysis of the Adequacy of Financial Assurance Requirements for Oil and Gas Infrastructure Located on State Trust and Private Lands in New Mexico, April 30, 2021, https://www.nmstatelands.org/wp-content/uploads/2021/05/NM-Assurance-Assessment-May-FINAL.pdf.

[63] Apps' Ex 23, State of New Mexico Energy, Minerals, and Natural Resources Department, State of New Mexico Application for Initial Grant Funding for Orphan Well Plugging under the Infrastructure Investment and Jobs Act, at p. 22 (May 13, 2022).

costs."[64]

At OCD's average plugging cost of $163,000 per well, the shortfall for those 100 wells would be $15,900,000. And that assumes OCD would deem it worth the effort to forfeit the bonds.

Q: What is the financial risk to the state from unplugged wells?

A: All oil and gas wells drilled in New Mexico will eventually need to be plugged, and the majority that have ever been drilled in New Mexico have yet to be plugged. Each unplugged well represents a potential liability to the state. If the operator defaults on its plugging obligation, the state bears responsibility for ensuring the well is plugged.

The number of orphaned wells in New Mexico estimated by the Legislative Finance Committee—between 700 and 2,100—makes clear that the oil and gas industry does default on its obligations. The actual number is almost certainly at the higher end of this range, and includes wells that have stopped producing and have yet to be plugged, and where the operator lacks the means or willingness to complete the plugging. The ranks of these inactive wells grows every year.

Approximately 110,000 wells have been drilled for oil and gas in New Mexico. Of these, approximately 63,000 still need to be plugged.[65] That's a total maximum liability to the state of over $11 billion.

New Mexico must ensure that its regulatory program is structured in such a way that industry covers as much of that $11 billion plugging liability as possible.

Q: Are certain types of wells at greater risk of abandonment than others?

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[64] State of New Mexico Energy, Minerals, and Natural Resources Department, Work Plan/Proposal for Formula Phase 2 Grant Funds, at p. 14 (Dec. 13, 2024).

[65] Robert Schuwerk & Greg Rogers, Billion Dollar Orphans, Carbon Tracker (Sept. 2020), at p. 27.

Yes. Some types of wells are at greater risk of orphaning, and therefore should be subject to higher financial assurance requirements.

In general, wells that have stopped producing, or produce oil or gas at only very low quantities, carry a high risk of well orphaning. This is because these wells have transitioned from being a net revenue generating asset to a liability. Operators have a strong economic incentive to avoid the cost of plugging these wells, or they may simply lack the resources to do so.

The risk of well orphaning grows with the length of time following the last profitable production. The longer the gap of time between when the well generated revenue and when plugging expenses are incurred, the greater the risk of orphaning. "[D]elaying reclamation raises the probability that the operator falls into financial distress and is unable to pay for decommissioning, in which case the liability for the well falls to the state and its taxpayers."[66] OCD itself has recognized that "[i]t is OCD's experience that wells which have been inactive for extended periods of time are often held by operators who have become insolvent or, at a minimum, are incapable of complying with applicable regulatory requirements including those related to production and well plugging."[67]

For this reason, the wells most likely to be orphaned are:

- Inactive wells;
- Wells in approved temporary abandoned status;
- Wells in expired temporary abandoned status;
- Low-producing "marginal" wells (particularly at the time of transfer); and

[66] Weber et al., Identifying the End: Minimum Production Thresholds for Natural Gas Wells, University of Pittsburgh Graduate School of Public and International Affairs Working Paper No. 21-500 (May 27, 2021) at p. 7.

[67] State of New Mexico Energy, Minerals, and Natural Resources Department, Work Plan/Proposal for Formula Phase 2 Grant Funds, (Dec. 13, 2024).

- Wells (including active wells) held by operators with a large number of inactive wells and low production averages.

Such wells require particular attention and should be subject to additional requirements to minimize the risks of well orphaning and ensure that sources of plugging funds are available, so that the state is not forced to re-direct general funds to cover the costs of plugging these wells.

Q: How do the proposed amendments allow financial assurance requirements to be tailored to directly target those wells at greatest risk of abandonment?

A: The proposed amendments address the need for financial assurance requirements specifically tailored to the higher risk posed by certain types of wells. The Oil and Gas Act authorizes the establishment of "categories of financial assurance after notice and hearing." NMSA 1978, § 70-2-14(A). The proposed amendments establish categories of increased financial assurance for high risk wells and high risk operators. These categories are (1) marginal wells, (2) operators with over 15% of their wells in marginal or inactive status, and (3) inactive wells, including wells in approved temporary abandonment and expired temporary abandonment. *See* Apps' Ex. 1, Proposed 19.15.8.9.D and E NMAC.

In addition, the proposed amendments increase the amount of single well financial assurance for active wells to better reflect the actual costs to the state of plugging and increase the blanket bond for active wells to the statutory maximum of $250,000, no matter how many active wells are held by an operator. *See id.* 19.15.8.9.C NMAC; NMSA 1978, § 70-2-14(A).

Q: Will increased financial assurance requirements harm small businesses and hurt New Mexico's economy?

A: The experiences of regulators in other jurisdictions make clear that increasing financial assurance requirements leads to decreases in well orphaning and better environmental

compliance among operators, with no or minimal impact to overall oil and gas production. Although such changes may lead some small operators to exit the market, these operators are the ones most likely to orphan wells and to have other compliance problems. Other operators are able to take over the wells of operators who exit the market, or are otherwise make up the production. And many small operators continue to operate after the regulatory changes take effect.

An economic analysis of the effect of a 2001 increase to Texas' financial assurance requirements for oil and gas producers concluded that:

> Small producers were substantially less likely to plug wells after production and more likely to violate water protection rules when firms could avoid environmental costs through bankruptcy. Despite affecting small firms, the bond requirement yielded large environmental improvements because small producers caused a disproportionate share of environmental problems. The bond requirement reduced the number of orphan wells per lease among the smallest 80 percent of firms by 76 percent, decreasing the industry-wide orphan well rate by 65 percent. The number of rules violations per lease among the smallest 80 percent of firms fell by 33 percent, reducing the industry-wide violation rate by 25 percent.[68]

The study looked at the effects of imposition of the first across-the-board financial assurance requirement in the state,[69] and found that the new financial assurance requirement had a negligible impact on oil and gas production:

> Notably, the state's total output of oil and gas was essentially unaffected by the policy. This is because the firms affected by the policy accounted for a small fraction of production, and because most of the valuable production associated with exiting firms was reallocated to other producers instead of shutting down.[70]

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[68] Judson Boomhower, Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk, American Economic Review Vol. 109, No. 2, Feb. 2019 at pp. 420-21.
[69] *Id*. at pp. 403-4. The new financial assurance requirement set bond amounts at $2 per foot of well depth, and blanket bonding ranging from $25,000 for up to 10 wells to $250,000 for over 100 wells. *Id*.
[70] *Id*. at p. 422.

The reason for this negligible economic impact is that most producers, including some small producers, continued to operate under the new requirements. And the operators who exited the market were the ones most responsible for wells being orphaned and for environmental violations:

> First, the industry continued to include many small firms that secured coverage and operated profitably. Even after the bond requirement, over half of producers had fewer than five leases. Second, firms that left the industry in response to the policy had systematically poor environmental records, while firms that remained increased their safety effort.[71]

A separate study, looking at the effects of changes to oil and gas regulations in North Dakota, including increased financial assurance requirements, observed nearly identical results as those found in the Texas study.[72] Among other things, the North Dakota study compared changes to production in North Dakota following implementation of the regulations with changes to production across the border in Montana during the same time period. The study found "no statistical change in the pace of drilling wells after the ND regulations came into effect," and that "[t]he reduction in production for small operators in ND after the regulation went in effect, relative to production in MT, is about 0.5%."[73] Ultimately, the authors of the North Dakota study concluded that "[t]he regulation is associated with a level shift down in the number of incidents that occur while drilling, which is consistent with higher bond requirements encouraging better safety and exit of relatively unsafe operators."[74]

Although the Texas and North Dakota laws reviewed in the two studies required bond amounts that are lower in absolute terms than the adjusted financial assurance amounts in the

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[71] *Id.* at p. 423.
[72] Ian Lange & Michael Redlinger, Effects of stricter environmental regulations on resource development, Journal of Environmental Economics and Management, 96, 60–87 (July 19).
[73] *Id*. at p. 61.
[74] *Id*. at p. 76.

proposed amendments, each law represented a significant increase compared to prior requirements. The Texas law was the first time the majority of operators had been required to provide any financial assurance,[75] and the North Dakota law more than doubled the amount of the required bond.[76] I believe that the proposed amendments would have a similar effect in New Mexico to what was observed in those states: irresponsible operators may be pushed out of the market, but the overall impact to the industry will be small and the companies who continue to operate will have better compliance with plugging and environmental requirements.

Small operators make the same commitments as large operators to complete plugging once wells stop producing. Timely and proper plugging and site remediation is a fundamental part of doing business as a well operator. If an operator is not able to cover the cost of plugging their wells or to satisfy financial assurance requirements, they should not be operating wells. When I go to the doctor, I expect them to be properly licensed and to carry adequate malpractice insurance, whether they're in solo practice or part of a big corporate medical practice. I don't compromise on those fundamental baseline requirements just because of the size of the practice. The same principle should hold for companies that choose to participate in the oil and gas industry.

The public overwhelmingly expects and demands that all operators bear financial responsibility for plugging their wells. A recent Colorado College poll of voters in New Mexico and other western states found that:

> Western voters offer almost unanimous agreement that oil and gas companies should be required to pay for all the clean-up and land restoration costs after drilling is finished. Support for this proposal is staggering (92 percent) and

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[75] Judson Boomhower, Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk, American Economic Review Vol. 109, No. 2, Feb. 2019 at pp. 403-4.
[76] Ian Lange & Michael Redlinger, Effects of stricter environmental regulations on resource development, Journal of Environmental Economics and Management, 96, p. 63 (July 19).

> consistent with previous years (90 percent support in 2024 and, and 91 percent in 2023 and 2022). This year, 89 percent or more voters in each state support requiring companies pay for clean-up and restoration, with 71 percent or more saying they "strongly" support the clean-up requirements. Overwhelming support for this proposal transcends gender, age, party lines, community type, and ethnic background.[77]

There is no reason this expectation should apply differently to small operators compared to large operators.

While increasing financial assurance requirements and making other commonsense changes to New Mexico's oil and gas regulations may lead to changes to the overall makeup of oil and gas operators, these changes should not affect overall production in the state, but should lead to greater compliance with plugging and other requirements.

Q: If financial assurance amounts are increased, will the full cost of the increases be borne by the operators?

A: Most operators satisfy financial assurance requirements by posting surety bonds. The operator is not required to pay the full-face value of the bond. Instead, the surety bond company charges a premium that the operator must pay on an annual basis to maintain the bond. In exchange, the surety commits to paying out up to the face value of the bond to the regulator in the event the operator defaults on its well plugging obligation. Annual premiums for surety bonds are typically between 1.0 and 2.5 percent.[78] Surety providers may also require operators to pledge collateral, which would be released once the well is plugged and the bond no longer needed.[79] These are costs to the operator, but amount to less—often far less—than the face value

[77] New Mexico, Colorado College's State of the Rockies Project: 2025 Conservation in the West Poll, Colorado College (2025), at p. 4.
[78] Judson Boomhower, Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk, American Economic Review Vol. 109, No. 2, Feb. 2019 at p. 404.
[79] *Id*.; David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97 at pp. 192, 194, Oct. 2, 2000.

of the bond.

The surety bonding industry is a competitive market, with multiple providers competing for the business of operators. Surety providers set the terms of individual bonds depending on the risk of default they perceive from the operator, balanced against the risk that a different provider will offer more favorable terms. To the extent an operator may only be able to secure a bond under onerous terms, with higher premiums and more collateral required, this is a clear signal that the surety industry perceives that operator to represent a high risk of default. Such operators also pose a high risk to the state's interests in that they are more likely to default and orphan wells and to pose other compliance problems. If the market makes it difficult or impossible for such operators to secure the bonds needed to operate, that is to the benefit of New Mexico by keeping high-risk operators out of the industry.

The operators who have profited from oil and gas production should be the ones to bear the costs of cleanup. Under current policy, that is often not the case, with those costs instead passed on to the public as the direct cost of plugging and/or through negative environmental, property value, and health impacts from unplugged wells.

Current New Mexico Requirements

Q: Mr. Morgan, what are the requirements for financial assurance for oil and gas operators currently set forth in the Oil and Gas Act at NMSA 1978, § 70-2-14?

A: The Act requires that operators furnish financial assurance for the plugging and abandonment of their wells, and directs OCD[80] to "establish categories of financial assurance after notice and hearing." NMSA 1978, § 70-2-14(A). The Act identifies several categories for

[80] The Commission exercises concurrent jurisdiction and authority with OCD. NMSA 1978, § 70-2-6(B).

OCD to include. The Act does not limit the categories that OCD may create, but instructs OCD that "[i]n establishing categories of financial assurance, the oil conservation shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and such other factors as the oil conservation division deems relevant." *Id.*

Two of the categories of financial assurance explicitly listed include a general blanket plugging financial assurance not to exceed $250,000, and a blanket plugging financial assurance for temporarily abandoned status wells to be set at an amount greater than $50,000. The Act also requires a one-well financial assurance for wells held in a temporary abandonment for more than two years or, at the operator's election, the operator may increase its blanket plugging financial assurance to cover wells held in temporary abandonment. *Id.*

Q: What are the general requirements for financial assurance currently set forth in the Commission's rules at 19.15.8 NMAC?

A: Requirements for financial assurance are set forth in the Commission's rules at 19.15.8 NMAC. Among other provisions, the rules specify requirements for financial assurance for active and inactive wells, for surety bonds, and for the release of financial assurance upon transfer.

The rules specify under 19.15.8.9.A NMAC that an operator who drills or acquires oil, gas, or injection wells shall furnish financial assurance in an acceptable format.

For active wells, 19.15.8.9.C NMAC requires either a single well financial assurance or a blanket plugging financial assurance dependent on the number of wells the operator holds. The single well financial assurance is set at $25,000 plus $2 per foot of the projected depth of the well. The blanket plugging financial assurance is set at $50,000 for 1-10 wells, $75,000 for 11-50 wells, $125,000 for 51-100 wells, or $250,000 for more than 100 wells.

For inactive wells, which have been in temporarily abandoned status for more than two years or for which the operator is seeking approved temporary abandonment, 19.15.8.9.D NMAC again requires either a single well financial assurance or a blanket plugging financial assurance. The single well financial assurance is again set at $25,000 plus $2 per foot of the projected depth of the well. The blanket plugging financial assurance is set at $150,000 for 1-5 wells, $300,000 for 6-10 wells, $500,000 for 11-25 wells, and $1,000,000 for more than 25 wells.

Under 19.15.8.9.E NMAC, operators whose financial assurance does not cover all of their wells may file either additional single-well financial assurance or a replacement blanket bond.

The rules provide additional requirements for cash and surety bonds at 19.15.8.10 NMAC. Specifically, surety bonds must be issued by a reputable corporate surety authorized by the office of the superintendent of insurance to do business in New Mexico.

Under 19.15.8.12.B NMAC, the transfer of a property or change of operator does not by itself release a financial assurance. The OCD must not approve a request for change of operator for a well until the new operator has the required financial assurance in place.

Q: Mr. Morgan, in your opinion, are the Commission's rules governing financial assurance adequate to protect the State of New Mexico and taxpayers from orphaned wells for which the state then becomes responsible?

A: No, they are not, for the reasons set forth above. Even within the statutory limitations, the Commission's rules should be amended to better protect the state, its residents, and its environment from the risks of orphaned wells.

Applicants' Proposed Amendments

Q: I'd like to now discuss Applicants' specific proposals to amend 19.15.8.9 NMAC – Categories and Amounts of Financial Assurance for Well Plugging, beginning with 19.15.8.9.A NMAC. What amendments do Applicants propose to that subsection?

A: Applicants propose the following:

> **19.15.8.9.A Applicability.** An operator who has drilled or acquired, is drilling or proposes to drill or acquire an oil, gas or injection or other service well within this state shall furnish a financial assurance acceptable to the division in accordance with 19.15.8.9 NMAC and in the form of an irrevocable letter of credit, plugging insurance policy or cash or surety bond running to the state of New Mexico conditioned that the well be plugged and abandoned and the location restored and remediated in compliance with commission rules, unless the well is covered by federally required financial assurance. The division shall not approve, and the operator shall not proceed with any proposed drilling or acquisition until the operator has furnished the required financial assurance.

This amendment ensures that the financial assurance is in place prior to drilling or acquisition. This amendment does not change current practice but simply clarifies the regulatory requirement. Still, it is an important principle to establish unambiguously.

This is an important requirement because it prevents a situation where an operator may incur a plugging obligation—by drilling or acquiring a well—before it has provided the required financial assurance. This avoids a scenario where the operator ultimately fails to secure the financial assurance, but has already incurred the obligation. Under that scenario, there would be a chance that the operator could then default on its obligation and there would be no financial assurance available for OCD to claim and then put toward the cost of finishing the work and plugging the well.

Q: What amendments do Applicants propose to financial assurance requirements for active wells at 19.15.8.9.C NMAC?

A: Applicants propose:

C. Active wells. An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsections D and E of 19.15.8.9 NMAC in one of the following categories:

(1) a one well plugging financial assurance in the amount of $150,000 per well;~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance in the amount of $250,000 ~~following amounts~~ covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC.~~:~~

~~**(a)** $50,000 for one to 10 wells;~~
~~**(b)** $75,000 for 11 to 50 wells;~~
~~**(c)** $125,000 for 51 to 100 wells; and~~
~~**(d)** $250,000 for more than 100 wells.~~

The proposed amendments would modify the "categories and amounts of financial assurance for well plugging" at 19.15.8.9 NMAC to increase the one-well financial assurance amount for active wells to $150,000, and would set all blanket financial assurances to the statutory maximum of $250,000.

One-well financial assurance: The proposed modification to the one-well financial assurance alters the way that one-well financial assurance amounts are calculated. Under the current approach, one-well financial assurances are set at "$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well." 19.15.8.9.C(1) NMAC. The proposed amendment would replace this formula with the fixed amount of $150,000.

As mentioned, the Oil and Gas Act requires OCD to "establish categories of financial assurance after notice and hearing. Such categories shall include a . . . one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance." NMSA 1978, § 70-2-14(A). While the Commission may consider the well depth in setting financial assurance amounts, there is no statutory requirement that the financial assurance amount be pegged to the depth of the well.

A one-well financial assurance of $150,000 per well closely approximates an amount

"sufficient to reasonably pay the cost of plugging the wells." As described above, OCD reports that the average cost to plug a single orphaned well is $163,000.[81] While there will always be some variation in actual plugging costs from well to well, it is reasonable to use a figure close to the average plugging cost. This approach eases the administrative burden on both operators and OCD. And because the vast majority of operators maintain multiple wells, this averaging is likely to work out across the operator's well inventory. Although the use of a $150,000 per well figure is still likely to result in a gap between financial assurance amounts and actual plugging costs, the significantly smaller scale of this gap can be addressed through use of the Reclamation Fund.

In contrast, the current approach to calculating a one-well financial assurance—$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well—is not sufficient to reasonably pay the cost of plugging a well. In almost all cases, actual plugging costs will far exceed a financial assurance calculated on this basis. Even a well with a depth of 10,000 feet would have a financial assurance of only $45,000, far below the actual cost of plugging.

Furthermore, the primary cost drivers in well plugging are not related to the depth of the well. Much more important are factors including the condition of the well and issues related to access to the well. If a well's casings have corroded or otherwise deteriorated, or if there are foreign materials in the well, it will be more expensive to plug. Similarly, if access roads need to be created or improved in order to allow for passage by the plugging rig, the costs will be higher. These cost factors are inherently incorporated into the $150,000 based on average plugging costs, but are not captured by an approach based purely on one variable, well depth.

[81] *See, e.g.*, Apps' Ex. 16, New Mexico Legislative Finance Committee, Fiscal Impact Report for H.B. 481, 57th Leg. (NM 2025).

The proposed amendment also includes a clarification, adding the word "plugging" to the phrase "one well financial assurance" to clarify that this is a "one-well plugging financial assurance." This modification makes this provision consistent with other references to "plugging financial assurance" throughout this section. The modification also makes this provision consistent with Section 70-2-14(A) NMSA 1978, which uses the phrase "one-well plugging financial assurance."

Blanket financial assurance: The proposed amendments would replace the current scaled approach to calculating blanket financial assurance amounts with a single blanket financial assurance set at the maximum rate of $250,000.

The amendments would provide for a single blanket financial assurance amount of $250,000 for "active wells" at 19.15.8.9.C(2) NMAC.

The current regulations provide four categories of blanket assurance amounts for active wells, from $50,000 for one to 10 wells, to $250,000 for more than 100 wells. 19.15.8.9.C(2)(a-d). This means that the per-well bonded amount ranges from $25,000 (for an operator with two wells) to less than $1,250 (for an operator with more than 200 wells). These amounts are far below OCD's average per-well plugging cost of $163,000. However, the legislature has set the maximum amount for blanket bonds at $250,000.

Q: What amendments do Applicants propose to the financial assurance requirements for the new category of marginal wells and for inactive wells at 19.15.8.9.D NMAC?

A: Applicants propose:

> **D. Marginal wells and inactive wells.** Notwithstanding the provisions in Subsection C(2) in this Section:
>
> **(1)** As of the [effective date of amendments] a transferee operator shall provide a one well plugging financial assurance of $150,000 for each marginal well prior to transfer.
>
> **(2)** Beginning January 1, 2028, an operator shall provide a one well plugging financial assurance for each marginal well.
>
> **(3)** An operator with over 15 percent of their wells in

marginal or inactive well status, or a combination thereof, shall provide a one well plugging financial assurance in the amount of $150,000 for each well registered to the operator until the percentage of the operator's marginal and inactive wells is decreased below 15 percent.

(4) An operator may furnish all necessary one well plugging financial assurance in the form of a single instrument.

Q: What is the basis for the new category of marginal wells?

A: As discussed earlier in this testimony, "marginal well" is a new category of financial assurance initially proposed by OCD based on their staff's experience with high risk wells. OCD proposed the provisions for 19.15.8.9.D NMAC in its February 12, 2025 Redline Proposal, and Applicants have adopted these proposals.

"Marginal well" is defined, under the proposed amendments, as "an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period." 19.15.2.7.M(2) NMAC. Such marginal wells pose a significant risk of being orphaned because the revenue they will produce over their remaining production may be less than the cost of plugging and remediating the well. This creates a powerful incentive for operators, particularly new operators who did not enjoy the original profitable period of higher production, to avoid these costs. The proposed definition of "marginal well" includes components related to both the amount of production (less than 1,000 BOE in 12 months) and the number of days the well produces (180 days within consecutive 12 months). Each component is critical. The total amount of production relates directly to the revenue generated by that well. The number of days producing is also important, because operators can manipulate well production to make wells appear artificially productive, but only over short periods of time, giving a false impression that a well is economic when it is not.

Q: Approximately how many wells would be categorized as marginal wells?

A: As stated above, according to Mr. Purvis's analysis, approximately 3,900 wells would be

categorized as marginal wells under the new rules, constituting 6.6% of the well population and 0.048% of total production.[82] These wells provide essentially no economic utility to their owners or to the state, but pose a very high risk of being orphaned and requiring state resources to plug.

Q: What is the basis to require that operators provide a one well plugging financial assurance of $150,000 for all marginal wells beginning January 1, 2028?

A: Proposed 19.15.8.9.D NMAC imposes increased financial assurance requirements for marginal wells by requiring one-well financial assurances for all marginal wells beginning January 1, 2028. 19.15.8.9.D(2) NMAC. The proposal recognizes that marginal wells carry a high risk that should be reflected in the amount of financial assurance the state requires to protect against the well becoming orphaned and recognizes that $150,000 approximates the average cost to OCD to plug a well. This phased-in approach gives operators with existing marginal well inventories currently covered under blanket financial assurances time either to plug these wells or secure individual-well financial assurances.

Q: What is the basis to require that operators post a one well plugging financial assurance of $150,000 for marginal wells at the time of transfer?

A: The one well financial assurance requirement would apply immediately for any marginal well being transferred to a new operator. 19.15.8.9.D(1) NMAC. This requirement recognizes that the transfer of low-producing wells to under-resourced operators is a major contributor to well orphaning. Transfers increase the risk of a well being orphaned by separating the profits generated by that well (held by the prior operator) from the expense of plugging (now passed on to the new operator). The transfer requirement also precludes operators from avoiding the January 2028 deadline by transferring away their marginal wells rather than plugging them or

[82] Apps' Ex. 40.

providing the one-well financial assurance.

Q: Do any other states require one well plugging financial assurances for low-producing or marginal wells at the time of transfer?

A: Yes. At least two other states—Arkansas and California—require operators to provide one well plugging financial assurances at the time a low-producing well is transferred.

Arkansas' oil and gas regulations pertaining to well transfers provide that "[i]f the transfer is for a gas well producing less than 25 MCF[83]/day per Arkansas Oil and Gas Commission records, or a well that has received an approved temporarily abandonment status in accordance with General Rule B-7, then . . . the New Permit Holder shall file an additional, well specific financial assurance of $35,000 for each natural gas well." Code Ark. R. 118.03.1-B-4(h)(4). Twenty-five MCF/day is equivalent to 4.4 BOE/day[84] or approximately 1,606 BOE per year, comparable to the proposed definition of "marginal well" as a well producing 1,000 BOE per year or less. In Arkansas, $35,000 constitutes a full cost financial assurance. In a 2021 filing with the DOI, Arkansas's oil and gas regulator has estimated the average cost of plugging orphaned wells in the state to be $15,000.[85] This regulation therefore requires a one well full cost bond for the transfer of any marginal well (or any well in temporarily abandoned status).

In California, before an operator can acquire by transfer a well whose "average daily production" is equal to or less than "15 barrels of oil or 60,000 cubic feet of natural gas," the operator must "file with the supervisor an individual indemnity bond for the well or production facility, or a blanket indemnity bond for multiple wells or production facilities, in an amount

[83] One thousand cubic feet.
[84] 6 MCF is equivalent to 1 BOE. https://www.eia.gov/petroleum/wells/.
[85] Arkansas Department of Energy and Environment, Notice of Intent to Apply for Formula Grant Funding, (Dec. 22, 2021) at p. 3.

determined by the supervisor to be sufficient to cover, in full, all costs of plugging and abandonment, decommissioning of the facility, and site restoration." Cal. Pub. Res. Code § 3205.8(a). Although this California statute allows the use of a blanket bond for multiple marginal wells, the amount of that blanket bond must still be sufficient to cover the full cost of plugging all of the covered wells. In other words, the amount of financial assurance required is equivalent to one well financial assurances for each covered well.

The proposed amendment therefore represents a commonsense approach to financial assurances for low producing wells at the time of transfer, consistent with the approach already employed by other states.

Q: What is the basis to require an operator with over 15% of their wells in marginal or inactive status, or a combination of both, to provide a one well plugging financial assurance of $150,000 for all of their wells?

A: The proposed amendments also require one well financial assurances for all wells held by an operator "with over 15 percent of their wells in marginal or inactive well status, or a combination thereof." 19.15.8.9.D(3) NMAC. This addresses the fact that operators with a significant proportion of marginal and inactive wells pose a heightened threat of failure because they may not be able to generate sufficient cash flow to meet their well plugging obligations. Operators with a higher proportion of marginal and inactive wells generate less revenue at the same time they face higher costs from plugging.

Requiring a one well financial assurance set at an amount pegged to the actual cost of plugging is not a penalty imposed on operators. Instead, it is a commonsense means by which the state can protect its own interests and those of its residents.

As discussed above, financial assurances set at levels at or near the actual cost of

plugging protect the interests of the state by providing a financial backstop in the event of operator default, and by providing an incentive for operators to complete timely plugging. Some regulators, including in New Mexico, have made the determination that such protections and incentives are not necessary for certain types of operators. Some operators, the theory goes, generate sufficient ongoing revenue that they should not have any trouble covering their plugging costs, and therefore represent a low risk of default and do not require a full financial assurance backstop. This is a benefit extended to certain operators, which must be weighed against the corresponding increased risk borne by the state.

The logic underlying the policy of allowing certain operators to provide less than adequate bonding simply does not hold for operators who have more than 15 percent of their wells inactive or producing at only marginal levels. Such operators face the simultaneous pinch of reduced revenues at the same time they face increased immediate plugging costs.

The proposed amendments' approach of requiring operators to provide one well financial assurances for all wells when more than 15 percent of their wells are marginal or inactive provides an incentive for operators to plug wells to keep their percentage low, and discourages operators from specializing in the acquisition of low-producing wells. Such operators who take this approach may be betting on a dramatic increase in commodity prices that would render their wells profitable, or may be betting that they can pocket whatever remaining revenue their wells can produce while avoiding the plugging costs. In either case, the state and public monies should not be compelled to underwrite the risk.

Q: Why do Applicants propose giving an operator the option of furnishing a single financial instrument to satisfy multiple one well financial assurance requirements?

A: The proposed amendment maintains the ability of operators to avail themselves of the

administrative efficiency of providing a single financial assurance for all of their wells, but the amount of that bond would be calculated as "equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E of 19.15.8.9 NMAC." 19.15.8.9.E(2) NMAC. This lets operators avoid the need to negotiate and secure multiple separate bonds or other financial assurances, while still allowing New Mexico to protect its interests by setting the amount on the basis of the one well financial assurance.

Q: Are such financial assurance instruments available in the marketplace?

A: Yes. The financial assurance industry is a competitive market with many participants. Surety providers regularly negotiate and provide a wide range of bonds and other financial assurance instruments, as do other financial assurance providers such as commercial banks. If there is demand for a certain type of financial assurance instrument, the market will fill that demand (albeit on terms—including collateral and premium requirements—that provide the financial assurance provider with an opportunity to recover a profit).

Q: Turning to inactive wells and wells in approved and expired temporarily abandoned status, what amendments do Applicants propose for 19.15.8.9.E NMAC?

A: Applicants propose:

> **E.~~D.~~ Inactive wells and wells in approved and expired temporarily abandoned status.** An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories:
>
> **(1)** a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or
>
> **(2)** a blanket plugging financial assurance equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E~~D~~

of 19.15.8.9 NMAC.~~:~~

~~**(a)** $150,000 for one to five wells;~~
~~**(b)** $300,000 for six to 10 wells;~~
~~**(c)** $500,000 for 11 to 25 wells; and~~
~~**(d)** $1,000,000 for more than 25 wells.~~

The proposed amendments provide for a one well plugging financial assurance of $150,000 per well for "inactive wells and wells in approved and expired temporarily abandoned status." 19.15.8.9.E NMAC. Similarly, the proposed amendments modify the blanket bond plugging financial assurance to also require financial assurance "equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E." The provision of a blanket bond offers operators the convenience of posting a single financial assurance for all of their inactive and temporarily abandoned wells.

Q. Why is it necessary to increase the required bonding for inactive wells and wells in approved and expired temporarily abandoned status?

A. By increasing the bonding required for inactive wells and wells in temporary abandoned status, the proposed amendment ensures that New Mexico will have adequate financial assurances for the categories of wells at highest risk of being orphaned.

The Interstate Oil and Gas Compact Commission (IOGCC) has specifically highlighted the risk of well orphaning posed by inactive wells and by operators with a high percentage of inactive wells. In a 2021 report, the IOGCC noted that:

> The number of idle wells in a state or province is a concern because of the potential for the wells to deteriorate over time or become orphans. An even more critical factor is the number of idle wells held by an individual operator, especially as a percentage of the operator's total wells that have been drilled but not plugged. A high percentage of idle wells may indicate an increased vulnerability of the state or province to the operator becoming insolvent and leaving orphan wells. States and provinces use various approaches to ensure operators actively manage their idle well inventories and plug wells with no future

beneficial use.[86]

A report prepared by the Louisiana Legislative Auditor reached a similar conclusion, and similarly noted that it is common for state regulators to impose stricter financial assurance requirements on inactive wells and operators with a high percentage of inactive wells:

> At least 11 states implement additional financial security requirements for inactive wells that account for higher risk of becoming orphaned. For example, some states require higher amounts for wells that have remained inactive past a certain time period, for inactive wells with greater depths or larger facilities, when operators have a history of noncompliance, or when operators have more than a certain number of inactive wells. In addition, some states limit whether inactive wells can be covered by blanket security policies.[87]

The proposed amendment therefore adopts a commonsense solution to address a demonstrated risk of well orphaning. This approach is in line with the regulations of many other oil and gas producing states.

This amendment specifically includes eliminating the availability of blanket plugging financial assurance for inactive wells and wells in approved and expired temporarily abandoned status because these wells are at the highest risk of orphaning, and blanket financial assurances by definition cover only a fraction of actual plugging costs.

The New Mexico legislature has recognized that wells in temporary abandonment/inactive status represent a higher risk by setting a **minimum** blanket bond amount of $50,000 for wells in temporary abandoned status—there is no maximum—and by requiring a one well financial assurance on any well that has been held in a temporary abandonment for more than two years. NMSA 1978, § 70-2-14(A).[88]

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[86] Apps' Ex. 28, Interstate Oil & Gas Compact Commission, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies, (2021) at p. 8.

[87] Louisiana Legislative Auditor, Progress Report: State Efforts to Address Orphaned Oil and Gas Wells, (Oct. 24, 2024), at p. 18.

[88] Or the operator may increase its blanket plugging financial assurance to cover wells held in temporary abandoned status. *Id.*

Q. Please elaborate on the risks associated with blanket bonding.

A. Simply put, allowing blanket plugging financial assurances for high risk wells dramatically increases the likelihood that the state will be compelled to redirect general funds to cover the costs of well plugging. Eliminating this option for high risk wells protects the state and makes it more likely that the operators themselves will plug the wells.

The first problem with blanket financial assurances is that this approach results in very limited per-well coverage. As discussed above, under the amounts provided in New Mexico's current financial assurance regulations, per-well coverage under a blanket financial assurance can be $1,250 or lower. That's less than one percent of OCD's actual average plugging cost of $163,000. When an operator who has provided only a blanket financial assurance defaults and orphans its wells, almost all of those plugging costs must be covered by the state.

The fundamental flaws with blanket financial assurances go deeper than just the failure to cover actual plugging costs, however. Blanket financial assurances provide very little incentive for operators to plug their wells as they cease producing. This is because when an operator plugs a well covered under a blanket financial assurance, it does not receive a corresponding decrease in the carrying costs associated with maintaining the blanket financial assurance. Instead, the operator continues to pay the same costs to maintain the same blanket financial assurance for its remaining wells. Plugging a particular well does not reduce the financial assurance obligation, because the remaining number of plugged wells would be covered by the same blanket bond. This encourages operators to delay plugging these wells, potentially until all wells covered under that blanket financial assurance have stopped producing. As discussed above, the greater the gap of time between when a well stops producing revenue and when the plugging costs come due, the greater the risk that the well will be orphaned, and that insufficient funds will be available to

OCD in the event of operator bankruptcy.

The use of blanket financial assurance bonding is particularly inappropriate for an industry like oil and gas extraction that experiences industry-wide "boom-and-bust cycles" that "can lead operators to drill wells when prices for oil and gas are high but can contribute to bankruptcies when prices are low."[89] Bankruptcy occurs at the operator level, rather than the individual well level. So, when an operator defaults, all of its wells—particularly its inactive and marginal wells—are likely to be orphaned. This poses only a minimal problem for the regulator when those wells are all covered by individual bonds, but it poses a massive problem when those wells are covered by a single blanket financial assurance.

The Center for Applied Research recognized this dynamic in its 2021 report, noting that "[i]t is worth emphasizing that the NMOCD requires operator-specific financial assurance as opposed to well-specific financial assurance. Therefore, the effective financial assurance coverage for individual wells on state trust and private fee lands within New Mexico can vary considerably. That is, as the number of wells a permitted entity operates increases, the per well financial assurance coverage decreases."[90] The Center referred to this as a "regressive financial assurance requirement structure."[91]

Even though the current regulations set blanket financial assurance amounts for inactive wells at levels higher than what's required for active wells, these amounts are still far too low. Under the blanket financial assurance categories currently provided at 19.15.8.9 NMAC, the

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[89] U.S. Gov't Accountability Office, Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells, GAO-19-615 at p. 1 (Sept. 2019).

[90] Center for Applied Research, An Analysis of the Adequacy of Financial Assurance Requirements for Oil and Gas Infrastructure Located on State Trust and Private Lands in New Mexico, April 30, 2021, https://www.nmstatelands.org/wp-content/uploads/2021/05/NM-Assurance-Assessment-May-FINAL.pdf.

[91] *Id*.

highest per-well amount possible is $75,000, for an operator with two inactive wells covered by a single blanket financial assurance. The lowest per-well amount is $20,000 per well or lower, for operators with 25 inactive wells, or with 50 or more inactive wells. These amounts are all far below OCD's actual average per well plugging cost of $163,000.

The proposed elimination of the use of blanket financial assurances for marginal, inactive, and approved and expired temporarily abandoned status wells is appropriate and justified. These wells have the greatest chance of being orphaned, because the revenue generated by their remaining production will be less than the cost to plug the wells. This creates a powerful incentive for the operator to find a way to avoid the plugging costs, including by orphaning the wells. Eliminating the availability of blanket financial assurances for these wells also creates additional incentives for operators to plug these wells in a timely fashion. Imposing individual well financial assurance requirements for these wells should lead operators to plug these wells sooner in an effort to avoid the ongoing fees and carrying costs required to maintain individual financial assurances.

As discussed above, the availability of certain alternate financial assurance requirements for operators of wells with a low risk of default is a benefit that the state may choose to extend in certain circumstances. A restriction of the availability of this benefit for certain types of wells or certain operators is not a penalty, but a commonsense step to reduce the risk to the state.

Q: Why do Applicants propose expressly including "approved and expired temporarily abandoned" wells in 19.15.8.9.E NMAC?

A: The proposed amendment provides better consistency between the language of the regulation and the language of the statute at 70-2-14 NMSA 1978. The statute expressly references wells in "temporarily abandoned status." NMSA 1978, § 70-2-14(A). It specifies

requirements for financial assurances for such wells, requiring that any "blanket plugging financial assurance for temporarily abandoned status wells . . . shall be set by rule at amounts greater than fifty thousand dollars ($50,000), and one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance" and requiring "a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years or, . . . allow[ing] an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status." *Id*. The current regulations, however, only address financial assurances for wells "that have been in temporarily abandoned status for more than two years or for which the operator is seeking approved temporary abandonment." *Id*.

The current regulations therefore omit several important categories of inactive and temporarily abandoned wells, including: (1) wells that are inactive but for which the operator has not sought temporarily abandoned status; (2) wells that have received approved temporarily abandoned status but have been in this status for less than two years; and (3) wells in expired temporarily abandoned status (wells that received approved temporarily abandoned status but have exceeded the five-year period without filing a new application or where that application was rejected). The proposed amendment closes this gap by expressly including such wells among the categories of wells to which the financial assurance requirements of 19.15.8.9.E NMAC apply.

Applicants' amendments and clarifications are important because all types of inactive wells, including all wells in temporarily abandoned status, pose an increased risk of being orphaned and thus must be subject to the higher financial assurance amounts required under section 19.15.8.9.E NMAC. The proposed amendment provides important clarity to operators

and OCD regarding which wells fall within subsection E.

In fact, the vast majority of inactive wells on OCD's inactive well list are not in approved temporary abandonment status. As of July 3, 2025, there were 3,765 inactive wells, 419 of which were in approved temporary abandonment status and 155 of which were in expired temporary abandonment status.[92] Only a little over 10% of the wells on the inactive well list are in approved temporary abandonment status. The vast majority of inactive wells in New Mexico are flatly out of compliance with Commission rules. Wells that are both inactive and noncompliant carry a particularly high degree of risk to the state.

Q: What is the basis for requiring a one well plugging financial assurance of $150,000 or a blanket bond averaging $150,000 per well in 19.15.8.9.E(1) and (2) NMAC for these wells?

A: The proposed amendment ensures that New Mexico's interests are protected by calculating financial assurance amounts for inactive wells and wells in approved and expired temporarily abandoned status based on the $150,000 figure derived from actual plugging costs, while still allowing operators to avail themselves of the administrative efficiency of providing a single financial assurance instrument for all of their wells.

In addition, this amendment retains consistency with the Oil and Gas Act. In relevant part, that statute requires that OCD provide "a blanket plugging financial assurance for temporarily abandoned status wells" and that such financial assurance "shall be set by rule at amounts **greater** than fifty thousand dollars ($50,000)." NMSA 1978, § 70-2-14(A) (emphasis added). The statute further provides that OCD "shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years or, at the

[92] *See* Apps' Ex. 3, Alexander Dir. Test.

election of the operator, may allow an operator to **increase** its blanket plugging financial assurance to cover wells held in temporarily abandoned status." *Id.* (emphasis added). The statute therefore recognizes the need for higher financial assurance levels for temporarily abandoned status wells, including when the form of the financial assurance is a blanket plugging financial assurance.

The proposed amendment retains consistency with these requirements by setting the blanket financial assurance amount greater than $50,000 and by providing operators the option of either a one well financial assurance or a blanket financial assurance at an increased amount.

Q: The Oil and Gas Act, as you discussed, requires a one well financial assurance for wells that have been in approved temporarily abandoned status for more than two years. Applicants propose requiring a one well financial assurance for all wells in approved temporarily abandoned status, including those that have been in that status for less than two years. Is this proposal allowed under the Oil and Gas Act?

A: Yes. The Oil and Gas Act provides only the minimum requirements for categories of financial assurance, setting a floor, not a ceiling. The statute requires" a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years" and further allows "an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status." NMSA 1978, § 70-2-14(A). The statute is silent as to what requirements should apply to other wells in temporarily abandoned status. There is therefore no barrier to applying the same requirements to a broader set of wells in temporarily abandoned status.

As discussed earlier, the statute expressly requires OCD to "establish categories of financial assurance after notice and hearing," and further specifies several categories that OCD

"shall include." NMSA 1978, § 70-2-14(A). Nowhere does the statute limit the allowable categories. The statute provides broad criteria for the different categories, directing the OCD to consider factors that it deems relevant. *Id*.

Here, the proposed amendment to subsection E imposes higher financial assurance requirements on all wells in temporarily abandoned status in consideration of the fact that all inactive wells, including all wells in temporarily abandoned status, pose a heightened risk of being orphaned. All of these inactive wells no longer produce revenue and therefore represent a net liability and burden on their operators. Operators face enormous economic pressure to delay or avoid the cost of plugging these wells. In order to protect its communities and economic interests, New Mexico should require greater financial assurances for these wells to ensure that they are either plugged by their operator or, in the event they are orphaned, they can be plugged at no or minimal additional cost to the state.

Q: What is your response to industry's concerns about the costs of increasing financial assurance for inactive wells and wells in approved and expired temporary abandonment?

A: As an initial matter, the statute recognizes the need to require higher financial assurances for wells in temporarily abandoned status. Whereas the statute sets a **maximum** amount for the general blanket plugging financial assurance, it sets a **minimum** amount for the blanket financial assurance for "temporarily abandoned status wells," requiring that such financial assurance "shall be set by rule at amounts greater than fifty thousand dollars ($50,000)." This minimum requirement was established in 2015, 2015 N.M. Laws, ch. 99, § 1, and, as mentioned, expresses the legislature's understanding and intent that wells in temporarily abandoned status require higher levels of financial assurance. The proposed amendment builds on this understanding of the higher risk of being orphaned posed by wells in temporarily abandoned status and

supplements it with data on the actual costs of well plugging.

Furthermore, operators who object to the increase in costs associated with these higher financial assurances for inactive wells and wells in approved and expired temporary abandonment always have the option to plug these wells and thereby avoid any costs associated with maintaining the financial assurance or go back into production. Such wells are already close to the point of requiring plugging, and any responsible operator will have already budgeted for those plugging costs. If any planned or hoped for future return to production or other beneficial use will not generate sufficient revenue to cover the carrying costs for the increased financial assurance, then that well should be plugged.

On the other hand, to the extent an operator cannot afford the costs associated with the increased financial assurance, and has also failed to set aside funds for plugging its wells, then it's extremely unlikely the operator will have the capacity to plug those wells, and the change to the financial assurance requirements does not alter that fact. With or without a change to the financial assurance requirements, the responsibility for plugging such wells will fall to the state. It is better for that fact to be known now so that OCD can take appropriate action, rather than allow the well to remain inactive and unplugged under some false pretext of future use or an empty promise to plug.

Q: What changes do Applicants propose to make to 19.15.8.9.D NMAC pertaining to the procedure for providing financial assurances for additional wells beyond those already covered under a blanket financial assurance?

A: Applicants propose:

> **F.**~~**D.**~~ Operators who have on file with the division a blanket plugging financial assurance that does not cover additional wells shall file additional one ~~single~~ well plugging ~~bond~~ financial assurance for any wells not covered by the existing blanket plugging financial assurance ~~bond~~ in an amount as

determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978.~~or, in the alternative, may file a replacement blanket bond.~~

The proposed amendment—which includes shifting this subsection from 19.15.8.9.D to 19.15.8.9.F NMAC—brings this section into alignment with the other proposed changes to 19.15.8.9 NMAC, while still addressing the scenario where an operator with an existing blanket financial assurance acquires additional wells. The amendment is also consistent with the overall approach of shifting toward one well financial assurances where possible in order to ensure that financial assurance amounts are "sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance." NMSA 1978, § 70-2-14(A).

Q: What amendments do Applicants propose to 19.15.8.9.G NMAC?

A: Applicants propose:

> **G.** On January 1, 2028 and on January 1 of each successive year, the division may adjust the financial assurance amounts provided by Subsections C(1), D, E and F of this Section by multiplying the financial assurance as of January 1, 2027 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2026; provided that any financial assurance shall not be adjusted below the minimum amounts required in Subsections C(1), D, E and F of this Section as a result of a decrease in the consumer price index. By November 1, 2027 and by November 1 of each successive year, the division shall post on its website the financial assurance requirements in Subsection A through E of this Section for the next year. As used in this subsection, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a 12 month period ending September 30.

Q: Why is it important that the regulations provide for adjustments based on inflation over time?

This provision allowing adjustments based on inflation avoids the risk that, as actual plugging costs increase over time as the costs of materials and labor go up, financial assurance amounts specified under 19.15.8.9 NMAC will cover a decreasing proportion of those costs. The

automatic adjustment also avoids the need for repeated rulemaking proceedings merely to adjust the financial assurance amount.

The IOGCC has recognized that plugging costs increase over time, including as a result of inflation. In a 2021 report, the IOGCC noted that "Plugging and restoration costs rise over time due to inflation and in some cases due to improved and more stringent regulatory requirements for materials and methods. States and provinces typically review and revise their financial assurance requirements periodically to account for these increases."[93]

The federal Bureau of Land Management, in its recent rulemaking increasing bond amounts for oil and gas wells on federal land, similarly cited the role of inflation in necessitating adjustments to financial assurance amounts, stating in the proposed rule that "BLM is proposing to increase the minimum bond amounts to reflect inflation and the minimum coverage that would be required for operations on Federal land, based on the BLM's estimate of current plugging and reclamation costs."[94] In the final rule, BLM stated that it "received multiple comments recommending the BLM periodically adjust the minimum bond amounts to better protect the taxpayer's interests in adequate reclamation. The BLM agrees with these comments and updates the final rule to include inflation adjustments to bond amounts by way of a final rule and titled this § 3104.1 'Bond amounts. 'This update will allow the BLM to periodically update bond amounts based upon the rates of inflation."[95]

Other jurisdictions similarly provide for regular adjustments for inflation, based on consumer price indexes in a manner similar to the proposed amendments. For example,

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[93] Apps' Ex. 28, Interstate Oil & Gas Compact Commission, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies 2021, at p. 18 (2021).
[94] 88 Fed. Reg. 47562, 47579 (Jul. 24, 2023).
[95] 89 Fed. Reg. 30916, 30935 (Apr. 23, 2024).

Wyoming's regulatory bonding requirements for oil and gas wells provide that bond amounts shall be "adjusted every three (3) years based on the Wyoming consumer price index or actual plugging costs."[96]

Q: Turning to 19.15.8.10 NMAC – Additional Requirements for Cash and Surety Bonds, what amendments do Applicants propose to 19.15.8.10.A NMAC?

A: Applicants propose:

> **A.** Surety bonds shall be issued by a reputable corporate surety authorized by the office of the superintendent of insurance to do business in the state. The surety shall be listed on U.S. department of the treasury circular 570.

Q: What is the U.S. Department of Treasury Circular 570?

A: The U.S. Treasury Department maintains Circular 570 to provide a list of "companies holding certificates of authority as acceptable sureties on acceptable bonds and as acceptable reinsuring companies"[97] who are therefore eligible to provide surety bonds for the benefit of the U.S. government. The criteria surety providers must satisfy in order to qualify to be listed on Circular 570 are specified in statute at 31 U.S.C. § 9305 and regulation at 31 C.F.R. Part 223. These criteria include consideration of the surety's solvency, profitability, and liquidity, including the amount and type of the surety's assets.[98] The regulations also impose a cap on the size of any individual bond a listed surety may issue, specifying that "no company holding a certificate of authority shall underwrite any single risk on any bond or policy on behalf of any individual, firm, association, or corporation, whether or not the United States is interested as a party thereto, the amount of which is greater than 10 percent of the paid-up capital and surplus of

[96] 055-3 Wyo. Code R. §§ 3-4(b)(i)(A) (Bonding Requirements).
[97] U.S. Department of the Treasury, Department Circular 570: Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reinsuring Companies, July 1, 2024, https://www.fiscal.treasury.gov/surety-bonds/circular-570.html.
[98] 31 C.F.R. § 223.9.

such company, as determined by Treasury."[99]

Q: Why is it necessary to add a requirement that the surety be listed on the U.S. Department of Treasury Circular 570?

A: This amendment addresses an additional concern that arises in the context of financial assurances, which is the need to ensure the reliability of the provider of the financial assurance, including surety bond providers.

Surety bonding is a very common way for operators to satisfy financial assurance requirements.

A surety bond functions as a three-way contract, with the operator as the principal, the regulator as the beneficiary or obligee, and the surety. The operator pays a fee to the surety, in exchange for which the surety agrees to pay the regulator the amount of the bond if the operator defaults on its plugging obligation.[100] In effect, a surety bond allows the regulator to shift the risk of operator default from itself to the surety.[101]

However, the regulator remains at risk that the surety provider itself may ultimately default and not be able to pay out the full value of the bond provided. This risk is magnified when a single surety provides multiple bonds for multiple operators all subject to the same economic forces, including fluctuations in commodity prices. Should multiple operators fail at the same time, the surety may not be able to cover all of the bonds it must pay out.

The existing regulations partially address this concern by requiring that "[s]urety bonds shall be issued by a reputable corporate surety authorized by the office of the superintendent of

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[99] 31 C.F.R. § 223.10.

[100] David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97 at p.191, Oct. 2, 2000.

[101] *Id*.

insurance to do business in the state." 19.15.8.10.A NMAC.

The proposed amendment provides an additional protection, by adding a sentence further requiring that "[t]he surety shall be listed on U.S. department of the treasury circular 570." This requirement would allow New Mexico to rely on the vetting and regulation of sureties already performed by the U.S. Treasury Department. If a surety operator does not qualify for listing on Circular 570, it should not be able to issue bonds to cover the risk of operator default in New Mexico.

It should be noted that even sureties listed on Circular 570 still carry a risk of default. This is particularly true for sureties exposed to a high aggregate risk by specializing in providing surety bonds to oil and gas operators. Such sureties face a high risk of encountering multiple operator defaults simultaneously, for example during a drop in oil or gas commodity prices. Such sureties are unlikely to maintain adequate liquid assets to pay out all bonds issued to those multiple operators. For this reason, it is critical that oil and gas regulatory programs not rely solely on financial assurances, but must also take additional steps to minimize the risk of well orphaning.

Q: Turning to 19.15.8.12 NMAC – Release of Financial Assurance, what amendments do Applicants propose to 19.15.8.12.B NMAC?

A: Applicants propose:

> **B.** Transfer of a property or a change of operator does not of itself release a financial assurance. The division shall not approve a request for change of operator for a well until the new operator has the required financial assurance in place and is otherwise in compliance with the requirements of 19.15.5.9 NMAC and 19.15.9.9 NMAC.

The proposed amendment codifies existing practice and ensures consistency with other regulatory provisions.

Similar to the proposed amendment to 19.15.8.9.A NMAC, this amendment clarifies that financial assurance for a new operator must be in place before the prior operator's financial assurance may be released, and further clarifies that the new operator satisfies prerequisites for OCD to approve the change of operator application. Those requirements are provided at 19.15.5.9 NMAC (Compliance) and 19.15.9.9 NMAC (Change of Operator).

The proposed amendment thereby avoids a scenario where a prior operator secures release of its financial assurance for a well or wells to be transferred before the transfer is complete. If OCD is then unable to finalize the transfer of the permit to the new operator—because the new operator is unable to provide an acceptable replacement financial assurance, or otherwise fails to satisfy the requirements of 9.15.5.9 NMAC (Compliance) or 19.15.9.9 NMAC (Change of Operator)—OCD would be left with a scenario where the wells' ownership is uncertain and there is no financial assurance. That scenario would make it very likely that OCD would be in a position of needing to plug the wells but without the ability to offset those costs by drawing on the financial assurance. Even if OCD were able to continue to hold the prior operator responsible, that operator may not be able to secure a replacement financial assurance on similar terms.

Q: In addition to the financial assurance requirements, New Mexico also maintains the Reclamation Fund. Why not just rely on the Reclamation Fund to make up any shortfall, rather than amend the financial assurance requirements?

There's simply not enough money in the Reclamation Fund to cover the shortfall between existing financial assurance levels and the current and anticipated inventory of orphaned wells.

According to the Legislative Finance Committee's orphaned wells report, the

Reclamation Fund contained $66.7 million as of April 2025.[102]

The Legislative Finance Committee further estimates that the state's potential liability far exceeds that total:

> At recent state-contracted rates, plugging, remediating and reclaiming currently orphaned wells and their associated infrastructure will likely take close to a decade and cost more than $208 million. Plugging and reclaiming the other 1,400 inactive wells on state and private land could cost more than $468 million. Should additional extremely low-producing wells be orphaned by their operators, the costs for plugging and reclaiming them could approach $1 billion. **Altogether, the state's current and near-future liability for well plugging and site remediation is estimated at $700 million to $1.6 billion.**[103]

Some of the plugging costs for those existing orphaned wells may be covered by federal funds administered DOI under its Orphaned Well Plugging Program, but not nearly the full amount. DOI has already calculated New Mexico's eligibility for formula, phase 1, and phase 2 grants to be approximately $132 million.[104] The Legislative Finance Committee's orphan well report lists New Mexico's total federal fund eligibility as $167.3 million.[105] The total congressional allocation for the entire program is $4.7 billion.[106] There are 26 states participating in the program, not to mention additional tribal partners.[107] That averages to $181 million per state. And at least seven states have total numbers of existing identified orphaned wells

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[102] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 11.

[103] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 1 (emphasis added).

[104] U.S. Department of the Interior, Orphaned Wells Program Annual Report to Congress, November 2024, at p. 22, https://www.doi.gov/sites/default/files/documents/2024-11/fy-2024-owpo-annual-congressional-reportfinal-publishing.pdf.

[105] Apps' Ex. 4, New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, June 24, 2025, at p. 12.

[106] *Id.* at p. 8.

[107] *Id.* at p. 22.

exceeding New Mexico's, entitling them to greater shares of the fund.[108] Accordingly, federal funds will not cover the shortfall between what will be required to plug and remediate New Mexico's orphaned wells, and what will be available in the Reclamation Fund. Indeed, all of the funds in the Reclamation Fund will not be sufficient to plug even the *existing* inventory of orphaned wells, even assuming the availability of additional federal funding. Additional orphaned wells will only add to this burden to the state.

OCD has also struggled to keep up with plugging this existing inventory of orphaned wells using the Reclamation Fund. The Annual Reports on Use of the Oil & Gas Reclamation Fund for Fiscal Years 2019 through 2024 describe plugging rates of 13 to 49 wells per year, with an average rate of 29 wells per year.[109] At that rate, it will take between 24 and 72 years just to clear the existing backlog of between 700 and 2,100 orphaned wells, not including any additional wells subsequently orphaned over those decades.

Because all funds available in the Reclamation Fund will be needed just to plug the existing inventory of orphaned wells in the state, the financial assurance requirements and related provisions in the oil and gas regulations must minimize the number of future well orphanings

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[108] *Id.* at p. 22 (identifying PA, TX, WV, OH, OK, CA, LA as having well plugging needs in excess of New Mexico's).

[109] Apps' Ex. 17, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2019, (Dec. 27, 2019); Apps' Ex. 18, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2020, (Dec. 31, 2020); Apps' Ex. 19, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2021, (Dec. 20, 2021); Apps' Ex. 20, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2022, (Dec. 27, 2022); Apps' Ex. 21, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2023, (Jan. 23, 2024); Apps' Ex. 22, State of New Mexico Energy, Minerals, and Natural Resources Department, Annual Report on Use of the Oil Reclamation Fund for Fiscal Year 2024, (July 1, 2025).

and must adequately cover the costs of plugging any future orphaned wells.

Relying on the Reclamation Fund to cover the costs of plugging newly orphaned wells also creates a negative incentive and moral hazard for operators. If operators know that OCD will not seek to enforce plugging requirements and will not seek to recover plugging costs from operators themselves, this will create a powerful incentive for operators to continue and even increase the practice of orphaning wells to OCD. Why would an operator choose to bear the cost of plugging a well itself if it knows that its competitors are avoiding that cost category? To make up the difference, complying operators would either have to market their oil or gas at a higher cost, leading to reduced sales, or make up the difference from their profits. This means that the vast majority of the 63,000 wells in New Mexico that will someday need to be plugged will become the responsibility of the state, further overwhelming the Reclamation Fund, which already is inadequate to cover the costs of plugging the existing inventory of orphaned wells.

19.15.9 NMAC – WELL OPERATOR PROVISIONS

Q: Mr. Morgan, let's turn to 19.15.9 NMAC – Well Operator Provisions. What is the general purpose of this section?

A: This section governs OCD's registration and approval of new operators, and changes of operator for specific wells (essentially, well transfers). It specifies the types of information OCD is authorized to collect when considering operator applications and provides the grounds on which OCD may deny an application. This section therefore enables and empowers OCD to evaluate the qualifications and capacity of an operator to meet the requirements of New Mexico's oil and gas program.

Q: Why are these provisions governing operator registration and transfer of wells important to the overall regulatory structure of the Commission's rules?

A: Unfortunately, some operators pose too high of a risk of non-compliance, including non-compliance with well plugging requirements. These provisions allow OCD to evaluate this risk at two points: initial operator registration and change of operator associated with well transfer. The ability of OCD to evaluate this risk, and to deny applications where warranted, is particularly important as relates to the change of operator associated with well transfer.

The proposed amendments address the increased risk of orphaning through well transfers in two ways.

First, the amendments provide OCD with additional information on operators that would allow OCD a better understanding of the fitness and capacity of those operators. *See* proposed 19.15.9.8.B, C, and E and 19.15.9.9.B NMAC. And the amendments would empower OCD to deny a change of operator associated with a permit transfer based on the current and past record of compliance of that operator and its officers, directors, partners, and persons with an interest exceeding 25 percent. Proposed 19.15.9.9.C NMAC.

Second, the amendments restrict the transfer of specific wells, facilities, or sites that are out of compliance with the well plugging requirements at 19.15.25.8 NMAC or with regulations pertaining to spills and remediation at 19.15.29 or 19.15.30 NMAC. *See* proposed 19.15.9.9.E NMAC.

Taken together, these amendments empower OCD to take appropriate action when a proposed well transfer poses a high risk of well orphaning.

Q: Beginning with 19.15.9.8 NMAC – Operator Registration, what amendments do Applicants propose to 19.15.9.8.B NMAC?

A: Applicants propose:

> **B.** Prior to commencing operations, an operator shall provide to the division a certification by an officer, director, or partner that the new operator is

in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC.

Q: What is the basis for this proposal?

A: This proposal partially clarifies the current rule and adds a new criterion for approving an operator registration. **Current** section 19.15.9.8.B NMAC allows OCD to deny a registration based on all but one of the criteria set forth above in newly **proposed** 19.15.9.8.B NMAC. The criteria upon which OCD may **currently** deny a registration include:

- Whether an officer, director, partner in the applicant or person with an interest in the applicant exceeding 25 percent, is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC, and

- Whether the applicant is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC.

See 19.15.9.8.B(2), -(3) NMAC. Proposed 19.15.9.8.B NMAC clarifies that operators must provide the above information through certification to OCD when applying for registration.

Proposed 19.15.9.8.B NMAC also includes one new criterion for approval of an operator registration: whether the new operator is in compliance with federal and state oil and gas laws and regulations in the states where the operator does business. This criterion is also added as a basis for denial of a registration in proposed 19.15.9.8.C(2) NMAC.

The required disclosure of whether an operator (including associated entities) is "in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business" is important because many oil and gas operators have holdings or

otherwise do business in multiple jurisdictions. OCD currently has the capacity to track operator compliance at wells and sites within New Mexico, but has no means to efficiently collect that information outside the state. OCD should be able to know if an operator proposing to conduct oil and gas operations in New Mexico has a past history of non-compliance at its facilities out of state. Among other things, this is necessary to prevent bad-actor operators from seeking refuge in New Mexico after running afoul of regulators in other jurisdictions. More fundamentally, it allows OCD to gauge the likelihood of an operator's capacity and willingness to satisfy the obligations associated with operating oil and gas wells, including the obligation to plug and remediate wells.

The current required disclosures also include information not only on whether the named operator itself is in compliance with the well plugging obligations of 19.15.5.9 NMAC, but also how the operator relates to other entities who may have a history of non-compliance with these well plugging obligations. The requirement applies to officers, directors, partners, and persons with an interest in the new operator exceeding 25 percent. This prevents individuals who incurred violations at one company from walking away from that company (and its liabilities) and starting a new company or seeking operator status as an individual. OCD would be able flag such individuals and their proposed new operations for further scrutiny.

This approach, adopted by the Commission in 2008—of tracking officers, directors, and other interested parties across companies—is common in the regulation of resource extractors. For example, the DOI's Office of Surface Mining Reclamation and Enforcement (OSMRE) maintains an "Applicant Violator System (AVS)" as part of its implementation of the federal

Surface Mining Control and Reclamation Act (SMCRA) for coal mines.[110] OSMRE describes the AVS as providing a "nationwide database" of "[i]nformation on applicants, permittees, operators, application and permit records, as well as unabated or uncorrected environmental violations" for surface coal mine operations.[111] The purpose of the AVS is to "assist OSMRE and States in making a permit eligibility determination required under section 510(c) of SMCRA for applicants of surface coal mining permits." Section 510(c) of SMCRA prohibits issuance of a new permit to any applicant who owns or controls mining operations having unabated or uncorrected violations anywhere in the United States until those violations are abated or corrected or are in the process of being abated or corrected to the satisfaction of the agency with jurisdiction over the violation.

The proposed amendments to 19.15.9.8.B NMAC would similarly assist OCD in making operator eligibility determinations and clarify that operators must provide OCD the information upon which OCD may **currently** deny operator registrations.

Q: What amendments do Applicants propose to 19.15.9.8.C NMAC?

A: Applicants propose:

> ~~**B.**~~**C.** The division may deny registration as an operator if:
>
> **(1)** the applicant is not in compliance with Subsection A of 19.15.5.9 NMAC;
>
> **(2)** the applicant is out of compliance with federal and state oil and gas laws and regulations in each state in which the applicant does business;
>
> **(~~2~~3)** an officer, director, partner in the applicant or person with an interest in the applicant exceeding 25 percent, is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;
>
> **(~~3~~4)** the applicant is or was within the past five years an officer, director, partner or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; or

[110] U.S. Department of the Interior, Office of Surface Mining Reclamation and Enforcement, Applicant/Violator System (AVS), https://www.osmre.gov/avs.
[111] *Id.*

(45) the applicant is a corporation, ~~or~~ limited liability company, or limited partnership and is not registered or is not in good standing with the New Mexico secretary of state ~~public regulation commission~~ to do business in New Mexico.~~; or~~

~~**(5)** the applicant is a limited partnership and is not registered with the New Mexico secretary of state to do business in New Mexico.~~

Q: What is the basis for these amendments?

A: As discussed, Applicants propose to add an additional criterion for approval of an operator registration, *i.e.*, compliance with other jurisdictions' laws, and therefore have added that criterion to the circumstances under which OCD may deny an operator registration in 19.15.9.8.C(2) NMAC.

The proposed amendment at 19.15.9.8.C(5) contains a purely administrative amendment, reflecting the already established change to the office with which companies are required to register from the "public regulation commission" to the "New Mexico secretary of state." Corporations and limited liability companies no longer register to do business in the state with the New Mexico Public Regulation Commission, but instead register with the New Mexico Secretary of State. *See* 2013 N.M. Laws, ch. 75, § 9. Amended section 19.15.9.8.C(5) NMAC recognizes this change. That same section clarifies that a corporate applicant for registration must be in good standing with the State of New Mexico.

The proposed amendment contains additional purely administrative changes, moving "limited partnership" to the list of entities in 19.15.9.8.C(4) NAMC that must be registered and in good standing with the New Mexico Secretary of State.

Q: What amendments do Applicants propose to 19.15.9.8.E NMAC?

A: Applicants propose:

~~D.~~E. ~~The division may require an~~ An operator shall ~~or applicant to~~ certify compliance annually of ~~identify~~ its current and past officers, directors and partners and its current and past ownership interest in other operators consistent with 19.15.9.8.C(2) and

(3) NMAC.

Q: What is the basis for these amendments?

A: The proposed amendment at 19.15.9.8.E NMAC provides an expansion of the existing regulatory provision allowing OCD to require an operator to disclose its current and past officers, directors and partners and its current and past ownership interest in other operators. The proposed amendments would make such disclosures mandatory, specify the form of the disclosure as a certification, and require operators to update that certification annually. These amendments are necessary to give effect to other existing and proposed provisions pertaining to entities associated with operators, including officers, directors, partners, and persons with an interest in the new operator exceeding 25 percent. As discussed above, such information allows OCD to track these entities across operators, and to address scenarios where entities associated with a failed or non-compliant operator simply jump ship to form or join a different operator. This includes the existing provisions at 19.15.9.8.C(2) and (3) NMAC, which authorize OCD to "deny registration as an operator" if an entity associated with that operator "is not currently in compliance with Subsection A of 19.15.5.9 NMAC" (pertaining to well plugging requirements). It also includes the proposed amendments adding provisions at 19.15.9.9.C(2) and (3) NMAC, which authorize OCD to "deny a change of operator" if an entity associated with that operator "is not currently in compliance with Subsection A of 19.15.5.9 NMAC." These provisions, including existing provisions, cannot be effective if an operator is not required to provide annually updated information on the identity of its "current and past officers, directors and partners and its current and past ownership interest in other operators."

Q: Applicants propose a number of changes to the Change of Operator rules at 19.15.9.9 NMAC. Before you discuss the specific amendments, can you describe the

increased risk of well orphaning that is associated with well transfer?

A: Well transfers—particularly of inactive, marginal, or other low-producing wells—dramatically increase the risk that the well will be orphaned. This is because such transfers create a separation between the operator who profited from the well's highest production and the operator who must bear the cost of plugging and decommissioning the well. Often, at the time a low-producing well is transferred, the remaining revenue that the well will generate will be less than the cost of plugging and decommissioning that well. In other words, the well is a net burden and liability. For such transfers, where the revenue to be generated by the transferred wells is less than the aggregate plugging costs, the economics of the transaction typically only make sense if the transferee operator can avoid the cost of plugging. And yet such transactions regularly occur.

Even if, at the time a transferee assumes the well-plugging obligation, it intends to satisfy that responsibility, it may lack the means to do so when the time comes. Unfortunately, some operators accept transfer of such wells with the intention of doing little to no maintenance and ultimately avoiding the costs of plugging altogether. In either case, the transferred well becomes orphaned.

Industry participants have recognized this common trend of low-producing wells being transferred from larger, well-resourced companies, to under-resourced operators. An Executive Vice President for Mobil Oil Corporation described the pattern this way:

> [I]t is rare for the larger companies to plug and abandon their older wells. Rather, at some point, a smaller company with lower overheads and less expensive operating costs will offer to buy the old wells at a price that gives the original company a better return than continued operations. . . . The chain may end there or continue through smaller and ever lower cost operators who do no preventive maintenance at all, do the bare minimum of repairs to keep the well going and eventually walk away, maybe after plugging the hole as cheaply as possible and

maybe not plugging at all.[112]

The New Mexico Court of Appeals has described the same phenomenon, in the context of transfers of state oil and gas leases: "larger oil and gas companies tend to assign their leases to smaller and less profitable companies, which then reassign the leases to even smaller and less profitable operations," posing a risk that "the burden of paying for a former lessee's tortious conduct would be shifted to these assignees, even though they are less likely to have the resources to remediate the land."[113]

This pattern is particularly concerning because the vast majority of wells in the United States—and therefore the vast majority of wells being transferred—are low-producing. According to the U.S. Energy Information Administration, 77% of U.S. wells produced less than 15 BOE/day in 2023, while only 7% of wells produced more than 100 BOE/day.[114] A paper in the prestigious, peer-reviewed journal *Nature* found a similar pattern, noting that "[e]ighty percent of US oil and natural gas (O&G) production sites are low production well sites, with average site-level production ≤15 barrels of oil equivalent per day and producing only 6% of the nation's O&G output in 2019."[115] The overwhelming majority of production, and therefore revenue generation, comes from that slim minority of high-producing wells. Wells producing 100 BOE/day or more supplied 75% of oil production and 74% of natural gas production in

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[112] Ronald E. Bishop, Historical Analysis of Oil and Gas Well Plugging in New York: Is the Regulatory System Working?, 23 NEW SOLS. 103, 104-105 (2013).

[113] *Stephanie Garcia Richard v. Marathon Petroleum*, ___-NMCA-___, ¶ 58 (No. A-1-CA-40747, May 14, 2025).

[114] U.S. Energy Information Administration, The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with data through 2023, December 2024 at p. 8.

[115] Mark Omara et al., Methane emissions from US low production well sites, Nat. Commun. 13, 2085, 2022, https://www.nature.com/articles/s41467-022-29709-3 (Methane emissions from US low production oil and natural gas well sites").

2021.[116]

Operators who regularly drill new wells may plausibly assert that the production from their newer wells can cover the costs of plugging older wells. Cash flow from higher-producing wells can be used to pay for plugging older, low-producing wells (though this still begs the question of where the funds will come from to plug the operator's last remaining wells once it stops drilling new wells). This strategy is not available to operators who do not drill new wells but instead specialize in the acquisition of older wells. Cash flow for those operators is limited to revenue from production from their inventory of low-producing wells. That production is likely to be inadequate to cover the plugging and decommissioning costs for all of those wells. All of this means that when older, low-producing wells are transferred away from operators who also hold newer, high-producing wells, the risk of well orphaning increases substantially for the transferred wells.

A variety of oil and gas regulators, including OCD, have recognized the risk of orphaning that is inherent in the transfer of low-producing wells.

The IOGCC—a body representing and made up of state regulators—has found that:

> It is common for operators to transfer wells and associated facilities and pipelines to other companies. State and provincial regulators have a special concern with transfers of wells with declining production because of the increased risk that such wells may become orphans. Many states and provinces have implemented measures to reduce this risk by setting additional requirements for financial assurance and by evaluating corporate solvency and compliance history and the status and condition of the wells and associated facilities and pipelines before approving a transfer.[117]

DOI has similarly found that:

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[116] U.S. Energy Information Administration, The Distribution of U.S. Oil and Natural Gas Wells by Production Rate with data through 2023, December 2024 Figures 3 and 4, p. 5.

[117] Apps' Ex. 28, Interstate Oil & Gas Compact Commission, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies, (2021).

> There are risks to states arising from the transfer of interests in oil and gas wells, underlying leases, and/or the associated infrastructure. These risks may arise from a sale to or merger of previously affiliated or unaffiliated parties. These risks can also arise from a bankruptcy. A State may attempt to mitigate these risks.[118]

And OCD itself has recognized this dynamic that operators with a higher number of inactive or low-producing wells are more likely to orphan their wells. In its 2024 application to the DOI for Orphaned Well Plugging Grants, OCD stated that: "It is OCD's experience that wells which have been inactive for extended periods of time are often held by operators who have become insolvent or, at a minimum, are incapable of complying with applicable regulatory requirements including those related to production and well plugging."[119]

For all of these reasons, an effective regulatory program for oil and gas operations will include provisions addressing the transfer of wells, particularly inactive, marginal, and other low-producing wells.

Q: Why isn't it sufficient to just increase the amount of financial assurance required, as other parts of the proposed rulemaking do?

A: In theory, a truly comprehensive and effective financial assurance program would address the primary risks posed by the transfer of inactive, marginal, and other low-producing wells. The proposed changes to financial assurance requirements in this rulemaking are a step in the right direction, but still fall short of what would be required, particularly given the ongoing reliance on blanket bonds. Several factors conspire to prevent New Mexico from maintaining a truly comprehensive and effective financial assurance program at this time. These include:

- Average plugging costs are just that, an average. Actual plugging costs are not known

[118] United States Department of the Interior, Orphaned Wells Program Office State Regulatory Improvement Grants Guidance, at p. 17.
[119] State of New Mexico Energy, Minerals, and Natural Resources Department, Work Plan/Proposal for Formula Phase 2 Grant Funds, (Dec. 13, 2024).

until the plugging and decommissioning is complete. Some number of wells will have actual plugging costs that exceed the average. In such cases, where responsibility to plug the well has passed to the regulator, the provided financial assurance will not cover the full cost of plugging, with the state forced to bear the additional cost.

- Financial institutions, including the providers of surety bond coverage, may fail. This risk is particularly high for surety bond providers who specialize in providing financial assurances for the oil and gas industry. Such providers may be driven to bankruptcy if multiple bonded operators go out of business at the same time (including following a drop in commodity prices for oil or gas), or even if a single operator with a high number of bonds provided by a single surety goes out of business. In those instances, the state will be left without a bond or other financial assurances to forfeit, with the state forced to bear the full cost of plugging and decommissioning.
- New Mexico statute currently places limits on the state's authority to require full-cost financial assurances, including by mandating the use of blanket financial assurances and specifying a cap on the blanket financial assurance amount for active wells.[120]

A regulatory program that includes limitations on transfers also has the benefit of shifting the incentive structure for operators. If the original driller—or another operator who acquires a well during its initial high production—knows that they will not be able to transfer the well away once production decreases, they will understand that they will retain the responsibility for well plugging and will ensure that they have the funds necessary to pay for that plugging. They may also choose to plug the well at an earlier time point, once the costs of maintaining the well are higher than the revenue generated by that well. All of this works to ensure that wells are plugged

[120] *See* NMSA 1978 § 70-2-14(A).

at the appropriate time and that costs are not passed along to the state.

This dynamic has been recognized in the economic literature. A peer reviewed economic study of the law and economics of reclamation bonding found that compliance with plugging requirements "can be induced with bond levels that are below the expected reclamation costs" where regulators "have the authority to block permits for any operator that has a record of noncompliance."[121]

Accordingly, an effective regulatory program designed to prevent the creation of additional orphaned wells will both require adequate financial assurances and restrictions on the transfer of wells.

Q: Can you provide an example of how the current absence of limitations on transfers in New Mexico leads to orphaned wells?

A: Yes. An example of these dynamics can be found in the ongoing bankruptcy of Acacia Resources, LLC, and its affiliated company Acacia Operating Company, LLC (collectively, "Acacia").

Acacia is the named operator of approximately 400 oil and gas wells in New Mexico. Acacia was formed in 2020 to acquire those wells out of the bankruptcy liquidation of another operator, Remnant Oil Operating.[122] Remnant itself had not drilled those wells. The wells were drilled and previously operated by oil majors including Anadarko Production Company (now part of Occidental Petroleum)[123] and ConocoPhillips.[124] Many of the wells followed a long and

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[121] David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97, Oct. 2, 2000.

[122] Mark Olalde et al., The Rising Cost of the Oil Industry's Slow Death, ProPublica (Feb. 22, 2024), https://www.propublica.org/article/the-rising-cost-of-the-oil-industrys-slow-death.

[123] *Id*.

[124] Complaint, *ConocoPhillips Company, et al., v. Acacia Resources et al.*, D-506-cv-2024-01193, (5th Jud. Dist. Ct. Dec. 11, 2024) at ¶¶ 18-21.

convoluted path of transfers before coming to rest with Remnant and then Acacia.[125] Some wells, for example, were transferred from Anadarko, to Xeric Oil & Gas Corp., to GP II Energy Inc., to CBS Operating Corp., to Boaz Energy LLC, to Memorial Production Operating LLC, to Marker Oil, to Remnant, to Acacia.[126]

Over the course of their lifespan, Acacia's wells generated approximately $2 billion in revenue, adjusted for inflation.[127] None of the wells' operators put that revenue to use plugging the wells. Instead, they diverted the revenue to other purposes, including, presumably, paying executives and shareholders. Rather than plug the wells, they transferred them away. In its bankruptcy filings, Acacia includes among its list of assets its status as "operator of record for 400+ wells."[128] It lists the current "fair market value" of those wells as "$0.00."[129]

OCD ultimately approved the transfer of the wells from Remnant to Acacia.[130] In its applications for "change of operator" to OCD, Acacia acknowledged it is "responsible for ensuring that the wells and related facilities comply with applicable statutes and rules."[131] Those statutes and rules include the obligation to "properly plug and abandon [each] well."[132]

It appears that, despite that acknowledgment and commitment, Acacia did not possess the means to plug the wells. Although it had acquired over 400 wells, it appears that Acacia's bankruptcy was precipitated by a demand that it plug just six of those wells. On December 11,

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[125] Mark Olalde et al., The Rising Cost of the Oil Industry's Slow Death, ProPublica (Feb. 22, 2024), https://www.propublica.org/article/the-rising-cost-of-the-oil-industrys-slow-death.
[126] *Id.*
[127] *Id.*
[128] *In re: Acacia Resources, LLC*, U.S. Bankruptcy Court for the W.D. TX, Case No. 24-70195, Doc. 6, Jan. 10. 2025 at p. 7.
[129] *Id.*
[130] *See*, Complaint, *ConocoPhillips Company, et al., v. Acacia Resources et al.,* D-506-cv-2024-01193, (5th Jud. Dist. Ct. Dec. 11, 2024) at ¶¶ 32-33.
[131] *Id.* at ¶ 34.
[132] NMAC § 19.15.25.8.B.

2024, ConocoPhillips Company filed a lawsuit against Acacia in New Mexico state court responding to a plugging demand letter sent by the New Mexico State Land Office to ConocoPhillips as leaseholder and alleging that Acacia has a duty, as well operator, "to plug six inactive oil and gas wells and remediate and reclaim the affected lands."[133] The relief sought by ConocoPhillips in the lawsuit includes a declaration that Acacia is "responsible for plugging the above Wells and remediation and reclamation of the related well pits," as well as recovery of costs related to ConocoPhillips' "efforts to plug the above wells and remediate and reclaim the affected lands."[134] Just over two weeks later, on December 27, 2024, Acacia filed its petition for bankruptcy liquidation.[135] Acacia's bankruptcy filing discloses that it is subject to the ConocoPhillips lawsuit, describing the "nature of the case" as "failure to plug and abandon six inactive wells."[136]

The financial assurances for the more than 400 wells will not cover the costs of plugging those wells. Acacia lists among its assets a "letter of credit from Community National Bank to NM OCD" in the amount of $250,000.[137] This is consistent with the maximum blanket bond amount required for 100 or more wells under 19.15.8.9.C NMAC. That comes out to approximately $625 per well. And it is possible that OCD may never see any of that money. Acacia lists that $250,000 letter of credit as the primary collateral used to secure a $3,240,000

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[133] Complaint, *ConocoPhillips Company, et al., v. Acacia Resources et al.*, D-506-cv-2024-01193, (5th Jud. Dist. Ct. Dec. 11, 2024) at ¶ 1. ConocoPhillips initiated this lawsuit because it, as a State Land Office lessee of record, was jointly liable for cleanup costs. *Id.* at. ¶39.

[134] *Id*. at p. 10.

[135] *In re: Acacia Operating Company, LLC*, U.S. Bankruptcy Court for the W.D. TX, Case No. 24-70194, Doc. 1, Dec. 27, 2024.

[136] *In re: Acacia Resources, LLC*, U.S. Bankruptcy Court for the W.D. TX, Case No. 24-70195, Doc. 7, Jan. 10. 2025 at p. 3.

[137] *In re: Acacia Operating Company, LLC*, U.S. Bankruptcy Court for the W.D. TX, Case No. 24-70194, Doc. 7, Dec. 27, 2024, at p. 2.

debt owed to "Cibolo Energy Resources."[138] OCD is not listed as a secured creditor, but is instead listed among Acacia's "creditors who have unsecured claims."[139]

The saga of these 400+ wells illustrates why it is critically important that New Mexico's oil and gas regulations be amended to include limits on well transfers. Prior operators clearly had the resources to plug these wells. Instead, the wells were transferred through a succession of owners until they came to rest with an operator unable to complete the plugging.

Q: Beginning with 19.15.9.9.B NMAC, what amendments do Applicants propose?

A: Applicants propose a number of changes to that Subsection. Applicants propose:

> **B.** The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an officer, director, or partner of the new operator that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a plugging and abandonment plan; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator. The plugging and abandonment plan shall be certified by an officer, director, or partner of the new operator and shall demonstrate that the new operator has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells to be transferred in light of all the operator's assets and liabilities. The division may request the operator to provide additional information including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics report, records of the operator's historical costs for decommissioning activities, estimate of the operator's decommissioning obligations, and history of

[138] *Id*. at p. 10.
[139] *Id*. at pp. 12-13.

inactive wells and returning wells to production.

Q: What is the basis for these amendments?

A: This proposed amendment includes two components: it requires the same certification regarding the operator's compliance with regulations in other jurisdictions and tracking the compliance history of associated entities that also applies to new operator registrations, and it also requires change of operator applicants to provide a certified plugging and abandonment plan.

The justification for the certification of the operator's compliance with regulations in other jurisdictions and the compliance history of associated entities is discussed above in the context of proposed amendments to 19.15.9.8 NMAC pertaining to new operator registration. The same rationale applies to applications for change of operator associated with well transfers. In fact, these requirements are even more critical for changes of registration associated with well transfers because the risk of wells being orphaned is even higher for transferred wells. These wells already have established plugging liabilities, but may no longer have the capacity to generate revenue sufficient to cover these plugging costs. Operators who assume responsibility for transferred wells must be able to immediately meet these well plugging obligations. Operators with a demonstrated history of non-compliance, or who have officers, directors, or other associated entities with demonstrated histories of non-compliance, should be scrutinized to determine if the risk to the state is too great.

The proposed amendments also include a new requirement at 19.15.9.9.B NMAC that the new operator provide "a plugging and abandonment plan." Specifically, the proposed amendment would require that:

> The plugging and abandonment plan shall be certified by an officer, director, or partner of the new operator and shall demonstrate that the new operator has and

> will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells to be transferred in light of all the operator's assets and liabilities. The division may request the operator to provide additional information including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics report, records of the operator's historical costs for decommissioning activities, estimate of the operator's decommissioning obligations, and history of inactive wells and returning wells to production.

This proposed amendment is necessary to prevent the scenario observed with Acacia and other operators where the new operator plainly lacked the resources to satisfy the plugging obligations it assumed. For existing operators who may already hold inactive and marginal wells, it allows OCD to consider those existing plugging liabilities in addition to the new liabilities being assumed through the proposed transfer. It also allows OCD to interrogate and verify an operator's claims that future production—from existing wells and the wells to be transferred—will be adequate to produce revenue sufficient to satisfy the operator's aggregate plugging obligations, including consideration of "long-term liabilities, reserves and economic reports, . . . [and] estimate of the operator's decommissioning obligations." It also allows OCD to consider the new operator's actual history of compliance and success at eliciting additional production from wells other operators consider spent, including the operator's "history of inactive wells and returning wells to production."

These amendments authorize OCD to take appropriate action when a proposed transfer of wells raises questions about whether the new operator will have the resources and capacity to actually satisfy the well plugging obligations it is assuming.

Q: The proposed amendment to 19.15.9.9.B NMAC requiring a plugging and abandonment plan authorizes OCD to request information regarding the operator's financial condition. Why is it appropriate for OCD to consider factors including a transferee's financial condition?

A: When OCD issues a permit or approves a transfer, it is effectively extending credit to the operator. Every well will need to be plugged one day. As discussed in detail above, there is a significant cost associated with that plugging. If the operator doesn't complete the plugging, then that responsibility—and cost—falls to the state. This is an extension of credit, because OCD is assuming the ultimate responsibility to ensure well plugging. This is just the same as the credit a bank extends to the holder of a credit card: if you don't pay your credit card bill, the bank is still obligated to pay the vendors for the charges you made. And just as a bank considers an applicant's credit score and other indicators of credit worthiness before issuing a credit card or a mortgage, OCD—as the issuer of credit—must be able to ensure the credit worthiness of the operator. This is common sense and would be completely unremarkable in any other setting involving extension of credit.

Q: What amendments do Applicants propose to 19.15.9.9.C NMAC?

A: Applicants propose:

> **C.** The director or the director's designee may deny a change of operator if:
>
> **(1)** the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC; ~~or~~
>
> ~~**(2)** the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order.~~
>
> **(2)** the new operator is out of compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business;
>
> **(3)** any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;
>
> **(4)** the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9

NMAC;

(5) the applicant is a corporation, limited liability company, or limited partnership and is not registered or is not in good standing with the New Mexico secretary of state to do business in New Mexico; or

(6) the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

Q: What is the basis for these amendments?

A: The proposed amendments add new provisions to 19.15.9.9.C NMAC, expanding the bases on which OCD may deny a change of operator application.

Under the existing regulations at 19.15.9.9.C NMAC, OCD may only deny a change of operator application if (1) "the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC," or (2) "the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order."

The proposed amendments would retain Subsection C(1) as is, allowing OCD to deny a permit transfer application if the new operator is not in compliance with Subsection A of 19.15.5.9. Subsection A of 19.15.5.9 requires compliance with financial assurance provisions, enforcement orders, penalty assessments, well plugging requirements, and (under the proposed amendments) limitations on venting.

The proposed amendments would strike the current Subsection C(2), and replace it with a substantially similar provision at 19.15.9.9.E NMAC, also addressing the conditions under which a well may be transferred if the well is out of compliance with specified provisions. The new proposed language for 19.15.9.9.E NMAC is discussed in more detail below.

The proposed amendments would add new provisions at Subsections C(2)-(5).

Proposed new provisions 19.15.9.9.C(2)-(4) NMAC mirror nearly identical provisions already found in the existing regulations at 19.15.9.8.C(2)-(4) NMAC, specifying grounds OCD may rely on to "deny registration of an operator." These provisions allow OCD to deny registration of an operator—or, under the proposed amendments, deny a change of operator—where an operator, or an officer, director, or other entity associated with that operator, is not in compliance with Subsection A of 19.15.5.9 NMAC, or where the new operator itself has served as an officer, director, or other role with an entity not in compliance with Subsection A of 19.15.5.9 NMAC. The provisions also allow OCD to deny a change of operator where the new operator is not registered or in good standing with the New Mexico secretary of state.

The proposed amendments at 19.15.9.8C(2)-(4) NMAC therefore bring the "change of operator" provisions in line with the "operator registration" provisions. This change is necessary because New Mexico has the same interest in ensuring the fitness of operators assuming new operational and plugging obligations for transferred wells as it does with ensuring the fitness of new operators just forming. As described above, transferred wells carry particularly high risks of orphaning, including because low-producing wells may not generate sufficient revenue to offset plugging costs.

This need for OCD to determine the operator's fitness at the time of proposed transfer holds true even for operators previously vetted by OCD at the time of initial operator registration. Developments with the operator may have occurred since the time of initial registration that raise questions about the operator's ongoing fitness to operate, or its fitness to assume the increased costs and obligations that come with the transferred wells. This could include compliance issues with the operator itself, or with officers, directors, or other parties who have joined the operator following its initial registration.

The proposed amendments also add a new provision at 19.15.9.9.C(6) NMAC, allowing OCD to deny a change of operator application if "the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over." This provision gives effect to the additional information disclosures required under 19.15.9.9.B NMAC, discussed above, including the requirement that the new operator provide a plugging and abandonment plan for the wells to be transferred. If the new operator fails to make the required certifications and disclosures, or if the information presented to OCD disclose a "substantial risk" that the transfer will result in the wells being orphaned, then OCD is empowered to prevent the transfer.

These amendments will allow OCD to avoid a situation where it is compelled to approve a transfer even where there is reason to believe that the new operator will lack the resources or ability to satisfy operating and plugging obligations.

Q: What amendments do Applicants propose to 19.15.9.9.D NMAC?

A: Applicants propose:

> **D.** In determining whether to grant or deny a change of operator when the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC, the director or the director's designee shall consider such factors as whether the non-compliance with Subsection A of 19.15.5.9 NMAC is caused by the operator not meeting the financial assurance requirements of 19.15.8 NMAC, being subject to a division or commission order finding the operator to be in violation of an order requiring corrective action, having a penalty assessment that has been unpaid for more than 70 days since the issuance of the order assessing the penalty or having ~~more than the allowed number of~~ wells out of compliance with 19.15.25.8 NMAC. If the non-compliance is caused by the operator having ~~more than the allowed number of~~ wells not in compliance with 19.15.25.8 NMAC, the director or director's designee shall consider the number of wells not in compliance, the length of time the wells have been out of compliance and the operator's efforts to bring the wells into compliance.

This amendment reflects the proposed changes to Subsection A of 19.15.5.9 NMAC that I

discussed above, and maintains regulatory consistency with those changes.

Q: What amendments do Applicants propose to 19.15.9.9.E NMAC?

A: Applicants propose a new Subsection E:

> **E.** No well, facility or site that is out of compliance with Subsection A of 19.15.5.9 NMAC, 19.15.29 NMAC, or 19.15.30 NMAC shall be transferred unless, prior to transfer, the current operator brings the associated well, facility or site into compliance or the new operator submits a schedule of compliance approved by the division.

As discussed above, Subsection A of 19.15.5.9 NMAC (including as amended by this proposed rulemaking) relates to compliance, including compliance with the well plugging requirements at 19.15.25.8 NMAC. Sections 19.15.29 and 19.15.30 NMAC pertain to spills and remediation, respectively.

The proposed amendment therefore prohibits transfer of wells that are overdue for plugging, or have unaddressed spills or otherwise have outstanding remediation needs, unless OCD determines that the well is in compliance or there is an approved schedule of compliance.

The proposed amendment ensures that a current operator cannot use transfer as a means to avoid liability for plugging or cleanup obligations that have already come due.

The proposed amendment also ensures that OCD does not approve the transfer of wells with higher than normal remediation costs without first taking steps to ensure that the remediation will be addressed by the current operator prior to transfer, or that the new operator has a plan, and the resources, to handle the remediation.

As discussed above, transfer of a well can dramatically increase the chances of that well being orphaned. That is particularly true for wells with higher remediation costs, or with plugging and remediation obligations that are due immediately, before the well can generate any revenue to offset those costs. The proposed amendment creates an opportunity for OCD to

monitor the status of the wells to be transferred and to take steps to minimize the chance of those wells being orphaned.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Peter Morgan — August 5, 2025
Peter Morgan — Date

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EXHIBIT 16

Fiscal impact reports (FIRs) are prepared by the Legislative Finance Committee (LFC) for standing finance committees of the Legislature. LFC does not assume responsibility for the accuracy of these reports if they are used for other purposes.

FISCAL IMPACT REPORT

SPONSOR McQueen **LAST UPDATED** **ORIGINAL DATE** 2/26/2025

SHORT TITLE Costs of Plugging & Abandonment of Wells **BILL NUMBER** House Bill 481

ANALYST Davidson/Dodson/Joyce

REVENUE*
(dollars in thousands)

Type	FY25	FY26	FY27	FY28	FY29	Recurring or Nonrecurring	Fund Affected
Remediation Costs		**See Fiscal Implications**	**See Fiscal Implications**	**See Fiscal Implications**	**See Fiscal Implications**	Nonrecurring	Oil and Gas Reclamation Fund

Parentheses ( ) indicate revenue decreases.
*Amounts reflect most recent analysis of this legislation.

Relates to House Bill 403

Sources of Information

LFC Files

Agency Analysis Received From
Energy, Minerals and Natural Resources Department (EMNRD)

Agency Analysis was Solicited but Not Received From
New Mexico Attorney General (NMAG)

Agency Declined to Respond
New Mexico Environment Department (NMED)

SUMMARY

Synopsis of House Bill 481

House Bill 481 (HB481) amends sections of the Oil and Gas Act, adding language requiring past and present operators, owners, and/or lessees of oil and gas exploration facilities to reimburse the Oil and Gas Conservation Division (OCD) for costs incurred by the state associated with plugging, deconstructing, and remediation of abandoned and/or orphan wells, flow lines and other environmental contamination related to oil and gas exploration, development, and production.

The bill specifies that affected entities can come to agreement among themselves about which entity is responsible for payment but reserves the right for the state to seek reimbursement from any party.

The effective date of this bill is July 1st, 2025.

FISCAL IMPLICATIONS

When an operator does not plug a well in accordance with administrative rules, OCD has the authority to plug the well itself. OCD currently deploys a mixture of state and federal funding for the plugging and remediation of those 'abandoned' wells. State funding comes primarily from the oil and gas reclamation fund, which receives distributions from the oil and gas conservation tax. If House Bill 481 is implemented, OCD would be able to directly recover cleanup costs from operators and those with an interest in the well or facility, possibly reducing the need for the use of the reclamation fund.

Prior to drilling, operators in the state must put up financial assurance to guarantee the eventual plugging of the well, often called an 'oil bond'. The bond level is set depending on the number of permitted wells:

- Active well "single": $25,000 plus $2 per foot of the projected depth of a proposed well
- Active well "blanket" (Note: NMSA 70-2-14 set "blanket bond" limit at 250k):
    - $50,000 for one to 10 wells;
    - $75,000 for 11 to 50 wells;
    - $125,000 for 51 to 100 wells; and
    - $250,000 for more than 100 wells.

It is unclear as the bill is written whether the recovered costs include forfeited bonds.

OCD costs for plugging in FY24 averaged $163 thousand per well, but plugging costs can vary widely based on well depth, age, type, and contractor availability. Environmental remediation for spills and cleanup of infrastructure associated with wells (tank batteries, gathering lines etcetera) can cost considerably more than plugging. Due to these factors, LFC estimates the potential costs to the operators to reimburse the state for remediation and plugging costs could range between $30 thousand to potentially millions, depending on the scale of remediation needed.

Analysis from the Energy, Minerals and Natural Resources Department (EMNRD) notes the bill has the potential to establish a more "efficient pathway for OCD to seek indemnification" i.e. compensation for harm to the state. EMNRD analysis notes passage of the bill also has the potential to mitigate civil litigation OCD is involved in, which could increase the amount of funding the division uses to plug wells.

SIGNIFICANT ISSUES

Current Operations. In FY24, OCD contracted entities to plug 105 abandoned or orphaned wells. OCD estimates there are over 2,000 abandoned or orphaned wells in the state, with this total depending on how abandoned is defined. OCD currently has the ability within statute to sue an operator for reimbursement for costs related to plugging, remediation, and deconstruction. However, litigation can be lengthy and expensive, and many operators that abandon their wells are financially insolvent, leaving decisions about allocation of their assets up to bankruptcy courts.[1] House Bill 481 enables OCD to require operators with "prior interest" to reimburse the division for remediation and plugging operations, which would expand liability for cleanup to everyone who profited from the well or facility.

[1] https://www.koat.com/article/dry-wells-new-mexico-cost-millions/46290123

Statute. Current statute provides OCD with the authority to require oil and gas operators to plug dry or abandoned wells, and the authority to expend monies from the reclamation fund to plug dry or abandoned wells (Section 70-2-12 NMSA 1978). Abandoned well is not defined in statute. In administrative rule, OCD requires oil and gas operators to plug wells that have been continuously inactive for more than a year or subsequent to a determination that the well is no longer useable for beneficial purposes, although there are a number of exceptions to those rules. The purpose of plugging is to protect both surface and subsurface resources, including groundwater.

Legal Context. A recent agreement between the state and Ridgeway Arizona (an active oil and gas company) resulted in OCD taking responsibility for plugging 299 of the company's inactive wells, with the company reimbursing the state at least $30 thousand a month as long as it remains in business. OCD spent roughly $1.3 million in FY24 plugging six wells belonging to Ridgeway, for an average cost of $210 thousand. The settlement has the potential to set a precedent whereby an operators that claims it cannot plug its abandoned wells is able to shift responsibility to the state. House Bill 481 would instead shift the responsibility to those with a prior financial interest in the well.

CONFLICT, DUPLICATION, COMPANIONSHIP, RELATIONSHIP

House Bill 481 relates to House Bill 403. House Bill 403 increases the distribution to the oil and gas reclamation fund from the oil and gas conservation tax from 19.7 percent to 100 percent over a three-year phase-in, significantly expanding the funds available to OCD for remediation and plugging operations. If both bills are passed, the extra funds created from HB403 could be duplicative due to HB481 making operators responsible for reimbursing cleanup costs, not the state.

POSSIBLE QUESTIONS

The bill does not provide a clear mechanism for collection of the reimbursement or specify if the reimbursement is deposited into the oil and gas remediation fund. Further, the bill does not specify clear guidelines for OCD to determine proportional responsibility of current and prior operators.

AD/hj/SL2

EXHIBIT 17

Michelle Lujan Grisham, Governor
Sarah Cottrell Propst, Cabinet Secretary
Todd E. Leahy, JD, PhD, Deputy Cabinet Secretary
Adrienne Sandoval, Oil Conservation Division Director

December 27, 2019

Governor Michelle Lujan Grisham
State Capitol
Santa Fe, NM 87501

Chair Patricia A. Lundstrom
House Appropriations and Finance Committee
3406 Bluehill Avenue
Gallup, NM 87301

Chair John Arthur Smith
Senate Finance Committee
PO Box 998
Deming, NM 88031

Cabinet Secretary Sarah Cottrell Propst
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Raul Burciaga
Director Legislative Council Service
411 State Capitol
490 Old Santa Fe Trail
Santa Fe, NM 87501

Re: Annual Report on Use of the Oil Reclamation Fund

Dear Governor Lujan Grisham, Chair Lundstrom, Chair Smith, Cabinet Secretary Cottrell Propst and Director Burciaga.

Enclosed is the Oil and Gas Reclamation Fund Report for Fiscal Year 2019.

If you have any questions regarding the report or would like additional information, please contact me at 505-231-3316.

Sincerely,

Adrienne Sandoval
Oil Conservation Division Director

Cc: David Abbey, Director, Legislative Finance Committee
Olivia Padilla-Jackson, Cabinet Secretary, Department of Finance and Administration

OIL AND GAS RECLAMATION REPORT

FOR FISCAL YEAR 2019

(July 1, 2018 – June 30, 2019)

WELL PLUGGING AND SITE REMEDIATION PROGRAM

The Oil and Gas Act requires the Director of the New Mexico Oil Conservation Division ("OCD") to prepare an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor, and the Legislature on the use of the Oil and Gas Reclamation Fund. The OCD Director has prepared this report for the fiscal year ending the preceding June 30.

NMSA 1978, Sections 70-2-37 and 70-2-38 create the Oil and Gas Reclamation Fund ("Fund") and provide for administration of the Fund. Expenditures may be used to plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. In addition, up to $150,000 of the Fund may be spent annually to promote energy education in the State. The Fund is supported principally by the oil and gas conservation tax.

The OCD is authorized by the Oil and Gas Act (the "Act") to plug and abandon oil and gas wells to prevent the migration of fluids, gasses, and other contaminates to other strata or to fresh water, and to restore and remediate abandoned well sites and associated production facilities. See NMSA 1978 Section 70-2-12(B) (1) and (18) and 70-2-38. That Act allows the OCD to require oil and gas operators to post plugging bonds conditioned upon performance of their plugging obligations. See NMSA 1978 Section 70-2-14. A well operator may furnish a single-well bond for each of its wells or a blanket bond. Blanket plugging bonds in the following amounts cover all oil, gas or service wells drilled, acquired or operated in the state:

$50,000 for one to 10 wells;
$75,000 for 11 to 50 wells;
$125,000 for 51 to 100 wells; and
$250,000 for more than 100 wells.

An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC in one of the following categories:

(1) a one well financial assurance in the amount of $25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells; or

(2) a blanket plugging financial assurance covering all wells of the operator subject to Subsection D of 19.15.8.9 NMAC:

$150,000 for one to five wells;
$300,000 for six to 10 wells;
$500,000 for 11 to 25 wells; and
$1,000,000 for more than 25 wells.

If a bond covers a well, site, or facility that the OCD has plugged or remediated, the OCD may foreclose on the bond, with the proceeds deposited into the Oil and Gas Reclamation Fund.

Effective on July 1, 2011, NMSA 1978 Section 7-1-6.21, as amended, provides for monthly distribution of proceeds of the Oil and Gas Conservation Tax to the Fund, as follows:

A. With respect to any period for which the rate of the tax imposed by Section 7-30-4 NMSA 1978 is nineteen-hundredths percent, a distribution pursuant to Section 70-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to two-nineteenths of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act [7-30-1 NMSA 1978].

B. With respect to any period for which the total rate of the tax imposed on oil by Section 7-30-4 NMSA 1978 is twenty-four hundredths percent, a distribution pursuant to Section 7-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to nineteen and seven-tenths percent of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act.

The OCD employs independent contractors to perform the plugging, restoration, and remediation work. The contracts are issued pursuant to the State Procurement Code. Contract amounts can range from a few thousand dollars to several hundred thousand dollars. Contractors awarded contracts are oil field service companies specializing in plugging oil and gas wells or companies specializing in environmental cleanups.

WELL PLUGGING AND SITE REMEDIATION ACTIVITIES

The following pages provide details on the Fund and its uses. These details include an FY19 balance sheet for the Fund and information on the procurement of well plugging, emergency services, and site remediation for the fiscal year.

OIL RECLAMATION FUND

Beginning Cash Balance @ July 1, 2018	$4,226,365.00
Oil & Gas Conservation Tax Revenue	$3,529,475.00
Bond Forfeitures, Salvage and Reimbursement Recoveries	$ 88,473.00
Total Revenues:	**$3,617,948.00**
Balance:	**$7,844,313.00**
Total Expenses Expended directly from the Reclamation Fund: (Including the following: Paul Baca, Court Reporters - $80,406.60; IOGCC Annual Dues - $42,500.00; and IOGCC Travel - $693.73)	**$1,521,587.00**
Ending Cash Balance @ June 30, 2019:	**$6,322,726.00**

FY19 EXPENDITURES AND USAGE DETAIL

	Well Name	Contractor	Plugging Cost
1.	Orphan Well MW #1	J & B Well Service	$32,391.24
2.	Orphan Well MW #2	J & B Well Service	$15,360.80
3.	Artesia Metex Unit #6	J & B Well Service	$23,328.69
4.	Artesia Metex Unit #8	J & B Well Service	$24,388.96
5.	Artesia Metex Unit #10	J & B Well Service	$21,910.77
6.	Artesia Metex Unit #11	J & B Well Service	$28,280.33
7.	Artesia Metex Unit #12	J & B Well Service	$28,797.54
8.	Artesia Metex Unit #13	J & B Well Service	$28,161.91
9.	Artesia Metex Unit #14	J & B Well Service	$27,991.79
10.	Artesia Metex Unit #15	J & B Well Service	$28,799.13
11.	Artesia Metex Unit #16	J & B Well Service	$20,325.89
12.	Artesia Metex Unit #17	J & B Well Service	$17,936.58
13.	Artesia Metex Unit #18	J & B Well Service	$24,953.97
14.	Artesia Metex Unit #19	J & B Well Service	$24,976.78
15.	Artesia Metex Unit #20	J & B Well Service	$24,023.67
16.	Artesia Metex Unit #21	J & B Well Service	$18,761.86
17.	Artesia Metex Unit #22	J & B Well Service	$25,627.27
18.	Artesia Metex Unit #23	J & B Well Service	$24,656.70
19.	Artesia Metex Unit #24	J & B Well Service	$24,981.58
20.	Artesia Metex Unit #25	J & B Well Service	$28,979.27
21.	Artesia Metex Unit #26	J & B Well Service	$28,084.10
22.	Artesia Metex Unit #27	J & B Well Service	$21,185.97
23.	Artesia Metex Unit #29	J & B Well Service	$24,953.45
24.	Artesia Metex Unit #30	J & B Well Service	$25,615.40
25.	Artesia Metex Unit #31	J & B Well Service	$25,040.16
26.	Artesia Metex Unit #32	J & B Well Service	$26,354.16
27.	Artesia Metex Unit #33	J & B Well Service	$18,127.54
28.	Artesia Metex Unit #34	J & B Well Service	$23,448.96
29.	Artesia Metex Unit #35	J & B Well Service	$28,080.14
30.	Artesia Metex Unit #36	J & B Well Service	$28,085.42
31.	Artesia Metex Unit #46	J & B Well Service	$24,688.32
32.	Artesia Metex Unit #47	J & B Well Service	$29,969.65
33.	Artesia Metex Unit #48	J & B Well Service	$25,750.18
34.	Artesia Metex Unit #49	J & B Well Service	$28,517.97
35.	Artesia Metex Unit #50	J & B Well Service	$28,207.80
36.	Artesia Metex Unit #51	J & B Well Service	$24,767.75
37.	Artesia Metex Unit #52	J & B Well Service	$25,738.04
38.	Artesia Metex Unit #53	J & B Well Service	$23,255.37
39.	Artesia Metex Unit #63	J & B Well Service	$21,773.09
		TOTAL:	**$976,278.20**

Apps' Ex. 17

EXHIBIT 18

Michelle Lujan Grisham, Governor
Sarah Cottrell Propst, Cabinet Secretary
Todd E. Leahy, JD, PhD, Deputy Cabinet Secretary
Adrienne Sandoval, Oil Conservation Division Director

December 31, 2020

Governor Michelle Lujan Grisham
State Capitol
Santa Fe, NM 87501

Cabinet Secretary
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Director Legislative Council Service
411 State Capitol
490 Old Santa Fe Trail
Santa Fe, NM 87501

Re: Annual Report on Use of the Oil Reclamation Fund

Enclosed is the Oil and Gas Reclamation Fund Report for Fiscal Year 2020.

If you have any questions regarding the report or would like additional information, please contact me at 505-231-3316.

Sincerely,

Adrienne Sandoval
Oil Conservation Division Director

Cc: David Abbey, Director, Legislative Finance Committee
Olivia Padilla-Jackson, Cabinet Secretary, Department of Finance and Administration

OIL CONSERVATION DIVISON

OIL AND GAS RECLAMATION FUND REPORT

FISCAL YEAR 2020

(July 1, 2019 – June 30, 2020)

The New Mexico Oil and Gas Act ("Act") requires the Director of the New Mexico Oil Conservation Division ("OCD") to prepare an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor, and the Legislature on the use of the Oil and Gas Reclamation Fund provided by the Act. NMSA 1978, §70-2-38(C). The OCD Director has prepared this report for the fiscal year ending the preceding June 30, 2020.

Sections 70-2-37 and 70-2-38 of the Act create the Oil and Gas Reclamation Fund ("Fund") and provide for the administration of the Fund. Fund expenditures may be used to plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. In addition, up to $150,000 of the Fund may be spent annually to promote energy education in the State. The Fund is supported by a distribution of a portion of the revenues from the oil and gas conservation tax. NMSA 1978, §7-1-6.21.

Section 70-2-14 of the Act allows the OCD to require oil and gas operators to post plugging bonds to ensure performance of their plugging obligations. A well operator may furnish a single-well bond for each of its wells or a blanket bond for all wells on state or fee lands. Oil Conservation Commission regulations specify the formulas for determining bond amounts. 19.5.8 NMAC.

If the OCD must plug or remediate a well, site, or facility, the OCD may foreclose on the operator's bond and deposit the proceeds into the Fund. NMSA 1978, §70-2-14(B).

The OCD employs independent contractors to perform the plugging, restoration, and remediation work. The contractors who are awarded contracts after a competitive process are oil field service companies specializing in plugging oil and gas wells or companies specializing in environmental cleanups. Wells are chosen to be plugged by their potential to cause harm to human health, underground sources of drinking water, and the environment. These wells must also have completed the regulatory process, where an OCD Hearing Order has been issued, providing the OCD the authority to plug and properly abandon wells.

During Fiscal Year 2020, approximately $1.89 million was expended from the Fund. Of that $1.89 million a total of 19 wells were plugged by OCD using the Fund at a total cost of $600,490.40 (See Table 1), averaging approximately $31,600 per well that was plugged. In addition, another 6 wells were plugged by OCD in FY 2020 using funds from the U.S. Bureau of Land Management at a cost of $189,600. The additional approximately $1.2 million expended out of the Fund was used to support reclamation and compliance work, OCD hearings, and IT infrastructure improvements. These are vital support costs that are critical to the reclamation work that must be performed. Without these items, reclamation work cannot be completed in a timely fashion and the OCD cannot ensure that the reclamation work was appropriately completed. OCD relies heavily on having the most up to date technical information readily

available on tablets that inspectors use in the field. OCD has worked over the past years to update our IT infrastructure to better support the work that we do. These upgrades have positioned the OCD to manage plugging work more effectively and efficiently in the future.

A new Statewide Plugging Agreement has been approved for the 2nd half of FY21 and 30 wells have been sent out for bid. These wells will be plugged in the 3rd quarter of FY21 at an estimated cost of **$1,050,000**. Another group of 30 are anticipated to be sent out for bids in the 4th quarter of FY21. The wells chosen to be plugged were on an approved "Orphan Well List". The wells came from the abandoned Canyon E&P Company list.

For FY 21, the Legislature also appropriated $2,000,000 from the Fund for the remediation of the Carlsbad brine well.

The following provides details on the Fund and its uses. These details include an FY20 balance sheet for the Fund and information on the procurement of well plugging, for the fiscal year:

OIL RECLAMATION FUND (See details below)

Beginning Cash Balance @ July 1, 2019	**$6,322,726.49**
Oil & Gas Conservation Tax Revenue	$3,340,307.80
Bond Forfeitures, Salvage and Reimbursement Recoveries	$ 0.00
Total Revenues:	$3,340,307.80
Balance:	$9,663,034.29
Total Expenses Expended directly from the Reclamation Fund:	$1,885,362.53
Ending Cash Balance @ June 30, 2020:	**$7,777,671.76**

Table 1

FY20 EXPENDITURES AND USAGE DETAIL

	Well Name	Contractor	Plugging Cost
1.	North Shugart Queen Unit #10	J & B Well Service	$42,815.23
2.	North Shugart Queen Unit #11	J & B Well Service	$42,815.23
3.	Artesia Metex Unit #54	J & B Well Service	$29,183.88
4.	Artesia Metex Unit #55	J & B Well Service	$29,838.85
5.	Artesia Metex Unit #56	J & B Well Service	$29,838.85
6.	Artesia Metex Unit #57	J & B Well Service	$24,985.04
7.	Artesia Metex Unit #58	J & B Well Service	$29,183.88
8.	Artesia Metex Unit #59	J & B Well Service	$24,953.39
9.	Artesia Metex Unit #64	J & B Well Service	$21,298.39
10.	Artesia Metex Unit #68	J & B Well Service	$20,221.29
11.	Cato San Andres Unit #191	J & B Well Service	$34,325.64
12.	Cato San Andres Unit #194	J & B Well Service	$23,527.08
13.	Cato San Andres Unit #199	J & B Well Service	$25,770.91
14.	Cato San Andres Unit #201	J & B Well Service	$41,044.41
15.	Cato San Andres Unit #202	J & B Well Service	$40,075.39
16.	Cato San Andres Unit #183	J & B Well Service	$31,939.61
17.	Cato San Andres Unit #189	J & B Well Service	$35,682.48
18.	Cato San Andres Unit #190	J & B Well Service	$36,434.07
19.	Cato San Andres Unit #195	J & B Well Service	$36,436.78
		TOTAL:	**$600,490.40**

EXHIBIT 19

Michelle Lujan Grisham, Governor
Sarah Cottrell Propst, Cabinet Secretary
Todd E. Leahy, JD, PhD, Deputy Cabinet Secretary
Adrienne Sandoval, Oil Conservation Division Director

December 20, 2021

Governor Michelle Lujan Grisham
State Capitol
Santa Fe, NM 87501

Cabinet Secretary
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Director Legislative Council Service
411 State Capitol
490 Old Santa Fe Trail
Santa Fe, NM 87501

Re: Annual Report on Use of the Oil Reclamation Fund

Enclosed is the Oil and Gas Reclamation Fund Report for Fiscal Year 2021.

If you have any questions regarding the report or would like additional information, please contact me at 505-231-3316.

Sincerely,

Adrienne Sandoval
Oil Conservation Division Director

Cc: David Abbey, Director, Legislative Finance Committee
Debbie Romero, Cabinet Secretary, Department of Finance and Administration

OIL CONSERVATION DIVISON

OIL AND GAS RECLAMATION FUND REPORT

FISCAL YEAR 2021

(July 1, 2020 – June 30, 2021)

The New Mexico Oil and Gas Act ("Act") requires the Director of the New Mexico Oil Conservation Division ("OCD") to prepare an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor, and the Legislature on the use of the Oil and Gas Reclamation Fund provided by the Act. 70-2-38(C) NMSA 1978. The OCD Director has prepared this report for the fiscal year ending June 30, 2021.

Sections 70-2-37 and 70-2-38 of the Act create the Oil and Gas Reclamation Fund ("Fund") and provide for its administration. Expenditures from the Fund may be used to survey and plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. The Fund allows for limited monies to be used for OCD salaries. In addition, the Fund may be spent for costs associated with plugging and remediation activities, such as equipment, and up to $150,000 annually to promote energy education in the State. The Fund is supported by a distribution of a portion of the revenues from the oil and gas conservation tax. 7-1-6.21 NMSA 1978.

Section 70-2-14 of the Act allows the OCD to require oil and gas operators to post plugging bonds to ensure performance of their plugging obligations. A well operator may furnish a single-well bond for each of its wells or a blanket bond for all wells on state or fee lands. Oil Conservation Commission rules specify the formulas for determining bond amounts. 19.5.8 NMAC. If the OCD must plug or remediate a well, site, or facility, the OCD may foreclose on the operator's bond and deposit the proceeds into the Fund. 70-2-14(B) NMSA 1978. OCD is also authorized to pursue recovery in state court for costs associated with well site plugging and reclamation. 70-2-38(B) NMSA 1978. When companies become insolvent, or bonding is inadequate the state has to step in to plug and remediate.

For its well plugging and remediation, the OCD employs independent contractors to perform the work. Contractors are awarded contracts after a competitive bidding process consistent with Procurement Code requirements. These contractors are oil field service companies specializing in plugging oil and gas wells and/or companies specializing in environmental cleanups. Wells are chosen to be plugged by their potential to cause harm to human health, underground sources of drinking water, and the environment. Wells to be plugged by the OCD must go through administrative hearing process wherein OCD obtains an order authorizing it to plug and properly abandon such wells.

During Fiscal Year 2021, approximately $3.38 million was expended from the Fund. Of that, $2,359,698 million was spent plugging 49 wells.

Additional monies expended from the Fund were used to support programmatic reclamation and compliance work, OCD hearings, and IT infrastructure improvements. These are vital support costs that are critical to the reclamation work OCD performs. Without this support, reclamation

work cannot be completed in a timely fashion and the OCD cannot ensure that any reclamation undertaken was completed properly. For example, before a well is plugged there must be a public hearing and an order issued by the OCD. Additionally, the OCD relies heavily on having the most up to date technical information readily available for field inspectors reviewing work that has been completed. OCD has worked diligently this most recent year, as it has in years past, to update IT infrastructure to support OCD well plugging. This program support has positioned the OCD to manage plugging work more effectively and efficiently in the future.

Finally, in FY21, the Legislature appropriated a one-time amount of $2 million dollars from the Fund for the Carlsbad brine well remediation for use in FY21 through FY23. Of this, $26,624.84 was expended in FY21. The remaining balance will be expended in FY22 consistent with existing contracts for that work.

The following provides details on the Fund and its uses. These details include an FY21 balance sheet for the Fund and information on the procurement of well plugging for the fiscal year:

OIL RECLAMATION FUND (See details below)

Beginning Cash Balance on July 1, 2020	**$7,777,671.76**
Oil & Gas Conservation Tax Revenue	$4,656,337.11
Bond Forfeitures, Salvage and Reimbursement Recoveries	$ 0.00
Total Revenues:	$ 4,656,337.11
Balance:	$12,434,008.87
Total Expenses from the Reclamation Fund:	$3,361,328.87
Ending Cash Balance @ June 30, 2021:	**$9,072,680.00**

EXHIBIT 20

Michelle Lujan Grisham, Governor
Sarah Cottrell Propst, Cabinet Secretary
Todd E. Leahy, JD, PhD, Deputy Cabinet Secretary
Adrienne Sandoval, Oil Conservation Division Director

December 27, 2022

Governor Michelle Lujan Grisham
State Capitol
Santa Fe, NM 87501

Cabinet Secretary
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Director Legislative Council Service
411 State Capitol
490 Old Santa Fe Trail
Santa Fe, NM 87501

Re: Annual Report on Use of the Oil and Gas Reclamation Fund

Enclosed is the Oil and Gas Reclamation Fund Report for Fiscal Year 2022.

If you have any questions regarding the report or would like additional information, please contact me at 505-231-3316.

Sincerely,

Adrienne Sandoval
Oil Conservation Division Director

Cc: David Abbey, Director, Legislative Finance Committee
Debbie Romero, Cabinet Secretary, Department of Finance and Administration

OIL CONSERVATION DIVISON

OIL AND GAS RECLAMATION FUND REPORT

FISCAL YEAR 2022

(July 1, 2021 – June 30, 2022)

The New Mexico Oil and Gas Act ("Act") requires the Director of the New Mexico Oil Conservation Division ("OCD") to prepare an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor, and the Legislature on the use of the Oil and Gas Reclamation Fund. 70-2-38(C) NMSA 1978. This report is for fiscal year 2022, which ran from July 1, 2021 through June 30, 2022.

Sections 70-2-37 and 70-2-38 of the Act create the Oil and Gas Reclamation Fund (the "Fund") and provide for its administration. Under the Act, monies in the Fund, subject to legislative appropriation, may be used to survey and plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. The Fund also allows for limited monies to be used for OCD salaries, for costs associated with plugging and remediation equipment, and up to $150,000 annually to promote energy education in the State. The Fund is supported by a distribution of a portion of the revenues from the oil and gas conservation tax. 7-1-6.21 NMSA 1978.

Section 70-2-14 of the Act allows the OCD to require oil and gas operators to post plugging bonds to ensure performance of their well plugging obligations. An operator may furnish a single-well bond for each of its wells or a blanket bond for all wells on state or private lands. Oil Conservation Commission rules specify the formulas for determining bond amounts in 19.5.8 NMAC. If the OCD steps in to plug or remediate a well, site, or facility in lieu of an operator, the OCD may foreclose on the operator's bond and deposit the proceeds into the Fund. 70-2-14(B) NMSA 1978. OCD is also authorized to pursue recovery in state court for costs associated with well site plugging and reclamation from the responsible operator. 70-2-38(B) NMSA 1978. The OCD steps to plug and remediate a well when companies become insolvent, bonding is inadequate, or an operator abandons a well.

For its well plugging and remediation, the OCD employs independent contractors to perform the work. Contracts are awarded after a competitive bidding process consistent with Procurement Code requirements. These contractors are oil field service companies specializing in plugging oil and gas wells and/or companies specializing in environmental cleanups. Wells are prioritized to be plugged by their potential to cause harm to human health, underground sources of drinking water, and the environment. In order for a well to be plugged by the OCD, a well must first go through an administrative hearing process wherein OCD obtains an administrative order authorizing it to plug and abandon the well consistent with applicable requirements.

During Fiscal Year 2022, $4,462,054.85 was expended from the Fund. Of that, the Legislature made a one-time appropriation of $2 million dollars from the Fund for the Carlsbad brine well remediation project for use in FY21 through FY23. In FY22, the remaining amount available, $1,973,375.14, was expended on the Carlsbad brine well remediation project. Additionally, $1,788,941.23 was spent plugging and reclaiming 27 wells and an associated facility.

Additional monies expended from the Fund were used to support programmatic reclamation and compliance work, OCD hearings and IT infrastructure improvements to support the plugging and remediation of orphaned sites and research to better understand geologic formations and aquifers to ensure proper environmental protection during plugging. These are vital support costs that are critical to the reclamation work OCD performs. Without this support, reclamation work cannot be completed in a timely fashion and the OCD cannot ensure that any reclamation undertaken was completed properly. For example, before a well is plugged there must be a public hearing and an order issued by the OCD. Additionally, the OCD relies heavily on having the most up to date technical information readily available for field inspectors who are reviewing work that has been completed. OCD has worked diligently to continue to make updates to IT infrastructure to support OCD well plugging. This program support has positioned the OCD to manage plugging work more effectively and efficiently in the future, which is enabling it to, among other things, efficiently utilize the grant funding made available under the Bipartisan Infrastructure Law.

The following provides details on the Fund and its uses. These details include an FY22 balance sheet for the Fund and information on the procurement of well plugging for the fiscal year:

OIL RECLAMATION FUND (See details below)

Beginning Cash Balance on July 1, 2021	**$9,073,219.68**
Oil & Gas Conservation Tax Revenue	$22,222,631.48
Bond Forfeitures, Salvage and Reimbursement Recoveries	$ 161,250.00
Total Revenues:	$ 22,383,881.48
Balance:	$31,457,101.16
Total Expenses from the Reclamation Fund:	$4,462,054.85
Ending Cash Balance @ June 30, 2022:	**$26,995,046.31**

Attachment A – Wells plugged in FY22 using Reclamation Funds

Fiscal Year	Well Name	API #
2022	Cato San Andres Unit #041	30-005-20047
2022	Cato San Andres Unit #042	30-005-20089
2022	Cato San Andres Unit #044	30-005-20004
2022	Cato San Andres Unit #061	30-005-20005
2022	Cato San Andres Unit #064	30-005-20028
2022	Cato San Andres Unit #302	30-005-21163
2022	Cato San Andres Unit #330	30-005-21165
2022	Cato San Andres Unit #063	30-005-20049
2022	Cato San Andres Unit #328	30-005-21164
2022	Cato San Andres Unit #017	30-005-10501
2022	Cato San Andres Unit #001	30-005-10584
2022	Cato San Andres Unit #002	30-005-20932
2022	Cato San Andres Unit #031	30-005-20170
2022	Cato San Andres Unit #032	30-005-10522
2022	Cato San Andres Unit #046	30-005-10538
2022	Cato San Andres Unit #045	30-005-20130
2022	Cato San Andres Unit #059	30-005-10570
2022	Cato San Andres Unit #060	30-005-10571
2022	Cato San Andres Unit #058	30-005-10500
2022	Cato San Andres Unit #047	30-005-10578
2022	Cato San Andres Unit #050	30-005-29021
2022	Cato San Andres Unit #027	30-005-10491
2022	Cato San Andres Unit #049	30-005-10455
2022	Cato San Andres Unit #028	30-005-10503
2022	Cato San Andres Unit #020	30-005-10504
2022	Cato San Andres Unit #081	30-005-10572
2022	Cato San Andres Unit #051	30-005-10539

EXHIBIT 21

Michelle Lujan Grisham
Governor

Dylan Fuge
Deputy Cabinet Secretary
and Acting Director, Oil Conservation Division

January 23, 2024

Governor Michelle Lujan Grisham
490 Old Santa Fe Trail, Room 400
Santa Fe, New Mexico 87501

Cabinet Secretary
Energy, Minerals & Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505

Raul Burciaga, Director
Legislative Council Service
490 Old Santa Fe Trail, Room 411
Santa Fe, New Mexico 87501

RE: Annual Report on Use of the Oil & Gas Reclamation Fund

Enclosed is the Oil & Gas Reclamation Fund Report for Fiscal Year 2023. Given the influx of federal dollars under the Bipartisan Infrastructure Law and the requirement that OCD expend its twenty-five million dollar initial grant within two years, OCD has been prioritizing plugging with those federal funds in the prior fiscal year. Wells plugged with federal funds are not reported in the attached report.

If you have any questions regarding the report or would like additional information, please feel free to contact me at (505) 476-3200 or by email at dylan.fuge@emnrd.nm.gov.

Respectfully,

Dylan Fuge
Deputy Cabinet Secretary, EMNRD

cc: Charles Sallee, Director, Legislative Finance Committee
Wayne Propst, Cabinet Secretary, Department of Finance and Administration

OIL CONSERVATION DIVISION
OIL & GAS RECLAMATION FUND REPORT
FISCAL YEAR 2023
(July 1,2022 – June 30, 2023)

The New Mexico Oil and Gas Act ("Act") requires the Director of the New Mexico Oil Conservation Division ("OCD") to prepare an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor, and the Legislature on the use of the Oil and Gas Reclamation Fund. 70-2-38(C) NMSA 1978. This report is for fiscal year 2023, which ran from July 1, 2022 through June 30, 2023.

Sections 70-2-37 and 70-2-38 of the Act create the Oil and Gas Reclamation Fund ("Fund") and provide for its administration. Under the Act, monies in the Fund, subject to legislative appropriation, may be used to survey and plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. The Fund also allows for limited monies to be used for OCD salaries, for costs associated with plugging and remediation equipment, and up to $150,000 annually to promote energy education in the State. The Fund is supported by a distribution of a portion of the revenues from the oil and gas conservation tax. 7-1-6.21 NMSA 1978.

Section 70-2-14 of the Act allows the OCD to require oil and gas operators to post plugging bonds to ensure performance of their well plugging obligations. An operator may furnish a single-well bond for each of its wells or a blanket bond for all wells on state or private lands. Oil Conservation Commission rules specify the formulas for determining bond amounts in 19.5.8 NMAC. If the OCD steps in to plug or remediate a well, site, or facility in lieu of an operator, the OCD may foreclose on all or part of the operator's bond and deposit the proceeds into the Fund. 70-2-14(B) NMSA 1978. The OCD is also authorized to pursue recovery in state court for costs associated with well site plugging and reclamation from the responsible operator. 10-2-38(B) NMSA 1978. The OCD steps in to plug and remediate wells when companies become insolvent, bonding is inadequate, or an operator abandons a well.

For its well plugging and remediation, the OCD employs independent contractors to perform the work. Purchase orders are issued to pre-qualified contractors under a General Services Department- approved price agreement or after a competitive bidding process, both consistent with Procurement Code requirements. These contractors are oilfield service companies specializing in plugging oil and gas wells and/or companies specializing in environmental cleanups. Wells are prioritized for plugging by their potential to cause harm to human health, underground sources of drinking water, and the environment. In order for a well to be plugged by the OCD, it must first go through an administrative hearing process wherein the OCD obtains an administrative order authorizing it to plug and abandon the well consistent with applicable requirements in 19.15.25 NMAC.

During Fiscal Year 2023, $3,030,666.66 was expended from the Fund. Of that, $2,235,241.99 was spent plugging 13 abandoned wells. The balance of Reclamation Fund expenditures were made in support of the plugging of abandoned wells and the restoration of associated facilities.

The following provides details on the Fund and its usage.

OIL RECLAMATION FUND

Beginning Cash Balance on July 1, 2022	**$26,995,046.31**
Oil & Gas Conservation Tax Revenue	$26,933,678.40
Bond Forfeitures and Reimbursements	$0.00
Total Revenues	$26,933,678.40
Balance	$53,928,724.71
Total Expenses from the Reclamation Fund	$3,030,666.66
Ending Cash Balance on June 30, 2023	**$50,898,058.05**

WELLS PLUGGED IN FY23 USING RECLAMATION FUNDS

Well Name	API#
Twin Lakes San Andres Unit #032	30-005-60795
Twin Lakes San Andres Unit #041	30-005-60768
Twin Lakes San Andres Unit #012	30-005-60578
Twin Lakes San Andres Unit #011	30-005-60563
Twin Lakes San Andres Unit #010	30-005-60571
Twin Lakes San Andres Unit #005	30-005-60572
Twin Lakes San Andres Unit #048	30-005-60697
Twin Lakes San Andres Unit #034	30-005-60033
Twin Lakes San Andres Unit #006	30-005-60596
Twin Lakes San Andres Unit #030	30-005-60595
Lawton State #001	30-025-07119
Shelly 36 State #006	30-025-36464
New Mexico 36 State #001	30-025-36485

EXHIBIT 22

State of New Mexico
Energy, Minerals and Natural Resources Department

Michelle Lujan Grisham
Governor

Melanie A. Kenderdine
Cabinet Secretary

Ben Shelton
Deputy Secretary

Erin Taylor
Deputy Secretary

Albert Chang
Division Director
Oil Conservation Division

July 1, 2025

Governor Michele Lujan Grisham
State Capitol
Santa Fe, NM 87503

Representative Nathan Small
Chair, House Appropriations and Finance Committee
PO Box 697
Dona Aña, NM 88032

Senator George Muñoz
Chair, Senate Finance Committee
Box 2679
Gallup, NM 87305

Cabinet Secretary Melanie Kenderdine
Energy, Minerals and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, NM 87505

Re: FY 2024 Annual Report on Use of the Oil Reclamation Fund

Attached is the Oil and Gas Reclamation Fund Report for Fiscal Year 2024. If you have any questions or desire additional information, please feel free to contact me via email at *albert.chang@emnrd.nm.gov*.

Respectfully,

Albert Chang
Director, Oil Conservation Division

attachment

cc: Charles Sallee, Director, Legislative Finance Committee
Wayne Propst, Cabinet Secretary, Department of Finance and Administration

OIL AND GAS RECLAMATION REPORT FOR FISCAL YEAR 2024

(July 1, 2023 - June 30, 2024)

The Oil and gas Act requires the Director of the New Mexico Oil Conservation Division (OCD) to make an annual report to the Secretary of the Energy, Minerals and Natural Resources Department, the Governor and the Legislature on the use of the Oil and Gas Reclamation Fund. The OCD Director makes this report for the fiscal year 2024, ending the preceding June 30.

The OCD is authorized by the Oil and Gas Act to plug and abandon oil and gas wells to prevent the migration of fluids, gases and other contaminants to other strata or to fresh water, and to restore and remediate abandoned well sites and associated production facilities.

See NMSA 1978 Section 70-2-12.B. (1) and (18) and 70-2-38.

That same authority allows OCD to require oil and gas operators to post plugging bonds conditioned upon performance of their plugging obligations. A well operator may furnish a single-well bond for each of its wells or a blanket bond covering all wells.

Additional single-well bonds are required for wells on state and private land that have been inactive for two years or more. Bonds for other production facilities range from $25,000 to$250,000. If a bond covers a well, site or facility that the OCD has plugged or remediated, the OCD forecloses on the bond and places the proceeds in the Oil and Gas Reclamation Fund.

NMSA 1978, Sections 70-2-37 and 70-2-38 create the Oil and Gas Reclamation Fund ("Fund") and provide for administration of the Fund. Expenditures may be used to plug abandoned wells and to restore and remediate abandoned well sites and associated production facilities. In addition, up to $150,000 of the Fund may be spent annually to promote energy education in the State. The Fund is supported principally by the oil and gas conservation tax.

Effective on July 1, 2011, NMSA 1978 Section 7-1-6.21, as amended, provides for monthly distribution of proceeds of the Oil and Gas Conservation Tax to the Fund, as follows:

A. With respect to any period for which the rate of the tax imposed by Section 7-30-4 NMSA 1978 is nineteen-hundredths percent, a distribution pursuant to Section 7-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to two-nineteenths of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act [Chapter 7, Article 30 NMSA 1978].

B. With respect to any period for which the total rate of the tax imposed on oil by Section 7-30-4 NMSA 1978 is twenty-four hundredths percent, a distribution pursuant to Section 7-1-6.20 NMSA 1978 shall be made to the oil and gas reclamation fund in an amount equal to nineteen and seven-tenths percent of the net receipts attributable to the tax imposed under the Oil and Gas Conservation Tax Act.

During all of FY 2024, the higher conservation tax applied, such that the monthly distribution to the Fund was computed pursuant to Subsection B of Section 7-1-6.21.

The OCD employs independent contractors to perform the plugging, restoration and remediation work. The contracts are Purchase Orders pursuant to the Procurement Code. Contractors awarded contracts are oil field service companies specializing in plugging oil and gas wells or firms specializing in environmental cleanups.

WELL PLUGGING, SITE REMEDIATION, PRE- AND POST METHANE EMISSIONS TESTING, BOND REQUIREMENTS

The following pages provide details on the Oil and Gas Reclamation fund and its uses. These details include an FY 24 balance sheet for the fund and information on the procurement of well plugging, emergency services and site remediation during the year.

The Oil Conservation Division used Reclamation funds in FY 2024 to plug 46 wells, conduct eight (8) site assessments followed by remediation and reclamation work, continues to monitor one (1) project, conducted 257 pre- and post-plug methane tests on wells, and reimbursed contractors for performance bonds. For continued funding from the Bipartisan Infrastructure Law, the Federal Phase One Formula Grant, requires States to provide on-site research information regarding the Federal Endangered Species Act of 1973 (ESA) and the National Historic Preservation Act of 1966 (NHPA). Two consultants were hired to conduct on site research, compile the data and prepare the reports covering areas in southeast New Mexico. Once the reports are approved by the appropriate Federal agency, OCD can begin working on plugging wells using the Federal Grant funds.

OCD staff and contractors were challenged with remediation and reclamation efforts on four sites found to be highly contaminated. While most of the sites have been approved for reseeding, one site, the Cano San Andres #6 Tank Battery, requires further remediation work.

Regarding the former I&W Brine well in Carlsbad, surface subsidence and cavern pressure monitoring including an early warning system along with indirect geophysical characterization continued to progress through the fiscal year.

The division did not use funds to pay the OCD staff salaries and benefits.

The OCD entered into a settlement agreement with Ridgeway Arizona Oil Corporation on December 13, 2023. The agreement contemplates OCD plugging 299 of Ridgeway's 337 wells. OCD entered the settlement after review of financial disclosures indicating that Ridgeway was incapable of plugging the wells. In consideration of OCD plugging activity, Ridgeway was required to perform site assessments for all inactive wells and to make monthly reimbursement payments to the state at the rate of $2.00 per gross barrel of oil sold or $30,000 per month, whichever is greater. Ridgeway is prohibited from transferring wells without OCD approval and may not continue operating within New Mexico if it fails to make any necessary reimbursement payment.

OIL RECLAMATION FUND

Beginning Cash Balance @ July 1, 2023	**$50,898,058.05**
Oil & Gas Conservation Tax Revenue	**$25,986,480.04**
Bond Forfeitures, Salvage and Reimbursement Recoveries	**$ 0.00**
Total Revenues:	**$25,986,480.04**
Balance:	**$64,401,673.23**
Subtotal expenditures for plugging, remediation, and reclamation, methane testing, bond reimbursement, and Endangered Species Act reports:	**($11,349,842.82)**
Subtotal Other Expenses:	**($922,105.16)**
TOTAL EXPENSES FY 2024	**(12,330,131.66)**
Ending Cash Balance June 30, 2024	**$52,071,541.57**

FY24 EXPENDITURE AND USAGE DETAIL

PLUGGED ORPHANED WELLS SERVICES (46)

1. Elks #1, well owned by the Office of the State Engineer, in Chavez County.
   Paid $127,495.16, Contractor: JA Drake Well Service Inc, Invoice #21804.
2. Lansford #002, operator Energy Acumen, in Lea County.
   Paid $89,429.66. Contractor: JA Drake Well Service, Inc, Invoice #22169.
3. Alves #004, operator Energy Acumen, in Lea County.
   Paid $144,820.79. Contractor JA Drake Well Service, Inc, Invoice #22122.
4. Alves #002, operator Energy Acumen, in Lea County.
   Paid $194,690.23, Contractor: JA Drake Well Service, Inc, Invoice #22121.
5. Mike #002, operator Energy Acumen LLC, Lea County.
   Paid $92,623.43, Contractor: A-Plus P&A Holdings LLC, Invoice #1983.
6. Double L Queen #001Y, operator Canyon E&P Company, Chaves County.
   Paid $11,703.83, Contractor: A-Plus P&A Holdings LLC, Invoice #1882 (remainder of invoice paid using federal funds).
7. Double L Queen #001H, operator Canyon E&P Company, Chaves County.
   Paid $8,792.46, Contractor: A-Plus P&A Holdings LLC, Invoice #1858 (remainder of invoice paid using federal funds).
8. Lansford #001, operator Energy Acumen LLC, Lea County.
   Paid $145,075.74, Contractor: JA Drake Well Service, Inc, Invoice #22157.
9. Lansford #004, operator Energy Acumen LLC, Lea County.
   Paid: $122,744.92, Contractor: JA Drake Well Service, Inc, Invoice #22181.
10. Pruitt #001, operator Energy Acumen LLC, Lea County.
    Paid: $137,015.56, Contractor: JA Drake Well Service, Inc, Invoice #22245.
11. GW Shahan #002, operator Unified Operating, LLC, Lea County.
    Paid: $31,456.46, Contractor: JA Drake Well Service, Inc., Invoice #22198.
12. Mike #004, operator Energy Acumen LLC, Lea County.
    Paid $128,328.19, A-Plus P&A Holdings, LLC, Invoice #1989.
13. Lansford #003, operator Energy Acumen LLC, Lea County.
    Paid $135,115.27, JA Drake Well Service Inc, Invoice #22180.
14. Alves #003, Operator Energy Acumen LLC, Lea County.
    Paid $214,185.83, JA Drake Well Service Inc, Invoice #22197.
15. Lansford #005, Operator Energy Acumen LLC, Lea County.
    Paid $197,772.25, JA Drake Well Service Inc, Invoice #22199.
16. Lansford #006, Operator Energy Acumen LLC, Lea County.
    Paid $166,599.96, JA Drake Well Service Inc, Invoice #22223.
17. Double L Queen #003, Operator Canyon E & P Company, Chaves County.
    Paid $69,279.31, A-Plus P&A Holdings LLC., Invoice #1860.
18. Double L Queen #003G, Operator Canyon E & P Company, Chaves County.
    Paid $69,148.62, A-Plus P&A Holdings LLC, Invoice #1862.
19. Double L Queen #003Q, Operator Canyon E & P Company, Chaves County.
    Paid $90,128.62, A-Plus P&A Holdings LLC, Invoice #1865.
20. Mike #001, operator Energy Acumen LLC, Lea County.
    Paid $86,416.72, A-Plus P&A Holdings LLC, Invoice #1962.
21. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $204,077.39, A-Plus P&A Holdings LLC, Invoice #1972.
22. Mike #003, operator Energy Acumen LLC, Lea County.
    Paid $147,724.34, A-Plus P&A Holdings LLC, Invoice #1955.
23. Schwalbe #001, operator Robinson Oil Inc., Lea County.
    Paid $336,762.47, JA Drake Well Service, Invoice #21755.
24. Bagley #002, operator Lease Holders Acquisitions, Inc., Lea County.
    Paid $523,725.26, JA Drake Well Service, Invoice #22090.
25. Buckskin Federal #002, operator Energy Acumen, LLC., Lea County.
    Paid $49,579.19, JA Drake Well Service, Invoice #22260.
26. JP Collier #001, operator Lease Holders Acquisitions, Inc., Lea County.
    Paid $476,334.72, JA Drake Well Service, Invoice #22107.

PLUGGED ORPHANED WELL SERVICES, continued (46)

27. Alves A #001, operator Energy Acumen, LLC., Lea County.
    Paid $454,014.69, JA Drake Well Service, Invoice #22226.
28. Robert #001, operator Energy Acumen, LLC., Lea County.
    Paid $183,222.16, JA Drake Well Service, Invoice #22243.
29. Seanna #002 cut off, operator Canyon E & P Company, Chaves County.
    Union Happy #001 cut off, operator Canyon E & P Company, Chaves County.
    Union Happy #002 cut off, operator Canyon E & P Company, Chaves County.
    Paid $5,481.66, JA Drake Well Service, Invoice #22167.
30. Robert #002, operator Energy Acumen, LLC., Lea County.
    Paid $143,401.02, JA Drake Well Service, Invoice #22244.
31. Twin Lakes San Andres #109, operator Blue Sky NM, Inc., Chaves County.
    Paid $12,744.93, JA Drake Well Service Inc., Invoice #21510.
32. Twin Lakes San Andres #065, operator Blue Sky NM, Inc., Chaves County.
    Paid $5,480.93, JA Drake Well Service Inc, Invoice #21265.
33. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $76,382.70, A-Plus P&A Holdings LLC, Invoice #2227.
34. Miller Comm #001, operator Energy Acumen LLC, Lea County.
    Paid $149,142.11, A-Plus P&A Holdings LLC, Invoice #2226.
35. Brown 93 #001, operator Ridgeway Arizona Oil Corporation, Lea County.
    Paid $189,275.69, JA Drake Well Service LLC, Invoice #22586.
36. Double L Queen #001R, operator Canyon E & P Company, Chaves County.
    Paid $115,772.09, A-Plus P&A Holdings, LLC., Invoice #1884.
37. Na Dzis Pah #002, operator Biya Operators Inc., Sandoval County.
    Paid $121,722.05, Aztec Well Servicing Co., Invoice #2024-00865
38. Na Dzis Pah #001, operator Biya Operators Inc., Sandoval County.
    Paid $104,801.86, Aztec Well Servicing Co, Invoice #2024-00866.
39. State Senate #002, operator Biya Operators Inc., Sandoval County.
    Paid $72,572.08, Aztec Well Servicing Co, Invoice #2024-00867.
40. Indian #002, operator Biya Operators Inc., Sandoval County.
    Paid $107,681.62, Aztec Well Servicing Co, Invoice #2024-00868.
41. Chaveroo San Andres Unit #004, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $161,592.64, A-Plus P&A Holdings LLC, Invoice #2414.
42. Chaveroo San Andres Unit #004, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $14,852.07, A-Plus P&A Holdings LLC, Invoice #DR-02815.
43. Chaveroo San Andres Unit #006, operator Ridgeway Arizona Oil Corporation, Roosevelt County.
    Paid $159,524.24, A-Plus P&A Holdings LLC, Invoice #2284
44. Chaveroo San Andres Unit #003, operator Ridgeway Arizona Oil Corp, Roosevelt County.
    Paid $168,526.06, A-Plus P&A Holdings LLC, Invoice #2426.
45. Brown 84 #002, Lea County, Arizona Ridgeway Oil Corporation, Lea County.
    Paid $274,383.81, JA Drake Well Service Inc, Invoice #22516.
46. Brown 84 #001, operator Arizona Ridgeway Oil Corporation, Lea County.
    Paid $276,444.71, JA Drake Well Service Inc, Invoice #22597.

Subtotal $6,798,045.50

SALVAGE, REMEDIATION, RECLAMATION AND REVEGETATION SERVICES (8)

1. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $337,068.19, Contractor: Young Environmental Services, dba Envirotech, Invoice #63351.
2. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
   Paid: $418,495.10, Contractor: Young Environmental Services, dba Envirotech, Invoice #63245.
3. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $19,519.28, Intera Incorporated, Invoice #03-24-01.
4. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $40,675.41, Intera Incorporated, Invoice #03-24-18.
5. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $298,678.93, Contractor: Young Environmental Services, dba Envirotech, Invoice #63564.
6. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County
   Paid: $87,001.78, Contractor: Young Environmental Services, dba Envirotech, Invoice #63697.
7. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $65,852.09, Unlimited Construction 2 LLC, Invoice #5328.
8. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
   Paid $127,657.73, Unlimited Construction 2 LLC, Invoice #5317.
9. Cano San Andres Unit Tank Battery #006, operator Cano Petro of New Mexico Inc.
   Paid $66,682.27, Ensolum LLC, Invoice #28774.
10. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $32,881.03, Intera Incorporated, Invoice #03-24-101 REV.
11. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $42,082.08, Contractor: Young Environmental Services, dba Envirotech, Invoice #63840.
12. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $425,216.13, Unlimited Construction 2 LLC, Invoice #5342.
13. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $69,900.74, Intera Incorporated, Invoice #5346.
14. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $47,682.91, Intera Incorporated, Invoice #04-24-01.
15. Artesia Metex Unit #005, operator Cannon E & P Company., Eddy County.
    Paid $11,073.47, Miller Engineers, Inc, Invoice #5E3179601Revise.
16. Artesia Metex Unit #006, operator Cannon E & P Company., Eddy County.
    Paid $9,541.80, Miller Engineers, Inc. , Invoice #5E3179602
17. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $9,333.62, Miller Engineers, Inc, Invoice #5E3179603.
18. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $27,362.95, Miller Engineers, Inc, Invoice #5E3179608.
19. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $27,662.07, Miller Engineers, Inc, Invoice #5E3179609
20. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $26,080.90, Miller Engineers, Inc, Invoice #5E3179610.
21. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $11,880.73, Miller Engineers, Inc, Invoice #5E3179611.
22. Artesia Metex Unit #017, operator Cannon E & P Company., Eddy County.
    Paid $12,174.60, Miller Engineers, Inc, Invoice #5E3179612.
23. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $4,613.22, Contractor: Young Environmental Services, dba Envirotech, Invoice #64599.
24. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $60,327.99, Intera Incorporated, Invoice #05-24-68.
25. Artesia Metex Unit #018, operator Cannon E & P Company., Eddy County.
    Paid $10,929.29, Miller Engineers, Inc, Invoice #5E31779604.

26. Artesia Metex Unit #019, operator Cannon E & P Company., Eddy County.
    Paid $6,623.47, Miller Engineers, Inc, Invoice #5E3179605.
27. Artesia Metex Unit #019, operator Cannon E & P Company., Eddy County.
    Paid $42,760.42, Miller Engineers, Inc, Invoice #5E3179606.
28. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid: $5,932.04, Contractor: Young Environmental Services, dba Envirotech, Invoice #64191.
29. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $407,412.23, Unlimited Construction 2 LLC, Invoice #5374.
30. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $45,657.67, Intera Incorporated, Invoice #04-24-21.
31. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $609,716.93, Unlimited Construction 2 LLC, Invoice #5358.
32. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $60,327.99, Intera Incorporated, Invoice #05-24-68.
33. Artesia Metex Unit #005, operator Cannon E & P Company., Eddy County.
    Paid $26,027.45, Miller Engineers, Inc, Invoice #5E3179607.
34. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $94,890.63, Intera Incorporated, Invoice #05-24-70 Rev.
35. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $31,736.13, Intera Incorporated, Invoice #06-24-02.
36. Reed Estate #001, operator Hal J. Rasmussen Oper Inc., Lea County.
    Paid $425,035.29, Unlimited Construction 2 LLC, Invoice #5380.
37. Canyon E & P Double L Queen Tank Battery #006, operator Canyon E & P Company, Chaves County.
    Paid $17,458.49, Young Environmental Services, dba Envirotech, Invoice #64482.

Subtotal $4,003,625.06

PRE- AND POST-PLUG METHANE TESTING (257 Sites):

1. Double L Queen Unit #s 001D, 001H, 001K, 001P, 001Q, 001R, 001Y, 002, 002G, 002P, 002Q, 002X, 002Z, 003, 003G, 003L, 003Q, 003Y, 004, 004G, 004Q, 005, 005Q, 006, 007, operator Canyon E & P Company, in Chaves County.
   Paid: $51,173.00. Contractor: Well Done New Mexico, LLC, Invoice #1081.
2. INBE 12 #001, INBE 13 #001, Bagley #002, J P Collier #001, JP Collier #004Y, operator Lease Holders Acquisitions, Inc. and Schwalbe #001, #002, operator, Robinson Oil Inc., Chaves County.
   Paid: $16,911.28, Well Done New Mexico, LLC, Invoice #1090.
3. Cato San Andres Units #097, #098, #100, #119, #127, #515, #517, #518, #520, #531, #532, #533, #535, #544, #558, #559, #560, #561, #573. #574, #586, #587, #588, #822, #827, operator Cano Petro of New Mexico, Inc., Chaves County
   Paid $63,455.54, Well Done New Mexico LLC, Invoice #1083.
4. Barkeht #001, Elizabeth #001, #002, #003, #004, Elizabeth C #005, Graves #001, Lewis Neff #003, McDermott #001, Nancy #001, Seanna #001, #002, #003, Union Happy #001, #002, operator Canyon E & P Company, Chaves County.
   Paid $31,680.00, Well Done New Mexico LL, Invoice #1089.
5. EF King #003, operator Roca Production Inc, Lea County.
   Paid $2,085.82, Well Done New Mexico LLC, Invoice #1088.
6. Twin Lakes San Andres #081, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1079.
7. Twin Lakes San Andres #078, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1078.
8. Twin Lakes San Andres #065, operator Blue Sky NM, Inc., Chaves County.
   Paid $1,474.10 Well Done New Mexico LLC, Invoice #1077.

9. Cato San Andres #545, 557Y, #558, #559, #560, #561, #573, #574, #586, #587, #588, Chaves County, Cano Petro of New Mexico, Inc., and South Lucky Lake Queen #001, #002, operator Bar V Barb LLC, Chaves County.
   Paid $27,662.91 A-Plus P&A LLC for subcontractor, Well Done New Mexico, LLC, Invoice #1441.
10. Elizabeth #001, #002, #003, #004, operator Canyon E & P Company, Chaves County.
    Paid $8,511.66 A-Plus P&A LLC for subcontractor, Well Done New Mexico, LLC, Invoice #1440.
11. Alves A #001, Alves #002, #004, Lansford #001, Lansford #002, Lansford #003, Lansford #004, Lansford #005, Lansford #006, Mike #001, Mike #002, Mike #003, Mike #004, Millller Com #001, Pruitt #001, Robert #001, Robert #002, operator Energy Acumen LLC, Lea County.
    Paid $62,594.14, Well Done New Mexico, LLC, Invoice #1093.
12. Chaveroo San Andres Unit #003, #004, #005, #006, #007, Farrell Federal #002, Haley Chaveroo SA Unit #010, Jennifer Chaveroo SA Unit #028, Roosevelt County, KM Chaveroo SA Unit #012, #016, #018, #021, #032, #035, #049, #110, #111, #112, #113, KMS,#001, #002, #003, #004, #005, Levic 1 State #001, operator Ridgeway Arizona County, Chaves County
    Paid $25,391.28, Well Done New Mexico LLC, Invoice #1105.
13. Indian #003, State Senate #002, Na Dzis Pah #001, #002, Natani #014, #017, #018, #032, #033, #034, operator M &M Production & Operation, San Juan County.
    Paid $21,159.36, Well Done New Mexico LLC, Invoice #1106.
14. Allied 93 #004, Bilbrey 23 #004, #005, Bilbrey 51 #002, #003, Brown 84 #001, #002, Brown 93 #001, Lea County, operator Ridgeway Arizona Oil Corp., Lea County.
    Paid $16,748.97, Well Done New Mexico LLC, Invoice #1094.
15. Anderson State #005, operator Ridgeway Arizona Oil Corp., Roosevelt County.
    Paid $2,117.93, Well Done New Mexico LLC, Invoice #1095.
16. Chaveroo San Andres Unit #003, #004, #005, #006, KMS #001, operator Ridgeway Arizona Oil Corp, Roosevelt County
    Paid $10,589.63, Well Done New Mexico LLC, Invoice #1096.
17. Humble Tucker #001, #003, #004, James McFarland A #001, #002, #003, #004, James McFarland #001, #002, #003, #004, operator Ridgeway Arizona Oil Corp, Roosevelt County.
    Paid $17,552.28, TS Nano, Invoice #10029OCD.

Subtotal $362,056.10

PERFORMANCE BOND REIMBURSEMENT:

1. Elks #001, operator, Wayne J. Spears, in Lea County.
   Paid $2,987.06 Contractor: JA Drake Well Service Inc, Invoice #21775.
2. Alves #002, #003, #004, Alves A #001, Lansford #001, #002, #003, #004, #005, #006, Pruitt #001, Robert #001, Robert #002, operator, Energy Acumen Wells, Lea County.
   Paid $64,683.14, Contractor: JA Drake Well Service Inc, Invoice #22088.
3. Cano San Andre's Unit Tank Battery #006, operator Cano Petro of New Mexico, Inc., Chaves County.
   Paid $2,924.00, Contractor: Ensolum LLC, Invoice #Performance.
4. Reed Estate #001, operator Hal J. Rasmussen Operator, Inc., Lea County.
   Paid $8,099.90, Contractor: Intera Incorporated, Invoice #02-24-03.
5. Chaveroo San Andres Unit #003, #004, #005, #006, #007, Farrell Federal #002, Haley Chaveroo SA Unit #010, Jennifer Chaveroo SA Unit #028, KM Chaveroo SA Unit #012, #016, #018, #021, #032, #035, #049, #110, #111, #112, #113, KMS #001, #002, #003, #004, #005, Levick 1 State #001, Chavaroo A State #001, #002, Chaveroo B #001, #002, Chaveroo San Andres Unit #001, #002, former operator Ridgeway Arizona Oil Corp, Roosevelt County.
   Paid $1,441.16, Well Done New Mexico, LLC, Invoice #1092.
6. Allie Partin Et Al #001, #002, Allied 93 #004, Anderson State #001, #002, #003, #004, #005, #007, #008, #009, Bilbrey 23 #003, #004, #005, Bilbrey 51 #002, #003, Brown 84 #001, #002, Brown 93 #001, Lea County, Chavaroo A State #001, #002, Chaveroo B #001, #002, Chaveroo San Andres Unit #001, #002, operator Ridgeway Arizona Oil Corp., Roosevelt County.
   Paid $2,882.32, Well Done New Mexico LLC, Invoice #1091.

7. Barkneht #001, Elizabeth #001, #002, #003, #004, Elizabeth C #005, Graves #001, Lewis Neff #003, McDermott #001, Nancy #001, Seanna #001, #002, #003, Union Happy #001, #002, operator Canyon E & P Company, Chaves County.
   Paid $965.02, Well Done New Mexico LLC, Invoice #1099.
8. Mike #001, # 002, #003, #004 and Miller Com #001, operator Energy Acumen LLC, Lea County.
   Paid $22,175.12, A-Plus P&A Holdings LLC, Invoice #2421.
9. Brown 84 #001, operator Arizona Ridgeway Oil Corporation, Lea County.
   Paid $14,182.30, JA Drake Well Service Inc, Invoice #22524.
10. Double L Queen Units #001D, #001H, #001K, #001P, #001Q, #001R, #001Y, #002, #002G, #002P, #002Q, #002X, #002Z, #003, #003G, #003L, #003Q, #003Y, #004, #004G, #004Q, #005, #005Q, #006, #007, operator Canyon E & P Company, Chaves County
    Paid $3,188.40, Well Done New Mexico LLC, Invoice #1097.
11. Cato San Andres Unit #097, #098, #100, #119, #127, #516, #517, #518, #520, #531, #532, #533, #535, #544, #545, #558, #559, #560, #561, #573, #574, #586, #587, #588, #822, #827, Cano Petro of New Mexico LLC, Chaves County.
    Paid $3,315.94, Well Done New Mexico LLC, Invoice #1098.
12. INBE 12 #001, INBE 13 #001, Bagley #002, JP Collier #001, JP Collier #004Y, operator Lease Holders Acquisitions, Inc., Schwalbe #001, #002, operator Robinson Oil Inc. Cano Petro of New Mexico LLC, Lea County.
    Paid $59,271.80, JA Drake Well Service Inc, Invoice #22635.

Subtotal: $186,116.16

Endangered Species Act (ESA) and National Historic Preservation Act (NHPA) Reports

The payments made below are partial payments. During the fiscal year 2024, no NHPA progress reports were received.

1. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $16,518.82, Daniel B Stephens & Associates, Invoice #268961R.
2. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $7,154.91, Daniel B Stephens & Associates, Invoice #0270194.
3. ESA services located in Lea, Chaves, and Eddy counties in Southeastern New Mexico. The services include biological surveys, biological assessments and evaluations and finally consultation.
   Paid $34,509.95, Daniel B Stephens & Associates, Invoice #269765R.

Subtotal: $58,183.68

OTHER EXPENSES:

Below are categories with vendors associated and cumulative charges by category.

1. **Vehicle Maintenance and Replacement:**
   - O&S Quik Change Inc. ($2,448.89)
   - Wex Bank ($34,834.93)
   - Chalmers Ford Inc. ($408,660.00)
   - Farmington Tire ($10,380.29)
   - Advantage Dodge CPJ ($1,394.82)
   - Forrest Tire Company Inc. ($3,732.00)
   - Bob Turners Ford Country Inc. ($40,498.00)
   - Jose Alvarez ($533.35)
   - Mesa Tire ($1,180.00)
   - Ziems Ford Corners ($150.00)

   Subtotal: $503,812.28

2. **OCD Field Technician Work Clothing**
    - Boot Barn Inc. ($11,930.87)
    - The Graphic Designer LLC ($235.01)

Subtotal $12,165.88

3. **OCD Staff Training**
    - National Environmental Management Academy LLC. ($5,000.00)
    - Leigh Barr, OCD Staff Travel ($494.92)
    - Bank of America NA: Lodging for OCD Staff ($1,879.70)
    - Rosa Romero, OCD Staff Travel ($184.30)
    - Michael Buchanan, OCD Staff Travel ($120.41)
    - Brittany Hall, OCD Staff Travel ($116.74)

Subtotal $7,796.07

4. **Legal Services (OCD Hearings)**
    - Pfeifer Hanson Mullins & Baker PA

Subtotal $105,020.60

5. **Professional Memberships**
    - State Bar of New Mexico ($925.00)
    - Ground Water Protection Council ($12,000.00)

Subtotal $12,925.00

6. **EMNRD IT Division (Software and Hardware)**
    - Carahsoft Technology Corporation ($7,974.33)
    - SHI International Corporation ($613.11)
    - Advanced Network Management ($42,350.68)
    - PC Specialist Inc. ($49,342.98)
    - ABBA Technologies Inc. ($58,456.13)
    - APIC Solutions Inc. ($77,378.47)

Subtotal $236,115.60

7. **Expert Investigator (Critical, technical data and experts regarding seismicity)**
    - New Mexico Institute of Mining and Technology

Subtotal $36,620.13

8. **Carlsbad Brine Well Project (continued monitoring)**
    - WSP USA Environment & Infrastructure

Subtotal $7,649.60

Subtotal: $922,105.16

EXHIBIT 23

State of New Mexico
Energy, Minerals and Natural Resources Department

Michelle Lujan Grisham
Governor

Sarah Cottrell Propst
Cabinet Secretary

Todd Leahy, PhD, JD
Deputy Cabinet Secretary

May 13, 2022

United States Department of the Interior
1849 C St., NW
Washington, DC 20240
Submitted via email: orphanedwells@ios.doi.gov
Re: State of New Mexico Application for Initial Grant Funding for Orphan Well Plugging Under the Infrastructure Investment and Jobs Act

Secretary Haaland,

Please accept this application for initial grant funding from the New Mexico Energy, Minerals and Natural Resources Department (EMNRD), Oil Conservation Division (OCD) pursuant to Section 40601(c)(3) of the Infrastructure Investment and Jobs Act (IIJA) to address orphan oil and gas well identification, plugging, site remediation, and restoration on state trust, private and split estate lands in the State of New Mexico.

EMNRD requests OCD be provided with the maximum allowable Large-Scale Initial grant amount of twenty-five million dollars ($25,000,000) which will be used almost entirely on third party contractual obligations. These funds will be incorporated into OCD's existing well plugging program, which has successfully addressed orphan well issue for many years; however, its aggregate impact in terms of number of wells plugged per year and sites remediated has been limited by available funding. The funding made available by the initial grant and any future formula grants will enable the OCD to greatly expand and enhance its well plugging and site remediation efforts.

OCD's regulations already establish requirements for the identification of orphan wells, their plugging, and the remediation of contaminated soils and groundwater, and minimum criteria for surface reclamation. These existent regulations meet or exceed those required by the IIJA and existing federal plugging and remediation standards applicable on federal lands under Bureau of Land Management (BLM) rules. This is evidenced by the fact that OCD already does plugging work for the BLM on federal lands under an existing grant agreement. OCD is also actively working to identify tools that will enable it to develop a measurement and tracking system to demonstrate a reduction in gaseous emissions associated with its plugging activities. These efforts are consistent with the recommendations in the Department's initial guidance.

OCD anticipates being able to fully use grants funds within the prescribed time period, but if it does not, any unobligated funds will be reimbursed to the Department of the

Interior. EMNRD believes this application contains all the required elements discussed in the application guidance. Completed federal forms for assistance, budget information and justification, lobbying and contact information, along with an executed certification are provided in the multiple attachments to this letter. A narrative response to the additional recommended application elements is also included.

EMNRD acknowledges the Davis-Bacon Act requirements for this award and confirms applicable labor rates will not be less than those prevailing on similar projects in that locality. EMNRD is not aware of any actual or potential conflicts-of-interest at this time.

EMNRD appreciates the opportunity provided to it by this program. EMNRD expects to put this initial grant along with any subsequent formula and performance grants to beneficial use in the coming years. Thank you.

Respectfully,

Todd Leahy, PhD, JD
Deputy Secretary

Attachment A – Form SF-424v4 Application for Federal Assistance
Attachment B – Form 424A Budget Information for Non-Construction Programs
Attachment C – Form SF-LLL Disclosure of Lobbying Activities (OMB Form 4040-0013)
Attachment D – OMB Form 4040-0010 Key Contacts
Attachment E – Detailed Budget Proposal/Justification
Attachment F – OMB Form 4040-0019 Project Abstract Summary
Attachment G – Narrative of Recommended Application Elements
Attachment H – State Certification for Large-Scale Initial grant

Attachment A – Form SF-424v4 Application for Federal Assistance

OMB Number: 4040-0004
Expiration Date: 12/31/2022

Application for Federal Assistance SF-424

* 1. Type of Submission:	* 2. Type of Application:	* If Revision, select appropriate letter(s):
☐ Preapplication	☒ New	
☒ Application	☐ Continuation	* Other (Specify):
☐ Changed/Corrected Application	☐ Revision	

* 3. Date Received:	4. Applicant Identifier:
05/13/2022	

5a. Federal Entity Identifier:	5b. Federal Award Identifier:

State Use Only:

6. Date Received by State:	7. State Application Identifier:

8. APPLICANT INFORMATION:

* a. Legal Name:	NM ENERGY, MINERALS & NATURAL RESOURCES DEPARTMENT

* b. Employer/Taxpayer Identification Number (EIN/TIN):	* c. UEI:
85-600565	MJKLQGKGWHL9

d. Address:

* Street1:	1220 South St. Francis Drive
Street2:	
* City:	Santa Fe
County/Parish:	
* State:	NM: New Mexico
Province:	
* Country:	USA: UNITED STATES
* Zip / Postal Code:	87505-8214

e. Organizational Unit:

Department Name:	Division Name:
Energy, Minerals & Natural Res	Oil Conservation

f. Name and contact information of person to be contacted on matters involving this application:

Prefix:	Mr.	* First Name:	Jim
Middle Name:			
* Last Name:	Griswold		
Suffix:			

Title:	Projects Coordinator
Organizational Affiliation:	NM ENERGY, MINERALS & NATURAL RESOURCES DEPARTMENT
* Telephone Number:	505-660-1067
Fax Number:	
* Email:	jim.griswold@state.nm.us

Apps' Ex. 23

Application for Federal Assistance SF-424

*** 9. Type of Applicant 1: Select Applicant Type:**

A: State Government

Type of Applicant 2: Select Applicant Type:

Type of Applicant 3: Select Applicant Type:

* Other (specify):

*** 10. Name of Federal Agency:**

Department of the Interior

11. Catalog of Federal Domestic Assistance Number:

CFDA Title:

*** 12. Funding Opportunity Number:**

D-AQD-FA-22-003

* Title:

Sec. 40601. ORPHANED WELL SITE PLUGGING, REMEDIATION, AND RESTORATION.

13. Competition Identification Number:

Title:

14. Areas Affected by Project (Cities, Counties, States, etc.):

Add Attachment | Delete Attachment | View Attachment

*** 15. Descriptive Title of Applicant's Project:**

Orphan well site plugging, remediation and restoration

Attach supporting documents as specified in agency instructions.

Add Attachments | Delete Attachments | View Attachments

Apps' Ex. 23

Application for Federal Assistance SF-424

16. Congressional Districts Of:

* a. Applicant: NM-003 * b. Program/Project: NM-all

Attach an additional list of Program/Project Congressional Districts if needed.

Add Attachment | Delete Attachment | View Attachment

17. Proposed Project:

* a. Start Date: 07/01/2022 * b. End Date: 06/30/2023

18. Estimated Funding ($):

* a. Federal	25,000,000.00
* b. Applicant	0.00
* c. State	0.00
* d. Local	0.00
* e. Other	0.00
* f. Program Income	0.00
* g. TOTAL	25,000,000.00

*** 19. Is Application Subject to Review By State Under Executive Order 12372 Process?**

☐ a. This application was made available to the State under the Executive Order 12372 Process for review on

☐ b. Program is subject to E.O. 12372 but has not been selected by the State for review.

☒ c. Program is not covered by E.O. 12372.

*** 20. Is the Applicant Delinquent On Any Federal Debt? (If "Yes," provide explanation in attachment.)**

☐ Yes ☒ No

If "Yes", provide explanation and attach

Add Attachment | Delete Attachment | View Attachment

21. *By signing this application, I certify (1) to the statements contained in the list of certifications and (2) that the statements herein are true, complete and accurate to the best of my knowledge. I also provide the required assurances** and agree to comply with any resulting terms if I accept an award. I am aware that any false, fictitious, or fraudulent statements or claims may subject me to criminal, civil, or administrative penalties. (U.S. Code, Title 218, Section 1001)**

☒ ** I AGREE

** The list of certifications and assurances, or an internet site where you may obtain this list, is contained in the announcement or agency specific instructions.

Authorized Representative:

Prefix:	Mr.
* First Name:	Todd
Middle Name:	
* Last Name:	Leahy
Suffix:	PhD, JD
* Title:	Deputy Cabinet Secretary, NM EMNRD
* Telephone Number:	505-476-3200
Fax Number:	
* Email:	todd.leahy@state.nm.us

* Signature of Authorized Representative: * Date Signed: 5/10/22

Apps' Ex. 23

Attachment B – Form 424A Budget Information for Non-Construction Programs

BUDGET INFORMATION - Non-Construction Programs

OMB Number: 4040-0006
Expiration Date: 02/28/2022

SECTION A - BUDGET SUMMARY

Grant Program Function or Activity (a)	Catalog of Federal Domestic Assistance Number (b)	Estimated Unobligated Funds		New or Revised Budget		
		Federal (c)	Non-Federal (d)	Federal (e)	Non-Federal (f)	Total (g)
1. SEC. 40601. ORPHANED WELL SITE PLUGGING, REMEDIATION, AND RESTORATION.		$	$	$ 25,000,000.00	$	$ 25,000,000.00
2.						
3.						
4.						
5. Totals		$	$	$ 25,000,000.00	$	$ 25,000,000.00

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SECTION B - BUDGET CATEGORIES

6. Object Class Categories	GRANT PROGRAM, FUNCTION OR ACTIVITY (1)	(2)	(3)	(4)	Total (5)
	SEC. 40601. ORPHANED WELL SITE PLUGGING, REMEDIATION, AND RESTORATION.				
a. Personnel	$	$	$	$	$
b. Fringe Benefits					
c. Travel					
d. Equipment					
e. Supplies					
f. Contractual	25,000,000.00				25,000,000.00
g. Construction					
h. Other					
i. Total Direct Charges (sum of 6a-6h)	25,000,000.00				$ 25,000,000.00
j. Indirect Charges					$
k. TOTALS (sum of 6i and 6j)	$ 25,000,000.00	$	$	$	$ 25,000,000.00
7. Program Income	$ 25,000,000.00	$	$	$	$ 25,000,000.00

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SECTION C - NON-FEDERAL RESOURCES

(a) Grant Program	(b) Applicant	(c) State	(d) Other Sources	(e)TOTALS
8. SEC. 40601. ORPHANED WELL SITE PLUGGING, REMEDIATION, AND RESTORATION.	$	$	$	$
9.				
10.				
11.				
12. TOTAL (sum of lines 8-11)	$	$	$	$

SECTION D - FORECASTED CASH NEEDS

	Total for 1st Year	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
13. Federal	$ 25,000,000.00	$ 6,250,000.00	$ 6,250,000.00	$ 6,250,000.00	$ 6,250,000.00
14. Non-Federal	$				
15. TOTAL (sum of lines 13 and 14)	$ 25,000,000.00	$ 6,250,000.00	$ 6,250,000.00	$ 6,250,000.00	$ 6,250,000.00

SECTION E - BUDGET ESTIMATES OF FEDERAL FUNDS NEEDED FOR BALANCE OF THE PROJECT

(a) Grant Program	FUTURE FUNDING PERIODS (YEARS) (b)First	(c) Second	(d) Third	(e) Fourth
16. SEC. 40601. ORPHANED WELL SITE PLUGGING, REMEDIATION, AND RESTORATION.	$ 25,000,000.00	$	$	$
17.				
18.				
19.				
20. TOTAL (sum of lines 16 - 19)	$ 25,000,000.00	$	$	$

SECTION F - OTHER BUDGET INFORMATION

21. Direct Charges: $25,000,000 in contracts to service providers.

22. Indirect Charges: $0

23. Remarks:

Attachment C – Form SF-LLL Disclosure of Lobbying Activities
(OMB Form 4040-0013)

DISCLOSURE OF LOBBYING ACTIVITIES

Complete this form to disclose lobbying activities pursuant to 31 U.S.C.1352

OMB Number: 4040-0013
Expiration Date: 02/28/2022

1. * Type of Federal Action:
- [ ] a. contract
- [x] b. grant
- [ ] c. cooperative agreement
- [ ] d. loan
- [ ] e. loan guarantee
- [ ] f. loan insurance

2. * Status of Federal Action:
- [ ] a. bid/offer/application
- [x] b. initial award
- [ ] c. post-award

3. * Report Type:
- [x] a. initial filing
- [ ] b. material change

4. Name and Address of Reporting Entity:

[x] Prime [ ] SubAwardee

*Name: NM Energy, Minerals & Natural Resources Dept.

*Street 1: 1220 St. Francis Drive Street 2:

*City: Santa Fe State: NM: New Mexico Zip: 87505

Congressional District, if known: NM 003

5. If Reporting Entity in No.4 is Subawardee, Enter Name and Address of Prime:

6. * Federal Department/Agency:
Department of the Interior

7. * Federal Program Name/Description:
Orphaned Well Site Plugging, Remediation, and Restoration

CFDA Number, if applicable:

8. Federal Action Number, *if known:*

9. Award Amount, *if known:*
$ 25,000,000.00

10. a. Name and Address of Lobbying Registrant:

Prefix: *First Name: Not Applicable Middle Name:

*Last Name: Not Applicable Suffix:

*Street 1: Street 2:

*City: State: Zip:

b. Individual Performing Services (including address if different from No. 10a)

Prefix: *First Name: Not Applicable Middle Name:

*Last Name: Not Applicable Suffix:

*Street 1: Street 2:

*City: State: Zip:

11. Information requested through this form is authorized by title 31 U.S.C. section 1352. This disclosure of lobbying activities is a material representation of fact upon which reliance was placed by the tier above when the transaction was made or entered into. This disclosure is required pursuant to 31 U.S.C. 1352. This information will be reported to the Congress semi-annually and will be available for public inspection. Any person who fails to file the required disclosure shall be subject to a civil penalty of not less than $10,000 and not more than $100,000 for each such failure.

*Signature: [signature]

*Name: Prefix: *First Name: TODD Middle Name:

*Last Name: LEAHY Suffix: PhD

Title: Cabinet Secretary or Designee Telephone No.: 505-476-3200 Date: 5/16/22

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Apps' Ex. 23

Attachment D – OMB Form 4040-0010 Key Contacts

OMB Number: 4040-0010
Expiration Date: 12/31/2022

Key Contacts Form

*** Applicant Organization Name:**
New Mexico Energy, Minerals and Natural Resources Department

Enter the individual's role on the project (e.g., project manager, fiscal contact).

*** Contact 1 Project Role:** Project Coordinator

Prefix:	Mr.
* First Name:	Jim
Middle Name:	
* Last Name:	Griswold
Suffix:	
Title:	

Organizational Affiliation:
Oil Conservation Division

* Street1:	5200 Oakland Ave. NE, Suite A
Street2:	
* City:	Albuquerque
County:	Bernalillo
* State:	New Mexico
Province:	
* Country:	USA: UNITED STATES
* Zip / Postal Code:	87113
* Telephone Number:	(505) 660-1067
Fax:	
* Email:	jim.griswold@state.nm.us

Next Person

Apps' Ex. 23

OMB Number: 4040-0010
Expiration Date: 12/31/2022

Key Contacts Form

*** Applicant Organization Name:**
New Mexico Energy, Minerals and Natural Resources Department

Enter the individual's role on the project (e.g., project manager, fiscal contact).

*** Contact 1 Project Role:** Division Director

Prefix:	Ms.
* First Name:	Adrienne
Middle Name:	
* Last Name:	Sandoval
Suffix:	
Title:	Division Director

Organizational Affiliation:
Oil Conservation Division

* Street1:	1220 South St. Francis Drive
Street2:	
* City:	Santa Fe
County:	Santa Fe
* State:	New Mexico
Province:	
* Country:	USA: UNITED STATES
* Zip / Postal Code:	87505
* Telephone Number:	(575) 703-3842 or (575) 241-7063
Fax:	
* Email:	adrienne.sandoval@state.nm.us

Next Person

Apps' Ex. 23

Attachment E – Detailed Budget Proposal/Justification

New Mexico Oil Conservation Division Initial grant Budget Proposal

This budget proposal covers New Mexico's state Fiscal Year 2023 (July 1, 2022 – June 30, 2023) for the plugging of orphan wells, the environmental assessment of well pads and facilities, along with surface restoration. We are assuming the grant award and expenditure period for the initial grant will run roughly contemporaneously with the New Mexico's fiscal year. The Energy, Minerals and Natural Resources Department (EMNRD), Oil Conservation Division (OCD) is the lead regulatory agency for oil and gas exploration and development in New Mexico. OCD enforces the State's Oil & Gas Act and Water Quality Act within the upstream sector. OCD also has primacy from the USEPA over Class I, II, III, and V injection and disposal wells under the federal Underground Injection Control program when wells are associated with activities in the oil and gas industry.

OCD has authority under the Oil and Gas Act (NMSA 1978, Section 70-2-38) to plug orphan wells and remediate and restore well sites and associated oil and gas facilities. OCD generally undertakes these efforts using its Oil and Gas Reclamation Fund, which is derived from severance taxes on oil and gas operators, operator financial assurance, legal judgments, and special appropriations from the State Legislature. Over the last three years that fund has provided OCD with on average $XX million per year in funds for plugging and reclamation activities. The initial grant from the Department of the Interior (DOI) will greatly expand and enhance the resources to this program. OCD intends to direct nearly all the initial grant to contracts with plugging and environmental service providers and other public institutions without retaining any portion for OCD's administrative and indirect costs and has certified that it will not use less than 90% of requested funds to issue new contracts, amend existing contracts, or issue grants for plugging, remediation, and reclamation work. Private sector work is facilitated via one or more price agreements stipulating fixed rates for labor and equipment which can be renegotiated on a yearly basis. Efforts involving public institutions are facilitated through memorandums of understanding.

Funding from the initial grant will be used to:

- plug, remediate, and reclaim orphan wells on state trust lands and privately-owned lands that have already been identified;
- assist OCD in the ranking and prioritization of wells and associated facilities;
- assist OCD in the identification of previously undocumented orphan wells and facilities;
- assist OCD in identifying and addressing any disproportionate burden on disadvantaged communities;
- assist OCD in making information associated with the program accessible via its website, including program expenditures;
- assist OCD in the preparation of required reporting to DOI;
- properly dispose of contaminated materials derived from orphan plugging and remediation at facilities in New Mexico permitted by OCD to manage oil field waste;
- reclaim salvageable materials and equipment while directing those funds back into the program;
- measure and track gaseous emissions, including methane, from orphan wells;
- measure and track contamination of surface water, groundwater, and soils; and
- restore degraded vegetation and habitat.

Initial grant funds will not be used for activities on federal or tribal lands, but may be used, consistent with DOI's guidance for federal wells on split estate lands. Initial grant funds will not be used to administer the program. Any funds that remain unobligated one year after the date of receipt of funds will be reimbursed to DOI as required by the IIJA.

Attachment F – OMB Form 4040-0019 Project Abstract Summary

OMB Number: 4040-0019
Expiration Date: 02/28/2022

Project Abstract Summary

This Project Abstract Summary form must be submitted or the application will be considered incomplete. Ensure the Project Abstract field succinctly describes the project in plain language that the public can understand and use without the full proposal. Use 4,000 characters or less. Do not include personally identifiable, sensitive or proprietary information. Refer to Agency instructions for any additional Project Abstract field requirements. If the application is funded, your project abstract information (as submitted) will be made available to public websites and/or databases including USAspending.gov.

Funding Opportunity Number

D-AQD-FA-22-003

CFDA(s)

Applicant Name

New Mexico Energy, Minerals & Natural Resources Department

Descriptive Title of Applicant's Project

Orphaned Well Site Plugging, Remediation, and Restoration

Project Abstract

The purpose of this project is to greatly expand the capacity of the State of New Mexico's established program to properly plug orphaned oil and gas wells, remove and salvage unused equipment and surface infrastructure, assess incidents at orphan sites where contaminants have been released into the environment, remediate the impacts of such incidents, undertake surface restoration, and to recoup as much of the costs as possible from available financial assurance. These efforts may reduce methane and volatile hydrocarbon emissions from unplugged orphan wells, minimize the waste of mineral resources, protect and restore water and soil, and to return lands to a state similar to that which existed before oil and gas activities. The prioritization of plugging and remedial efforts takes into consideration such factors as active leaks, nearby human activity, the proximity to water supplies and sensitive environments, the age of wells, known well integrity issues, citizen complaints, and the proximity of other orphans among other criteria. Not only will this enhance the quality of life and the environment in these areas, but it will also provide high-paying jobs for local individuals with a broad variety of skills.

Attachment G – Narrative of Recommended Application Elements

The following are items the Department of the Interior considers important components of a successful orphan well program. Although not required, states are being encouraged to incorporate these features into projects funded with Initial Grant.

a) Overview of New Mexico's process for determining that a well has been orphaned, including what efforts will be made to redeem financial assurances or otherwise recoup remediation costs from any parties responsible under state law:

OCD rules do not provide a definition of orphan well. Under its rules, OCD can initiative a quasi-judicial enforcement process to obtain a plugging order for a well that has been inactive (i.e., not reported production) for a period of more than 12 months. In the past OCD considered a well orphan once it had gone through the full legal process and the agency obtained a plugging order. However, given internal resource limitations, OCD has never been able to pursue plugging orders against all potentially eligible wells (i.e., those without production for more than 15 months). As explained below, with the infrastructure act finalization, OCD has done a further review to identify wells that are likely to be orphaned given their current status and lack of production, even though they may not have been through the full legal process and be subject to a current plugging order.

Operators are required to report production from each of their wells to OCD on a monthly basis. That information is provided to OCD electronically and incorporated into a database. At regular intervals the database is queried for those wells without reported production. If a well does not show production for a period of one year (inactive well), the operator is required to either place the well in approved temporary abandonment status or to properly plug and abandon the well within ninety days. A subset of inactive wells in the system represents a group of wells that have a high likelihood of becoming orphan. This number may fluctuate over time as additional operators become insolvent or some wells resume production but represents the most likely universe of wells that have a high potential to be orphaned (either currently or in the near-term).

If an operator fails to comply with these production requirements, they are issued a Notice of Violation, taken to an administrative hearing seeking compliance, and an order is thereafter agreed upon or issued after hearing. These hearings are noticed to the public and open for public participation. Because the plugging hearings are quasi-judicial enforcement actions, they are subject to due process requirements and prosecutorial discretion that preclude public involvement prior to the hearing.

The orders resulting from a plugging hearing will require the operator to either immediately return the wells to production, enter into a compliance schedule for returning their wells into compliance with OCD rules, or plug the wells. If an operator fails to take these steps, the order also explicitly provides OCD with the right to plug the wells and recoup financial assurance and excess costs. When an operator fails to meet these requirements or show up for the administrative hearing, OCD is given authority to plug the wells.

With respect to financial assurance, before a new operator can be registered in the state, they must obtain the proper financial assurance depending on the number and type of wells they intend to operate. The financial assurance will either be in the form of

single-well bonds or as part of a blanket bond covering all the operator's wells. If OCD is required to plug and abandon the sites because the operator is unable or unwilling to, OCD has the authority to forfeit any applicable financial assurance once plugging work is complete. The financial assurance helps the state to offset the cost of plugging and abandonment operations; however, because of statutory limits on financial assurance the amounts available for forfeiture are typical below plugging costs.

b) A description of New Mexico's plugging standards, including the witnessing requirements:

The State of New Mexico's regulations for the plugging and abandonment of wells (19.15.25 New Mexico Administrative Code (NMAC)) provide general expectations and requires a detailed plan of the plugging procedure from an operator that must be preapproved by OCD. OCD's plugging requirements are very similar and either meet or exceed those contained in the Bureau of Land Management's (BLM) Onshore Oil and Gas Order No. 2 with only slight deviations in specific circumstances. These similarities are essential in New Mexico due to the diversity of land ownership (federal, state, and private; including split estate) and the significance of federal lands in the state's overall oil and gas operations.

Operators are required to notify OCD 24 hours prior to commencing plugging operations to provide OCD with the opportunity to witness. Operators are also required to contact OCD upon completion of plugging and restoration operations. OCD will not approve the record of plugging or release a bond until we have inspected and approved the location.

While OCD is not subject to the notice and pre-approval requirements, when it plugs a well its contractors comply with the substantive requirements of OCD's plugging rules.

c) Details of New Mexico's prioritization process for evaluating and ranking orphan wells and associated surface reclamation, including criteria, weighting, and how such prioritization will address resource and financial risk, public health and safety, potential environmental harm (including methane emissions where applicable), and other land use priorities:

The current prioritization for both plugging and surface restoration is to identify orphaned facilities that present high-level concerns such as active or historic leaks, proximity to occupied structures, risks to surface or groundwater, proximity to water supply wells and wetlands, known or suspected well integrity issues, lack of well control at the surface, elevated downhole pressures, the age of the well, proximity to agricultural areas, the possible presence of hydrogen sulfide or naturally occurring radioactive materials, the presence of threatened or endangered species, public complaints, and cost efficiencies.

There are currently more than 30 unique factors which are considered when prioritizing OCD's efforts. The presence of an active leak will place a well or associated facility at the top of OCD's prioritization. Increased weight is given to areas with high proximity to human activity, proximity to supplies of usable water, and known well integrity concerns. Each unique factor is given a score number and by summing all the criteria that apply to

the well or site, it will be given an overall score. The higher the score, the higher the priority.

Additionally, a factor OCD is always mindful of is the proximity of orphaned wells and facilities to one another. Plugging and restoration operations often include locations with varied rankings due to the proximity of wells to one another. Mobilization and demobilization costs can be substantially reduced if plugging work orders are issued for groups of wells that are in the same well. By plugging wells in a general area at the same time OCD can realize some cost savings. This ensures that OCD makes the best use of the funds that are available.

d) Details of how New Mexico will identify and address any disproportionate burden of adverse human health or environmental effects of orphaned wells on disadvantaged communities, including communities of color, low-income communities, and Tribal and indigenous communities;

The majority of the oil and gas production in New Mexico occurs in two unique basins, the San Juan Basin consisting primarily of San Juan, Rio Arriba, McKinley and Sandoval counties, and the Permian Basin consisting primarily of Lea, Eddy, and Chaves counties. Based upon the definitions provided in the initial grant guidance, these areas qualify as "disadvantaged communities" broadly speaking (e.g., poverty rates range from 10% to 32% across these areas). This on-the-ground reality means that many, if not all the wells and associated facilities that OCD plugs and reclaims will be in disadvantaged communities. Notwithstanding that general condition, OCD's prioritization process includes additional weighting for proximity to homes and businesses as well as locations within municipal boundaries when we are making decisions about where to plug first.

e) The methodology to be used by New Mexico to measure and track methane and other gases associated with orphaned wells, including how the State will confirm the effectiveness of plugging activities in reducing or eliminating such emissions:

Currently, OCD inspection staff use audio/visual/olfactory inspections and carry explosivity monitors which will detect methane of sufficient concentration if methane is leaking from an orphan well. This methodology provides a yes or no indication that there is methane being released from an orphaned well and indicates where follow-up may be required. Orphan wells with active methane or other leaks, be it liquid or gas, are elevated on OCD's priority list as is explained in section c) above.

Currently, the plugging and reclamation contractors that are on a price agreement with the State (which tend to be smaller and local) are either not familiar, trained, or properly equipped to perform more precise measurements. OCD is working on updating those contracts and evaluating additional opportunities to identify and quantify potential methane emissions from orphaned wells as part of the plugging program and is currently evaluating means to provide such measurement. This includes finding contractors capable of providing those specific services. The suggestions about methodologies in the existing guidance provides helpful starting points and we would encourage that sufficient flexibility be retained going forward so that we can select

methodologies appropriate for the program and the type of orphaned resources we see in New Mexico.

f) The methodology to be used by New Mexico to measure and track contamination of groundwater and surface water associated with orphaned wells, including how the state will confirm the effectiveness of plugging activities in reducing or eliminating such contamination:

For the remediation of orphan well sites and associated facilities, OCD will first evaluate the site for any active or historic liquid and gas releases. Sites without releases will be plugged, the equipment removed, and the site reclaimed without undertaken a ground or surface water assessment. Sites with releases (either known or suspected) will receive an assessment by an environmental contractor. The contractor will determine the horizontal and vertical extents of any spill. They will also evaluate whether there is a potential that any release may have impacted groundwater. Depending upon such a determination, they may decide to drill and install groundwater monitoring wells. Not every site will require the installation of monitoring wells especially those where the depth to groundwater is significant. New Mexico believes it is most appropriate to install water monitoring infrastructure when and where appropriate as opposed to incurring the additional expense and disturbance at every site.

If ground or surface water contamination does exist, its extent will be delineated, and an abatement plan implemented. Where fund, such contamination is remediated to the numeric standards established by the New Mexico Water Quality Control Commission (20.6.2.3101 NMAC) and we are required demonstrate compliance with those standards for eight consecutive quarters after active remedial efforts have ended.

g) The methodology to be used to decommission or remove associated pipelines, facilities, and infrastructure and to remediate soil and restore habitat that has been degraded due to the presence of orphaned wells and associated infrastructure:

The decommissioning of inactive non-retrieved pipelines containing regulated naturally occurring radioactive material (NORM) is addressed in 19.15.35.10 NMAC. It requires such activities to be done in a manner protective of the environment, public health, and fresh waters. The location of the pipe must be determined, hydrocarbons and produced water must be flushed from the pipe, and a radiation survey is required at all points accessible at the surface which are then permanently capped. No additional NORM can be placed into the pipe. The surface owner must be informed of the intent to leave idle underground pipeline in place.

The closure of pits and below-grade tanks is addressed in 19.15.17 NMAC, which allows the in-place burial or offsite disposal of drilling wastes but requires the removal of tanks. Facilities and other surface infrastructure are removed entirely unless the surface owner requests otherwise. Any marketable salvage is sold to offset OCD's plugging and remediation costs.

The corrective action requirements for spills and releases which arise during oil and gas exploration and production operations in New Mexico are contained within 19.15.29 and

19.15.30 NMAC. As such, there are defined procedures for the reporting, assessment, remediation, and closure of releases adversely affecting soils, surface waters, and groundwater. Though these regulations were written with active operators as the responsible party in mind, OCD uses the closure requirements of the regulations when addressing orphaned well sites and associated facilities. Most incidents are remediated by direct excavation and disposal of contaminated materials, but in situ treatment options are continuously being evaluated.

Surface restoration is also addressed in 19.15.29 NMAC, requiring surface areas to be returned to the condition that existed prior to any release or to the land's eventual use. There are requirements for erosion control, long-term stability, the preservation of surface water flow patterns, and the prevention of ponding. The uppermost four feet of soil in disturbed areas must be non-waste containing and uncontaminated including a background thickness of topsoil. The disturbed area must be reseeded in the first favorable growing season following final grading, and a vegetative cover needs to be established which reflects the surrounding area. OCD typically considers reclamation complete when a uniform vegetative cover has been established the reflects a life-form ratio or plus or minus 50% of pre-disturbance levels and a total percent plant cover of at least 70% of pre-disturbance levels, excluding noxious weeds. The New Mexico State Land Office (NMSLO) has requirements for reseeding that are adhered to on state trust lands.

h) Methods New Mexico will use to solicit recommendations from local officials and the public regarding the prioritization of well plugging and site remediation activities, and any other processes the State will use to solicit feedback on the program from local officials and the public:

Two of the factors currently used in developing individual well and site rankings are citizen's complaints and relative importance to the NMSLO, which oversees and controls state trust lands. OCD is working with the State Land Office to prioritize sites based on the criteria listed above in section c). Once ranked, OCD prioritizes plugging and remediation activities first by wells/sites which pose a possible risk of harm to public health and the environment, and secondly according to plugging schedules which maximize administrative efficiency.

Additionally, as discussed in section a) above, before OCD can plug or reclaim a site, it must go through a public administrative hearing to obtain a plugging order. During this public hearing there are opportunities for additional parties to enter appearances in the case as well as opportunities for public comment (oral and written). Any public comment that is provided will be a factor that is taken into consideration in the site ranking criteria within the universe of wells subject to approved plugging orders.

i) Latitude/Longitude and all other data elements and associated units of measure as indicated in the Orphaned Well Data Reporting Template that accompanied the grant application guidance:

OCD will provide information on program performance to the Department of Interior on a quarterly basis in spreadsheet form using the Orphaned Well Data Reporting Template

as a guide with the indicated units of measure. All data elements currently within the template, including the latitude and longitude of orphan wells, will be included as applicable and when available.

OCD has an information technology system that was developed internally known as OCD Permitting and OCD Imaging, both of which are accessible to the public using a standard web browser. The permitting component is currently being updated to allow for easier and more transparent tracking of costs associated with the plugging of orphan wells and associated surface restoration. The imaging system allows for the easy retention of and access to associated reports.

j) How New Mexico will use funding to locate currently undocumented orphaned wells:

OCD is currently evaluating and testing new ways to find abandoned wells. Undocumented wells are sometimes simply found by OCD inspectors during their daily efforts in the field. OCD is currently using contractors to review existing well files using OCD's on-line imaging system to identify wells which may be orphaned and in need of plugging. Additionally, OCD has recently initiated an effort to determine if unmanned aerial systems (drones) are useful to provide OCD with quick and cost-effective information which might lead to the discovery of undocumented orphans including identifying surface distress caused by historic operations. Finally, in recognition of New Mexico long history as an oil and gas producer, OCD is also re-evaluating wells that were plugged prior to the imposition of modern standards to see if those wells need to be re-visited. For example, some historical plugging practices did not require sufficient isolation between zones.

k) Plans New Mexico has to engage third-parties in partnerships around well plugging and site remediation, or any existing similar partnerships the state currently belongs to:

OCD has worked cooperatively with both the NMSLO and the BLM on oil and gas issues including the plugging and abandonment of orphan wells on state trust and federal lands. OCD has a memorandum of understanding with the SLO which allows OCD unrestricted entry, the ability to install soil borings and groundwater monitoring wells for environmental assessments, and clean soil for replacement of contaminated soil excavated at release sites, all without the charges required of other entities.

OCD and BLM also have a grant structure where BLM has provided funds to OCD for OCD to plug wells on federal lands. When plugging wells on federal land, OCD adheres to any additional requirements under BLM rules, including those to protect animal habitats. This includes the installation of below-grade plug and abandonment markers that would otherwise serve as hunting perches for predators and adherence to restrictions on field operations during the communal breeding season.

Finally, in terms of who does the actual plugging work OCD endeavors to contract with, consistent with applicable rules, local companies most of which are based in the regions where the orphan facilities are located.

l) Training programs, registered apprenticeships, and local and economic hire agreements for workers that New Mexico intends to conduct or fund in well plugging or site remediation;

Training itself is outside the direct purview of OCD; however, training programs for individuals wanting to find a career in the oil and gas industry already exist in two major producing basins – in the Permian Basin at New Mexico Junior College in Hobbs and in the San Juan Basin at San Juan College in Farmington (both of which are in disadvantaged communities). Both provide associate degrees and certificate programs. Baccalaureate degrees in petroleum engineering can be earned at New Mexico Institute of Mining and Technology (NMIMT) in Socorro, which is recognized as one of the leading programs in the nation. Environmental engineering programs exist at NMIMT, the University of New Mexico in Albuquerque, and New Mexico State University in Las Cruces. These programs provide strong existing workforce development opportunities, although they tend to be more development focused.

OCD has existing agreements with the institutions to provide paid assistance to OCD, and we are working with other state agencies to explore opportunities to potentially use some of the grant money to support programs at those more specifically focused on plugging and remediation.

m) Plans New Mexico has to support opportunities for all workers, including workers underrepresented in well plugging or site remediation, to be trained and placed in good-paying jobs directly related to the project:

OCD supports this goal but would not directly employ most of the folks doing the plugging work, instead it works through contractors. To the extent feasible, and consistent with the New Mexico Procurement Code, OCD has tried to focus on using smaller local contractors who tend to be based in the primary producing basins which tend to employ individuals from those same communities which also happen to contain populations most likely to be displaced by energy sector transitions. Therefore OCD has consistently encouraged DOI to carefully balance the requirements imposed by any grant awards under this program that might make it harder for smaller entities to provide services under this program.

OCD don't currently have specific metrics on these questions but can talk with the New Mexico Department of Workforce Solutions to identify appropriate training and employment support that might be provided given available funds.

n) Plans New Mexico has to incorporate equity for underserved communities into their planning, including supporting the expansion of high-quality, good paying jobs through workforce development programs and incorporating workforce strategy into project development:

Please see the previous responses to items d), l), and m).

o) Procedures New Mexico will use to coordinate with federal or tribal agencies to determine whether efficiencies may exist by combining field survey,

plugging, or surface remediation work across private, state trust, federal, and tribal land:

OCD has historically coordinated extensively with the BLM in New Mexico. For plugging orphans this coordination is typically initiated by requests from the BLM to ensure awareness and that all agencies agree and are aligned prior to beginning any work. Due to the jurisdictional limitations associated with tribal lands, OCD functions as a service provider and advisor rather than a regulatory agency and will not plug wells or remediation and reclaim facilities on Tribal lands without a direct request from the applicable Tribal government.

p) New Mexico's authorities to enter private property, or procedures to obtain landowner consent to enter private property, in the event that any wells to be plugged will be accessed from privately owned surface:

OCD holds broad authority to regulate, inspect, investigate, and plug and abandon wells situated on private property per state statute. Specifically, NMSA 1978, Sections 70-2-1 to 39, including Section 70-2-12 B. (18) Enumeration of powers, which says "*...the oil conservation division may...do all acts necessary and proper to plug dry and abandoned oil and gas wells and to restore and remediate abandoned well sites and associated production facilities in accordance with the provisions of the Oil and Gas Act, the rules adopted under that act and the Procurement Code, including disposing of salvageable equipment and material removed from oil and gas wells being plugged by the state;*"

In any event, OCD incorporates good neighbor practices in plugging, remediation, and reclamation efforts to ensure that it works with potentially impact landowners.

q) A work schedule covering the period of performance of the initial grant:

Efforts toward locating undocumented orphan wells and to prioritize wells to be plugged and facilities to remediate are already underway using state funding. We intend to continue and expand these efforts as appropriate with additional funding.

Based upon the language in the enabling federal legislation, grant award notification should occur within 30 days of application submittal. As such, notification should be provided to OCD no later than June 13, 2022. The state's Fiscal Year 2023 begins on July 1, 2022, and the earliest purchase orders can realistically be issued will be the end of July of this year. OCD intends to provide purchase orders for groups of wells and sites following receipt of workplans and cost estimates from multiple plugging and environmental service providers. Field work will occur thereafter until the obligated funds are expended. The required quarterly reports to the Department of the Interior are anticipated to be delivered on or about 10/30/22, 1/31/23, 4/30/23, and 7/30/23. The final report covering the entire effort funded by the initial grant is anticipated to be delivered on or about 10/30/23.

r) A federally approved Indirect Cost Rate Agreement or statement regarding the state's intention to negotiate or use the de minimis rate:

EMNRD has an approved Indirect Cost Rate Agreement and its rate for the upcoming state fiscal year is 15.45%.

Attachment H – State Certification for Large-Scale Initial Grant

State Certification

Orphan Well Site Plugging, Remediation, and Restoration

Large-Scale Initial Project Grant

Consistent with Section 40601(c)(3)(A)(i)(II)(aa) of the Infrastructure Investment and Jobs Act, the State of New Mexico certifies that it is a Member State of the Interstate Oil and Gas Compact Commission.

The State of New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division ("EMNRD") also certifies that it has one (1) or more documented orphan wells within the state.

And EMNRD also certifies it will use no less than ninety percent (90%) of the funds requested under this grant to issue new contracts, amend existing contracts, or issue grants for plugging, remediation and reclamation work on orphan wells within New Mexico by not later than 90 days after the date of receipt of the funds.

Todd E. Leahy	Deputy Cabinet Secretary
Certifying Official Name	Title
Signature	5/6/22
	Date

Apps' Ex. 23

EXHIBIT 24



Air Quality Issues in Natural Gas Systems

Updated April 16, 2013

Congressional Research Service
https://crsreports.congress.gov
R42833

CRS REPORT
Prepared for Members and
Committees of Congress

Summary

Natural Gas Systems and Air Pollution

Congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing, directional drilling) used on unconventional resources (e.g., shale, tight sands, and coal-bed methane), has made natural gas an increasingly significant component in the U.S. energy supply. This expansion, however, has prompted renewed questions about the potential impacts of natural gas systems on human health and the environment, including impacts on air quality. Unlike the debate over groundwater contamination or induced seismicity—where questions exist as to whether or not production activities contribute significantly to these impacts—there is little question that natural gas systems emit air pollutants. The concerns, instead, are the following:

- Which pollutants?
- How much of each pollutant?
- From which sources?
- What are the impacts of the emissions?
- How much is the cost of abatement?
- What are the respective roles of federal, state, and local governments?

Air pollutants are released by natural gas systems through the leaking, venting, and combustion of natural gas; the combustion of other fossil fuel resources; and the discharge of particulate matter during associated operations. Emission sources include pad, road, and pipeline construction; well drilling, completion, and flowback activities; and gas processing and transmission equipment such as controllers, compressors, dehydrators, pipes, and storage vessels. Pollutants include, most prominently, methane and volatile organic compounds—of which the natural gas industry is one of the highest-emitting industrial sectors in the United States—as well as nitrogen oxides, sulfur dioxide, particulate matter, and various forms of hazardous air pollutants.

EPA's 2012 Air Standards

The U.S. Environmental Protection Agency (EPA), in response to a consent decree issued by the U.S. Court of Appeals, D.C. Circuit, promulgated air standards for several source categories in the crude oil and natural gas sector on August 16, 2012. These standards—effective October 15, 2012—revised existing rules and promulgated new ones to regulate emissions of volatile organic compounds (VOCs), sulfur dioxide, and hazardous air pollutants (HAPs) from many production and processing activities that had never before been covered by federal oversight. The standards control air pollution, in part, through the capture of fugitive releases of natural gas. Thus, compliance with the standards has the potential to translate into economic benefits, as producers may be able to offset abatement costs with the value of product recovered and sold. Using this assumption, EPA estimated the annual benefits of the standards to be VOC reductions of 190,000 tons, HAP reductions of 12,000 tons, methane reductions of 1.0 million tons, and a net cost savings of $11 million to $19 million after the sale of recovered product. Industry and other stakeholders have disputed these figures as both too high and too low. Moreover, the expansion of both industry production and government regulation of natural gas has sparked discussion on a number of outstanding issues, including the following:

- defining the roles of local, state, and federal governments,
- determining the proper coverage of pollutants and sources,
- establishing comprehensive emissions data,
- understanding the human health and environmental impacts of emissions, and
- estimating the costs of pollution abatement.

Scope and Purpose of This Report

The report begins by briefly outlining the production, processing, transmission, and distribution phases of the natural gas industry, then characterizes the types and sources of pollutants in the sector. It then turns to the role of the federal government in regulating these emissions, including the provisions in the Clean Air Act and the regulatory activities of the EPA. It concludes with an extended discussion of the aforementioned outstanding issues. For an abbreviated version of this report, see CRS Report R42986, *Air Quality Issues in Natural Gas Systems: In Brief*.

Contents

Background 1
The Natural Gas Industry 3
Air Quality Issues in Natural Gas Systems 5
Emissions 5
Sources 6
Pollutants 8
The Clean Air Act and the Federal Role in Air Quality Issues in Natural Gas Systems 13
Prior Federal Air Standards and Other Rules for Crude Oil and Natural Gas Systems 13
2012 Federal Air Standards for Crude Oil and Natural Gas Systems 16
2012 NSPS for Crude Oil and Natural Gas Systems 17
2012 NESHAPs for Crude Oil and Natural Gas Systems 19
Effects of the 2012 Federal Air Standards on State Attainment Planning and Permitting 19
Reported Costs and Benefits of the 2012 Federal Air Standards 20
Agency Reconsideration of the 2012 Federal Air Standards 21
Issues for Congressional Consideration 21
The Regulatory Role of Federal, State, and Local Governments 22
Covered Sources and Pollutants 24
Major Source Aggregation 25
Measurement of Emissions 28
Impacts of Emissions 33
Ozone 35
Air Toxics 37
Greenhouse Gases 40
Cost Benefit Analysis of Federal Standards 42
Relevant Legislation in the 113th Congress 44
Conclusion 45

Figures

Figure 1. The Natural Gas Industry 4
Figure 2. Selected Emissions Inventories for U.S. Industrial Sectors 12
Figure 3. Reduced Emissions Completion Equipment 18

Tables

Table 1. Methane Emissions in the U.S. Natural Gas Industry 30

Table A-1. New Source Performance Standards for Volatile Organic Compounds in Crude Oil and Natural Gas Systems 47
Table A-2. New Source Performance Standards for Sulfur Dioxide in Crude Oil and Natural Gas Systems 56

Table A-3. National Emissions Standards for Hazardous Air Pollutants in Crude Oil and Natural Gas Systems 57
Table A-4. Comparison of 2012 Federal Air Standards for Crude Oil and Natural Gas Systems to Selected State Regulations 60
Table B-1. Composition of Raw Natural Gas 66
Table B-2. Air Pollution Emissions by Combusted Fuel Type 67
Table C-1. Glossary of Terms Related to Crude Oil and Natural Gas Systems 68

Appendixes

Appendix A. Federal Air Standards for Crude Oil and Natural Gas Systems 47
Appendix B. Composition of Fugitive and Combusted Natural Gas Emissions 66
Appendix C. Glossary of Terms 68

Contacts

Author Information 70

Background

Congressional interest in U.S. energy policy has focused in part on ways through which the United States could secure more economical and reliable fossil fuel resources both domestically and internationally. Recent expansion in natural gas production, primarily as a result of new or improved technologies (e.g., hydraulic fracturing)[1] used on unconventional resources (e.g., shale, tight sands, and coal-bed methane),[2] has made natural gas an increasingly significant component in the U.S. energy supply. While the practice of hydraulic fracturing is not new, relatively recent innovations have incorporated processes such as directional drilling, high-volume slick-water injection, and multistage fractures to get to previously unrecoverable resources. As a result, the United States has again become the largest producer of natural gas in the world.[3] The U.S. Energy Information Administration (EIA) projects unconventional gas activity to more than double from 2010 to 2040, and forecasts that it will make up almost 80% of total U.S. natural gas production by 2040.[4] In addition, some analysts believe that by significantly expanding the domestic gas supply, the exploitation of new unconventional resources has the potential to reshape energy policy at national and international levels—altering geopolitics and energy security, recasting the economics of energy technology investment decisions, and shifting trends in greenhouse gas (GHG) emissions.[5]

Many in both the public and private sector have advocated for the increased production and use of natural gas because the resource is domestically available, economically recoverable, and considered a potential "bridge" fuel to a less polluting and lower GHG-intensive economy.[6] Natural gas is cleaner burning than its hydrocarbon rivals, emitting, on average, about half as much carbon dioxide as coal and one-quarter less than oil when consumed in a typical electric

[1] Hydraulic fracturing (hydrofracking, fracking, or fracing) is commonly defined as an oil or gas well completion process that directs pressurized fluids typically containing any combination of water, proppant, and any added chemicals to penetrate tight rock formations, such as shale or coal formations, in order to stimulate the oil or gas residing in the formation, and that subsequently requires high-rate, extended flowback to expel fracture fluids and solids. The National Petroleum Council estimates that hydraulic fracturing will account for nearly 70% of natural gas development within the next decade, see National Petroleum Council, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," September 15, 2011. For more discussion on this technology, see the section on "Hydraulic Fracturing" in CRS Report R42333, *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws*, by Mary Tiemann et al.

[2] These unconventional resources are commonly defined as follows: Tight sands gas is natural gas trapped in low permeability and nonporous sandstones. Shale gas is natural gas trapped in shale deposits, a very fine-grained sedimentary rock that is easily breakable into thin, parallel layers. Coal-bed methane is natural gas trapped in coal seams. These resources are referred to as "unconventional" because, in the broadest sense, they are more difficult and/or less economical to extract than "conventional" natural gas, usually because the technology to reach them has not been developed fully, or has been too expensive. For a more detailed discussion of these definitions, see the Natural Gas Supply Association's website, http://www.naturalgas.org/overview/unconvent_ng_resource.asp.

[3] The United States surpassed Russia as the world's leading producer of dry natural gas beginning in 2009. See U.S. Energy Information Administration, "Today in Energy," March 13, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=5370.

[4] U.S. Energy Information Administration, *Annual Energy Outlook, 2013*, http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm.

[5] For more discussion on natural gas resources, see CRS Report R42814, *Natural Gas in the U.S. Economy: Opportunities for Growth* , by Robert Pirog and Michael Ratner.

[6] Support for the natural gas industry has come also from the Obama Administration. In his 2012 State of the Union speech, President Obama stated, "We have a supply of natural gas that can last America nearly 100 years, and my administration will take every possible action to safely develop this energy." President Barack Obama, "Remarks by the President in State of the Union Address," Washington, DC, January 24, 2012, http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address.

utility plant.[7] Further, natural gas combustion emits no mercury—a persistent, bioaccumulative neurotoxin—virtually no particulate matter, and less sulfur dioxide and nitrogen oxides, on average, than either coal or oil. For these reasons, pollution control measures in natural gas systems have traditionally received less attention relative to those in other hydrocarbon industries. However, the recent increase in natural gas production, specifically from unconventional resources, has raised a new set of concerns regarding environmental impacts. These concerns centered initially on water quality issues, including the potential contamination of groundwater and surface water from hydraulic fracturing and related production activities. They have since incorporated other issues, such as water management practices (both consumption and discharge), land use changes, induced seismicity, and air pollution. The new set of questions about hydraulic fracturing in unconventional reservoirs has led, in part, to various grassroots movements, some political opposition, and calls for additional regulatory actions, moratoria, and/or bans at the local, state, and federal levels.

Currently, the development of natural gas in the United States is regulated under a complex set of local, state, and federal laws that addresses many—but not all—aspects of exploration, production, and distribution. State and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems. The organization of this oversight within each gas-producing jurisdiction varies considerably. In general, each state has one or more regulatory agencies that may permit wells, including their design, location, spacing, operation, and abandonment, and may regulate for environmental compliance. With respect to pollution controls, state laws may address many aspects of water management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety.

Furthermore, several federal statutes address pollution control measures in natural gas systems; and, where applicable, these controls are largely implemented by state and local authorities. For example, the Clean Water Act (CWA) regulates surface discharges of water associated with natural gas drilling and production, as well as contaminated storm water runoff from production sites.[8] The Safe Drinking Water Act (SDWA) regulates the underground injection of wastewater from crude oil and natural gas production, and the underground injection of fluids used in hydraulic fracturing if the fluids contain diesel fuel.[9] The Clean Air Act (CAA) limits emissions from associated engines and gas processing equipment, as well as some natural gas extraction, production, and processing activities.

[7] These values are averages based on carbon dioxide emitted per unit of energy generated. See Energy Information Administration (EIA), Office of Oil and Gas. Carbon Monoxide: derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106, ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/gg98rpt/057397.pdf. Other pollutants derived from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 1, Stationary Point and Area Sources*, 1998, http://www.epa.gov/ttn/chief/ap42/.

[8] For more discussion, see CRS Report R42333, *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws*, by Mary Tiemann et al.

[9] For more discussion, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Regulatory Issues*, by Mary Tiemann and Adam Vann.

The Natural Gas Industry

Natural gas is a nonrenewable fossil fuel that is used both as an energy source (for heating, transportation, and electricity generation) and as a chemical feedstock (for such varied products as plastic, fertilizer, antifreeze, and fabrics). Raw natural gas is commonly recovered from geologic formations in the ground through drilling and extraction activities by the oil and gas industry.[10] This industry includes operations in the extraction and production of crude oil and natural gas, as well as the processing, transmission, and distribution of natural gas. For both operational and regulatory reasons, the sector is commonly separated into four major segments: (1) crude oil and natural gas production, (2) natural gas processing,[11] (3) natural gas transmission and storage, and (4) natural gas distribution (see **Figure 1**). This report uses these basic categories to track the various activities in natural gas systems, including the operations, emissions, and regulations discussed below. While the focus of this report is on the production sector, it also highlights air quality issues in other sectors, where appropriate. Below is a brief outline of the crude oil and natural gas industry.[12] For more detail regarding specific activities or equipment, see the glossary of terms provided in **Table C-1**.

Production (Upstream). Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation, and treating of oil and/or natural gas (including condensate). Production operations span the initial well drilling, hydraulic fracturing, well completion, and workover activities and cover all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ‘‘pads’’ where the wells are located, but also the stand-alone sites where oil, condensate, produced water, and gas from several wells may be separated, stored, and treated, as well as the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

Processing (Midstream). Natural gas is primarily made up of methane. However, in its raw state, natural gas is a mixture of various hydrocarbons and may contain trace amounts of other chemical substances that must be removed before distribution. The additional hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. Raw natural gas may also contain water vapor, nonhydrocarbon compounds, and other chemical substances. Processing operations are used to separate out the additional components from raw natural gas to produce ‘‘pipeline quality’’ or “dry” natural gas for consumption.

Transmission and Storage (Downstream). Dry natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines, that carry natural gas across state boundaries, or intrastate pipelines, that transport the gas within a single state. While interstate pipelines may be of a larger diameter and operate at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compressor stations are required at regular

[10] Natural gas can also be recovered as a byproduct from various other sources including mining, industrial, or agricultural processes. These secondary sources are not discussed in this report. For a more detailed description of the oil and gas industry, see CRS Report R40872, *U.S. Fossil Fuel Resources: Terminology, Reporting, and Summary*, by Carl E. Behrens, Michael Ratner, and Carol Glover.

[11] Crude oil after the production phase (i.e., beginning with petroleum refining) is classified as a different industrial sector for most regulatory purposes. Petroleum refining is not discussed in this report. See CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by Anthony Andrews et al.

[12] The description of the natural gas sector is drawn from the U.S. Environmental Protection Agency, “Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews,” 76 *Federal Register* 52738, August 23, 2011.

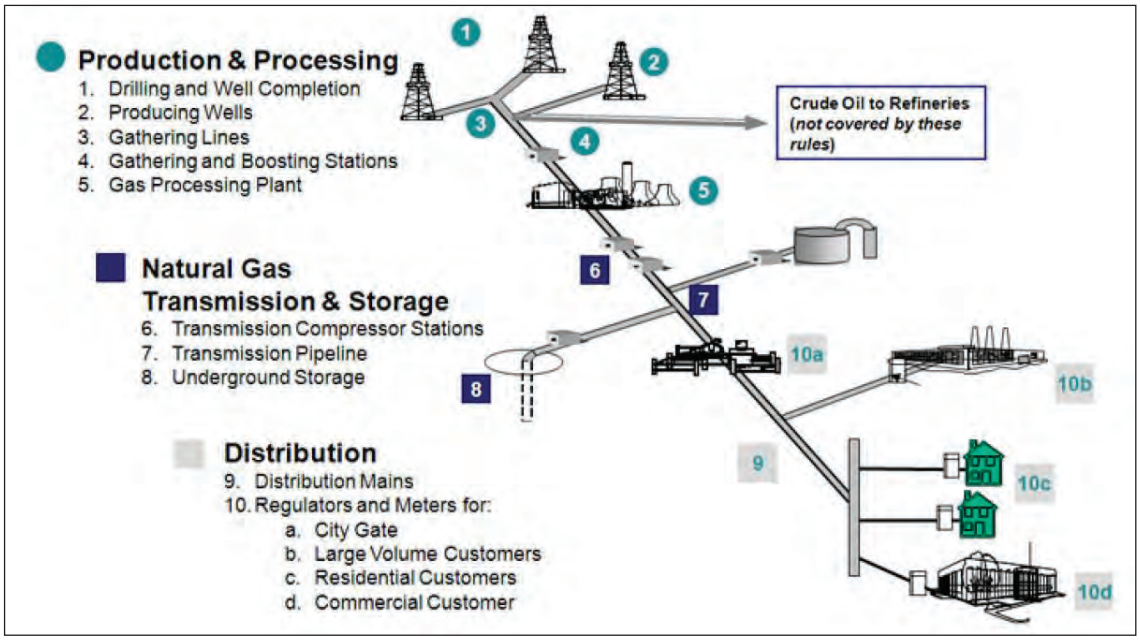
Apps' Ex. 24

0462

intervals. Further, to ensure proper load balancing during the delivery and receipt of natural gas, the transmission segment often includes storage facilities, typically consisting of both man-made and natural sites, such as depleted gas reservoirs and/or salt dome caverns.

Distribution. The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines and then flows to business and household customers. Nationwide, natural gas distribution systems consist of thousands of miles of pipes, including mains and service lines to the customers. Distribution systems also include compressor and metering stations, which allow companies to both move and monitor the natural gas in the system. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the ''citygate.'' Typically, the citygate serves as the transfer point of ownership from producers to utilities.

Figure 1. The Natural Gas Industry



Source: U.S. Environmental Protection Agency.

Air Quality Issues in Natural Gas Systems

Raw natural gas is a mixture of various hydrocarbons (primarily methane) and may contain trace amounts of other chemical substances that must be removed before distribution. Air pollutants associated with the natural gas industry may be emitted through the release of natural gas vapors (either purposefully or accidently), the combustion of natural gas (either for use or for safety/disposal), the combustion of other fuel resources (for process heat, power, and electricity), and the discharge of particulate matter during construction, transportation, and associated operations. Sources of emissions include pad, road, and pipeline construction; drilling, completion, and flowback activities that occur during the development of a well; and gas processing and transmission equipment such as controllers, compressors, dehydrators, pipelines, and storage vessels. Pollutants include, most prominently, methane and volatile organic compounds, of which the natural gas industry is one of the highest emitting industrial sectors in the United States.[13] Pollutants also include nitrogen oxides, sulfur dioxide, particulate matter, and various forms of hazardous air toxics, including n-hexane, the BTEX compounds (i.e., benzene, toluene, ethylbenzene, and xylene), and hydrogen sulfide.

Emissions

Natural gas systems release air emissions in several ways. This report categorizes these emissions into three types: *fugitive*, *combusted*, and *associated*.[14]

Fugitive. *Fugitive* refers to the natural gas vapors that are released to the atmosphere during industry operations. Fugitive emissions can be either intentional (i.e., vented) or unintentional (i.e., leaked).[15] Intentional emissions are releases that are designed specifically into the system: for example, emissions from vents or blow-downs used to guard against over-pressuring; or gas-driven equipment used to regulate pressure, store, or transport the resource. Conversely, unintentional emissions are releases that result from uncontrolled leaks in the system: for example, emissions from routine wear, tear, and corrosion; improper installation or maintenance of equipment; or the overpressure of gases or liquids in the system. Fugitive natural gas is primarily a mixture of low molecular-weight hydrocarbon compounds that are gaseous in form at normal conditions. While the principal component of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as heavier hydrocarbons. These nonmethane hydrocarbons include types of volatile organic compounds (VOCs), classified as ozone (i.e., smog) precursors, as well as, in some cases, hazardous (i.e., toxic) air pollutants (HAPs). Nonhydrocarbon gases, such as carbon dioxide (CO_2), helium (He), hydrogen sulfide (H_2S), nitrogen (N_2), and water vapor (H_2O), may also be present in any proportion to the total hydrocarbon content. The chemical composition of raw natural gas varies greatly across resource reservoirs, and the gas may or may not be "associated" with crude oil resources. When natural gas is found to be primarily methane, it is referred to as "dry" or "pipeline quality" gas. When natural gas is found bearing higher percentages of heavier hydrocarbons, nonhydrocarbon gases, and/or water vapor, it is commonly referred to as "wet,"

[13] For more discussion, see section "Pollutants" of this report.

[14] EPA categorizes emissions as either "equipment leaks and vented emissions" or "combustion-related emissions." See U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, Washington, DC, EPA 430-R-11-005, April 2011.

[15] For further definitions of fugitive emissions, see U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, Washington, DC, EPA 430-R-12-001, April 15, 2012, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf.

"rich," or "hot" gas. Similarly, quantities of VOCs, HAPs, and H_2S can vary significantly depending upon the resource reservoir. VOC and HAP compositions typically account for only a small percentage of natural gas mixtures; however, this ratio increases the "wetter" the gas. Natural gas mixtures with a higher percentage of H_2S are generally referred to as "sour" or "acid" gas.[16]

Combusted. *Combusted* refers to the byproducts that are formed from the burning of natural gas during industry operations. Combusted emissions are commonly released through either the flaring of natural gas for safety and health precautions or the combustion of natural gas for process heat, power, and electricity in the system (e.g., for compressors, dehydrators, and other machinery). The chemical process of combusting natural gas releases several different kinds of air pollutants, including carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), and trace amounts of sulfur dioxide (SO_2) and particulate matter (PM). Flaring is a means to eliminate natural gas that may be impracticable to use, capture, or transport. As with venting, the primary purpose of flaring is to act as a safety device to minimize explosive conditions. Gas may be flared at many points in the system; however, it is most common during the drilling and well completion phases. Natural gas combustion is generally considered a greater pollution control mechanism than the venting of natural gas, because the process serves to incinerate many of the VOCs and HAPs that would otherwise be released directly into the atmosphere. Similarly, natural gas combustion is generally considered as "cleaner" than other fossil fuel combustion with respect to various criteria pollutants and greenhouse gas (GHG) emissions.[17]

Associated. *Associated* refers to secondary sources of emissions that arise from associated operations in natural gas systems. Associated emissions may result from the combustion of other fossil fuels (i.e., other than the natural gas stream) to power equipment, machinery, and transportation, as well as the associated release of dust and particulate matter from construction and road use. Associated emissions have the potential to contribute significantly to air pollution.

The focus of this report is on fugitive and combusted natural gas emissions. While there may be significant emissions from the natural gas sector as a result of the combustion of other fossil fuels for process heat, power, and transportation, as well as the associated release of particulate matter from construction and road use, the primary focus of this report is on air quality issues related to the resource itself (i.e., the fugitive release of natural gas and its combustion during operations). It is this release of natural gas—and the pollutants contained within it—that makes air quality considerations in the crude oil and natural gas sector unique from other industrial-, construction-, and transportation-intensive sectors.

Sources

Natural gas systems include many activities and pieces of equipment that have the potential to emit air pollutants. Most of these emissions sources are common to both conventional and unconventional natural gas development.

Drilling. Fugitive natural gas and other air pollutants may escape to the atmosphere during initial drilling operations through the circulation of drilling fluids back to the surface. Further, emissions from combusted natural gas—including CO_2, NO_x, and potentially SO_2—may also be released at

[16] For more discussion on the chemical composition of raw natural gas emissions, see **Appendix B**.

[17] For more discussion on emissions from combusted fossil fuel resources, see **Appendix B**. While there is general agreement that the combustion of natural gas produces less GHG emissions than other combusted fossil fuels, the GHG emission intensity for the full fuel life-cycle of natural gas (i.e., from extraction through combustion), compared to petroleum and coal is under greater debate. For further discussion on the comparable impacts of the natural gas industry on GHG emissions, see section "Greenhouse Gases."

Apps' Ex. 24

0465

the well site due to both engine combustion and flaring activities. These include "well test flaring," which occurs during the drilling and testing of oil and gas wells, and "solution gas flaring," which occurs during the disposal of associated gas produced along with crude oil (as is the case currently with oil production in the Bakken formation).

Well Completions. Well completions contain several processes which have the potential to emit air pollutants. For example, hydraulic fracturing uses pressurized fluids containing any combination of water, proppant, and added chemicals to penetrate and produce natural gas from tight formations (e.g., shale, sand, or coal formations). The process requires a high rate, extended flowback period to expel fracture fluids and solids from the well. Gas may escape with these fluids during flowback or impoundment, allowing emissions of methane and VOCs to be released to the atmosphere. Conversely, if the flowback gas is captured, separated from the fluids, and flared, emissions of nitrous oxides and carbon dioxide may be released to the atmosphere. EPA estimates that well completions involving hydraulic fracturing can vent substantially more natural gas—approximately 230 times more—than well completions not involving hydraulic fracturing,[18] if not controlled by reduction equipment.[19] Other sources from industry and academia estimate these emissions levels differently, in part because the data are limited.[20]

Compressors. There are many locations throughout the natural gas sector where compression is required to move gas along the pipeline. This is accomplished by different machinery such as combustion turbines, reciprocating internal combustion engines, and electric motors. Both the turbine-powered centrifugal compressors and the reciprocating internal combustion compressors may use a small portion of the natural gas they compress to fuel the turbine. Both are potential sources of fugitive VOCs and methane emissions as well as significant sources of combusted emissions. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the casing. The seals in some compressors use oil (e.g., "wet seal compressors"), and they commonly vent the absorbed gas to the atmosphere when they are purged. Reciprocating compressors, on the other hand, leak natural gas throughout the course of their normal operation, with the highest volume of gas loss associated with worn down piston rod packing systems. Using dry-seal centrifugal systems or periodically replacing worn down rod packing systems are the most effective ways of controlling emissions from gas-driven compressors. Conversely, where available, electric motors can be used to operate compressors. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity.

Controllers. Pneumatic controllers are automated instruments widely used in the natural gas sector for maintaining pressure, temperature, and flow rate conditions in the system. In many situations, the pneumatic controllers make use of the available high-pressure natural gas in the system to regulate these conditions. In these "gas-driven" pneumatic controllers, natural gas may be released intermittently with every valve movement or continuously from the valve control pilot. Gas driven pneumatic controllers are typically characterized as either "high-bleed" or "low-bleed," where a high-bleed device releases at least 6 cubic feet of gas per hour. Conversely, "non-

[18] Specifically, EPA estimates uncontrolled well completion emissions for a hydraulically fractured well at about 23 tons of VOCs, and emissions for a conventional gas well completion at around 0.1 ton VOCs. See EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," 76 *Federal Register* 52738, August 23, 2011.

[19] Reduced emission completions (REC), which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Based on information provided to EPA Natural Gas STAR program, over 90% of gas potentially vented during a completion can be recovered during a reduced emission completion. For more discussion of REC and a schematic, see **Figure 3**.

[20] For further discussion, see section "Measurement of Emissions" of this report.

Apps' Ex. 24

0466

gas driven" pneumatic controllers use sources of power other than pressurized natural gas, greatly reducing levels of emissions. Examples include solar, electric, and instrument air.

Storage Vessels. After being separated from the natural gas stream, crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. These vessels, which are operated at or near atmospheric pressure conditions, can release various emissions to the atmosphere as a result of working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. The two ways of controlling tanks with significant emissions are to install vapor recovery units (VRU) or to route the emissions from the tanks to control devices (i.e., flares).

Dehydrators. Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. One of the most widely used natural gas dehydration processes is glycol dehydration. Glycol dehydration is an absorption process in which a liquid absorbent (glycol) directly contacts the natural gas stream and absorbs both the entrained water vapor as well as a number of selected hydrocarbons, including BTEX, n-hexane, and other HAPs. During the recirculation stages, the hydrocarbons are boiled off along with the water and are either vented to the atmosphere or directed to a control device.

General Equipment and Pipeline Leaks. Fugitive emissions can emanate from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components at any point during operations. Leaks may be due to routine wear, tear, and corrosion; improper installation or maintenance; or the overpressure of gases or liquids in the system. Because of the large number of valves, pumps, and other components within a natural gas production, processing, or transmission facility, equipment leaks collectively can be a significant source of emissions. Further, there are over 300,000 miles of transmission pipelines alone in the United States, and these pieces of equipment exist throughout the system.

Workovers, Maintenance, and Upsets. Periodically, wells require restimulation workovers or routine maintenance—such as the unloading of liquids or blowdowns—in order to reestablish productive gas flows. These activities, depending upon their methods, may release significant amounts of fugitives into the atmosphere. Further, all activities are susceptible to occasional upsets and accidental losses.

Pollutants

Through provisions in the Clean Air Act (CAA),[21] the U.S. Environmental Protection Agency (EPA) classifies air pollutants under several different categories, including the following:

- **Criteria Pollutants.** Common emissions that can harm human health or the environment, or cause property damage, including ground-level ozone (i.e., smog), nitrogen oxides, sulfur dioxide, carbon monoxide, particulate matter, and lead,[22]

[21] 42 U.S.C. 7401 *et seq.*

[22] See authorities as defined in 42 U.S.C. 7409.

Apps' Ex. 24

0467

- **Hazardous Air Pollutants.** Toxic chemicals that are known or suspected to cause cancer or other serious health effects, such as reproductive diseases or birth defects,[23]
- **Greenhouse Gas Pollutants.** Chemical compounds that trap heat in the atmosphere and contribute to the forcing of climate change.[24]

The "Criteria" and "Hazardous Air Pollutant" categories are identified and regulated under specific provisions of the CAA. In contrast, greenhouse gases may be regulated under several different ones.[25] The natural gas industry produces emissions from each of these categories, some of which may overlap (e.g., benzene is a volatile organic compound [VOC]; and it is considered both a ground-level ozone-producing criteria pollutant and a carcinogenic hazardous air pollutant [HAP]). See **Figure 2** for a comparison of air pollution emissions from the natural gas industry against those of other U.S. industrial sectors.

Methane (CH_4). Methane—the principal component of natural gas—is both a precursor to ground-level ozone formation (i.e., smog)[26] and a potent greenhouse gas (GHG), albeit with a shorter climate-affecting time horizon than carbon dioxide.[27] Every process in natural gas systems has the potential to emit methane. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (published April 15, 2013) estimates 2011 methane emissions from "Natural Gas Systems" to be 358 billion standard cubic feet (bscf), or 1.5% of the industry's gross national production that year.[28] In 2011, natural gas systems represented nearly 25% of the total methane

[23] See authorities as defined in 42 U.S.C. 7402.

[24] See authorities as defined in U.S. Environmental Protection Agency, "Endangerment and Cause or Contribute Findings for Greenhouse Gases," 74 *Federal Register* 66496-66516, December 15, 2009.

[25] The "endangerment" language in §§108, 111, 211, 213, 115, and 231 provides fundamental authorities. Also, Section 111(d) provides authority to control GHG emissions from existing sources and Section 111(b) and (e) provide similar authorities for new sources.

[26] While methane is a precursor to ground-level ozone formation, it is less reactive than other hydrocarbons. Thus, EPA has officially excluded it from the definition of regulated hydrocarbons called volatile organic compounds (VOCs). See U.S. Environmental Protection Agency, *Conversion Factors for Hydrocarbon Emission Components*, Washington, DC, EPA-420-R-10-015, July 2010, http://www.epa.gov/otaq/models/nonrdmdl/nonrdmdl2010/420r10015.pdf.

[27] As a greenhouse gas, methane emitted into the atmosphere absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. According to the Intergovernmental Panel on Climate Change (IPCC) *Fourth Assessment Report (2007)*, in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14% to global warming due to anthropogenic GHG sources, making methane the second-leading long-lived climate forcer after CO_2 globally. While the perturbation lifetime for methane is 12 years, CO_2's is considerably longer and does not undergo a simple decline over a single predictable timescale. Instead, the excess carbon is first diluted by the carbon cycle as it mixes into the oceans and biosphere (e.g., plants) over a period of a few hundred years, and then it is slowly removed over hundreds of thousands of years as it is gradually incorporated into carbonate rocks. For further discussion on climate change and its potential impacts, see CRS Report RL34266, *Climate Change: Science Highlights*, by Jane A. Leggett.

[28] EPA reported 2011 GHG emissions from natural gas systems as 177.0 million metric tons of carbon dioxide equivalent ($MMtCO_2e$). EPA reported 2011 GHG emissions from all sources as 6702.3 $MMtCO_2e$. U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf. Here, as elsewhere in the report, Greenhouse gases are quantified using a unit measurement called carbon dioxide equivalent (CO_2e), wherein gases are indexed and aggregated against one unit of CO_2. CRS used a conversion factor of 0.4045 $MMtCO_2e$ = 1000 bscf CH_4 at 60 degrees Fahrenheit (15.6 degrees Celsius) and 14.696 psi (1 atm or 101.325 kPa) of pressure. The U.S. Energy Information Administration reports 2011 U.S. natural gas marketed production as 24,036 bscf, see http://www.eia.gov/dnav/ng/hist/n9050us2a.htm. EPA's 2011 emission estimates were revised, in part, by industry information released under the Greenhouse Gas Reporting Program (GHGRP) (for more information about the program, see section on GHG Reporting under "Prior Federal Air Standards and Other Rules for Crude Oil and Natural Gas Systems" of this report). The first GHGRP report by the crude oil and natural gas sector was

emissions from all domestic sources and accounted for about 2% of all GHG emissions in the United States. In each year since 1990, natural gas systems were cited as being the single largest contributor to U.S. anthropogenic (i.e., man-made) methane emissions. Because of methane's effects on climate, EPA has found that it, along with five other well-mixed greenhouse gases, endangers public health and welfare within the meaning of the Clean Air Act.[29]

Volatile Organic Compounds (VOCs)—A Ground-Level Ozone (O_3) Precursor. The crude oil and natural gas sector is currently one of the largest sources of VOC emissions in the United States, accounting for approximately 12% of VOC emissions nationwide (and representing 67% of VOC emissions released by industrial source categories).[30] VOCs—in the form of various hydrocarbons—are emitted throughout a wide range of natural gas operations and equipment. The interaction between VOCs and NO_x in the atmosphere contributes to the formation of ozone (i.e., smog). EPA quantifies several health effects associated with exposure to ozone, including premature death, heart failure, chronic respiratory damage, and premature aging of the lungs. Ozone may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation, and congestion.[31]

Nitrogen Oxides (NO_x)—A Ground-Level Ozone (O_3) Precursor. Significant amounts of NO_x are emitted at natural gas sites through the combustion of natural gas and other fossil fuels (e.g., diesel). This combustion occurs during several activities, including (1) the flaring of natural gas during drilling and well completions, (2) the combustion of natural gas to drive the compressors that move the product through the system, and (3) the combustion of fuels in engines, drills, heaters, boilers, and other production, construction, and transportation equipment.[32] In addition to ozone formation (see VOCs description above), current scientific evidence links short-term NO_x exposures with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Carbon Monoxide (CO). Similar to NO_x, CO is emitted from combustion processes in stationary and mobile sources. CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues.

Sulfur Dioxide (SO_2). SO_2 is emitted from crude oil and natural gas production and processing operations that handle and treat sulfur-rich, or "sour," gas. Current scientific evidence links short-term exposures to SO_2 with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms.

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released in February 2013. Some 1,800 facilities reported 225 $MMtCO_2e$ of total GHG emissions, of which 83 $MMtCO_2e$ were methane (substantially lower than EPA's 2010 estimate of 215.4 $MMtCO_2e$). Notwithstanding, the industry-reported emissions from the crude oil and natural gas sector accounted for almost 40% of total U.S. anthropogenic methane emissions reported by the GHGRP. For discussion, see section "Measurement of Emissions" of this report.

[29] U.S. Environmental Protection Agency, "Endangerment and Cause or Contribute Findings for Greenhouse Gases," 74 *Federal Register* 66496-66516, December 15, 2009.

[30] The 2008 National Emissions Inventory estimated the crude oil and natural gas sector's VOC emissions at 1.7 million tons. Mobile sources are the highest category for VOC emissions domestically, at 45.2% in 2008. Data for VOCs, as well as the other criteria and HAP pollutants, are derived from EPA's National Emissions Inventory, and can be found at http://www.epa.gov/ttn/chief/eiinformation.html. These figures have been contested by some sources. For further discussion, see the section "Measurement of Emissions" of this report.

[31] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Final National Ambient Air Quality Standards for Ozone*, Research Triangle Park, NC, July 2011.

[32] NO_x emissions from engines and turbines are covered by 40 C.F.R. §60, subpart JJJJ and KKKK respectively.

Apps' Ex. 24

0469

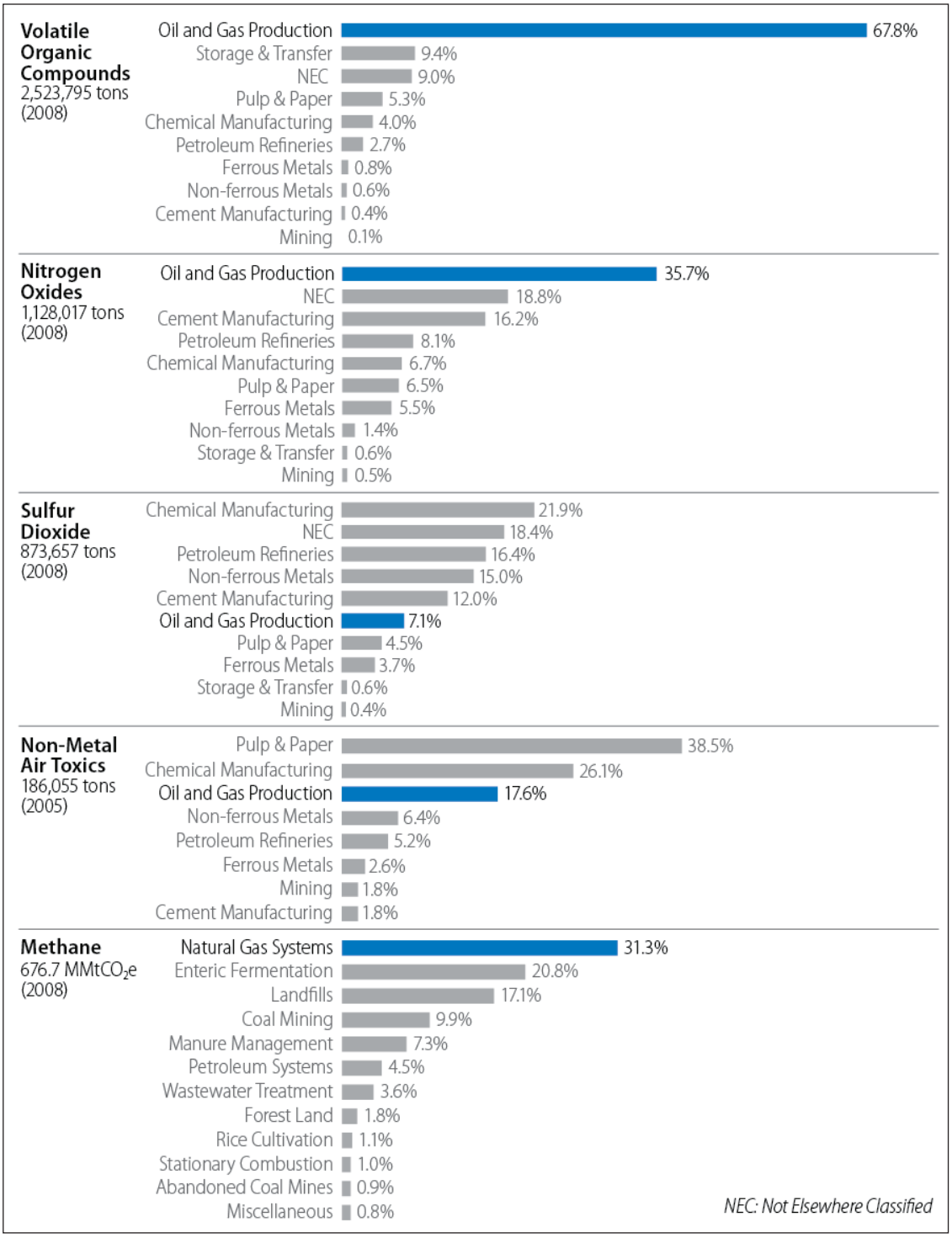
Particulate Matter (PM). PM may occur from dust or soil entering the air during well-pad construction, traffic on access roads, and diesel exhaust from drilling machinery, vehicles, and other engines. PM is linked to respiratory and cardiovascular problems, including aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death.[33]

Hazardous Air Pollutants (HAPs). HAPs, also known as air toxics, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive diseases, or birth defects. Of the HAPs emitted from natural gas systems, VOCs are the largest group, and typically evaporate easily into the air. The most common HAPs in natural gas systems are n-hexane, the BTEX compounds (benzene, toluene, ethylbenzene, and xylenes), and hydrogen sulfide.[34] HAPs are found primarily in natural gas itself, and are emitted from equipment leaks and from various processing, compressing, transmission, distribution, or storage operations. They are also a byproduct of fuel combustion and may be components in various chemical additives.

[33] U.S. Environmental Protection Agency, *Particulate Matter Health* website, http://www.epa.gov/pm/health.html. For more discussion, see CRS Report R40096, *2006 National Ambient Air Quality Standards (NAAQS) for Fine Particulate Matter (PM2.5): Designating Nonattainment Areas*, by Robert Esworthy.

[34] Hydrogen sulfide was on the original list of hazardous air pollutants in the CAA, Section 112(b), but was subsequently removed by Congress. Currently, hydrogen sulfide is regulated under the CAA's Accidental Release Program, Section 112(r)(3). According to EPA, there are 14 major areas found in 20 different states where hydrogen sulfide is commonly found in natural gas deposits. As a result of drilling in these areas, "the potential for routine [hydrogen sulfide] emissions is significant." See U.S. Environmental Protection Agency, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas*, EPA-453/R-93-045, Research Triangle Park, NC, October 1993, at ii, III-35; see also ii, II-5 to II-11.

Figure 2. Selected Emissions Inventories for U.S. Industrial Sectors



Source: EPA, National Emissions Inventory 2008, v.1.5 GPR, http://www.epa.gov/ttnchie1/net/2008inventory.html; National Air Toxics Assessment, 2005, http://www.epa.gov/ttn/atw/natamain/; Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, http://www.epa.gov/climatechange/ghgemissions/usinventoryreport/archive.html.

The Clean Air Act and the Federal Role in Air Quality Issues in Natural Gas Systems

The Clean Air Act (CAA)[35] seeks to protect human health and the environment from emissions that pollute ambient, or outdoor, air.[36] It requires the U.S. Environmental Protection Agency (EPA) to establish minimum national standards for air emissions from various source categories (sources in the "Crude Oil and Natural Gas Production," and the "Natural Gas Transmission and Storage" sectors are included under these categories), and assigns primary responsibility to the states to assure compliance with the standards. EPA has largely delegated day-to-day responsibility for CAA implementation to all 50 states, including permitting, monitoring, inspections, and enforcement; and in many cases, states have further delegated program implementation to local governments. Sections of the CAA which are most relevant to air quality issues in the natural gas industry are discussed below. Some of the regulations implementing these sections have been revised by federal air standards promulgated by EPA on August 16, 2012. The paragraphs below summarize relevant sections of the CAA prior to these revisions. For a summary of the 2012 air standards and their relationship to the prior ones, see the subsequent section, "2012 Federal Air Standards for Crude Oil and Natural Gas Systems," as well as **Appendix A**.

Prior Federal Air Standards and Other Rules for Crude Oil and Natural Gas Systems

National Ambient Air Quality Standards (NAAQS). Section 109 of the CAA requires EPA to establish NAAQS for air pollutants that may reasonably be anticipated to endanger public health or welfare, and whose presence in ambient air results from numerous or diverse sources. Using this authority, EPA has promulgated NAAQS for sulfur dioxide (SO_2), particulate matter ($PM_{2.5}$ and PM_{10}), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone, and lead. States are required to implement specified air pollution control plans to monitor these pollutants and ensure the NAAQS are met, or "attained." Additional measures are required in areas not meeting the standards, referred to as "nonattainment areas." "Nonattainment" findings for ground-level ozone, nitrogen oxides, and sulfur dioxide in areas with crude oil and natural gas production may result in states establishing specific pollution controls that could affect the industry.

Permits. The 1990 CAA Amendments add Title V (i.e., "5"),[37] which requires major sources of air pollution to obtain operating permits. Primary responsibility for Title V permitting has been delegated by EPA to state and local authorities. Sources subject to the permit requirements generally include new or modified sources that emit or have the potential to emit 100 tons per year of any regulated pollutant, plus new or existing "area sources" that emit or have the potential to emit lesser specified amounts of hazardous air pollutants. In "nonattainment" areas, the permit requirements may include sources which emit as little as 50, 25, or 10 tons per year of VOCs, depending on the severity of the region's nonattainment status ("serious," "severe," or "extreme" respectively). A Title V permit must, among other things, list all emissions limitations and

[35] 42 U.S.C. 7401 et seq. For a summary of the CAA and EPA's air and radiation activities and its authorities, see EPA's website at http://www.epa.gov/air/basic.html; and CRS Report RL30853, *Clean Air Act: A Summary of the Act and Its Major Requirements*, by James E. McCarthy, Claudia Copeland, and Linda-Jo Schierow.

[36] "Outdoor" is defined as that to which the public has access (see 40 C.F.R. §50.1(e)).

[37] 42 U.S.C. §§7661-7661f; 40 C.F.R. §§71, 72.

Apps' Ex. 24

0472

standards applicable to the source, ensure that monitoring and recordkeeping are sufficient to demonstrate compliance, and require the payment of fees. Currently, most crude oil and natural gas production activities upstream from the processing plant are not classified as "major sources" under EPA Title V operating permits.[38]

Greenhouse Gas Reporting. In the FY2008 Consolidated Appropriations Act (H.R. 2764; P.L. 110-161), Congress directs EPA to develop regulations that establish a mandatory GHG reporting program that applies to emissions that are "above appropriate thresholds in all sectors of the economy." EPA issued the Mandatory Reporting of Greenhouse Gases Rule (MRR)[39] which became effective on December 29, 2009, and included reporting requirements for facilities and suppliers in 32 source categories.[40] Affected facilities in the petroleum and natural gas industry include onshore petroleum and natural gas production, offshore petroleum and natural gas production, natural gas processing, natural gas transmission compressor stations, underground natural gas storage, liquefied natural gas (LNG) storage, LNG import and export terminals, and natural gas distribution. The rule requires petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide (CO_2) equivalent per year to report annual fugitive emissions of methane and CO_2 from equipment leaks and venting, and annual combusted emissions of CO_2, methane, and nitrous oxide from gas flaring, from stationary and portable equipment involved in onshore petroleum and natural gas production, and from stationary equipment involved in natural gas distribution. Since methane is the most prominent emission from upstream oil and gas activities, and since the rule requires producers to aggregate emissions from all commonly controlled wells and their associated equipment (e.g., compressors, generators, piping, and storage tanks), many facilities may likely be required to report GHG emissions in coming years.[41] EPA estimates that the rule covers 85% of the total GHG emissions from most of the U.S. petroleum and natural gas industry with approximately 2,800 facilities reporting. On February 5, 2013, EPA released for the first time GHG data for crude oil and natural gas systems collected under industry reporting.[42] Further to this, many states have their own GHG reporting requirements independent of the 2009 federal rules (e.g., the Regional GHG Initiative, the Western Climate Initiative, and California).

New Source Performance Standards (NSPS). Section 111 of the CAA requires EPA to promulgate regulations establishing emissions standards that are applicable to new, modified, and reconstructed sources—if such sources cause or contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. A performance standard reflects

[38] EPA's guidance for "major source" determinations includes consideration of proximity, ownership, and industrial grouping. For further discussion, see section "Major Source Aggregation."

[39] U.S. Environmental Protection Agency, "Mandatory Reporting of Greenhouse Gases," 74 *Federal Register* 56260, October 30, 2009.

[40] U.S. Environmental Protection Agency, "Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems," 75 *Federal Register* 74458, November 30, 2010, see final rule revision to Subpart W—Petroleum and Natural Gas Systems—amending 40 C.F.R. §98 (i.e., the regulatory requirements for the Program).

[41] In the final rule (40 C.F.R. §98.238), EPA defined "facility" with respect to onshore petroleum and natural gas production to mean "all petroleum or natural gas equipment on a well pad or associated with a well pad and CO_2 EOR [enhanced oil recovery] operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin [i.e., as defined on a county level and by geologic formation]. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility."

[42] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html. The data show 2011 GHG emissions from over 1,800 facilities in the crude oil and natural gas sector, accounting for 225 MMtCO2e. For a discussion of these measurements in relation to other reported estimates, see section "Measurement of Emissions" of this report.

Apps' Ex. 24

0473

the degree of emission limitation achievable through the application of the ‘‘best system of emission reduction’’ (BSER) which EPA determines has been adequately demonstrated. As new technology advances are made, EPA is required to revise and update NSPS applicable to designated sources.

The following federal NSPS may apply to crude oil and natural gas systems (some parts have been rewritten by the August 16, 2012, standards; see the next section and **Appendix A** for further discussion):

- 40 C.F.R. Part 60, Subpart JJJJ—Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). Subpart JJJJ applies to manufacturers, owners, and operators of SI ICE, which affects new, modified, and reconstructed stationary SI ICE (i.e., generators, pumps, and compressors), combusting any fuel (i.e., gasoline, natural gas, LPG, landfill gas, digester gas etc.), except combustion turbines. The applicable emissions standards are based on engine type, fuel type, and manufacturing date. The regulated pollutants are NO_x, CO, and VOCs, and there is a sulfur limit on gasoline. Subpart JJJJ applies to facilities operating spark ignition engines at compressor stations;
- 40 C.F.R. Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition (CI) ICEs. Subpart IIII applies to manufacturers, owners, and operators of CI ICE (diesel), which affects new, modified, and reconstructed (commencing after July 11, 2005) stationary CI ICE (i.e., generators, pumps, and compressors), except combustion turbines. The applicable emissions standards (phased in Tiers with increasing levels of stringency) are based on engine type and model year. The regulated pollutants are NO_x, PM, CO, and non-methane hydrocarbons (NMHC), while the emissions of sulfur oxides (SO_x) are reduced through the use of low sulfur fuel. Particulate emissions are also reduced by standards. Subpart IIII applies to facilities operating compression ignition engines at compressor stations;
- 40 C.F.R. Part 60, Subpart KKK—Standards of Performance for Equipment Leaks of VOCs from Onshore Natural Gas Processing Plants. Subpart KKK applies to gas processing plants that are engaged in the extraction of natural gas liquids from field gas and contains provisions for VOCs leak detection and repair (LDAR) (this section was revised by the 2012 air standards);
- 40 C.F.R. Part 60, Subpart LLL—Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions. Subpart LLL governs emissions of SO_2 from gas processing plants, specifically gas sweetening units (which remove H_2S and CO_2 from sour gas) and sulfur recovery units (which recover elemental sulfur) (this section was revised by the 2012 air standards); and
- 40 C.F.R. Part 60 Subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which construction, reconstruction, or modification commenced after July 23, 1984.

National Emission Standards for Hazardous Air Pollutants (NESHAPs). Section 112 of the CAA requires EPA to promulgate regulations establishing standards to control emissions of hazardous air pollutants (HAPs). NESHAPs are applicable to both new and existing sources of HAPs, and there are NESHAPs for both “major” sources and “area” sources of HAPs. A “major” source of HAPs is one with the potential to emit in excess of 10 tons per year (tpy) of any single HAPs or 25 tpy of two or more HAPs combined. Conversely, an “area” source of HAPs is a stationary source of HAPs that is not major. The aim is to develop technology-based standards

Apps' Ex. 24
0474

which require levels met by the best existing facilities (commonly referred to as maximum achievable control technology, or MACT, standards). The pollutants of concern in the oil and gas sector are primarily the BTEX compounds, formaldehyde, and n-hexane.

The following federal NESHAPs may apply to crude oil and natural gas systems (some parts have been rewritten by the August 16, 2012, standards; see the next section and **Appendix A** for further discussion):

- 40 C.F.R. Part 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE);
- 40 C.F.R. Part 63, Subpart H—National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks. Subpart H applies to equipment that contacts fluids with a HAPs concentration of 5%;
- 40 C.F.R. Part 63, Subpart HH—NESHAPs from Oil and Natural Gas Production Facilities. Subpart HH controls air toxics from oil and natural gas production operations and contains provisions for both major sources and area sources of HAPs. Emission sources affected by this regulation are tanks with flash emissions (major sources only), equipment leaks (major sources only), and glycol dehydrators (major and area sources) (this section was revised by the 2012 air standards);
- 40 C.F.R. Part 63, Subpart HHH—NESHAPs from Natural Gas Transmission and Storage Facilities. Subpart HHH controls air toxics from natural gas transmission and storage operations. It affects glycol dehydrators located at major sources of HAPs (this section was revised by the 2012 air standards); and
- 40 C.F.R. Part 61, Subpart V—National Emission Standard for Equipment Leaks (Fugitive Emission Sources). Subpart V applies to equipment that contacts fluids with a volatile HAPs concentration of 10%.

2012 Federal Air Standards for Crude Oil and Natural Gas Systems

On January 14, 2009, two non-governmental organizations filed a complaint under the citizen suit provision of the CAA, alleging that EPA failed to meet its obligations under CAA Sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAPs with respect to the "Crude Oil and Natural Gas Production" source category.[43] On February 4, 2010, the U.S. Court of Appeals for the D.C. Circuit entered a consent decree requiring EPA to sign proposed standards and/or determinations not to issue standards by January 31, 2011 (modified to July 28, 2011), and to take final action by November 30, 2011 (modified to April 17, 2012). EPA proposed a new set of air standards for the "Crude Oil and Natural Gas Production" sector and the "Natural Gas Transmission and Storage" sector on July 28, 2011,[44] and held three public hearings for the proposal. After several court-agreed extensions, the final rules establishing the new standards were signed by the Administrator on April 17, 2012, were published in the *Federal Register* on August 16, 2012,[45] and became effective on October 15,

[43] *WildEarth Guardians, et al. v. Jackson,* No. 1:09-CV-00089-CKK (D. D.C.), https://www.federalregister.gov/articles/2009/12/17/E9-30044/proposed-consent-decree-clean-air-act-citizen-suit.

[44] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," 76 *Federal Register* 52738, August 23, 2011.

[45] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012, https://www.federalregister.gov/articles/2012/08/16/2012-16806/oil-and-natural-gas-sector-new-source-performance-standards-and-national-emission-standards-for.

Apps' Ex. 24

0475

2012. A summary of the 2012 federal air standards is provided below. For a detailed comparison of the 2012 federal air standards against the prior federal air standards, see **Appendix A**.

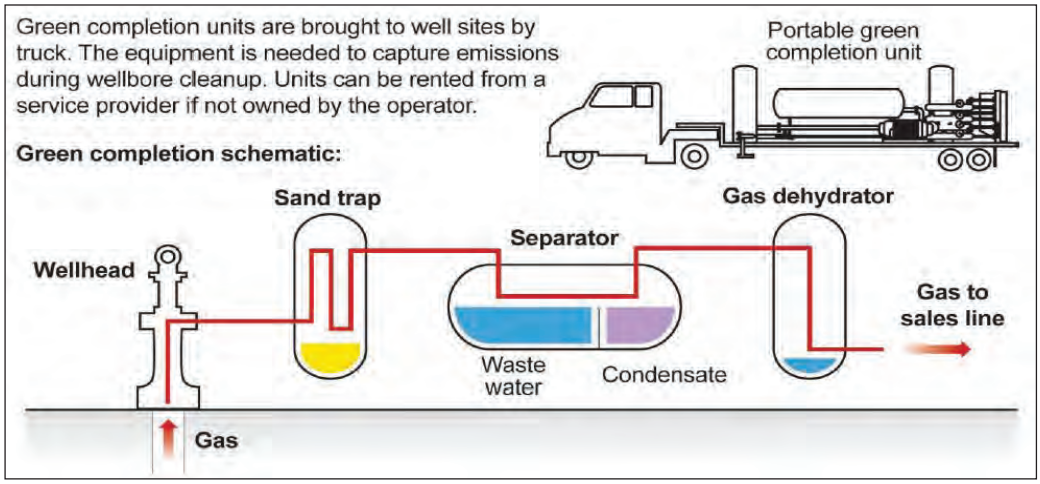
2012 NSPS for Crude Oil and Natural Gas Systems

The 2012 NSPS for the "Crude Oil and Natural Gas Production" and the "Natural Gas Transmission and Storage" source categories regulate volatile organic compounds (VOCs) emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, and leaking components at onshore natural gas processing plants, as well as sulfur dioxide (SO_2) emissions from onshore natural gas processing plants. Prior to the 2012 standards, processing plants were the only source category regulated at the federal level. The 2012 standards include the following:

- **Gas Wells.** The rule covers any gas well that is "an onshore well drilled principally for production of natural gas" and is "hydraulically fractured." Oil wells (i.e., wells drilled principally for the production of crude oil) or conventional gas wells (i.e., wells drilled without hydraulic fracturing for the production of natural gas) are not subject to the rule. For fractured and refractured gas wells, the rule requires owners/operators to use "reduced emissions completions"—also known as "REC" or "green completions"—to reduce VOCs emissions during well completions. A REC is defined by EPA as "a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere" (see graphic in **Figure 3**). To provide industry enough time to order and manufacture the necessary REC equipment, the NSPS establishes two phases for compliance. Owners and/or operators may use either REC or completion combustion devices (e.g., flaring) until January 1, 2015. After January 1, 2015, REC will be required. The rule exempts exploratory, delineation, and low-pressure gas wells from the REC requirement, stipulating the use of completion combustion devices instead.[46]

[46] Exploratory well is defined as a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists; delineation well is defined as a well drilled in order to determine the boundary of a field or producing reservoir; and low pressure well is defined as a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Figure 3. Reduced Emissions Completion Equipment



Source: U.S. Environmental Protection Agency.

Graphic: Dave Merrill/BGOVgraphics, Bloomberg Government, http://www.bgov.com.

- **Storage Vessels.** The rule requires individual storage vessels in the crude oil and natural gas production segment and the natural gas processing, transmission, and storage segments with emissions equal to or greater than 6 tons per year (tpy) to achieve at least 95% reduction of uncontrolled VOCs emissions.[47]
- **Certain Controllers.** The rule sets a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) for individual, continuous bleed, natural gas-driven pneumatic controllers located between the wellhead and the point at which the gas enters the transmission and storage segment. For individual, continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants, the rule sets a natural gas bleed limit of zero scfh.
- **Certain Compressors.** The rule requires a 95% reduction of VOCs emissions from wet seal centrifugal compressors located between the wellhead and the point at which the gas enters the transmission and storage segment. The rule also requires measures intended to reduce VOCs emissions from reciprocating compressors located between the wellhead and the point where natural gas enters the natural gas transmission and storage segment. Owners and/or operators of these compressors must replace the rod packing systems within the compressors based on specified usage or time.
- **Onshore Natural Gas Processing Plants.** The rule revises the existing NSPS requirements for leak detection and repair (LDAR) to reflect the procedures and leak thresholds established in the NSPS for equipment leaks of VOCs emissions in the synthetic organic chemicals manufacturing industry. This rule also revises the existing NSPS requirements for SO_2 emission reductions based on sulfur feed rate and sulfur content of gas.

[47] This section is currently under reconsideration in a proposed rule, U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013.

2012 NESHAPs for Crude Oil and Natural Gas Systems

The 2012 rules revise the NESHAPs for glycol dehydration unit process vents and leak detection and repair (LDAR) requirements and retain the existing NESHAPs for storage vessels. The 2012 standards include the following:

- **Glycol Dehydration Units.** The rule establishes MACT standards for "small" glycol dehydration units, which were unregulated under the initial NESHAPs. Covered glycol dehydrators now include those with an actual annual average natural gas flow rate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr), and they must meet unit-specific limits for benzene, toluene, ethylbenzene, and xylene (collectively, "BTEX").[48]
- **Leak Detection and Repair.** The rule lowers the leak definition for valves at natural gas processing plants from 10,000 parts per million (ppm) to 500 ppm for major sources at crude oil and natural gas production facilities, thus requiring the application of LDAR procedures at this level.

Effects of the 2012 Federal Air Standards on State Attainment Planning and Permitting

With the release of the 2012 air standards for the crude oil and natural gas production, transmission, and storage sectors, EPA constituted a federally required minimum level of control for various source categories. States have the flexibility to put their own programs in place or implement existing programs as long as they are at least as protective as the federal standards.

Attainment Planning. EPA has designated attainment and nonattainment areas for the 2008 ozone National Ambient Air Quality Standards (NAAQS). Some of these areas have significant crude oil and natural gas activities. States with ozone nonattainment areas are required to submit modified state implementation plans (SIP) in 2015 and to attain the standard by 2015 and 2018 for areas classified as "marginal" and "moderate," respectively. A few areas classified as "serious" nonattainment must attain by 2021. As the 2012 air standards may likely help states make progress in attaining the ozone NAAQS in nonattainment areas where there is significant well development, states are allowed to include the federal NSPS as a federally enforceable strategy in their nonattainment SIP. States may "take credit" for the NSPS in their SIP towards meeting two requirements: (1) the 2012 standards are expected to achieve 95% control of VOCs emissions from new gas wells, making it easier for states to obtain the overall reduction in emissions they need to attain the ozone NAAQS without adding any federal or state permitting requirements; and (2) SIPs in "moderate" and "serious" areas must also show "reasonable further progress" in controlling emissions in the years before they attain the ozone NAAQS. In most areas, states may choose to measure this progress relative to emissions in 2011. In areas that had wells drilled in 2011 and will continue to have more wells drilled in the years ahead, the 95% control from the NSPS may provide emission reductions that can be credited toward the reasonable further progress requirement. In areas that had no or few wells drilled in 2011 but that will see drilling activity in the future, the 95% control from the NSPS may ensure that emissions from new well development do not impede meeting the reasonable further progress requirement.

[48] The final MACT standards for small dehydrators at crude oil and natural gas production facilities require that existing affected sources at a major source meet a unit-specific BTEX limit of 3.28×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv.

Apps' Ex. 24

0478

Permitting. The 2012 NSPS regulates all new and modified gas wells whether or not they attain existing thresholds that define a "major source" for pre-construction permit and Title V operating permit purposes. In the absence of the NSPS, some hydraulically fractured gas wells could have emissions above these thresholds in some ozone nonattainment areas. Wells complying with the 2012 NSPS, however, most likely will not trigger major source permitting thresholds. Wells complying with the 2012 NSPS may also have emissions low enough to avoid needing a minor source permit from the state, as the NSPS provides a path (i.e., REC) for existing wells that are refractured to avoid falling under the scope of the NSPS at all, thereby avoiding any automatic requirement to get a state minor source permit. Nevertheless, states may still include modified wells in their minor source permitting rules if they choose.

Reported Costs and Benefits of the 2012 Federal Air Standards

Natural gas is a product of—and thus a source of revenue for—the oil and gas industry. It is also a main source of pollution for the industry when it is emitted into the atmosphere. Due to this unique linkage, pollution abatement has the potential to translate into economic benefits for the industry, as producers can offset compliance costs with the value of natural gas and condensate recovered and sold at market. EPA reports the environmental and the economic benefits of the 2012 air standards as follows:[49]

- **VOCs Reductions of 190,000 to 290,000 Tons Annually.** VOCs emissions reductions of nearly 95% from hydraulically fractured gas wells are expected to help reduce ground-level ozone (i.e., smog) in areas where crude oil and natural gas production occurs.
- **Air Toxics Reductions of 12,000 to 20,000 Tons Annually.** The 2012 rules are intended to protect against potential cancer risks from emissions of several air toxics, including the BTEX compounds.
- **Methane Reductions of 1.0 Million to 1.7 Million Short Tons Annually.** (Equivalent to 19 to 33 million metric tons of CO_2 equivalent (CO_2e).) While not targeted by the 2012 rules, methane reductions from new and modified well completions and other activities would yield an additional environmental co-benefit.
- **Industry Costs of $170 Million Annually.** EPA estimates the rule will cost producers about $170 million annually in 2015 (in 2008$). Industry and third party sources have estimated anywhere from $450 million to over $2.8 billion, depending upon assumptions regarding the number of wells subject to compliance, the cost of REC equipment and rentals, and the number and cost of completion combustion requirements.[50]
- **Net Cost Savings for Industry of $11 Million to $19 Million.** EPA estimates that compliance costs would be offset by the sales of the captured methane and natural gas liquids, resulting in a net gain of $11 million to $19 million in 2015. EPA's cost-benefit analysis, as put forth in its *Regulatory Impact Analysis* for the

[49] As reported in U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012.

[50] For reference, U.S. natural gas producers sold about 24 trillion cubic feet of gas in 2011, with a value of $72.5 billion at $3/Mcf. Energy Information Administration, *U.S. Natural Gas Wellhead Value and Marketed Production*, http://www.eia.gov/dnav/ng/ng_prod_whv_dcu_nus_a.htm.

Apps' Ex. 24

0479

proposed air standards, has been critiqued as both too high and too low by industry and environmental stakeholders, respectively.[51] Industry stresses that the economic analyses must include the full variety of conditions (e.g., the full range of VOCs content found across different reservoirs) in upstream production activities to support all the costs of compliance with the proposed rule; and that the analysis does not fully take into account the effect that operational standards (i.e., the requirements for additional green completions and other abatement equipment) will have on the production and growth of the industry in the near term.[52] Industry claims that fluctuations in the market price of recovered products may also serve to further depress EPA's revenue estimates. Conversely, environmental stakeholders argue that the costs of control used by EPA are conservative estimates and do not properly account for the full social and environmental benefits created by the capture of methane.[53]

Agency Reconsideration of the 2012 Federal Air Standards

On April 12, 2013, EPA announced proposed amendments to the 2012 federal air standards for the oil and gas sector.[54] The proposed rule reconsiders certain issues related to implementation of the storage vessel provisions and adjusts compliance dates to allow more time for the availability of control devices. In summary, the proposed rule grants reconsideration of the following: (1) an extension to the implementation date for the storage vessel provisions (from October 15, 2013, to April 15, 2014, for new and modified sources after April 12, 2013); (2) definition of "storage vessel" (to clarify that it refers only to vessels containing crude oil, condensate, intermediate hydrocarbon liquids, or produced water); (3) definition of "storage vessel affected facility" (to include the 6 tpy VOC emission threshold); (4) requirements for storage vessels constructed, modified, or reconstructed during the period from the NSPS proposal date, August 23, 2011, to April 12, 2013 (to remove the requirement for control devices and to require instead notification to regulatory agencies by October 15, 2013, of the existence and location of the vessels); (5) an alternative mass-based standard for storage vessels after extended periods of low uncontrolled emissions (to include a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95% control in the final NSPS under specified circumstances).

Issues for Congressional Consideration

The expansion of both industry production and government regulation of natural gas systems has sparked discussion on a number of outstanding issues. Some of the more significant debates involving air quality concerns are outlined in the sections below.

[51] For further discussion on costs, see section "Cost Benefit Analysis of Federal Standards."

[52] For an example of industry comments on the cost analysis, see comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov.

[53] For an example of environmental stakeholder comments on the cost analysis, see comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Sierra Club, et al., November 30, 2011, accessed on http://www.regulations.gov.

[54] U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013.

The Regulatory Role of Federal, State, and Local Governments

According to EPA, the 2012 federal air standards are designed to provide minimum requirements for emissions of air pollutants from the crude oil and natural gas sector that can both protect human health and the environment and allow for continued growth in production. However, some believe that state and local governments are better positioned to develop these emission standards. They claim that states can more readily address the regional and state-specific character of many crude oil and natural gas activities, including differences in geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics, and the effects these components have on air quality. They argue that federal rules add unnecessary and often repetitive requirements on the industry, which may increase project costs and delays with little added benefit. Others, attesting to the "patchwork" of state and local requirements, support the need for the federal government to institute minimum standards for emissions that are consistent, predictable, and reach across state lines. They claim a federal standard would extend regulatory certainties to the industry and would best ensure health and environmental protections for all stakeholders. They also contend that many state laws and state agencies are still gaining experience with unconventional oil and natural gas development, and that industry is operating under insufficient and outdated rules. In light of these considerations, Congress may choose to re-examine proposed and/or existing federal requirements apropos of existing state and local regulations, or introduce new federal requirements if deemed necessary.

Currently, states lead the day-to-day permitting, monitoring, and enforcement of crude oil and natural gas development, and any federal requirements that might apply have typically been delegated to the states. In general, each state has one or more regulatory agencies that may permit wells, including their design, location, spacing, operation, and abandonment, and may regulate for environmental compliance, including water management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. The organization of regulatory agencies within the various oil and gas producing states varies considerably. In many cases, state agencies were established initially to provide a structure to facilitate—not regulate—oil and gas development. These facilitatory agencies served primarily to provide a central state system for administering resource claims and mediating disputes. In some instances, these agencies have taken on oversight activities for environmental protection. In other instances, they have operated alongside a separate agency that has been mandated to prevent environmental pollution and public health impacts.

For example, Colorado provides multiple state agencies with different authorities to regulate industry operations. The Colorado Department of Public Health and Environment (CDPHE) and the Colorado Department of Natural Resources maintain separate but complementary oversight of industry operations. Colorado's Air Quality Control Commission (under CDPHE) has regulations to address emissions from tanks, engines, compressors, and associated equipment. Colorado's Oil and Gas Conservation Commission has regulations pertaining to such issues as well completions, odors, noise, and drill rig setbacks. Conversely, Pennsylvania's Department of Environmental Protection (DEP) Office of Oil and Gas Management is responsible for all statewide oil and gas programs. The office manages activities both to facilitate the exploration, development, and recovery of Pennsylvania's oil and gas reservoirs while also overseeing the protection of the commonwealth's natural resources and environment. The office develops policy and programs for the regulation of oil and gas development pursuant to the commonwealth's Oil and Gas Act, the Coal and Gas Resource Coordination Act, and the Oil and Gas Conservation Law. It oversees the oil and gas permitting and inspection programs, develops statewide regulation and standards,

conducts training programs for industry, and works with the Interstate Oil and Gas Compact Commission and the Technical Advisory Board.

All crude oil and natural gas producing states have laws in place related to oil and gas development. Most state requirements are written into rules or regulations. Requirements may also be added to permits on a case-by-case basis as a result of findings from environmental reviews, on-the-ground inspections, public comments, or commission hearings. For example, emissions from oil and gas development in Colorado are governed primarily by statutory provisions of the Oil and Gas Conservation Act (Colo. Rev. Stat. §34-60-100, et seq.), Colorado's Air Pollution and Prevention Control Act (§25-7-100, et seq.), and Water Quality Control Act (§25-8-100, et seq.). In other states, such as Montana or Texas, emissions from oil and gas development are addressed most prominently during permitting, registration, and authorization activities (e.g., Montana Department of Environmental Quality, Air Quality Permits [MAQP], under Rule 17.8.752, and Montana Registration Requirements, under Rule 17.8.1711[1][a]; or Texas Commission on Environmental Quality, Permit by Rule [PBR], Standard Permit, and New Source Review [NSR] Permit, under Title 30, Texas Administration Code, Chapter 116, et seq.).

Most state oil and gas regulations were written well before unconventional natural gas development became widespread. A number of major gas producing states have recently revised regulations, with particular focus on emerging areas of concern, including disclosure of hydraulic fracturing chemicals, well construction and operation to prevent aquifer contamination, and management of waste from flowback and produced water. Similarly, many states and counties have some regulatory structures to address air quality issues based on each jurisdiction's individual circumstance. Some states and counties have adopted relatively stringent standards, while others have not. Some have rules proposed or are in the process of revising or implementing them. Others are considering rolling back existing regulations.[55] EPA's 2012 federal air standards were drawn primarily from existing requirements found in the state codes of Colorado and Wyoming. For a comparison of EPA's 2012 air standards for source categories in the crude oil and natural gas industry to those from selected states, see **Table A-4** of this report.

Critics of federal oversight maintain that the states have long regulated oil and gas exploration and production and are best positioned to continue to do so as they have established governing structures and trained staff in place. They argue that a distant federal bureaucracy unfamiliar with local conditions is rarely the best entity to ensure environmental needs are balanced with economic growth and job creation. They claim that states can more readily address the regional and state-specific character of many crude oil and natural gas activities, including differences in geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. Critics argue that federal rules add unnecessary and often repetitive requirements on the industry, which may increase project costs and delays with little added benefit. They claim federal rules would require increased federal resources and skilled staff to administer regulations for oil and gas development (or, as is sometimes the case, to administer federal requirements redundantly alongside existing state programs). They contend that a well-run state permitting and regulatory program can adjust more quickly, is better positioned to meet the challenges presented by constantly developing technologies, and can effectively administer rules across private, state, and federal lands.[56]

[55] For example, see New Mexico's current efforts to loosen regulations on pits for waste or drill cuttings and the use of steel tanks as part of a "closed loop" system, Mike Soraghan, "N.M. is loosening drilling rules, bucking trends and riling ranchers," *E&E News*, Thursday, November 15, 2012, http://www.eenews.net/energywire/2012/11/15/1.

[56] For example, see the comments made by Wyoming governor Matthew Mead, as reported in the *Washington Times:* Matthew Mead, "Commentary: Hydro-fracking regulations should be left to states," *Washington Times*, September 17,

Apps' Ex. 24

0482

Others note that it has neither been the practice nor the intention of EPA to administer regulations for oil and gas development at the state level. However, seeing the patchwork mix of state and local requirements, they have called for the federal government to institute a minimum nationwide standard for emissions from the crude oil and natural gas sector. Proponents of federal oversight contend that many state laws and state agencies are still gaining experience with unconventional oil and natural gas development, and that industry is operating under insufficient and outdated rules.[57] They claim that many of the agencies that regulate development at the state level are underfunded and understaffed, are tasked with the dual purposes of developing the state's resources and protecting the state's environment, and thus, are caught between policing and promoting the industry. They suggest that state agencies and state regulators are often overwhelmed by oil and gas companies, which are generally national or international in scope, and start with the advantage of sheer size. They point to examples where state regulators have failed to seek large penalties for violations or track enforcement data, and cite statistics that show 40% of state drilling regulators have industry ties.[58] A 2012 report, released by a non-governmental environmental organization, surveyed active oil and gas wells in six states and summarized the findings as follows: (1) over half (or close to 350,000 active wells in 2010) are operating with no independent inspections to determine whether they are in compliance with state rules; (2) when inspections do uncover rule violations, the violations often are not formally recorded; (3) when violations are recorded, they result in few penalties; (4) when penalties are assessed, they provide little incentive for companies to not offend again (noting that no state assessed annual fines that added up to the average value of a single gas well, about $2.9 million).[59]

Covered Sources and Pollutants

The 2012 federal air standards focus primarily on the upstream sectors of the oil and gas industry and cover only some of the pollutants and potential sources of emissions. The standards regulate emissions of VOCs from some, but not all, of the equipment and activities at onshore natural gas well sites, gathering and boosting stations, and processing plants. Similarly, the standards regulate emissions of SO_2 from sweetening units at some natural gas processing plants, as well as HAPs from some dehydration units and storage facilities in the sector. Some pollutants from natural gas systems remain uncovered by any federal law or regulation, and critics point specifically to methane emissions from the midstream and downstream sectors, as well as hydrogen sulfide, as the most significant omissions. The scope of the 2012 federal standards are the result of several

2012, http://www.washingtontimes.com/news/2012/sep/17/hydro-fracking-regulations-should-be-left-to-state/#ixzz26uwFzyr3.

[57] For example, see the comments made by Peter Zalzal, Environmental Defense Fund, "National Clean Air Standards For The Oil And Gas Industry Provide a Trifecta," EDF Energy Exchange, March 20, 2012, http://blogs.edf.org/energyexchange/2012/03/20/national-clean-air-standards-for-the-oil-and-gas-industry-provide-a-trifecta/.

[58] As reported in Mike Soraghan, "Puny fines, scant enforcement leave drilling violators with little to fear," *E&E News*, Monday, November 14, 2011, http://www.eenews.net/Greenwire/2011/11/14/archive/1; Mike Soraghan, "40% of state drilling regulators have industry ties," *E&E News*, Monday, December 19, 2011, http://www.eenews.net/Greenwire/ground_rules/2011/12/19/1. The reporting found that in Texas, 96% of the 80,000 violations by oil and gas drillers in 2009 resulted in no enforcement action. West Virginia, a state with 56,000 wells, issued 19 penalties last year. And Wyoming, the center of Rocky Mountain development, collected $15,500 in fines in 2010. Pennsylvania sought penalties for more than a quarter of the violations found last year, but levied fines for only 4% of the violations, with the penalties totaling $3.7 million. Further, the reporting reviewed the backgrounds of 95 oil and gas commissioners, board members and agency heads in the top 27 oil and gas states, and found, 39 had an oil and gas background, or 41%.

[59] Lisa Sumi, *Breaking All the Rules: The Crisis in Oil & Gas Regulatory Enforcement*, Earthworks, Washington, DC, September 25, 2012, http://www.earthworksaction.org/library/detail/breaking_all_the_rules_the_crisis_in_oil_and_gas_regulatory_enforcement.

Apps' Ex. 24

0483

factors, including (1) EPA-conducted cost-benefit and risk analyses, (2) stakeholder comments provided to the agency during rulemaking, and (3) statutory limitations placed upon the agency by provisions in the CAA. In light of these considerations, Congress may decide to re-examine ways in which oversight activities address the most significant pollutants and point sources.

While the 2012 air standards for crude oil and natural gas systems are more detailed and comprehensive than previous standards, several pollutants and sources in the sector remain uncovered.

The 2012 standards do not directly cover emissions of the following pollutants in the sector: methane, nitrogen oxides, particulate matter, and hydrogen sulfide (although reductions in some of these pollutants may occur as a co-benefit of VOCs and SO_2 reductions). Many observers have noted, however, that the 2012 standards, as written, use natural gas emissions as a surrogate for VOCs and H_2S/SO_2 emissions. Some argue that basing standards on the volume of natural gas emissions as opposed to the content of VOCs in the gas does not adequately account for the geographic variability of VOCs within the resource (e.g., EPA calculated cost effectiveness based on a national average of 3.7% VOCs by volume [18% by weight] for natural gas streams; however, many streams may produce little or no VOCs). Critics of the rule maintain that requiring standards for natural gas emissions as opposed to VOCs content essentially regulates the industry for methane as opposed to VOCs. From this perspective, requiring an operational standard (e.g., reduced emissions completions) instead of a performance standard (e.g., a VOCs threshold) may impose unnecessary compliance costs in some instances.[60] The 2012 standards do address the smaller volume of VOCs in natural gas streams after the processing stage by exempting many activities and pieces of equipment in the transmission, storage, and distribution sectors of the industry.

Further, the 2012 standards do not cover emissions from the following sources in the sector: all oil wells; all off-shore sources; all coal-bed methane production facilities; all field engines, drilling rig engines, and turbines; well-head and transmission and storage segment compressors; well-head activities such as liquids unloading; all heater-treaters; all pneumatic devices other than controllers; storage vessels such as skid-mounted, mobile, well cellars, sumps, and produced water ponds; and LDAR for non-processing plant facilities. Additionally, the 2012 standards do not cover VOCs or SO_2 emissions from existing sources, unless they are classified as HAPs. Finally, the 2012 standards assume non-gas-driven controllers cannot replace gas-driven controllers as "best system of emission reduction" (BSER) for regulatory purposes; low-bleed controllers cannot replace high-bleed controllers as BSER; centrifugal compressors cannot replace reciprocating compressors as BSER; and vapor recovery units cannot replace combustion devices as BSER. Many of these sources may still emit significant quantities of pollutants; however, EPA has determined that standards on these sources are either technically or economically unfeasible.[61]

Major Source Aggregation

The 2012 federal air standards exempt well completions, pneumatic controllers, compressors, and storage vessels from "major source" determination with respect to CAA Title V permit requirements. Viewed at the component level, these smaller "emissions units" at natural gas facilities may not generate enough pollution on their own to be classified as "major sources." However, it may be possible that an entire natural gas operation (e.g., a well site, a field, or a

[60] See comments submitted by Howard J. Feldman, API, *op cit.*

[61] See comments submitted by Sierra Club, *op cit.*

Apps' Ex. 24

0484

station) is a "major source" (i.e., one that emits typically 10 tons to 250 tons per year, depending upon the pollutant and the area's attainment status). Determining which equipment and activities should be grouped together, or "aggregated," in the crude oil and natural gas sector for permitting purposes remains an open issue for the states, the courts, EPA, and the regulated entities. In light of these considerations, Congress may further assess EPA's requirements for major source categories in upstream oil and gas activities.

The past few decades have seen several developments in the evaluation of crude oil and natural gas facilities at multiple locations for possible aggregation into a single source for permitting purposes. The ability of EPA and the state permitting authorities to aggregate multiple operations into a single major source permit is founded upon the definition of "stationary source" within the CAA. The CAA defines a "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant."[62] *Alabama Power Co. v. Costle*[63] established boundaries on the scope of a source such that "(1) it must carry out reasonably the purposes of New Source Review/Prevention of Significant Deterioration (NSR/PSD); (2) it must approximate a common sense notion of 'plant'; and (3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of 'building,' 'structure,' 'facility,' or 'installation.'"[64] In response, in the 1980 revisions to the PSD regulations, EPA clarified that emissions from operations may be aggregated and considered a single major source for PSD permitting if they meet each of the following three criteria: (1) the sources are located on one or more "contiguous or adjacent" properties, (2) the sources are under common control of the same person (or persons under common control), and (3) the sources belong to a single major industrial grouping (same two digit major Standard Industrial Classification (SIC) code). Only if all three criteria are met will the CAA permitting authority aggregate the operations into a single NSR/PSD permit. After the 1990 CAA Amendments created the Title V Operating Permit Program, this three-factor analysis was extended to Title V major source permitting.

The source definition established by EPA was intended to aggregate only "major projects that would cause air quality deterioration" but "avoid review of projects that would not increase deterioration significantly."[65] EPA has recently addressed the issue of CAA source determinations in the oil and gas industry in a 2009 guidance document from the EPA Office of Air and Radiation (the "McCarthy Memo").[66] The McCarthy Memo withdrew earlier guidance from EPA which concluded that the three prong aggregation analysis for oil and gas activities should begin by looking at and focusing most heavily on the proximity of the surface locations. This emphasis on proximity may have been a result of previous actions by EPA that interpreted "contiguous and adjacent" as meaning "functionally interdependent" (e.g., sources connected by pipelines, conveyors, roads, and other means by which materials and products or intermediate products are transferred between them). The McCarthy Memo attempted to negotiate a path between the broad mandate of "functional interdependence" and the more narrow use of "proximity." It recognized that source determinations in the oil and gas industry continue to be complex, and re-emphasized that the regulations list all three criteria to be used in the analysis. It then acknowledged that there would be cases in which proximity is the "overwhelming factor," but the agency is not going to

[62] 42 U.S.C. §7411 (a)(3).

[63] *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979).

[64] 45 *Federal Register* 52676, August 7, 1980.

[65] 45 *Federal Register* 52676, August 7, 1980.

[66] See "Withdrawal of Source Determinations for Oil and Gas Industries," memorandum from Gina McCarthy to Regional Administrators, September 22, 2009, withdrawing the 2007 EPA memo "Source Determinations for Oil and Gas Industries," memorandum from William L. Wehrum to Regional Administrators, January, 12, 2007.

Apps' Ex. 24

0485

pre-judge that by using a simplified approach, and that "reasoned decision-making" of each of the relevant factors needs to occur on a case-by-case basis.

EPA's three prong aggregation analysis for oil and gas activities was recently challenged in the case of *Summit Petroleum Corp. v. EPA* before the U.S. Court of Appeals for the 6th Circuit.[67] In an August 7, 2012, decision, the 6th Circuit rejected 2-1 the agency's "functional interrelationship" analysis used to support its definition of "adjacency," vacating EPA's determination that a Michigan natural gas plant and its production wells constitute a single major source. Further, on October 29, the court issued an order denying EPA's motion to rehear the case. The denial cements the appellate court's ruling, remanding the issue back to EPA, and ordering the agency to conduct a new analysis of the Michigan facilities using physical proximity as the sole basis for determining adjacency. In response, EPA has stated that relying on physical proximity alone may lead both to "absurd results" and increased regulatory burdens under the NSR and PSD programs.[68] The agency announced that it plans to implement the 6th Circuit's ruling solely in the 6th Circuit states of Michigan, Ohio, Tennessee, and Kentucky.[69]

Contrary to this, source determinations for NESHAPs in the sector are clearly outlined in the CAA. In Section 112(n)(4), Congress specifically exempted upstream oil and gas operations from aggregation in several ways. First, with respect to the "major source" category, Section 112(n)(4) of the CAA provides that, notwithstanding the general definition of "major source,"

> emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources, and in the case of any oil or gas exploration or production well (with its associated equipment), such emissions shall not be aggregated for any purpose under this section.

Second, with respect to the "area source" category, Section 112(n)(4) provides that

> the Administrator shall not list oil and gas production wells (with its associated equipment) as an area source category under subsection (c), except that the Administrator may establish an area source category for oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million, if the Administrator determines that emissions of hazardous air pollutants from such wells present more than a negligible risk of adverse effects to public health.

At the time, the 101st Congress (1990) found that

> oil and gas wells, and associated equipment and gas processing, have generally very low emissions of air toxics. Furthermore, these operations are typically located in remote areas, with wells and equipment widely dispersed geographically, rather than concentrated in a

[67] *Summit Petroleum Corp. v. EPA*, 6th Cir., Nos. 09-4348, 10-4572, 8/7/12.

[68] For example, the agency argues that the Summit ruling could actually lead to increased regulatory burdens under the NSR and PSD programs because permitting obligations are triggered by modifications at a source that result in net emission increases. Under the program, facilities can reduce emissions from another unit at that source to balance out emissions increases and avoid the trigger. EPA also says that relying on physical proximity alone will lead to "absurd results," saying that regulators as a result of the vacatur would have to consider a group of oil wells that are located near a series of gas wells and owned by the same operator to be one source although they emit different streams of pollutants.

[69] See "Applicability of the Summit Decision to EPA Title V and NSR Source Determinations," memorandum from Stephen Page, Director of the Office of Air Quality Planning and Standards, to Regional Administrators, December 21, 2012, http://cleanenergyreport.com/iwpfile.html?file=jan2013%2Fepa2013_0040.pdf.

> single area. For these reasons, it is very unlikely that oil and gas sources would present a significant risk to human health and it is not expected that this source category would need to be a listed category designated for regulation.[70]

In response, EPA wrote in the 1999 preamble that the definition of facility should "lead to an aggregation of emissions in major source determinations that is reasonable, consistent with the intent of the Act, and easily implementable." Consequently, EPA determined it was not appropriate to aggregate crude oil and natural gas facilities at that time.[71]

Measurement of Emissions

The 2012 federal air standards are based on EPA's emission estimates for the crude oil and natural gas sector. While emissions from certain activities and equipment lend themselves to credible estimates, others—specifically fugitive emissions from production activities such as hydraulically fractured well completions, flowback, and produced water ponds—are more difficult to evaluate, have fewer data available, and remain under considerable debate. Currently, the primary source of information on emissions from the sector is a methane study published in 1996 by EPA and the Gas Research Institute (GRI). EPA annually calculates industry emissions using the methodology derived from this report, and while many of the factors have been representative over the period of 1992 to the present, several have been recalculated due to new information. EPA's inventory has been criticized by industry groups and other sources, many of which have put forth competing, and sometimes conflicting, estimates over the past few years. At this time, a comprehensive national inventory that directly measures the quantity and composition of fugitive emissions from natural gas systems does not exist. Until there is an adequate and reliable assessment of industry-wide emissions, the benefits, costs, and basis for regulation may remain uncertain. In light of these considerations, Congress may examine ways in which to best facilitate more comprehensive and technically accurate emissions estimates.

By definition, "fugitive" emissions are those which are elusive and transitory. Thus, the single greatest difficulty in estimating emissions from natural gas systems is acquiring comprehensive and consistent measurement data. Currently, the most comprehensive study of emissions in the industry is more than a decade old, uses emissions factors and activity levels to calculate data, and focuses primarily on methane. EPA has initiated a more detailed inventory of the oil and gas sector's GHG emissions (i.e., methane and CO_2) under the agency's GHG Reporting Rule, and the first data for major sources were released in February 2013.[72] National emissions inventories for criteria and hazardous air pollutants, however, are distinct from GHG inventories and are complicated by the fact that concentrations of these chemicals vary geographically across resource reservoirs. A few states have begun the process of acquiring emissions inventories from

[70] Representative Jack Fields (R-TX-08), Conference Report on S. 1630, Clean Air Act Amendments of 1990 (House of Representatives - October 26, 1990), *Congressional Record*, vol. 136, p. H12868.

[71] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and National Emission Standards for Hazardous Air Pollutants: Natural Gas Transmission and Storage," 64 *Federal Register* 32610, June 17, 1999.

[72] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/petroleum.html.

Apps' Ex. 24

0487

upstream production activities (e.g., Texas,[73] Pennsylvania,[74] California,[75] and Colorado,[76] as well as a national survey to be conducted by the University of Texas at Austin),[77] but few have presented or harmonized this information. There are also many examples of local emissions inventories, commissioned by a range of stakeholders—from regional and municipal agencies to community groups and academic institutions. None are fully consistent with shared measurement practices and each use different techniques for their data collection. It is for these reasons that the first recommendation in the report released by the U.S. Secretary of Energy Advisory Board Shale Gas Production Subcommittee is to "immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other emissions data."[78]

Currently, the primary source of information on emissions in the natural gas industry is a methane study published in 1996 by EPA and the Gas Research Institute (GRI).[79] At the time, the EPA/GRI study was conducted to assess the GHG emissions from various U.S. industrial sectors to assist in data analysis for the Intergovernmental Panel on Climate Change and emissions reporting for U.S. commitments to the United Nations Framework Convention on Climate Change.[80] The study focuses on 1992 (as a base year) and uses three primary methodologies to generate emissions factors from over 100 different sources within the industry. The methods include (1) "component measurement," wherein emissions are measured directly from a large number of randomly selected pieces of equipment to determine an average emission factor for each type; (2) "tracer gas," wherein facility-wide emissions are calculated by releasing a tracer gas at a known and constant rate near the facility and measuring the downwind concentrations of the tracer and methane; and (3) "leak statistics," wherein emissions are measured for a large number of pipeline leaks to determine an average emissions rate per leak as a function of pipe material, age, operating pressure, and environmental characteristics. Total industry emissions are then estimated by multiplying these emissions factors by the activity levels for each system component (i.e., the

[73] See Texas Commission on Environmental Quality, *Barnett Shale Special Inventory*, http://www.tceq.texas.gov/assets/public/implementation/air/ie/pseiforms/summarydatainfo.pdf.

[74] See Pennsylvania Department of Environmental Protection announced protocol, http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Long-Term_Marcellus_Ambient_Air_Monitoring_Project-Protocol_for_Web_2012-07-23.pdf.

[75] See California Environmental Protection Agency, Air Resources Board, *2007 Oil and Gas Industry Survey Results, Final Report*, December 2011, and other relevant documents on the ARB website, http://www.arb.ca.gov/cc/oil-gas/oil-gas.htm.

[76] See Colorado Department of Natural Resources press release, "State to undertake major study on oil and gas emissions," January 9, 2013, http://dnr.state.co.us/Media/Pages/PressReleases.aspx.

[77] The University of Texas at Austin, along with two environmental engineering firms, URS and Aerodyne Research, announced on October 10, 2012, the launch of a comprehensive study of methane emissions around gas wells. Researchers are to focus on gas production sites in the Marcellus, Eagle Ford, Haynesville, Barnett, Fayetteville, and Niobrara shale formations. Nine oil and gas companies have agreed to allow sampling teams onto their sites: Anadarko Petroleum Corp., BG Group PLC, Chevron Corp., Encana Oil & Gas (USA) Inc., Pioneer Natural Resources Co., Shell Oil Co., Southwestern Energy, Talisman Energy and XTO Energy, a subsidiary of Exxon Mobil Corp. The announced study is part of a broader five-part investigation to measure methane leakage across the natural gas supply chain, http://www.utexas.edu/news/2012/10/10/university-of-texas-at-austin-study-measures-methane-emissions-released-from-natural-gas-production/.

[78] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Shale Gas Production Subcommittee 90-Day Report*, p.16.

[79] Gas Research Institute and U.S. Environmental Protection Agency, *Methane Emissions from the Natural Gas Industry, Volumes 1-15*, GRI-94/0257 and EPA 600/R-96-080, June 1996.

[80] UNFCCC, Treaty Number: 102-38, October 7, 1992, the resolution of advice and consent to ratification agreed to in the Senate by Division Vote. For more discussion of U.S. commitments, see CRS Report R40001, *A U.S.-Centric Chronology of the International Climate Change Negotiations*, by Jane A. Leggett.

Apps' Ex. 24

0488

number of wellheads, compressors, processing plants, miles of pipeline in operation, and other components) across the entire industry. The EPA/GRI study estimates that the industry emitted 314 ± 105 billion standard cubic feet (bscf) of methane in 1992 (i.e., 127 ± 42 million metric tons of carbon dioxide equivalent [$MMtCO_2e$], or 1.42% ± 0.47% of the industry's gross national production that year).[81] Roughly 60% of the industry's methane emissions are estimated to be from fugitive sources, about 30% from venting, and about 8% from combustion. Results of the EPA/GRI study, by source categories, are reported in **Table 1**.

EPA annually calculates emissions estimates for the industry using the methodology from the 1996 EPA/GRI study. Since its publication, activity data for some of the components in the system have been updated based on publicly available information. For other sources where annual activity data are not available or have not been reported by industry, EPA has developed a set of industry activity factor drivers to assist in modeling. While many of the emissions factors modeled by the EPA/GRI study were considered representative over the period of 1992 to the present, several factors have been re-calculated since publication. Most notably, emissions factors for gas well cleanups, condensate storage tanks, and centrifugal compressors have been revised due to new information. Emissions factors for gas well completions in unconventional resources with hydraulic fracturing—which were not industry practice at the time of the EPA/GRI study—have also been added to the inventory. With these revisions, EPA estimates that the industry emitted 247.7 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) greenhouse gases in 2010, of which 215.4 $MMtCO_2e$ was methane (i.e., 532 bscf of methane, or 2.4% of the industry's gross national production that year).[82]

Table 1. Methane Emissions in the U.S. Natural Gas Industry

For the base year 1992

Source		Annual Methane Emissions (Bscf)	% of Total
Fugitive Emissions	**Subtotal**	**195.3**	**62.1**
Equipment Leaks			
Production Facilities		17.4	5.5
Gas Plants		24.4	7.8
Compressor Stations (transmission and storage)		67.5	21.5
Metering and Pressure Regulating Stations		31.8	10.1
Customer Meter Sets		5.8	1.8
Underground Pipeline Leaks (all segments)		48.4	15.4
Vented Emissions	**Subtotal**	**94.2**	**30.0**
Pneumatic Devices		45.7	14.6

[81] 314 bscf of methane is equivalent to approximately 127 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) greenhouse gases, using the conversion 1000 bscf CH_4 = 0.4045 $MMtCO_2e$ at 60 degrees Fahrenheit (15.6 degrees Celsius) and either 14.696 psi (1 atm or 101.325 kPa) or 14.73 psi (30 inHg or 101.6 kPa) of pressure.

[82] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2010*, Washington, DC, EPA 430-R-12-001, April 15, 2012, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf. Conversion factor of 1000 bscf CH_4 = 0.4045 $MMtCO_2e$ at 60 degrees Fahrenheit (15.6 degrees Celsius) and either 14.696 psi (1 atm or 101.325 kPa) or 14.73 psi (30 inHg or 101.6 kPa) of pressure. The U.S. Energy Information Administration reports 2010 U.S. natural gas marketed production as 22,402 bscf, see http://www.eia.gov/dnav/ng/hist/n9050us2a.htm.

Source		Annual Methane Emissions (Bscf)	% of Total
Blow and Purge		30.2	9.6
Dehydrator Glycol Pumps		11.1	3.5
Dehydrator Vents		4.8	1.5
Chemical Injection Pumps		1.5	0.5
Other		0.9	0.3
Combusted Emissions	**Subtotal**	**24.9**	**7.9**
Compressor Exhaust		24.9	7.9
	Total	**314.0**	**100.0**

Source: David A. Kirchgessner et al., *Estimate of Methane Emissions from the U.S. Natural Gas Industry*, U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, Research Triangle Park, NC, 1996, p. 12.

Notes: Emissions from meter and pressure regulating stations result from both pneumatic and fugitive emissions. Since these components cannot be separated using the tracer measurement method, emissions are shown as fugitive by default.

The emissions estimates EPA uses for hydraulically fractured well completions and re-completions come from data provided by industry sources at several EPA Natural Gas STAR technology transfer workshops between 2004 and 2007.[83] Using the reported data in its 2010 Background Technical Support Document, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry*,[84] EPA creates separate categories for conventional and unconventional well completions, and increases its estimate of methane emissions from both categories from 0.02 metric tons per well completion to 0.71 metric tons per conventional well and 177 metric tons per unconventional well (or 37 thousand cubic feet [Mcf]/completion and 9,175 Mcf/completion respectively). EPA assumes a 3-10 day flowback period with an uncontrolled release of methane. Further, EPA assumes that 51% of the fugitive emissions from hydraulically fractured well completions are flared—and the rest vented—based upon state and local regulations for control devices that are currently in place.

EPA's methodology for estimating methane emissions from hydraulically fractured well completions has been criticized by a number of sources. A detailed critique of EPA's numbers can be found in IHS CERA's 2011 report, *Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development*.[85] CERA's main concerns involve the small

[83] The figures were drawn from four studies over two workshops that included data from over 1,000 wells completed between 2002 and 2006. U.S. Environmental Protection Agency, "Green Completions," Natural Gas STAR Producers' Technology Transfer Workshop, September 21, 2004, and U.S. EPA, "Reducing Methane Emissions During Completion Operations," Natural Gas STAR Producers' Technology Transfer Workshop, September 11, 2007. The presentations included a Devon case study from the Fort Worth Basin (30 wells, 11,900 Mcf/completion), a Williams case study from the Piceance Basin (1,064 wells, 24,449 Mcf/completion), a Weatherford coal bed methane case study (3 wells, 667 Mcf/completion), and a nationwide industry data set (106 wells, 5,820 Mcf/completion). For more on the EPA Natural Gas STAR program, see http://www.epa.gov/gasstar/.

[84] U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry: Background Technical Support Document*, Climate Change Division, Washington, DC, 2010, http://www.epa.gov/ghgreporting/documents/pdf/2010/Subpart-W_TSD.pdf.

[85] IHS CERA estimates methane emissions from the oil and gas "production" sector to be 43 $MMtCO_2e$ as opposed to EPA's estimate of 130 $MMtCO_2e$ from "field production." See Mary Barcella, Samantha Gross, and Surya Rajan, *Mismeasuring Methane: Estimating Greenhouse Gas Emissions from Upstream Natural Gas Development*, IHS CERA,

Apps' Ex. 24

0490

sample size for emissions data and the unsupported assumptions on venting practices. Further, several industry sources have reported competing emissions estimates, including the American Petroleum Institute and the America's Natural Gas Alliance (which list total industry emissions at half of EPA's estimate due to a re-calculation of emissions factors and activity levels for liquids unloading[86] and re-fractured well completions),[87] URS (which estimates emissions of 765 Mcf of gas on a per well basis compared to EPA's 9,175 Mcf),[88] and Devon Energy Company (which reports data from eight of its operators demonstrating that flowback periods last on average only 3.5 days compared to EPA's estimated 3-10 days).[89] As with any self-selected and self-reported survey, it is difficult to determine how representative these samples are of overall industry practice.

Other published studies use different methodologies for the calculation of leakage (e.g., satellite observations, ambient measurements, and dispersion modeling). A National Oceanographic and Atmospheric Administration (NOAA) study analyzes daily air samples collected at the Boulder Atmospheric Observatory in Weld County in northeastern Colorado and concludes that fugitive natural gas emissions from drilling operations range from 2.3% to 7.7% of industry's gross annual production.[90] The study uses an extensive data set of ambient concentrations of methane and related hydrocarbons in the vicinity of oil and gas operations in the region, along with the known emissions profiles for these gases from oil and gas operations, to infer the emissions from the industry. In December 2012, the research team reported updated Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage at 9% of the total production.[91]

On February 5, 2013, the industry-reported dataset for GHG emissions collected under EPA's Greenhouse Gas Reporting Program (GHGRP) was released for the first time for crude oil and natural gas systems.[92] The data show 2011 GHG emissions from over 1,800 facilities in the crude

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Private Report, Cambridge, MA, 2011, http://press.ihs.com/press-release/recent-estimates-greenhouse-gas-emissions-shale-gas-production-are-likely-significantl.

[86] "Liquids unloading" is a maintenance activity in depleted conventional reservoirs where water produced with the gas has accumulated to the point where it stops gas flow. In order to reestablish gas flow, the well is blown to the atmosphere, causing the vented release of emissions. The 2011 GHG Inventory has this category listed for contributing approximately 34% of all methane emissions from the natural gas industry for that year.

[87] Terri Shires and Miriam Lev-On, *Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses*, Final Report, June 1, 2012, http://www.api.org/news-and-media/news/newsitems/2012/oct-2012/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf. The authors present data reported by over 20 of their industry partners from over 91,000 wells (or 20% of known wells in operation) demonstrating that a re-calculation of two of EPA's source categories—liquids unloading and unconventional gas re-fracture rates—returned a 50% reduction in industry emissions compared to EPA's estimate. The study did not report any new estimates for the quantity of emissions from hydraulically fractured well completions or re-completions, only estimates on the rates of re-fracture.

[88] URS, "Gas Well Completion Data," Attachment 3 of the American Exploration and Production Council and America's Natural Gas Alliance, *Comments – Proposed Rule – Oil and Natural Gas Sector Consolidated Rulemaking, NSPS and NESHAP Reviews*, November 30, 2011, http://epa.gov/quality/informationguidelines/documents/12003-attB.pdf.

[89] Darren Smith, Devon Energy Corporation, Testimony before the Senate Environment and Public Works Subcommittee on Clean Air and Nuclear Safety, Washington, DC, June 19, 2012, http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=5a14d73e-36d6-4f5b-8985-98a506e3cbab.

[90] Gabrielle Pétron et al., "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study," *Journal of Geophysical Research*, vol. 117 (2012).

[91] As reported by Jeff Tollefson, "Methane leaks erode green credentials of natural gas," *Nature*, 493:12, January 2, 2013, http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123#auth-1.

[92] See EPA's GHGRP 2011 data on the agency's website, http://www.epa.gov/ghgreporting/ghgdata/reported/

Apps' Ex. 24

0491

oil and natural gas sector, including production, processing, transmission, and distribution. In total, these facilities accounted for GHG emissions of 225 $MMtCO_2e$. Of note in the reporting: (1) The crude oil and natural gas sector is the second-largest stationary source of U.S. GHG emissions, behind power plants; (2) CO_2 emissions from the crude oil and natural gas sector account for 142 $MMtCO_2e$, and methane emissions account for 83 $MMtCO_2e$; (3) Onshore crude oil and natural gas production is the largest contributor, covering approximately 41% of reported emissions; (4) Emissions from onshore production facilities are primarily methane (such as leaks from equipment and vented emissions) while emissions from natural gas transmission and processing facilities are primarily CO_2 (such as combustion emissions associated with compressors); and (5) While the total emissions of CO_2e reported by industry is consistent with the total emissions previously reported by EPA's national inventory, the ratio of CO_2 to methane emissions is notably different, with more CO_2 (and less methane) reported by the industry than estimated by EPA. The agency has instituted a multi-step data verification process for the GHGRP and intends to review the data on an ongoing basis, anticipating that the overall data quality will increase over time as facilities become familiar with the calculation methods and begin using more direct measurement.

Using the data reported by industry under comments to the 2012 air standards as well as under the GHG Reporting Program, EPA again revised its calculations for the sector in its *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, released April 15, 2013.[93] For the 2011 inventory, EPA revisits its calculations for liquid unloading—the process of flushing excess water from a drilling well which the agency had estimated contributed as much as 51% of the total CH_4 emissions from the sector (an estimate that was disputed by many industry operators) and makes other changes, including its count of the number of active wells and its methodology for estimating emissions from hydraulic fracturing and refracturing well completions. With these revisions, EPA estimates that the industry emitted 177.0 $MMtCO_2e$ greenhouse gases in 2011, of which 144.7 $MMtCO_2e$ was methane (i.e., 358 bscf of methane, or 1.5% of the industry's gross national production that year).

As debate continues over the level of methane emissions from natural gas production activities, a full assessment of VOCs, HAPs, hydrogen sulfide, and other aromatic hydrocarbons becomes even more complicated, since the concentrations of these chemicals can vary greatly from reservoir to reservoir. Thus, an accurate assessment of the levels of VOCs, SO_2, and HAPs emissions from various production activities would require not only an accurate measurement of natural gas emissions but a full accounting of the component compositions of the gas across the geographic variability of the resource.

Impacts of Emissions

The 2012 federal air standards are based on EPA's expectations that the avoided emissions under the rules would result in improvements in air quality and reductions in health effects associated with exposure to HAPs, ozone, and methane. However, the relationship between air pollution from natural gas systems and its impacts on human health and the environment has never been fully quantified and assessed. EPA acknowledges this shortcoming in the rule's proposal, stating that a full quantification of health benefits for the 2012 standards could not be accomplished due

petroleum.html.

[93] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf.

to the "unavailability of data and the lack of published epidemiological studies correlating crude oil and natural gas production to respective health outcomes."[94] Various stakeholders assert that the lack of published and peer-reviewed literature makes it challenging to scientifically assess the impacts of natural gas operations. Some contend that this uncertainty argues against additional pollution controls at this time. Others maintain that the relevant question for determining whether pollution controls are necessary is whether natural gas systems impact an area's ability to attain air quality standards (NAAQS). In light of these considerations, Congress may wish to evaluate whether existing requirements are adequate to address concerns over the human health and environmental impacts of oil and gas activities, or, if different requirements are necessary.

Quantifying the extent to which crude oil and natural gas systems contribute to air pollution is a complicated task, due in part to the difficulties in modeling the direct and indirect impacts of emissions reductions from a single industrial sector on the greater environment. Although there are many different methodologies that can be used to assess emissions from the industry, each is burdened with unique disadvantages.[95] Thus, while science has demonstrated that emissions of VOCs and NO_x contribute to the generation of ground-level ozone (i.e., smog), emissions of various organic air toxics can pose a threat to human health, and emissions of methane produce ground-level ozone and force climate change, comprehensive epidemiological studies correlating the emissions from natural gas systems to specific long-range and cumulative health outcomes are virtually nonexistent. It should be noted that such studies are generally difficult, rare, and expensive to conduct, requiring data that are typically absent or inadequate for assessment (e.g., precise and accurate estimates of emissions, fate and transport, and exposure levels, as well as impacts data on relatively large populations of exposed individuals over long durations of time). More common, instead, are localized studies or anecdotal reports—by stakeholders who live and work near oil and gas operations—of general air quality issues such as haze, odor, or ill health. These studies are countered by industry and/or agency reports that present information on recommended practices, regulatory compliance, and a history of monitored and reported environmental stewardship.

Various stakeholders assert that the lack of published and peer-reviewed literature makes it challenging to scientifically assess the impacts of oil and gas drilling operations. The Centers for Disease Control and Prevention warns that the science on the impacts of natural gas drilling on health and the environment is "not yet clear," stating that there is "not enough information to say with certainty whether shale gas drilling poses a threat to public health," and that "more research is needed for us to understand public health impacts from natural gas drilling and new gas drilling

[94] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry*, Research Triangle Park, NC, July 2011, p. 4-1.

[95] Scientists typically use two different methods when trying to understand how a given air pollution source affects local air quality. One approach is to conduct ambient air monitoring, which directly measures air pollution levels that people breathe. However, in using this method, the presence of a pollutant likely reflects contributions from many different sources, such as motor vehicles, gasoline stations, and industrial plants. Another approach is to use dispersion modeling, which estimates air pollution levels using models that predict how pollutants move through the air from the point where they are released. However, in using this method, measurements of the initial outputs must be completed and verified in order to make accurate dispersion assessments. Satellite modeling and direct component measurements are other ways of quantifying emissions. These top-down and bottom-up approaches to assessments also have their specific drawbacks, including source attribution and data availability.

technologies."[96] Similarly, a recent report by GAO[97] examines the available studies of air quality at shale gas development sites and finds that they are "generally anecdotal, short-term, and focused on a particular site or geographic location." Thus, they "do not provide the information needed to determine the overall cumulative effect that shale oil and gas activities have on air quality." GAO concludes that "the cumulative effect shale oil and gas activities have on air quality will be largely determined by the amount of development and the rate at which it occurs, and the ability to measure this will depend on the availability of accurate information on emission levels. However ... data on the severity or amount of pollutants released by oil and gas development, including the amount of fugitive emissions, are limited." It is for these reasons that the final recommendation in the report released by the U.S. Secretary of Energy Advisory Board Shale Gas Production Subcommittee is to advise federal, regional, state, and local jurisdictions "to place greater effort on examining [the] cumulative impacts" from "drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities [which] can overwhelm ecosystems and communities."[98]

Some federal, state, and local agencies have embarked upon or are considering further investigation into the human health and environmental impacts of oil and gas production. These include the U.S. Department of Health and Human Services, and the states of Colorado[99] and Maryland,[100] among others. Examples of published studies on the human health and environmental impacts of oil and gas production are as follows:

Ozone

Many studies report that at each stage of natural gas production, VOCs—including BTEX and other hydrocarbons—and methane can escape and mix with nitrogen oxides from the exhaust of diesel-fueled equipment, and, in the presence of sunlight, produce ground-level ozone (i.e., smog). Several areas of the country with heavy concentrations of drilling suffer from serious ozone problems.

For example, new oil and gas development has begun across sections of the Rocky Mountains that may be connected to the rise in ozone pollution. A 2005 Western Governors' Association report finds that crude oil and natural gas production operations released more than 430,000 tons of VOCs in Colorado, New Mexico, Utah, Wyoming, and Montana in 2002. The report projects that operations in these states would more than double their VOCs emissions in 15 years,

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[96] Comments by Dr. Christopher Portier, head of CDC's National Center for Environmental Health and Agency for Toxic Substances and Disease Registry (ATSDR), as covered on January 5, 2012, by Kevin Begos of the Associated Press quoting excerpts of an email. Publication of the full text of the email, as released by the CDC press office, can be found at http://www.slopefarms.com/2012/01/08/shale-gas-drilling-and-public-health-first-publication-of-full-text-email-on-public-health-risks-of-from-cdcs-national-center-for-environmental-health-and-agency-for-toxic-substances-and-dis/.

[97] U.S. Government Accountability Office, *Oil and Gas: Information on Shale Resources, Development, and Environmental and Public Health Risks*, GAO-12-732, September 2012, pp. 33-37, http://www.gao.gov/assets/650/647791.pdf.

[98] Secretary of Energy Advisory Board Shale Gas Production Subcommittee, *Shale Gas Production Subcommittee 90-Day Report*, p.25. For example, as a part of New York state's ongoing review of hydraulic fracturing, the New York State Department of Environmental Conservation (NY DEC) has asked New York State Department of Health (NY DOH) to undertake a review of the NY DEC health impact analysis, see http://www.dec.ny.gov/press/85071.html.

[99] See Colorado Department of Public Health and the Environment news release, "State to undertake major study on oil and gas emissions," January 9, 2012, http://www.colorado.gov/cs/Satellite/CDPHE-Main/CBON/1251590280071.

[100] See Maryland, Department of the Environment, Marcellus Shale Safe Drilling Initiative Study: Part I (December 2011), http://www.mde.state.md.us/programs/Land/mining/marcellus/Pages/index.aspx.

Apps' Ex. 24

0494

releasing more than 965,000 tons annually by 2018.[101] This release would equal the average amount of VOCs emitted annually from approximately 50,000 gas stations or by more than 25 million passenger cars, each driven 12,500 miles.[102] A 2008 analysis by the Colorado Department of Public Health and Environment concludes that smog forming emissions from Colorado's crude oil and natural gas operations exceed vehicle emissions for the entire state.[103] In 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[104] An extended assessment by the Wyoming Department of Environmental Quality finds the state's ozone pollution problems are "primarily due to local emissions from oil and gas ... development activities: drilling, production, storage, transport, and treating."[105] Recently, northeastern Utah recorded unprecedented ozone levels in the Uintah Basin, with more than 68 exceedances of the federal health standard during the first three months of 2010, and over 24 exceedances during the winter of 2011.[106] The Bureau of Land Management identifies oil and gas activities in the region as the primary cause of the ozone pollution.[107] Further, a 2009 study concludes that numerous "Class I areas" in the Rocky Mountain region—a designation reserved for national parks, wilderness areas, and other such lands—are likely to be impacted by increased ozone pollution as a result of oil and gas development, including Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico. These areas are all near concentrated oil and gas development in the San Juan Basin.[108] However, the evidence linking oil and gas development directly to high ozone levels in the region remains inconclusive. Researchers caution that many factors can contribute to the Rocky Mountains' ozone problems. For example, uniform snow cover reflects and concentrates sunlight, boosting ozone levels, as do temperature inversions that trap pollutants in mountain basins.[109] In support of this point, the interim findings of the *2012 Uintah Basin Winter Ozone & Air Quality Study,* released in August 2012, report that there were no

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[101] Russell and Pollack, *Oil and Gas Emission Inventories for the Western States*, Environ International Corporation study prepared for the Western Governors' Association, December 27, 2005, http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf.

[102] See EPA Clearinghouse for Inventories and Emissions Factors, *Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources,* January 1995, http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf.

[103] Colorado Dept. of Public Health & Environment, Air Pollution Control Division, *Oil and Gas Emission Sources Presentation for the Air Quality Control Commission Retreat,* May 15, 2008, at pages 3-4.

[104] See Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8 - Hour Ozone Designation Recommendations"), http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf.

[105] Wyoming Department of Environmental Quality, *Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin*, March 26, 2009 ("Wyoming Nonattainment Analysis"), http://deq.state.wy.us/out/downloads/Ozone%20TSD_Outside%20UGRB%20%282%29.pdf.

[106] Randal Martin, et al., *Final Report: Uinta Basin Winter Ozone and Air Quality Study, December 2010-March 2011,* Energy Dynamics Laboratory, Utah State University, for Uintah Impact Mitigation Special Service District, June 14, 2011, http://rd.usu.edu/files/uploads/ubos_2010-11_final_report.pdf.

[107] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact Statement* ("GASCO DEIS"), p. 3-13, http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html.

[108] Marco Rodriguez, et al., "Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States," *Journal of the Air and Waste Management Association,* 111 (Sept. 2009), http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf.

[109] See comments made by Keith Guille, spokesman for Wyoming DEQ, in Charles W. Schmidt, "Blind Rush?: Shale Gas Boom Proceeds amid Human Health Questions," *Environmental Health Perspectives*, vol. 119, no. 8 (August 2011), p. A352.

Apps' Ex. 24

0495

exceedances of the eight-hour ozone standard for the basin in 2012, even though higher levels of ozone precursors and VOCs were measured in the region (the lack of sunlight-reflecting snowpack in 2012 is suggested as a possible reason).[110]

As another example, the Dallas-Fort Worth area in Texas is home to substantial oil and gas development. Of the nine counties surrounding the Dallas-Fort Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[111] A 2009 study finds summertime emissions of smog-forming pollutants from oil and gas operations in the Dallas-Fort Worth area exceed emissions from all motor vehicles in the area.[112] A 2012 study finds that emissions from natural gas compressor stations and flares contribute to significant amounts of ground-level ozone and formaldehyde in the Dallas-Fort Worth area, estimating that a single natural gas processing facility in the Barnett shale area could add as much as 3 parts per billion (ppb) to the hourly average ambient ozone.[113] Still, the evidence linking oil and gas development directly to high ozone levels in the region remains inconclusive. In 2009 and 2010, the Texas Commission on Environmental Quality (TCEQ) conducted several large, in-depth surveys of air quality in the six counties surrounding Fort Worth. The TCEQ study identifies a 15% drop in the 8-hour ozone design value, despite a 10-fold increase in natural gas production in the region over the past decade. TCEQ attributes at least part of this reduction to the state's NO_x control strategies as well as the prevailing winds.[114]

Air Toxics

Other studies (e.g., epidemiological studies) focus on the human health impacts of hazardous air pollutants (HAPs) known or suspected to be released by crude oil and natural gas operations. A 2011 survey of existing literature on the topic reported that of the known chemicals used and/or found in natural gas operations, approximately 37% of the chemicals are volatile and may become airborne. The study further noted that if exposures exceed certain levels, over 89% of these chemicals can harm the eyes, skin, sensory organs, respiratory tract, gastrointestinal tract, or liver; 81% can cause harm to the brain and nervous system; 71% can harm the cardiovascular system and blood; and 66% can harm the kidneys. Overall, the hazardous air pollutants produce a profile that displays a higher frequency of health effects than the water soluble chemicals. In addition, because they vaporize, not only can they be inhaled, but they can be ingested or absorbed through the skin, increasing the chance of exposures.[115]

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[110] See *2012 Uintah Basin Winter Ozone & Air Quality Study-Summary of Interim Findings, Ongoing Analyses, and Additional Recommended Research*, August 7, 2012, at http://op.bna.com/env.nsf/id/smiy-8x9rv3/$File/UintahWinter.pdf.

[111] Texas Railroad Commission, http://www.rrc.state.tx.us/data/fielddata/barnettshale.pdf.

[112] Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*, January 26, 2009, http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf. It should be noted that Al Armendariz is the former EPA Region 6 Administrator who resigned on April 30, 2012, after remarks made in 2010 regarding EPA's enforcement policy.

[113] Eduardo P. Olaguer, "The Potential Near-source Ozone Impacts of Upstream Oil and Gas Industry Emissions," *Journal of the Air & Waste Management Association*, vol. 62, no. 8 (2012), http://www.tandfonline.com/doi/abs/10.1080/10962247.2012.688923.

[114] Texas Commission on Environmental Quality, "A Commitment to Air Quality in the Barnett Shale," *Natural Outlook Newsletter*, Fall 2010, http://www.tceq.state.tx.us/publications/pd/020/10-04/a-commitment-to-air-quality-in-the-barnett-shale.

[115] Theo Colborn, Carol Kwiatkowski, Kim Schultz, Mary Bachran, "Natural Gas Operations from a Public Health Perspective," *Human and Ecological Risk Assessment*, vol. 17, no. 5, 2011, pp. 1039-1056, http://www.endocrinedisruption.com/chemicals.journalarticle.php.

Several studies report that sources of HAPs in the oil and gas industry may be numerous. Data from the State of Colorado suggest that there may be more than 26 individual sources of HAPs in the oil and gas sector, including "venting, dehydration, gas processing, compression, leaks from equipment (fugitive emissions), open-pit waste ponds, and land application of volatile wastes."[116] A study of HAPs emissions from natural gas related sources within the city of Fort Worth, TX, documents the following for HAPs emissions: 0.02 to 2 tons per year (tpy) from well pads (including emissions from equipment leaks, produced water and condensate storage and loading, and lift compressors); 0.9 to 8.8 tpy from well pads with compressors; 10 to 25 tpy from compressor stations (including emissions from combustion at the compressor engines or turbines, equipment leaks, storage tanks, glycol dehydrators, flares, and condensate and/or wastewater loading); 47 tpy on average from processing facilities (including emissions from equipment leaks, storage tanks, separator vents, glycol dehydrators, flares, condensate and wastewater loading, compressors, amine treatment and sulfur recovery units); and 0.4 tpy on average from saltwater treatment facilities.[117]

Although oil and gas development generally has not occurred in densely populated areas, this is not always the case, particularly with respect to recent expansion in unconventional resources. Several local, state, and national health agencies have expressed concerns about the health impacts of HAPs emissions from oil and gas facilities, including the Center for Disease Control and Prevention (CDC),[118] the Agency for Toxic Substances and Disease Registry (ATSDR),[119] the Association of Occupational and Environmental Clinics (AOEC) and the Pediatric Environmental Health Specialty Unit (PEHSU),[120] the Colorado School of Public Health,[121] the Town of Dish, Texas,[122] the City of Fort Worth, Texas,[123] and the City of Houston, Texas.[124] In particular, the ATSDR investigation was spurred by community health complaints such as dizziness, nausea, respiratory problems, and eye and skin irritation to more severe concerns including cancer. The investigation identifies elevated cancer risk at one site and recommends further investigation into HAPs emissions and risks at all the sites. Similarly, the Colorado School of Public Health identifies air pollution from the crude oil and natural gas activities as contributing to acute and

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[116] Amy Mall et al., *Drilling Down: Protecting Western Communities from the Health and Environmental Effects of Oil and Gas Production*, NRDC, October 2007, (citing CDPHE data), http://www.nrdc.org/land/use/down/down.pdf

[117] Eastern Research Group, *City of Fort Worth Natural Gas Air Quality Study*, 2011, at http://fortworthtexas.gov/gaswells/?id=87074.

[118] Comments by Dr. Christopher Portier, CDC, *op cit.*

[119] ATSDR, *Health Consultation: Public Health Implications of Ambient Air Exposures to Volatile Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas Garfield County, Colorado*, 2008, http://www.cdphe.state.co.us/dc/ehs/GarfieldCounty.pdf.

[120] PEHSU, *Information on Natural Gas Extraction and Hydraulic Fracturing for Health Professionals*, 2011, http://aoec.org/pehsu/documents/hydraulic_fracturing_and_children_2011_health_prof.pdf.

[121] Roxana Witter, et al., *Draft Health Impact Assessment for Battlement Mesa, Garfield County, Colorado*, Colorado School of Public Health, 2011, http://www.garfield-county.com/index.aspx?page=1408; Lisa McKenzie, et al., *Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources*, Colorado School of Public Health, 2012, http://www.energyindepth.org/wp-content/uploads/2012/03/McKenzie-CSPH-Study-02-10-2012.pdf.

[122] Wolf Eagle Environmental, *Town of DISH, Texas Ambient Air Monitoring Analysis Final Report*, 2009, http://townofdish.com/objects/DISH_-_final_report_revised.pdf.

[123] Eastern Research Group, *City of Fort Worth Natural Gas Air Quality Study*, 2011, at http://fortworthtexas.gov/gaswells/?id=87074.

[124] Barbara Zielinska, Eric Fujita, Dave Campbell, *Monitoring of Emissions from Barnett Shale Natural Gas Production Facilities for Population Exposure Assessment. Houston TX*, Desert Research Institute, 2011, http://www.sph.uth.tmc.edu/mleland/attachments/Barnett%20Shale%20Study%20Final%20Report.pdf.

Apps' Ex. 24

0497

chronic health problems for those living near natural gas drilling sites, stating that "exposures to air pollutants during well completion activities present the greatest potential for health effects."[125] The CSPH analysis, based on three years of monitoring, finds a number of air toxics near the wells including benzene, toluene, ethylbenzene, and xylene.

However, critics have taken issue with the Colorado School of Public Health and other studies for a number of reasons including the use of (1) out of date data, (2) unrealistic estimates of emissions from sources, (3) overly conservative risk assessments when viewed in context, and (4) poor study design and input assumptions (e.g., the use of ambient collection methodology in a region populated with other emission sources such as roads, highways, and other industries).[126] In support of this point, other studies have reported little or no health effects from the sector. For example, in 2012, the Houston-based Plains Exploration and Production Company (PXP) released a report that said hydraulic fracturing operations at the Inglewood oil field in the Baldwin Hills area in Los Angeles County posed "no public health or environmental threats."[127] Similarly, in a review of health studies conducted by the Energy Institute at the University of Texas at Austin and published in February 2012, the authors conclude that "none of the studies reviewed ... showed a clear link between shale gas activities and documented adverse health effects, [and] that the gas industry has been using hydraulic fracturing for over 50 years, but the studies examined ... did not find any direct evidence for health impacts on workers in the industry or the public living near oil and gas industry activity."[128] Further, many industry sources have argued that the standards promulgated under the 1999 Crude Oil and Natural Gas Production NESHAPs have demonstrated protection of public health with an ample margin of safety.[129] Critics of EPA's regulatory requirements for air toxics have also expressed concern with the agency's decision to make significant and substantive changes to the agency's residual risk procedures, changes which they assert result in risk estimates between 100 and 1,000 times higher than actual. The contested procedures include (1) the consideration of risk from the total facility, (2) the consideration of risk across selected social, demographic, and economic groups within the population living near the facility, (3) the consideration of the hypothetical risk associated with the level of emissions allowed by the MACT standard, and (4) unreasonable assumptions concerning exposure points, times, and durations.

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[125] McKenzie, et al., *op cit.*

[126] Comments critical of the CSPH reports can be found at the Energy In Depth blog, http://www.energyindepth.org/non-elite-eight-worst-inputs-used-in-new-colorado-health-study/.

[127] Cardno Entrix, *Hydraulic Fracturing Study: PXP Inglewood Oil Field*, Prepared for Plains Exploration & Production Company, Los Angeles, CA, October 10, 2012, http://www.inglewoodoilfield.com/res/docs/102012study/Hydraulic%20Fracturing%20Study%20Inglewood%20Field10102012.pdf.

[128] Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas Development*, The Energy Institute, The University of Texas at Austin, Austin, TX, February 2012, p. 30. It should be noted that in July 2012, the objectivity of The Energy Institute study was called into question by the Public Accountability Initiative. Officials at the University of Texas commissioned an outside review of the study and have since expurgated the findings.

[129] For an example of industry responses, see the comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov. API asserts that establishing new and more stringent standards would be "patently unreasonable and cannot be justified ... because the so-called regulatory 'gaps' in the current rules clearly are not contributing to unacceptable risk," and that EPA's 2012 NESHAPs are "regulation for the sake of regulation and, as such, contradict Congress's clear intent that an ample margin of safety is an appropriate stopping point for emissions limitations under § 112" of the CAA. Industry's (and others') comments were incorporated into the final rules, and the revisions are reflected and discussed in EPA's "Summary of Key Changes to the Rules" Fact Sheet, at http://www.epa.gov/airquality/oilandgas/pdfs/20120417changes.pdf.

Apps' Ex. 24

0498

Greenhouse Gases

Finally, other studies focus on the impact of greenhouse gas emissions from crude oil and natural gas operations. Many of these studies advocate for the increased production and use of natural gas as a substitute for other fossil fuel resources because it is domestically available, economically recoverable, and considered a potential "bridge" fuel to a less polluting and lower GHG-intensive economy. However, when fugitive emissions of methane from all sectors of the industry are factored into the total life-cycle assessment of the resource,[130] the advantage of natural gas over other fossil fuels is less clear. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (published April 15, 2013) estimates natural gas systems emitted 144.7 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) of methane in 2011, a 10% decrease from 1990 emissions, and 32.3 $MMtCO_2e$ of non-combustion CO_2 in 2011, a 14% decrease from 1990 emissions. EPA cites improvements in management practices and technology, along with the replacement of older equipment, as helping to stabilize emissions of CO_2. The decrease in methane emissions is the result of a decrease in emissions from transmission and storage due to increased voluntary reductions and a decrease in distribution emissions due to a decrease in unprotected pipelines.[131] However, natural gas systems in 2011 were cited as being the single largest contributor to U.S. anthropogenic (i.e., man-made) methane emissions, representing nearly 25% of the total methane emissions from all domestic sources and accounting for about 2% of all GHG emissions in the United States. Some recent studies (outlined below) argue that expanding the production and use of natural gas could actually exacerbate rather than help mitigate global warming because methane's global warming potential (GWP)[132] is as much as 20—if not 50—times more potent than carbon dioxide, depending upon the time interval used to express warming impacts. These studies suggest that if significant amounts of methane were to leak during the production of natural gas, the climate forcing of methane could cancel out or even outweigh any benefit gained from switching away from oil or coal combustion processes.

Many of the published and publicly available life-cycle GHG emissions assessments of natural gas rely on the 1996 EPA/GRI emissions factors for methane leakage in the industry. EPA's recently updated emissions estimates suggest that leakage from natural gas systems is approximately 1.5% of gross national production.[133] EPA has neither calculated nor stated whether these revisions negate the apparent advantage natural gas has over oil or coal when it comes to climate change. But some researchers, most notably Robert Howarth of Cornell University, have argued that they would. Howarth estimates that emissions from natural gas leakage are likely to be in the range of 3.6% to 7.9% of gross national production over the entire natural gas life-cycle (which includes production, processing, transmission, storage, and distribution). He estimates leakage at the wellhead during both well completion and production to

[130] For a brief explanation of life-cycle emissions assessment methodology, see text box "Estimating the GHG Footprint of Unconventional Natural Gas."

[131] Of the 144.7 $MMtCO_2e$ of methane reported, 53.4 $MMtCO_2e$ is from "field production," 19.6 $MMtCO_2e$ is from "processing," 43.8 $MMtCO_2e$ is from "transmission and storage," and 27.9 $MMtCO_2e$ is from "distribution." U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, Washington, DC, EPA 430-R-13-001, April 15, 2013, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Chapter-3-Energy.pdf. For a definition of carbon dioxide equivalent, see footnote 28.

[132] Global-warming potential (GWP) is a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide. A GWP is calculated over a specific time interval, commonly 20, 100 or 500 years. See United Nations Framework Convention on Climate Change, "Global Warming Potentials" webpage, http://unfccc.int/ghg_data/items/3825.php.

[133] As discussed in section "Measurement of Emissions" of this report.

Apps' Ex. 24

0499

be between 2.2% and 3.8%.[134] At these rates, "the footprint of shale gas is at least 20% greater [than coal] and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years." Others, however, argue that Howarth's analysis is flawed, claiming that he significantly overestimates the fugitive emissions associated with unconventional gas extraction, undervalues the contribution of "green technologies" (e.g., REC) to reducing these emissions, bases the comparison between gas and coal on heat rather than electricity generation (almost the sole use of coal), and assumes a time interval (i.e., 20 years) over which to compute the relative climate impact of gas compared to coal, thus failing to capture the contrast between the long residence time of CO_2 and the short residence time of methane in the atmosphere.[135]

The controversy has led to a number of life-cycle GHG assessments comparing natural gas to coal. Most use the emissions measurement data from the 1996 EPA/GRI study as a starting point for their assumptions. For example: Wigley (2011)[136] considers the effects of methane leakage, changes in radiative forcing due to changes in the emissions of sulfur dioxide and carbonaceous aerosols, and differences in the efficiency of electricity production between coal- and gas-fired power generation, to find, on balance, "these factors more than offset [natural gas's] reduction in warming due to reduced CO_2 emissions" such that "when gas replaces coal there is additional warming out to [the year] 2050 with an assumed leakage rate of 0%, and out to 2140 if the leakage rate is as high as 10%." Hultman (2011),[137] however, estimates that for electricity generation, the GHG impacts of shale gas are 11% higher than those of conventional gas, and only half that of coal for standard assumptions. Fulton (2011)[138] concludes that U.S. gas-fired electricity generation emits 47% less GHG than coal using the IPCC's 100-year global warming potential index for methane, instead of the 20-year index used by Howarth. Jiang (2011)[139] estimates that emissions from coal-fired electric generation are so much greater than gas-combustion plants that a fuel switch would reduce climate-forcing emissions as long as leakage in a natural gas system is less than 14% (using the IPCC 100-year GWP) or 7% (using the IPCC 20-year GWP). Alvarez (2012),[140] however, in an assessment similar to Jiang's, concludes that leakage in the natural gas system would only need to be 3.2% before the overall lifecycle emissions estimates for natural gas electricity generation surpassed those of coal in the near term. Further, powering vehicles with natural gas rather than gasoline would not strike the same balance in the near term unless gas producers bring their leakage rate down to a maximum of 1.6%; and replacing diesel with natural gas would cause greater near-term climate impacts unless

[134] Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change*, vol. 106, no. 4 (June 2011), pp. 679-690, http://rd.springer.com/article/10.1007/s10584-011-0061-5.

[135] Lawrence M. Cathles III, Larry Brown, Milton Taam, and Andrew Hunter, "A Commentary on "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations" by R.W. Howarth, R. Santoro, and Anthony Ingraffea," *Climatic Change*, vol. 113, no. 2 (July 2012), pp. 525-535, http://rd.springer.com/article/10.1007/s10584-011-0333-0.

[136] Tom Wigley, "Coal to Gas: The Influence of Methane Leakage," *Climate Change*, vol. 108, No. 3 (October 2011), pp. 601–608.

[137] Nathan Hultman et al., "The Greenhouse Impact of Unconventional Gas for Electricity Generation," *Environmental Research Letters*, vol. 6, no. 4 (2011). http://iopscience.iop.org/1748-9326/6/4/044008.

[138] Mark Fulton, et al., "Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal," Deutsche Bank Group Climate Change Advisors and Worldwatch Institute, August 25, 2011, http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf.

[139] Mohan Jiang, et al., "Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas," Environmental Research Letters, vol. 6 (July-September 2011), http://iopscience.iop.org/1748-9326/6/3/034014/fulltext/.

[140] Ramón A. Alvarez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," *Proceedings of the National Academy of Sciences*, vol. 109, no. 17 (April 24, 2012), pp. 6435–6440, http://www.pnas.org/content/109/17/6435.

Apps' Ex. 24

0500

leak rates were under 1.0%. Alvarez stresses that the climatic effect of replacing other fossil fuels with natural gas may vary widely depending upon the examined time horizon (e.g., 20, 100, or 500 years), the end-use sector (e.g., electricity generation or transportation) and the fuel replaced (e.g., coal, gasoline, or diesel).

Estimating the GHG Footprint of Unconventional Natural Gas

Life-cycle assessment (LCA) is an analytic method used for evaluating and comparing the environmental impacts of various products (in this case, the climate change implications of hydrocarbon resources). LCA can be used in this way to identify, quantify, and track emissions of carbon dioxide and other GHG emissions arising from the development of these hydrocarbon resources, and to express them in a single, universal metric of carbon dioxide equivalent (CO_2e) GHG emissions per unit of fuel or fuel use. This figure is commonly referred to as the "emissions intensity" of a fuel. The results of an LCA can be used to evaluate the GHG emissions intensity of various stages of the fuel's life-cycle, as well as to compare the emissions intensity of one type of fuel or method of production to another.

As researchers point out: "Gas produced from unconventional wells has roughly the same methane content as that produced from conventional wells and therefore combustion can be assumed to yield the same climate effect. However, extraction techniques for unconventional gas differ from those used for conventional gas, and figures on well-lifecycle methane emissions have not been comprehensively established. Calculating the GHG footprint of unconventional gas requires three steps and associated assumptions. First, emissions of GHG from the production process, leaked methane and CO_2, must be estimated. Second, these numbers must be converted to a common GHG metric such as CO_2-equivalent (CO_2e). Third, because electricity generation technologies vary greatly in their combustion efficiencies, the emissions attributable to a kilogram or GJ of fuel are more appropriately compared on the basis of electricity delivered to the end-user—i.e. on a per kWh basis."[141]

Different published studies have approached these three inputs differently, accounting for the wide spectrum of estimates for natural gas's GHG footprint in comparison to coal, oil, or other fuel sources.

Cost Benefit Analysis of Federal Standards

Natural gas is a product of—and thus a source of revenue for—the oil and gas industry. It is also a main source of pollution from the industry when it is emitted into the atmosphere. Due to this unique linkage, pollution abatement has the potential to translate into economic benefits for the industry, as producers may be able to offset compliance costs with the value of natural gas and its byproducts recovered and sold at market. To capitalize on these incentives, many recovery technologies have been incorporated into industry practices, and have thus served as the basis for several local, state, and federal regulations. The 2012 federal air standards require natural gas producers to use recovery technologies to capture approximately 95% of the methane and VOCs that escape into the air as a result of hydraulic fracturing operations. The agency estimates that the equipment and the activities required to comply with the 2012 standards will cost producers about $170 million a year, but calculates that incorporating the sale of recovered products into the cost will result in an estimated net gain of about $11 million to $19 million a year. The industry disagrees with these estimates and counters with compliance cost estimates at more than $2.5 billion annually. Third parties, such as Bloomberg Government, project a net cost between $316 million and $511 million, or, approximately 1% of industry's annual revenue. All estimates are based on assumptions regarding the quantity of captured emissions, the cost and availability of capital equipment, and the market price for natural gas. In light of these considerations, Congress may opt to examine ways in which to best align the costs of requirements with sustainable resource expansion, industry growth, and job creation.

EPA estimates the 2012 air standards would yield a cost savings of $11 million to $19 million in 2015, as pollution abatement costs would be offset by the value of natural gas and condensate

[141] Nathan Hultman et al., *op cit.*

Apps' Ex. 24

0501

recovered and sold at market. EPA's annual cost estimates include (1) cost of capital, (2) operating and maintenance costs, (3) cost of monitoring, inspection, recordkeeping and reporting (MIRR), and (4) associated product recovery credits. All costs are reported in 2008 dollars, and calculated as follows: The total estimated net annual cost to industry to comply with the final amendments in the Crude Oil and Natural Gas Production NESHAPs is approximately $3.3 million. The total estimated net annual cost in the Natural Gas Transmission and Storage NESHAPs is approximately $180,000. The total estimated net annual cost to industry to comply with the final NSPS is approximately $170 million; and, when revenues from additional product recovery are considered, the final NSPS is estimated to result in a net annual engineering cost savings of approximately $15 million. EPA assumes that producers will be paid $4/Mcf for the recovered gas at the wellhead and $70 per barrel for recovered condensate, with about 43 million Mcf (i.e., 43 billion cubic feet) of natural gas and 160,000 barrels of condensate recovered by control requirements in 2015. Further, EPA estimates that the operation cost of 3-10 days of hydraulic fracturing with reduced emissions completions would be $700 to $6,500 per day with an additional $3,500 per well for flare equipment, for an average incremental cost of using the abatement technology of $33,237 per completion. EPA annualizes the cost using a 7% discount rate.

The American Petroleum Institute (API), in its comments to EPA on the proposed regulation, included a consultant's report that projects compliance costs of more than $2.5 billion annually after accounting for incremental sales of the fuel.[142] API estimates the cost of flaring emissions to be $90,000 per well, and the operation cost of using (i.e., renting and setting up) reduced emissions completions to be $180,000 per completion. API reports that only 300 REC sets are currently in existence, with the capacity to produce only 4,000 wells a year. Working with EPA's projection that there would be 25,000 new or modified hydraulically fractured wells completed annually, API argues that the equipment prescribed to conduct reduced emission completions would not be available in time to comply with the rule schedule. Further, API contends that EPA's cost analyses are based on "average model facilities" that do not represent all equipment and compliance costs and fail to identify when the controls are no longer economic. At the time of the proposed rule, API's consultant claimed that the proposed air standards could create "a significant slowdown in unconventional resource development ... resulting in less reserve additions, less production, lower royalties to the Federal government and private landowners, and lower severance tax payments to state governments. The delays in drilling result in delays in production, which result in the delays in the economic benefits associated with that production." Other industry commentators have gone further by stating that the full burden of regulations would fall squarely upon the producers, because economic incentives dictate that producers are currently capturing and selling all economically recoverable natural gas. EPA's rule would "divert investments from capital and energy development into regulatory compliance efforts, and impose onerous notification, record keeping, monitoring, reporting, and performance testing requirements that industry will necessarily incur costs to keep up with."[143]

In the final *Regulatory Impact Assessment* issued in April 2012, EPA examines the compliance costs for slightly more than 11,000 hydraulically fractured wells that would be drilled in unconventional formations, and nearly 1,500 that would be re-fractured to stimulate production.

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[142] Advanced Resources International Inc., *Estimate of Impacts of EPA Proposals to Reduce Air Emissions from Hydraulic Fracturing Operations*, prepared for the American Petroleum Institute, February 2012, http://www.api.org/~/media/Files/Policy/Hydraulic_Fracturing/NSPS-OG-ARI-Impacts-of-EPA-Air-Rules-Final-Report.ashx.

[143] Thomas J. Pyle, "EPA's Flawed Rule Warrants Scrutiny," *National Journal*, April 23, 2012, http://energy.nationaljournal.com/2012/04/regulating-natural-gas-whats-t.php#2201556.

Apps' Ex. 24

0502

Of those, approximately 6,600 are assumed to be using reduced emissions completions voluntarily or under state/local regulations, and an additional 12% would be classified as exploratory, delineation, or low-pressure wells exempt from the 2012 standards, leaving about 4,600 that would be compelled to use REC as a result of federal regulation.[144] API, however, claims that most large producers in the natural gas sector are currently using REC where feasible and "where it makes economic sense." Chesapeake Energy, the number two U.S. gas producer, has said it limits emissions on "a very high percentage" of its wells. Fourth-ranked Devon Energy has stated it uses REC for 91% of its wells. A survey of nine API members working in 29 drilling areas reported their members doing REC on 70% of their wells. America's Natural Gas Alliance (ANGA) submitted a survey to EPA of eight unidentified production companies that report using REC on 93% of their wells in 2011.[145] As with any self-selected and self-reported survey, it is difficult to determine how representative these samples are of overall industry practice.

A comparative report by Bloomberg Government—using slightly different values to analyze the available data on affected wells, compliance costs, products recovered, and market prices—calculates that the costs would fall somewhere in between both EPA's and API's projections. In their analysis, the regulation would generate an initial $125 million in spending on new equipment and $383 million in annual rental and service fees beginning in 2015. Factoring in product recovery, the total net costs of compliance would fall between $316 million and $511 million per year depending upon the market price of natural gas—or, more than twice the amount estimated by EPA and less than half that projected by API. This increase would account for approximately 0.5% to 0.7% of the industry's 2011 gas sales, which they determined "may cause a slight reduction in drilling activity."[146] Bloomberg Government noted that EPA's analysis assumed natural gas prices 40% above levels at the time and estimates that prices would need to rise to $10/Mcf to make the value of recovered products equal to the compliance costs.

Relevant Legislation in the 113th Congress

Legislation in the 113th Congress to amend the Clean Air Act to address emissions from crude oil and natural gas production activities includes the following:

The BREATHE Act. On March 14, 2013, Representative Jared Polis (D-CO-2) and 40 co-sponsors introduced H.R. 1154, a bill "to amend the Clean Air Act to eliminate the exemption for aggregation of emissions from oil and gas development sources, and for other purposes." Dubbed the Bringing Reductions to Energy's Airborne Toxic Health Effects Act, or BREATHE Act, the

[144] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry*, April 2012, p. 3-6, http://www.epa.gov/ttnecas1/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf.

[145] Comments to "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute, November 30, 2011, accessed on http://www.regulations.gov; Jim Efstathiou Jr. and Mark Drajem," Gas Groups' Strategies Diverge in Opposing Obama Fracking Rules," *Bloomberg News*, March 26, 2012, http://www.bgov.com/news_item/tChIVzjpbV4O4xTaVVX-FA; Comments submitted by Devon Energy, Nov. 30, 2011, accessed on http://www.regulations.gov; David A. Simpson, P.E., *Review of the Regulatory Impact Analysis (RIA) for the Well Completions Portion of the Proposed New Source Performance Standards for the Oil and Natural Gas Industry*, Attachment G to comments by API, op cit.; Comments submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC), November 30, 2011, accessed on http://www.regulations.gov.

[146] Rich Heidorn Jr., *Fracking Emission Rules: EPA, Industry Miss Mark on Costs, Consequences*, Bloomberg Government, 2012, http://about.bgov.com/2012/07/19/fracking-emissions-rules-re-estimating-the-costs/. The report cites EIA figures of 24 trillion cubic feet of gas sold by U.S. natural gas producers in 2011, with a value of $72.5 billion at $3/Mcf.

Apps' Ex. 24

0503

proposed bill would amend the CAA to (1) include hydrogen sulfide in the list of hazardous air pollutants, and (2) repeal the exemption on aggregating emissions from any oil or gas sources for any purpose relating to hazardous air pollutant emission standards. The bill was referred to the House Committee on Energy and Commerce on March 14, 2013.

Conclusion

U.S. natural gas production has grown markedly in recent years. This growth is due in large part to increased activities in unconventional resources brought on by technological advance. Many have advocated for the increased production and use of natural gas in the United States for economic, national security, and environmental reasons. They argue that natural gas is the cleanest-burning fossil fuel, with fewer emissions of carbon dioxide, nitrogen oxide, sulfur dioxide, particulate matter, and mercury than its hydrocarbon rivals (e.g., coal and oil) on a per-unit-of-energy basis. For these reasons, many have looked to natural gas as a "bridge" fuel to a less polluting and lower greenhouse gas-intensive economy. However, the recent expansion in natural gas production in the United States has given rise to a new set of concerns regarding human health and environmental impacts, including impacts on air quality.

To address air quality and other environmental issues, the oil and gas industry in the United States has been regulated under a complex set of local, state, and federal laws. Currently, state and local authorities are responsible for virtually all of the day-to-day regulation and oversight of natural gas systems, and many states have passed laws and/or have promulgated rules to address air quality issues based on local needs. Further to this, organizations like the State Review of Oil and Natural Gas Environment Regulations (STRONGER) are available to help states assess the overall framework of environmental regulations supporting oil and gas operations in their regions.[147] At the federal level, EPA has promulgated minimum national standards for VOCs, SO_2, and HAPs for some source categories in the crude oil and natural gas sector. The federal air standards focus primarily on the production and processing sectors of the industry, and were drawn, in part, from existing requirements found in the state codes of Colorado and Wyoming. Further to this, many producers in the crude oil and natural gas sector have set forth a series of recommended practices. These practices are sustained by the economic incentives provided by capturing the fugitive releases of natural gas and its byproducts to be sold at market. Several voluntary partnerships sponsored by various federal and international agencies also serve to facilitate recommended practices for emissions reductions in the oil and gas industry. EPA's Natural Gas STAR Program, the Global Methane Initiative (formerly the Methane to Markets Partnership), and the World Bank Global Gas Flaring Reduction Partnership are three such programs.[148]

Many believe that air standards similar to those promulgated by Colorado, Wyoming, and the federal government are sufficient to control VOC, SO_2, and HAP emissions from the natural gas production sector. Some argue that the cost of compliance with state and federal air standards could affect industry profits, thereby reducing economic interest to invest and slowing production

[147] STRONGER is a non-profit, multi-stakeholder organization which specializes in assessing the overall framework of environmental regulations supporting oil and gas operations. Their collaborative review teams encompass industry, regulators, and environmental/public interest stakeholders. Since its initiation, STRONGER has completed reviews of 21 state programs responsible for the regulation of over 90% of the domestic onshore production of oil and natural gas. Stronger has completed specific hydraulic fracturing reviews in Colorado, Louisiana, Oklahoma, Pennsylvania, and Ohio. For more information, see http://www.strongerinc.org/.

[148] For more information about EPA's Natural Gas STAR Program, see http://www.epa.gov/gasstar/. For the Global Methane Initiative, see EPA's website, http://www.epa.gov/globalmethane/index.htm. For the Global Gas Flaring Reduction Partnership, see the World Bank's website, http://go.worldbank.org/KCXIVXS550.

Apps' Ex. 24

0504

activities. Others are concerned that some pollutants and some emission sources remain unregulated by any standard, including methane, hydrogen sulfide, oil wells, offshore wells, conventional gas wells, and most operations downstream of the gas processing plant. Debate over the costs of compliance, covered sources and pollutants, and the proper regulatory institutions (i.e., local, state, or federal) continues. Complicating these debates is the fact that a comprehensive national inventory that directly measures the quantity and composition of fugitive emissions from natural gas systems does not exist. This is due to many factors, including costs and technical uncertainties. But, until there is an adequate and reliable assessment of industry-wide emissions, the benefits, costs, and basis for regulation may remain uncertain.

Apps' Ex. 24

0505

Appendix A. Federal Air Standards for Crude Oil and Natural Gas Systems

Table A-1. New Source Performance Standards for Volatile Organic Compounds in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Natural Gas Well Sites	**New Hydraulically Fractured Well Completions**	Not covered.	Exploratory wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Exploratory well defined as a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.
			Delineation wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Delineation well defined as a well drilled in order to determine the boundary of a field or producing reservoir.
			Hydraulically fractured low-pressure wells: operators must use completion combustion device (e.g., flaring) unless hazardous or prohibited by state or local regulations.	October 15, 2012.	Low pressure well defined by a formula based on well depth and pressure. (A well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.) EPA estimates that this exclusion for low pressure gas wells would cover 10% of all natural gas wells and, specifically, 87% of coal-bed methane wells.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
			All other hydraulically fractured wells, prior to January 1, 2015: operators must use either completion combustion device (e.g., flaring) or reduced emissions completion (i.e., "green completion").	Prior to January 1, 2015.	Completion combustion device defined as any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.
			All other hydraulically fractured wells, after January 1, 2015: operators must use reduced emissions completion (i.e., "green completion").	On or after January 1, 2015.	Reduced emissions completion defined as a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. The extended compliance date is to allow for the availability of REC equipment. Of note, the rule provides that if using REC technology is "infeasible" or "unsafe," the operator may use a completion combustion device to control flowback emissions.
			Notification and annual reporting requirements.	October 15, 2012.	Owners or operators of hydraulically fractured and refractured natural gas wells must notify EPA (or in some cases, a state or local air agency) by e-mail no later than two days before completion work begins. Further, each year, owners/ operators must submit a report on all well completion activities during the year.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
	Refractured Natural Gas Well Completions	Not covered.	All wells that are refractured or recompleted prior to January 1, 2015: the well will not be considered "modified" under the Clean Air Act if operators use reduced emissions completions (i.e., "green completion") rather than flaring.	Prior to January 1, 2015.	The provisions are designed to encourage operators to use REC technology before it is required, and will allow operators in many states to refracture wells without triggering additional state permitting requirements. EPA believes that this provision will result in an additional 1,000 to 1,500 REC.
			All wells that are refractured or recompleted on or after January 1, 2015: operators must use reduced emissions completion (i.e., "green completion").	On or after January 1, 2015.	The provisions are equivalent to new fractured wells.
	New & Modified Compressors	Not covered.	Not covered.	N/a.	N/a.
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	Storage vessel defined as a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. It excludes skid-mounted vessels and mobile vessels attached to vehicles that are intended to remain at a site for less than 180 consecutive days, as well as process vessels, and pressure vessels designed to operate in excess of 204.9 kilopascals with no emissions to the atmosphere. The extended compliance date is to allow for the availability of control devices.
Natural Gas Gathering & Boosting Stations	**New & Modified Compressors**	Not covered.	Centrifugal compressors with wet-seals: operators must utilize a control system that captures emissions from the wet seal fluid degassing system and routes them to a control device in order to reduce VOCs emissions by at least 95%.	October 15, 2012.	Centrifugal compressors with dry-seals are exempt from the 2012 rules due to low VOCs emissions.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
			Reciprocating compressors: operators required to change rod packings after either 26,000 hours (operating hours must be monitored and documented) or 36 months of operation.	October 15, 2012.	Operating hours must be monitored and documented for usage by hour, but monitoring is waived if operators choose the 36 month requirement.
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Natural Gas Processing Plants	**New & Modified Compressors**	Covered under LDAR program	Centrifugal compressors with wet-seals: operators must utilize a control system that captures emissions from the wet seal fluid degassing system and routes them to a control device in order to reduce VOCs emissions by at least 95%.	October 15, 2012.	Centrifugal compressors with dry-seals are exempt from the 2012 rules due to low VOCs emissions.
			Reciprocating compressors: operators required to change rod packings after either 26,000 hours or 36 months of operation.	October 15, 2012.	Operating hours must be monitored and documented for usage by hour, but monitoring is waived if operators choose the 36 month requirement.
	New & Modified Pneumatic Controllers	Covered under LDAR program.	Natural gas-driven, continuous-bleed devices: operators must reduce natural gas bleed rate to zero scfh.	October 15, 2012.	The standards for pneumatic controllers at natural gas processing plants reflect the emission level achievable from the use of non-natural gas-driven pneumatic controllers.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
	New Storage Vessels	Covered under LDAR program.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)
	Leak Detection and Repair	The prior NSPS for equipment leaks of VOCs at natural gas processing plants (40 C.F.R. Part 60, subpart KKK) requires compliance with specific provisions of 40 C.F.R. Part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks.	Existing NSPS requirements for LDAR revised to reflect the procedures and leak thresholds established by 40 C.F.R. 60, subpart VVa: Subpart VVa lowers the leak definition for valves from 10,000 ppm to 500 ppm, and requires the monitoring of connectors, pumps, pressure relief devices, and open-ended valves or lines.	October 15, 2012.	EPA excludes compressors from the leak detection and repair (LDAR) requirements applicable to equipment at onshore natural gas processing plants because the rule already imposes control requirements on compressors.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Natural Gas Transmission, Storage, and Distribution	**New & Modified Compressors**	Not covered.	Not covered.	N/a.	EPA states that it needs additional information in order to set cost-effective standards in this sector where VOCs content of gas is generally low.
	New & Modified Pneumatic Controllers	Not covered.	Not covered.	N/a.	EPA states that it needs additional information in order to set cost-effective standards in this sector where VOCs content of gas is generally low.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)
Oil Well Sites	**Well Completions**	Not covered.	Not covered.	N/a.	EPA excludes oil wells from requirements. Only "gas wells" or "natural gas wells" defined as onshore wells drilled principally for the production of natural gas are covered.
	New & Modified Compressors	Not covered.	Not covered.	N/a.	N/a.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart KKK	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
	New & Modified Pneumatic Controllers	Not covered.	Natural gas-driven, continuous-bleed devices with bleed rate greater than 6 standard cubic feet per hour (scfh): operators must reduce natural gas bleed rate to less than 6 scfh.	1-year phase-in period beginning October 15, 2012.	The provisions are designed to exclude pneumatic controllers that meet the NSPS standard (e.g., low-bleed, intermittent-bleed, and/or non-gas-driven devices), exempting them from the recordkeeping and reporting requirements of the rule to encourage operators to install.
	New Storage Vessels	Not covered.	Vessels with VOCs emissions equal to or greater than 6 tons per year (tpy): operators must reduce VOCs emissions by 95%, employing means such as a floating roof or a closed vent system and control device (e.g., flare).	1-year phase-in period beginning October 15, 2012. (Proposal under 78 FR 22125 to revise compliance dates to April 15, 2014, for new and modified sources beginning construction after April 12, 2013.)	(See definition of "Storage Vessel" above.)

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013; and 40 C.F.R. Part 60, Subpart KKK.

Table A-2. New Source Performance Standards for Sulfur Dioxide in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 60, Subpart LLL	40 C.F.R. Part 60, Subpart OOOO	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Natural Gas Processing Plants	**New and Modified Sweetening Units**	Sweetening units at onshore affected natural gas processing plants: operator required to achieve an SO_2 emission reduction efficiency determined from an equation based on the sulfur feed rate and the sulfur content of the acid gas of the affected facility.	Sweetening units at onshore affected natural gas processing plants: operators must reduce SO_2 emissions for units with sulfur production rate of at least 5 long tons per day based on sulfur feed rate and sulfur content of gas.	October 15, 2012.	Sweetening unit defined as a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; and 40 C.F.R. Part 60, Subpart LLL.

Table A-3. National Emissions Standards for Hazardous Air Pollutants in Crude Oil and Natural Gas Systems

Source Sector	Affected Facility	Prior Rules: 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	2012 Rules: 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	Compliance Dates: 77 FR 49489, August 16, 2012	Comments: New or Modified Facilities Defined as Beginning Construction After August 23, 2011
Major Sources, All Sectors	**Large Dehydrators**	Glycol dehydration units at major sources that have annual average natural gas throughputs of 85,000 cubic meters a day or emit an average of one ton or more of benzene annually: required to connect, through a closed vent system, each process vent to an air emission control system. The control system must reduce emissions: (1) by 95% or more of HAPs, (2) to an outlet concentration of 20 parts per million by volume (ppmv) or less (for combustion devices), or (3) to a benzene emission level of one ton per year or less.	Retains existing standards.	N/a.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.
	Small Dehydrators	Not covered.	Small glycol dehydrators that have annual average natural gas throughputs of less than 85,000 standard cubic feet per day or emit an average of less than one ton of benzene annually: required to comply with unit-specific limits on annual emissions of benzene, toluene,	October 15, 2012, for new units; October 15, 2015, for existing units.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.

Source Sector	Affected Facility	Prior Rules	2012 Rules	Compliance Dates	Comments
		40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	77 FR 49489, August 16, 2012	New or Modified Facilities Defined as Beginning Construction After August 23, 2011
			ethylene, and xylene (collectively, "BTEX").		
	Storage Vessels	Storage vessels at major sources with the potential for flash emissions: required to have either a closed vent system that is linked to a control device that either recovers or destroys 95% or more of HAPs emissions, or a combustion device (such as flares) that reduces HAPs emissions to an outlet concentration of 20 ppmv or less.	Retains existing standards	N/a.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction. EPA chose not to promulgate new standards covering non-flash potential storage tanks (e.g., crude oil and condensate storage tanks) because it determined that additional data is necessary to establish the MACT standard.
	Leak Detection and Repair	Natural gas processing plants that are major HAPs sources: control HAPs emissions from leaks from ancillary equipment and compressors. The owner or operator of such equipment is required to implement a Leak Detection and Repair (LDAR) program and where necessary, perform equipment modifications.	Under the 2012 standards, a leak triggering the rule's LDAR requirements is strengthened to include any measurement exceeding 500 ppm of any regulated HAPs.	October 15, 2012.	The final rule eliminated the exemption for periods of startup, shutdown, and malfunction.
	Associated Equipment	Associated equipment for major source determinations defined as equipment associated with an oil or natural gas exploration or	Associated equipment for major source determinations amended to exclude emissions from all storage vessels.	October 15, 2012.	The treatment of HAPs emissions from oil and gas production has differed from the general requirements of Section 112 of the CAA. Section 112(n)(4) provides that,

Source Sector	Affected Facility	Prior Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	2012 Rules 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector)	Compliance Dates 77 FR 49489, August 16, 2012	Comments New or Modified Facilities Defined as Beginning Construction After August 23, 2011
		production well, including all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels with the potential for flash emissions.			notwithstanding the general definition of "major source," … "emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station shall not be aggregated with emissions from other similar units, whether or not such units are in a contiguous area or under common control, to determine whether such units or stations are major sources." Thus, for facilities that are production field facilities, only HAPs emissions from glycol dehydration units and storage vessels are aggregated for a major source determination. For facilities that are not production field facilities, HAPs emissions from all HAPs emission units are aggregated for a major source determination.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012; U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013; and 40 C.F.R. Part 63, Subparts HH (Covering the Crude Oil and Natural Gas Production Sector) and HHH (Covering the Natural Gas Transmission and Storage Sector).

Notes: The NESHAPs in the table cover "Major Sources" of air toxics in the Crude Oil and Natural Gas Production Sector, and in the Natural Gas Transmission and Storage Sector. "Major Source" is defined as emitting 10 or more tons of a single air toxic and 25 tons or more of a combination of toxics in a year.

Table A-4. Comparison of 2012 Federal Air Standards for Crude Oil and Natural Gas Systems to Selected State Regulations

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Well Completions	Hydraulically fractured wildcat, delineation, and low-pressure natural gas wells must route flowback emissions to completion combustion device. All other hydraulically fractured natural gas wells must route flowback emissions to completion combustion device or use green completions prior to January 1, 2015, and must use green completions after January 1, 2015, unless "infeasible."	COGCC HB-07-1341, Section 805.b(3). Green completions shall be used when technically and economically feasible. If not feasible, Best Management Practices shall be used.	MT DNRC BOGC 36.22.1221. All gas vented to the atmosphere at a rate exceeding 20 MCF per day for a period in excess of 72 hours shall be burned.	None.	None.	None.	C6 S2 O&G Permitting Guidance. Green completions are required in the JPAD area and CDA in Wyoming as of August 1, 2011.
Processing Plants	Equipment leaks at onshore natural gas processing plants require a LDAR program.	Colorado has adopted NSPS Subpart KKK on LDAR under Reg. 7, XII.G.1 (KKK applies at gas processing plants located in ozone non-attainment areas regardless of the date of construction of the affected facility).	Montana has adopted NSPS Subpart KKK on LDAR.	New Mexico has adopted NSPS Subpart KKK on LDAR.	North Dakota has adopted NSPS Subpart KKK on LDAR.	Utah has adopted NSPS Subpart KKK on LDAR.	Wyoming has adopted NSPS Subpart KKK on LDAR.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Pneumatic Controllers	Continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants must meet natural gas bleedrate of zero. Continuous bleed natural gas-driven pneumatic controllers with a bleed rate greater than 6 scfh between wellhead and natural gas processing plant must meet natural gas bleedrate less than 6 scfh.	Reg. 7, XVIII.C.1. No or low-bleed pneumatic devices required for all new & existing applications. (exceptions allowed) (only applies in ozone non-attainment areas). COGCC HB-07-1341, Section 805.b(2)E. No or low-bleed required for new, repaired or replaced devices where technically feasible.	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	None.	None.	C6 S2 O&G Permitting Guidance. Install low or no-bleed at all new facilities. Upon modification of facilities, new pneumatic controllers must be low/no-bleed and existing controllers must be replaced with no/low-bleed. (Well site facilities only—not gas plants.)

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Compressors	Centrifugal compressors with dry seals are exempt. Centrifugal compressors with wet seals must reduce emissions by 95%. Reciprocating compressors must change rod packing after 26,000 hours or after 36 months.	None.	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	None.	None.	None.

Storage Vessels	Storage vessels with VOCs emissions equal to or greater than 6 tpy must reduce emissions by 95%. Proposal under 78 FR 22125 to revise storage vessel standards to include a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95% control under specified circumstances. HAPs at production facilities must reduce emissions by 95%.	Reg. 7, XII.G.2. 95% VOCs reduction at gas processing plants if uncontrolled emissions from condensate tanks are ≥ 2 tpy (only applies in ozone non-attainment areas). Reg. 7, XVII.C.1. 95% VOCs reduction for condensate storage tanks if uncontrolled emissions ≥ 20 tpy. Reg. 7, XIID. Condensate tanks in ozone non-attainment areas shall be controlled under a system wide approach. COGCC HB-07-1341, Section 805.b(2)A). 95% VOCs reduction for liquids condensate & crude oil tanks if uncontrolled emissions ≥ 5 tpy within 1/4 mile of an affected building (Garfield, Mesa & Rio Blanco).	17.8.1603(1)(b). VOCs vapors from O&G oil or condensate storage tanks with a PTE > 15 tpy must be routed to a gas pipeline or emissions minimizing technology. Registration - 17.8.1711 (1)(a). VOCs vapors from each piece of O&G well facility equipment with PTE >15 tpy must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.1711(1)(b). Requires submerged filling technology on all hydrocarbon liquid loading or unloading.	None.	NDAC Section 33-15-07. Submerged filling requirements for tanks >1,000 gallons and control of organic compounds.	R307-327 Ozone Nonattainment Area. Volatile Petroleum Liquid Tanks (> 40,000 gallons, true vapor pressure (TVP) > 1.52 psia at storage temperature) shall be controlled to minimize vapor loss. New tanks shall be fitted with an internal floating roof resting on the liquid surface with the space (roof edge to tank wall) sealed. Owner/operator shall maintain records of the liquid type/ maximum TVP. Records required of average monthly storage temperature, the liquid type, throughput and maximum TVP for tanks not subject to above (petroleum liquid TVP > 1.0 psia).	C6 S2 O&G Permitting Guidance. JPAD - 98% control of all new/modified tank emissions upon startup/modification. CDA - 98% control of all new/modified tank emissions ≥ 8 tpy VOCs within 60 days of startup/ modification. Statewide - 98% control of all new/ modified tank emissions ≥10 tpy VOCs within 60 days of startup/ modification.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Dehydrators	95% reduction of HAPs in all large glycol dehydrators (> 3 MMCFD or > 1 tpy benzene emissions). Small dehydrator emission limits of 4.66 E-6 grams BTEX/scm-ppmv (new units) or 1.1 E-4 grams BTEX/scm-ppmv (existing units)	Reg. 7, XII.H and XVII.D. 90% reduction of VOCs where uncontrolled VOCs emissions ≥ 15 tpy. COGCC HB-07-1341, Section 805.b(2)C). 90% reduction of VOCs required where uncontrolled VOCs emissions ≥ 5 tpy within 1/4 mile of an affected building (applies only to Garfield, Mesa & Rio Blanco Counties).	17.8.1603(1)(a). VOCs vapors (> 500 BTU/scf) from O&G wellhead equipment must be captured and routed to a gas pipeline if within ½ mile, or to emissions minimizing technology or smokeless combustion device. 17.8.1711(1)(a). VOCs vapors (>200 Btu/scf) from each piece of O&G well facility equipment, with a PTE > 15 tpy, must be captured and routed to a gas pipeline, or routed to air pollution control equipment with a 95% or greater control efficiency. 17.8.752. Requires a case by case BACT determination.	None.	TEG units with a condenser require temperature monitoring.	None.	C6 S2 O&G Permitting Guidance. JPAD - 98% control of all new/modified dehydrator VOCs/HAPs emissions at start up. CDA & Statewide - PAD Facilities - 98% control upon startup. SINGLE Well Facilities - 98% control within 60 days of startup for VOCs emissions ≥6 OR 98% control within 30 days of startup for VOCs emissions ≥8 tpy.

Source	EPA's 2012 Air Standards	Colorado	Montana	New Mexico	North Dakota	Utah	Wyoming[a]
Minor Source Permitting	exempt	Reg. 3 Part B, II.D. Minor Source permitting required for sources with thresholds that vary by pollutant and area (generally required in non-attainment areas for criteria emissions > 1-5 tpy – required statewide for criteria emissions > 5-10 tpy – thresholds depend on the pollutant).	17.8.743 Montana Air Quality Permits (MAQP). NSR permitting required for sources with > 25 tpy PTE. 17.8.1702. A registration eligible facility may register in lieu of obtaining a MAQP.	20.2.72 NMAC. Requires permits for all sources >25 tpy of a criteria pollutant. 20.2.73 NMAC. Requires Notices of Intent for all sources >10 tpy of a criteria pollutant	None. (Registration of O&G facilities required per Chapter 33-15-20 rules in lieu of a permit.)	UAC Rule 307-401-9. NSR permitting exempted for sources with controlled emissions below de minimis levels: PTE< 5 tpy each PM10, NOx, SOx, CO, VOCs, or single HAPs < 500 lbs per year, combined HAPs < 1 tpy.	Emissions from minor sources must be approved through permitting applied through the WAQSR Chapter 6 Section 2(a)(i) O&G Permitting Guidance. For VOCs emissions ≥8 tpy from sources other than tanks, dehydrators, pneumatic controllers and pumps, water tanks, BACT is considered on case-by-case basis.

Source: Federal summaries from U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012, and U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards," 78 *Federal Register* 22125, April 12, 2013. State summaries from Lee Gribovicz, *Analysis of States' and EPA Oil & Gas Air Emissions Control Requirements for Selected Basins in the Western United States*, Western Regional Air Partnership, January 8, 2012, http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20%2801-08%29.pdf.

a. Wyoming has three area categories: (1) Jonah-Pinedale Anticline Development (JPAD), (2) Concentrated Development Area (CDA) and (3) statewide.

Appendix B. Composition of Fugitive and Combusted Natural Gas Emissions

Fugitive Natural Gas

Fugitive natural gas is primarily a mixture of low molecular-weight hydrocarbon compounds that are gases at surface pressure and temperature conditions. While the principal component of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane, propane, and butane, as well as trace amounts of heavier hydrocarbons. Non-hydrocarbon gases, such as carbon dioxide (CO_2), helium (He), hydrogen sulfide (H_2S), nitrogen (N_2), and water vapor (H_2O), may also be present in any proportion to the total hydrocarbon content (see **Table B-1**).

Table B-1. Composition of Raw Natural Gas

Component	Abbreviation	Percent of Composition
Methane (Natural Gas)	CH_4	70-90
Ethane (Natural Gas Liquid)	C_2H_6	0-20
Propane (Natural Gas Liquid)	C_3H_8	0-20
Butane (Natural Gas Liquid)	C_4H_{10}	0-20
Heavier Hydrocarbons	C_xH_y	0-20
Carbon Dioxide	CO_2	0-8
Oxygen	O_2	0-0.2
Nitrogen	N_2	0-5
Hydrogen Sulfide	H_2S	0-5
Rare Gases	A, He, Ne, Xe	Trace

Source: The Natural Gas Supply Association, http://www.naturalgas.org/overview/background.asp.

Combusted Natural Gas

Combusted natural gas releases carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NOx), and trace amounts of sulfur dioxide (SO_2), particulate matter (PM), uncombusted methane (CH_4), VOCs, and HAPs. Combusted natural gas is generally regarded as "cleaner" than other fossil fuels with respect to various criteria pollutants and greenhouse gas (GHG) emissions (see EPA's and EIA's data comparisons in **Table B-2**). Coal, fuel oil, and petroleum-based transportation fuels are composed of more complex long-chain hydrocarbon molecules, with higher carbon ratios, and may contain higher nitrogen and sulfur contents as well as increased amounts of ash and particulate matter. By comparison, the combustion of natural gas releases minimal amounts of sulfur dioxide and nitrogen oxides, virtually no ash or particulate matter, and lower levels of carbon dioxide, carbon monoxide, and other reactive hydrocarbons. While comparisons among the emission profiles of natural gas, coal, fuel oil, and transportation fuels are useful in certain contexts, it should be noted that these comparisons are not wholly substitutable, as end-uses of the fuels vary across sectors and pollution control mechanisms are in place for many of the fuels' combustion activities.

Apps' Ex. 24

0525

Table B-2. Air Pollution Emissions by Combusted Fuel Type

Pounds per Billion Btu of Energy Input

Pollutant	Natural Gas	Fuel Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	1	1,122	2,591
Particulates	7	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury	0.000	0.007	0.016

Source: Energy Information Administration (EIA), Office of Oil and Gas. Carbon Monoxide: derived from EIA, *Emissions of Greenhouse Gases in the United States 1997,* Table B1, p. 106. Other Pollutants: derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Vol. 1, 1998.*

Notes: No pre- or post-combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in an uncontrolled residential gas burner. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64% sulfur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03% sulfur content—derived from Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

Apps' Ex. 24

0526

Appendix C. Glossary of Terms

Table C-1. Glossary of Terms Related to Crude Oil and Natural Gas Systems

As defined by the U.S. Environmental Protection Agency in the Final Rules

Terminology	Definition
Bleed rate	The rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.
Centrifugal compressor	Any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.
City gate	The delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.
Completion combustion device	Any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.
Compressor station	Any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.
Continuous bleed	A continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.
Dehydrator	A device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).
Delineation well	A well drilled in order to determine the boundary of a field or producing reservoir.
Exploratory well	A well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.
Flare	A thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.
Flowback	The process of allowing fluids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface immediately following hydraulic fracturing or refracturing. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first.
Flow line	A pipeline used to transport oil and/or gas from the well to a processing facility, a mainline pipeline, reinjection, or other useful purpose.
Hydraulic fracturing	The process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.
Hydraulic refracturing	Conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Apps' Ex. 24

0527

Terminology	Definition
Intermittent/snap-action pneumatic controller	A pneumatic controller that vents non-continuously.
Low pressure gas well	A well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.
Natural gas-driven pneumatic controller	A pneumatic controller powered by pressurized natural gas.
Natural gas liquids	The hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.
Natural gas processing plant	Any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both.
Natural gas transmission	The pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).
Natural gas well	An onshore well drilled principally for production of natural gas.
Non natural gas-driven pneumatic controller	An instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.
Onshore	All facilities except those that are located in the territorial seas or on the outer continental shelf.
Pneumatic controller	An automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.
Pressure vessel	A storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.
Process unit	Components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.
Reciprocating compressor	A piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.
Reciprocating compressor rod packing	A series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.
Reduced emissions completion	A well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.
Salable quality gas	Natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas, regardless of whether such gas is sold.

Apps' Ex. 24
0528

Terminology	Definition
Storage vessel	A unit that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. The following are not considered storage vessels: (1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. (2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels. (3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.
Sweetening unit	A process device that removes hydrogen sulfide and/or carbon dioxide from a "sour" natural gas stream.
Underground storage vessel	A storage vessel stored below ground.
Well	An oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.
Well completion	The process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.
Well completion operation	Any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.
Well site	One or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.
Wellhead	The piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Source: U.S. Environmental Protection Agency, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, Final Rule," 77 *Federal Register* 49489, August 16, 2012.

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EXHIBIT 25

Groundwater

Issue Paper/

Groundwater Protection and Unconventional Gas Extraction: The Critical Need for Field-Based Hydrogeological Research

by R.E. Jackson[1], A.W. Gorody[2], B. Mayer[3], J.W. Roy[4], M.C. Ryan[3], and D.R. Van Stempvoort[4]

Abstract

Unconventional natural gas extraction from tight sandstones, shales, and some coal-beds is typically accomplished by horizontal drilling and hydraulic fracturing that is necessary for economic development of these new hydrocarbon resources. Concerns have been raised regarding the potential for contamination of shallow groundwater by stray gases, formation waters, and fracturing chemicals associated with unconventional gas exploration. A lack of sound scientific hydrogeological field observations and a scarcity of published peer-reviewed articles on the effects of both conventional and unconventional oil and gas activities on shallow groundwater make it difficult to address these issues. Here, we discuss several case studies related to both conventional and unconventional oil and gas activities illustrating how under some circumstances stray or fugitive gas from deep gas-rich formations has migrated from the subsurface into shallow aquifers and how it has affected groundwater quality. Examples include impacts of uncemented well annuli in areas of historic drilling operations, effects related to poor cement bonding in both new and old hydrocarbon wells, and ineffective cementing practices. We also summarize studies describing how structural features influence the role of natural and induced fractures as contaminant fluid migration pathways. On the basis of these studies, we identify two areas where field-focused research is urgently needed to fill current science gaps related to unconventional gas extraction: (1) baseline geochemical mapping (with time series sampling from a sufficient network of groundwater monitoring wells) and (2) field testing of potential mechanisms and pathways by which hydrocarbon gases, reservoir fluids, and fracturing chemicals might potentially invade and contaminate useable groundwater.

Introduction

Increased natural gas extraction from low-permeability rocks (rather than traditional permeable reservoirs) has transformed the outlook for electricity generation, building heating, industry, and transportation in North America over a mere 10 years (MIT 2011). The economic development of unconventional gas reservoirs has been spurred by recent advances in both directional drilling and reservoir stimulation by hydraulic fracturing. Deep and long horizontal wells (up to 3 km or 9000 ft in horizontal length) combined with multi-stage hydraulic fracturing can now effectively exploit geographically extensive (Figure 1), often relatively thin (tens of meters) formations that contain unconventional hydrocarbon resources, resulting in an increased supply of natural gas and a commensurate increase in gas use in North America; between 1989 and 2009, 88% of the 306 GW of electrical generation capacity constructed in the United States was gas-fired. Gas-fired energy now provides about one quarter of U.S. energy uses (MIT 2011),

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Apps' Ex. 25

0532

approximately 90% of which comes from U.S. gas-field production and approximately 10% from Canadian fields (U.S. Energy Information Administration 2012).

Unconventional gas resource developments have occurred both in frontier areas and areas with historic conventional oil and gas development (Figure 1). While conventional gas extraction activities are typically focused in well-defined, spatially restricted areas above oil and gas reservoirs, unconventional gas fields are developed on the premise that the gas-bearing formations are widely distributed in the subsurface. Unconventional gas wells are thus typically drilled in densely spaced and equidistant surface patterns that cover far larger subsurface areas than conventional plays. Although recent advances in directional drilling technology permit over 20 horizontal wells to be drilled from a single well pad, large numbers of well pads can still create extensive regional footprints.

The rapid expansion of the unconventional gas industry has been accompanied by public concern regarding protection of environmental and human health particularly over possible pollution of shallow groundwater[1] by migration of natural gas, formation water, and/or fracturing fluids from deep formations induced by hydraulic fracturing. In some jurisdictions—New York State, France, and Québec (Canada) for example—explicit or de-facto moratoria on hydraulic fracturing exist until uncertainties surrounding the process have been resolved. Indeed many articles in newspapers, journals, and the electronic news media regarding pollution of groundwater by the hydraulic fracturing industry (e.g., Zoback et al. 2010; Molofsky et al. 2011; Osborn et al. 2011; Myers 2012; Schnoor 2012; Warner et al. 2012) convey widely differing views regarding risks of groundwater contamination by the development of unconventional gas plays. Unfortunately, little peer-reviewed scientific information is available on the hydrogeological conditions—shallow groundwater quality in particular—associated with unconventional gas production or, for that matter, with conventional oil and gas production. There is a distinct possibility such moratoria will continue until more objective scientific information is available.

As an example of widely differing views, a recent national review in the UK concluded that while it may be possible to propagate a fracture to the ground surface from deep unconventional reservoirs (i.e., more than 2000 m or more than 6000 ft) by hydraulic fracturing, it is generally not practically feasible to do so because the pressures required to increase the fracturing over the full depth are not tractable in hydraulic stimulation (UK Royal Society/Royal Academy of Engineering 2012). In contrast, an article in this Journal (Myers 2012) suggested that under some conditions there could be surface discharge of fracturing fluids along naturally occurring fractures in less than 10 years after hydraulic fracturing of unconventional gas wells.

Widely differing views, such as those expressed above (the UK's Royal Society/Royal Academy of Engineering [2012] vs. Myers [2012]) clearly indicate the need for a more comprehensive and conclusive knowledge base. This is best approached with more extensive field and laboratory-based research, which is needed to support the development of groundwater models with well-defined hydrogeological settings, calibrated parameter values, and appropriate initial and final boundary conditions. This Issue Paper identifies issues and related hydrogeological research needs and approaches that will help protect groundwater quality during the development of unconventional gas resources. As such, we outline a new challenge in contaminant hydrogeology. Addressing this challenge will require an improved cooperation and communication between hydrogeological researchers and industry, ideally through collaborative research.

To support our case, we briefly describe the nature of unconventional gas production activities as they relate to identifying contaminants of concern. We discuss the potential contaminant migration pathways to shallow groundwater and the behavior of these contaminants in shallow groundwater and factors affecting aquifer vulnerability. We stress that many of these problems are also common to conventional hydrocarbon production activities and are not solely related to unconventional gas production. Finally we address the field-based hydrogeological research needs necessary to help protect groundwater quality during the development of unconventional gas resources and briefly describe how such research might be conducted.

Stimulation and Extraction of Unconventional Gas

The recovery of economic volumes of unconventional natural gas from low permeability and regionally extensive formations requires stimulation through hydraulic fracturing—that is, "fracing" or "fracking"—of the host rock. Hydraulic fracturing has been conducted in vertical boreholes since the 1940s for enhanced conventional production of oil and gas.

The increasingly long horizontal wells (most laterals are more than 1 km or more than 3000 ft) with an increasing number of fracturing stages (Tutuncu et al. 2012) used in unconventional gas production require substantially higher hydraulic fracturing-fluid injection volumes, however. For example, water-based hydraulic fracturing of the Horn River Basin (British Columbia, Canada) requires approximately 50,000 m^3 of fluid (10–20 million gallons) and approximately 2000 metric tons of proppant per horizontal well with 20 fracs per well (Johnson and Johnson 2012). Similarly, 7700 to 38,000 m^3 of fluid (2–10 million gallons) is used to fracture each horizontal deep well in the

[1]We use the term "shallow groundwater" throughout this article as a short-hand to indicate potable or otherwise useable water with a total dissolved solids (TDS) content of less than 1,000 mg/L that is—or may in future—be used as a groundwater supply for homes, farms, industries or municipalities. Thus the term "groundwater protection" refers to the protection of this groundwater, while "saline groundwater" and "saline aquifers" indicate waters with higher TDS, typically more than 4,000 mg/L, which are not suitable for human or livestock consumption.

Apps' Ex. 25

0533

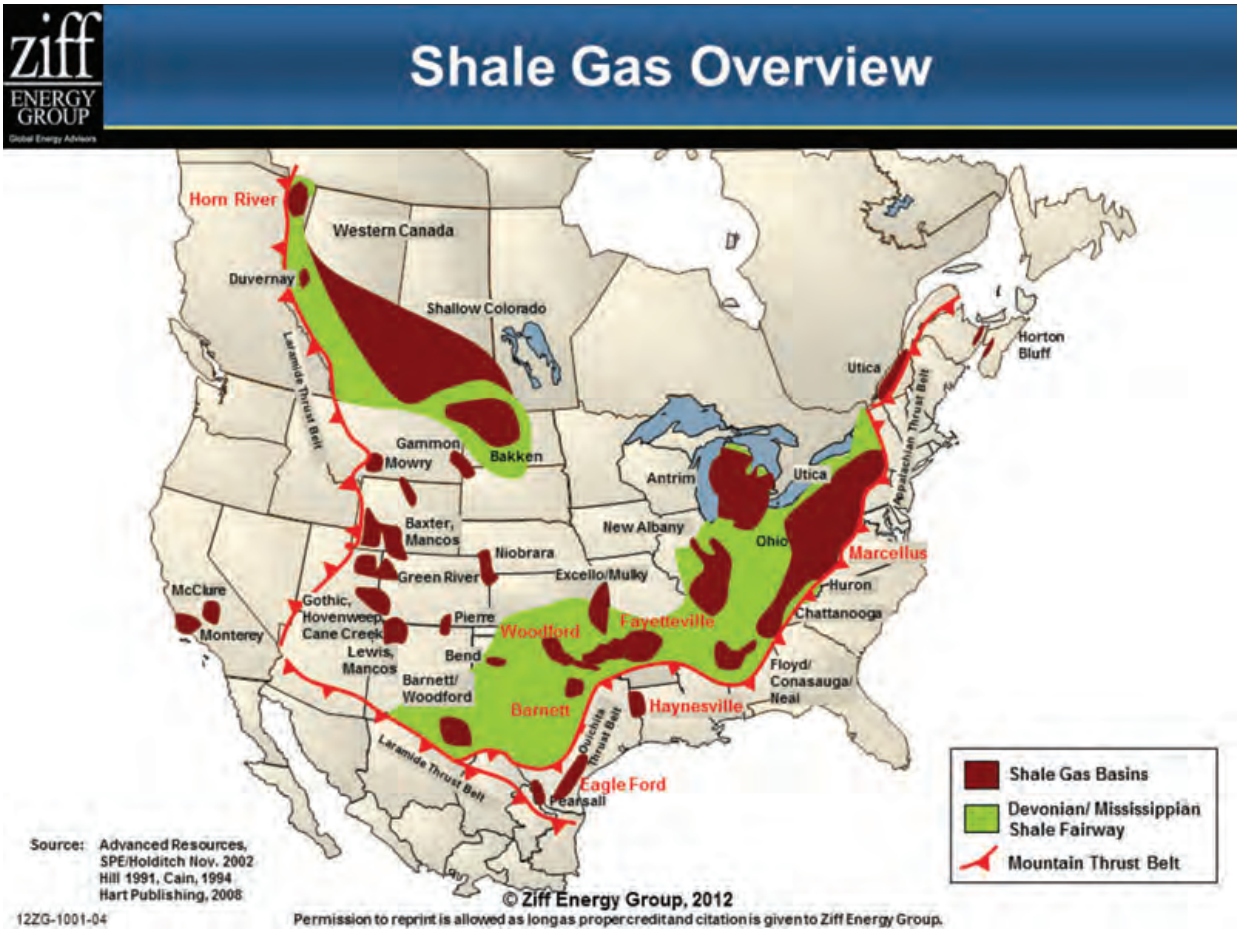


Figure 1. Distribution of shale gas plays in North America. Note that other unconventional formations (e.g., tight-gas, sandstones, and coal formations) are not shown. (Courtesy of Ziff Energy Group, Calgary, 2012.)

Marcellus Shale in the northeastern United States (Kargbo et al. 2010). Because water used in hydraulic fracturing can imbibe into the host rock's matrix and reduce gas relative permeability (and hence gas production), nonaqueous based fracturing fluids (Table 1; e.g., Lestz et al. 2007) provide an alternative approach that also assists with water supply and gas recovery issues.

Hydraulic fracturing is conducted sequentially in "stages" or perforated sections of the horizontal production casing (Figure 2), and involves the injection of fluids (gases, liquids, foams), with a mix of additives (discussed below), at elevated hydraulic pressures around each "stage" to produce and propagate fractures. The fractures increase the bulk formation permeability through shear failure (see Zoback et al. 2012), allowing hydrocarbon gases to flow into the production well. The hydraulic fracturing liquids are designed to conduct proppants (e.g., sand and other noncrushable substances; Table 1) that enter the new fractures formed in shales and tight sandstones, preventing them from reclosing.

Hydraulic fracturing-induced fractures predominantly develop in the plane perpendicular to the orientation of the least principal stress, which in deep shale gas reservoirs (more than 2 km or more than 6000 ft) is usually one of the two horizontal stresses (Zoback 2010). In some cases "preferential opening of the natural fracture systems" is more dominant than opening of new hydraulic fractures (King 2010). While "pre-existing fractures and faults have some influence on fracture propagation, the overall trajectory of fracture propagation is controlled by the orientation of the least principal stress" (Zoback 2010).

While most shale gas plays in North America are deeper than one kilometer, a few shallower plays are exploited to a limited extent (e.g., the eastern extent of the Colorado Group in Alberta (~300 m depth) and the Antrim Shale in Michigan [180 to 670 m]). Many coalbed gas formations are also present at shallower depths (less than 600 m), where vertical wells that are typically fracked with nitrogen (NEB 2009) and horizontal fracturing orientation predominate. Empirical data suggest that horizontal fracturing predominates in stimulation conducted shallower than 450 m depth, while vertical fracture orientations predominate below 600 m depth (Warpinski 2011), because of the principal stress orientations. This is because at these shallow depths within the overburden the direction of least principal stress is vertical due to erosional unloading that has occurred in sedimentary basins (for discussion see Goodman, 1989

Apps' Ex. 25
0534

Table 1
Composition of Fluids Potentially Present in Fracking Fluids

Component and Purpose	Chemical
Carrier or "make-up" fluid	Water, N_2, CO_2, LPG, foams, emulsions
Proppants—designed to keep fractures open after fracking fluid pressure decreases	Sand, resin-coated sand, sintered bauxite, alumina, ceramics, and silicon carbide
Clean up damage from initial drilling, initiate fracturing	HCl, other acids
Additives to adjust frack fluid viscosity, and form gels—designed to keep proppants suspended in frack fluid so it will enter and "prop open" new fractures	Viscosity adjusters: Guar gum, cellulose-based derivatives. Gel formation: Cross-linking agents (borate compounds or metal complexes)
Viscosity "breakers" (reducers) designed to decrease viscosity after frack fluid has reached its target zone	Ammonium persulfate, sodium peroxydisulfate
Stabilizers to delay the action of breakers, biocides, fluid-loss additives, friction reducers	Latex polymers or copolymers of acrylamides, and acid corrosion inhibitors, e.g., alcohols
Acid corrosion or scale inhibitors	Isopropanol, methanol, formic acid, acetaldehyde
Friction reducers for low-viscosity "slickwater" fracking where proppants penetrate more deeply into fractures	Surfactants, polyacrylamide, ethylene glycol
Biocides to inhibit sulfate reducers	Aldehydes, amides
Surfactants to improve relative gas permeability	Isopropanol
Clay stabilizer to prevent clay flocculation	KCl (for clays)
Other	Glycols, amines, defoamers

Sources: Lyons and Plisga 2004; Kaufman et al. 2008, MIT 2011; US EPA 2011; van Stempvoort and Roy, 2011, and Schlumberger (www.slb.com), and OpenFrac.com.

and Zoback 2010). Data from tiltmeters and microseismic imaging also indicate that mixed vertically and horizontally oriented fractures are often generated when stimulating reservoirs at depths below 450 m and above 2 km.

Fracture growth monitoring by microseismic and microdeformation techniques suggests that induced vertical fracture heights do not exceed "tens to hundreds of feet" (Fisher and Warpinski 2012). The evidence available is largely related to remotely measured or modeled fracture propagation. For instance, the empirical analyses of microseismic data from several thousand fracturing operations in four U.S. shale gas plays by Davies et al. (2012) indicated a maximum fracture height of approximately 590 m and a probability estimate of approximately 1% that a stimulated hydraulic fracture would extend vertically more than 500 m. From this, the authors (Davies et al. 2012) derived a general minimum separation distance of 600 m between target shale and overlying freshwater aquifers but they also suggested that minimum separation distances be investigated for each new geologic area.

However, a Society of Exploration Geophysicists research committee has reported that "downhole microseismic monitoring has limited spatial coverage creating a bias at the event locations and an incomplete view of the stimulated reservoir volume" (Tutuncu et al. 2012). Reducing this bias would require one or more shallow (30 to 60 m deep) boreholes drilled exclusively for seismic monitoring (which, notably, could be used for subsequent groundwater monitoring). A related technique, near surface microseismic data acquisition, has also recently been adopted for hydraulic fracturing monitoring (Duncan and Eisner 2010) to improve the estimation of the reservoir volumes that are stimulated by hydraulic fracturing, identify subsurface faults, and monitor posthydraulic fracturing microseismic activity after the hydraulic fracturing pumps are turned off (Wessels et al. 2011).

Table 2
Composition of Inorganic Ions in Flow-back Fluids from Three U.S. Shale Plays

	Formation		
Analytes (mg/L)	Fayetteville	Marcellus	Barnett
Na	5363	24,445	12,453
Mg	77	263	253
Ca	256	2921	2242
Sr	21	347	357
Ba	0.8	679	42
Mn	0.5	3.9	44
Fe	28	26	33
SO_4	149	9.1	60
HCO_3	1281	261	289
Cl	8042	43,578	23,798
TDS	15,219	72,533	39,570
Sp Gravity	1.01	1.05	1.03
Depth (m)	300–2000	1200–2600	2000–2600

Source: Aqua-Pure Ventures, Calgary, Alberta, http://www.fountainquail.com/news/presentations/assets/IOGCC_Shale_Gas_Water_Mngt.pdf.

"Flow-back fluids" are extracted from the gas well after hydraulic fracturing to improve relative gas permeability and enhance gas production. These fluids (Table 2) initially tend to be comprised mainly of the

Apps' Ex. 25
0535

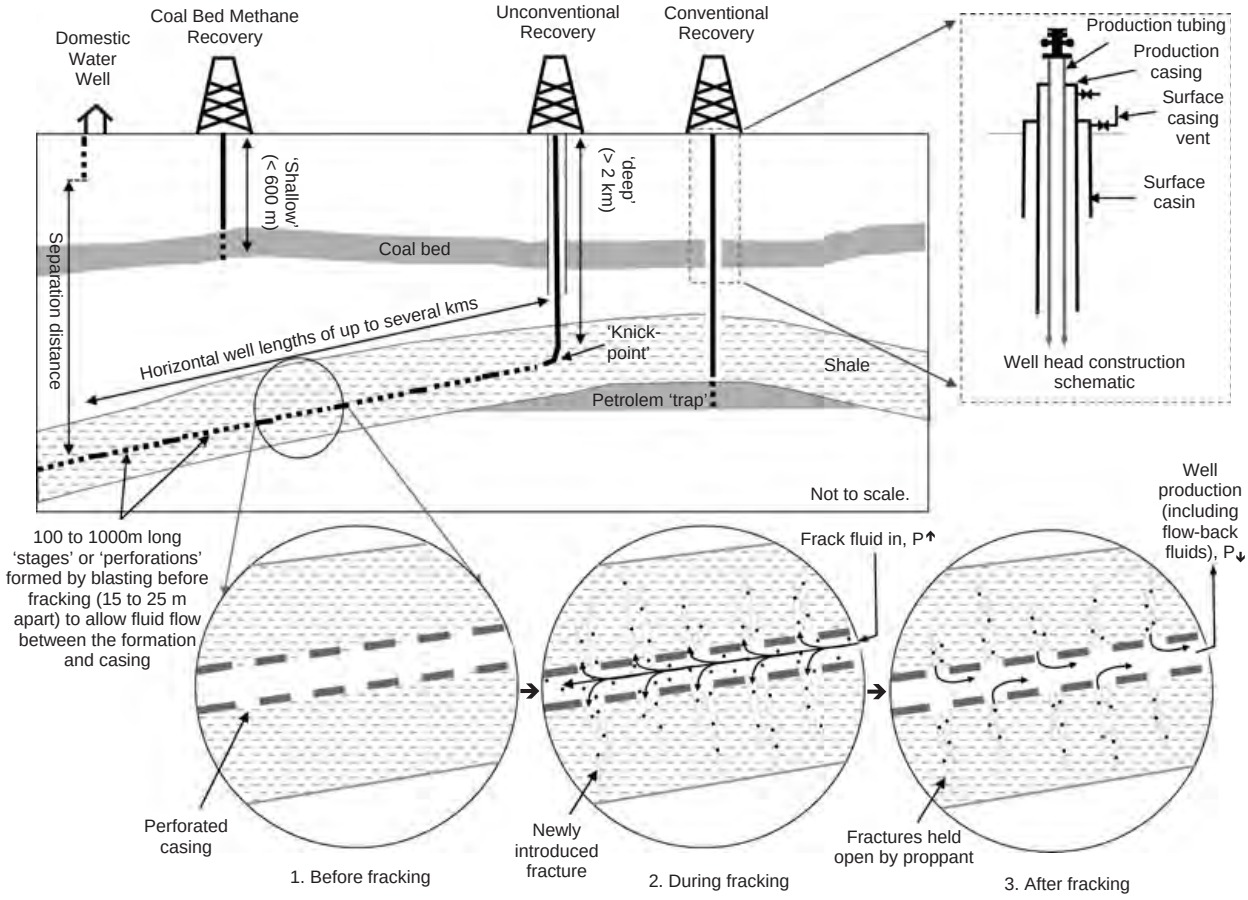


Figure 2. Schematic illustrating (i) the nature of conventional, coal-bed methane, and "unconventional" resource recovery, (ii) the hydraulic fracturing process; and (iii) the nature of surface and production casing (and associated borehole annulus cementing).

injected fracturing fluids, but with continued production an increasing contribution may come from formation waters if the formation contains "movable fluids," that is, they exhibit higher than irreducible water saturation. Injected fluids can react with the host formation and leach both salts and radionuclides that change flow-back water quality.

These flow-back fluids usually require on-site storage followed by recycling, reinjection, or deep-well disposal into a saline aquifer. The potential for groundwater contamination by flow-back fluids is therefore quite varied. For example, flow-back fluids may contaminate shallow groundwater due to releases from lagoons during extreme precipitation events or failure of the impoundments. Consequently, regulatory agencies have increasingly required on-site storage containers (and lagoons) to be covered to prevent such releases (e.g., ERCB 2011).

Contaminants of Concern

Groundwater can be affected during unconventional gas production by substances associated with natural gas itself, that is, principally methane (US NIOSH 1983). The primary problem with methane in shallow aquifers is that it poses both an explosion and asphyxiation (confined spaces) hazard either during well water extraction or by escaping and accumulating in basements, well pits, etc. The American Conference of Governmental Industrial Hygienists' (ACGIH) methane exposure limit in air is 1000 ppm (time-weighted average). Many jurisdictions require reporting for "trigger levels" of dissolved methane in well water (e.g., 28 mg/L is a "recommended action level" from the U.S. Department of the Interior Office of Surface Mining Reclamation and Enforcement; US DOI 2001).

Within shales, we may expect roughly equal gas-phase and water-phase porosities, that is, saturations (Curtis 2002). However, methane dissolved in formation waters will have a solubility controlled by the temperature, hydraulic pressure, and salinity of the formation (Duan et al. 1992) that is likely far greater than the solubility of methane in groundwater at ground-surface temperatures and atmospheric pressure (~30 mg CH_4/L). By fracturing the gas reservoir, an operator removes some formation water to increase the relative gas permeability and recovers the gas as it desorbs, depressurizes (decreasing the bubbling pressure), enters the fractures and is extracted (see Figure 2). If this gas is not captured,

Apps' Ex. 25
0536

it is available to migrate as the buoyant free gas phase up the annulus of poorly cemented wells.

Free gas exsolving or bubbling through water in water wells may also lead to deterioration of water quality including well water discoloration and turbidity due to microbubbles or particulate suspension (Harrison 1983; Bair et al. 2010; Gorody 2012). Microbiologically-mediated oxidation of free and dissolved hydrocarbons (e.g., methane) can be accompanied by iron and sulfate reductions leading to Fe(II) and/or Mn(II) sulfide mineral precipitation, and the attendant odor of reduced gases such as H_2S (Rauch 1983; Kelly et al. 1985; Gorody 2012). Free gases in groundwater around well screens can also cause a decrease in hydraulic conductivity with an associated decrease in water well yield (Yager and Fountain 2001; Gorody 2012). "Stray gas" or "fugitive gas" is one of the main concerns around unconventional gas recovery. Chemical and isotopic analyses (see Box 1) are used to differentiate between "thermogenic" gases produced from the target reservoirs, mixed gases from intermediate formations, and "biogenic" gases most frequently found in shallower geologic formations and aquifers.

Box 1

Geochemistry of Natural Gas

Natural gas forms in the subsurface by the transformation of organic matter to methane (CH_4 or C_1) and potentially other low molecular weight, volatile hydrocarbons such as ethane (C_2H_6 or C_2) and propane (C_3H_8, or C_3). This can occur through anaerobic microbial reactions such as methanogenesis resulting in ''biogenic'' or ''bacterial'' gas mainly composed of CH_4, or by abiotic processes at elevated temperatures and pressures, resulting in ''abiogenic'', ''thermocatalytic'', or ''thermogenic'' natural gas. The latter often contains not only methane (C_1) and ethane (C_2), but also higher alkanes such as propane (C_3), butane (C_4), and pentane (C_5).

Over the course of the last 30 years the natural formation of biogenic and thermogenic methane has been documented to occur in a wide array of anaerobic environments (e.g., Barker and Fritz 1981; Schoell 1988; Whiticar 1999). Biogenic methane is commonly associated with organic-rich marine and lacustrine sediments, peat, and coal deposits and is generated in low-temperature and -pressure environments. For some shallow aquifers in Alberta (Taylor et al. 2000) and Texas (Grossman et al. 1989) it has been suggested that not only methane but also ethane is generated by biogenesis. In other shallow aquifers in Ontario (Aravena et al. 1995), Illinois (Coleman et al. 1988) and Iowa (Simpkins and Parking 1993) only biogenic methane has been found. The absence of propane, butane, and pentane in biogenic natural gas results typically in wetness parameters (the ratio of C_1/C_2-$C_5) > 1000$. Thermogenic methane is created under high temperatures ($>120\,^{\circ}C$) and pressures (50–80 MPa) found at depth (>2500 m) within sedimentary basins (Hunt 1979; Barker 1990). Due to often appreciable amounts of ethane, propane, butane, and pentane in thermogenic gas its wetness parameter is typically much lower than 1000. Coal-bed gas systems can contain thermogenic, migrated thermogenic, biogenic, or mixed (thermogenic and biogenic) gas. Mixed gas may be produced through a variety of mechanisms including the incursion of Pleistocene meltwaters into sedimentary basins containing organic-rich shales (Martini et al. 2003).

Natural gas formed through these different processes and in different formations can be distinguished by a suite of geochemical and isotopic analyses. These include the concentrations of methane (C_1), ethane (C_2), propane (C_3), butane (C_4), and pentane (C_5), the stable carbon and hydrogen isotope ratios contained within these normal alkanes, as well as ^{14}C, which allows discrimination between recent biogenic and fossil thermogenic hydrocarbons. The upper figure presents a cross-plot of $\delta^{13}C$ and $\delta^{2}H$ values of biogenic and thermogenic methane for selected shallow aquifers and resource plays in North America. $\delta^{13}C$ values predominantly < -55‰ in shallow groundwaters of Alberta and selected groundwater wells from Pennsylvania suggest that the methane is of biogenic origin (Cheung et al. 2010; Osborn and McIntosh 2010). In contrast, thermogenic and mixed gas from various resource plays is typically characterized by $\delta^{13}C$ values > -60‰ and sometimes higher $\delta^{2}H$ values (Jenden et al. 1993; Desrocher 1997; Laughrey and Baldassare 1998; Martini et al. 2003; Hill et al. 2007; Cheung et al. 2010; Osborn and McIntosh 2010; Rodriguez and Philip 2010; Tilley et al. 2011; Tilley and Muehlenbachs 2013) compared to those found for biogenic methane. This graph is typically known as a Schoell (1988) diagram. The lower figure shows a Bernard diagram where biogenic gas is typically distinguished by $\delta^{13}C$ values < -55‰ and wetness parameters more than 1000 (Cheung et al. 2010; Osborn and McIntosh 2010) from thermogenic gases that are often characterized by $\delta^{13}C$ values of methane > -60‰ and wetness parameters less than 1000 (Jenden et al. 1993; Desrocher 1997; Laughrey and Baldassare

Apps' Ex. 25

0537

1998; Martini et al. 2003; Hill et al. 2007; Cheung et al. 2010; Osborn and McIntosh 2010; Rodriguez and Philip 2010; Tilley et al. 2011).

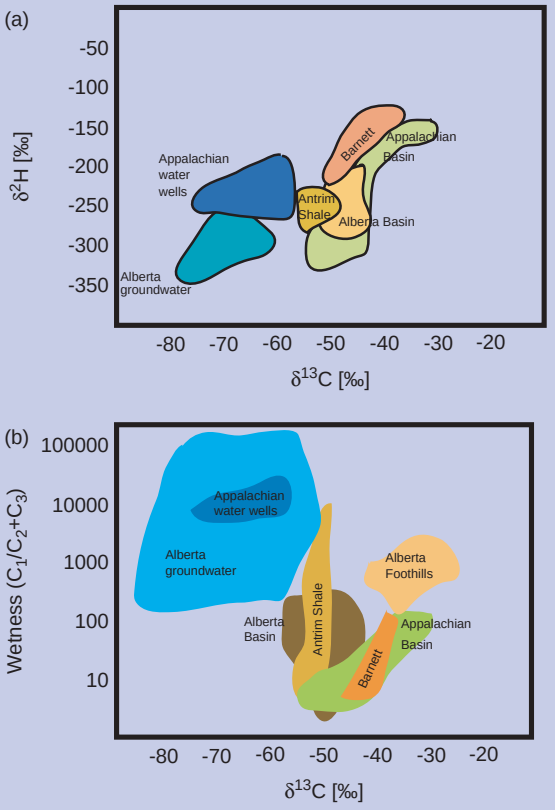


Figure for Box 1. Schoell (upper) and Bernard (lower) diagrams displaying the $\delta^{13}C$ values of methane vs. $\delta^{2}H_{CH4}$ values (Schoell) and gas wetness (Bernard) in shallow groundwater of Alberta (Cheung et al. 2010, unpublished data) and Pennsylvania (Osborn and McIntosh 2010), and various natural gas plays in Northern America (Jenden et al. 1993; Desrocher 1997; Laughrey and Baldassare 1998; Martini et al. 2003; Hill et al. 2007; Cheung et al. 2010; Osborn and McIntosh 2010; Rodriguez and Philip 2010; Tilley et al. 2011).

There is much public concern that specific chemicals present in fracturing fluids may pollute shallow groundwater in the vicinity of unconventional gas sites. Fracturing fluids may be based on, or made up with, a number of fluids (water, hydrocarbon, emulsions, foams, or gases, e.g., N_2 or CO_2), and may contain a wide range of chemical additives (Table 1 and Van Stempvoort and Roy 2011). Access to information about the chemical composition of hydraulic fracturing fluids and additives is emerging as appropriate information databases are published (e.g., http://fracfocus.org/).

Shallow groundwater might also become contaminated by natural liquids from the producing formation, including saline formation waters and gas condensates (Box 2). Formation waters are usually Na-Cl saline fluids or brines with elevated total dissolved solids and can contain naturally occurring heavy metals (e.g., barium) and radionuclides (e.g., ^{226}Ra from decay of natural ^{238}U in the shales). Because of the deleterious effects of saline formation waters or brines on activated sludge processes in municipal treatment plants, the disposal of brines is increasingly directed to injection wells or to recycling facilities where they exist (e.g., Pennsylvania and Texas). Condensates can also have elevated salinity, sodium, metals, naturally occurring radionuclides, and organic compounds (Hitchon et al. 1971; Orem et al. 2007; Kargbo et al. 2010).

Box 2

Defining 'Groundwater Gas' Terms—An Interdisciplinary Challenge

States in which "gases" can exist:

- True "gas" state, also known as "free" gas or bubbles.
- *Sorbed* gas—coal-bed gases (i.e., mostly methane) that don't flow into wells unless the formation pressure is lowered by pumping.
- *Dissolved* gas—gas molecules that are dissolved in water. Dissolved gas concentrations are discussed below.
- *Nonaqueous phase liquid (NAPL)*—many hydrocarbons can occur as an oily liquid. This can also be called "liquid natural gas" or "condensate".
- Gas *condensate*—hydrocarbons, usually coproduced with (or "condensed from") natural gas, which are near-liquid at ambient conditions. Typically C_2 to C_{20} compounds.

Terminology

Gasoline or **petrol** is comprised mainly of fractionally distilled petroleum that is liquid under ambient conditions.

Gasoline Range Organic' (GRO) compounds include four volatile petroleum compounds often known by their acronym "**BTEX**": benzene, toluene, ethylbenzenes, and xylene. They are commonly used as indicator parameters for gasoline or petrol spills.

Natural Gas is dominantly methane, but can have minor concentrations of CO_2, H_2S, and C_2-C_5 hydrocarbons.

Shale Gas (also known as **Unconventional Gas** and **Tight Gas**) is natural gas produced from relatively impermeable formations.

Apps' Ex. 25

0538

Methane in natural gas can be:

- biogenic—formed by microbial processes (e.g., CO_2 reduction in relatively shallow, low temperature environments)
- thermogenic—formed by ''cracking'' of organic matter in deeper formations at higher temperature (more than 120 °C). Also called ''thermocatalytic'' gas.

Liquefied petroleum gas—gas mixtures that occur in the liquid and/or nonaqueous phase under ambient conditions (e.g., propane and butane).
Wet or **associated gas** is natural gas with liquid hydrocarbon or condensate phases present.
Dry or **nonassociated gas** is more than 95% methane (or C_1).
C_1-C_n gases—one of two nomenclature approaches, where the subscript indicates the number of carbons in a chain (aliphatic) or ring (aromatic) structure (for example methane is C_1; ethane, also known as ethylene are C_2, etc.).
''**Wetness**'' is often used to characterize natural gas—often estimated as ($C1/\sum C_{2+3}$) where biogenic gas typically more than 1000 and thermogenic less than 1000. Thermogenic gas often is rich in C_{2+3} hydrocarbons, whereas biogenic gas is not.
Gas as biogeochemical parameter:

- ''**biogeochemical**'' gases (formed of carbon, hydrogen, oxygen, nitrogen, and sulfur; e.g., O_2, CO_2, CH_4, N_2, H_2, H_2S, etc.)—gases are produced or consumed in major biogeochemical processes. Almost all of these gases are redox sensitive or redox determining.
- ''**permanent**'' or ''**fixed**'' gases have two possible definitions:
  - do not form a liquid phase under near-surface temperatures and pressures—also known as ''incondensable'' gases;
  - are those gases within the atmosphere with relatively constant (i.e., ''permanent'') concentrations (e.g., O_2, N_2, and Ar);
- **inert** gases can be defined as monoatomic gases with low chemical reactivity (e.g., He, Ne, Ar, Kr, Xe, and Rn),

Describing gas ''concentration'' in the subsurface:

- **Total dissolved gas pressure** *(TDGP or P_{TGD})*—sum of the partial pressures of all dissolved gases, measured *in situ* or by using advanced gas sampling and analytical techniques. P_{TGD} can be measured in absolute or gauge (absolute minus atmospheric pressure). At the groundwater table, absolute P_{TGD} is equal to atmospheric pressure and gauge P_{TGD} is equal to zero. Because dissolved gas solubility increases with water pressure (Manning et al. 2003), estimation of true dissolved gas concentrations requires the measurement of *in situ* total dissolved gas pressure (P_{TDG}; Manning et al. 2003) together with gas composition unless advanced sampling and laboratory techniques (Beyerle et al. 2000; Gardner and Solomon 2009) are used. True or *in situ* dissolved gas concentration can be estimated as the product of the lab-estimated dissolved gas concentration (really equivalent to a gas composition since it is measured at the atmospheric pressure in the lab; P_{LAB}) multiplied by the ratio of P_{TDG}:P_{LAB} (McLeish et al. 2007). Dissolved groundwater gas concentrations are at their maximum at a depth in the subsurface (or a given hydraulic pressure) when P_{TDG} is at its ''bubbling pressure'' (equal to absolute pressure, or the sum of atmospheric and hydraulic pressures; Manning et al. 2003; Roy and Ryan 2010). At this point, the groundwater is saturated with respect to dissolved gases, and increased gas production can result in a phase change to free gas state, or bubble exsolution. Since stray gas migration often involves free gas transport, the P_{TDG} can be compared to the bubbling pressure to determine the likelihood that free gas would be present in a formation. Although the build up, and possibly ''pulsed migration'', of free gases (Gorody 2012) can cause significant changes in the mass of gases within a formation, the P_{TDG} may stay at or near the bubbling pressure. In this case, changes with time or space in dissolved gas and isotopic composition may be more diagnostic than changes in P_{TDG}.
- **Gas composition** is the relative concentrations of different gases as a percentage of all gases. Gas compositions can be expressed as equivalent volumetric ratios (i.e., ppmv) or volume percentages in the gas phase. When they are at STP (Standard Temperature & Pressure), gas compositions can be equal to gas concentrations if they are expressed as volume ratios (e.g., the atmosphere is 78.1% N_2, or 780,900 ppmv).
- **Dissolved gas concentration** is
  - the mass of a gas per unit volume of water (or unit mass of water for brines).

Apps' Ex. 25
0539

Common dissolved gas units are (1) mg/L or mmol/L; (2) cm^3_{STP}/L or ppmv, or (3) equivalent partial pressure of gas phase (atm or mm Hg). If units like ppmv are used, care needs to be taken to ensure both the units of the gas solute and matrix (i.e., mass or volume; gas or liquid state of matrix) are clearly stated;
  - limited by formation of free gas or mass transfer with free gas at the ''bubbling pressure'';
  - a function of Henry's Law (temperature and salinity dependent) and the *in situ* partial pressure of the gas of interest;

- Although *dissolved gas concentrations* are often estimated by ''headspace extraction'' (Kampbell and Vandegrift 1998), this technique is only valid if the P_{TDG} is close to water equilibrated with the atmosphere (i.e., absolute P_{TDG} equal to atmospheric pressure).
- **Bubbling pressure** is reached when P_{TDG} is equal to the hydrostatic pressure. If P_{TDG} increases past this pressure, mass transfer into the free gas phase should occur—i.e., exsolution, field effervescence, bubbling.
- **gas solubility** is the maximum concentration of a gas that can exist in water at specific salinity, temperature, and (hydrostatic) pressure in combination with the other gases in the same water.

Gas ''Saturation'' can have multiple meanings:

1. The relative proportion of gas phase to total porosity (also know as gas porosity) within subsurface pore space. The presence of a free gas phase implies that there is a measureable gas saturation, S_g, in the pore volume (PV) such that the PV is ''saturated'' with gas (S_g), water (S_w) and perhaps oil (S_o) in which $PV = S_g + S_w + S_o$.
2. Critical gas saturation (in coal-bed methane) is the gas saturation (or gas porosity) upon which coal yields gas when pumped. Gas saturation can be increased by decreasing the formation pressure (and hence decreasing the critical bubbling pressure).
3. *Dissolved gas* saturation occurs when the P_{TDG} is equal to the *bubbling pressure*.

Stray or fugitive gas: Terms usually applied to natural gas (or perhaps carbon dioxide) that has escaped from a well or gas-handling facility near the oil or gas well and has been detected in a location where it is unwanted. In the context of this article, it is natural gas that has migrated into shallow groundwater from a geological source most likely through a poorly or incompletely cemented well.

The State of the Science

Over the past few years numerous editorials, reports, and issue papers have been written about environmental issues related to shale gas development, all of which address groundwater issues to varying extents (e.g., Kargbo et al. 2010; Zoback et al. 2010; Schnoor 2012; ALL Consulting 2012; Groat and Grimshaw 2012; Rozell and Reaven 2012; Tutuncu et al. 2012; UK Royal Society/Royal Academy of Engineering 2012). Many of these contributions are "white papers," focusing mainly on delineating the potential environmental issues, probable causes, and possible solutions (largely associated with more rigorous regulation and improved industry practices).

Here we address the state of hydrogeologic science, that is, what is known and what is not known, with reference to a series of case histories or grouped study work (Table 3). We argue that a better understanding of the hydrogeologic conditions, gas-migration processes and potential leakage pathways is required—that is, critical science gaps remain—to minimize the potential environmental effects of groundwater contamination by development of unconventional gas plays. The wide range of probabilities used in a recent risk analysis of potential groundwater pollution by hydraulic fracturing (Rozell and Reaven 2012) reflects the lack of field data used in their probability bounds analysis. Many of these probability ranges were based on newspaper articles or were the authors' "estimates," which clearly demonstrates the critical science gaps that confront hydrogeologists and regulatory officials as well as risk estimators.

Contaminant Pathways to Shallow Groundwater

Fugitive Gas Leakage from Active Production Wells

Many of the current, well-publicized controversies surrounding unconventional gas development in particular relate likely to the accidental releases of "stray" or "fugitive" gases into shallow aquifers via the annuli of imperfectly cemented gas wells. The source(s) of these stray gases are rarely clear (Bair et al. 2010; Gorody 2012). Although they could include the production zone, the shallower overlying formations in the "intermediate zone" between producing formations and shallow groundwater appear to be a more common source.

In an extensive study comparing the chemical and isotopic compositions of gases from surface casing vent flows (SCVF) and production zones accessed by almost 300 conventional oil and gas wells in Alberta (Canada), the majority of the SCVF samples (~75%) were sourced from formations above the production

Apps' Ex. 25
0540

Table 3
Case Histories of Gas Migration to Shallow Aquifers and What They Reveal About the Sources, Migration, and Fate of Fugitive Gas

Location	Source of Gas	Outcome	References
Animas River Valley, Colorado and New Mexico	Primarily leaking conventional gas wells and uncemented annuli of conventional gas wells in coal-bed formations. Less important were seeps into buried valley aquifers from gas-bearing sandstone.	Gas well annuli were more important than natural fractures as the primary source of fugitive gas contaminating shallow water wells in the Animas River Valley. Tectonic history important in reducing significance of natural fractures.	Chafin (1994)
Lloydminster, Alberta	Oil well venting natural gas along annulus of well	Contamination of groundwater sampled from monitoring wells in sand and gravel aquifer; isotope geochemistry used to document bacterial sulfate reduction associated with fugitive methane	Van Stempvoort et al. (2005)
Hutchinson, Kansas	Gas release from gas storage caverns apparently due to casing failure and a damaged annular well seal penetrating the storage caverns	Gas migration over 11 km apparently in fractures through a few relatively tight dolostone layers within shale; gas emergence to the surface via abandoned solution mining wells	Allison (2001), Watney et al. (2003)
Bainbridge Township, Ohio	Gas release due to poorly completed primary cement job allowed gas to migrate up surface casing annulus into sandstone aquifer	Gas penetration of the sandstone aquifer which contained numerous water wells. Structural features within sandstone acted as a gas trap resulting in long-term gas release to the water wells.	Bair et al. (2010)
Southern Alberta	Shallow coal-bed methane development with beds approximately 400 m depth	Demonstrated the importance of full geochemical and isotopic analysis to establish baseline shallow groundwater quality and to identify any natural gas that might migrate from producing formations	Cheung et al. (2010)
Southern Alberta	Widespread SCVF and contamination of shallow wells from deeper gas reservoirs	$\delta^{13}C$ for CH_4 and C_2H_6 and use of mixing curves was able to resolve the origin of methane occurrences in certain water wells. Complete identification of sources requires gas isotope analysis of each potential source formation.	Tilley and Muehlenbachs (2011)
Several U.S. gas fields	Commercial gas wells extracting from a variety of gas reservoirs are associated with shallow groundwater contamination	Surface casing head & produced gases may be different, thus source gases should be sampled repetitively and while drilling, (i.e., mud gas samples). Free and dissolved CH_4:C_2H_6 ratios provide the best baseline sampling and analysis criteria to differentiate thermogenic and biogenic fugitive gas sources. Sampling and analysis from a single gas well should be conducted multiple times.	Gorody (2012)

0541
Apps' Ex. 25

zones, while the remainder of the SCVF samples were often isotopically similar to gases from the production formation (Muehlenbachs 2012; Tilley and Muehlenbachs 2013). Similar measurements recently conducted at newly completed and hydraulically stimulated horizontal shale gas wells in the Montney and Horn River areas of northeastern British Columbia also revealed in some cases SCVF from intermediate zones and in other cases from the production formation (Muehlenbachs 2012; Tilley and Muehlenbachs 2013).

The potential for stray gas migration into shallow aquifers depends on various parameters including reservoir pressures, well completion details, etc., but is often thought to be related to inadequate construction, completion or maintenance of production wells (Chafin 1994). Indeed, unintended natural gas migration along production wellbores for conventional gas has been a *"chronic problem for the oil and gas industry . . . as a result of poor primary cement jobs, particularly in gas wells"* (Stein et al. 2003). Between 7% and 19% of more than 1000 wells drilled from 2005 to 2007 in western Canada had gas migration along the casing annulus, and 9% to 28% of them had gas leakage through surface casing vents (Bexte et al. 2008). Similarly, a 1995 study determined that 15% of primary cement completions in the United States had failed (Dusterhoft et al. 2002).

Uncemented well annuli can become primary migration pathways for stray or fugitive gas migration into shallow aquifers. For example, uncemented well annuli were identified as the principal source of stray gases migrating along vertical wells in the San Juan basin of New Mexico and Colorado (Chafin 1994). Other causes of stray gas migration include casing corrosion (particularly prevalent prior to the advent of cathodic protection) and accidental rupture. Historically, regulators have not required casing cement across formations above the principal production target zone.

The problem of leaky hydrocarbon wells is not confined to a few areas of western Canada and the southwestern states of the United States. A report by Louisiana State University (Bourgoyne et al. 1998) indicated that there were 11,500 strings of casing in over 8000 offshore wells in the Gulf of Mexico that exhibit gas migration in the annular space between casing and rock or within inner casings. The pressure gauges on all casing strings should measure zero pressure after any hydrocarbon well comes to steady state flowing conditions and once the gauge has been opened and the pressure bled off through its needle valve. If continual bleeding off is required, the effect is known as sustained casing pressure (SCP). Brufatto et al. (2003) cite U.S. Mineral Management Service data from the Gulf of Mexico indicating that "by the time a well is 15 years old, there is a 50% probability that it will have measurable SCP in one or more of its casing annuli. However SCP may be present in wells of any age."

Groundwater monitoring-well data from the immediate vicinity of hydrocarbon wells are very sparse. Van Stempvoort et al. (1996) selected oil and gas well sites in the Lloydminster area (Alberta and Saskatchewan, Canada) with indications of seepage of natural gas through defective, permeable zones in the surface casing cement sheaths of these vertical wells into soil. These well sites were considered to also be susceptible to seepage of the gas into shallow aquifers. Monitoring wells were installed in shallow aquifers immediately adjacent to these hydrocarbon wells, and subsequent sampling indicated evidence for gas migration along well casings into the groundwater at several of these sites.

It is conceivable that at other well sites, where there is no detectable gas leakage at surface, annular gas flow could be leaking into shallow aquifers that have pore pressures less than the annular gas. This could result from an inadequate surface casing cement seal between an aquifer and a gas source below. Therefore, those wells with records of surface casing vent flow and/or SCP are also more likely to be those with gas seepage into any aquifer meeting this criterion because the aquifer's capillary entry pressure to gas will be very low. This is one reason why regulators address risk mitigation by requiring operators to routinely monitor casing head pressures and report pressures exceeding predefined thresholds.

Cement grouting in a typical horizontal production well is usually conducted between both surface and intermediate casings and the shallow formations they penetrate to prevent hydrocarbon gases in the deeper formations from entering the casing or borehole annuli and traveling toward more shallow formations (Figure 2). Cement bonding between the well casing and rock is typically verified by a wireline acoustic logging tool known as a "cement bond log" (CBL), which will clearly identify the absence of a cement sheath over long pipe lengths of a few meters or more (i.e., "free pipe"). In many cases, but not always, geophysical logging is successful in identifying discontinuities in the cement sheaths (Boyd et al. 2006; also Claude Cooke Jr, Conroe, Texas, personal communication, November 28, 2012). Newer ultrasonic logging tools complement these acoustic logs but drilling-mud channels between the cement sheath and the rock wall are still not well imaged with logs in the opinion of logging experts consulted by the authors. If identified, these discontinuities can be plugged with injected cement by a process known as "remedial cementing" or "squeezing."

There are little, if any, data to evaluate the radius of formation damage that may occur during drilling that is not sealed by cement grouting. Similarly, there is little information about the effect on the casing and surrounding cement of consecutive pressuring of the vertical casing through the shallow and intermediate zones due to progressive fracturing in multiple stages.

Improved cementation procedures (e.g., Dusterhoft et al. 2002; Ravi et al. 2002) and modern acoustic and ultrasonic tools will hopefully reduce the incidence of failure. However, as the Gulf of Mexico data (Brufatto et al. 2003) indicate, the aging of the cement sheath means that a CBL conducted at well completion cannot be relied upon after years of continuing production during which

Apps' Ex. 25
0542

time the casings may expand and contract with fracturing fluids and hot, pressurized oil and/or gas, thus stressing the annular cement sheath.

There are various potential reasons for inadequate cementation of well annuli (see Cooke et al. 1983; Dusseault et al. 2000; Bellabarba et al. 2008). The net effect of these failures is to create a condition that may allow pressurized gas—and possibly, although less likely, fracturing and formation fluids—to escape from the producing zone if appropriate pressure gradients exist. More typically, pressurized gas in shallower gas-rich formations, that is, the "intermediate zone" (Dusseault 2000; Muehlenbachs 2012), can enter the uncemented or compromised cement bonding in the casing annulus, and then migrate up the annulus behind the well casing. In either manner a scenario develops by which such gases, and possibly other fluids, could invade shallow aquifers.

Such problems were illustrated by gas releases from a vertical production well in Bainbridge Township (Ohio, USA) that caused numerous shallow water wells within the Berea Sandstone aquifer to become contaminated with natural gas. An Expert Panel reporting to the State Department of Natural Resources (Bair et al. 2010) concluded that there were three successive factors leading to the accident. First, there was inadequate cement grout present to safely isolate both the top of the Clinton sandstone reservoir zone and the overlying gas-bearing Newburg Formation. Second, hydraulic fracturing pressures breached the available cement and allowed gas to flow through fractured cement and into to the open annulus above the Newburg. Third, a decision was made to shut in the resulting gas flow through the casing head. Had the casing head annulus valve not been closed and the well allowed to vent, pressure would not have been allowed to build up in the subsurface and gas would not have had sufficient pressure to migrate into water wells. Locally a structural dome within the Berea Sandstone aquifer acted as a gas trap resulting in longer-term gas release to the water wells.

The conclusions from the above examples of fugitive gas migration illustrate that for gas to migrate into shallow aquifers it requires a pathway (e.g., either an uncemented or incompletely cemented annulus), the presence of gas under pressure at or near the path through the annulus, and pressure build up below the surface casing shoe. For these reasons, casing pressures should be routinely monitored. If pressure exceeds certain critical levels then the gas must be vented to mitigate the risk of it escaping into the subsurface. Once vented, if SCP reoccurs, then appropriate measures need to be taken to mitigate the problem, for example, cementing off the nontarget gas-producing zones and determining if shallow groundwater has become contaminated by leak-off of casing gases. This pathway should receive more attention for potential migration of fracturing fluids and formation waters although migration periods for these fluids are expected to be limited to times of pressurization.

Fugitive Gas Leakage from Abandoned Wells

The risk of fugitive gas emissions (as well as formation water and fracturing fluid leakage) in areas with improperly plugged and abandoned wells installed during previous eras of oil and gas extraction is considerable based on the analysis of historic contamination incidents in Ohio and Texas by the Ground Water Protection Council (Kell 2011). For example, the Railroad Commission of Texas acknowledges that there are over 110,000 inactive wells in Texas plus another 7900 formally identified as orphan wells, that is, abandoned (Shields 2010). An estimate of the number of abandoned wells that exist in Alberta is 116,000 (Watson and Bachu 2007), and van Everdingen and Freeze (1971) estimated there were approximately 30,000 abandoned wells in the old oil and gas fields of southwestern Ontario. "Orphan well" programs operated by U.S. states and Canadian provinces seek to properly plug these wells; between 2002 and 2009 the Texan program plugged and abandoned 1500 such wells per year (Kell 2011). Several operators drilling in areas with known historic drilling activity are actively developing a variety of methods to pinpoint the location of old abandoned wells (McKee and Beasley 2012).

Improperly plugged and abandoned wells installed during previous eras of oil and gas extraction could pose a risk for shallow groundwater contamination with gases and fluids if the formations that they penetrate become re-pressurized as a result of either gas drilling, completion and well stimulation activities or deep well disposal practices. The contamination of a shallow alluvial water-supply aquifer near Fort Knox (Kentucky, USA) provides an example of formation water influx deteriorating groundwater quality. Here, chloride in excess of 10,000 mg/L discharged from abandoned exploration wells deep within the aquifer (Lyverse and Unthank 1988).

Similarly, Chafin (1994) describes gas wells in the San Juan basin in New Mexico and Colorado drilled in the 1930s that were abandoned and discharged methane into shallow groundwater (maximum measured groundwater concentration of 39 mg/L; with 25% of soil gas concentrations exceeding 100 $mg/L_{(gas)}$). Therefore regions of historical oil and gas exploration and production where unconventional gas development occurs may witness future problems of natural gas or formation fluid leakage.

Although not directly related to unconventional gas extraction, a fugitive gas release from natural gas storage in a salt cavern identified after natural gas explosions in 2001 in Hutchinson, Kansas provides insight into free gas transport in the subsurface (Allison 2001; Watney et al. 2003). Watney et al. (2003) concluded that a total of 3.5 million ft^3 at 600 psi (100,000 m^3 at 4 MPa) had migrated along the crest of an anticline at the contact between two shales at depths from 420 ft (130 m) below ground surface (bgs) at the cavern to 240 ft bgs (75 m) beneath the city. Leakage occurred through a casing failure that damaged an annular seal in a well penetrating the storage cavern. After reaching Hutchinson, the gas escaped by flowing upward through abandoned salt wells and into

Apps' Ex. 25
0543

buildings. The Kansas Geological Survey (Allison 2001; Watney et al. 2003) had great difficulty in identifying the thin dolostone units that transmitted the gas as they sought to drill venting wells to mitigate the problem. This indicates that the detection of deep gas migration pathways will probably not be straightforward and will require knowledge of the structural geology of the region and the location of existing operating and abandoned wells—both groundwater and hydrocarbon wells. Révész et al. (2010) and Bair et al. (2010) provide further examples of the difficulty of identifying gas migration pathways.

Interwellbore Communication

Cross-connection can also occur with active oil or gas wells in the neighboring area. Such cases have been reported in Alberta, including a recent case in which hydraulic fracturing in one well caused a blow-out in an adjacent oil well completed years earlier in the same formation (e.g., ERCB 2012a). The distance of such interwellbore communication (IWB) in Alberta is similar to that measured in the Barnett Shale play in Texas and appears to be up to 200 m (~600 ft) from the well being stimulated (M. Zoback, Stanford University, personal communication, November 30, 2012).

In addition, water wells can be pathways for migration of natural gas from shallow formations that contain coal seams (Armstrong et al. 2009). This is likely due to the fact that production from the water well itself (or any gas well) causes compressive stress redistribution around the well that in turn leads to a loss of the radial stress seal around the well and an opening up of natural fractures (Dusseault et al. 2000; M. Dusseault, University of Waterloo, personal communication, December 7, 2012). A technical review commissioned by the ECRB in Alberta determined that a 200 m (~600 ft) offset between a hydraulically fractured coal-bed gas well and a water well provides a sufficient safety margin to protect water wells from potential contamination (Taurus Reservoir Solutions Ltd. 2008).

Surface Spills and Infiltration of Produced Waters

The majority of examples of groundwater contamination from oil and gas operations arise from historically persistent problems with fluid containment at the surface. Leakage from surface storage has been a significant cause of groundwater contamination in the past, including saline contamination of alluvial groundwaters adjacent to oilfield brine-holding ponds (Pettyjohn 1982) and water wells (Novak and Eckstein; 1988). The storage of flow-back water may also pose risks from heavy metals, naturally occurring radioactive materials (NORMs; e.g., ^{226}Ra), and hydraulic fracturing chemicals.

On-site earth storage impoundments ("reserve pits"), typically constructed of compacted local clays and perhaps geosynthetic membranes to yield an expected hydraulic conductivity of approximately 10^{-9} m/s, are still used. Brine-induced hydraulic conductivity (K) increases due to clay shrinkage and fissuring in a salt-cavern brine pond at Fort Saskatchewan (Alberta, Canada) were implicated in seepage into the underlying clay till, with permeameter-measured K values that increased from 10^{-11} to 10^{-9} m/s to approximately 10^{-8} m/s (Folkes 1982). These results caused regulatory concern because of the presence of a buried channel aquifer 30 m (90 ft) beneath the impoundments although no contamination was reported. These impoundments are also susceptible to overflow due to extreme precipitation events or to the failure to empty the impoundment over periods of several years. As a result, double-walled storage tanks are increasingly required by regulatory agencies to replace such holding ponds and reduce the potential for overflow due to extreme precipitation events or to the failure to empty the impoundment over periods of several years.

Holding ponds associated with coal-bed gas development in the Powder River Basin of Wyoming continue to be an area of active research because infiltration and chemical reactions between produced water, surface water, groundwater, and aquifer matrix can affect the quality of drinking water, stock water, and irrigation water locally used by ranchers. As a result, the Wyoming Department of Environmental Quality (2008) has established regulations governing both the location of storage ponds and monitoring of groundwater adjacent to ponds.

Gas Migration through Natural Faults and Fractures

While gas migration via abandoned wells and production well annuli is well documented, we know little about the potential for gas migration following stimulation of horizontal wells in unconventional gas plays through natural fracture or fault systems. Structurally induced fracture zones, such as those believed to have directed gas migration near Hutchinson, Kansas (Allison 2001; Watney et al. 2003), and local structural closures (e.g., the shallow anticline in the Berea Sandstone in Ohio; Bair et al. 2010) will be important in determining potential local and regional pathways for fugitive gas. In the Hutchinson case described above, the Kansas Geological Survey (Allison 2001; Watney et al. 2003) had difficulty identifying the gas migration pathway as they sought to drill venting wells to mitigate the problem. Ultimately, the pathway was identified as a 300 m (~1 000 ft) wide zone of fractured dolomite that was only 0.9 m (3 ft) thick with a fracture porosity of 2% that stretched 14 km (8.7 miles) along the crest of an anticline.

Numerous examples of structural pathways for gas migration have been identified in the Appalachian region (Scott and Rauch 1978; Beebe and Rauch 1979; Harrison 1983 1985; Rauch 1983, 1984; Rauch et al. 1984). Recent investigations of thermogenic gas migration in New York and Pennsylvania (Fountain and Jacobi 2000; Révész et al. 2010; Molofsky et al. 2011; Osborn et al. 2011; Warner et al. 2012) implicate gas migration along structural features as pathways for gas discharge to shallow groundwaters. For example, Fountain and Jacobi (2000) documented the presence of natural gas seepage from depth via the Clarendon-Linden fault zone in upstate New York. Molofsky et al. (2011) reported that 78% of the more than 1700

Apps' Ex. 25
0544

shallow water wells sampled as part of preshale gas assessments (2008–2011) in Susquehanna County, Pennsylvania, had detectable levels of dissolved methane (biogenic, thermogenic, and mixed). Although they were not able to statistically relate gas concentration to the location of existing gas wells, they demonstrated that water wells with elevated dissolved methane tend to be clustered near and within river valleys and their tributaries. Similar to Rauch's findings 30 years before (Rauch 1983, 1984; Rauch et al. 1984), this suggested a natural geologic origin of the gas in this area (as opposed to hydraulic fracture stimulated), possibly related to the surface expression of valleys carved into regional fracture networks.

The concept of gas flow by such "microseepage" has a long history in the oil and gas literature (e.g., Levorsen 1967; Hunt 1979; Stahl et al. 1981). Brown (2000) quantitatively evaluated the potential mechanisms of gas migration concluding that free-phase gas flow explains the observation of petroleum "microseeps." According to Brown, these seeps are a consequence of a relatively low capillary entry pressure for gas to penetrate water-wet fractures and will exhibit a flux rate governed by the cubic law (i.e., gas discharge $Q \sim [2b]^3$, where 2b is the fracture aperture). Even so, gas discharge via such fractures is "low enough so that petroleum accumulations can exist for geological time" without being depleted. Leakage of hydrocarbons through faults remains of intense interest to petroleum geologists (e.g., Ingram and Urai 1999; Aydin 2000; Cartwright et al. 2007).

Gorody (2012) has provided an extensive account of the processes by which methane migrates in porous and fractured rocks toward groundwater discharge areas. Of particular interest is his observation that gas breakthrough may occur in pulses due to changes in the pore pressure and the nonwetting phase pressure exerted by the buoyant gas. Gas migration can result in rapid temporary declines in gas flow, until gas accumulation and associated pressures in the fracture path recover to a sufficient level to again exceed the gas entry pressure of the fracture or porous medium. If gas flow is intermittent, a single sampling of a contaminated groundwater well is an inappropriate monitoring strategy.

Gas Migration Through Induced Fractures

Much of the public concern around unconventional gas development appears focused on hydraulic fracturing creating pathways for gas, formation water and fracturing chemicals from the usually deep target formation to shallow aquifers. There is no evidence that fracture propagation "out-of-zone" to shallow groundwater has occurred from deep (>1000 m or >3000 ft) shale gas reservoirs, although no scientifically robust groundwater monitoring to detect gas migration has been attempted to our knowledge. A weight-of-evidence is that such fracture propagation is unlikely in deep (>1 km) operations (ALL Consulting 2012; UK Royal Society/Royal Academy of Engineering 2012). Available evidence is largely related to measured or modeled fracture propagation as aforementioned.

This conclusion may not be true when shallow hydraulic fracturing occurs associated with coal-bed methane development because of the shallow depth of the coal formations. Hydraulic fracturing in shallow formations, in particular using nitrogen or propane fracturing fluids for coal-bed methane operations, has resulted in different interpretations of the occurrence of shallow groundwater contamination in Alberta, Canada (Blyth 2008; Tilley and Muehlenbachs 2011).

The one documented case (ERCB 2012b) in which a shallow aquifer became contaminated with hydraulic fracturing fluids was due to the accidental injection of hydraulic fracturing fluids directly into a sandstone at 136 m depth (443 ft depth) when the operators believed they had perforated the coiled tubing at 1500 m depth (4900 ft). Here a chain of human errors caused the shallow groundwater contamination but no vertical propagation of hydraulic fracturing fluids from depth was involved.

The totality of these findings suggests a low probability of shallow groundwater contamination by upward propagation of hydraulic fractures from deep shale gas plays. As noted above (see Interwellbore Communication), there is evidence of induced horizontal fracturing to approximately 200 m from the stimulated well. The potential for elevated pore-pressure transmission (rather than fracture propagation) beyond this distance through preexisting fracture or fault zones has been considered by geophysicists interested in remote triggering of earthquakes (Manga et al. 2012).

Monitoring and Behavior of Contaminants in Shallow Groundwater

Hydrocarbon Gases

The presence of methane in shallow groundwater is, by itself, not definitive evidence of contamination resulting from unconventional gas development. In many areas targeted for unconventional gas, elevated concentrations of methane have existed in shallow groundwater prior to any drilling activities. "Biogenic" methane can be generated in situ in shallow groundwater (e.g., by CO_2 reduction or acetate fermentation reactions) but gas occurrences in shallow aquifers can also result from upward migration of thermogenic or mixed thermogenic/biogenic methane (Barker and Fritz 1981; Révész et al. (2010); Bair et al. 2010).

Although it may be difficult to ascertain gas source(s), some well-constrained case studies are instructive. Fugitive gas (mainly methane) migrated along the annulus of an oil well and then migrated about 10 m laterally from the oil well into a buried sand and gravel aquifer near Lloydminster, Alberta, Canada (Van Stempvoort et al. 2005). In situ bacterial methane oxidation coupled with bacterial sulfate reduction occurring within a contaminated groundwater plume was identified by a depletion of the stable isotope ^{13}C in bicarbonate and an enrichment of ^{34}S in residual sulfate in down-gradient groundwater monitoring wells. The authors concluded that these processes could

Apps' Ex. 25
0545

also be important near other oil and gas wells in western Canada and perhaps globally.

Forensic identification of stray or fugitive gas origin requires a comprehensive approach (e.g., Van Stempvoort et al. 2005; Révész et al. 2010; Tilley and Muehlenbachs 2011). In addition to the usual geochemical approach in groundwater quality investigations (e.g., measurement of pH, DO, Eh, major ions, and redox sensitive minor ions, such as Mn and Fe), a field investigation would also ideally include the following: (1) appropriate sampling techniques to collect representative groundwater samples of dissolved or free gas, (2) dissolved or free gas composition analyses, (3) estimation of in situ total dissolved gas pressure (Roy and Ryan, in press this issue), (4) determination of the stable isotope composition of gases; and (5) possibly the identification of microbial consortia responsible for catalyzing redox reactions. Inexpensive and reliable methods have been developed for dissolved gas sampling to determine composition (e.g., Gorody 2007; Hirsche and Mayer 2007). Compositional analyses for dissolved gas (Box 2) can follow different approaches and are increasingly undertaken at commercial laboratories.

Fingerprinting the chemical and isotopic compositions of natural gas associated with both shales and shallow groundwater is an effective tool for evaluating potential environmental impacts of hydraulic fracturing of horizontal wells in unconventional gas plays. Biogenic gases produced *in situ* in shallow aquifers are predominantly composed of CH_4 with low $\delta^{13}C$ (-50 to -110‰ VPDB) and $\delta^{2}H$ values (as low as -350‰ VSMOW). In contrast, thermogenic gases generated at elevated pressures and temperatures are usually composed of methane (C_1) and higher alkanes such as ethane (C_2), propane (C_3), and possibly butane (C_4) and pentane (C_5), with $\delta^{13}C$ values often ranging between -55 and -25‰. Therefore, stable isotope analyses, wetness parameters and Bernard diagrams (see Box 1) when used together can be an effective tool to assess the sources of natural gas in shallow aquifers. If the chemical and isotopic compositions of natural gas in all gas-bearing formations are known, it may also be possible to identify the formation from which stray gases have been derived contaminating shallow groundwater with natural gas (e.g., Tilley and Muehlenbachs 2011). While natural gas occurrences in some formations, such as coal-bed methane in Alberta, are readily fingerprinted by geochemical and isotopic measurements (Cheung et al. 2010; Tilley and Muehlenbachs 2011), other formations display considerable variability in these parameters (Gorody 2012). Tilley and Muehlenbachs (2013) provide a comprehensive review of the isotope geochemistry of several United States and western Canadian shale-gas reservoirs.

A widely accepted methodology for sampling, analysis, and data interpretation would help to resolve uncertainties and disputes regarding impact of fugitive gases on shallow aquifers and their potential causes. The protocol presented in Gorody (2007) is one example that could be advanced and adopted; additional field methods and isotopic tools could be employed where conditions warrant for interpretation of complex data (e.g., van Stempvoort et al. 2005; Hirsche and Mayer 2007; McLeish et al. 2007; Roy and Ryan 2010; Gorody 2012).

A particularly important component needed for the isotopic fingerprinting of gas-bearing formations is the characterization of $\delta^{13}C$ values of gases in drilling muds recovered from the vertical portion of energy wells (Rowe and Muehlenbachs 1999; Tilley and Muehlenbachs 2006, 2011). This would greatly facilitate the identification of sources of potential stray gas in shallow aquifers and may facilitate the remediation of gas leakage into aquifers, if necessary.

Formation Waters

Saline formation waters typically contain solutes that, when brought to the surface, can potentially contaminate soil and groundwater. These solutes are primarily sodium and chloride but may also include arsenic, barium and radium-226, the latter generated by the radioactive decay of uranium in shales. Because of the deleterious effects of saline formation waters or brines on activated sludge processes in municipal treatment plants, the disposal of brines is increasingly directed to injection wells or to recycling facilities where they exist (e.g., Pennsylvania and Texas).

Saline formation waters have recently become part of the shale-gas controversy due to the claims that Marcellus formation brines are migrating to shallow aquifers through pathways "unrelated to recent drilling activities" (Warner et al. 2012). Given that the Silurian sandstones and Devonian shales of the Appalachian basin have water-phase porosities approaching irreducible saturations (Soeder 1988; Ryder and Zagorski 2003), there is some question as to the availability of such brine for migration. Engelder (2012) suggests a higher brine saturation but also argues for "capillary binding" of the brine within the Marcellus shale. Nevertheless, geochemical characterization of formation waters should be part and parcel of the hydrogeological baseline reporting that will increasingly become standard if further disputes are to be rapidly and fairly resolved.

Fracturing Chemicals and Other Compounds of Interest

The US EPA (2011) is currently conducting research on hydraulic fracturing, specifically related to its potential impacts on drinking water. In part, it is anticipated that this study will determine whether some of the chemicals used in fracturing fluids can be detected in groundwater, and if so, obtain information about their fate and transport and toxicity. This study is using a combination of (1) analysis of existing data, (2) new case studies, both retrospective (studies at locations where hydraulic fracturing has already occurred) and prospective (collection of data at new sites prior to, during, and after hydraulic fracturing activities), (3) scenario evaluations, (4) laboratory studies, and (5) toxicity assessments.

Apps' Ex. 25
0546

The hydrogeological community has suitable expertise to evaluate the transport and fate of relevant chemicals in groundwater, including their attenuation by dispersion, sorption, and biodegradation. The behavior of some of the relevant chemicals (e.g., brine salts, aromatic hydrocarbons) in groundwater has already been well studied in other applications in contaminant hydrogeology. By contrast there is little or no peer-reviewed and published field data regarding the groundwater occurrence and fate of various anthropogenic chemicals that are widely used in unconventional natural gas production. These include various glycols, amines, and metal complexes used as corrosion inhibitors, some of which have been deemed "proprietary," or metabolites and degradates that may form from these chemicals, for example, acrylamide. In many cases, assumptions about the biodegradability of the various chemical additives, if available, have been based on laboratory studies in oxygenated environments using samples of soil, surficial sediments and/or surface waters, which are not necessarily applicable to the deep subsurface (Van Stempvoort and Roy 2011). Also there is apparently very little information about groundwater contamination by and the fate of some of the less abundant chemicals that occur in produced gas and/or condensates (e.g., hydrocarbons that contain sulfur) or produced water (e.g., ^{226}Ra, Ba, among others).

The peer-reviewed literature about groundwater monitoring programs at both conventional and unconventional natural gas production sites is sparse, suggesting that such monitoring is rarely conducted unless spills have been reported. Furthermore, many of the above chemicals are typically not included in groundwater monitoring programs. To address these science gaps, it would make sense to study the fate and transport of those chemicals considered to be threats to the environment and public health, as well as some chemicals that would be good tracers or indicators of the fluids produced or used in unconventional gas development.

Recommendations as to Research Programs

To support both sustainable development of unconventional gas and protection of groundwater resources, we identify two areas of hydrogeological research that will address key science gaps: (1) the characterization of the background or baseline conditions (including groundwater flow, geochemical and isotopic characterization, and gas pressure (P_{TDG}; Box 2) in shallow groundwater); and (2) field experiments and studies to understand better the processes by which natural gas, saline formation waters and fracturing chemicals may invade and contaminate shallow groundwaters and then be remediated where necessary. Laboratory experiments and computational studies will be needed to support this research into the transport and fate of natural gas, saline formation waters and fracturing chemicals into and within shallow groundwaters.

Baseline Groundwater Quality Mapping

Baseline or background testing of groundwater for methane concentrations and its carbon (and sometimes hydrogen) isotope ratios in some jurisdictions (e.g., ERCB 2006) is becoming standard practice in areas where unconventional gas development occurs. The aim is to determine a baseline of water quality screening parameters from which any perceived changes following the drilling and stimulation of wells in unconventional gas plays can be compared. Regulatory requirements to collect such data are principally used to address complaints. These baseline surveys tend to include existing water wells only, without use of groundwater profiling systems to detect spatial variability in free- and dissolved-gas phases, and usually fail to assess natural variations in concentrations and isotopic compositions of methane, and how these are affected by geographic region and/or geology, and with differences in aquifer properties, well construction, and pumping scenarios.

Generalized monitoring analytes useful for screening water quality are presented in Box 3 (*Forensic analysis of hydrocarbons in shallow groundwater and surface gas seeps*). This information could assist in rapid resolution in any disputes that arise. While domestic water well surveys provide useful analytical chemical data for public health authorities, the data are susceptible to gas exchange and microbially-catalyzed redox reactions within the well itself (Bair et al. 2010). These wells can also be poorly protected from surface contamination, poorly maintained and the source of the water is often uncertain. More comprehensive geochemical mapping could involve a time series of an expanded suite of parameters, ideally in a network of dedicated groundwater monitoring wells. The continued use of domestic or landowner wells requires careful consideration as they provide an initial screening of groundwater quality but one which is likely to reflect biases as identified above.

Box 3

Forensic Analysis of Hydrocarbons in Shallow Groundwater and Surface Gas Seeps

Forensic analyses of free and dissolved hydrocarbons in groundwater are designed to:

- Unambiguously identify the source(s) of stray hydrocarbons impacting surface and groundwater resources;
- Provide defensible data to demonstrate whether groundwater and surface water impacts are due to oil and gas operations, and if so, to determine when such impacts have been satisfactorily mitigated so that there is no

Apps' Ex. 25

0547

longer a threat to public health, safety, and the environment.

The approach is to sample potential gas sources within a certain radius of influence and to compare them with baseline and postimpact sample data of free and dissolved gases from affected water wells. If there is good pressure communication between a point source of natural gas and a gas seep, then the stable isotopic composition of the free gas phase at the seep tends to correspond precisely to that of the source. More often than not in such cases, the gas composition of both source and seep is also nearly identical. When gas contaminants occur in the dissolved phase, then source hydrocarbons are more likely to influenced by dilution, alteration, and mixing.

Because of the hydrologic complexity of shallow groundwater environments, the objectives of a comprehensive sampling and analysis plan should strive to unravel three principal factors affecting the interpretation of results. These are dilution (Hirsche and Mayer 2007; Gorody 2012), mixing (Jenden et al. 1993; Tilley and Muehlenbachs 2006, 2011; Révész et al. 2010), and hydrocarbon oxidation (Barker and Fritz 1981; Coleman et al. 1988; Whiticar 1999).

Dilution of hydrocarbon contaminants in a groundwater plume depends on the size of a plume, plume velocity, adsorption effects within the aquifer matrix, dispersion and fluids incorporated and mixed along the migration path. Mixing occurs as a result of the interaction between dissolved gas plumes of multiple origins. For example, it is common to observe mixing between naturally occurring biogenic gas and contaminant thermogenic gas sources. Baseline samples provide the needed end-member dissolved hydrocarbon compositions required for mixing model calculations.

Hydrocarbon oxidation is principally mediated by bacteria. Ordinarily, hydrocarbon oxidation trends in gas composition and stable isotope data do not tend to appear until well after a contaminant point source has been mitigated, for example, a leaky gas well. However, hydrocarbon oxidation rates also vary depending on the size of a plume, plume velocity, the extent of the oxidation gradient near the leading edge of the plume, and the redox environment in the host aquifer. Furthermore, if the rate of fresh dissolved hydrocarbon influx into a water well is significantly greater than oxidation rates in the surrounding wellbore environment, then the chemical and isotopic composition of hydrocarbons is not significantly altered.

Demonstrating the effects of bacterially mediated hydrocarbon oxidation is one requirement needed to demonstrate that a contaminant source has been mitigated. High oxidation rates will lower the concentration of dissolved hydrocarbons. However, when a contaminant plume mixes with aquifer fluids devoid of dissolved hydrocarbons in a water well, dilution could be mistaken for the effects of remediation. For this reason it is important to determine the composition of fluids hosting a contaminant plume and to differentiate those fluids, if possible, from fluids that may be derived from other aquifers supplying water to a water well.

Addressing the effects of dilution, mixing, and oxidation is best achieved by collecting multiple samples of both potential hydrocarbon point sources (produced hydrocarbons, hydrocarbons in annular spaces, and shallow gas obtained by sampling while drilling), and of shallow groundwater receptor sites (water and monitor wells, and hydrocarbon seeps). Using a variety of such sample types is vital to satisfactorily interpret the source of hydrocarbons in shallow groundwater environments.

Sampling available water wells within a radius of influence from potential contaminant point sources (e.g., commercial oil or gas wells) multiple times is most easily accomplished by collecting pre and postdrilling sample sets. Although providing detailed sampling protocols is beyond the scope of this paper, all sampling events should follow written, and preferably standardized, sampling and analysis plans to ensure that data quality is defensible. This includes routine collection and analysis of selected blind duplicate sample sets.

Minimum screening parameters needed to address the occurrence and source of free and dissolved hydrocarbons in groundwater samples should ideally include the following:

- dissolved methane, ethane, and BTEX concentrations;
- stable isotope analysis of carbon and hydrogen in both free and dissolved methane;
- stable isotope analysis of carbon in both free and dissolved ethane;
- fixed gases (including argon) and hydrocarbon gas chromatography of samples containing dissolved methane and ethane concentrations above a predetermined threshold or in free gas samples;
- charge-balanced major ion analyses;
- parameters useful for identifying the redox state of shallow groundwater samples; and
- routine monitoring, sampling, and analysis of gases derived from the headspace of a water well.

Apps' Ex. 25

0548

Forensic investigations designed to address impacts from potential point sources on shallow groundwater should include all the above parameters, and additional parameters to further characterize both fluid and hydrocarbon sources as needed. Parameter selection should be based on site and potential point source-specific criteria and may include one or more of the following:

- Volatile organic compounds (including benzene, toluene, ethylbenzene, *o*-xylenes, *m*-xylenes, *p*-xylenes, 1,2,4, and 1,3,5-trimethylbenzenes) and semi-volatile organic compound analysis using standard GC/MS methods;
- Stable isotope analyses of hydrogen and oxygen in water;
- Stable isotope analysis of carbon in dissolved inorganic carbon.

Minimum parameters useful for characterizing hydrocarbons in produced and bradenhead or casing-head gas samples ideally include the following:

- Fixed (including argon) and hydrocarbon gas chromatography;
- Stable isotope analysis of carbon in methane, ethane, propane, butane, and CO_2;
- Stable isotope analysis of hydrogen in methane;
- BTEX compounds (i.e., benzene, toluene, ethylbenzene, o-xylenes, m-xylenes, p-xylenes, 1,2,4, and 1,3,5trimethylbenzenes) using standard GC/MS methods.

Given the potential role of fractures and structural features in gas migration to shallow aquifers, carefully designed and located groundwater monitoring instrumentation will likely be needed, particularly for research studies and dispute resolution. Depth discrete monitoring has long been used by those industries regulated under U.S. environmental laws (e.g., the Safe Drinking Water Act or SDWA, the Comprehensive Environmental Response, Compensation and Liability Act or CERCLA and the Resource Conservation and Recovery Act or RCRA) using multilevel well systems (e.g., Einarson 2006; Cherry et al. 2007; Mayer et al. 2008). Monitoring to detect upward migration of contaminants is unusual in contaminant hydrogeology. Lesage et al. (1991) presented an approach that was used to assess the potential for upward migration of refinery wastewaters following their deep-well injection; they employed the complementary use of deep, multilevel wells and shallow, conventional monitoring wells.

Experimental Field Studies

Further scientific investigation into the potential for groundwater contamination following unconventional gas development activities is warranted. At least three approaches to field programs are possible: (1) a forensic or "retrospective" analysis of existing cases of unconventional gas development, (2) an investigation that includes gathering of field data prior to the installation and stimulation of unconventional gas wells, and periodically during the subsequent production period, and (3) controlled experiments to understand processes that are believed to be responsible for or may result in groundwater contamination.

The U.S. Environmental Protection Agency study (US EPA 2011), which deals specifically with hydraulic fracturing, involves hydrogeologic field research components, including retrospective case studies at five developed sites with reported instances of water contamination, and two prospective case studies at sites where hydraulic fracturing will occur following baseline monitoring. Site identification, initial assessment and the first round of sampling have occurred for the five retrospective sites (includes oil, shale gas, and coal gas).

Rather than simply undertaking forensic or "retrospective" analyses of unconventional natural gas sites, an appropriate approach to understanding the potential propagation of natural gases into aquifers would be to design and conduct field-scale experiments in a controlled setting. A handful of prominent field sites with collaborative, long-term research programs have spawned dozens of research papers on the fate and transport of other contaminants, in particular chlorinated solvents and gasoline components, and many of the major advances in hydrogeology have occurred as a result of these integrated field-research programs (Anderson and McCray 2011).

A similar field-focused approach for unconventional gas development with hydraulic fracturing would allow engineers and geoscientists from industry to work with research hydrogeologists and environmental chemists to develop a greater understanding of how effective monitoring systems might be developed to detect potential migration and fate of gases and chemicals used in the hydraulic stimulation process. Controlled field experiments were critical to understanding the practice of hydraulic fracturing in the 1980s at U.S. Department of Energy's Multiwell Experiment program in western Colorado (e.g., Lorenz et al. 1989; Warpinski 1990). Sites selected for this approach could include variable hydrogeologic settings in major play areas such as those in Rocky Mountain foothills in the Western Canadian sedimentary basin, the Front Range of Colorado, the Appalachian region of New York and Québec, and emerging CBM plays in Wyoming and Alberta.

Recent advances in carbon capture and geological storage and in unconventional oil and gas production have developed separately. Given the overlap in research needs for these activities, for instance with respect to potential gas leakage, there appear to be significant opportunities for technology transfers and other mutually beneficial and

Apps' Ex. 25
0549

synergetic interactions (Nicot and Duncan 2012). It will be essential that collaboration between government, industry, academia and other third party groups ensures experimental studies are conducted in a manner that inspires widespread credibility without politically motivated conflicts of interest. Furthermore, it will be necessary that the design, implementation and analysis of such studies are independently reviewed and verified by experts.

Industry has an opportunity to play a cooperative role in ensuring that unconventional natural gas production is environmentally safe and sustainable. We propose that working groups of environmental geoscientists and engineers from industry and academia cooperate to test and develop new methods to detect and monitor the presence of fugitive gas, saline water, and flowback chemicals in shallow groundwater at unconventional gas sites. Industry participation would also help to defer costs required for more comprehensive monitoring of shallow groundwater and soil coring of impoundments to address the fate of potentially hazardous chemicals in stored flow back and produced fluids. Other research objectives might also include the following: identification of gas and other fluids that may have escaped the production string of casings; improved understanding of cement curing and cement emplacement techniques; improved downhole monitoring of cement bonding; and testing the confinement of wastewaters injected into saline aquifers, depleted oil reservoirs, and other formations as proposed by Van Everdingen and Freeze (1971). Finally, it will be important to greatly expand the techniques available to hydrogeologists to undertake aquifer remediation in the event of contamination (e.g., Van Stempvoort et al. 2007a, 2007b).

Laboratory and Computational Experiments

There will be numerous reasons to conduct laboratory and numerical simulation experiments and investigations. For example, in order to design field experiments with a minimal risk of failure, it will be necessary to carefully study transport and attenuation processes of compounds of concern in the laboratory and by numerical simulation before undertaking field experiments under controlled conditions. Soil column studies and aquifer tank experiments of the fate and transport of fracturing chemicals can be used to identify the more mobile and recalcitrant compounds for field testing. Numerical simulations can also be used to evaluate risks of fluid migration through deep fault zones with known surface expressions based on parameters derived from the hydraulic testing of fault zones (e.g., Rafini and Larocque 2012).

Summary and Conclusions

This article has referred to issues that are not confined to unconventional gas extraction. It also mentioned issues that have arisen with conventional hydrocarbon extraction and which can be expected to occur with unconventional gas extraction. Articles on groundwater contamination arising from conventional oil and gas extraction sites have appeared infrequently in the two journals of the NGWA (*Ground Water* and *Ground Water Monitoring & Remediation*). Notably, oil and gas exploration and production were exempted from U.S. Federal regulations (RCRA and CERCLA) in the 1970s and 1980s; perhaps in part as a result of that policy, "upstream" groundwater issues that arose during exploration and production—gas leakage from wells and contamination from impoundments—received relatively little research attention.

Consequently, less than 10 articles in total can be counted in both NGWA journals since the early 1980s on upstream oil and gas issues. By contrast, both journals have carried numerous articles on the characterization and remediation of sites contaminated by chlorinated solvents, gasoline, and other contaminants. This lack of "anticipatory research" was observed 30 years ago to have harmed groundwater protection (Brooks 1982) through limited research. Kell (2011) has emphasized in his review of groundwater investigations conducted by state oil and gas agencies in the USA that competent site investigation is the driving force for regulatory reform.

We identify several case histories (Table 3) involving the migration of natural gas to shallow aquifers, water wells, or buildings. Several of the examples indicate the long-standing problems arising from poorly completed oil or gas wells, while one identifies the importance of abandoned wells in gas migration. It is likely that the natural gas migrated as a buoyant free phase in all cases. While these case studies are the exception and not the rule, the migration of the gas through bedrock indicates the importance of fracture flow systems and the ability of hydrogeologists to identify those pathways in order to monitor them to the depth of surface casings, that is, the full depth of potentially potable groundwater. Table 3 represents a "canon" of peer-reviewed publications on this subject.

We have identified two areas where science gaps are evident and field-focused research is required: (1) baseline geochemical mapping and the development of problem-specific groundwater monitoring systems and networks; and (2) field testing of potential mechanisms by which hydrocarbon gases, saline fluids, and fracturing chemicals might invade and contaminate shallow groundwater and of methods of aquifer remediation. To support these research initiatives it will be necessary to undertake laboratory and computational studies to (1) design and analyze field experiments, (2) screen potential groundwater contaminants and (3) evaluate potentially vulnerable aquifers near fault zones with near-surface expression.

Thus we have illustrated the potential role of the hydrogeologists in identifying, characterizing, and monitoring aquifers deemed vulnerable to contamination by natural gas and perhaps other gas-field fluids and chemicals. All of these topics will require collaboration of engineers and geoscientists from industry with hydrogeologists and geochemists from the research community. These gaps in knowledge are harmful to the safe development of natural gas resources and the protection of groundwaters as well as to the social perception of their safe development.

Apps' Ex. 25
0550

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0554

EXHIBIT 26

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TOPICAL REVIEW

Reducing oil and gas well leakage: a review of leakage drivers, methane detection and repair options

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Keywords: oil and gas wells, methane, contaminant, leakage repair, leakage detection, monitoring, regulations

Abstract

Oil and gas wells (OGWs) with integrity failures can be a conduit for methane and contaminant leakage to groundwater aquifers, surface water bodies and the atmosphere. While there have been numerous reviews addressing OGW leakage, there is a gap in the literature regarding an examination of OGW leakage that encompasses both abandoned and active wells, as well as factors that impact leakage, methane emission measurements, and options for repairing leaks. Here, we review the literature to evaluate factors and policies affecting leakage of active and abandoned OGWs, studies quantifying OGW methane emissions, and leakage repair and emission reduction options. Furthermore, our review places a greater emphasis on abandoned oil and gas wells and does not focus on one well type, such as unconventional wells. Of the 38 factors in published literature reviewed here, studies find that 15 (39%) factors, including geographic location, well deviation, casing quality and plugging status consistently affect OGW leakage. For 15 (39%) factors, including surface casing depth, well elevation and land cover, one or two studies show that they do not affect OGW leakage. For the remaining eight (21%) factors, including well age, studies show conflicting results. Although increased frequency of well monitoring and repair can lead to reduced OGW leakage, several studies indicate that monitoring and repair requirements are not always enforced. Moreover, we find 13 studies quantifying OGW methane emissions to the atmosphere at the oil and gas wellhead scale across Canada and the United States with major gaps in the geographical distribution of the collected data. Moreover, although studies measuring abandoned wells include measurements from orphaned wells, available measurements do not differentiate between orphaned and abandoned OGWs, which is important for policy makers aiming to quantify methane emission reductions of plugging hundreds of thousands of orphaned wells. To repair OGW leakage, we find that most studies focus on well cement and casing repair. There are alternatives to cement and casing repair that only reduce methane emissions, such as soil methane oxidation, but their widespread applicability requires further study. Overall, our review of factors affecting OGW leakage can be used to identify OGWs with high leakage potential and guide OGW leakage monitoring and repair policies, thereby reducing climate and environmental impacts.

1. Introduction

Millions of oil and gas wells (OGWs) exist in Canada, the United States (US) and around the world (Davies *et al* 2014, Kang *et al* 2021). OGWs can lose their integrity, the ability to contain formation fluids within the wellbore, and lead to fluid leakage from oil and gas reservoirs to groundwater aquifers, surface water bodies, the shallow subsurface and the atmosphere (King and King 2013). Here, we use the term 'OGW leakage' to broadly represent fluid leakage from OGWs to groundwater aquifers, surface water bodies, the shallow subsurface and the atmosphere, and use the term 'OGW emissions' to specifically refer to gases that are emitted to the atmosphere. Fluids that can leak through OGWs include methane (CH_4), a potent greenhouse

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gas, and other contaminants that affect human and ecosystem health, such as brine, hydrogen sulfide and volatile organic compounds (Richardson 1995, Doujaiji and Al-Tawfiq 2010, Prenni *et al* 2016, Jackson *et al* 2020). Therefore, it is important to understand OGW leakage so that greenhouse gas emissions and releases of harmful fluids to the environment can be reduced.

CH_4 is a greenhouse gas 79.7–82.5 times more potent than carbon dioxide on a 20 year timeframe (Intergovernmental Panel on Climate Change 2021). Due to its high global warming potential and the many cost-effective mitigation options (Ocko *et al* 2021), CH_4 emissions from OGWs have been a major focus of recent research (Ingraffea *et al* 2014, Kang *et al* 2016, Kiran *et al* 2017, Riddick *et al* 2019, Saint-Vincent *et al* 2020). CH_4 emissions from OGWs can occur from multiple pieces of infrastructure on the well site, including wellheads, storage tanks, separation units and batteries (Brantley *et al* 2014). In this work, we study CH_4 leakage from OGWs at the wellhead scale, with a focus on CH_4 emissions.

Several reviews have addressed OGW leakage but there is a need for analysis of OGW leakage, including both active and abandoned wells and considering factors and policies affecting leakage, CH_4 emission measurements, and leakage repair options. Dusseault *et al* (2000), Jackson (2014) and Jackson *et al* (2014) conducted reviews on OGW leakage; however, the authors did not delve into leakage detection and repair options. Moreover, Allen (2016) conducted a review to assess changes in greenhouse gas and air contaminant emissions from the energy supply infrastructure in the US, and although the review addresses OGW leakage, the focus is on oil and gas production systems as a whole. Furthermore, Allen (2016) gives limited considerations to abandoned wells, wells not producing hydrocarbons, and does not address factors affecting OGW leakage. Cahill *et al* (2019) conducted a review on OGW leakage but focused only on British Columbia. Rice *et al* (2018) and Vengosh *et al* (2014) also conducted reviews addressing OGW leakage; however, both studies focus on leakage impacts on water resources. Other reviews addressing OGW leakage focus on plugging and abandonment techniques (Calvert and Smith 1994, Barclay *et al* 2001, Prasetya *et al* 2018, Trudel *et al* 2019). In contrast to these studies, our paper has a stronger focus on abandoned OGWs and do not explicitly focus on the role of unconventional OGWs. Looking across Canada and the US, we review OGW leakage from abandoned and active wells, factors affecting leakage, CH_4 emission measurements, and leakage repair options.

Measurement and data analysis studies show that a few large OGW leaks represent the majority of leakage in oil and gas systems (Brandt *et al* 2014, 2016, Jackson 2014). At the wellhead scale, multiple factors can contribute to the occurrence of large OGW leaks, including the well construction period and quality, production status, and geographic location (Brantley *et al* 2014, Ingraffea *et al* 2014, Atherton *et al* 2017, Kiran *et al* 2017). Analyzing factors affecting leakage occurrence and magnitude helps in identifying and fixing large OGW leaks (Jackson 2014, Montague *et al* 2018, Cusworth *et al* 2022). Moreover, understanding these factors and their contribution to increased OGW leakage is essential to determine leakage potential, better understand environmental impacts of leakage, develop targeted mitigation strategies and reduce the risk of OGW leaks including CH_4 emissions to the atmosphere.

Here, to help identify large OGW leaks and optimize mitigation efforts, we compile a list of factors affecting OGW leakage and explain how these factors have been shown to affect OGW leakage in published literature. We also review the literature on emissions monitoring and repair policies aimed at reducing OGW leakage. Then, we review studies that measured CH_4 emissions from OGWs at the wellhead, and identify states in the US and provinces/territories in Canada that lack such measurements. Finally, we review CH_4 emissions quantification methods and repair strategies to inform emissions monitoring and repair programs. The results of our review can be used to inform future studies and policy developments aimed at reducing OGW leakage and associated climate and environmental impacts.

2. Methods

We divided the reviewed literature into four categories (table 1): 'Impact factors', 'Monitoring/repair policies and enforcement', 'Measurements of CH_4 emissions' and 'Repair strategies' (table 1). The 'Impact factors' category includes literature that discusses the role of factors contributing to increased OGW leakage. The 'Monitoring/repair policies and enforcement' category includes literature addressing the role of monitoring and repair policies on reducing OGW leakage. The 'Measurements of CH_4 emissions' category includes studies that quantify CH_4 emissions from OGWs at the wellhead scale, and addresses the technologies used for CH_4 emissions detection and quantification. Although a detailed review of all wellbore leakage repair techniques is beyond the scope of this paper, the 'Repair strategies' category includes literature that touches on cement and casing repair methods, abandonment and alternatives to repairing OGW leakage.

To guide future studies aimed at quantifying CH_4 emissions from OGWs and understanding factors affecting wellhead leakage, we created a map showing all provinces, states and territories where measurements of CH_4 emissions from OGWs were conducted in Canada and the US at the wellhead scale

Table 1. Categories and keywords.

Category	Sub category	Key keywords	Relevant literature
Impact factors	Not applicable	Abandonment, casing cement bond, casing failure, cement integrity, construction quality, hydraulic pressure, maintenance quality, operator, plugging status, pressure, risk of impairment, sealing, structural integrity, well age, well depth, well design, well geometry, well orientation, well type, acidic environments, carbon dioxide, chemical compositions, coal areas, coalbed methane, conventional oil and gas, fluid properties, geologic strata, hydraulic fracturing, hydrogen sulfide, *in-situ* conditions, pore pressure, production type, shale, temperature, unconventional oil and gas.	Watson and Bachu (2009), King and King (2013), Ingraffea *et al* (2014), (Ingraffea *et al* 2020), Jackson (2014), Nowamooz *et al* (2015), Kang *et al* (2016), Bachu (2017), Kiran *et al* (2017), Lackey *et al* (2017), Bois *et al* (2019), Riddick *et al* (2019), Saint-Vincent *et al* (2020), Wisen *et al* (2020), El Hachem and Kang (2022)
Monitoring/repair policies and enforcement	Not applicable	Comprehensive reform, federal governments, inadequate enforcement, leakage testing, legal abandonment, management strategies, methane reduction targets, mitigation strategies, monitoring, policy initiatives, provincial requirements, regulations, state agencies, state regulators, state reporting, testing procedure.	Bishop (2013), Ho *et al* (2016), Alboiu and Walker (2019), Kang *et al* (2019b) , (Kang *et al* 2021), Abboud *et al* (2020), Lavoie *et al* (2022)
Measurements of CH_4 emissions	Leakage	Broken well casing, casing leakage, cement failure, equipment leaks, ethane, fugitive emissions, gaseous emissions, geochemistry, geological formations, high emitters, leak points, leakage pathways, methane plumes, noble gas concentrations, point sources, preferential paths, production-normalized emissions, soil gas methane, surface casing vent flow, thermogenic gas, upstream oil and gas, volatile organic compounds, wellheads.	Gasda *et al* (2004), Miller *et al* (2013), Davies *et al* (2014), Kang *et al* (2014), Pétron *et al* (2014), Warneke *et al* (2014), Nathan *et al* (2015), Zavala-Araiza *et al* (2015), (Zavala-Araiza *et al* 2018), Allen (2016), Boothroyd *et al* (2016), Omara *et al* (2016), Townsend-Small *et al* (2016), Atherton *et al* (2017), Emran *et al* (2017), Johnson *et al* (2017), Lavoie *et al* (2017), Moortgat *et al* (2018), Pekney *et al* (2018), Cahill *et al* (2019), Fox *et al* (2019), Hoschouer and Townsend-Small (2018), Johnson *et al* (2019), Pandey *et al* (2019), Riddick *et al* (2019), Schout *et al* (2019), Whiticar (2019), Deighton *et al* (2020), Ingraffea *et al* (2020), Lebel *et al* (2020), Saint-Vincent *et al* (2020), Wisen *et al* (2020), MacKay *et al* (2021), Singh *et al* (2021), Williams *et al* (2021), El Hachem and Kang (2022)
	Technologies	Aerial surveys, aeromagnetic surveys, aircraft, alternative technologies, bag sampling, bottom-up approaches, canister samples, close-range methods, detection technology, direct measurements, drone-based surveys, dynamic chamber, field-portable flame ionization detector, fixed sensors, gas rover, ground-based measurements, handheld instruments, helicopter-based survey, Hi-Flow sampler, infrared camera, inverse Gaussian dispersion model, Los Gatos Ultra-Portable Greenhouse Gas Analyzer, Picarro, sensit, low-cost sensor, mass-balance approach, mobile downwind intercepts, mobile ground labs, mobile plume integration, open path sensor, open-path laser spectrometer, plane-based surveys, radioactive tracer survey, satellite, screening technologies, sensor signals, static flux chamber, top-down, unmanned aerial vehicles, vehicle-based surveys.	

(Continued.)

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Table 1. (Continued.)

Category	Sub category	Key keywords	Relevant literature
Repair strategies	Cement and casing repair	Anti-fluid migration additive, cement additives, cement blends, cement squeezes, chemical expansive admixture, colloidal silica, conventional cement, downhole packers, elastomer properties, expanding additives, expanding casing, fine particle cement, foam cement, gas-block additive, granular foam, glass heat expansion, high density cement, micro-fine cement, nanofillers, nanomaterials, nanosynthetic graphite, polymer, polymer latex, rubber nanocomposites, self-healing cement, silica fume, smart gel, sodium silicate, volcanic ash, wear resistance.	Calvert and Smith (1994), Bender and Conrad (1995), Boeckx *et al* (1997), Barclay *et al* (2001), Smith, Seshadri, and Wilder (2001), Price *et al* (2004), Roth *et al* (2008), Al-Yami *et al* (2009), Abbas *et al* (2013), Dusseault *et al* (2014), McDonald and Li (2017), Ahmed *et al* (2018), Bugrayev *et al* (2019), Chartier and Graham (2020), Ming *et al* (2022)
	Repair alternatives	Anaerobic degradation, methane oxidation, methane production, methane uptake, methanogenesis, methanogens, methanotrophic bacteria, microbial activity, microbial mitigation, nitrogen availability, pH, photocatalysis, renewable electricity generation, rigless remediation, soil core incubation, soil variables, wetland soils.	

(figure 2). We selected studies whose measurement methods include enclosures, as these methods provide high certainty emission estimates suitable for studying factors affecting wellhead emissions. We obtained data on the distribution of OGWs per province, state, and territory from Kang *et al* (2021) and performed a Google Scholar search on CH_4 emissions from OGWs by state, province and territory to include all studies that measured CH_4 emissions from OGWs at the wellhead scale in Canada and the US. We reviewed 37 studies measuring CH_4 emissions from OGWs, and included in our map 13 studies measuring methane emissions at the wellhead scale (Allen 2016, Kang *et al* 2016, Townsend-Small *et al* 2016, Pekney *et al* 2018, Hoschouer *et al* 2018, Forde *et al* 2019, Riddick *et al* 2019, Saint-Vincent *et al* 2020, Deighton *et al* 2020, El Hachem and Kang 2022, Lebel *et al* 2020, Lyman *et al* 2020, Williams *et al* 2021). We excluded studies measuring CH_4 emissions from offshore wells (Gorchov Negron *et al* 2020), studies not differentiating between emissions from multiple point sources, and studies providing regional, facility or site scale estimates (Caulton *et al* 2014, Pétron *et al* 2014, Peischl *et al* 2016, 2018, Cui *et al* 2019, Floerchinger *et al* 2019).

3. Results and discussions

3.1. Impact factors

Factors that have been found to affect leakage from active and abandoned wells are the production type (conventional/unconventional), number of remedial treatments, seismic activity, reservoir pressure, well casing and cement quality, well construction period, geographic area, uncemented casing intervals, well status and well deviation (Watson and Bachu 2009, Ingraffea *et al* 2014, Kang *et al* 2016, Lackey *et al* 2017, Sandl *et al* 2021) (figure 1 and table 2). The impact of the geographic area on abandoned and active OGW leakage has been studied on the national, provincial and county scale and has been addressed in 11 studies covering multiple regions such as Alberta, British Columbia and Ontario in Canada, and Pennsylvania, Texas, Colorado and Wyoming in the US. The second most studied factor, among factors affecting leakage from abandoned and active OGWs, is wellbore deviation and has been addressed in six studies conducted in Alberta, British Columbia, Colorado and Utah. Among factors found to affect leakage from abandoned and active wells, only two studies explored the role of seismic activity, reservoir pressure, and casing and cement quality, and only one study explored the role of the number of remedial treatments on OGW leakage. Moreover, our conclusions on the impact of 15 (39%) factors linked to OGW leakage are based only on one study (figure 1).

Factors that have been found not to affect leakage from abandoned and active wells are surface casing depth, well producing formation, topography, volume of hydraulic fracturing fluid used, number of fractured and acid treatments, number of drilling/completion events, kicks and blowouts, cement returns at the surface and completion interval (figure 1 and table 2). However, the conclusion that these factors do not affect active and abandoned OGW leakage is based on one or two studies conducted in specific regions such

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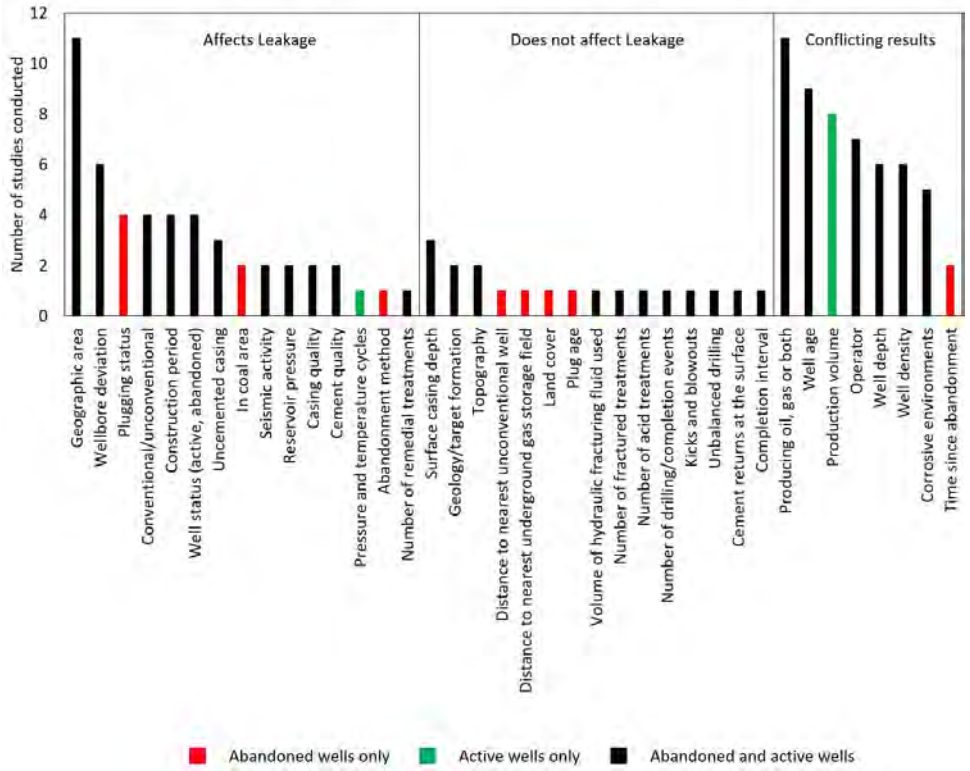


Figure 1. Bar charts showing factors whose impact on abandoned and active OGW leakage has been studied in the reviewed literature. Factors are ranked from most studied to least studied and divided by their impact on OGW leakage.

as Alberta, Ontario, British Columbia and Colorado (Watson and Bachu 2009, Lackey *et al* 2017, Sandl *et al* 2021, El Hachem and Kang 2022). Therefore, it is possible that analysis of larger datasets or data from other regions, obtained through future measurement studies, may reach different conclusions.

The body of available literature remains inconclusive about the impact of many factors, including plug age, formation fluids, well depth, density, age and operator (Watson and Bachu 2009, Kang *et al* 2016, Saint-Vincent *et al* 2020). For example, in West Virginia, the highest emitting unplugged abandoned wells were found to be the ones most recently abandoned (Riddick *et al* 2019). In Oklahoma, no correlation was found between time since abandonment/plugging and emissions from abandoned wells (Saint-Vincent *et al* 2020). The correlation between well age and CH_4 leakage from OGWs was studied for wells in Alberta, Ontario and West Virginia, and no correlation was found in all three regions (Watson and Bachu 2009, Riddick *et al* 2019, El Hachem and Kang 2022). However, in British Columbia, well age was found to affect leakage occurrence (Atherton *et al* 2017, Wisen *et al* 2020). Another example is the role of hydrogen sulfide presence and acidic environments. In Ontario, abandoned wells emitting hydrogen sulfide were, on average, the highest CH_4 emitters (El Hachem and Kang 2022), and in British Columbia wells in contact with acidic environments showed high leakage frequency (Wisen *et al* 2020); however, in Alberta no correlation was found between the presence of hydrogen sulfide or acidic environments and increased leakage from abandoned and active wells (Watson and Bachu 2009). Conflicting results on the impact of certain factors on OGW leakage in multiple regions suggest high spatial variability in factors affecting leakage. A reason for the conflicting results may be that some studies focus on subsurface leakage while others focus on CH_4 emissions to the atmosphere. Importantly, well integrity failure may lead to subsurface leakage with no surface emissions (Schout *et al* 2019).

A key issue in investigating factors affecting OGW leakage is the correlation among factors (Sandl *et al* 2021). For example, active unconventional wells are at a higher risk of leakage compared to active conventional wells (Ingraffea *et al* 2014, 2020, Bachu 2017), and well deviation is a strong predictor of active and abandoned OGW leakage, where deviated wells are more prone to leakage compared to vertical wells (Watson and Bachu 2009, Kiran *et al* 2017, Lackey *et al* 2017, Montague *et al* 2018). Unconventional wells are more likely to be deviated than conventional wells; hence, it is challenging to isolate the role of well deviation

Apps' Ex. 26
0561

Table 2. Factors potentially contributing to CH_4 leakage from OGWs.

Factors investigated	Studies	Wells investigated (active, abandoned, both)	Affects leakage?
Pressure and temperature cycles	Kiran *et al* (2017)	Active	Yes
Abandonment method	Watson and Bachu (2009)	Abandoned	
In coal area	Kang *et al* 2016, Townsend-Small *et al* (2016)	Abandoned	
Plugging status	Kang *et al* (2016), Saint-Vincent *et al* (2020), Williams *et al* (2021), El Hachem and Kang (2022)	Abandoned	
Conventional/ unconventional	Ingraffea *et al* (2014), (2020), Omara *et al* (2016), Bachu (2017)	Both	
Number of remedial treatments	Sandl *et al* (2021)	Both	
Seismic activity	Kiran *et al* (2017), Kang *et al* (2019a)	Both	
Reservoir pressure	King and King (2013), Davies *et al* (2014)	Both	
Casing quality	Kiran *et al* (2017), Wisen *et al* (2020)	Both	
Cement quality	King and King (2013), Kiran *et al* (2017)	Both	
Construction period	King and King (2013), Ingraffea *et al* (2014), Lackey *et al* (2017), Montague *et al* (2018)	Both	
Geographic area	Watson and Bachu (2009), Allen *et al* (2013), King and King (2013), Brantley *et al* (2014), Ingraffea *et al* (2014), Robertson *et al* (2017), (Robertson *et al* 2020), Lyman *et al* (2020), Sandl *et al* (2021), Williams *et al* (2021), El Hachem and Kang (2022)	Both	
Uncemented casing	Watson and Bachu (2009), Lackey *et al* (2017), Wisen *et al* (2020)	Both	
Well status (active, abandoned)	Atherton *et al* (2017), Riddick *et al* (2019), Wisen *et al* (2020), El Hachem and Kang (2022)	Both	
Wellbore deviation	Watson and Bachu (2009), Kiran *et al* (2017), Lackey *et al* (2017), Montague *et al* (2018), Lyman *et al* (2020), Sandl *et al* (2021)	Both	
Distance to nearest unconventional well	Kang *et al* (2016)	Abandoned	No
Distance to nearest underground natural gas storage field	Kang *et al* (2016)	Abandoned	
Land cover	Kang *et al* (2014)	Abandoned	
Plug age	El Hachem and Kang (2022)	Abandoned	
Volume of hydraulic fracturing fluid used	Lackey *et al* (2017)	Both	
Number of fractured treatments	Lackey *et al* (2017)	Both	
Number of acid treatments	Sandl *et al* (2021)	Both	
Number of drilling/completion events	Sandl *et al* (2021)	Both	
Kicks and blowouts	Sandl *et al* (2021)	Both	
Unbalanced drilling	Sandl *et al* (2021)	Both	
Cement returns at the surface	Sandl *et al* (2021)	Both	
Geology/target formation	Sandl *et al* (2021), El Hachem and Kang (2022)	Both	

(Continued.)

Apps' Ex. 26

0562

Table 2. (Continued.)

Factors investigated	Studies	Wells investigated (active, abandoned, both)	Affects leakage?
Surface casing depth	Watson and Bachu (2009), Lackey *et al* (2017), Sandl *et al* (2021)	Both	
Topography	Watson and Bachu (2009), El Hachem and Kang (2022)	Both	
Completion interval	Watson and Bachu (2009)	Both	
Production volume	El Hachem and Kang (2022)	Active	No
	Brantley *et al* (2014), Lan *et al* (2015), Lyon *et al* (2016), Omara *et al* (2016), Lavoie *et al* (2017), Riddick *et al* (2019)	Active	Yes
Time since abandonment	Saint-Vincent *et al* (2020)	Abandoned	No
	Riddick *et al* (2019)	Abandoned	Yes
Well depth	Saint-Vincent *et al* (2020)	Abandoned	Yes
	Watson and Bachu (2009), Kang *et al* (2016), Lackey *et al* (2017), Sandl *et al* (2021), El Hachem and Kang (2022)	Both	No
Well age	Atherton *et al* (2017), Zavala-Araiza *et al* (2018), Lyman *et al* (2020), Wisen *et al* (2020)	Both	Yes
	Watson and Bachu (2009), Riddick *et al* (2019), Saint-Vincent *et al* (2020), Sandl *et al* (2021), El Hachem and Kang (2022)	Both	No
Corrosive environments	King and King (2013), Kiran *et al* (2017), Wisen *et al* (2020), El Hachem and Kang (2022)	Both	Yes
	Watson and Bachu (2009)	Both	No
Well density	El Hachem and Kang (2022)	Both	Yes
	Watson and Bachu (2009), Lackey *et al* (2017), Montague *et al* (2018), Sandl *et al* (2021), Warrack *et al* (2021)	Both	No
Producing oil, gas or both	Brantley *et al* (2014), Kang *et al* (2016), Atherton *et al* (2017), Robertson *et al* (2017), p 202, Zavala-Araiza *et al* (2018), Lyman *et al* (2020), Wisen *et al* (2020), MacKay *et al* (2021), Williams *et al* (2021)	Both	Yes
	Watson and Bachu (2009), Sandl *et al* (2021)	Both	No
Operator	Atherton *et al* (2017), Kiran *et al* (2017), Saint-Vincent *et al* (2020)	Both	Yes
	Watson and Bachu (2009), Lackey *et al* (2017), Riddick *et al* (2019), El Hachem and Kang (2022)	Both	No

and production type (conventional/unconventional). Similarly, reservoir pressure affects the well production volume (Ilk *et al* 2008) and both can affect leakage rates (King and King 2013, Kiran *et al* 2017, Riddick *et al* 2019). Other potentially correlated factors that may affect OGW leakage are the well casing and concrete integrity and well age. Moreover, multiple factors, including production type, well density, seismic activity, topography and subsurface geology are likely correlated with the geographic location, a factor that has been found to consistently affect leakage. Therefore, it is important to analyze intercorrelations among factors when assessing their impact on OGW leakage.

There are many factors that may be strong predictors of high OGW leaks, which have not been investigated due to a lack of data and measurements. In addition, due to the large geographic variability in leakage rates and occurrence, our understanding of the impact of factors on OGW leakage is likely to be limited to the regions studied. Hence, additional field, modeling and data-based studies are needed to determine factors that affect the occurrence and magnitude of OGW leakage.

Apps' Ex. 26

0563

3.2. Monitoring/repair policies and enforcement

Strategies to monitor wellbore integrity include downhole monitoring and surface monitoring techniques. These monitoring strategies are essential to ensure the integrity of OGWs and reduce OGW leakage. In oil and gas producing provinces such as Alberta and Saskatchewan, wellbore integrity monitoring is required at the surface (Alberta Energy Regulator 2021, Government of Saskatchewan 2022). These monitoring tests include testing wells for surface casing vent flows representing leakage along the surface casing, and gas migration which aims to capture leakage away from the wellbore into surrounding soils. In the US, monitoring requirements include monitoring the surface casing pressure, which is an indication of OGW leakage (Lackey *et al* 2021). Although multiple studies address downhole monitoring techniques (Sharma *et al* 2020), here we focus on surface monitoring due to its widespread use in Canada and the US.

We find several studies that indicate how increased emissions monitoring and repair frequency are essential to identify and reduce OGW CH_4 emissions. Measurements of CH_4 emissions from active wells in Ontario appear to indicate that licensed commercial gas wells, required to be tested for leakage, emit less CH_4 than low producing private gas wells that can be unlicensed (El Hachem and Kang 2022). In Peace River, Alberta, regulations to reduce olfactory compound emissions from heavy oil production were implemented in 2017; a comparison between CH_4 emissions in 2016 and 2018 shows that the implementation of the regulations was also effective in decreasing OGW CH_4 emissions by 60% (Lavoie *et al* 2022). Moreover, Ravikumar *et al* (2020) assessed the effectiveness of monitoring and repair programs in reducing leaks by measuring unconventional wells before and after leakage repair. The authors found that more than 90% of the leaks in the pre-repair survey were not leaking in the post-repair survey, highlighting the effectiveness of leakage repair in reducing leakage. However, the authors estimated that emission reductions from leak repair were only 22% because new leaks occurred between the two surveys, which emphasizes the need for increased monitoring frequency to identify leaks and flag them for repair. Similarly, in Pennsylvania, 89% of wells drilled between 2009 and 2012 were inspected for leakage, compared to 76% for wells drilled between 2000 and 2008 (Jackson 2014). The higher inspection frequency for the newer wells can lead to the identification of more OGW leaks compared to the older wells (Ingraffea *et al* 2014, Jackson 2014).

In addition to reducing OGW leakage, monitoring and repair requirements, accompanied by reporting requirements, allow the creation of valuable databases that can be analyzed to better understand OGW leakage. By using publicly available data, Lackey *et al* (2021) found that 24.5%, 27.1% and 36% of all wells in Colorado, New Mexico, and Pennsylvania have undergone leakage testing as a result of monitoring requirements in these states. The reported data indicate that 14.1% of the tested wells in Pennsylvania show signs of leakage. In Colorado and New Mexico, data from different producing regions showed that 0.3%–26.5% of the tested wells exhibited signs of leakage (Lackey *et al* 2021). In Canada, oil and gas producing provinces such as Alberta and British Columbia have also implemented leakage monitoring requirements. In Alberta, testing for leakage along and outside the surface casing was reported for 6.2% and 0.75% of all wells, respectively (Abboud *et al* 2020). In British Columbia, since 2010, operators have been required to test OGWs for leakage after drilling, during completion and during routine maintenance (Wisen *et al* 2020). Out of the 21 525 tested wells, 10.8% showed signs of leakage during their lifetime (Wisen *et al* 2020). These routine integrity tests in both Canada and the US have allowed researchers to better characterize the risk of increased OGW leakage (Watson and Bachu 2009, Bachu 2017, Lackey *et al* 2017, 2021, Wisen *et al* 2020).

Specifically, for unplugged abandoned wells, out of the ten states with the largest number of drilled OGWs, we find that only California and Pennsylvania have implemented annual wellbore monitoring requirements (Interstate Oil and Gas Compact Commission (IOGCC) 2021). In Kansas, wellbore integrity monitoring is required when operators want to suspend wells for a duration longer than ten years, and in Texas, wellbore monitoring is required upon suspension of wells older than 25 years (Interstate Oil and Gas Compact Commission 2021). However, monitoring is not required after well suspension. In West Virginia, wellbore monitoring is required before the suspension of any active well, and in Oklahoma, Ohio, Louisiana, Kentucky and Illinois, wellbore monitoring is not required to suspend or temporarily abandon OGWs (IOGCC 2021). For permanently abandoned wells or plugged abandoned wells, only California has implemented wellbore monitoring requirements (Kang *et al* 2021). However, there may be requirements for orphaned wells plugged with federal funds through the Bipartisan Infrastructure Law to monitor for CH_4 emissions at plugged orphaned wells in the US (US Department of the Interior, 2023).

Despite the importance of effective wellbore monitoring and repair requirements to reduce OGW leakage, these requirements are not always enforced. In Alberta, where 80% of Canada's active OGWs exist, monitoring for leakage along and outside the surface casing is required for 58.2% and 3.5% of all wells respectively (Abboud *et al* 2020). However, the study also found that actual monitoring for leaks along the surface casing was not conducted for 93.8% of all wells and monitoring for leakage outside the surface casing

Apps' Ex. 26

0564

was not conducted at 99.25% of all wells (Abboud *et al* 2020). In Pennsylvania, an analysis of the oil and gas state database shows that only 47% of active wells have been inspected for leakage, despite the requirement to test all active wells (Ingraffea *et al* 2020, Lackey *et al* 2021). In Ontario, active gas wells are required to be licensed under the Ontario Oil, Gas and Salts Resources Act; however, many gas wells remain unlicensed (El Hachem and Kang 2022). Unlicensed wells are operated without any leakage monitoring requirements which allow leaks to continue. These findings indicate that monitoring and repair requirements are not being enforced in multiple oil and gas producing regions across Canada and the US. This demonstrates the need for increased capacity of regulatory bodies, including funding and personnel, to verify adherence to current leakage monitoring and repair regulations.

For abandoned wells, the observation of lower emissions from plugged wells, on average, compared to unplugged abandoned wells is consistent in the literature (Kang *et al* 2016, Pekney *et al* 2018). A compilation of available CH_4 emission rate measurements from abandoned wells shows that unplugged wells emit 7 times more CH_4 than plugged wells (Williams *et al* 2021). In Ontario, wells plugged before the implementation of modern plugging standards were found to emit 4100 times more CH_4 compared to other plugged wells (El Hachem and Kang 2022). In New York, an analysis of reports from the Division of Mineral Resources reveals that 75% of the state's abandoned OGWs are unplugged, despite the presence of plugging requirements for all abandoned wells (Bishop 2013). In other words, emissions can be reduced if a well is plugged to modern standards.

In addition to enforcing existing regulations and policies, it may be beneficial to explore and adopt new regulations/policies to reduce OGW leakage. Previous studies focused on reducing CH_4 emissions from the oil and gas sector, not only OGWs, recommend policies that set emission targets, where operators are rewarded/penalized for exceeding/not meeting these targets (Ravikumar and Brandt 2017). To monitor for leaks, continuous monitoring systems and scheduled monitoring campaigns can be implemented (Ravikumar and Brandt 2017). Although scheduled monitoring is effective in detecting leakage, it is likely to miss leakage events that occur between monitoring campaigns (Ravikumar *et al* 2020). On the other hand, continuous monitoring using fixed sensors, allows for the rapid detection of CH_4 anomalies, but may not be able to capture and locate all leaks. Additional policy updates to reduce OGW leakage include promoting the use of technologies that capture and use CH_4 as a fuel, and prescribed techniques such as the conversion of high-bleed pneumatic devices to low-bleed or zero-bleed devices (Johnson and Tyner 2020).

Both Canada and the US have proposed new CH_4 emissions reductions from the oil and gas sector (Government of Canada 2017, Environmental Protection Agency (EPA) 2022). In the US, for active wells, the regulations differentiate between single wellhead sites, two or more wellhead sites, and multiple wellhead sites with major production and processing equipment. In Canada the main distinction is between single wellhead sites, common in Ontario, and multiple wellhead sites. In the US, the EPA is proposing quarterly audio, visual and olfactory assessment of CH_4 emissions on single wellhead sites (EPA 2022). In Canada, the proposed regulations aim to exempt single wellhead sites from implementing leak detection programs (Government of Canada 2017). For well sites with two or more wellheads, the EPA (2022) is proposing semi-annual optical gas imaging monitoring and quarterly audio, visual and olfactory inspections. For multi wellhead sites with major production and processing equipment, the EPA (2022) is proposing quarterly optical gas imaging monitoring and bi-monthly audio, visual and olfactory inspections. In Canada, multiple well head sites are required to be tested for leakage three times per year and repaired if leaks are observed (Government of Canada 2017).

For orphaned wells, a subset of abandoned wells with no responsible party, the US government allocated $4.7 billion in November 2021 through the Bipartisan Infrastructure Law to plug these orphaned OGWs and clean up and restore well sites nationwide (Boutot *et al* 2022). For states to receive the federal funding to plug orphaned wells, they may be required to report data that can be used to quantify methane emissions reductions achieved through the federal funding (US Department of the Interior, 2023). The proposed Department of the Interior guidelines require some level of pre- and post-plugging methane detection at all orphaned wells plugged with federal funds (US Department of the Interior, 2023).

For abandoned wells, a key policy update involves limiting the suspension duration for suspended wells. In Alberta, OGWs operators can suspend a well indefinitely ('Directive 013: Suspension Requirements for Wells). Suspended wells are non-producing unplugged wells. Unplugged wells have higher CH_4 emissions rates and may pose greater risks to air quality and climate compared to plugged wells (Kang *et al* 2021). In Western Canada, British Columbia was the first province to implement abandonment rules after defined suspension periods (Alboiu and Walker 2019). In the US, oil and gas producing states such as North Dakota and Texas have specific suspension timelines after which plugging and site reclamation are required; however, operators can apply for suspension extensions which can be up to seven years in North Dakota and indefinite in Texas (Alboiu and Walker 2019). Ho *et al* (2016), through the analysis of inactive well policies in 23

jurisdictions in the US, recommend the development of policies defining well suspension periods. Having defined suspension periods prevents the operator from suspending wells indefinitely in the hope of reactivating the wells once oil and gas prices are high enough to make production profitable. Moreover, applying plugging rules at the end of suspension periods allows the reduction of OGW CH_4 emissions and their associated impacts.

3.3. Measurements of CH_4 emissions

The majority of OGW emission studies focus on CH_4 emissions, as CH_4 is a potent greenhouse gas and is the main component of natural gas. In the US, we find that CH_4 emissions from abandoned OGWs have been measured at the wellhead scale in 9 out of 36 states with oil and gas development (figure 2). Moreover, based on the CH_4 emissions studies we reviewed, 542 abandoned wells representing 0.02% of all abandoned wells in the US have been measured at the wellhead scale. Oklahoma is the state with the highest percentage of abandoned wells measured (0.46%) relative to all abandoned wells in the state. Measurements from active wells have a similar geographic distribution compared to abandoned wells and cover 8 states. Only 464 active wells representing 0.03% of all active wells in the US have been measured at the wellhead scale. Utah is the state with the highest percentage of active wells measured (0.43%) relative to all active wells in the state. In our calculation of percentages of abandoned wells measured, we do not account for the up to 1 million undocumented OGWs (IOGCC, 2021, Boutot *et al* 2022).

In Canada, CH_4 emissions from abandoned and active wells have been conducted at the wellhead scale, using enclosure-based methods, in British Columbia and Ontario (figure 2). Overall, 48 abandoned wells representing 0.01% of all abandoned wells in Canada have been measured at the wellhead scale using enclosure-based methods. Ontatio is the province with the highest percentages of abandoned wells measured (0.13%) relative to all abandoned wells in the province. For active wells, 50 wells representing 0.02% of all active wells in Canada have been measured at the wellhead scale. Ontario is the province with the highest percentage of active wells measured (0.91%) relative to all active wells in the province.

Although studies measuring abandoned wells may include measurements from orphaned wells, the reviewed studies do not differentiate between orphaned and other abandoned wells, which is important for policy makers aiming to plug hundreds of thousands of orphaned wells.

Studies measuring CH_4 emissions from abandoned and active OGWs at the wellhead scale stress the importance of additional measurements due to the small number of wells sampled compared to the total number of wells drilled and the many factors that govern emission rates (Allen 2016, Williams *et al* 2021). Moreover, measurement studies indicate high geographic variability in CH_4 emission rates from OGWs (Robertson *et al* 2020, Williams *et al* 2021). Hence, our understanding of such emissions is unlikely to be representative beyond regions where measurements are available. Therefore, measuring and characterizing all types of OGWs, including undocumented, non-producing, injection, observation and test wells, is essential to obtain a more representative dataset of CH_4 emissions from OGWs. These measurements help determine the magnitude of emissions, inform greenhouse gas and air pollutant inventories, understand factors affecting leakage occurrence and magnitude and develop mitigation strategies to reduce OGW leakage.

There are multiple methods to measure emission rates, which generally depend on the magnitude of the emissions and site access. CH_4 emissions at abandoned OGWs appear to be relatively low compared to emissions from active OGWs (Riddick *et al* 2019). Therefore, CH_4 emission rates at abandoned wells are more frequently measured at the individual source level with methods requiring site access (Kang *et al* 2014, Forde *et al* 2019, Riddick *et al* 2019, Williams *et al* 2021, Bowman *et al* 2022, El Hachem and Kang 2022); only four studies used mobile surveys to quantify emissions from abandoned wells (Johnson and Heltzel 2016, Atherton *et al* 2017, Lebel *et al* 2020, Vogt *et al* 2022). The most common approaches to measure CH_4 emissions from abandoned OGWs are based on chambers or enclosures (Kang *et al* 2014), atmospheric modeling (Riddick *et al* 2019, Lebel *et al* 2020), Hi-Flow samplers (Pekney *et al* 2018), and soil gas sampling (Boothroyd *et al* 2016, Schout *et al* 2019). Aerial surveys using helicopters and drones have primarily been used to find abandoned wells and not to measure emission rates (Saint-Vincent *et al* 2020). At active wells, emission rates tend to be orders of magnitude higher than at abandoned wells and have frequently been detected and quantified using vehicles and aircrafts (Miller *et al* 2013, Nathan *et al* 2015, Zavala-Araiza *et al* 2015, Emran *et al* 2017, Lavoie *et al* 2017, Johnson *et al* 2019, Pandey *et al* 2019, Whiticar 2019, Taherdangkoo *et al* 2020, Cusworth *et al* 2022).

OGW leakage can be quantified at different scales using different leakage detection and measurement technologies (National Academies of Sciences, 2018). However, using vehicles, aircrafts and satellites to quantify emission rates requires the correct attribution of observed emission plumes to the emitting sources (Atherton *et al* 2017, MacKay *et al* 2021). OGW CH_4 emissions can occur from multiple pieces of infrastructure on the well site, including wellheads, storage tanks, separation units and batteries (Brantley

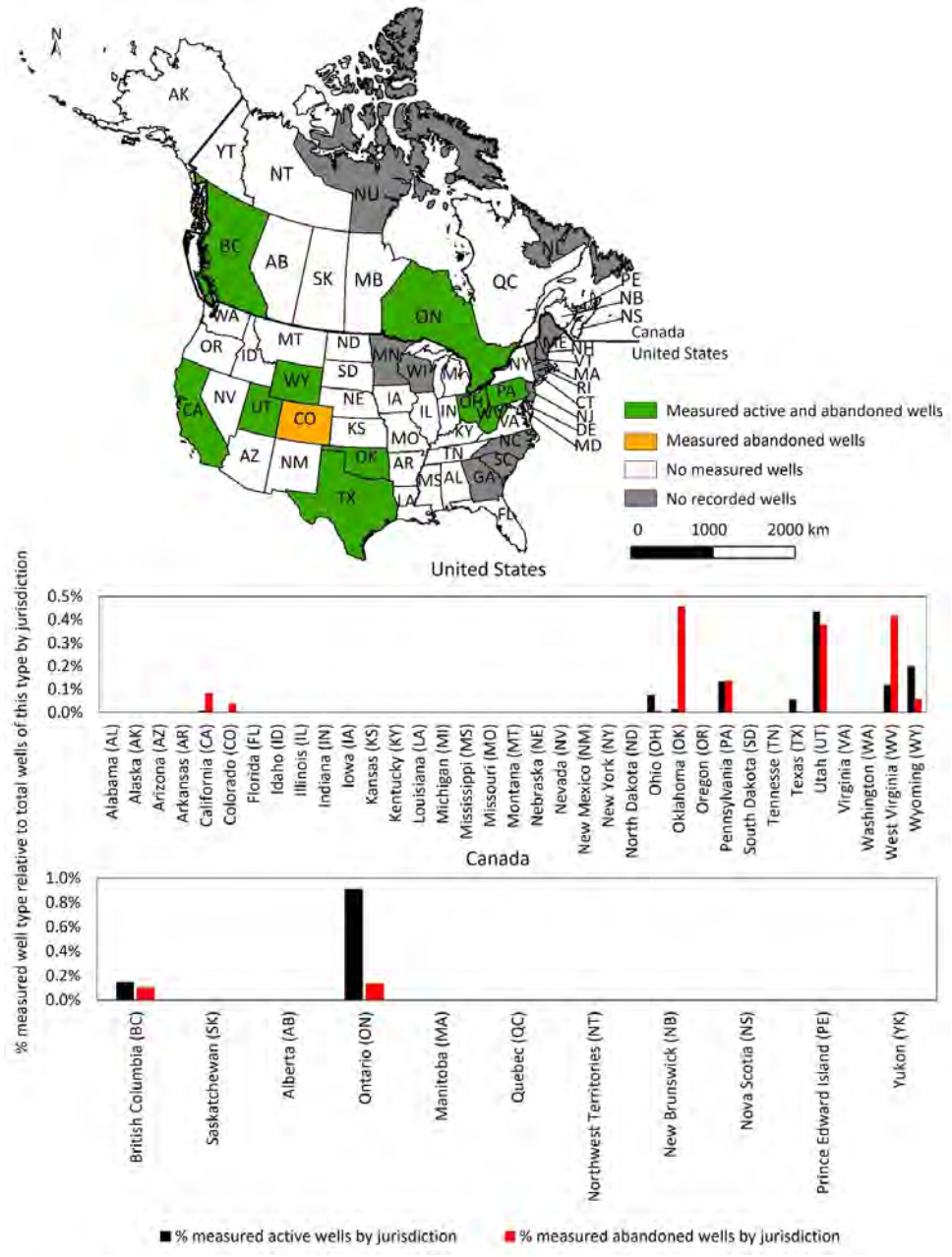


Figure 2. Map showing where measurements of CH_4 emission rates were/were not conducted from abandoned and active oil and gas wells in Canada and the US (top). Bar chart showing percentages of measured abandoned and active oil and gas wells per province, state, territory and country relative to the total number of abandoned and active wells per province, state, territory and country (bottom).

et al 2014). On well sites where multiple emitting sources exist, attributing emissions to the source can be challenging and leads to increased uncertainty in emission rate estimates (Atherton *et al* 2017). Therefore, due to the presence of multiple leaking sources and variability in leakage rates at OGW sites, it is challenging, if not impossible, to quantify leakage at the wellhead scale using mobile surveys, vehicles, aircrafts and satellites. Attributing emissions to emitting sources is not a problem when using enclosure-based methods as the method is directly applied at the leaking source. Another challenge is the difference in detection limits (Lebel *et al* 2020). Because vehicle, aircraft and satellite methodologies are designed to measure relatively

high emission rates (>100 g h^{-1}) (Brantley *et al* 2014, Peischl *et al* 2018, Cusworth *et al* 2022), the resulting dataset may miss some of the high-emitting abandoned OGWs.

3.4. Repair strategies

3.4.1. Cement

OGWs commonly lose their integrity due to the formation of cracks in the well cement or cement debonding with the formation or the well casing (Watson and Bachu 2009, Bachu 2017). The most common approach to repair cracks and debonding is squeezing cement (Yousuf *et al* 2021). Cement squeezes involve injecting, at high pressure, a cement slurry into the cement annulus or cracks; after the injection is complete, the well gets shut in for a duration between 48 and 72 h, and production stops, to allow the slurry to solidify (Yousuf *et al* 2021). The process of cement squeezing begins with preparing the wellbore. To prevent the cement mixture from flowing further down the hole, a plug is placed below the area where the cement is needed. The casing is then perforated and the mixture is pumped through a drill pipe until the wellbore reaches a set pressure level. In most cases, the drill pipe is removed from the cement mixture before or during the time it takes for the cement to set. The final step is to remove any excess cement mixture from the production casing of the wellbore (Wu *et al* 2020).

Although a full review is beyond the scope of this paper, we find many studies indicating how cement additives can be used to improve and monitor the integrity of OGWs and initiate mitigative action (Mangadlao *et al* 2015, Khalil *et al* 2020, Wu *et al* 2020, Kumar *et al* 2022). Current practices in oil and gas operations are governed by industry and government guidelines and typically involve the use of class G and H Portland cement (Yousuf *et al* 2021). However, conventional cement and micro fine cement cannot seal cracks that are smaller than 400 and 120 μm, respectively (Wu *et al* 2020). Therefore, there are on-going efforts to improve the cement mixture design in well construction operations and to develop cement additives. However, many of these cement additives, especially nano-particles, are still at the laboratory scale development stage and their field application in oil and gas operations has thus far been limited (Wu *et al* 2020, Kumar *et al* 2022). Overall, additional field scale research to demonstrate the advantages of using cement additives to improve the integrity of OGWs is needed, along with research on overcoming barriers such as high cost.

3.4.2. Casing

Casing repair technologies include the use of anti-corrosive material, expanding casings and casing repair patches (Sanabria *et al* 2016, Singh *et al* 2019, Chartier and Graham 2020). One of the common methods to control external casing corrosion and prevent leakage is cathodic protection (Xu *et al* 2006, Malekinejad and Alavi 2008). The method connects the well casing (cathode) to an easily corroded metal (anode), which corrodes instead of the casing (Malekinejad and Alavi 2008). To protect against internal casing corrosion, studies have used inner casing polymer coatings and thermal activated resin (Xu *et al* 2006, Sanabria *et al* 2016). In addition to anti-corrosion repair strategies, others have used expandable casings, expandable casing repair patches, and cement additives in cement squeeze operations to reduce casing leakage (Storaune and Winters 2005, Singh *et al* 2019, Chartier and Graham 2020). A comprehensive and detailed review of casing corrosion and repair can be found in Okyere (2018) and others.

3.4.3. Abandoned OGWs

For abandoned wells, plugging is the primary strategy used to reduce leakage (Barclay *et al* 2001, Kang *et al* 2019b). Plugging involves placing cement-based or mechanical-bridge plugs at the producing formation, other oil- and gas-bearing formations, and any other protected subsurface formations (e.g. groundwater aquifers) penetrated by the well (Barclay *et al* 2001, Kang *et al* 2019b, Kang *et al* 2020, Trudel *et al* 2019). The process of plugging typically starts with cleaning the production tubing and performing cement squeezes through wellbore perforations intersecting the producing formation. This is followed by placing a plug on top of the producing formation, called the production packer (Barclay *et al* 2001). In some cases, cement slurry is pumped to plug the main reservoir and form a barrier that covers the extent of the producing formation (Khalifeh and Saasen 2020). After the producing formation is fully isolated from the wellbore, the next step is creating additional perforations in the production tubing above the production packer and circulating cement between the production tubing and the well casing (Barclay *et al* 2001). At shallower depths, cement is circulated in all open annuli to establish a barrier that covers the entire well wall. Then, the production casing is perforated at shallow depths (typically around 150 m) and a surface plug is inserted. Once all the plugs have been placed and tested, the wellhead and casing stumps are removed (Barclay *et al* 2001). These barriers are assumed to stop fluid flow within the well indefinitely; therefore, the cement improvements discussed in the previous section can also be valuable for plug and abandonment. Moreover, improper cleaning of the wellbore prior to plugging can compromise the effectiveness of the plug operation.

Therefore, there is ongoing research on technological options, including the use of ultrasonic treatments to clean the wellbore and enhance the barrier placing process (Achang *et al* 2020). In addition, new technologies are being developed to effectively plug OGWs. For example, in shale areas, a method to substitute plugging uses the natural shale rock that is already present in the area. The process involves applying stress to the shale rock in a way that causes it to move and fill the wellbore, effectively sealing it (Stavland 2017).

Ensuring the effectiveness of plugging in stopping fluid flow is important; however, plugging one well may lead to CH_4 leakage from nearby unplugged OGWs due to pressure perturbations in the subsurface (Jackson *et al* 2020). Current studies assessing pressure increases in the subsurface focus on brine lift up to the base of the freshwater aquifer for geologic carbon sequestration applications (Nicot *et al* 2009, Birkholzer *et al* 2011). Despite the occurrence of increased OGW leakage from multiple wells due to plugging one well (Jackson *et al* 2020, Kang *et al* 2021), the literature lacks studies that assess how plugging operations at OGWs may lead to pressure perturbations that result in increased leakage from wells in their vicinity.

3.4.4. Alternatives for CH_4 emission reductions

There is active research on methods to reduce CH_4 emissions from a variety of sources, including OGWs. Although these technologies may not substitute cement and casing repairs and do not protect subsurface resources (e.g. groundwater), they can be useful in reducing CH_4 emissions or CH_4 concentrations in the atmosphere. Such alternatives include enhancing natural hydroxyl sinks, installing vapor recovery units and flare systems, and harvesting the soil's oxidation capacity to reduce leaking CH_4 (Smith, Seshadri, and Wilder 2001, Price *et al* 2004, Karakurt *et al* 2012, Ming *et al* 2022). Hydroxyl radicals are responsible for naturally removing 90% of atmospheric CH_4, and several startups aim to apply this technology to mitigate CH_4 emissions from point sources like OGWs (Johnson *et al* 2014, Ming *et al* 2022). Through the use of ozone and hydroxyl radical generators, startups like *Infuser* and *Airlabs* are applying this method to reduce methane emissions (Ming *et al* 2022). Installing vapor recovery units helps to capture light hydrocarbons that vaporize during crude oil production before they are vented to the atmosphere (Karakurt *et al* 2012). Moreover, small flaring systems can burn vented gas and convert CH_4 to carbon dioxide, a greenhouse with lower global warming potential than CH_4 (Karakurt *et al* 2012).

Microbial activity in the soils can lead to an uptake of CH_4, thereby reducing CH_4 emissions, and is responsible for naturally removing 5% of atmospheric CH_4 (Yoon *et al* 2009, Ming *et al* 2022). Moreover, methanotrophic bacteria that live in soils surrounding OGWs have the potential to oxidize some of the leaking CH_4 (Stein 2000). Yin *et al* (2020) collected soil samples near (0.5 m) and away (20 m) from OGWs, and conducted microcosm experiments to test the capacity of soils in oxidizing the leaking CH_4. The authors find that soils collected at a 0.5 m distance from the well can oxidize 97% of the added CH_4, while soils collected at a 20 m distance can only oxidize 14% of the added CH_4. Although soil CH_4 oxidation can be used to oxidize part of the leaking CH_4, its applicability in cold temperatures requires further study, as CH_4 uptake rates increase in summer and decrease in winter (Stein and Hettiaratchi 2001, Ishizuka *et al* 2009).

3.4.5. Link to factors

Our findings from Section 3.1 "Impact Factors" indicate that maintaining wellbore integrity through improved cement and casing quality can be an important step in limiting OGW leakage. 63% of the factors that have been found to affect OGW leakage from active and abandoned wells are related to the wellbore design, and therefore are directly affected by the cement and casing quality and maintenance (table 2). The production type (conventional/unconventional) and wellbore deviation are factors that affect OGW leakage and directly impact the design of the well. Unconventional wells operate at a higher pressure compared to conventional wells and therefore must be designed accordingly (Ingraffea *et al* 2014). The construction period, or the decade in which the well was drilled and completed, is another factor that affects OGW leakage and is certainly related to design and construction standards that vary with time. Other relevant factors are uncemented casings, and cement and casing quality. Our findings from section 3.1 'Impact Factors' indicate that maintaining wellbore integrity through improved cement and casing quality can be an important step in limiting OGW leakage. However, the extent to which repair strategies and alternatives are applied and more importantly, their commercial availability and costs are beyond the scope of this paper.

There are also external factors such as seismic activity and operator practices (e.g. human error) that can contribute to increased OGW leakage and may not be improved through wellbore design. Studies show that wells with higher number of remedial treatments leak more than other wells (Sandl *et al* 2021), which may be more likely to occur in regions with seismic activity, for example.

Apps' Ex. 26

0569

4. Conclusion

Our review shows that the well location, its operational status, deviation and plugging status are likely to be key factors affecting OGW leakage. However, our understanding of factors affecting OGW leakage and its contribution to environmental degradation remains limited due to the large number of potential factors, many of which have been considered in only one study. In addition to understudied factors, 21% of the factors have been studied in different regions and the literature shows conflicting results in terms of their impact on OGW leakage. Therefore, it is important to conduct studies in many geographical regions, which inherently captures the role of many factors that are difficult to represent explicitly.

In terms of policies, we find that implementing and enforcing policies on leakage monitoring and repair likely reduces OGW leakage and can facilitate reporting. Therefore, these requirements can help in developing detailed databases that are essential to improve our understanding of OGW leakage. Moreover, for abandoned wells, implementing strict suspension and plugging timelines are help reduce CH_4 emissions from unplugged abandoned wells.

OGW CH_4 emissions quantification studies are important for improved greenhouse gas inventories and provide some indication of OGW leakage. However, studies quantifying CH_4 emissions from OGWs at the wellhead scale are missing from 26 states in the US and 9 provinces in Canada for abandoned wells, and 27 states and 9 provinces for active wells. Given the strong geographic variability in CH_4 emission rates from abandoned and active OGWs (Brantley *et al* 2014, Williams *et al* 2021) and our finding on the importance of geographic region in OGW leakage, measurements from all states and provinces with current and previous history of oil and gas development are needed.

In terms of repair options, there are many on-going studies aimed at improving wellbore cement and casings. In particular, cement improvement strategies are widely being studied on a laboratory scale but available literature point to the need for additional field scale research to demonstrate their applicability across the millions of OGWs around the world. Additionally, more research is needed to assess the wide scale applicability of soil CH_4 oxidation as a soil emissions mitigation option. The resulting data can be analyzed with the factors linked to OGW leakage and CH_4 emissions monitoring to develop effective monitoring and repair strategies, thereby reducing climate and environmental impacts of OGWs.

Data availability statement

No new data were created or analyzed in this study.

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Apps' Ex. 26

0570

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EXHIBIT 27

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REVIEW ARTICLE

The demographic characteristics of populations living near oil and gas wells in the USA

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Abstract

This study documents the prevalence of historically marginalized populations (across age, income, education, race-ethnicity, and language) living near active oil and gas wells throughout the USA, at both local and aggregated scales. This is performed by way of areal apportionment using well location data and population characteristics from the American Community Survey. A clustering analysis of marginalized populations living near a high density of wells reveals four distinct regions of high prevalence: southern California, southwest Texas, Appalachia, and northwest New Mexico. At the nationwide scale, we find large absolute numbers of people living near wells, including marginalized groups: nearly 18 million people in total across the USA, many of which are Hispanic (3.3 million), Black (1.8 million), Asian (0.7 million), and Native American (0.5 million), live below the poverty line (3 million), older individuals (3 million), or young children (over 1 million). In certain states, this represents a large share of the total population – over 50% in the case of West Virginia and Oklahoma. Estimates are subsequently compared to county-level control groups to assess patterns of disproportionality. Wide variations are found across regions and metrics, underscoring the locally specific nature of these data. Our research contributes to the field of environmental justice by describing the populations living near oil and gas wells.

Keywords Oil and gas wells · Fossil fuel production · Demographics

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Apps' Ex. 27

0576

Introduction

New developments in crude oil and natural gas production technology have led to increasingly rapid deployment of wells across the USA. There are currently over one million known active wells (DrillingInfo, 2018). Concurrently, the scientific community is building a more holistic understanding of the environmental impacts resulting from this growth. Besides observed air, surface water and groundwater pollution, and explosion hazards and climate disruption due to methane leakage (Adgate et al., 2014; Osborn et al., 2011), increased attention is being paid to public health effects. McKenzie et al., (2017, 2018) for example documented increased cancer risk (in one case, over 8 times EPA's standard) for populations living in the proximity of oil and gas operations due to inhalation of non-methane hydrocarbons. This is one piece of a growing body of literature illustrating health risks across a range of impacts, including respiratory conditions (notably asthma), birth complications, and observations of increased hospitalization across a variety of medical fields, including cardiology, neurology, and oncology (Currie et al., 2017; Jemielita et al., 2015; Rasmussen et al., 2016; Stacy, 2017; Whitworth et al., 2018). These public health threats are associated with unconventional (i.e., shale/coalbed/tight) gas development in particular. Additional effects on these populations include losses in aesthetic and property values (Evensen & Stedman, 2018; McKenzie et al., 2016; Muehlenbachs et al., 2015) as well as increases in violent crime (Bartik et al., 2019).

Many studies exploring environmental justice issues demonstrate how adverse externalities are most likely to fall upon historically marginalized communities. Researchers have documented ubiquitous evidence of environmental inequities based upon race and other factors (Banzhaf, 2012; Banzhaf et al., 2019; Mohai et al., 2009; Taylor, 2014). These groups have been historically underserved and often at greater risk of exposure to environmental impacts.

To date, several prior analyses have explored community-level characteristics surrounding oil and gas wells. Most have used the same methods as herein and explored population and subgroup counts in specific production basins (Clough & Bell, 2016; Meng, 2015; Ogneva-Himmelberger & Huang, 2015; Pellow, 2016; Slonecker & Milheim, 2015), while few have explored national-level counts (Czolowski et al., 2017; Earthworks, 2018; Long et al., 2016). However, no prior studies have assessed, on a national scale, trends in narrower population groups, looking specifically at marginalized communities. In addition, few other studies disclose census margins of error with population estimates. This article addresses these research gaps.

Kroepsch et al. (2019) identified a range of critical questions for developing a research agenda on environmental justice in this context, and this study informs one of them: who lives near wells? This is a first, but critical step, in better understanding distributional inequity in this context. We hope this study will assist researchers, policymakers, and advocates to uncovering the mechanisms that resulted in systemic inequity and addressing persistent environmental injustice (Ma, 2020).

Apps' Ex. 27

0577

Methods

Input datasets

Demographic data was obtained using the U.S. Census Bureau's American Community Survey (henceforth, ACS; U.S. Census Bureau, 2021) 5-year estimates for 2012–2016. Census tracts provide the starting point for the analyses herein and represent the best balance between depth of demographic insight, accuracy of estimates, minimizing margin of error, and geographical resolution. While census block or block groups would have been more desirable in reducing the systematic uncertainty inherent to the areal apportionment calculations, margins of error were unfortunately too large for most demographic metrics at these scales.

Locations of over one million identifiable active oil and gas wells in 2015, both conventional and unconventional, were taken from the DrillingInfo database (2018). This database has near comprehensive national coverage and is a compilation of public datasets from state agencies. Exact locations of wells are given by latitude/longitude coordinates in the database. Data from 2015 were used, despite some states possessing more recent production data, because it provided the most comprehensive single-year database nationwide. Indiana and Illinois are not included due to the low quality of source data for these states, where characteristics such as production, specific location, well type, and status are rarely specified. Thus, marginalized groups in these two states are unfortunately not able to be represented in this analysis. It is estimated that the database covers ~ 95% of the nation's wells and ~ 94% of its population (DrillingInfo, 2018).

Demographic estimation

We recombined ACS variables to create a shortlist of 13 demographic metrics to investigate covering race-ethnicity, educational attainment, language, age, unemployment, and income (see Online Resource 1 for additional details). These metrics were selected for this study due to their utility in the literature of environmental justice (Federal Interagency Working Group on Environmental Justice, 2016; Flanagan et al., 2018; U.S. Environmental Protection Agency, 2017). Our focus was on exploring links to race-ethnicity in addition to key socioeconomic metrics, such as poverty, unemployment, age, language, and education.

We extracted population counts of each population group living within four different buffer distances of each well (radii of 1/10, 1/4, 1/2, and 1 mile). The latter two distances are employed in intercomparisons with other studies (see Online Resource 2), and are the most common metric in extant literature (1 mile in particular). The former two are used in recognition of the fact that currently documented health impacts typically occur in very close proximity to wells with 1/10 mile representing an important threshold (McKenzie et al., 2018). Buffer zones were then overlaid on each census tract, and the share of each tract intersecting a

buffer is calculated via areal apportionment, the most commonly used approach for this type of demographic analysis (Chakraborty et al., 2011).

Once population estimates are extracted at the census tract level, additional metrics (counts as a percent of total population and margins of error) are calculated. These are then aggregated up to county, state, and national levels.

Population statistics for each group are produced, and the margin of error (MOE; using the Census Bureau standard 90% confidence level) is calculated according to:

$$MOE_{agg} = \pm\sqrt{\sum\nolimits_c MOE_c^2}$$

where MOE_c is the MOE of the cth component estimate. This step is reproduced for aggregation to the state and national levels. Water bodies were omitted using the 2015 Census Areal Hydrography National Geodatabase (U.S. Census Bureau, 2015).

To explore the prevalence of regions where marginalized groups live near wells, and metrics overlap, we perform a clustering analysis and develop an index. First, statistically high values for a subset of each population were identified by binning distributions into five categories according to the Jenks natural breaks classification method (i.e., minimizing variance within bins while maximizing variance between them). Online Resource 3 depicts the geographic distributions for the highest bin of each population. Then, to create a multivariate index, a score of 1 was assigned to each well-variable pair that fell into the highest bin. These were summed, such that for any given well, a score may range from 0 to 11 depending on the amount of demographic metrics exhibiting high values. The resulting index can be interpreted as a localized, overlapping measure of marginalized communities.

This index is smoothed using a kernel density function according to:

$$f(x) = \frac{1}{n}\sum_{i=1}^{n} K\left(\frac{x - x(i)}{h}\right)$$

where x is a datapoint (well), n is 1,040,537 (wells), K is a quartic kernel estimator, and h is 0.5 decimal degrees. This specific bandwidth parameter (h) was chosen as it represented the best tradeoff between highlighting local clusters and ensuring they were clearly visible in the full extent of the map. This smoothing process is performed only for Fig. 1C to enable an intuitive interpretation of results at a national scale and account for the role of well density in cumulating and exacerbating potential health impacts. Only wells with scores of 1 or above are depicted.

Comparative statistics

Population estimates were also compared with respective control groups. Within counties, this is performed by contrasting our estimate of the share of populations living near wells to that of corresponding county-wide estimates for the same group, as given by:

Apps' Ex. 27

0579

$$e_{i,b,j} = \left(1 - \left(\frac{p_{i,b}}{t_{i,b}} \div \frac{p_{i,j}}{t_{i,j}}\right)\right) \times 100$$

where p is the population estimate for demographic variable i, in buffer zone b or county j. Denominators t represent total population estimates for respective variable/region pairs. The resulting metric, e, is perhaps best understood as a county/variable pair's percent deviation from the expected value of its control group. To determine whether these deviations are statistically significant, we then follow the Census Bureau guidelines and apply the z-score formula below:

$$z_{i,b,j} = \frac{\left|Est_{i,b} - Est_{i,j}\right|}{\sqrt{MoE_{i,b}{}^2 + MoE_{i,j}{}^2}}$$

Here, *Est* refers to population estimates (as a share of total, or $\frac{p}{t}$ as defined above) and *MoE* denotes associated census margins of error. This yields a z-score for each county/variable pair that describes the extent to which estimates are statistically different from their control group counterparts at a 90% confidence level. Limitations of our methodology are discussed in the supplementary information.

Results

Population-specific clustering

Oil and gas resources are extracted across a wide swath of the USA – the combined land area within one mile of all wells covers approximately 270,000 mi^2, or ~ 7.6% of the country. Figure 1A and B illustrate the degree to which this infrastructure is not only widespread but also concentrated in the same large production basins.

We begin with a local, census tract level analysis of each population group in isolation. This allows us to explore the prevalence of clusters or regions across the country where certain marginalized groups may be living near wells in relatively high numbers, as a share of total population. An array of maps highlighting the predominant clusters by group are provided in Online Resource 3. For Blacks, these stretch across several southern states (LA, MS, AL, AR) and several urban settings (Los Angeles, Cleveland, Akron, Youngstown). Alaskan Native and Native American clusters can be observed in Alaska (Prudhoe Bay, Utqiagvik, Anchorage) and pueblos in northwestern New Mexico. For Asian communities, these are largely concentrated in California, in urban settings of the San Joaquin Delta and greater Los Angeles area, as are Hawaiians and Pacific Islanders. Clusters of Hispanic populations stretch across large expanses of California and Texas.

In terms of socioeconomic metrics, clusters of populations with lower levels of educational attainment are predominantly located in California (Central Valley, Los Angeles), Texas (mainly near the U.S.-Mexico border), Louisiana (Lafayette, New Orleans), southwest West Virginia, and eastern Kentucky. These regions are

Apps' Ex. 27
0580

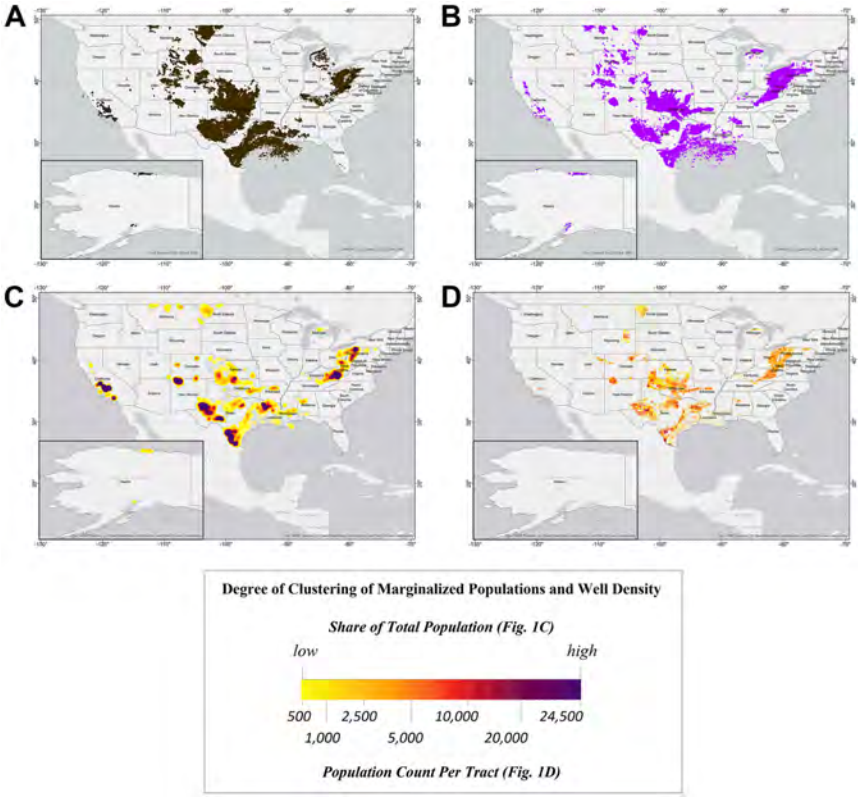


Fig. 1 Disposition of oil and gas wells and marginalized population clusters across the USA. **A** depicts active oil wells in black ($n = 473{,}469$), and **B** active gas wells in purple ($n = 377{,}738$) for the year 2015. **C** and **D** illustrate clustering of multiple marginalized population groups overlapping with areas of high well density. **C** denotes an index score calculated using an equally weighted aggregate statistic, representing how many marginalized populations overlap as a share of total population living near wells. **D** depicts these data terms of absolute population count per census tract, rather than relative shares as in **C**. All well types are factored into this analysis ($n = 1{,}040{,}537$); Hawaii is omitted in this figure given its lack of wells

mirrored in the findings both for communities with high unemployment and those under the poverty line, with the addition of several regions (San Joaquin Delta, CA; Farmington, NM; north-central MT, areas across LA/MS/Appalachia). Limited English-speaking communities are concentrated in northern Alaska, California (Central Valley, Los Angeles), Texas (South Texas and the Rio Grande Valley, Houston and Dallas metro areas), and Garden City (KS).

Regarding age groups, communities with relatively higher numbers of children under 5 years old are found in California's Central Valley, throughout Texas (particularly across the Eagle Ford, Permian, and Anadarko Basins), and in the North (north-central MT, western ND in the Bakken Formation). These regions are comprised

Apps' Ex. 27
0581

of children composing up to 13% of the total population living near wells – over double the national average. Communities with high levels of older individuals (over 64 years old) are observed across the nation, yet are concentrated in the following states: MT, ND, TX, KS, OK, NE, CO, MI, WV, TN, OH, and PA. A subset of these (CO, NE, MI) intersect very little with other demographic metrics.

Additional income metrics (in particular the GINI coefficient) reveal many communities facing relatively high income inequality in southern states (TX, LA, MS, OK), in Appalachian states (WV, OH, PA), and in Montana. Median Family Income metrics further highlight clustering in both poor and affluent neighborhoods, with the latter typically surrounding major cities where fossil fuel extraction is prevalent.

Marginalized population overlap index

We then created a national index to highlight regions where clusters across multiple marginalized population groups and areas of high well density coincide. Figure 1C illustrates areas with a high degree of intersectionality for all wells across the country. Approximately 41 distinct (non-contiguous) clusters can be observed. The highest ones are found in CA's Central Valley, notably near Bakersfield and Coalinga (in the San Joaquin Basin). Moving east, a large cluster can be observed in the area surrounding Farmington, NM – a region containing several Native American tribes, with the Navajo Nation, Southern Ute, and Jicarilla Apache Nation having the greatest overlap. In the Permian Basin, two clusters emerge (one northwest of Odessa, TX, and the other west of Sonora, TX). Nearby, we observe three distinct clusters on the TX-Mexico border, near the environs of Laredo, TX (Eagle Ford Shale). Three significant clusters remain: one located northwest of Shreveport, LA (Haynesville-Bossier Shale), and two in Appalachia: south of Charleston, WV, and near Allegheny National Forest, PA. Figure 1D adapts the approach used in panel 1C to use absolute population counts, rather than relative shares. Clusters remain largely the same with the exception of some regions diminishing (e.g., California and Wyoming). This underlines the fact that these clusters represent areas where marginalized groups are found both in disproportion and in high numbers.

Summary statistics by distance from well

A local lens is most useful to identify larger disparities and truly explore questions of environmental justice. The analyses presented above were completed to provide a deeper and more focused assessment of such trends. Though it conveys a limited perspective, aggregation at the national and state levels is helpful for obtaining a broad snapshot of trends.

Table 1 summarizes national statistics for each population within one mile of a well. For each group, two comparative statistics are provided: national totals and control counties. The latter represents a control group reflecting demographic trends specific to oil and gas producing regions: population estimates for counties within which wells are located. There is a varying degree to which the county-level population estimates are significantly statistically different from controls (5–57%; 90% CI),

Table 1 National summary statistics of population counts within one mile of a well. Percentage rows denote population counts as a share of the total population within the same one-mile buffer. The control counties column denotes population counts for population groups within the counties where wells are located. Column 3 shows differences between estimates of population shares within a one-mile buffer, and their respective county controls. Column 4 provides summaries of the overall share of counties that exhibited significantly different estimates from their control groups, while column 5 provides *p*-values from this analysis (see Online Resource 5 for county/variable level detail)

Population group	Population living within one mile of a well	Difference in share of population in one mile proximity, versus county controls (%)	Aggregate share of counties with estimates significantly different from control groups (%)	Mean *p*-value (normal dist., 90% CI)	Control counties	National total
Black	1,836,200	−1.9	41	0.069	12,773,100	44,654,400
[%]	10.00%				11.90%	13.90%
Asian	697,500	−3.3	24	0.244	7,668,400	16,614,600
[%]	3.80%				7.10%	5.20%
Hawaiian/Pacific Islander	34,600	−0.1	5	0.377	361,700	560,000
[%]	0.20%				0.30%	0.20%
Hispanic	3,318,000	−6	34	0.17	25,776,600	58,691,300
[%]	18.00%				24.00%	18.20%
Native American	457,000	0.5	16	0.298	2,172,600	5,430,300
[%]	2.50%				2.00%	1.70%
White	15,129,100	7.1	41	0.054	80,570,800	244,659,400
[%]	82.20%				75.10%	76.00%
Below poverty line	2,872,400	−0.4	23	0.297	17,230,500	48,509,300
[%]	15.60%				16.00%	15.10%
Under 5 years old	1,184,400	−0.1	17	0.346	6,981,800	20,050,500
[%]	6.40%				6.50%	6.20%
Over 64 years old	2,692,000	0.9	26	0.296	14,682,500	46,794,900
[%]	14.60%				13.70%	14.50%
Less than HS degree	1,814,600	4.7	19	0.315	10,870,100	28,445,400
[%]	14.80%				10.10%	13.30%

0583 Apps' Ex. 27

Table 1 (continued)

Population group	Population living within one mile of a well	Difference in share of population in one mile proximity, versus county controls (%)	Aggregate share of counties with estimates significantly different from control groups (%)	Mean *p*-value (normal dist., 90% CI)	Control counties	National total
Limited English spoken	143,300	− 0.2	7	0.378	1,119,400	6,136,700
[%]	0.80%				1.00%	1.90%
Unemployed	604,700	− 0.4	10	0.368	3,979,800	12,032,700
[%]	3.30%				3.70%	3.70%
Total population	18,405,100				107,301,000	322,087,500
[%]	5.70%				100.00%	100.00%

Apps' Ex. 27

0584

depending on the metric (see Table 1). For many counties, population numbers were simply too low and/or metrics had margins of error too large to yield strong statistical power in the relationships explored. Significance measures for each county/variable pair are provided in Online Resource 4, and summary statistics for the half, quarter, and tenth mile buffer distances are found in Online Resource 5.

These results underscore the degree to which the US population and oil and gas production are intertwined. Over 18 million people live within one mile of wells. Many of these consist of marginalized groups (Hispanic: 3.3 m; Black: 1.8 m; Asian: 0.7 m; Native American: 0.5 m; below the poverty line: 2.9 m; over 64 years old: 2.7 m; under 5 years old: 1.2 m). From a relative standpoint, at a national aggregated scale, most population groups are found to be less prevalent near wells than their county-level controls. The exceptions to this are Native Americans, Whites, people over 64 years old, and people with less than a high school degree. For these populations, we find a respective 25.0%, 9.5%, 6.6%, and 46.6% higher prevalence living within one mile of wells than controls.

State-level tables were also derived to depict population counts by demographic group within one mile of wells. Online Resource 6 provides data for the 29 states where oil and gas production is prevalent. The five states with the greatest number of people living near wells are Texas (5.0 m), Ohio (3.0 m), California (2.2 m), Oklahoma (1.9 m), and Pennsylvania (1.9 m). On a percentage of total state population basis, these are: West Virginia (50.9%), Oklahoma (50.1%), Ohio (25.9%), Texas (18.7%), and Pennsylvania (15.0%). These measures highlight the fact that many people across the country are bearing the externalities of oil and gas development – particularly in West Virginia and Oklahoma where a majority of people live near active wells.

With respect to summary results, a subset for one mile and ½ mile (state and national levels) can be compared to other estimates in the literature; see Online Resource 2 for a comprehensive assessment. In cases where metrics and methodological approaches overlap, our findings are extremely similar.

The comparative analyses outlined in this section were performed as an additional means of investigating disproportionality through county, state, and national scales. Percentage differences from respective control groups for each county/variable pair can be found in Online Resource 4. These data illustrate the wide distribution that can be seen across counties, in terms of disproportionality for any given population, and emphasize the locally specific nature of these findings.

Discussion

In this study, we shine a light on the colocation of historically marginalized groups and wells. While the negative impacts of production are real and widespread, a nuanced approach is needed in moving beyond this framework and exposing cases of environmental injustice. A key factor to acknowledge is that oil and gas development may be desired and spurred on by local communities, in seeking royalties and potential employment. This stands to reason as Bartik et al. (2019) have noted large positive welfare implications on frontline communities. This economic benefit is likely to be more tangibly perceived than the indirect negative externalities,

Apps' Ex. 27
0585

particularly with respect to health impacts that are still being uncovered. It should be noted that, more generally, the permitting process for oil and gas development differs on Native American lands, where most of these populations live.

Production also relies on labor inputs, meaning that fossil fuel extraction industries and inhabited areas frequently overlap. The analysis presented herein is not causal, but correlative; we provide a characterization of the extent to which the colocation phenomenon is prevalent. Developing this knowledge is particularly important in light of the fact that there is evidence of health impacts for populations living in close proximity to wells (Gold & McGinty, 2013; Macey et al., 2014; Rabinowitz et al., 2015; Steinzor et al., 2013). Additionally, there have been numerous examples of recent incidents involving gas leaks from wellheads, such as in Belmont County, Ohio, in February 2018. Vulnerable communities are often at a disadvantage when it comes to mitigating environmental exposures and overcoming impacts, so it is critical to understand where they might be most readily exposed to the negative externalities of production. In turn, understanding where and how oil and gas development intersect with diverse communities should aid in formulating the appropriate industry practices and public policies to reduce impacts to proximate populations.

There are four notable regions in the country where intersectionality across marginalized groups points to a need for deeper region-specific research, particularly surrounding health impacts. The first such region is southern California, particularly in greater Los Angeles and the Central Valley. The former reveals a prevalence of Hispanic, Asian, Black, and Hawaiian/Pacific Islander populations living in proximity to oil and gas wells, while the latter registers more along metrics such as language, poverty, and unemployment, among Hispanic communities. This is in large part explained by the fact that wells in the Los Angeles urban setting tend to be located within ethnically diverse central neighborhoods, while the Central Valley is home to a large agricultural workforce facing its own set of socioeconomic challenges.

The second notable region, concentrated in southwest Texas, includes the Permian Basin and the Eagle Ford Shale. These regions mirror similar characteristics as California's Central Valley. A third major region of note, Appalachia, differs somewhat from the others in terms of demographics. Here, these are predominantly elderly White populations and groups with low income and high unemployment. Finally, a fourth region to highlight appears in northwest New Mexico, largely composed of Native American populations and communities with high unemployment, poverty, and children under the age of five. These areas should form a primary focus for science and policy given the degree to which this colocation and cumulation can dramatically worsen inequities and health disparities (Morello-Frosch et al., 2011).

Another important policy aspect for exploration in subsequent research is the relationship between employment and populations living near wells. Our results highlight widespread clusters of high unemployment near wells 4–12 times the national average (Online Resource 3). While this question has been explored nationally in the context of shale wells (Maniloff & Mastromonaco, 2017), the approach presented in this study, supplemented by time-series analysis and causal inference methods (e.g., using difference-in-differences or instrumental variables), is well suited to exploring

Apps' Ex. 27
0586

this question for a broader range of well types using the frequent (i.e., annual) time step proffered by the ACS.

Our study differs in several key ways to the most similar prior analyses (Czolowski et al., 2017; Earthworks, 2018; Gold & McGinty, 2013). One chief aspect is that our study uncovers national statistics for 12 new population groups, and the intersectionality of these. It is the first national study to include census margins of error alongside estimates, and uses more recent data for both wells and populations: all prior national studies rely on the 2010 Census and demographic trends have likely changed significantly since then, particularly in fossil fuel extraction zones. Finally, Alaska is also included in our scope of analysis, exposing areas of potential interest (particularly near Prudhoe Bay).

We envision multiple ways in which these findings can be useful to a variety of audiences. First, for policymakers having a responsibility to ensure the safety and welfare of people living near oil and gas operations, these data can aid in crafting policy tailored to protecting vulnerable populations on the front lines. Second, these communities themselves and representative organizations will have the means to contextualize and quantify affected groups, in advocacy efforts aimed at addressing environmental injustice. Third, researchers can more accurately scope areas of interest for studies aimed at furthering our understanding of impacts from wells on proximate populations. Fourth, industry can use these data to customize and enhance their stakeholder outreach efforts and operational considerations by better understanding the makeup of the populations with which operators interact.

Our findings illustrate the sheer extent to which aggregate numbers of people live in close proximity to wells, both in terms of marginalized populations and specific geographies where fossil fuel production is prevalent. The data highlights key areas of layered social vulnerability, and by way of these quantification efforts, reinforces the need to further understand how frontline communities are impacted by oil and gas development.

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Declarations

Conflict of interest The authors declare no competing interests.

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Apps' Ex. 27

0587

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Apps' Ex. 27
0588

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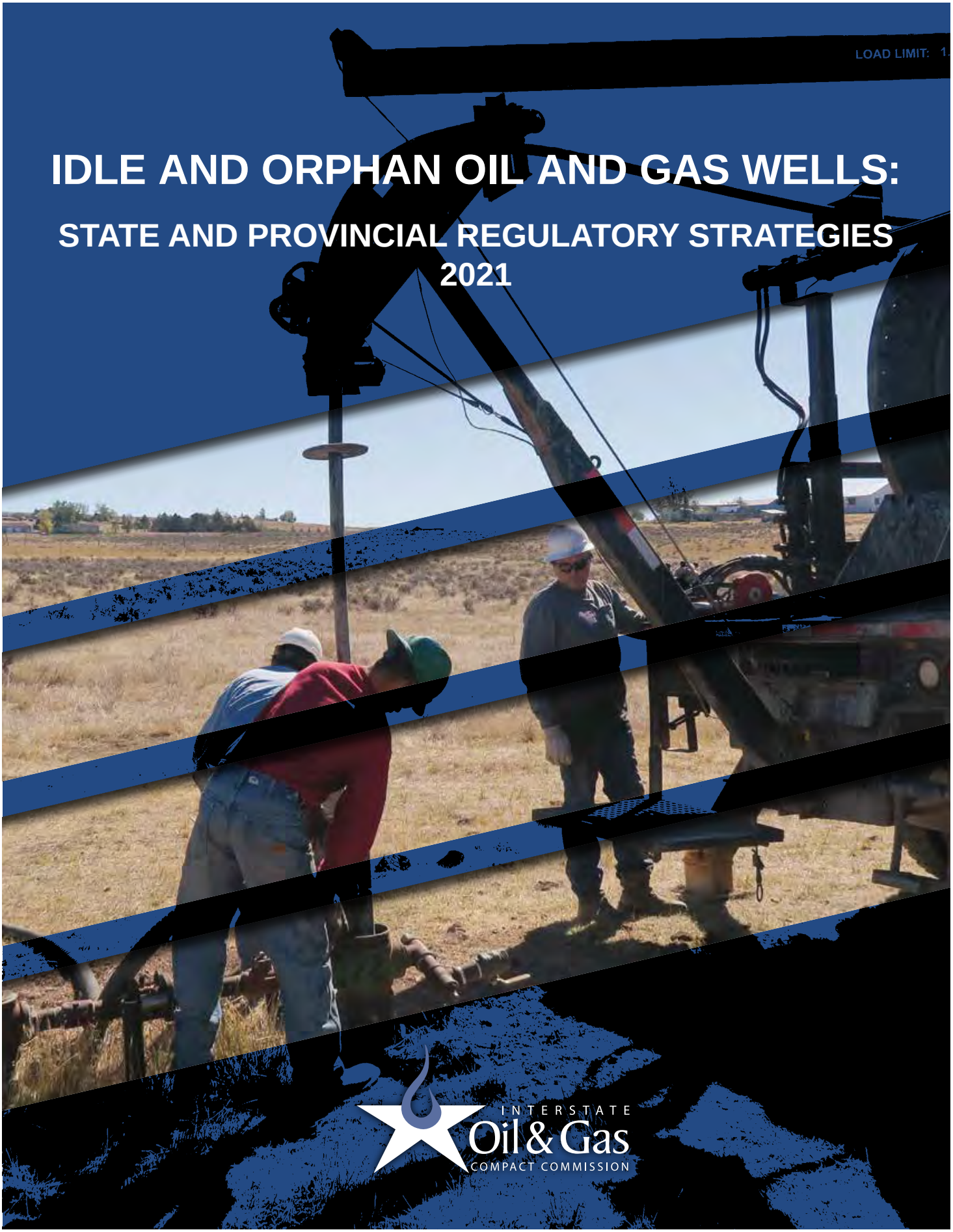
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EXHIBIT 28

IDLE AND ORPHAN OIL AND GAS WELLS:

STATE AND PROVINCIAL REGULATORY STRATEGIES

2021



INTERSTATE
Oil & Gas
COMPACT COMMISSION

IDLE AND ORPHAN OIL AND GAS WELLS:

STATE AND PROVINCIAL REGULATORY STRATEGIES 2021



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TABLE OF CONTENTS

PREFACE 1

EXECUTIVE SUMMARY 2
- IDLE WELLS 2
- ORPHAN WELLS 2
- REGULATORY STRATEGIES 3

INTRODUCTION 4
- PURPOSE AND SCOPE OF REPORT 4
- TERMINOLOGY 4
- BACKGROUND 4

STUDY METHODOLOGY 6
- DATA COLLECTION 6
- STUDY LIMITATIONS 6
- ACRONYMS AND ABBREVIATIONS 6

STUDY RESULTS 7
- DOCUMENTED WELLS DRILLED AND NOT PLUGGED 7
- IDLE WELLS 7
- DOCUMENTED ORPHAN WELLS 9
- UNDOCUMENTED WELLS 11
- ORPHAN WELL PLUGGING AND SITE RESTORATION 12
- SOURCES OF FUNDS 16
  - FINANCIAL ASSURANCE 17
  - PLUGGING FUNDS 18
- PROGRAM IMPROVEMENTS 19
- INCENTIVES 19

AREAS FOR FURTHER WORK 21
- IOGCC REPORT ON INFRASTRUCTURE AND LIABILITY TRANSFER 21
- ORPHAN WELLS ON FEDERAL AND TRIBAL LANDS 21
- FEDERAL FUNDING UNDER THE OIL POLLUTION ACT 22
- REVIEW OF CONTRACTING PROCEDURES 22
- ASSESSING POPULATIONS AND RISKS OF UNDOCUMENTED WELLS 22

AFTERWORD 23

DATA TABLES 25
- Table 1. Documented Wells Drilled and Not Plugged (2020) 26
- Table 2. Approved Idle Wells (2020) 27
- Table 3. Documented and Undocumented Orphan Wells (2018-2020) 28
- Table 4. Operator Status of Documented Orphan Wells (2020) 29
- Table 5. Documented Orphan Wells by Land Ownership (2020) 30
- Table 6. Total Wells Plugged (2018-2020) 31
- Table 7. Orphan Well Plugging and Expenditures (2018-2020) 32
- Table 8. Orphan Well Restoration and Expenditures (2018-2020) 33
- Table 9. Idle Well Requirements 34
- Table 10. Funding Sources for Plugging Orphan Wells 35
- Table 11. Financial Assurance 36
- Table 12. Plugging Funds 37
- Table 13a. Updated Data on Documented Orphan Wells 38
- Table 13b. Explanations for Updated Data on Documented Orphan Wells 39

STATE AND PROVINCIAL SUMMARIES 40

LIST OF FIGURES 77

REFERENCES 78

ABOUT IOGCC

The Interstate Oil and Gas Compact Commission (IOGCC) is a multi-state government agency that champions the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. IOGCC provides member states and international affiliates with a clear and unified voice and serves as a primary authority on issues surrounding these vital resources.

ACKNOWLEDGMENTS

The production of this report required a team effort of member states, international affiliates, committees, contractors, and staff. IOGCC extends sincere thanks to those who contributed their time and expertise to make this report an authoritative and useful compilation of information on a topic of paramount importance to the organization and its constituents.

The Council of Regulatory Officials (CRO), under the leadership of the chair, David Hardie of the Alberta Energy Regulator, provided overall direction and support for the project. The CRO consists of regulatory officials of IOGCC's 31 member states, seven associate member states, and seven affiliated Canadian provinces.

Harold "Hal" Fitch of H.R. Fitch Consulting served as the lead author, and IOGCC Executive Director Lori Wrotenbery served as the lead editor. IOGCC Executive Project Manager Amy Childers and Technical Coordinator Kaitlyn Smith assisted in compiling the information included in the report. The State of Wyoming supplied the photo used in the cover graphics, and Daren Shepherd of Shepherd Graphics designed the cover and prepared the report for publication.

Most importantly, IOGCC thanks the states and provinces for responding to repeated requests for data and other information for this report. We trust that the report both honors and supports their continued leadership in establishing effective regulatory programs for idle and orphan wells.

DISCLAIMER

The states and provinces provided a wealth of data and other information for this report. The authors and editors have endeavored to summarize this information in an accurate and meaningful way.

Should you have a question about the contents of this report, feel free to contact IOGCC for assistance. Please note, however, that a question regarding information from a specific state or province may be referred to sources within the state or province, who are the most knowledgeable about their own data and regulations. Note, too, that readers should consult with the state or province before relying on any summary, statement, or interpretation of the requirements or procedures of that state or province.

PREFACE

This report updates and expands upon information previously published by the Interstate Oil and Gas Compact Commission (IOGCC) on the issue of idle and orphan oil and gas wells. It includes data and other information submitted by the states and provinces for calendar years 2018, 2019, and 2020. Like IOGCC's earlier publications on the issue, the primary purpose of this report is to help states and provinces evaluate their idle- and orphan-well programs and identify useful regulatory tools and strategies from other jurisdictions.

We are grateful to the states and provinces for their support in the production of this report. They contributed their time and expertise by responding to the survey and follow-up requests that provided the data and other information published here. They also contributed through their financial support of IOGCC. No other source of funds was used in the production of the report.

Shortly before publication, Congress passed, and the President signed, bipartisan infrastructure legislation that includes funding for the plugging of orphan wells on federal, state, private, and tribal lands. We are gratified that IOGCC's 2019 report on idle and orphan wells, on which this report builds, served as a useful reference in the development of federal legislation.

IOGCC and its member states are already working with federal agencies and others to implement the new legislation. Providing support for this effort will remain a top priority for IOGCC throughout the decade.

Immediately following enactment of the bipartisan infrastructure legislation, IOGCC conducted a short, follow-up survey of the states to obtain updates on their inventories of documented orphan wells. Please refer to the Afterword for more information on the results of the follow-up survey, as well as brief comments on the unparalleled opportunity presented by the federal funding.

Apps' Ex. 28

0596

EXECUTIVE SUMMARY

This report updates and expands upon the information previously published by the Interstate Oil and Gas Compact Commission (IOGCC) on the issue of idle and orphan oil and gas wells. IOGCC has researched and analyzed this issue for many years, and published reports in 1992, 1996, 2000, 2008, and 2019. Like IOGCC's earlier reports on the issue, the primary purpose of this report is to help states and provinces evaluate their idle- and orphan-well programs and identify useful regulatory tools and strategies from other jurisdictions.

The report covers the numbers of idle and orphan wells, regulatory tools for managing these wells, orphan well plugging and restoration activities and costs, and funding sources for plugging and restoration. It is based on survey responses from 32 IOGCC member and associate member states and five Canadian provinces, including data for calendar years 2018, 2019, and 2020.

IDLE WELLS

Idle wells are wells that have not yet been plugged and are not producing, injecting, or otherwise being used for their intended purpose. Many idle wells have potential for future oil or gas production or associated uses. If not properly monitored and maintained, however, they may pose a risk to the environment, public health, and safety. They also present an elevated risk of becoming orphan wells. States and provinces use various regulatory mechanisms to manage these risks while recognizing the potential for future beneficial uses of idle wells.

Thirty-three states and provinces reported the number of wells approved to remain in idle status. The total number of approved idle wells reported by the states as of December 31, 2020, is 231,287, which is 14 percent of the total number of documented wells that have been drilled but not plugged. In the provinces, the corresponding numbers are 140,183 and 38 percent. The total number of documented wells that have been drilled but not plugged are 1,619,071 in the states and 372,697 in the provinces.

In most states and provinces, idle wells with no future beneficial use must be plugged. In the three years covered by this report, operators plugged 62,463 wells in the states and 16,295 wells in the provinces.

ORPHAN WELLS

Orphan wells are idle wells for which the operator is unknown or insolvent. Most states and provinces maintain inventories of documented orphan wells and prioritize the wells for plugging according to risk.

As of December 31, 2020, the states reported a total of 92,198 documented orphan wells, and the provinces reported a total of 5,015 documented orphan wells. In the states, the number of documented orphan wells increased by 50 percent from 2018 to 2020, due primarily to the efforts of states to document these wells through investigation and verification of the status of wells and their operators.

In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300.

The cost to plug an orphan well varies widely depending on well depth and condition, location, accessibility, and other factors. For the 25 states that plugged orphan wells from 2018 through 2020, the average expenditure per well ranged from $2,400 to $227,000, with an overall three-year average of $25,634. Most states conduct basic site restoration as part of an orphan well plugging operation.

For the three provinces that plugged orphan wells from 2018 through 2020, the average expenditure per well ranged from C$37,528 to C$42,047, with an overall three-year average of C$41,156. These numbers do not include expenditures for site restoration.

This report contains estimates from some states of the number of undocumented orphan wells, i.e., wells the states have reason to believe exist but have not verified. Most of these wells are a legacy of early oil and gas development in the states. While estimated numbers for some states are large, they do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not constitute a significant risk to the environment or public health and safety. More work needs to be done to identify and assess these wells.

REGULATORY STRATEGIES

State idle and orphan well programs consist of various program elements that work together to ensure that wells are properly plugged at the end of their useful lives. These program elements include requirements for properly monitoring and maintaining idle wells, financial assurance requirements, and other sources of plugging funds.

Most states and provinces have requirements, such as periodic mechanical integrity testing, that must be met for wells to remain idle beyond a specified time. These requirements may be set by statute, rule, or written approval.

Most states and provinces also require financial assurance to provide money for plugging and restoration if the operator defaults. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. The types accepted and amounts required vary considerably among the states and provinces. The participating states all provide for single-well and blanket coverage, and the participating provinces provide for either single-well or blanket coverage, or both. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well or case-by-case evaluations.

To supplement the funds provided through financial assurance instruments, most states and provinces have established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry.

Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using Geographic Information Systems (GIS) and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration.

Through the decades, the states and provinces have made considerable progress in managing idle wells and identifying and plugging orphan wells. They have continued to evaluate and adjust their well operation standards, plugging requirements, inspection and enforcement procedures, financial assurance requirements, and plugging fund provisions to reduce the likelihood of additional wells being orphaned and provide resources for well plugging and site restoration.

States and provinces remain concerned, however, over the potential for escalating numbers of idle and orphan wells. The risk of wells becoming orphans is heightened during periods of oil and gas market volatility or when operators transfer aging wells to other companies. IOGCC will continue to periodically update the data and information in this report and coordinate other projects to support the states and provinces in developing effective regulatory strategies to address these challenges.

INTRODUCTION

PURPOSE AND SCOPE OF REPORT

This report updates the information previously published by the Interstate Oil and Gas Compact Commission (IOGCC) on the issue of idle and orphan oil and gas wells. It is an initiative of IOGCC's Council of Regulatory Officials, which consists of regulatory officials of IOGCC's 31 member states, seven associate member states, and seven affiliated Canadian provinces.

IOGCC has researched and analyzed this issue for many years, and published reports in 1992,[1] 1996,[2] 2000,[3] 2008,[4] and 2019.[5] IOGCC also published a brief supplemental report in May 2020[6] categorizing the population of documented orphan oil and gas wells by land ownership.

In addition to providing data on idle and orphan wells in the U.S. and Canada, this report outlines the regulatory tools and funding sources used to ensure that the responsible operators properly maintain and ultimately plug idle wells and that states and provinces have funds to plug orphan wells. Like IOGCC's earlier reports on the issue, the primary purpose of this report is to help states and provinces evaluate their idle- and orphan-well programs and identify useful regulatory tools and strategies from other jurisdictions.

Information in the report comes from the survey responses of 32 IOGCC member states and five Canadian provinces, including data for calendar years 2018, 2019, and 2020. The report compiles and summarizes data from the survey, compares it to data from previous surveys, and analyzes trends.

TERMINOLOGY

Most of the wells addressed in this report were drilled for production of oil or gas. Others were drilled for related purposes, such as fluid injection for enhanced oil recovery (EOR), waste fluid disposal, gas storage, or monitoring.

States and provinces use varied terms to describe well status. Regardless of the terms used by individual states and provinces, this report addresses wells that have been drilled and not yet plugged. It does not cover wells that have previously been plugged.

For purposes of this report, "idle wells" are defined as wells that are not producing, injecting, or otherwise being used for their intended purpose. "Orphan wells" are defined as idle wells for which the operator is unknown or insolvent. Where a state or province defines one of these terms in a substantially different manner, the state or provincial definition is noted in the "State and Provincial Summaries" section of the report.

The term "documented" is used to describe a well for which the regulatory agency has a drilling report, completion report, inspection report, or other record establishing the existence of the well. The term "undocumented" refers to a well that is entirely unknown to the agency or a well of which the agency has some evidence, but which requires further records research or field investigation for verification.

BACKGROUND

Most newly drilled wells are placed in service for many years or decades. During its life, a well may be converted from one use to another, e.g., from production to injection. It may become idle at different times for different reasons.

Many idle wells can produce oil or gas, but the cost to maintain and operate them may exceed revenue at prevailing oil and gas prices. Others may have potential future value for EOR, waste fluid disposal, gas storage, or other uses. Idle wells, however, may become a risk to the environment or public health and

safety if they are not properly monitored and maintained. The wellbore may deteriorate and become a conduit for oil, gas, or saltwater to migrate into aquifers or to the surface. Idle wells also present an elevated risk of becoming orphan wells and imposing a liability on the state or province for plugging and restoration. States and provinces have established regulatory requirements to manage these risks. Some provide incentives to put idle wells back into operation.

Once a well is determined to have no future beneficial use, it must be plugged, and the site restored. Proper plugging is essential to prevent migration of oil, gas, or saltwater that can damage freshwater resources, soils, and other underground and surface resources. Unplugged wellbores can collapse and create a hazard to humans and animals, and unrestored sites can interfere with other beneficial uses of the land.

Well operators are responsible for plugging wells, and most plugging operations are conducted by the operators and their contractors. If the well operator ceases to exist or becomes insolvent before a well is plugged, the responsibility for monitoring and plugging the well generally falls on individual states and provinces.

States and provinces require well operators to post financial assurance to provide money for plugging and restoration if the operator defaults. Most also have established funds designated specifically for orphan-well plugging. Some others have authority to spend money from operating funds or other sources to plug orphan wells. Money used for plugging comes primarily from production taxes, fees, or other assessments on the oil and gas industry.

Most states and provinces have inventories of documented orphan wells. To make effective use of limited resources, they prioritize the wells for plugging according to the risk to the environment and public health and safety.

Oil and gas drilling in North America began in the middle 1800s. Regulatory requirements were established in most oil- and gas-producing states and provinces in the early to middle 1900s. Many wells that are now orphaned were drilled before there was any regulatory oversight. Many of these pre-regulatory wells were abandoned without being properly plugged. There may be no record of the location, drilling, or construction details for these wells. They often go undetected for years or decades, to be discovered only when new land development takes place in the vicinity of the well.

This report contains estimates from some states of the number of undocumented orphan wells. While estimated numbers for some states are large, they do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not be a significant risk to the environment or public health and safety. More work needs to be done to identify and assess these wells.

Apps' Ex. 28

0600

STUDY METHODOLOGY

DATA COLLECTION

Data for this report was collected by surveying state and provincial regulatory agencies. The survey requested information on a range of topics to provide insight into state and provincial programs addressing idle and orphan wells. Thirty-two states and five provinces responded to the survey.

For many of the data elements in this report, numbers are shown for 2018, 2019, and 2020. Where inventory numbers fluctuate throughout the year, as in the case of the number of idle and orphan wells, the data is provided as of December 31st of the year.

STUDY LIMITATIONS

The information reported here for the current survey period is quite complete. It is considered reliable, although IOGCC cannot independently confirm the data in most cases, and this report relies on the data as reported by the states and provinces.

ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in the report:

EOR: Enhanced Oil Recovery, i.e., Secondary or Tertiary Recovery

GIS: Geographic Information System

IOGCC: Interstate Oil and Gas Compact Commission

MIT: Mechanical Integrity Test

P&A: Plugged and Abandoned

TA: Temporarily Abandoned

STUDY RESULTS

This section of the report provides a summary and analysis of the information collected. More detail on each state or province is provided in the Data Tables and State and Provincial Summaries sections of the report, as well as in the Summary of State Statutes and Regulations[7] on the IOGCC website.

DOCUMENTED WELLS DRILLED AND NOT PLUGGED

As of December 31, 2020, the states reported a total of 1,619,071 wells drilled and not plugged, and the provinces reported a total of 372,697. **Table 1** shows the breakdown of these wells by the following well types: oil and gas production, oil-and-gas-related injection, oil-and-gas-related monitoring, gas storage, and other.

IDLE WELLS

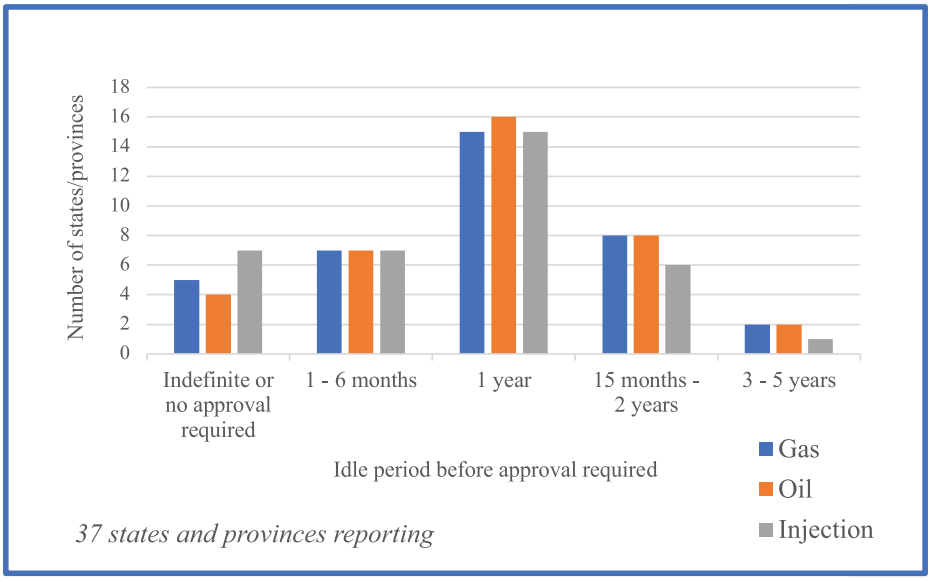
Setting requirements for idle wells is one of the tools the states and provinces use to protect public health and safety and the environment and to prevent idle wells from becoming orphan wells. Compliance may involve meeting criteria in statutes or rules, or it may require applying for and receiving written approval by the regulatory agency.

Most states and provinces specify how long a well may remain idle before approval is required and what requirements must be met for the well to remain idle. States and provinces often require testing and monitoring of idle wells or additional safety measures. Some require additional fees or financial assurance for an operator to maintain a well in idle status.

In most states and provinces, idle wells with no future beneficial use must be plugged by the responsible operators. In the three years covered by this report, operators plugged 62,463 wells in the states and 16,295 wells in the provinces. See **Figures 7** and **8** and **Table 6** for details.

Figure 1 summarizes the period a well may remain idle before approval is required in the states and provinces. See **Table 9** for details.

Figure 1. Period a Well May Remain Idle Before Approval is Required

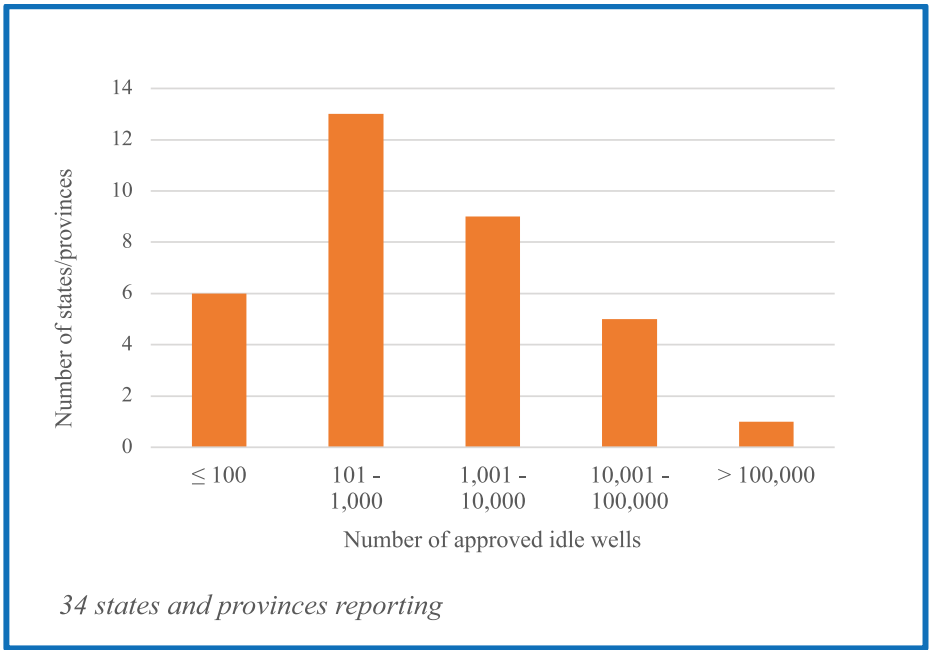


Provisions vary considerably for how long a well may remain in idle status after approval is granted. For details, see **Table 9** and the State and Provincial Summaries section of the report.

Of the 37 participating states and provinces, 34 reported the number of wells that are approved to remain idle. For the states, the number of approved idle wells ranged from zero to 122,944, with a total of 231,287; for the provinces, the number ranged from 88 to 95,512, with a total of 140,183.

Figure 2 summarizes the numbers of approved idle wells in the states and provinces. See **Table 2** for a detailed breakdown by state or province and well type (gas, oil, injection, and other).

Figure 2. Number of Approved Idle Wells (2020)



The ratio of approved idle wells to total wells that have been drilled but not plugged varies widely across the states and provinces. Of the 33 states and provinces that reported approved idle wells, the ratio ranges from less than one percent to 100 percent. The overall average is 14 percent for the states and 38 percent for the provinces.

The number of idle wells in a state or province is a concern because of the potential for the wells to deteriorate over time or become orphans. An even more critical factor is the number of idle wells held by an individual operator, especially as a percentage of the operator's total wells that have been drilled but not plugged. A high percentage of idle wells may indicate an increased vulnerability of the state or province to the operator becoming insolvent and leaving orphan wells. States and provinces use various approaches to ensure operators actively manage their idle well inventories and plug wells with no future beneficial use. See the State and Provincial Summaries section of the report for more information.

DOCUMENTED ORPHAN WELLS

The 32 states participating in this year's survey reported a total of 92,198 documented orphan wells as of December 31, 2020. While the states continued to plug orphan wells as discussed later in this report, the number of orphan wells documented in the states increased by 50 percent since 2018, largely due to state efforts to complete their inventories. The five participating Canadian provinces reported 5,015 documented orphan wells as of December 31, 2020, a 23 percent increase since 2018.

Changes in the numbers of documented orphan wells are attributable to several factors. Wells are removed from the inventory as they are plugged or are transferred to new operators. Wells are added to the inventory as states and provinces document orphan wells that were previously unknown or unverified and as some operators go out of business.

There are two primary reasons for the increase in documented orphan wells in the past few years. First is the work the states and provinces are doing to identify orphan wells through investigation and verification of the status of wells and their operators. Second is the effect of recent economic turmoil on oil and gas operators. Some operators filed for bankruptcy or went out of business when oil prices collapsed due the combined effects of reduced demand during the pandemic and an international oversupply of oil.

The biggest portion of the recent increase in state numbers reflects the efforts of the states to document their orphan wells. States have focused considerable time and effort on refining their criteria for orphan status consistent with the terminology used in this report, verifying and updating information on operators and wells in their databases, and confirming the existence, status, and location of wells using field inspection and drone surveillance. The result is a more complete inventory of documented orphan wells.

Figure 3 reflects the numbers of documented orphan wells in the states as published through the years in IOGCC reports on idle and orphan wells. Note that **Figure 3** does not include data from the Canadian provinces, which were not surveyed for this data before 2019.

Figure 3. Trend in State Reports of Documented Orphan Wells

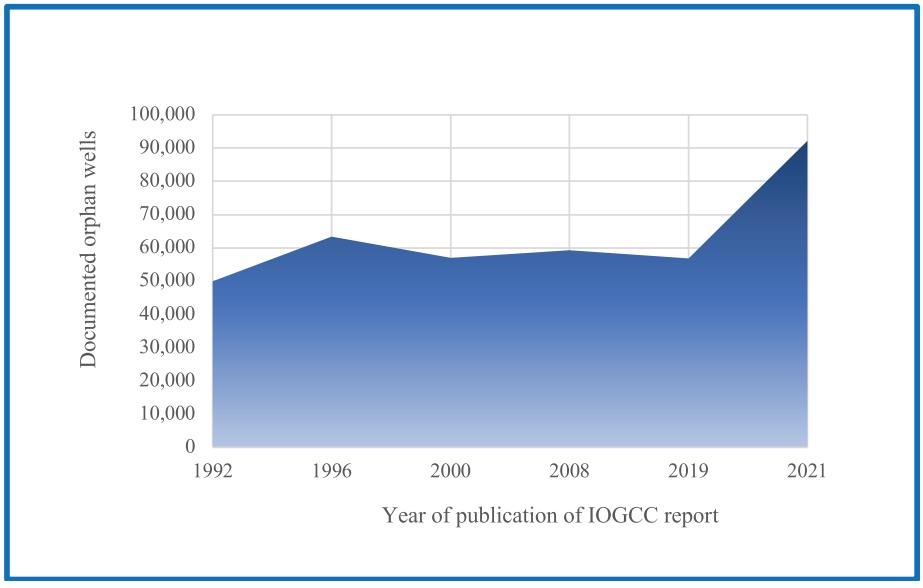
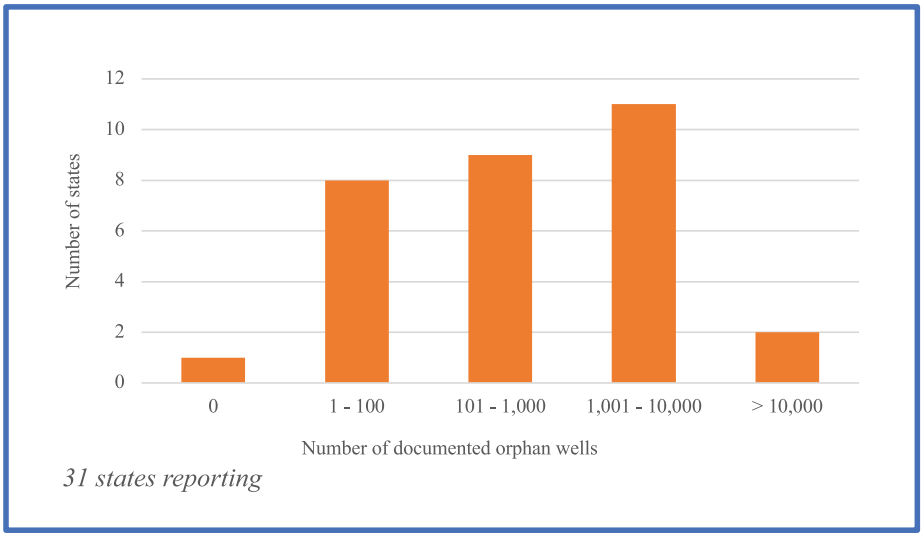


Figure 4 summarizes the numbers of documented orphan wells in the states. See **Table 3** for a detailed breakdown.

Figure 4. Documented Orphan Wells in States (2020)



The number of documented orphan wells by state or province ranges from zero to 27,972 in the states and zero to 2,983 in the provinces. For the states, the ratio of documented orphan wells to total wells that have been drilled and not plugged ranges from zero to 31 percent, with an overall average of 5.7 percent. For the provinces, the ratio of documented orphan wells to total wells that have been drilled and not plugged ranges from zero to 11 percent, with an overall average of 1.4 percent.

In many cases, the states and provinces have a record of the last known operator of an orphan well. Twenty-three states and four provinces reported on how many of their documented orphan wells have known operators. In the 23 states, the operator is known for 78 percent of these wells. In the four provinces, the operator is known for all but two wells.

Figure 5 summarizes the information reported by the states and provinces on known operators. See **Table 4** for details.

Figure 5. Documented Orphan Wells with Known Operators (2020)

	States (23 reporting)		Provinces (4 reporting)	
Documented orphan wells	69,615		5,015	
With operator known	54,001	78%	5,013	100%
Known operators of orphan wells	8,060		267	
With 1 well	4,128	51%	120	45%
With 2-10 wells	2,987	37%	88	33%
With 11-100 wells	881	11%	49	18%
With >100 wells	64	1%	10	4%

Table 5 contains information reported by the states and provinces on the classification of their documented orphan wells by land ownership. A large majority of the documented orphan wells reported by the states are located on private lands. Fewer occur on state lands or federal/tribal lands.

All states cover wells on private and state lands in their documented orphan well counts. They do not all cover wells on federal/tribal lands in their counts. Some states do not track wells on federal lands at all or do so only incidentally, as for example when addressing the wells owned by an operator in bankruptcy. Other states track all documented orphan wells without regard to land ownership.

For federal lands, the Bureau of Land Management, the Forest Service, or another federal land management agency has jurisdiction over oil and gas operations. There is some variation among the states as to the application of state regulations to wells on federal lands, and there is some variation between federal agencies and their regional offices as to collaboration with the states. As a result, states may or may not include wells on federal lands in their tallies of orphan wells.

The oversight situation is similarly complicated for tribal lands. Some tribes defer to the states for regulation; others maintain exclusive authority and may or may not share information with the state regulatory agency.

UNDOCUMENTED WELLS

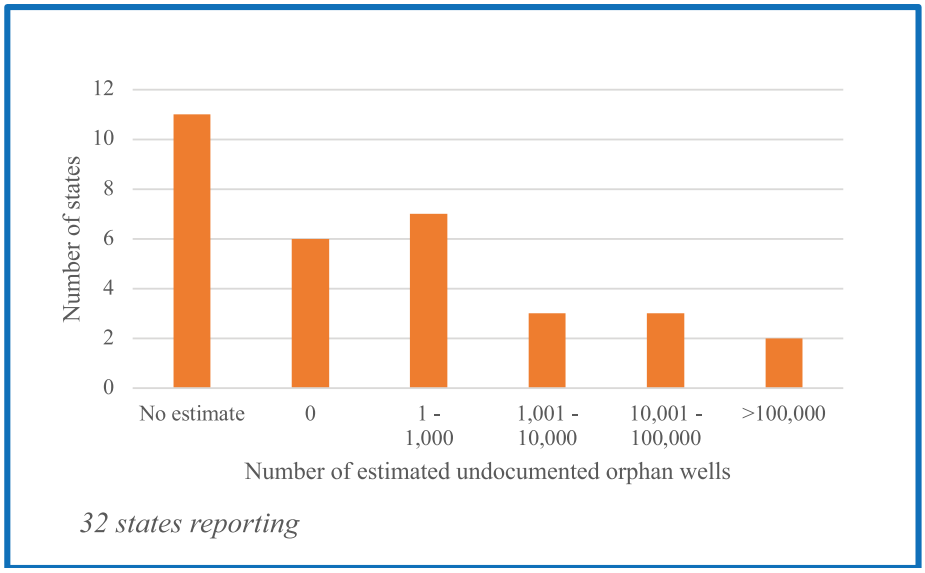
The term “undocumented well” refers to a well that is entirely unknown to the regulatory agency or a well of which the agency has some evidence, but which requires further records research or field investigation for verification. Undocumented wells are typically wells, sometimes called “legacy wells,” that were drilled early in the history of oil and gas development in a region and were abandoned before the regulatory programs were established.

Undocumented wells present special challenges. They often go undetected for years or decades. Leakage of oil, salt water, or gas from an undocumented orphan well is sometimes observed by the landowner or other person using the property. Landowners may discover these wells as they develop their properties. Currently states are exploring the possibilities of using advanced technologies, such as electromagnetic surveys conducted with drones, to identify these wells.

For 2020, the total number of undocumented orphan wells estimated by participating states is between 310,000 and 800,000. Eleven states did not report an estimate. Six other states and all five provinces reported they have no undocumented orphan wells. The remaining 15 states reported an estimate of six to 100,000 or more undocumented orphan wells.

Figure 6 summarizes the estimated numbers of undocumented wells reported by states and provinces. The detailed breakdown appears in **Table 3**.

Figure 6. Estimated Undocumented Orphan Wells in States (2020)



These estimates are by their nature imprecise. Some states reported a wide range in the estimated number and others were unable to provide any reliable estimate. Of the states that reported an estimate, eight based their estimates on information from historical records such as newspaper accounts or other sources that cannot be verified; the others based them on extrapolation from known occurrences, studies of orphan wells, review of accounts of pre-regulatory wells, or a combination of those sources.

The potential risk to public health and safety or to the environment from undocumented orphan wells varies considerably, depending on well depth, geologic setting, location, and other factors. Some wells certainly pose a threat of leakage or other hazards. Others, however, may constitute only a minimal risk. Many pre-regulatory wells were drilled to relatively shallow depths—often several hundred feet or less—and may not provide conduits for oil, gas, or saltwater migration. States are working to better define the numbers, locations, and risks of undocumented orphan wells, but these efforts involve significant time and resources.

ORPHAN WELL PLUGGING AND SITE RESTORATION

The states and provinces accelerated the pace of their orphan well plugging operations over the last three years. Twenty-five states and provinces plugged orphan wells in 2018 and 2019, and 27 states and provinces plugged orphan wells in 2020. States and provinces plugged a total of 6,580 orphan wells in 2020, compared to 3,415 in 2018 and 4,709 in 2019. In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells, and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300.

Figure 7 shows the number of wells, including orphan wells, plugged in the states each year. Most of the wells in the other category were plugged by the responsible operators. **See Tables 6** and **7** for more detail.

Figure 7. Wells Plugged in States

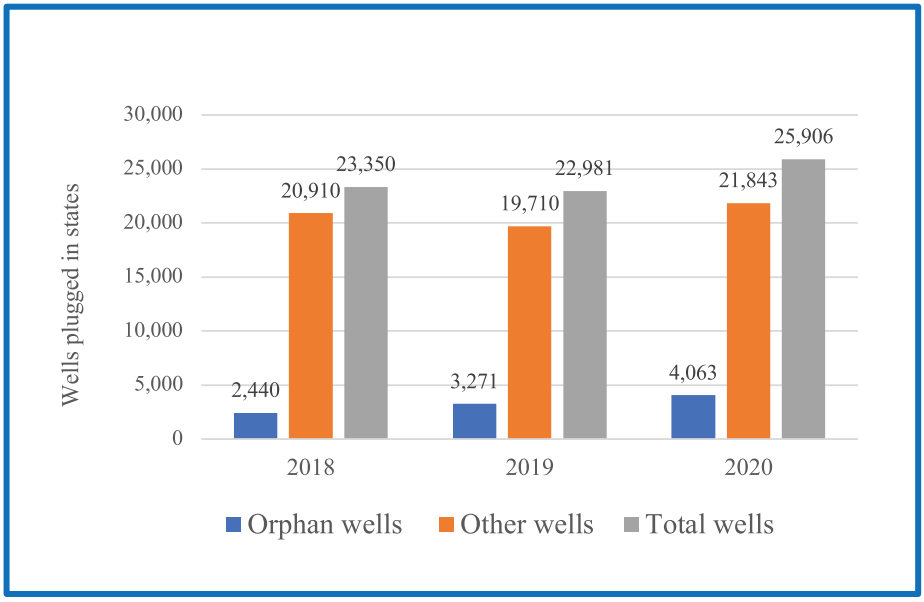
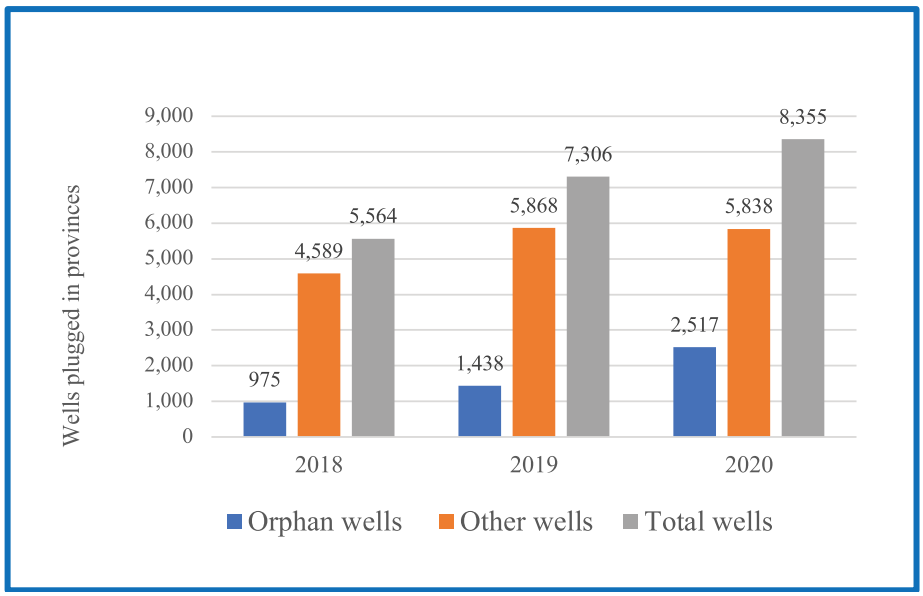


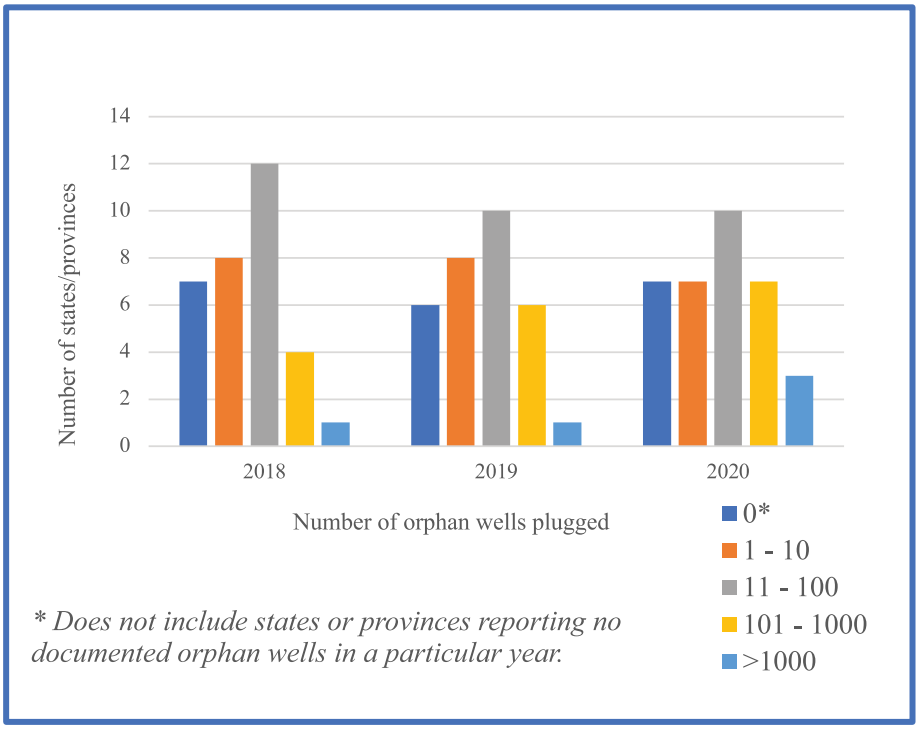
Figure 8 shows the number of wells, including orphan wells, plugged in the provinces each year. Again, most of the wells in the other category were plugged by the responsible operators. See **Tables 6** and **7** for more detail.

Figure 8. Wells Plugged in Provinces



The annual number of orphan wells plugged by an individual state or province ranged from zero to 1,922, with most states and provinces plugging from one to 100 wells each year. **Figure 9** summarizes the number of orphan wells plugged by states and provinces in 2018, 2019, and 2020. See **Table 7** for more detail.

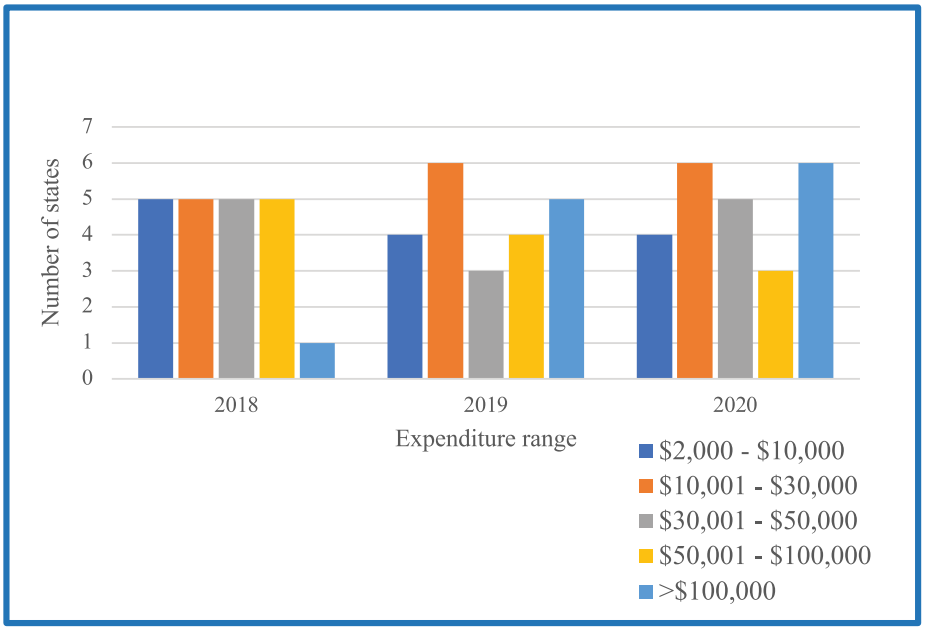
Figure 9. Orphan Wells Plugged in States and Provinces



The cost to plug an orphan well varies widely depending on well depth and condition, location, accessibility, and other factors. For the 25 states that plugged orphan wells from 2018 through 2020, the average expenditure per well ranged from $2,400 to $227,000, with an overall three-year average of $25,634. The overall average for the states was $20,527 in 2018, $23,410 in 2019, and $30,450 in 2020.

Figure 10 summarizes the range of average plugging expenditures for the states in 2018 through 2020. See **Table 7** for the plugging expenditures by state.

Figure 10. Orphan Well Plugging Expenditures in States



For the three provinces that plugged orphan wells from 2018 through 2020, the average expenditure per well ranged from C$37,528 to C$42,047, with an overall three-year average of C$41,156. In contrast to the states, where average plugging expenditures increased over those three years, the average expenditures for the three provinces declined from C$57,949 in 2018, to C$42,559 in 2019, to C$33,850 in 2020. See **Table 7** for more detail.

Twenty-nine states and provinces provided information on their site restoration activities related to orphan wells. In this report, site restoration is defined as removal of equipment, trash, and debris, repair of erosion, removal of hydrocarbons, closure of pits, and associated activities. It does not include groundwater remediation. The restoration actions required at orphan well sites vary widely depending on the nature, age, condition, and location of the sites.

The information gathered for this report does not support a determination of the overall average expenditure for site restoration because of the differences among the states and provinces in how they define terms, conduct operations, and allocate costs. Most states conduct basic site restoration as part of an orphan well plugging operation. For these states, the expenditures reported in **Table 7** combine plugging and basic site restoration, and the amount expended for site restoration is not broken out.

As noted in **Table 7**, three states and the three provinces that plugged orphan wells conduct and account for plugging and restoration separately. Other states conduct site restoration at some sites separately even if they conduct basic site restoration as part of orphan well plugging. See **Table 8** for details on the restoration activities that have been accounted for separately.

Other factors further complicate the analysis of site restoration costs. For example, well sites restored in a year may not correspond with wells that were plugged that year, and in some states and provinces, various aspects of restoration are carried out by separate agencies. Also, the state or province may carry out restoration for wells that have been plugged—sometimes years earlier—by an operator that has since ceased to exist.

SOURCES OF FUNDS

To plug orphan wells, most states and provinces use the proceeds of financial assurance supplemented with other funds. Three quarters of the states and provinces responding to the survey have established funds designated specifically for orphan-well plugging. Others have authority to spend money from operating funds or other sources to plug orphan wells. Funds used for plugging come primarily from production taxes, fees, or other assessments on the oil and gas industry.

Figure 11 shows sources of funding used by the states and provinces to cover plugging of orphan wells and restoration of well sites. Most states and provinces use funds from more than one of the sources listed. See **Table 10** for details by state and province.

Figure 11. Funding Sources for Plugging Orphan Wells, States and Provinces

Funding Source	Number of States/ Provinces
Annual fee	8
Idle well fee	7
Permit fee	11
Civil penalties	8
Settlements	6
Appropriations	8
Forfeited bonds	24
Salvage	13
Excise tax	4
Production assessment	11
Other	11
None	5

The sources listed in **Figure 11** are described as follows:

Annual fee: Routine fee charged to operators of oil and gas wells.
Idle well fee: Fee an operator pays for an inactive, unplugged well.
Permit fee: Fee an operator pays when applying for a permit to drill or produce.
Civil penalty: Penalty imposed by a regulatory authority for noncompliance.
Settlement: Binding agreement for payment in lieu of court proceedings in an enforcement matter.
Appropriations: Legislative action authorizing the expenditure of funds for some designated purpose.
Forfeited bonds: Monies collected on surety bonds or other forms of financial assurance provided by operators.
Salvage: Proceeds from the sale of any equipment or other items of value at a plugging site.
Excise tax: Tax imposed on the sale of specific goods or services.
Production assessment: A state or provincial tax or fee on oil and gas products levied at the wellhead.

While only 13 states and provinces identified salvage as a funding source for orphan well plugging, 21 reported recovering salvage value as part of the plugging process, often as a deduction from the amount

Apps' Ex. 28

0611

due the plugging contractor. **Table 12** identifies those 21 states and provinces. States and provinces indicate there is usually minimal, if any, salvage value associated with orphan wells.

Financial Assurance

Financial assurance (sometimes referred to as "bonding") is one of the tools used to ensure the regulatory authorities have resources to plug an oil and gas well and restore the site in the event the well becomes an orphan. The types and amounts of financial assurance vary among the states and provinces. The states and provinces have continued to evaluate and adjust their financial assurance requirements to ensure the types and amounts provide effective coverage in combination with other sources of plugging funds.

States and provinces reported the types of financial assurance accepted in their jurisdictions. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. Most accept more than one type. **Figure 12** summarizes the types of financial assurance accepted by the states and provinces. **Table 11** provides the details.

Figure 12. Types of Financial Assurance Accepted by States and Provinces

Type of Security	Number of states and provinces accepting
Cash Deposit	26
Certificate of Deposit	26
Financial Statements	5
Letter of Credit, Irrevocable	27
Surety or Performance Bond	32
Security Interest	2
Other	3

The types of financial assurance are described as follows:

Cash Deposit: A payment given as a guarantee that an obligation will be met.
Certificate of Deposit: A financial instrument certifying that the face amount is on deposit with the issuing bank to be redeemed for cash by the state if required.
Financial Statement: A report of basic accounting data that depicts a firm's financial history and activities.
Letter of Credit, Irrevocable: A letter of credit where payment is guaranteed if stipulated conditions are met.
Surety or Performance Bond: A contract by which one party agrees to make payment on the default or debt of another party.
Security Interest: The right to take property or a portion of property offered as security.
Other: Other forms of financial assurance such as certificates of insurance, consolidated financial funds, escrow accounts, and liens.

States and provinces also reported the amounts of financial assurance required in their jurisdictions. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well

or case-by-case evaluations. Most states and provinces provide for single-well coverage (a specified amount for each well) as well as blanket coverage (a specified amount that covers multiple wells, often capped at a maximum number).

Table 11 shows the amounts of financial assurance required by the states and provinces. These requirements are summarized here:

Single-Well Coverage

- Seven states have a set amount per well, ranging from $2,500 to $400,000.
- Two states base the amount on well depth, $2 per foot in one and $10 per foot in the other.
- Two states have a base amount plus an amount per foot or acre.
- Twenty-one states and one province have multi-tier amounts, ranging from a minimum of $1,100 to a maximum of $500,000.
- One province does not provide for single-well coverage, and two others use a case-by-case evaluation to determine amounts.

Blanket Coverage

- Eleven states have a set blanket amount, ranging from $15,000 to $100,000.
- Twenty-one states have multi-tier blanket amounts, ranging from a minimum of $7,500 to a maximum of $30,000,000.
- Two provinces do not provide for blanket coverage, and two others use a case-by-case evaluation to determine amounts.

Plugging and restoration costs rise over time due to inflation and in some cases due to improved and more stringent regulatory requirements for materials and methods. States and provinces typically review and revise their financial assurance requirements periodically to account for these increases.

The amounts of financial assurance may not fully cover orphan well plugging costs for several reasons. Many orphan wells were drilled before financial assurance requirements were instituted. For many others drilled decades ago, the financial assurance amounts were set at levels that were considered sufficient at the time but may not be commensurate with today's costs or plugging standards. Resetting the amounts may cause wells to be abandoned prematurely and increase the number of orphan wells. Some companies that provide surety or performance bonds have gone bankrupt or have not covered their obligations for other reasons. In other instances, financial assurance amounts were set at levels to cover typical costs of plugging operations but may not cover wells with unusually high or unpredictable plugging costs. For these reasons, the states and provinces supplement the proceeds of financial assurance with other sources of funding for plugging and restoration. These other sources often include dedicated plugging funds.

Plugging Funds

For this report, a plugging fund is a separate and distinct fund specifically intended to address orphan wells or a portion of another fund that may be used to address orphan wells. In 1939, Illinois became the first state to establish a plugging fund. Most plugging funds originated in the 1970s through the 1990s, with the most recent established in 2014. The money in the plugging funds comes primarily from the oil and gas industry in the form of forfeited financial assurance instruments, production taxes, fees, penalties, and other assessments.

Of the 37 states and provinces that participated in the survey, 28 have plugging funds. Two other states and one other province do not have a plugging fund but have authority to spend money from operating funds or other sources to plug orphan wells. See **Table 12** for more information.

Sixteen states and provinces have an annual authorized expenditure target for their plugging funds. Nineteen have authority to use plugging fund money for emergency remedial actions at wells that are not orphan wells, with subsequent action to obtain reimbursement of these expenditures from the responsible operator.

PROGRAM IMPROVEMENTS

Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using Geographic Information Systems (GIS) and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration.

INCENTIVES

Fifteen states and one province reported on incentives related to idle and orphan wells.

Incentives to Reactivate Idle Wells

Eleven states and one province report current or pending incentives to reactivate idle wells:

Alberta: The Alberta Energy Regulator's security deposit requirements encourage proactive management of company liabilities.

Arkansas: The state provides severance tax reductions in certain circumstances.

California: If an operator returns a well to production that has been inactive for the preceding five consecutive years or has been determined by the supervisor to be deserted, then the annual oil and gas assessments will be reduced to zero for the 10 subsequent years. If an operator reactivates an idle well and the well is active for six consecutive months, the operator will not have to pay idle well fees for the well.

Colorado: State rules require additional financial assurance for an operator with "excess" inactive wells. An operator may request a release of a portion of the additional financial assurance if a well is reactivated.

Illinois: Wells may be transferred to a new permittee that intends to place the wells back into production. Plugging costs become the liability of the new permittee.

Indiana: The state has enacted a well testing agreement program whereby operators may test orphan wells for a limited time to find out if they have any value before assuming responsibility for them. This program has resulted in some wells being reactivated and removed from the orphan well list each year.

Kentucky: An operator may apply for a permit, with a $25 fee, to test an orphan well for 60 days without commitment or penalty. After 60 days, the operator must either bond the well and assume ownership or return the well to its prior status.

Louisiana: The Inactive Well Incentive Program established by statute in 2017 allows for the reduction of severance taxes due on all well production for a period of 10 years for a qualifying inactive well.

Michigan: The state allows a new owner to acquire idle wells to be put into production if they meet certain criteria.

South Dakota: The Department of Agriculture and Natural Resources and the Board of Minerals and Environment now have authority and discretion to require an additional $20,000 bond for each idle well. Release of this bond provides an incentive for reactivation.

West Virginia: The state provides a severance tax exemption for idle wells that have been reactivated.

Wyoming: Upon reactivation, a well is removed from the idle well list and the idle well bond is refunded.

Apps' Ex. 28

0614

Incentives to Plug Orphan Wells

Seven states reported current or pending incentives to plug orphan wells:

Colorado: The state is conducting a pilot test of an operator reimbursement process for orphan well plugging. It will provide direct reimbursement or a levy credit.

Illinois: Under the state's Landowner Grant Program, an eligible landowner may receive up to five grants per year for orphan well plugging. Grants are awarded on a first-come, first-served basis and are awarded considering well condition (i.e., whether leaking), cost, and the proposed plugging contractor.

Kansas: The Kansas Legislature passed a bill during the 2021 session directing the Kansas Corporation Commission to develop regulations whereby any person may apply to be reimbursed for plugging abandoned wells for which they are not responsible. Regulations are currently being drafted.

Louisiana: The state offers a program where an operator may enter into a cooperative agreement with the department to plug an orphan well and receive an exemption from financial security requirements for a well of similar depth in the same field.

Ohio: The Ohio orphan well plugging statute allows the landowner to have an orphan well plugged. Recent revisions require the state to pay the reasonable plugging costs directly to the plugging contractor rather than reimburse the landowner, resulting in state income tax savings to the landowner.

Pennsylvania: The state has a Good Samaritan Act, under which an individual or contractor may plug a well for which they are not responsible by paying costs or providing supplies and/or equipment. If an individual or contractor meets criteria, they receive liability relief for plugging the well, and grant programs are available.

Texas: A program established in 2005 authorizes the Railroad Commission to reimburse surface estate owners up to 50 percent of the cost of plugging an orphan well.

AREAS FOR FURTHER WORK

Through the decades, the states and provinces have made considerable progress in managing idle wells and identifying and plugging orphan wells. They have continued to evaluate and adjust their well operation standards, plugging requirements, inspection and enforcement procedures, financial assurance requirements, and plugging fund provisions to reduce the likelihood of additional wells being orphaned and provide resources for well plugging and site restoration.

States and provinces remain concerned, however, over the potential for escalating numbers of idle and orphan wells. The risk of wells becoming orphans is heightened during periods of oil and gas market volatility or when operators transfer aging wells to other companies.

IOGCC is committed to supporting the states and provinces in their efforts to assess the effectiveness of their idle and orphan well programs and identify tools and strategies from other jurisdictions that may be useful. In addition to periodically updating the data and information in this report, IOGCC will coordinate other projects to assist the states and provinces in developing effective regulatory strategies to address the challenges of idle and orphan wells.

This section of the report describes five topics IOGCC intends to address further. In addition, IOGCC will work with the states, federal agencies, and tribes in implementing the orphan well funding provisions of recently enacted federal legislation. See the Afterword for further discussion of this legislation.

IOGCC REPORT ON INFRASTRUCTURE AND LIABILITY TRANSFER

It is common for operators to transfer wells and associated facilities and pipelines to other companies. State and provincial regulators have a special concern with transfers of wells with declining production because of the increased risk that such wells may become orphans. Many states and provinces have implemented measures to reduce this risk by setting additional requirements for financial assurance and by evaluating corporate solvency and compliance history and the status and condition of the wells and associated facilities and pipelines before approving a transfer.

IOGCC's Legal and Regulatory Affairs Committee, in cooperation with the International Committee, published a report in 2018[8] containing the results of a survey of states and provinces on transfers of infrastructure and liabilities. This report was designed to serve as a resource for states and provinces that are evaluating additional regulatory safeguards to reduce the potential for wells and associated facilities and pipelines to be transferred to operators without the requisite operational and financial capabilities. IOGCC will work with the states and provinces to review and update the information available through this report.

ORPHAN WELLS ON FEDERAL AND TRIBAL LANDS

As noted in this report, the information available to states concerning idle and orphan wells on federal and tribal lands is often incomplete. IOGCC looks forward to continuing a dialogue recently begun with officials of the U.S. Department of Interior (DOI) to strengthen the working relationship between state, federal, and tribal authorities on issues relating to idle and orphan wells. Improved communication, coordination, and cooperation among these authorities will improve the management of idle and orphan wells, regardless of land ownership.

Apps' Ex. 28

0616

FEDERAL FUNDING UNDER THE OIL POLLUTION ACT

IOGCC will continue to pursue an administrative or legislative clarification of the cost recovery provisions of the Oil Pollution Act of 1990 (OPA) consistent with IOGCC Resolution 19.054.[9] This resolution urges Congress to amend the Oil Pollution Act of 1990 to clarify that surface owners and royalty interest owners who have not produced or participated in ownership of wells are not "responsible parties" and therefore will not be subject to cost recovery efforts under OPA.

As currently applied, language in OPA exposes these surface owners and royalty interest owners to liability when an orphan well is plugged with OPA funds. This application of the OPA liability provisions has harmed innocent landowners and discouraged states from working in partnership with federal agencies to make use of OPA funding for plugging of orphan wells. If the language of the Act, or the implementing administrative procedures, were adjusted consistent with IOGCC Resolution 19.054, states and federal agencies could make greater use of existing OPA funding to plug orphan wells that pose a threat to surface waters.

REVIEW OF CONTRACTING PROCEDURES

Some states and provinces express frustration over the difficulties of retaining contractors to plug orphan wells. Government procurement procedures can be cumbersome and may discourage contractors from competing for state contracts. Also, states and provinces must compete for contractors with oil and gas operators who conduct the majority of well plugging operations.

Some states and provinces have implemented new approaches to procurement and contracting that have enabled them to engage plugging services more competitively and efficiently. IOGCC will gather the states and provinces in an appropriate forum to share information on effective practices for procuring plugging services and managing plugging contracts.

ASSESSING POPULATIONS AND RISKS OF UNDOCUMENTED WELLS

This report describes some of the challenges of identifying and assessing undocumented orphan wells, which are a particular concern in some states with a long history of oil and gas drilling and production. Due to the uncertainties surrounding this category of wells, the current estimates and characterizations of these wells are broad and general and the risks to public health and safety and the environment are unquantified. The development of effective strategies for addressing these wells requires further research on technologies and practices for identifying and assessing them.

The Infrastructure Investment and Jobs Act[10] includes funding for the U.S. Department of Energy (DOE) to conduct research and development activities in cooperation with IOGCC to assist the states, federal agencies, and tribes in identifying and characterizing undocumented orphan wells and mitigating the environmental risks of these wells. IOGCC looks forward to working with DOE in this effort.

AFTERWORD

Shortly before publication of this report, Congress passed, and the President signed, the bipartisan Infrastructure Investment and Jobs Act (IIJA). Among its many initiatives, the IIJA provides funding for the plugging of orphan wells and the performance of associated remediation, reclamation, and decommissioning activities on federal, state, private, and tribal lands. The twofold objective of this funding is to address the potential hazards of orphan wells while creating jobs for oil and gas workers.

The appropriations in the legislation include $4.275 billion in grants to states for orphan wells on state and private lands. Three types of state grants will be available: initial grants of up to $25 million per state for rapid deployment of plugging crews or up to $5 million per state for capacity building; a total of $2 billion in grants to be allocated to the states based on a formula developed by the Secretary of Interior; and performance grants of up to $70 million per state based on improvements in state programs. The appropriated funds will be available through federal fiscal year 2030.

With the funding provided under the IIJA, the states will accelerate the work they are doing to plug orphan wells, restore well sites and adjacent lands, and decommission associated pipelines, facilities and infrastructure. This funding will also enable states to identify and assess currently undocumented orphan wells with help from federal research and development.

At the time of publication of this report, IOGCC and its member states are already working with the U.S. Department of Interior (DOI) and the U.S. Department of Energy (DOE) to implement this legislation. The first statutory deadline is December 30, 2021, when states that will apply for a formula grant must submit a notice of intent. The notice of intent includes information on job losses since March 2020, the number of documented orphan wells on state and private lands, and the projected costs of plugging, reclamation, and decommissioning. The Secretary of Interior will consider this information in establishing the formula for distribution of formula grant funds to the states.

In anticipation of this process, IOGCC conducted a short survey of the states to obtain the updated information on their inventories of documented orphan wells. **Figure 13** presents the information reported by states in response to this survey. See **Tables 3, 7, 13a,** and **13b** for further details.

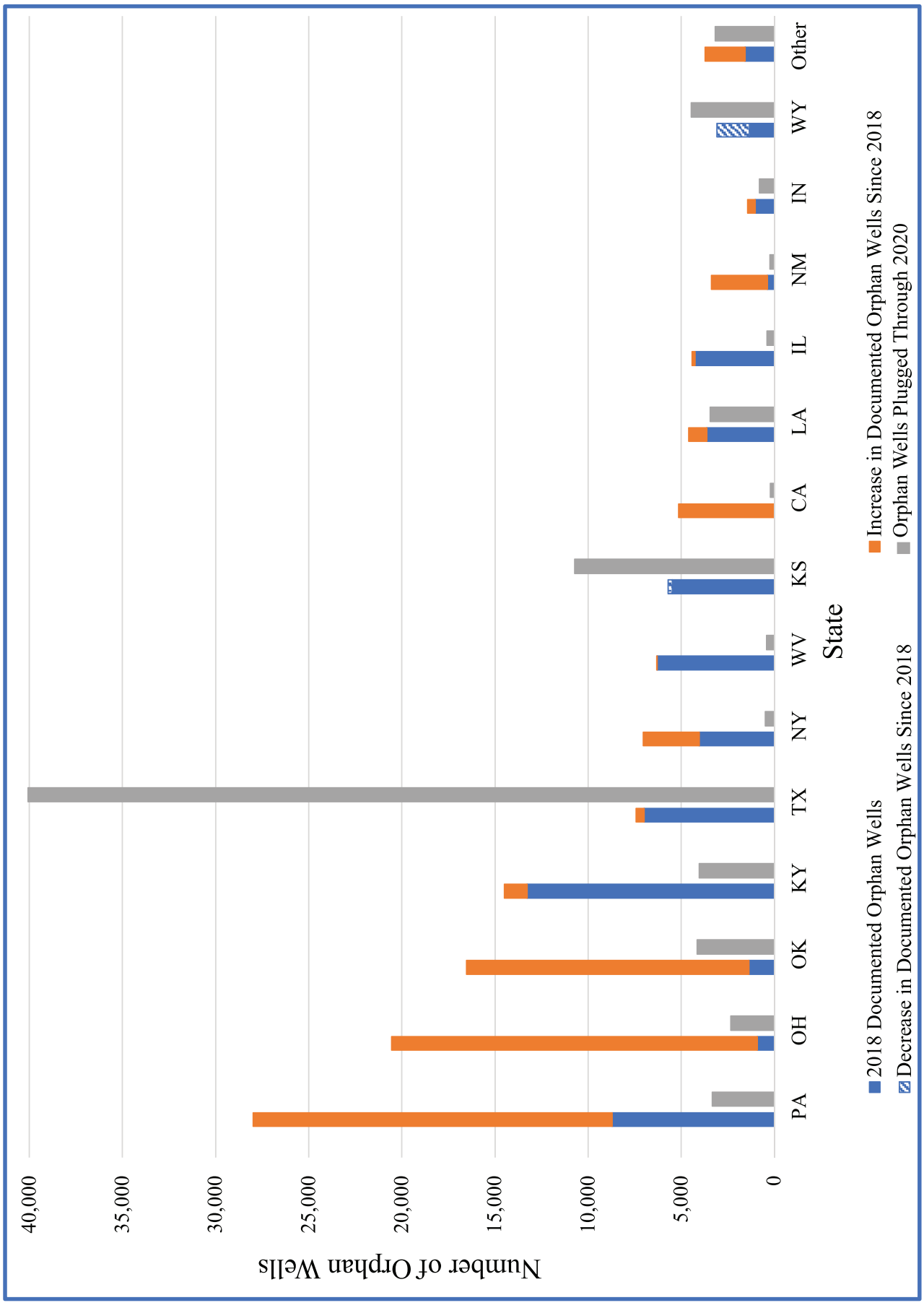
Figure 13 offers a glimpse of the scope and magnitude of the effort required to address the documented orphan wells, not to mention the still undocumented orphan wells. States will submit their first applications for IIJA grant funding in the spring of 2022 and will apply for and use grant funds through the remainder of the decade. Success will be measured largely by the number of orphan wells plugged. Plugging on the scale envisioned will involve a major deployment of plugging and remediation crews. It will also require close cooperation between federal agencies, states, tribes, and providers of plugging and remediation services.

Providing support for this effort will remain a top priority for IOGCC throughout the implementation of this legislation. IOGCC and its members states appreciate the unparalleled opportunity this funding presents. We are committed to making the most of it.

Apps' Ex. 28

0618

Figure 13. Documented Orphan Wells as of IIJA Enactment



DATA TABLES

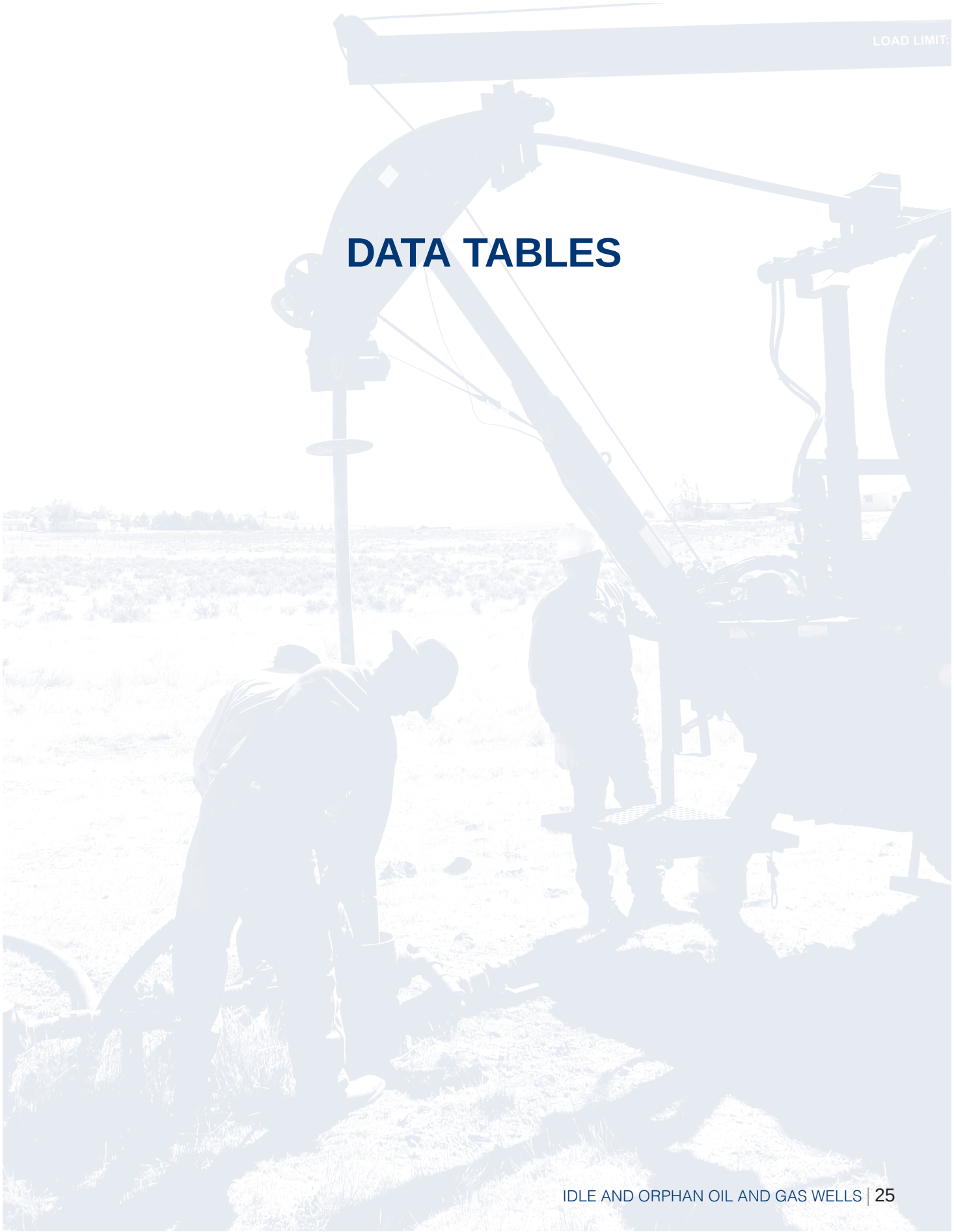


Table 1. Documented Wells Drilled and Not Plugged (2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2020.

State or Province	Oil and gas production	Oil-and-gas-related injection	Oil-and-gas-related monitoring	Gas storage	Other	Total
Alabama	6,754	245	0	14	18	7,031
Alaska	3,583	1,627	26	14	263	5,513
Arizona						
Arkansas	17,489	1,021		11	0	18,521
California	58,493	13,807	3,584	323	0	76,207
Colorado	51,228	697	116	257	0	52,298
Idaho						12
Illinois						44,165
Indiana	5,652	1,136	0	973	90	7,851
Kansas	95,332	18,305	10	883	0	114,530
Kentucky	57,818	2,715		599		61,132
Louisiana						59,093
Maryland						[1]
Michigan	14,576	1,124	0	2,116	2,506	20,322
Mississippi	5,060	1,221	94	163	0	6,538
Missouri	2,707	435	49	65	327	3,583
Montana						14,200
Nebraska	2,098	612	0	0	0	2,710
Nevada	105	15	0	0	0	120
New Mexico	55,620	4,134	115	24	20	59,913
New York	16,080	853	136	850	4,715	22,634
North Dakota	19,574	1,343	8	0	0	20,925
Ohio	61,211	396	0	3,351	0	64,958
Oklahoma	215,312	11,119	0	311	0	226,742
Pennsylvania	130,946	2,328	239	1,415	3	134,931
South Dakota	342	103	0	0	0	445
Tennessee	5,012					5,012
Texas						440,749
Utah	13,865	1,997	15	64	379	16,320
Virginia	8,690	9	0	38	0	8,737
West Virginia						74,596
Wyoming	44,659	4,162	413	49	0	49,283
Totals - States	**892,206**	**69,404**	**4,805**	**11,520**	**8,321**	**1,619,071**
Alberta	221,728	12,727	5,303	244	26,672	266,674
British Columbia	16,056	457	107	6	0	16,626
Northwest Territories	86	2	0	0	0	88
Saskatchewan	80,481	8,619	0	110	90	89,300
Yukon	9	0	0	0	0	9
Totals - Provinces	**318,360**	**21,805**	**5,410**	**360**	**26,762**	**372,697**

[1] No wells have been drilled in Maryland since the late 1990s.

Table 2. Approved Idle Wells (2020)

Blank fields indicate that no data was reported or available.

State or Province	Wells with approval to remain idle				
	Gas	Oil	Injection	Other	Total
Alabama	569	228	89	5	891
Alaska	111	577	287	12	987
Arizona					
Arkansas	295	28	15	0	338
California	1,229	25,518	10,354	419	37,520
Colorado[1]					
Idaho	0	0	1	0	1
Illinois		3,655	395		4,050
Indiana	119	99	39	6	263
Kansas	2,682	5,375	659	75	8,791
Kentucky	1,305	1,463	272	7	3,047
Louisiana	Unknown	Unknown	0	0	23,448
Maryland	0	0	0	0	0
Michigan	557	288	41	245	1,131
Mississippi	707	1,091	357	0	2,155
Missouri	17	114	8	4	143
Montana	1,064	2,218	327	58	3,667
Nebraska	142	288	72	0	502
Nevada	1	54	3	0	58
New Mexico	1,520	2,573	104	0	4,197
New York	48	72	32	6	158
North Dakota					159
Ohio					16
Oklahoma	54	1,049	0	457	1,560
Pennsylvania	544	79	1	71	695
South Dakota	3	4	5	0	12
Tennessee	406	98	0	45	549
Texas	41,849	72,670	8,416	9	122,944
Utah	111	103	128	0	342
Virginia	291			1	292
West Virginia					139
Wyoming	6,005	7,227	0	0	13,232
Totals - States	**59,629**	**124,871**	**21,605**	**1,420**	**231,287**
Alberta	29,967	40,160	4,344	21,041	95,512
British Columbia	3,697	982	266	1,605	6,550
Northwest Territories	86	0	2	0	88
Saskatchewan	6,114	28,665	3,103[2]	151	38,033
Yukon					
Totals - Provinces	**39,864**	**69,807**	**7,715**	**22,797**	**140,183**

[1] Rules establish requirements for idle wells; however, approval is not required, and the number of idle wells is not tabulated.

[2] Number includes observation wells, relief wells, casing repair re-entry wells, gas vent wells, and water source wells.

Table 3. Documented and Undocumented Orphan Wells (2018-2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2018, 2019, and 2020.

State or Province	Documented orphan wells			Estimated undocumented orphan wells
	2018	2019	2020	2020
Alabama	3	3	26	0
Alaska	14[1]	14	14	150+
Arizona				
Arkansas	484	430	418	
California	16	25	2,777	17,986
Colorado	275	268	276	200
Idaho	0	0	0	150 to 170
Illinois	4,253	4,330	4,355	
Indiana	1,028	1,107	1,459	<100
Kansas	5,709	5,653	5,632	
Kentucky	13,266	13,836	14,367	3,000
Louisiana	3,621[1]	3,966	4,260	
Maryland	0	0	0	
Michigan	98	116	154	0
Mississippi	21	6	11	6
Missouri	327	327	327	2,009
Montana	231	232	222	
Nebraska	75	98	103	120
Nevada	6	6	6	0
New Mexico	374	708	3,375[2]	
New York[3]	4,043	7,222	7,073	34,000
North Dakota	0	0	341	0
Ohio	910	959	972	36,342 to 66,400
Oklahoma	1,372	1,075	2,799	105,907
Pennsylvania	8,703	8,709	27,972[4]	100,000 to 560,000
South Dakota	0	40	33	0
Tennessee			446	54
Texas	6,989[5]	6,171	6,514	
Utah	33	47	41	
Virginia	10	10	9	
West Virginia	6,302[6]	6,625	6,309	9,000
Wyoming	3,083	2,906	1,907	0
Totals - States	**61,246**	**64,889**	**92,198**	**310,000 to 800,000**
Alberta	3,127	3,128	2,983	0
British Columbia	326	357	754	0
Northwest Territories	0	0	0	0
Saskatchewan	609[1]	640	1,277	0
Yukon	1	1	1	0
Totals - Provinces	**4,063**	**4,126**	**5,015**	**0**

[1] Revised 2018 number for documented orphan wells to correct an error in the number reported in 2019.
[2] Increased number of documented orphan wells to include orphan wells that do not yet have an approved plugging order.
[3] Revised 2018 number upward and reported larger numbers in 2019 and 2020 to include wells that are identified on lease maps or other records as having been drilled but have not yet been found or searched for in the field.
[4] Increased number of documented orphan wells to include various groups of wells identified as abandoned, including some without geographic coordinates.
[5] Revised 2018 number for documented orphan wells to report numbers on a calendar year, rather than a fiscal year, basis.
[6] Revised 2018 number for documented orphan wells to include orphan wells with a known operator that is bankrupt or deceased.

Table 4. Operator Status of Documented Orphan Wells (2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2020.

State or Province	Documented orphan wells		Known operators			
	Operator known	Operator unknown	With 1 well	With 2-10 wells	With 11-100 wells	With >100 wells
Alabama	26	0	1	2	1	0
Alaska	0	14				
Arizona						
Arkansas	418	0	57	25	9	1
California	2,777	0	623	231	35	2
Colorado	247	29	59	12	9	0
Idaho	0	0	0	0	0	0
Illinois						
Indiana	599	860	87	58	14	0
Kansas	5,200	432	409	360	100	4
Kentucky						
Louisiana[1]	4,612	1	717	406	72	5
Maryland	0	0	0	0	0	0
Michigan	152	2	17	6	14	0
Mississippi	11	0	5	3	0	0
Missouri						
Montana	222	0	35	13	5	0
Nebraska						
Nevada	6	0	4	1	0	0
New Mexico	3,375	0	115	188	50	5
New York	3,115	3,958	274	142	48	3
North Dakota	341	0	11	15	8	0
Ohio						
Oklahoma						
Pennsylvania	22,296	5,663	976	843	336	37
South Dakota	33	0	0	0	1	0
Tennessee	446	0	34	45	12	0
Texas	6,514	0	450	454	135	3
Utah	39	2	10	7	1	0
Virginia	9	0	7	1	0	0
West Virginia	1,656	4,653	228	161	20	0
Wyoming	1,907	0	9	14	11	4
Totals - States	**54,001**	**15,614**	**4,128**	**2,987**	**881**	**64**
Alberta	2,983	0	80	48	30	6
British Columbia	752	2	10	16	5	2
Northwest Territories	0	0				
Saskatchewan	1,277	0	29	24	14	2
Yukon	1	0	1	0	0	0
Totals - Provinces	**5,013**	**2**	**120**	**88**	**49**	**10**

[1] Numbers provided as of September 20, 2021.

Table 5. Documented Orphan Wells by Land Ownership (2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2020.

State or Province	Total documented orphan wells	State land	Private land	Federal/ Tribal land
Alabama	26	0	26	0
Alaska	14	9	2	3
Arizona				
Arkansas	418	0	418	0
California	2,777	200	2,394	183
Colorado	276	23	217	36
Idaho	0	0	0	0
Illinois	4,355[1]			
Indiana	1,459	17	1,441	1
Kansas	5,632	0	5,632	0
Kentucky	14,367	6	11,722	2,639
Louisiana	4,260	253	4,007	0
Maryland	0			
Michigan	154	5	147	2
Mississippi	11	0	10	1
Missouri	327	0	327	0
Montana	222	21	201	0
Nebraska	103	10	91	2
Nevada	6	0	0	6
New Mexico	3,375	890	859	1,626
New York	7,073	0	6,970	103
North Dakota	341	10	292	39
Ohio	972			
Oklahoma	2,799	0	2,799	0
Pennsylvania	27,972[2]	897	15,140	2,354
South Dakota	33	29	4	0
Tennessee	446	3	437	6
Texas	6,514	[3]	[3]	~50[4]
Utah	41	6	35	0
Virginia	9	0	9	0
West Virginia	6,309	816	5,429	64
Wyoming	1,907	150	1,757	Unknown
Totals - States	**92,198**	**3,345**	**60,366**	**7,115**
Alberta	2,983			
British Columbia	754	423	331	0
Northwest Territories	0	0	0	0
Saskatchewan	1,277			65
Yukon	1			
Totals - Provinces	**5,015**	**423**	**331**	**65**

[1] Land ownership is being determined as of the date of publication; preliminary information indicates all documented orphan wells are on private land.
[2] Geographic coordinates and land ownership are not yet determined for 9,581 of these wells.
[3] There are approximately 6,464 wells on state and private lands, of which 176 are in state waters. The number of these wells on other state lands is not currently available.
[4] These wells are located on federal lands. None are on tribal lands.

Table 6. Total Wells Plugged (2018-2020)

Includes orphan wells.
Data as of December 31, 2018, 2019, and 2020.

	2018					2019					2020				
State or Province	**Oil wells**	**Natural gas wells**	**Injection wells**	**Other wells**	**Total wells**	**Oil wells**	**Natural gas wells**	**Injection wells**	**Other wells**	**Total wells**	**Oil wells**	**Natural gas wells**	**Injection wells**	**Other wells**	**Total wells**
Alabama	13	124	2	8	147	22	113	6	9	150	36	153	24	7	220
Alaska	45	6	6	0	57	88	13	7	4	112	31	1	10	9	51
Arizona					0										
Arkansas	74	110	13	0	197	62	114	8	0	184	33	166	9	0	208
California	749	64	304	229	1,346	1,046	21	752	108	1,927	1,227	25	850	52	2,154
Colorado					2,251					2,436					1,508
Idaho	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0
Illinois	423	5	54	0	482					553					413
Indiana	56	8	12	22	98	122	24	25	49	220	70	13	24	14	121
Kansas	1,234	409	244	370	2,257	1,328	335	256	384	2,303	1,140	356	266	198	1,960
Kentucky	166	30	18	52	266					319					557
Louisiana	437	305	55	266	1,063	342	362	73	160	937	261	315	67	147	790
Maryland					0					1					0
Michigan	70	145	18	0	233	63	253	3	0	319	43	156	3	0	202
Mississippi	61	19	16	38	134	49	24	18	13	104	29	11	19	13	72
Missouri	7	5	15	37	64	2	0	3	4	9	4	4	2	0	10
Montana	24	42	7	0	73	31	43	8	0	82	25	152	10	8	195
Nebraska	48	0	11	0	59	52	0	8	0	60	55	0	11	0	66
Nevada	1	0	0	0	1	2	0	0	0	2	1	0	0	0	1
New Mexico	480	160	59	0	699	474	259	84	9	826	184	117	21	0	322
New York	89	27	8	24	148	121	51	36	15	223	105	11	38	28	182
North Dakota	130	7	19	0	156	127	6	14	0	147	141	0	34	7	182
Ohio	105	211	2	0	318	106	211	3	0	320	103	207	1	0	311
Oklahoma	545	554	95	1,607	2,801	618	484	120	2,466	3,688	397	323	23	2,289	3,032
Pennsylvania	134	329	8	53	524	141	335	1	66	543	134	262	2	32	430
South Dakota	7	5	0	0	12	8	3	0	0	11	1	27	0	0	28
Tennessee	22	46	0	60	128	29	79	0	66	174	27	65	0	48	140
Texas					7,566					5,046					10,860
Utah	58	82	23	14	177	28	127	15	25	195	45	102	10	78	235
Virginia	0	85	0	0	85	0	98	1	0	99	0	76	0	0	76
West Virginia					171					220					152
Wyoming	203	1,549	81	4	1,837	267	1,435	63	0	1,765	148	1,234	46		1,428
Totals - States	**5,181**	**4,327**	**1,070**	**2,784**	**23,350**	**5,128**	**4,390**	**1,504**	**3,378**	**22,981**	**4,240**	**3,776**	**1,470**	**2,930**	**25,906**
Alberta	1,574	1,969	140	0	3,683	1,643	2,815	220	0	4,678	1,667	3,498	292	45	5,457
British Columbia	51	207	19	95	372	63	393	19	65	540	53	538	14	114	722
Northwest Territories	4	0	0	0	4	1	0	0	0	1	3	0	0	0	3
Saskatchewan	434	981		90[1]	1,505	1,131	816	0	140[1]	2,087	771	1,278	0	124[1]	2,173
Yukon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals - Provinces	**2,063**	**3,157**	**159**	**185**	**5,564**	**2,838**	**4,024**	**239**	**205**	**7,306**	**2,494**	**5,314**	**306**	**283**	**8,355**

[1] Includes injector wells, disposal wells, observation wells, relief wells, casing repair wells, gas vent wells, and water source wells.

Apps' Ex. 28

0626

Table 7. Orphan Well Plugging and Expenditures (2018-2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2018, 2019, and 2020.

State or Province	Orphan wells plugged			Expenditures for plugging ($=US dollars; C$=Canadian dollars)			Includes restoration (Yes or No)	Plugged since start of program
	2018	2019	2020	2018	2019	2020		
Alabama	0	0	0	$0	$0	$0	Yes	
Alaska	0	0	0	$0	$0	$0		0
Arizona								
Arkansas	25[1]	1	23	$227,825	$56,521	$420,434	Yes	772
California	29[2]	60	43	$5,896,686	$9,981,893	$14,072,753	Yes	210
Colorado	16[3]	10	61	$644,880	$672,992	$1,990,278	No	
Idaho	0	0	0	$0	$0	$0		0
Illinois	9	20	23	$447,000	$721,537	$750,914	Yes	404+
Indiana	5	15	7	$45,399	$187,960	$90,432	Yes	~800
Kansas	168	137	161	$773,762	$755,943	$556,246	Yes	10,718
Kentucky	9	66	298	$33,000	$298,000	$1,291,000	Yes	4,036
Louisiana	219	1	135	$6,400,000	$4,638,918	$5,939,013	Yes	3,450
Maryland	0	0	0	$0	$0	$0		0
Michigan	6	5	2	$585,756	$795,199	$678,862	Yes	386
Mississippi	5	11	0	$168,000	$497,635	$0	Yes	457
Missouri	0	0	0	$0	$0	$0		
Montana	11	1	2	$387,000	$416,625	$264,667	Yes	481
Nebraska	16	21	13	$170,000	$320,000	$270,000	Yes	
Nevada	0	0	0	$0	$0	$0		0
New Mexico	60	36	49	$1,356,099	$1,022,249	$2,154,826	Yes	234[4]
New York	45	95	68	$1,400,000	$4,190,000	$2,850,000	Yes	487
North Dakota	3	0	282	$224,334	$0	$37,797,531	Yes	306
Ohio	51	92	150	$3,000,000	$8,867,580	$14,035,390	Yes	2,347
Oklahoma	58	127	112	$1,293,466	$1,640,774	$1,495,135	No	4,142
Pennsylvania	6	9	18	$474,111	$1,446,580	$1,499,741	Yes	3,329
South Dakota	0	0	7	$0	$0	$88,107	Yes	7
Tennessee	33	77	66	Unknown	$213,505	$131,000	Yes	~650
Texas	1,332	1,779	1,473	$24,502,884	$36,381,395	$31,126,662	No	40,068
Utah	1	1	2	$88,244	$65,546	$102,704	Yes	117
Virginia	0[5]	0	1	$0	$0	$111,854	Yes	14
West Virginia	0	2	1	$0	$236,804	$185,829	Yes	472
Wyoming	333[1]	529	1,066	$2,200,000	$3,165,531	$5,813,669	Yes	4,475 +
Totals - States	**2,440**	**3,271**	**4,063**	**$50,318,446**	**$76,573,187**	**$123,717,047**		**~78,360**
Alberta	799	982	1,922	C$45,800,000	C$46,200,000	C$63,700,000	No	5,100
British Columbia	84	312	510	C$8,500,000	C$7,000,000	C$18,500,000	No	510
Northwest Territories	0	0	0	C$0	C$0	C$0		0
Saskatchewan	92	144	85	C$2,248,411	C$8,000,000	C$3,000,000	No	670
Yukon	0	0	0	C$0	C$0	C$0		0
Totals - Provinces	**975**	**1,438**	**2,517**	**C$56,548,411**	**C$61,200,000**	**C$85,200,000**		**6,280**

[1] Revised 2018 orphan wells plugged to correct an error in the number reported in 2019.
[2] Revised 2018 orphan wells plugged to include wells plugged in state waters of the coastal zone.
[3] Revised 2018 orphan wells plugged to account for an orphan well that an operator plugged at no cost to the state.
[4] Number plugged since 2015.
[5] Revised 2018 orphan wells plugged because the numbers reported in 2019 were the total orphan wells plugged through 2018.

Table 8. Orphan Well Restoration and Expenditures (2018-2020)

Blank fields indicate that no data was reported or available.
Data as of December 31, 2018, 2019, and 2020.

State or Province	Sites restored separately from plugging			Expenditures for restoration, if not included in plugging expenditures ($=US dollars; C$=Canadian dollars)			Plugged orphan wells that need restoration		
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Alabama	0	0	0	$0	$0	$0	0	0	0
Alaska	0	0	0	$0	$0	$0	1	1	1
Arizona									
Arkansas	0	0	1	$0	$0	$8,641	0	0	0
California	0	0	0	$0	$0	$0	0	0	0
Colorado	10	16	12	$189,895	$888,089	$2,750,162	373	422	454
Idaho	0	0	0	$0	$0	$0	0	0	0
Illinois	0	0	0	$0	$0	$0			
Indiana	0	0	1	$0	$0	$19,230	0	0	10
Kansas	37			$26,730					
Kentucky	0	0	0	$0	$0	$0	0	0	0
Louisiana	0	0	0	$0	$0	$0	Unknown	Unknown	Unknown
Maryland	0	0	0	$0	$0	$0	0	0	0
Michigan	6	0	0	$83,697	$0	$0	0	0	1
Mississippi	0	0	8	$0	$0	$43,037			
Missouri	0	0	0	$0	$0	$0	0	0	0
Montana	0	0	0	$0	$0	$0	11	1	2
Nebraska	7	8	5	$98,000	$18,000	$6,000			
Nevada	0	0	0	$0	$0	$0	0	0	0
New Mexico	0	0	0	$0	$0	$0	172	197	227
New York	0	0	0	$0	$0	$0	0	0	0
North Dakota	0	6	186[1]	$0	$203,055	$28,870,850	0	0	156
Ohio	0	0	0	$0	$0	$0			
Oklahoma	608	712	539	$4,300,000	$6,441,406	$5,558,005			
Pennsylvania	0	0	0	$0	$0	$0	0	0	0
South Dakota	0	0	0	$0	$0	$0	0	0	0
Tennessee	0	0	0	$0	$0	$0	0	0	0
Texas	132	257	125	$761,020	$2,520,379	$2,273,584			
Utah	1	1	2	$16,772	$13,452	$24,462	5	5	5
Virginia	0	0	0	$0	$0	$0	0	0	0
West Virginia	4	0	0	$79,607	$0	$0	0	0	0
Wyoming	0	0	0	$0	$0	$0			
Totals - States	**805**	**1,000**	**879**	**$5,555,721**	**$10,084,381**	**$39,553,971**	**562**	**626**	**856**
Alberta	85	146	267	C$22,900,000	C$26,900,000	C$47,800,000	2,151	3,319	4,889
British Columbia	15	31	61	C$500,000	C$6,500,000	C$12,500,000	59	256	396
Northwest Territories	0	0	0	C$0	C$0	C$0	0	0	0
Saskatchewan	36	33	111	C$2,000,000	C$2,200,000	C$3,500,000	369	481	577
Yukon	0	0	0	C$0	C$0	C$0			
Totals - Provinces	**136**	**210**	**439**	**C$25,400,000**	**C$35,600,000**	**C$63,800,000**	**2,579**	**4,056**	**5,862**

[1] These sites consisted of 184 wells, one treating plant, and one pipeline.

Table 9. Idle Well Requirements

Blank fields indicate that no data was reported or available.
+ indicates provisions for extension of time.

State or Province	Idle period before approval needed			Idle period with approval		
	Gas	Oil	Injection	Gas	Oil	Injection
Alabama	6 months	6 months	6 months	1 year +	1 year +	1 year +
Alaska [1]	No approval required	No approval required	No approval required	No approval required	No approval required	No approval required
Arizona	60 days	60 days	60 days	5 years +	5 years +	5 years+
Arkansas	2 years	2 years	1-2 years	3 years+	3 years+	3 years+
California [2]	No approval required	No approval required	No approval required	No approval required	No approval required	No approval required
Colorado [3]	No approval required	No approval required	No approval required	No approval required	No approval required	No approval required
Idaho	2 years	2 years		3 years +	3 years +	
Illinois	2 years	2 years	2 years	2 years +	2 years +	2 years +
Indiana	60 days	60 days	60 days	5 years +	5 years +	5 years +
Kansas	90 days	90 days	90 days	1 years +	1 years +	1 years +
Kentucky	1 year	1 year	1 year	2 years +	2 years +	2 years +
Louisiana	5 years +	5 years +	No approval required	Indefinite	Indefinite	Indefinite
Maryland	No approval required	No approval required	No approval required	No approval required	No approval required	No approval required
Michigan	1 year	1 year	1 year	1 - 5 years +	1 - 5 years +	1 - 5 years +
Mississippi	1 year	1 year	Indefinite	Indefinite	Indefinite	Indefinite
Missouri	90 days	90 days	90 days	10 years	10 years	10 years
Montana	1 year	1 year	1 year	Unspecified	Unspecified	Unspecified
Nebraska	1 year	1 year	1 year	1 years +	1 years +	1 years +
Nevada	1 year	1 year	1 year	1 years +	1 years +	1 years +
New Mexico	15 months	15 months	1 year	5 years +	5 years +	1 years +
New York	1 year	1 year	1 year	1 years +	1 years +	1 years +
North Dakota	1 year	1 year	1 year	7 years +	7 years +	7 years +
Ohio	2 years	2 years	2 years	1 years +	1 years +	1 years +
Oklahoma	Indefinite	1 year	Indefinite	Indefinite	1 - 5 years +	Indefinite
Pennsylvania	1 year	1 year	1 year	5 years +	5 years +	5 years +
South Dakota	6 months	6 months	6 months	5 years +	5 years +	5 years +
Tennessee	1 year	1 year	1 year	5 years	5 years	5 years
Texas	1 year	1 year	1 year	Unspecified	Unspecified	Unspecified
Utah	1 year	1 year	1 year	5 years +	5 years +	5 years +
Virginia	3 years	3 years	3 years	Unspecified	Unspecified	Unspecified
West Virginia	1 year	1 year	1 year	5 years	5 years	5 years
Wyoming	2 years	2 years	2 years	Indefinite	Indefinite	Indefinite
Alberta	18 - 24 months	18 - 24 months	18 - 24 months	Indefinite	Indefinite	Indefinite
British Columbia	1 year	1 year	1 year	1 - 15 years	1 - 15 years	1 - 15 years
Northwest Territories	2 years	2 years	2 years	6 years	6 years	6 years
Saskatchewan	When unused	When unused	When unused	Unspecified	Unspecified	Unspecified
Yukon	1 year	1 year	1 year	3 years +	3 years +	3 years +

[1] The operator must report annually on the mechanical condition of an idle well and its potential future utility.
[2] Idle wells are subject to fees and testing requirements that are based upon the number of years a well has been idle.
[3] Rules specify requirements for idle wells, including testing requirements.

Table 10. Funding Sources for Plugging Orphan Wells

State or Province	Annual fee	Idle well fee	Permit fee	Civil penalty	Settlement	Appropriations	Forfeited bonds	Salvage	Excise tax	Production assessment	Other
Alabama			•				•				
Alaska											
Arizona											
Arkansas	•						•	•		•	
California	•	•		•		•				•	•
Colorado				•	•	•	•	•	•	•	
Idaho			•	•	•		•				
Illinois	•										
Indiana	•			•			•	•			
Kansas			•				•	•		•	•
Kentucky							•				•
Louisiana		•									•
Maryland											
Michigan				•		•	•			•	
Mississippi		•		•		•	•	•			
Missouri							•				
Montana							•				•
Nebraska		•					•	•			
Nevada											
New Mexico					•		•	•		•	•
New York			•		•	•	•				
North Dakota			•	•	•	•	•	•		•	
Ohio	•	•	•	•	•	•	•	•		•	•
Oklahoma									•	•	
Pennsylvania			•								
South Dakota							•				
Tennessee		•					•				•
Texas		•	•				•	•		•	
Utah									•		
Virginia			•								
West Virginia			•				•			•	•
Wyoming							•	•	•		
Totals - States	**5**	**7**	**10**	**8**	**6**	**7**	**21**	**11**	**4**	**11**	**9**
Alberta	•										
British Columbia	•						•	•			•
Northwest Territories											
Saskatchewan	•		•				•	•			•
Yukon						•	•				
Totals - Provinces	**3**		**1**			**1**	**3**	**2**			**2**

Table 11. Financial Assurance

State or Province	Financial assurance amounts				Financial assurance accepted						
	Single well		Blanket		Cash deposit	Certificate of deposit	Financial statement	Letter of credit	Surety or performance bond	Security interest	Other
	Minimum	Maximum	Minimum	Maximum							
Alabama	$5,000	$500,000	$100,000	$7,500,000				•	•		
Alaska[1]		$400,000	$400,000	$30,000,000	•	•		•	•		
Arizona	$10,000	$20,000	$25,000	$250,000	•	•			•		
Arkansas	$3,000	$50,000[2]	$25,000	$100,000[2]	•	•		•	•		
California	$25,000	$40,000	$200,000	$3,000,000		•			•		•[8]
Colorado	$10,000	$20,000	$60,000	$100,000	•	•	•	•	•	•	
Idaho	$10,000+$1/ft.	$10,000+$8/ft.	$50,000	$150,000					•		
Illinois	$1,500	$3,000	$25,000	$100,000		•		•	•		
Indiana		$2,500		$45,000	•	•			•		
Kansas	$.75/ft.	$30,000	$7,500	$45,000	•		•	•	•		•[9]
Kentucky	$2/ft.	$40,000[2]	$20,000	$1,500,000[2]	•	•		•	•		
Louisiana	$2/ft.	$12/ft.	$50,000	$5,000,000		•		•	•		
Maryland		$100,000		$500,000	•	•		•	•		
Michigan	$20,000	$60,000	$100,000	$250,000	•	•	•	•	•		
Mississippi	$20,000	$60,000		$100,000	•			•	•		
Missouri	$1,100	$5,500+$2/ ft.	$22,000	$25,000[3]		•		•	•		
Montana	$1,500	$10,000		$50,000		•			•		
Nebraska		$10,000		$100,000		•			•		
Nevada		$10,000[2]		$50,000[2]	•	•			•		
New Mexico		$25,000+$2/ft.	$50,000	$250,000	•			•	•	•	
New York	$2,500	Actual cost	$25,000	$2,000,000	•	•		•	•		
North Dakota	$20,000	$100,000		$100,000[4]		•			•		
Ohio		$5,000		$15,000	•	•	•	•	•		
Oklahoma	$25,000[5]	$100,000	$25,000	$50,000	•	•	•	•	•		
Pennsylvania[6]	$2,500	$10,000		$25,000	•	•			•		
South Dakota		$50,000		$100,000		•		•	•		
Tennessee	$2,000	$3,000+$1/ft.	$20,000	$30,000	•	•		•	•		
Texas		$2/ft	$25,000	$250,000	•			•	•		
Utah	$1,500	$60,000	$15,000	$60,000	•	•		•	•		
Virginia		$10,000+$2,000/acre	$25,000	$200,000	•	•			•		
West Virginia	$5,000	$50,000	$50,000	$250,000	•	•		•	•		
Wyoming		$10/ft		$100,000[2]	•	•		•	•		
				Totals - States	22	26	5	22	32	2	2
Alberta		None		Case-by-case	•			•			
British Columbia		Case-by-case		Case-by-case	•			•			
Northwest Territories[7]			C$10,000,000	C$25,000,000				•			•[10]
Saskatchewan	C$10,200	C$76,100		None	•			•			
Yukon		Case-by-case		None	•			•			
				Totals - Provinces	4			5			1

[1] Amounts may be increased or decreased on operator request or by agency action.
[2] Higher amounts may be required under certain circumstances.
[3] Wells deeper than 1,500 feet must be bonded individually by a single well bond.
[4] Covers six or fewer wells.
[5] May substitute actual cost to P&A.
[6] Wells drilled before 1985 do not require bonds.
[7] Information here concerns financial assurance required for damages associated with spills or debris. No information provided on financial assurance required for plugging and restoration.
[8] The other types include a share account, note, savings account, share certificate, or investment certificate. The state also has new authorities to place liens on real property.
[9] Other financial assurance approved by the Commission.
[10] Other forms of financial assurance are considered on a case-by-case basis.

Table 12. Plugging Funds

Blank fields indicate that no data was reported or available.
*An * indicates no plugging fund.*

State or Province	Year established	Last modified	Prioritization for plugging?	Emergency use for non-orphan wells?	Annual spending target?	Covers restoration?	Salvage recovered?
Alabama	1984[1]		Y	Y	N	Y	Y
Alaska*							
Arizona*							
Arkansas	2005		Y	Y	Y	Y	Y
California	1990	2017	Y	N	Y	Y	Y
Colorado	1990	2019	Y	Y	Y	Y	Y
Idaho*							
Illinois	1939		Y	Y	Y	Y	Y
Indiana	Unknown		Y	Y	Y	Y	Y
Kansas	1996	2021	Y	Y	N	Y	Y
Kentucky	1990	2019	Y	N	N	Y	Y
Louisiana	1993	2018	Y	Y	Y	Y	Y
Maryland*							
Michigan	1994		Y	Y	Y	Y	Y
Mississippi	1948	2019	Y	N	N	Y	N
Missouri	1983			Y	N	N	N
Montana	1989	2015	Y	Y	N	Y	N
Nebraska	2014		Y	Y	N	Y	Y
Nevada*			Y				
New Mexico	1977	2010	Y	Y	N	Y	Y
New York	1982	2021	Y	N	N	Y	N
North Dakota	1983	2019	Y	Y	Y	Y	Y
Ohio	1977	2018	Y	Y	Y	Y	Y
Oklahoma[2]	1990	2016	Y	Y	Y	N	Y
Pennsylvania	1985	2012	Y	N	N	Y	Y
South Dakota*[3]							N
Tennessee	1987	2019	Y	N	N	Y	N
Texas	1984	2013	Y	Y	N	Y	Y
Utah	1990	1992	Y		Y	Y	Y
Virginia	1991	2017	Y	N	N	Y	N
West Virginia	1977	2005	Y	Y	Y	Y	N
Wyoming*[3]			Y	Y	Y	Y	Y
Alberta	2002		Y	N	Y	Y	Y
British Columbia	2006	2019	Y	N	Y	Y	N
Northwest Territories *							
Saskatchewan	2007		Y	Y	Y	Y	Y
Yukon*[3]			N				

[1] For coalbed methane wells only.
[2] Has a separate restoration fund.
[3] Has access to other funding sources for plugging and restoration.

Apps' Ex. 28

Table 13a. Updated Data on Documented Orphan Wells

Data as of November15, 2021, unless otherwise indicated.
See next page for additional explanations.

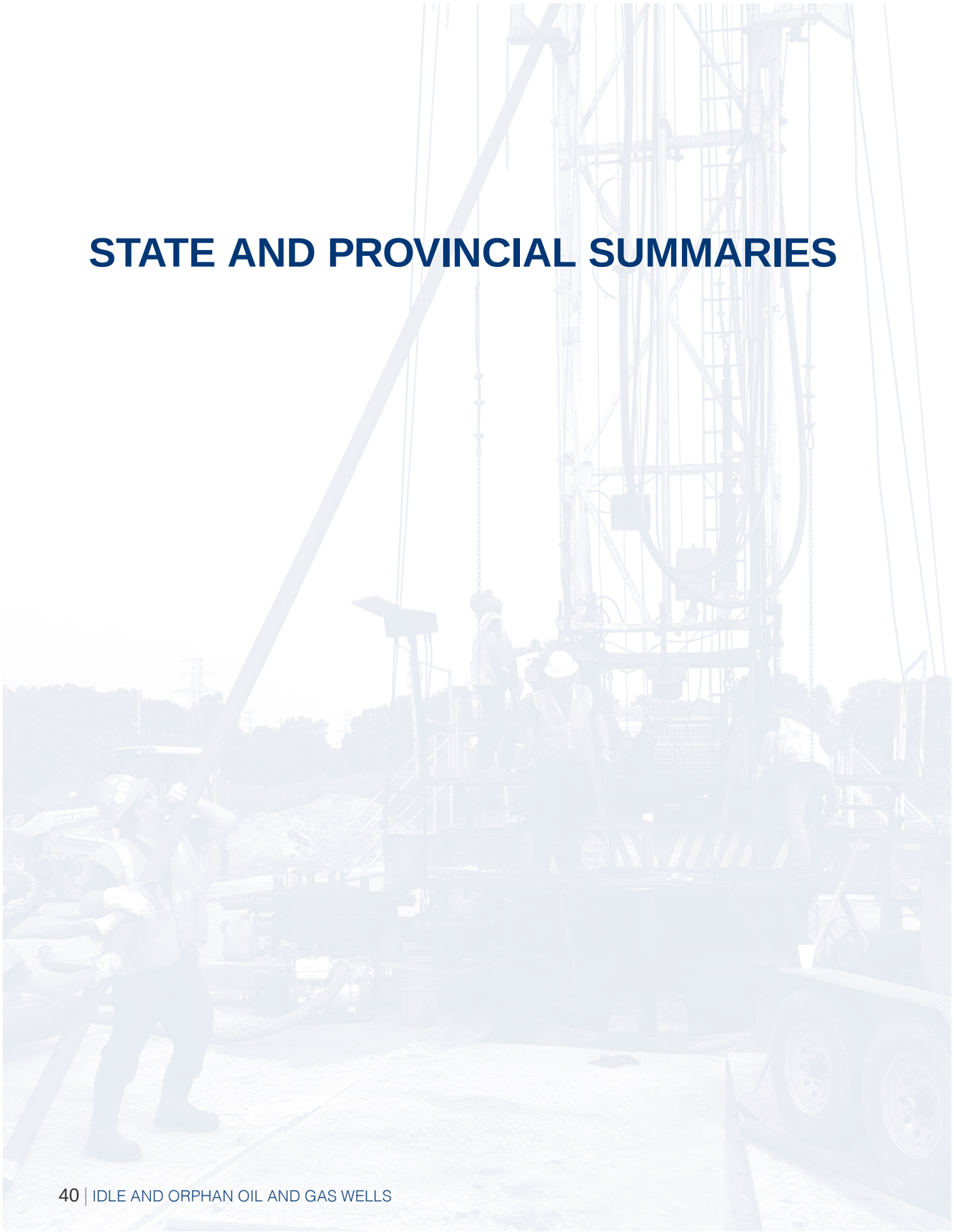
State	Total Documented Orphan Wells	Documented Orphan Wells on State and Private Lands	Date of Reported Numbers If other than November 15, 2021
Alabama	89	89	
Alaska	14	11	
Arizona	391	245	12/17/2021
Arkansas	423	423	
California	5,151	5,151	
Colorado	495	451	12/10/2021
Idaho	0	0	
Illinois	4,415[1]	3,663	12/10/2021
Indiana	1,442	1,441	
Kansas	5,486	5,486	
Kentucky	14,489	14,489	11/30/2021
Louisiana	4,601	4,601	11/22/2021
Maryland			
Michigan	442	441	
Mississippi	15	14	11/24/2021
Missouri	330	330	
Montana	279	279	11/29/2021
Nebraska	471	471	
Nevada	6	-	
New Mexico	3,375	1,749	11/17/2021
New York	7,040	6,937	
North Dakota	232	186	11/30/2021
Ohio	20,557	19,662	
Oklahoma	17,865	17,865	11/17/2021
Pennsylvania	27,991	16,056[2]	
South Dakota	19	19	
Tennessee	470	465	11/29/2021
Texas	7,436	7,396	10/31/2021
Utah	35	35	
Virginia	9	9	
West Virginia	6,309	6,245	
Wyoming	1,350	1,350	
Totals - States	**131,227**	**115,314**	

[1] Illinois has geographic coordinates for 3,663 wells. The locations of the remainder are being verified.
[2] Pennsylvania does not yet have geographic coordinates for 9,581 of the total documented orphan wells.

Table 13b. Explanations for Updated Data on Documented Orphan Wells

Explanation requested if the orphan well count differs by 10% or more from the count for 2020 in Table 3:	
Alabama	Since December 31, 2020, the state plugged nine abandoned wells, one operator in bankruptcy expressed intent to abandon 61 wells, another operator with seven inactive wells has been unresponsive, and another operator informed the state he does not have funds to plug four wells.
Arizona	In 2021, the state conducted a review of well records on historic wells. The wells reflected here were found to be lacking reports of plugging or abandonment.
California	The state previously considered only narrow evidence to designate a well as a documented orphan well. For this report, the state undertook additional review of well inventories and considered all evidence of wells that are eligible for state abandonment.
Colorado	No explanation provided.
Indiana	The state added a category of wells that should have been included as documented orphan wells originally. The category is "Revoked Injector Not Present at Surface and Field Verified." The wells in this category are all Class II wells that were removed from the injector list. The other reason for growth was the addition of old Trenton wells, which have been located and marked as possibly in personal use although no permitting or registration has taken place since they were drilled in the late 1800s or early 1900s. Inspection records in the database show these wells do still exist at surface and are hooked up like gas wells, but they are unpermitted, so they fall under the orphan well category.
Kentucky	The 8.5% increase in Kentucky's orphan well count comes through a continued focus by field inspectors on searching out, confirming the location of, and determining the status of idle and abandoned wells within their assigned counties.
Michigan	In 2021, two large companies with a total of 284 wells and two smaller companies with a total of 17 wells became insolvent. Their wells were added to the state's orphan well list.
Montana	No explanation provided.
Nebraska	The state added wells that have been shut in for more than 10 years with no plan to recomplete or produce.
North Dakota	The reduction in wells reported between December 31, 2020, and November 30, 2021, is a result of the state's ongoing plugging and reclamation work.
Ohio	The state's previously reported orphan well count consisted of wells that were fully evaluated in accordance with all statutory requirements for the well to be plugged under the state's orphan well program. In accordance with the definition of "documented orphan well" on the form provided by IOGCC, Ohio updated its numbers to include wells meeting the following criteria: the well has a drilling report, completion report, inspection report, or other record establishing the existence of the well; the state does not have a plugging report for the well; and the state does not have an owner of record for the well.
Oklahoma	The state increased the number of personnel working on the data clean-up project and made documentation of orphan wells a priority for field inspectors. This effort led to an increase in the number of documented orphan wells since December 31, 2020.
South Dakota	The state plugged 14 more orphan wells in 2021.
Texas	The state attributes the increase in orphan wells to the unprecedented volatility experienced by the energy industry in the last two years.
Utah	In October 2021, the state commenced a project to plug 15 wells. Six of those wells were plugged as of November 15, 2021.
Wyoming	As of November 15, 2021, the state plugged 652 wells in calendar year 2021 and added a few more orphan wells to the list.

STATE AND PROVINCIAL SUMMARIES



ALABAMA

Regulatory Agency

State Oil and Gas Board of Alabama
PO Box 869999
Tuscaloosa, AL 35486-6999
ogb.state.al.us

Statutory or Regulatory Authority

Onshore conventional and injection/disposalwells:
Rule 400-1-4-.14 and 400-1-4-.17
Offshore wells: Rule 400-2-4-.11 and 400-2-4-.14
Coalbed methane: Rule 400-3-4-.14 and 400-3-4-.17

Substantially Different Definitions

Idle well: Alabama classifies idle wells as either "shut-in" (those wells capable of producing but currently shut-in until connected to a gathering system, pipeline or processing facility, or for some other reason) or "temporary abandoned" (those wells currently not capable of producing but still having future utility).

Orphan well: Alabama does not statutorily define an orphan well perse but addresses abandoned wells.

Site restoration: Site restoration or restoration of location includes: the plugging and abandonment of the oil and gas well; the removal of all material, debris, equipment, wastes and other material, including contaminated soil, and disposal in accordance with permit(s) or regulation(s); stabilization of the site; and plugging and abandonment of water supply wells unless utilized by the landowner.

Idle Wells

General requirement(s): Demonstration of future utility and mechanical integrity.

Application fee(s): None.

Financial assurance requirement(s): A bond is required. The amount of the bond varies based on depth, location, and risk.

Mechanical integrity requirement(s): A well must demonstrate mechanical integrity of the casing. A MIT may be required to verify.

Surface equipment requirement(s): The well location must be maintained in accordance with all other rules and regulations.

Other requirement(s): Additional safeguards and requirements may be imposed on the operator by the Supervisor or Board as deemed necessary.

Provisions for exemptions or exceptions: Operators may petition the Board for approval of exceptions after notice and hearing.

Orphan wells

Actions to identify and address orphan wells: Alabama takes a proactive approach to identify and address inactive or idle wells, so this issue will not occur.

Alabama conducts regular ongoing field inspections and regulatory operations in the office (i.e., review of weekly activity reports, monthly production database queries, and annual audits of each operator's wells) to determine whether or not a well is inactive. Staff in the field and office work together to identify inactive wells and communicate with operators to get such wells plugged. Our rules and regulations limit how long an operator may allow a well to remain inactive. If an operator is not compliant, board action can be taken to order a well plugged and the site restored.

Process for prioritizing orphan wells for plugging: Alabama does not have a formal process to prioritize orphan (aka: abandoned) wells for plugging, since historically it has not been needed due to the low number of such wells. However, the safety of the public and ground water are our highest concerns. Therefore, highest priority is given to any well that poses a risk to either the public or ground water. Such risk factors increase, for example, with increasing levels of H_2S or CO_2 gas produced. They also increase as the depth and age of a well increases; and when there is more equipment on the well site.

Secondly, wells are prioritized according to the amount of bond money—if available—to plug the well and restore the site.

Apps' Ex. 28

0636

ALASKA

Regulatory Agency

Alaska Oil and Gas Conservation Commission
333 West Seventh Avenue, Suite 100
Anchorage, AK 99501-3935
commerce.alaska.gov

Statutory or Regulatory Authority

Citation: Regulation 20 AAC 25.110 and 20 AAC 25.115

Last update: 2/10/2018 for .110 and 11/7/1999 for .115

Substantially Different Definitions

Idle well: AOGCC refers to shut-in wells as wells that have had no production/injection activity during the full previous calendar year.

Orphan well: Alaska does not have a formal definition of "orphan well." The AOGCC uses the informal definition for "orphan well" as a well that has not been properly plugged and abandoned and an operator responsible for the well cannot be determined/found.

Site restoration: The AOGCC uses the term "location clearance," which has much the same definition as "site restoration." "Location clearance" requirements can be found in 20 AAC 25.170 and 172 for onshore and offshore locations respectively.

Idle Wells

General requirement(s): Must report on mechanical condition of the well, when it last produced/injected, and possible future utility by April 1st each year.

The AOGCC requires approval to suspend a well (set a downhole plug that makes the well incapable of flowing).

Suspended wells are subject to inspection requirements every five years and must be reauthorized every 10 years to keep a well in suspension status.

Application fee(s): None.

Financial assurance requirement(s): None beyond normal bonding requirements.

Provisions for exemptions or exceptions: None. Any well that is not suspended or plugged and abandoned is subject to the AOGCC's shut-in well annual reporting requirements as stated above.

Orphan wells

Actions to identify and address orphan wells: Continued research.

Process for prioritizing orphan wells for plugging: None.

ARKANSAS

Regulatory Agency

Oil and Gas Commission
5301 Northshore Drive North
Little Rock, AR 72118
aogc.state.ar.us

Statutory or Regulatory Authority

Citation: AOGC General Rules B-7, H-2 and H-3

Last update: November 19, 2018, June 03, 2019, and June 03, 2019, respectively

Substantially Different Definitions

Idle well: Arkansas utilizes the term "temporarily abandoned" for wells that require approval to remain idle after a set time.

Orphan well: A well where the operator/permittee is unknown or cannot be located and the well is not covered by financial assurance of any type as defined by AOGC rules; or the operator/permittee has not paid the annual Abandoned and Orphaned Well Plugging Program fee on the well.

Site restoration: Arkansas also includes the following to this document definition: "clean-up of any spills and remediation of any conditions endangering public health and safety, or causing contamination of water or the surface, or creating a fire hazard."

Idle Wells

Director's Approval (by Rule): Well operator does not have any outstanding Notices of Violations.

Dry natural gas well - Operator must provide well specific financial assurance in the amount of $35,000 per well or $15,000 per well for any liquid hydrocarbon production well is submitted for each well. The financial assurance shall be in a prescribed form and shall remain valid until the well is put back into sustained production, plugged or transferred.

Useable ground waters must be protected (bridge plug, or packer, at least 150 feet below the base of the lowest usable groundwater in the area; casing inspection log confirming mechanical integrity; or witnessed initial and annual fluid level test confirming static fluid level is at least 150 feet below the base of the lowest usable groundwater in the area).

No transfer of the well without first obtaining approval of the Commission at a subsequent hearing.

Application fee(s): Director's Approval (by Rule) – none. Full Commission Approval (after notice and hearing) - $500 filing fee per well for hearing docket fee.

Financial assurance requirement(s): If not previously submitted, Well Operator provides well specific financial assurance in the amount of $35,000 per well for any dry natural gas production well, or $15,000 per well for any liquid hydrocarbon production well. The financial assurance shall be in a form as prescribed by General Rule B-2 and shall remain valid until the well is put back into sustained production, plugged or transferred.

Mechanical integrity requirement(s): Not required.

Surface equipment requirement(s): Well must be secured with a suitable wellhead with no leakage of any substance at the surface.

Well site must be maintained in accordance with rules. Proper well identification must be maintained.

Provisions for exemptions or exceptions: Wells in an approved waterflood/enhanced oil recovery unit are exempt from the three year time limit as long as the unit remains active.

Wells which produce liquid hydrocarbons that are located on actively producing leases are exempt.

Additionally, the Director reserves right to refer requests for temporarily abandoned status to the full Commission for approval.

Orphan wells

Actions to identify and address orphan wells: Routine examination of Commission records and follow-up with field inspections.

Process for prioritizing orphan wells for plugging: Leaking wells and those where the well site creates an imminent danger to the health or safety of the public are prioritized first.

CALIFORNIA

Regulatory Agency

California Geologic Energy Management Division (CalGEM)
715 P Street, MS 1803
Sacramento, CA 95814
conservation.ca.gov/calgem

Statutory or Regulatory Authority

Citation: Public Resources Code sections 3206, 3206.1, 3206.3, 3206.5, 3237, 3250, 3251, 3251.5 and 3258. California Code of Regulations, title 14, sections 1760, 1772-1772.4, and 1772.6-1772.7

Last update: Public Resources Code section 3206 was revised in 2018. Public Resources Code section 3206.1 was revised in 2017. California Code of Regulations, title 14, sections 1760, 1772-1772.4, and 1772.6-1772.7 became effective April 1, 2019

Substantially Different Definitions

Idle well: California defines an idle well as any well that for 24 consecutive months has not either produced oil or natural gas; produced water to be used in production stimulation; been used for enhanced oil recovery, reservoir pressure management, injection, or as an observation well."

Long-term idle well: A well that has met the definition of idle well for eight years or more is classified as a long-term idle well.

Orphan well: California utilizes several terms to describe orphan wells. "Deserted" wells are wells for which a final plugging and abandonment order has been issued, but a determination of financial resources held by a current or prior operators has not yet been completed. "Orphan wells" are wells that have no responsible party, leaving the state to plug and abandon them. California statute differentiates between two types of orphan wells: idle-deserted wells and hazardous wells. An "idle- deserted well" is defined as a deserted well for which there is no operator responsible for its plugging and abandonment. A "hazardous well" is defined as an oil and gas well determined by the Supervisor to be a potential danger to life, health, or natural resources and for which there is no operator determined by the Supervisor to be responsible for its plugging and abandonment.

Site restoration: California does not define site restoration, although California regulations require operators to restore the well site and the lease.

Idle Wells

General requirements: Under California rules, when a well is idle for three years, annual idle well fees start being assessed on the well at rates that increase the longer the well remains idle. A well that is idle well for 10 years or more is classified as a long-term idle well. Operators may file a management plan for long-term idle wells in lieu of filing the annual idle well. This plan requires operators to reactivate or plug long-term idle wells at a prescribed rate. Failure to file the idle well fee or comply with the plan is conclusive evidence of desertion permitting the supervisor to order the well plugged and abandoned.

Additionally, a well is deemed deserted if it has been idle for 25 years or more and either does not have a management plan or is not covered by an indemnity bond. If declared deserted, the well can be ordered plugged and abandoned.

Financial assurance requirement(s): No additional financial assurance is required for idle wells.

Mechanical integrity requirement(s): Within two years of a well becoming an idle well, fluid level and casing pressure tests are required. Fluid levels are repeated every 24 months and casing pressure tests are repeated every 24 to 96 months, depending on the test pressure. Within eight years of the well becoming an idle well, the first clean out tag demonstrating that the well can be plugged and abandoned to current standards is required. A clean out tag is then required every 48 months. Within 15 years of a well becoming idle, the operator must submit an engineering analysis demonstrating that the well is viable to return to operation in the future.

Other requirement(s): Operators are required to submit an annual inventory and evaluation of their idle wells to CalGEM by January 31, 2021, or within one year of becoming the operator or whichever comes first. The evaluation must include identification of surface obstacles, mechanical integrity, penetration of USDWs, tubing and casing pressures,

whether the well is in a specified sensitive area, and known downhole issues.

Provisions for exemptions or exceptions: Idle well MIT requirements are waived for wells that are subject to an approved Testing Waiver Plan—a schedule for plugging and abandoning idle wells that extends for up to eight years.

Orphan wells

Actions to identify and address orphan wells:

CalGEM has identified the population of "potentially deserted" wells—wells that have not yet been determined to be "deserted," but for which other evidence suggests the wells likely have no responsible operator. This evidence includes failure to pay idle well fees, the operational history of the well, and lack of response from the operator. CalGEM anticipates that many wells will likely be found to have no legally responsible current or prior operator with financial resources sufficient to cover the costs of plugging and abandonment. CalGEM has in previous reports limited its evidence of desertion to nonpayment of idle well fees for three consecutive years. In this report, CalGEM also considered other relevant factors.

Operators are required to file indemnity bonds to support the cost of plugging a well should it be deserted. However, the minimum bond amounts required by statute are not generally sufficient and CalGEM is working to implement new statutory authority to revise its bonding program to ensure funds are sufficient to cover the costs of plugging and facility restoration. CalGEM has been developing cost estimates and consulting with State Lands Commission staff and offshore operators on this issue.

Recent legislation authorizes CalGEM to require operators to submit a report that demonstrates the operator's liability to plug and abandon all wells and to decommission all attendant production facilities, including site remediation. This reporting requirement will inform the financial security levels. Informal rulemaking efforts are underway.

CalGEM is working with key stakeholders to develop a prioritization plan to analyze and prioritize wells and facilities for state abandonment and decommissioning.

Process for prioritizing orphan wells for plugging: CalGEM has developed a well screening methodology to prioritize wells for state abandonment. This methodology consists of two phases. A screening tool is used to quantify the well surface and downhole risk, followed by a secondary screening that accounts for feedback from local jurisdictions (cities and counties), accessibility, and future development plans.

COLORADO

Regulatory Agency

Oil and Gas Conservation Commission
1120 Lincoln Street, Suite 801
Denver, CO 80203-2136
(303) 894-2100
cogcc.state.co.us

Statutory or Regulatory Authority

Citation: Oil and Gas Conservation Act, C.R.S. Title 34-Article 60; 100-Series, 400-Series, 700-Series, and 1100-Series Rules

Last update: January 15, 2021

Substantially Different Definitions

Idle well: Colorado classifies wells as "shut-in," "inactive," "suspended operations" (shut down before completion of drilling), "temporarily abandoned," or "waiting on completion." See COGCC's 100-Series Rules.

Inactive well means a shut-in well from which no production has been sold or that has not been utilized for a period of 12 consecutive months, or any well which has been temporarily abandoned for a period of six consecutive months.

Shut-in well means a well which is capable of production or injection by opening valves, activating existing equipment or supplying a power source.

Suspended operations well means a well in which drilling operations have been suspended prior to reaching total depth and at least surface casing has been set and cemented.

Temporarily abandoned well means a well that has all downhole completed intervals isolated with a plug set above the highest perforation or a well which is incapable of production or injection without the addition of one or more pieces of wellhead or other equipment.

Waiting on completion well means a well which has been drilled, cased, and cemented but the objective hydrocarbon formation has not yet been completed or stimulated.

Orphan well: Orphan well means a well for which no owner or operator can be found, or where the owner or operator is unwilling or unable to plug and abandon the well.

Orphaned site means a site where a significant adverse environmental impact may be or has been caused by oil and gas operations for which no responsible party can be found, or where the responsible party is unwilling or unable to mitigate the impact.

Site restoration: Reclamation means the process of returning or restoring the surface of disturbed land as nearly as practicable to its original condition or to landowner specifications.

Remediation means the process of reducing the concentration of a contaminant or contaminants in water or soil to the extent necessary to ensure compliance with regulatory standards.

Idle Wells

General requirement(s): Colorado does not have a defined time limit for the duration a well may remain shut-in or temporarily abandoned. Colorado requires the operator to perform an MIT on shut-in or temporarily abandoned wells. An operator with "excess" inactive wells is subject to an increase in their financial assurance requirements.

Shut-in wells: An MIT shall be performed within two years of the initial shut-in date, and subsequently every five years as long as the well remains shut-in.

Temporarily abandoned wells: An MIT shall be performed within 30 days of temporarily abandoning the well and subsequently every five years. The operator must submit a notice annually for each well temporarily abandoned well for more than six months, including the reason for the request state and plans for future operation.

The COGCC may require an operator to plug and abandon a well or close a facility if necessary to protect or minimize adverse impacts to public health, safety, welfare, the environment, or wildlife resources, or when the well is no longer used or useful.

Application fee(s): No applicable fees.

Financial assurance requirement(s): An operator is required to increase its financial assurance when its inactive well count is greater than its total financial assurance divided by $10,000 for each inactive well less than 3,000 feet deep, and by $20,000 for each inactive well equal to or greater than 3,000 feet in depth. The operator must increase its financial assurance by $10,000 / $20,000 depending on well depth for each excess inactive well.

Surface equipment requirement(s): The COGCC sets standards for inspection and operation of production equipment regardless of whether a well is active or idle.

Operators must provide 48-hour notice to COGCC of pressure testing of shut-in wells, temporarily abandoned wells, flowlines, and crude oil transfer lines prior to returning to service.

Provisions for exemptions or exceptions: An operator may submit an alternative plan for additional financial assurance, based on returning wells to production or plugging and abandoning wells on an approved schedule.

Orphan wells

Actions to identify and address orphan wells: Current actions include routine field inspections for historical well identification and complaint response. Staff audits historic orphaned well projects to evaluate reclamation progress until the sites are administratively closed.

Process for prioritizing orphan wells for plugging: Orphaned sites are prioritized into low, medium, and high categories based on multiple risk factors, including population density and urbanization; environmental factors; years in service; active spills; stormwater issues; noxious weeds; wildlife, livestock, or vegetation impacts; surface equipment; bradenhead pressure; mechanical integrity test data; any documented history of venting or leaking; and time since the well was designated as an orphaned well.

IDAHO

Regulatory Agency

Idaho Department of Lands

300 North 6th Street, Suite 103
Boise, ID 83702
ogcc.idaho.gov

Statutory or Regulatory Authority

Citation: IDAPA 20.07.02.220, IDAPA 20.07.02.320, IDAPA 20.07.02.501

Last update: March 20, 2020 – Temporary

Substantially Different Definitions

Idle well: Idaho utilizes the term "inactive well," defined as a well that is inactive for 24 continuous months unless the owner or operator has received approval for an extension, or after an owner or operator fails to submit an annual report for an active well.

Site restoration: Idaho uses the term "reclamation" instead of "restoration." Reclamation essentially means to stabilize the site structurally and environmentally, while restoration means returning the site to the pre-activity condition. Restoration is not always possible.

Idle Wells

General requirement(s): The owner or operator must plug and abandon an inactive well within six months after notification by the Department.

The owner or operator must apply to the Department to change the status of a well from inactive to active. A MIT may be required if the well has been worked over or if a test has not been conducted for five years or longer.

Application fee(s): None.

Financial assurance requirement(s): An owner or operator must provide a bond of at least $10,000 plus $8 for each foot of well length for each inactive well. Inactive wells may not be covered by a blanket bond.

Mechanical integrity requirement(s): Inactive wells shall have a MIT performed within two years after the date of last use. If the well becomes incapable of production, a mechanical integrity test shall be performed within 30 days.

Surface equipment requirement(s): If surface equipment excluding the wellhead is removed, a mechanical integrity test shall be performed within 30 days.

Provisions for exemptions or exceptions: The Department may approve an extension of the requirement to plug an inactive well of up to three years if the owner or operator submits (1) a written request to extend inactive status; (2) an individual bond if the well was covered by a blanket bond; and (3) a description of how the well is closed to the atmosphere with a swedge and valve, packer, or other approved method, and how the well is to be maintained.

Orphan wells

Actions to identify and address orphan wells: Historical records on file with the Idaho Geological Survey – None.

ILLINOIS

Regulatory Agency

Illinois Department of Natural Resources
Office of Oil and Gas Resource Management
One Natural Resources Way
Springfield, IL 62702-1271
illinois.gov

Statutory or Regulatory Authority

Citation: Production Wells – 62 Ill. Adm. Code Section 240.1130 (Amended at 42 Ill. Reg. 5811, effective March 14, 2018)

Class II UIC Wells – 62 Ill. Adm. Code Section 240.1132 (Amended at 42 Ill. Reg. 5811, effective March 14, 2018)

Last update: March 14, 2018

Substantially Different Definitions

Idle well: Idle wells must meet criteria for "temporary abandonment" in the Illinois Administrative Code.

A well that has not had commercial production during the last 24 consecutive months shall be deemed abandoned and must be plugged unless the well has been approved for TA status.

Orphan well: A well has not produced and for which no fee has been paid or no bond coverage provided for two consecutive years; and no permittee or owner can be identified or located.

Orphaned wells include wells for which an oil and gas well permit is not required if the well is a conduit for oil or saltwater intrusions into freshwater zones or onto the surface which may be caused by oil and gas operations.

Site restoration: Within six months after a well is plugged, all liquid plugging waste must be removed from the pit; pits filled and leveled; drilling and production equipment, rock or concrete bases, machinery, and equipment removed; casing cut off and capped; excavations, holes, and pits filled; and the surface leveled.

Idle Wells

General requirement(s): The permittee of either a production or Class II UIC well must apply for TA status on a prescribed form.

TA status may be approved for two to five years and may be extended. The well must have a proper bond in effect, have an intact wellhead cap and valve, and have a fluid level test. Additional downhole safeguards may be required depending on the results of the fluid level test. If a TA request is denied, the permittee shall plug the well or correct the deficiency within 90 days. Class II injection wells that are TA are subject to the same MIT requirements as for active wells.

Provisions for exemptions or exceptions: Illinois has a number of gas production wells that do not have access to pipelines. These wells are sitting idle, but due to a broad interpretation of the rules and lease language, these wells are considered active if they are providing yearly shut-in payments to the mineral owners. Illinois tracks this process through our Idle Well System.

Orphan wells

Actions to identify and address orphan wells: If a well inspector locates an undocumented or unidentified, i.e., abandoned, well, and no permittee can be identified, the well is determined to be orphan and placed in the Plugging and Restoration Program. The inspector may locate the well during a routine inspection or in response to a landowner's report of such a well to the Department.

Process for prioritizing orphan wells for plugging: Wells that are leaking produced fluids, oil, and saltwater are given highest priority. The higher the rate of leakage, the higher the priority. The location of the wells is also a consideration in establishing priority. If the location is on the bank or in the proximity of a "blue line" waterway (indicating waters of the U.S.) and danger of erosion exists that the well(s) will be in the blue line water way, priority is given to this well. Additionally, if conditions exist that could be a hazard to the public and/or wildlife, this, too, is taken into consideration in establishing priorities.

INDIANA

Regulatory Agency

Department of Natural Resources
Division of Oil and Gas
402 West Washington Street, Room 293
Indianapolis, IN 46204
in.gov/dnr

Statutory or Regulatory Authority Citation: 312 IAC 29-33-4

Last update: January 2018

Substantially Different Definitions

Idle well: A well that is determined to be a dry hole, ceases to produce oil or natural gas, or is no longer operated for its permitted purpose must be plugged unless an extension is granted. Indiana uses the term Temporarily Abandoned (TA) for wells that have received approval to remain in an idle status.

Orphan well: Indiana defines orphan wells as units that are not producing and for which no financially responsible party exists.

Site restoration: Not specifically defined; however, the operator must close tanks or plugging pits; remove drilling and production equipment, above ground flow lines, and debris associated with the well; fill and regrade all excavations; remove contaminated soil; and restore the well site as nearly as practicable to its condition before drilling.

Idle Wells

General requirement(s): An application for Temporary Abandonment must be submitted on a form prescribed by the Division. The application must include information demonstrating the reasons for retaining the well. The owner or operator must ensure that the well does not threaten an underground source of drinking water and report the results of monitoring annually. TA approval may be granted for a period of up to five consecutive years.

Application fee(s): There are no application fees for TA's.

Financial assurance requirement(s): No additional financial assurance required for TA.

Mechanical integrity requirement(s): Yes, a MIT, or the results of a fluid level test via acoustical or wireline measuring methods, are acceptable.

Surface equipment requirement(s): The well must be sealed at surface and any unrelated equipment must be removed from the site.

Other requirement(s): Pits must be filled, and identification posted.

Provisions for exemptions or exceptions: The well must otherwise be in compliance with state rules in order to be approved for TA.

Orphan wells

Actions to identify and address orphan wells: Created a program for landowners to register the wells free of charge for non-commercial uses.

Process for prioritizing orphan wells for plugging: Orphan wells are prioritized for plugging based upon factors such as whether the well is leaking, is within 500' of a residence or commercial building or water well, is in an area subject to frequent flooding, or is open at surface.

KANSAS

Regulatory Agency

Kansas Corporation Commission
266 N. Main Street, Suite 220
Wichita, KS 67202-1513
kcc.ks.gov

Statutory or Regulatory Authority

Citation: K.A.R. 82- 3-111

Last update: October 24, 2008

Substantially Different Definitions

Idle well: Kansas uses the term "temporarily abandoned" for idle wells requiring regulatory approval. If a well is inactive for greater than 90 days, is not granted TA approval, and is not exempt from the TA filing requirements as described below, it is deemed abandoned and must be plugged or returned to operation.

Orphan well: Kansas uses the term "abandoned well," defined as a well that is not claimed on an operator's license that is active with the commission and is unplugged, improperly plugged or no longer effectively plugged.

Idle Wells

General requirement(s): The operator must submit an application for TA on a prescribed form, including basic information on the well construction and operation, shut-in date, casing fluid level, and verification of a lease.

Application fee(s): None.

Mechanical integrity requirement(s): The Commission requires the operator demonstrate mechanical integrity in order for the well to have TA status beyond 10 years.

Surface equipment requirement(s): Commission staff may deny TA applications for lack of surface control.

Other requirement(s): Commission staff may deny TA applications where the operator indicates they no longer have a valid lease.

Provisions for exemptions or exceptions: Wells that are fully equipped and capable of returning to service and that have been in operation within the last 364 days are exempt from filing for TA status.

After 10 consecutive years of TA status, an operator must file an application for an exception to the 10-year limitation. The application has to be published, properly noticed, and the Commission may require a hearing on the application.

Orphan wells

Actions to identify and address orphan wells: Legislation passed in 2021 helped clarify the responsible parties for plugging abandoned wells.

Process for prioritizing orphan wells for plugging: Kansas prioritizes wells by the threat they pose to usable water, either surface or ground, and public safety. The categories are 1A, 1B, 1C, and 2 as outlined in our legislative report here: https://kcc.ks.gov/images/PDFs/legislative- reports/2019-Abandoned-Wells-Report.pdf.

Apps' Ex. 28

0646

KENTUCKY

Regulatory Agency

Department of Natural Resources
Division of Oil and Gas
300 Sower Boulevard
Frankfort, KY 40601
ky.gov

Statutory or Regulatory Authority

Citation: KRS 353.560, KRS 353.562-564, KRS 353.588, KRS 353.590, 805 KAR 1:060

Last update: June 27, 2019

Substantially Different Definitions

Idle well: Kentucky uses the term "temporarily abandoned" (TA) for a well approved by the Division to be idle, and "abandoned" for wells idle without regulatory approval.

Orphan well: "Orphan well" means any oil or gas well which has been determined by the Energy and Environment Cabinet to be improperly abandoned or improperly closed, and that: (1) predates the permitting requirements enacted in 1960, or (2) has no known history of permitting or bonding; and (1) has no known responsible owner or operator or (2) all responsible owners or operators are determined to be financially insolvent.

Idle Wells

General requirement(s): Operators must submit a temporary abandonment application form which must be signed by a Division field inspector. The Division issues a notice to the operator that the application has been granted or denied and specifies an expiration date.

Application fee(s): No fee.

Financial assurance requirement(s): There is no new bonding required for the TA status. The original plugging bond that was filed when the drilling permit was issued is all that is required.

Mechanical integrity requirement(s): Class II wells that remain idle over two years must be plugged, unless an exception is granted pursuant to a request by the operator with notice provided to the Division of steps taken to protect USDW during the idle period.

Surface equipment requirement(s): Well site must be maintained such that wellhead can be accessed and inspected properly to qualify for a TA.

Other requirement(s): All wells on which a TA permit has been issued shall be cased and capped prior to temporary abandonment in a manner to protect all potential oil, gas, and freshwater zones.

Provisions for exemptions or exceptions: No exemptions.

Orphan wells

Actions to identify and address orphan wells: Field inspectors identify and document new orphan wells in the course of their daily well inspections, and in response to citizen reports.

Process for prioritizing orphan wells for plugging: Yes, a rating system that considers presence of active leaks, safety risks, environmental damage, wellhead pressure, access, etc.

LOUISIANA

Regulatory Agency

Department of Natural Resources
PO Box 94275
Baton Rouge, LA 70804-9275
dnr.louisiana.gov

Statutory or Regulatory Authority

Citation: R.S. 43:XIX:101 and 137

Last update: June 2015

Substantially Different Definitions

Idle well: Louisiana classifies wells as "shut-in", "inactive", or "temporarily abandoned."

Shut-In – status given to non-producing wells by the operator to describe well condition, dry hole – future utility, dry hole no future utility, productive future utility, productive no future utility, waiting on pipeline, waiting on market.

Inactive – no reported production, disposal, injection, or other permitted activity for a period greater than six months and is not part of an approved production program.

Temporarily abandoned – all cement plugs set in the well as a permanent abandonment except for the top cement plug.

Orphan well: Orphaned oilfield site means an oilfield site which has no continued useful purpose for the exploration, production, or development of oil or gas and which has been declared to be an orphaned oilfield site by the Assistant Secretary.

Site restoration: Proper plugging and abandonment of orphan wells and return of sites to approximate pre-well site conditions suitable for redevelopment.

Idle Wells

General requirement(s): An inactive future utility well must be plugged within five years of becoming inactive unless the operator pays an annual assessment and provides financial security.

Application fee(s): $250.

Financial assurance requirement(s): Required.

Mechanical integrity requirement(s): No additional requirements.

Surface equipment requirement(s): No additional requirements.

Provisions for exemptions or exceptions: Wells can be exempt from these requirements if they are on an approved production program or an approved schedule of abandonment.

Orphan wells

Actions to identify and address orphan wells: On occasion during inspections, an unidentified wellbore is discovered, for which records are created and the well is placed in the orphan program.

Process for prioritizing orphan wells for plugging: After each orphan well is inspected, the subsequent findings detailed in the Oilfield Site Restoration Inspection Report are utilized by staff to complete an "Orphan Well Prioritizing System Worksheet." Points are assigned based on various factors such wellhead damage, leaks and leakage volume, hazards to navigation, etc. The total score is used to categorize the orphan well in the following manner:

Priority 1 – Urgent >30
Priority 2 – High >19
Priority 3 – Moderate >10
Priority 4 – Low 10 and under

MICHIGAN

Regulatory Agency

Oil, Gas, and Minerals Division
Environment, Great Lakes, and Energy Department
PO Box 30256
Lansing, MI 48909-7756
michigan.gov/egle

Statutory or Regulatory Authority

Citation: Natural Resources and Environmental Protection Act, Act No. 451 of the Public Acts of 1994, as amended - Part 615, Supervisor of Wells and the Administrative Rules and Part 616 Orphan Well Fund

Last update: March 2015

Substantially Different Definitions

Idle well: Michigan classifies idle wells as "Shut-in", "Temporary Abandoned", or "suspension of oil and gas operations."

Shut-in means an action by a permittee to close down a producing well, a well capable of producing, or an injection well temporarily for such things as repair; rework; recovering reservoir pressure; preparing for or evaluating for Enhanced Oil Recovery (EOR) or other injection projects; waiting for connection to a sales line; or lack of a market.

Temporary Abandoned (TA) means a well that has been granted approval to remain idle (not used for its permitted or intended purpose) for more than 12 consecutive months.

Suspension of oil and gas operations is an action by the Supervisor of Wells ordering the permittee to cease operations. Suspension of operation orders are made to protect the public health and safety and the environment, prevent waste, and for compliance and enforcement actions.

Orphan well: An abandoned or improperly closed well for which no owner or operator is known, or for which all owners or operators are insolvent.

Site restoration: Site restoration means the filling and leveling of all cellars, pits, and excavations; the removal or elimination of all debris; the elimination of conditions that may create a fire or pollution hazard; the minimization of erosion; and the restoration of the well site as nearly as practicable to the original land contour or to a condition approved by the supervisor after consulting with the surface owner of the land and with the operator of a natural gas storage field if the well site is within the boundary of a natural gas storage field.

Idle Wells

General requirement(s): Temporary abandonment status shall be allowed only upon written application to, and approval of, the supervisor. Permittee must demonstrate that retaining the well in idle status would not be a risk to public health and safety, cause waste, or harm the environment, and must provide the reasons the well should be granted TA status.

Application fee(s): None.

Financial assurance requirement(s): Supplemental bonds MAY be required. Bond amounts vary based on risk. The well must qualify for TA status for the following reasons: Mechanical back–up to a producing well on the same production unit; future use (deepening or re-completion); conversion to another use; sales line/market connection; processing constraints; EOR evaluation/ conversion; and future use as observation or monitor well.

Not more than 10 percent of a permittee's wells may be TA at any time.

Fluid level shall be checked to make sure it is at least 100 feet below freshwater zones.

To keep wells on TA status for longer time periods, permittees may enter into an agreement. This may include supplemental bonding, MITs, placement of down- hole plugs (mechanical or cement), additional pressure monitoring, or other requirement to reduce risks and prevent waste.

Mechanical integrity requirement(s): MITs may be required for temporary abandoned status to be granted.

Surface equipment requirement(s): Surface equipment must be secured. In some cases, tanks must be emptied.

Other requirement(s): Well sites must continue to be maintained and monitored by permittee; wells with greater than 300 ppm H_2S may require additional measures to protect public health; mineral leases and

other agreements must be maintained; and permit transfers must include a written agreement with the acquiring permittee.

Provisions for exemptions or exceptions: Michigan does not exempt any wells. Exceptions are made during the TA status approval process and are extensions of the approved time interval rather than exceptions.

Orphan wells

Actions to identify and address orphan wells: Primarily react to wells that are leaking or are discovered by landowners.

Process for prioritizing orphan wells for plugging: Michigan prioritizes wells based on risk to the public health and safety and the environment. Leaking wells are the top category and within that category wells are prioritized by level of H_2S, population and institutional sites, resource values affected or at risk such as surface water, wetlands, recreational areas, volume and type of fluid(s) leaking, age and construction of well, etc. The next category are unplugged wells that are not leaking. These are ranked by the risk or potential for the same items as listed above. The third category are plugged wells which have ongoing environmental issues. These are ranked based on the severity of the environmental issue, potential risks, size of the area affected, media impacted such as residential or public water supply well(s), surface water, or wetlands.

MISSISSIPPI

Regulatory Agency

Mississippi Oil and Gas Board
500 Greymont Avenue, Suite E
Jackson, MS 39202
ogb.state.ms.us

Statutory or Regulatory Authority

Citation: Statewide rules 28 and 53

Last update: For Rule 28, 2/21/2017; for Rule 53, 3/22/1990

Substantially Different Definitions

Idle well: Mississippi regulations use the term "inactive" to refer to a well where production or use as a service well has ceased. Mississippi uses the informal terms of "closed in" for idle oil and gas wells and "standby" for idle and EOR wells.

Orphan well: Mississippi defines "orphan well" as an oil or gas well, including Class II wells, which has not been properly plugged and for which a responsible party cannot be located or for which there is no other party which can be directed to plug the well.

Idle Wells

General requirement(s): Operators must file a report on each inactive well. If the well is inactive for 12 months it must be plugged or returned to use, unless the operator petitions for and is granted an extension. EOR wells in an active project are exempt. Inactive wells must comply with all other applicable rules.

Application fee(s): None.

Financial assurance requirement(s): Must be maintained until the well is plugged and abandoned.

Mechanical integrity requirement(s): Injection or disposal wells must pass annual MIT. None for oil or gas wells.

Surface equipment requirement(s): Injection or disposal wells must be equipped with appropriate pressure gauges. None for oil or gas wells.

Orphan wells

Actions to identify and address orphan wells: Attempts have been made to locate the wells but have not been successful.

Process for prioritizing orphan wells for plugging: Wells are prioritized, when necessary, based on danger to human health and the environment.

MONTANA

Regulatory Agency

Board of Oil and Gas Conservation
2535 St. John's Avenue
Billings, MT 59102
dnrc.mt.gov

Statutory or Regulatory Authority

Citation:

ARM 36.22.1303 Well Plugging Requirement
Last Update: 1998

ARM 36.22.1240 Report of Well Status Change
Last Update: 1993

ARM 36.22.1242 Reports by Producers
Last Update: 1993

Substantially Different Definitions

Idle well: Montana has no specific classification for idle wells; however, Montana regulations require a well operator to plug a well within one year after it is no longer capable of production and has no possible future use for EOR or disposal, unless otherwise authorized by the petroleum engineer. Monthly injection or production reports are utilized for idle well analysis.

Site restoration: Montana requires the operator to restore the surface of the location to its previous grade and productive capability and take necessary measures to prevent adverse hydrological effects from the well.

Idle Wells

Requirements for approval: Issues are addressed on a case-by-case basis taking into consideration whether or not the well is pre-regulatory, is located within the boundaries of an active enhanced recovery unit, and if the operator maintains the legal right to utilize the well.

Provisions for exemptions or exceptions: The petroleum engineer may grant an exception to the requirement to plug a well.

Orphan wells

Actions to identify and address orphan wells: File reviews followed by inspection, or inspections alone.

Process for prioritizing orphan wells for plugging: Field inspection ranking based on well status, location, and environmental risk.

NEBRASKA

Regulatory Agency

Nebraska Oil and Gas Conservation
PO Box 399
Sidney, NE 69162
nogcc.ne.gov

Statutory or Regulatory Authority

Citation: Rules, Chapter 3-040

Last update: June 2014

Substantially Different Definitions

Idle well: Nebraska uses the term "inactive well," which can be classified as "shut-in" (perforations open to the wellbore) or "temporarily abandoned" (perforations beneath a mechanical device which are not in communication with the wellbore). When well operations cease for 60 days, the operator must give notice to the Commission of the change to inactive status.

Idle Wells

General requirement(s): Within one year of giving notice of inactive status, the operator must either plug the well or submit request for a one-year extension with static fluid levels, wellhead pressures, and general statement of future use.

Application fee(s): After two years of inactivity, a fee of $200/well/year is required with the request for continued inactivity.

Financial assurance requirement(s): The wells remain bonded until final plugging and abandonment operations have been completed.

Mechanical integrity requirement(s): Annular pressure test can allow a five-year shut-in period.

Provisions for exemptions or exceptions: There are no exemptions for compliance with the rule.

Orphan wells

Process for prioritizing orphan wells for plugging: Yes, endangerment to water, land, or air.

NEVADA

Regulatory Agency

Nevada Division of Minerals
Commission on Mineral Resources
400 West King Street, Suite 106
Carson City, NV 89703-4212
minerals.nv.gov

Statutory or Regulatory Authority

Citation: NAC 522.430

Last update: December 21, 2015

Substantially Different Definitions

Idle well: Nevada classifies idle wells as "shut-in." Nevada regulations require a well in which production casing has been run but which has not been operated for one year, and a well in which no production casing has been run and for which drilling operations have ceased for 30 days, must be immediately plugged.

Site restoration: The operator shall, as soon as conditions permit, upon final abandonment and completion of the plugging of any well, clear the area around the well of all refuse, drain and fill all excavations, remove concrete bases, machinery and materials, and level the surface to leave the site as close to its condition when operations were commenced as practicable.

Idle Wells

General requirement(s): Well must be in compliance with all applicable regulations.

Application fee(s): Sundry notice fee of $100.

Financial assurance requirement(s): Well bonding must be in place.

Mechanical integrity requirement(s): MITs must be conducted for inactive injection wells under the same provisions as for active wells. They must be conducted at least once each five years for the life of an injection well. The Director may require more frequent tests if conditions warrant.

Surface equipment requirement(s): No specific language.

Provisions for exemptions or exceptions: A shut-in extension for a period of one year may be requested through a sundry notice form.

Orphan wells

Actions to identify and address orphan wells: Nevada conducts field observations and review of Google Earth. The Division does coordinate and communicate field observations with the BLM Petroleum Engineer Technician in the BLM's Nevada State Office, as well as personnel in the BLM's District and Field Offices within Nevada, on all aspects of oil and gas activities.

Process for prioritizing orphan wells for plugging: If the well is under bonding through the Division of Minerals, an orphan well matter will be addressed with the operator and landowner as the matter arises.

Apps' Ex. 28

NEW MEXICO

Regulatory Agency

New Mexico Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, NM 87505
emnrd.state.nm.us

Statutory or Regulatory Authority

Citation: 19.15.5 & 19.15.25 NMAC

Last update: February 2020

Substantially Different Definitions

Idle well: New Mexico does not use the term "idle." Instead, New Mexico categorizes unused wells as either "inactive" or "approved temporary abandonment" status.

"Inactive well" means a well that is not being used for production, injection, or monitoring, and is not in approved temporary abandonment status.

Approved temporary abandonment means the well is approved to remain unused, but the operator has demonstrated that the construction and condition of the well will prevent damage to the producing zone, migration of hydrocarbons or water, contamination to fresh water or other natural resources, and leakage at the surface.

Orphan well: This term is not expressly defined under New Mexico regulations. However, if a well has been inactive for one year, enforcement action is taken. If the operator fails to bring the well back into compliance, the well is deemed to be orphaned and the OCD may plug the well. If no funding is available from the operator or well financial assurance, the OCD can use the reclamation fund to plug the well and restore the site.

Site restoration: This term is not expressly defined. However, under OCD regulations the operator must level the location, remove deadmen and other junk, close all pits and below-grade tanks, and take other measures necessary or required by the Division to restore the location to a safe and clean condition.

Idle Wells

General requirement(s): Under OCD rules operators are not allowed to have more than the following number of unused wells, not counting those subject to an Agreed Compliance Order setting a schedule for bringing the wells into compliance:

Two wells or 50 percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;

Five wells if the operator operates between 101 and 500 wells;

Seven wells if the operator operates between 501 and 1,000 wells;

10 wells if the operator operates more than 1,000 wells.

Application fee(s): No additional fee for TA application.

Financial assurance requirement(s): The operator of a well on state or private land that has been inactive for more than two years must file either a single well inactive bond in the amount of $25,000 plus $2 per foot of measured depth, or blanket financial assurance in the following amounts:
First five wells: $150,000.
Six to 10 wells: $300,000.
Eleven to 25 wells: $500,000.
More than 25 wells: $1,000,000.

Mechanical integrity requirement(s): An operator of a well with approved temporary abandonment status must run an MIT, except for a non-injection well that has been completed within five years and has not been connected to a pipeline. Injection wells are subject to additional MIT requirements.

Surface equipment requirement(s): The operator must demonstrate that the well will not cause contamination of fresh water or other natural resources or surface leakage.

Other requirement(s): The operator shall either properly plug and abandon a well or place the well in approved temporary abandonment after drilling operations have been suspended for 60 days, the well has been determined to be no longer usable for beneficial purposes, or the well has been inactive for one year.

Provisions for exemptions or exceptions: Under New Mexico's Marginal Well Shut-In Program operators can apply for approval to shut-in wells for up to four years and three months during times of low commodity prices. Operators must provide economic justification and conduct periodic MITs.

Orphan wells

Actions to identify and address orphan wells: New Mexico conducts routine inspections in the field and replies to any reports of concern.

NEW YORK

Regulatory Agency

New York State Department of Environmental Conservation
Division of Mineral Resources
625 Broadway, 3rd Floor
Albany, NY 12233-6500
dec.ny.gov

Statutory or Regulatory Authority

Citations: (1) Environmental Conservation Law, Article 23; (2) Title 6 of the New York Codes, Rules, and Regulations (6 NYCRR 550-559)

Last update: April 29, 2019, for Environmental Conservation Law and September 6, 1991, for regulations

Substantially Different Definitions

Idle well: Not defined in statute or regulation; see "Idle Wells" below for working definition.

New York classifies idle wells as "shut-in", "temporarily abandoned", and "orphaned."

Shut-in – not defined in regulation but understood to be closing in of a well that has produced on a commercial basis without conducting plugging and abandonment operations.

Temporarily abandoned - the discontinuation of operations on or the closing in of a well not previously produced on a commercial basis without conducting plugging and abandoning operations.

Orphan well: Working definition (not in statute or regulation): unplugged, abandoned wells that have not been operated and maintained in accordance with prevailing statute and regulation, and for which no existing owner can be determined.

Site restoration: Working definition (not in statute or regulation): filling of any excavation used during drilling and smoothing the surface to match adjacent terrain. There may be additional requirements based on site conditions or per contract.

Idle Wells

General requirement(s): Written request for continued idle status (shut-in or temporary abandonment) must be submitted prior to one year for shut-in wells or 90 days for temporarily abandoned wells. Requests are granted upon "demonstration of sufficient good cause" by the operator.

Application fee(s): None.

Financial assurance requirement(s): No additional financial assurance is required.

Mechanical integrity requirement(s): None at present.

Surface equipment requirement(s): None at present.

Other requirement(s): None.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: New York carries out systematic inspections of known and suspected locations; research, evaluation, and collaboration on the use of UAS technologies; and interaction with other state regulators on shared experiences.

Process for prioritizing orphan wells for plugging: The Department systematically inspects locations where orphan wells are known or suspected to exist. The wells are scored using the IOGCC scoring methodology and the scores are used to guide the plugging prioritization process.

Apps' Ex. 28

0656

NORTH DAKOTA

Regulatory Agency

Industrial Commission
600 East Boulevard Avenue, Department 405
Bismarck, ND 58505-0840
dmr.nd.gov

Statutory or Regulatory Authority

Citation: North Dakota Century Code § 38-08-04, North Dakota Administrative Code § 43-02-03-55

Last update: April 1, 2020

Substantially Different Definitions

Idle well: North Dakota classifies idle wells as "inactive" (reported no production or injection for three months), "abandoned" (reported no production or injection for 12 consecutive months), "not completed" (drilled to TD but not completed for 12 months), and "temporary abandoned" (wellbore isolated from target formation, with MIT).

Orphan well: The person or company drilling or operating the well or equipment cannot be found, has no assets with which to properly plug or replug the well or reclaim the site, or cannot be legally required to plug or replug the well or to reclaim the site, pipeline or associated facilities.

Site restoration: North Dakota does not have a specific definition, but North Dakota law requires any land disturbed by construction to be reclaimed as close as practicable to its original condition as it existed before the construction disturbance.

Idle Wells

TA Requirements: Operator must file an application for prior approval. Commission reviews well file and field inspector may approve after MIT. Operator must file follow up report showing completion of requirements for approved TA status.

Application fee(s): $100 for approved renewal.

Financial assurance requirement(s): No more than six wells in TA status greater than seven years, abandoned wells, or plugged and abandoned) wells not properly plugged and/or reclaimed are allowed on blanket bond.

Mechanical integrity requirement(s): Wells must have perforations isolated and pass MIT in the presence of field inspector.

Provisions for exemptions or exceptions: The Commission may periodically grant waivers for wells to remain on inactive status or remain not completed for more than 12 months due to economic conditions.

Orphan wells

Actions to identify and address orphan wells: North Dakota accesses bonding and the Abandoned Oil and Gas Well Plugging and Site Reclamation Fund.

Process for prioritizing orphan wells for plugging: The well, equipment, pipeline, or associated facilities are leaking or likely to leak oil, gas, or saltwater, and/or is a threat to contaminate an Underground Source of Drinking Water (USDW).

The well, equipment, pipeline, or associated facilities are likely to cause a serious threat of pollution or injury to the public health or safety.

There is no bond covering the well to be plugged or the site to be reclaimed, or there is a bond but the cost of plugging or replugging the well exceeds the amount of the bond.

OHIO

Regulatory Agency

Ohio Department of Natural Resources
Division of Oil and Gas Resources Management
2045 Morse Road, Building F
Columbus, OH 43229-6693
ohiodnr.gov

Statutory or Regulatory Authority

Citation: Ohio Revised Code 1509.062 (idle well)
Ohio Revised Code 1509.071 (orphan well)

Last update: June 30, 2010

Substantially Different Definitions

Idle well: Referred to as nonproducing or idle. Temporary inactive status is Ohio's idle well regulatory program.

Orphan well: Ohio uses the term "Idle and orphaned well:" a well for which a bond has been forfeited or an abandoned well for which no money is available to plug the well.

Site restoration: Ohio requires the operator to fill all pits; remove drilling supplies and drilling equipment; grade or terrace and plant, seed, or sod the area; remove all production and storage structures, supplies, and equipment, and any oil, salt water, and debris, and fill any remaining excavations.

Idle Wells

General requirement(s): The well owner and the well must be in compliance with the statute, rules, permit terms and conditions, and applicable orders.

The applicant must demonstrate that the well is of future utility and that applicant has a viable plan to utilize the well within a reasonable period of time; and that the well poses no threat to the health or safety of persons, property, or the environment. In addition, the applicant must provide additional information such as GPS coordinates of all surface equipment, production equipment inventory, and well construction information and annular pressures.

Application fee(s): Nonrefundable $100 for initial application; nonrefundable $250 for first renewal; nonrefundable $500 for each subsequent renewal

Financial assurance requirement(s): The Chief may require a surety bond not to exceed $10,000 for each well after a third renewal of temporary inactive status.

Surface equipment requirement(s): All liquids and gases from all storage tanks, pipelines, and other equipment associated with the well must be emptied.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: The Division purchased a magnetometer to attach to a drone for surveying property to locate orphan wells.

The Division has also completed a memorandum of understanding with the Ohio Department of Transportation to fly a drone with the Division's magnetometer on a full-time basis to locate orphan wells. The Division has financially participated in a high accuracy LiDAR scan of the entire state. The Division intends to use the LiDAR to identify orphan well features. The Division is working with the state's oil and gas associations on data collection by the associations to identify orphan wells. Operators with field knowledge of potential orphan wells are reporting them in an organized manner to the Division.

Process for prioritizing orphan wells for plugging: The Division has a scoring matrix for determining the priority of plugging wells that includes high priority, medium priority, and low priority classifications.

The scoring matrix evaluates human health, safety, and environmental risk factors on a weighted basis to establish a plugging priority. Wells are given a classification and a separate overall score.

OKLAHOMA

Regulatory Agency

Oklahoma Corporation Commission
PO Box 52000
Oklahoma City, OK 73152-2000
www.occeweb.com

Statutory or Regulatory Authority

Citation: Oklahoma Administrative Code (OAC) Title 165: Corporation Commission Chapter 10: Oil and Gas Conservation 165:10-11-3

Title 165: Corporation Commission Chapter 5. Rules of Practice 165:5-7-39

Last update: Effective October 2020, are reviewed and updated on a regular basis

Oklahoma Statutes, Title 52-310

Substantially Different Definitions

Idle well: May be classified as shut-in, Temporarily Abandoned (TA), or inactive.

Orphan well: Oklahoma does not have a specific definition; however, the Commission considers a well an orphan when the company is out of business and the state is left with the responsibility of plugging.

Site restoration: Within 90 days after a well is plugged and abandoned, the well site shall be cleared of all equipment, trash, and debris. Any foreign surface material is to be removed and the location site restored to as near to its natural state as reasonably possible, except by written agreement with the surface owner. If the vegetative cover is destroyed or significantly damaged, a bona fide effort shall be made to restore or re-establish the vegetative cover within 180 days after abandonment of the well.

Idle Wells

General requirement(s): All wells listed as shut-in, TA, or inactive are deemed a well in operation and must meet all of the requirements for such: proper lease signs, removal of junk, trash, and debris, and removal of fire hazards, and the lease road shall be maintained at all times for any emergency vehicles and OCC field staff ingress and egress.

Application fee(s): No fees for shut-in or inactive wells; $100 for Temporary Exemption from Well Plugging.

Financial assurance requirement(s): All operators must have valid Cat. A or B surety of minimum of $25,000.00, for all their wells, this can be increased to $100,000.00 through notice and hearing if an operator demonstrates a poor track record with Commission rules. Some Commercial SWD well sites may be required to have a higher surety depending on the size of the facility and associated pits.

Mechanical integrity requirement(s): All MITs must be kept up to date.

Surface equipment requirement(s): Must be maintained to prevent pollution or trash and debris.

Other requirement(s): All idle well must be maintained as if they are active.

Provisions for exemptions or exceptions: Temporary Exemption from Plugging (Form 1003A) for any Oil or Gas wells. Any exceptions (other than a Temporary Exemption from Plugging) would be through application and hearing and would be issued (if approved) by an order of the commission.

Orphan wells

Actions to identify and address orphan wells: Oklahoma conducts ongoing record searches and site inspections. Oklahoma is developing a drone program and preparing to perform magnetometer surveys of areas where there have been numerous unknown wells located in the past.

Process for prioritizing orphan wells for plugging:

Category 1. Life Threatening
Category 2. Emergency: potential environmental pollution. Category 3. Potential danger to personal property.
Category 4. Not life threatening and is not an immediate danger to environment or personal property.
Category 5. No immediate danger: conditions have existed for many years and pose no immediate danger.

PENNSYLVANIA

Regulatory Agency

Department of Environmental Protection
PO Box 8765
Harrisburg, PA 17105-8765
(717) 772-2199
dep.pa.gov

Statutory or Regulatory Authority

Citation: 58 Pa.C.S. §§ 3203, 3213, 3214, 3220 and 3271

Last update: 2021

Substantially Different Definitions

Idle well: Although Pennsylvania does not have a definition for "idle" wells, the state has historically classified "idle" wells as either "abandoned" (see definition, below) or "inactive" (upon application, a well may be granted this status if it is mechanically sound and intended to be put back into production, among other requirements. However, the "idle" well classification is most appropriate for "inactive" wells, which encompasses wells in the Commonwealth that are legally eligible for deferred plugging requirements because they have a demonstrated future utility.

Abandoned well: A well (1) that has not been used to produce, extract or inject any gas, petroleum or other liquid within the preceding 12 months; (2) for which equipment necessary for production, extraction or injection has been removed; or (3) considered dry and not equipped for production within 60 days after drilling, redrilling or deepening. The term does not include wells granted inactive status.

Orphan well: "Orphan well" is defined as (1) an abandoned well or (2) a well abandoned prior to April 18, 1985, that has not been affected or operated by the present owner or operator and from which the present owner, operator or lessee has received no economic benefit other than as a landowner or recipient of a royalty interest from the well.

Site restoration: Although Pennsylvania does not have a definition of "site restoration," well operators are required to implement erosion and sedimentation control measures, restore the well site, remove or fill all pits, remove all supplies and equipment, and return the site to approximate original contours and capable of supporting the uses that existed prior to drilling the well.

Idle Wells

General requirement(s): To obtain inactive status, the applicant shall affirmatively demonstrate to the Department's satisfaction that the condition of the well is sufficient to prevent damage to the producing zone or contamination of fresh water or other natural resources or surface leakage; stop the vertical flow of fluid or gas within the well bore; protect fresh groundwater; and pose no threat to the health and safety of persons, property or the environment. The operator must demonstrate that the well has future utility, and the well must have an appropriate bond.

Application fee(s): None.

Financial assurance requirement(s): No additional financial assurance is required for idle wells.

Mechanical integrity requirement(s): An operator granted inactive status shall monitor the integrity of the well on an annual basis.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: Pennsylvania's statute requires abandoned/orphan wells to be reported to DEP and they are investigated as reports are filed by third parties.

Process for prioritizing orphan wells for plugging: Pennsylvania prioritizes wells based on a scoring system which considers environmental, health and safety concerns.

SOUTH DAKOTA

Regulatory Agency

Department of Agriculture and Natural Resources
2050 West Main, Suite One
Rapid City, SD 57702
danr.sd.gov

Statutory or Regulatory Authority

Citation: ARSD 74:12:03:03

Last update: January 12, 2012

Substantially Different Definitions

Idle well: South Dakota uses the term "temporarily abandoned wells." Temporarily abandoned wells are defined as wells that have not produced or injected for a period of six or more months. South Dakota also uses the term "Shut-In" for wells that are idle for a period of six months or less.

Orphan well: South Dakota does not have a specific definition.

Idle Wells

General requirement(s): Written approval must be obtained from the Secretary of the Department of Agriculture and Natural Resources for the temporary abandonment of a well. A well that is not completed with production casing may not be temporarily abandoned and must be plugged immediately. A well with production casing may not be temporarily abandoned for more than six months, unless the operator is granted an extension by the Secretary.

Before approving a request for extension, the Secretary may require mechanical integrity testing of the temporarily abandoned or shut-in well.

A temporarily abandoned or shut-in well that successfully passes a MIT may not be required to undergo another test for five years unless the Secretary finds that circumstances have substantially changed to alter the condition of the well.

The manner in which the well is to be maintained must be reported to and approved by the Secretary. Bonding requirements must be met until the well is permanently abandoned.

Application fee(s): None.

Financial assurance requirement(s): The Department of Agriculture and Natural Resources and the Board of Minerals and Environment have the authority and discretion to require an additional $20,000 in surety for each well that is idle or inactive for more than six months.

Mechanical integrity requirement(s): Before approving a request for extension, the Secretary may require a MIT of the temporarily abandoned or shut-in well. A temporarily abandoned or shut-in well that successfully passes a mechanical integrity test may not be required to undergo another test for five years unless the Secretary finds that circumstances have substantially changed to alter the condition of the well.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: Currently it is believed there are no undocumented or unidentified orphan wells.

Process for prioritizing orphan wells for plugging: None.

TEXAS

Regulatory Agency

Railroad Commission of Texas
PO Box 12967
Austin, TX 78711
rrc.state.tx.us

Statutory or Regulatory Authority

Citation: Texas Natural Resources Code 89.023 and 89.024

16 Texas Administrative Code 16 TAC §§ 3.14 (b)(2) and 3.15(a)(6)

Surface Equipment Removal Requirements and Inactive Wells SWR 3.15

Plugging- SWR 3.14

Last update: Amended to be effective January 1, 2017

Substantially Different Definitions

Idle well: Classification: Texas uses the term "Inactive Well:" an unplugged well that has been spudded or has been equipped with cemented casing and that has no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months.

Idle Wells

General requirement(s): In order to obtain a plugging extension:
Operator must maintain a valid Organization Report.
Operator must have a good faith claim to continue to operate the well.

Well must be in compliance with Commission rules and regulations.

Application fee(s): Fees apply in certain circumstances outlined below.

Financial assurance requirement(s): To obtain a plugging extension the operator must select one of eight options for each inactive well:

An Operator may select one of the following "Blanket" options: 10 percent Plugged/Restored at the time of the last annual renewal of the operator's Organization Report – Form P-5;

Blanket additional financial security covering the amount of the cost calculation for plugging all inactive wells or $2 million dollars, whichever is less;

If the operator is a publicly traded entity as the "debtor" and the Commission as the "secured creditor"

OR

An Operator may select one of the following "Individual Well" options:

- An Abeyance of Plugging Report covering the inactive well plus a fee of $250.00
- An Abeyance of Plugging Report is a document prepared by a professional engineer or geoscientist which certifies that the well may be ultimately restored to production
- Enhanced Oil Recovery (EOR) project status (if eligible) – EOR is defined as a project that uses any process for the displacement of oil or other hydrocarbons from a reservoir other than primary recovery and includes the use of an immiscible, miscible, chemical, thermal, or biological process.
- Integrity Test – performed on an inactive well not otherwise required by Commission rule to be tested plus a fee of $125.00.
- Additional approved financial security - supplemental bond, letter of credit, or cash deposit in an amount equal to the estimated plugging cost based on the average per foot cost, by district, for state funded plugging operations in the previous fiscal year.
- Escrow deposit – cashier's check in the amount of 10 percent of the estimated plugging cost based on the average per foot cost, by district, for state funded plugging operations in the previous fiscal year.

Mechanical integrity requirement(s): For a well more than 25 years old, the operator successfully conducts and the Commission or its delegate approves a fluid level or hydraulic pressure test establishing that the well does not pose a potential threat of harm to natural resources, including surface and subsurface water, oil, and gas.

Surface equipment requirement(s): The operator must comply with surface equipment removal requirements based on the age of the inactive well.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: Unknown or unidentified wells are brought to the Commission's attention through discovery by an inspector on a routine inspection, or through a complaint being filed. Once brought to the Commission's attention, a thorough research effort is conducted on all available records in the Central Records department and the district office. This includes mainframe system data, historical maps, run tickets, etc.

Process for prioritizing orphan wells for plugging: Prioritization system considers well completion, wellbore conditions, well location with respect to sensitive areas, and various environment, safety, or economic concerns. Wells posing greatest threat to public safety and the environment are plugged first.

UTAH

Regulatory Agency

Utah Department of Natural Resources
Division of Oil, Gas and Mining
PO Box 145801
Salt Lake City, UT 84114-5801
naturalresources.utah.gov

Statutory or Regulatory Authority

Citation: Utah Administrative Code R649-3-36

Last update: 2003

Substantially Different Definitions

Idle well: Utah uses the terms "Shut-in" and "temporarily abandoned."

Shut-in Well means a well that is completed, is shown to be capable of production in paying quantities and is not presently being operated.

Temporarily Abandoned Well means a well that is completed, is shown not capable of production in paying quantities, and is not presently being operated.

Orphan well: Utah uses the term "abandoned" to describe a well for which there is no reclamation surety or the forfeited surety is insufficient for plugging and reclamation.

Site restoration: The operator must meet the restoration requirements of a federal, Indian, or state landowner. If the operator cannot agree on restoration with a private landowner, the Division may establish minimum restoration requirements, which shall consider the condition of the land prior to disturbance, the extent of proposed disturbance, the difficulty to conduct complete restoration, the potential for pollution, the requirements for abating pollution, and the possible land use after restoration is completed.

Idle Wells

General requirement(s): If a well is to be shut-in or temporarily abandoned for a period exceeding 12 consecutive months, the operator shall file a Sundry Notice providing the following information:

Reasons for shut-in or temporarily abandonment of the well.

The length of time the well is expected to be shut-in or temporarily abandoned.

- An explanation and supporting data, showing the well has integrity, meaning that the casing, cement, equipment condition, static fluid level, pressure, existence or absence of USDW and other factors do not make the well a risk to public health and safety or the environment.

Application fee(s): None.

Financial assurance requirement(s): If the Division finds that a well is in violation of shut-in and temporarily abandoned well requirements, or if the minimum well site restoration requirements suggest to the Division that bond coverage for a well should be increased, the Division shall require a bond amount in the amount of actual plugging and site restoration costs.

Provisions for exemptions or exceptions: A well may be initially shut-in or temporarily abandoned for a period of twelve consecutive months without additional requirements.

Orphan wells

Actions to identify and address orphan wells: Utah inspects and investigates areas of historic oil and gas activity and looks at old reports to try to ensure all undocumented wells have been captured. Utah grids off areas for inspection. Utah will also be using drone technology to help with this process.

Process for prioritizing orphan wells for plugging: Yes.

VIRGINIA

Regulatory Agency

Department of Mines, Minerals and Energy
Division of Gas and Oil
3405 Mountain Empire Road
Big Stone Gap, VA 24219
dmme.virginia.gov

Statutory or Regulatory Authority

Citation: Virginia Gas and Oil Regulations 4VAC25- 150-390. Shut-In Wells

Last update: December 2016

Substantially Different Definitions

Idle well: Only classification Virginia has for nonproducing wells is "shut-in."

Orphan well: The Code of Virginia defines an orphaned well as a well abandoned prior to July 1, 1950, or a well for which no records exist concerning drilling, plugging, or abandonment.

Site restoration: The Code of Virginia defines restoration as all activity required to return a permitted site to other use after gas, oil, or geophysical operations have ended, as approved in the operations plan for the permitted site.

Idle Wells

General requirement(s): If a well is shut-in or otherwise not produced for a period of 12 consecutive months, the permittee shall measure the shut-in pressure on the production string or strings and report such pressures to the Division annually. If the well is producing on the backside or otherwise through the casing, the permittee shall measure the shut-in pressure on the annular space.

Should the well remain in a nonproducing status for a period of two years, the permittee shall submit a plan for future well production to the director. A nonproducing well shall not remain unplugged for more than a three-year period unless approved by the director.

Application fee(s): There is no fee. Shut-in wells are reported annually as part of each company's Annual Report.

Financial assurance requirement(s): Bonding and financial security required as for other wells.

Provisions for exemptions or exceptions: A nonproducing well shall not remain unplugged for more than a three-year period unless approved by the director.

Orphan wells

Actions to identify and address orphan wells: Information about the Orphaned Well Fund and instructions on how to report an abandoned well is provided on the Division website.

Process for prioritizing orphan wells for plugging: Prioritization is based on an assessment of risk to public safety and environmental impact.

WEST VIRGINIA

Regulatory Agency

West Virginia Department of Environmental ProtectionOffice of Oil and Gas
601 57th Street, Southeast
Charleston, WV 25304
dep.wv.gov

Statutory or Regulatory Authority

Citation: W. Va. Code Section 22-6-19, 22-10 and 35CSR5

Last update: 1993 for 35 CSR 5 and 2013 for 22-6

Substantially Different Definitions

Idle well: West Virginia uses the term "abandoned" (a well completed as a dry hole or is not in use for twelve consecutive months) and "inactive."

Abandoned wells: A well which is completed as a dry hole or which is not in use for a period of twelve consecutive months shall be presumed to have been abandoned and shall promptly be plugged by the operator, unless the operator furnishes satisfactory proof to the director that there is a bona fide future use for such well.

Inactive wells: For any well which is not in active (in use) status, an operator must demonstrate bona fide future use to avoid having such well deemed abandoned. Upon submittal of a completed designation of bona fide future use to the chief, any permitted well which satisfies the requirements shall be deemed to be in inactive status.

Site restoration: West Virginia refers to the activity defined as reclamation, which includes recontouring and revegetating the site.

Idle Wells

General requirement(s): For any well which is not in active status, an operator must demonstrate bona fide future use to avoid having such well deemed abandoned.

Upon submittal of a completed designation of bona fide future use to the chief, a permitted well which satisfies the following requirements shall be deemed to be in inactive status:

- The condition of the well is sufficient to prevent waste of oil and gas.
- The condition of the well is sufficient to prevent pollution of waters of the state.
- Report production annually as zero.

Application fee(s): There are no fees required for the filing of a Bona Fide Future Use request.

Financial assurance requirement(s): The operator must satisfy the standard bonding requirements.

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: Inspector's document and inspect potential orphan wells as they are discovered. Operators may identify and plug wells in the Area of Review for horizontal wells.

Process for prioritizing orphan wells for plugging: Yes, wells are classified by actual or potential threats to human health and safety or the environment.

WYOMING

Regulatory Agency

Oil and Gas Conservation Commission
PO Box 2640
Casper, WY 82602
wogcc.wyo.gov

Statutory or Regulatory Authority

Citation: Chapter 3, Sections 4, 16 and 22

Last update: March 2016

Substantially Different Definitions

Idle well: Wyoming uses the terms "shut-in" and "temporarily abandoned."

Shut-In Well shall mean a well not currently considered active in which the completion interval has not been isolated from the wellbore above and where the wellbore condition is such that its utility may be restored by opening valves or by energizing equipment involved in operating the well.

Temporarily Abandoned Well shall mean a well in which the completion interval has been isolated from the wellbore above and the surface. The completion interval may be isolated by a retainer, bridge plug, cement plug, tubing and packer with tubing plug, or any combination thereof.

Idle Wells

General requirement(s): Operator must request the Supervisor's approval every two years for a well to remain idle. The agency also does an annual idle well plan review for each operator to determine which wells are idle and if the operator has plans to plug or produce the idle wells during the next year. If there are no plans and if the well has been idle at least one year the agency may require idle well bonds be posted.

Application fee(s): None.

Financial assurance requirement(s): An operator can post either individual well bonds at $10/ft based on total depth or an operator's blanket bond of $100,000. If they have posted an operator blanket bond, as part of the annual idle well review the agency determines if additional bond is necessary (in excess of the $100,000) based on the total footage of idle wells which have no plans to plug or produce. The additional idle well bond is calculated at $10/ft based on total depth.

Mechanical integrity requirement(s): MIT required every five years that the well is idle with testing requirements the same as our UIC program.

Provisions for exemptions or exceptions: None.

Orphan wells

Process for prioritizing orphan wells for plugging: The agency prioritizes wells based on environmental or public health/safety risk. Agency natural resources staff and agency management review orphan well list and plan an annual plugging program based on this risk.

The agency may also consider wildlife issues, such as if the wells are in sage grouse core area or wildlife migration routes. If no wells are determined to pose an increased risk to environment/public then remainder of wells are prioritized based on length of time well has been orphan and other wells in geographic area that may be included as part of a bid package for plugging.

Apps' Ex. 28

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ALBERTA

Regulatory Agency

Alberta Energy Regulator
Suite 1000, 250 – 5th Street SW Calgary,
Alberta T2P 0R4
aer.ca

AER can assign care and custody of orphan wells to the Alberta Orphan Well Association (OWA) which is responsible to conduct closure work.

Statutory or Regulatory Authority

Citation: Directive 013: Suspension Requirements for Wells

Last update: December 20, 2016

Substantially Different Definitions

Idle well: Alberta classifies idle wells as "inactive" (no longer active and has not been properly plugged and abandoned) and "suspended" (meeting requirements to leave inactive in perpetuity).

Orphan well: A well, facility, or pipeline in the Licensee Liability Rating program is eligible to be declared an orphan when the licensee of that license becomes insolvent or defunct. Once it determines a party responsible for costs of a well, facility, or pipeline does not exist, cannot be located or does not have the financial means to contribute to those costs, the AER will designate the well, facility, or pipeline as an orphan for all aspects of this program: suspension, abandonment, remediation, and reclamation.

Site restoration: Alberta uses the term "reclamation," which means: removal or decontamination of equipment or structures; decontamination of land or water; stabilization and contouring of the surface; and any other requirement specified in regulations.

Idle Wells

General requirement(s): There are currently no programs that are only specific to idle (inactive) wells. There are liability management programs that are in place to address a number of issues including inactive infrastructure.

Application fee(s): None.

Financial assurance requirement(s): None.

Mechanical integrity requirement(s): As outlined in Directive 013 for suspension.

Surface equipment requirement(s): As outlined in Directive 013 for suspension.

Other requirement(s): None.

Provisions for exemptions or exceptions: Wells that are excluded from meeting suspension requirements are:

- Wells with a license status of Re-Entry, Abandoned, RecCertified, and RecExempt;
- Observation wells;
- Geothermal wells (used only for HVAC heating purposes);
- Training wells; and
- Farm wells.

Orphan wells

Actions to identify and address orphan wells: The province takes action to identify the possible owner on the occasion of an undocumented well being identified.

Process for prioritizing orphan wells for plugging: The OWA takes a risk informed approach to assessing its inventory and determining the priority actions that need to be taken in order to ensure public safety and environmental protection while efficiently closing the orphan inventory.

BRITISH COLUMBIA

Regulatory Agency

Oil and Gas Commission
PO Box 9331 Stn Prov, Govt.
Victoria, B.C., V8W 9N3
bcogc.ca

Statutory or Regulatory Authority

Citation: Oil and Gas Activities Act: B.C.

Drilling and Production Regulation: B.C. Dormancy and Shutdown Regulation: B.C. Environmental Protection and Management Regulation: B.C.

Last update: May 2019 New regulation – May 2019

Substantially Different Definitions

Idle well:

Inactive well – a well that has had no activity (production, disposal, drilling, completion, or monitoring) for 12 consecutive months.

Suspended well – an inactive well that has been suspended in accordance with regulations. Depending on the well type, this may involve the installation of temporary or permanent plugs and pressure testing.

Abandoned well – a well that has been permanently plugged, cut and capped below the ground surface.

Dormant well – a well that has not met a threshold of activity each year for five or more consecutive calendar years. This definition came into effect in 2019 so wells that had five years of inactivity prior to this were not considered dormant prior to 2019.

Orphan well: The Commission may designate a well and associated operating area as an orphan site if the operator is insolvent or can't be identified or located.

Site restoration: British Columbia describes "restoration" in legislation, though there is no specific definition.

An operator must perform specific obligations upon cancellation or suspension of a permit, including restoration actions that the Commission orders. A site is deemed restored if the site is remediated and reclaimed and is approved by the Commission. A site is remediated once the Commission is satisfied that contamination and residual risks are below the threshold levels.

Idle Wells

General requirement(s): Inactive well suspension requirements.

All wells must be suspended within 60 days of obtaining inactive status. Once suspended, the operator must establish a program of inspections sufficient to ensure the ongoing integrity of the well and must maintain records of these inspections. The Commission publishes a manual with the following guidance:

- Wells and wellsites must be inspected, wellhead valves must be chained and locked, flow lines must be disconnected and there must be no open-ended lines except for the surface casing vent.
- Medium and high-risk wells including disposal wells, sour gas wells (based on flowrate and H_2S content), wells with a flow rate >1,000,000 cubic feet/day and all wells that have been inactive for 10+ years must have downhole plugs installed (bridge plug or packer and tubing plug). Casing and tubing must be pressure tested as applicable.
- For low risk wells, service and inspect the wellhead and record the casing and tubing pressure as applicable. Wells with no open perforations must be pressure tested.
- All suspended wells must be inspected at least once per year and pressure tests must be completed every three to five years.

Application fee(s): None.

Financial assurance requirement(s): Not specific to individual wells. The Commission has a Liability Management program that considers the assets and liabilities of an operator's permits. If liabilities exceed assets, a security deposit is required. The Commission is also in development of a Permittee Capability Assessment, evaluating permit holders for financial and regulatory risk, that defines future security deposit requirements. Implementation of the PCA is planned for April 1, 2022.

Provisions for exemptions or exceptions: Wells may be exempted from suspension requirements on a case-by-case basis.

Orphan wells

Actions to identify and address orphan wells: A study was conducted in 2011 and 2014 for identification of wells drilled prior to legislative frameworks. Aerial photo analysis and field visits were conducted to identify wells documented in historical records.

Process for prioritizing orphan wells for plugging: The Orphan Site Reclamation Fund is financed by an Orphan Site Restoration Levy which charges an annual levy to each relevant permit holder based on its share of total liability in the province. Orphan wells are prioritized through the Orphan Site Protection and Restoration Plan.

NORTHWEST TERRITORIES

Regulatory Agency

Office of the Regulator of Oil and Gas Operations (OROGO)
orogo.gov.nt.ca

Statutory or Regulatory Authority

Citation: Oil and Gas Operations Act S.N.W.T. 2014, c.14

Last update: 2015 (S.N.W.T. 2019, c.24)

Substantially Different Definitions

Idle well: Well Suspension and Abandonment Guidelines and Interpretation Notes refer to a status of "no production/injection/disposal" or "no use of the well for its original intended purpose."

Regulations define a suspended well as "a well or part of a well in which drilling, or production operations have temporarily ceased."

Orphan well: No provincial definition.

Site restoration: OROGO only regulates well abandonment. It does not regulate site restoration and remediation, which is the responsibility of land and water boards established under the Mackenzie Valley Resource Management Act. Therefore, OROGO's legislation does not define "site restoration."

Idle Wells

General requirement(s): To suspend or abandon a well, an operator must obtain an Operations Authorization and a Well Approval. On a go-forward basis, OROGO's policy is that all operators of suspended wells must have an Operations Authorization until the well is fully abandoned (i.e., the Operations Authorization must be in place from drilling to abandonment).

Application fee(s): None.

Financial assurance requirement(s): Not specific to idle wells. OROGO holds Proof of Financial Responsibility (PFR) associated with each Operations Authorization. PFR can be used in specific circumstances to compensate third parties (including government) for loss or damages or costs associated with the cleanup of spills and debris from operations. Spills are limited to spills of petroleum only. PFR does not cover the cost of abandoning wells without an operator.

Mechanical integrity requirement(s): The operator shall ensure that every well that is suspended or abandoned can be readily located and is left in a condition that (a) provides for the isolation of all oil or gas bearing zones and discrete pressure zones and, in the case of an onshore well, potable water zones, and (b) prevents any formation fluid from flowing through or escaping from the well-bore.

The Guidelines further clarify the mechanical requirements for the suspension of different types of wells.

Surface equipment requirement(s): The Guidelines state that surface equipment must be removed within 12 months of cutting and capping the well.

Other requirement(s): The operator of a suspended well shall ensure that the well is monitored and inspected to maintain its continued integrity and to prevent pollution.

The Guidelines further clarify the expectations for frequency and type of monitoring, based on the risk classification of the well and the suspension methodology used.

Provisions for exemptions or exceptions: Operators may suggest alternative approaches for the Regulator's consideration if they meet or exceed the standards set in the Guidelines for the protection of human safety and the environment.

Orphan wells

Actions to identify and address orphan wells: NWT has no orphan wells.

Process for prioritizing orphan wells for plugging: N/A

SASKATCHEWAN

Regulatory Agency

Saskatchewan Ministry of Energy and Resources
saskatchewan.ca

Statutory or Regulatory Authority

Citation: Oil and Gas Conservation Regulations, 2012 (OGCR)

Last update: OGCR sections dealing with "end of life" obligations of oil and gas companies regarding wells, facilities and associated flowline will be replaced by new regulations – The Financial Security and Site Closure Regulations in Fall of 2022.

Substantially Different Definitions

Idle well: Saskatchewan has a well completion status of "suspended" which is set by the operator and has no requirements or stipulation as to when it is or can be set other than the well completion cannot be producing or injecting. No volumetric reporting is required on a suspended well.

However, Saskatchewan has defined an Inactive Well. An inactive well is classified as a well that has not reported production, injection, storage injection, or storage recovery within the last 12 months; the well has not been abandoned (cut and capped); and the well does not have a spud date or the spud date is not within the last 12 months.

Orphan well: A well, facility, or associated flowline or site, if the responsible person does not exist. cannot be located or does not have the financial capability to comply with requirements.

Site restoration: reclamation" means the process of:

- Decontaminating, excavating, removing, sequestrating, encapsulating, immobilizing, attenuating, degrading, processing or treating the contaminants in the soil or water in a manner so that, in the opinion of the minister, the contaminants no longer pose a threat or risk to human health, public safety, property or the environment; and
- Re-contouring, landscaping, replacing or replenishing the topsoil and re-vegetating the surface of the soil so that it is compatible with its surroundings.

Idle Wells

Provisions for exemptions or exceptions: None.

Orphan wells

Actions to identify and address orphan wells: Through the Licensee Liability Rating Program, ER monitors the financial health of oil and gas licensees. If a licensee is unable to meet its financial obligations related to costs associated with end-of -life obligations, ER may deem wells, facilities and associated pipelines to be orphaned and those would be transferred to the Orphan Well Fund for abandonment and reclamation.

Process for prioritizing orphan wells for plugging: Established each year through consultations with the Orphan Fund Advisory Committee, which is appointed by the Minister and includes representatives of several industry associations.

YUKON

Regulatory Agency

Yukon Government – Oil and Gas Resources
Suite 400, 211 Main Street,
4th Floor Shopper's Plaza
Whitehorse, YT Y1A 2B2.
(867) 667-3011
emr.gov.yk.ca

Statutory or Regulatory Authority

Citation: Yukon Oil and Gas Act

Yukon Oil and Gas Drilling and Production Regulations

Last update: Yukon Oil and Gas Act, December 2015

Substantially Different Definitions

Idle well: Yukon requires the licensee of a well that has never been completed, or of a well that has not produced or been used for injection in a 12-month period, shall ensure that the well is suspended or abandoned.

Suspended refers to a well for which drilling or production operations have temporarily ceased and which is in such a condition that formation fluid is prevented from flowing through or escaping from the well bore and no pressure is detected at the surface. A completed well that is suspended must have a down-hole mechanical plug and a tubing plug at the surface which are pressure-tested.

Abandoned refers to a well that has been permanently plugged and whose well site has been cleaned up.

Orphan well: No provincial definition. Yukon Oil and Gas Act provides for Chief Operations Officer to order that the well be abandoned at Government expense if the licensee of the well fails meet its obligations, which may result from the licensee being insolvent.

Site restoration: No provincial definition; however, regulations define "clean–up" as removal of all solid and petroleum waste, cleanup of surface, plugging of rat and mouse holes, removal of equipment and materials, and filling of excavations.

Idle Wells

Requirements for approval:

General requirement(s): Wells must be suspended after 12 months or more of no production or injection operations, put back into operation, or abandoned within three years of the date of suspension or otherwise as directed by the Regulator (COO).

A suspended well must be inspected once every 12 months.

Application fee(s): A Well Operation Approval is required for well suspension/abandonment. Application fee is $500.

Financial assurance requirement(s): Licensee required to submit an updated Corporate Profile every year to the Regulator.

Provisions for exemptions or exceptions: The Chief Operations Officer may approve an extension of length of time for suspension prior to abandonment.

Orphan wells

Process for prioritizing orphan wells for plugging: None.

LIST OF FIGURES

Figure 1. Period a Well May Remain Idle Before Approval is Required 10

Figure 2. Number of Approved Idle Wells (2020) 11

Figure 3. Trend in State Reports of Documented Orphan Wells 12

Figure 4. Documented Orphan Wells in States (2020) 13

Figure 5. Documented Orphan Wells with Known Operators (2020) 14

Figure 6. Estimated Undocumented Orphan Wells in States (2020) 15

Figure 7. Wells Plugged in States 15

Figure 8. Wells Plugged in Provinces 16

Figure 9. Orphan Wells Plugged in States and Provinces 17

Figure 10. Orphan Well Plugging Expenditures in States 18

Figure 11. Funding Sources for Plugging Orphan Wells, States and Provinces 19

Figure 12. Types of Financial Assurance Accepted by States and Provinces 20

Figure 13. Status of State Efforts to Document and Plug Orphan Wells 26

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7 Interstate Oil and Gas Compact Commission, 2019. *Summary of State Statutes and Regulations.*

8 Interstate Oil and Gas Compact Commission, 2018. *Transfer of Infrastructure and Liabilities - Assessment Criteria and Considerations Toolbox for State and Provincial Regulators.*

9 Interstate Oil and Gas Compact Commission, 2019. *Resolution 19.054 Urging the United States Congress to Amend the Oil Pollution Act of 1990 to Provide That Surface Owners and Royalty Interest Owners, Who Have Not Produced or Participated in Ownership of a Well Located on Their Surface Estate, May Not be Considered Responsible Parties by the United States Coast Guard's National Pollution Funds Center When Funds from the Oil Spill Liability Trust Fund Are Spent to Plug the Well.*

10 Infrastructure Investment and Jobs Act, Public Law No: 117-58, Section 40601, *Orphaned Well Site Plugging, Remediation, and Restoration.*

Apps' Ex. 28

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iogcc.ok.gov

Apps' Ex. 28

EXHIBIT 29

DWAYNE C. PURVIS, P.E.

1227 West Magnolia Ave, Suite 100
Fort Worth, TX 76104

O: 817-241-8501, ext. 901
C: 817-939-6468
dpurvis@purvisenergyadvisors.com

EXECUTIVE PROFILE: From Oil and Gas Leadership to Research in the Energy Transition

- Leading interdisciplinary technical and strategic analyses of oil and gas, energy industry, and commodity price issues. Forming recommendations for decision-makers in the United States and abroad for 30 years, including defense of conclusions in contested settings.
- Management, entrepreneurial, and executive experience over nearly three decades.
- Five highly reviewed technical courses and graduate level academic courses taught to hundreds of professionals. Adjunct professor in nationally ranked Energy MBA program. Mentored and trained young professionals formally and informally.
- Extensive speaking and writing on technical and strategic issues to local, regional and national meetings. Host of decarbonization conferences for the oil industry. SPE Distinguished Lecturer 2024-2025.
- Early engagement in decarbonization of oil and gas. Recently completed Master of Arts in Sustainable Energy at Johns Hopkins University.

EXPERIENCE

Founder and Principal Advisor
PURVIS ENERGY ADVISORS 2015 – present

Founded and lead petroleum engineering consulting practice, including multidisciplinary field studies, reserves analysis, strategic planning, teaching, and research. Research, writing and speaking on energy transition and decarbonization issues. Diverse client base including private, PE-backed, public companies, and NGOs on projects across the United States and in Canada. Highlights include:

Engineering and corporate leadership

- Led or leading analyses of paying for statewide decommissioning liabilities in California, Ohio, Pennsylvania and West Virginia.
- Led exploration and operations team for new plays in an old basin, including basin-wide integrated geologic and engineering study then led subsequent operations, proving extensive resource.
- Quantified risks and opportunities for circumspect handling of potential acquisitions of up to hundreds of millions of dollars.
- Advised public company on engineering matters through bankruptcy and liquidation.
- Evaluated greenfield microdarcy reservoir and advised participation, now proven highly productive. Designed and sold brownfield waterflood redevelopment project.

Influence and thought leadership

- Speak frequently for industry organizations at local, regional, and national meetings on strategic and technical topics including decarbonization, decommissioning, shale resources, peak oil demand, and the natural gas market.
- Authored highly trafficked articles for the Journal of Petroleum Technology, OilPrice.com, and LinkedIn.
- Organized and hosted one of the first decarbonization conferences for oil and gas, Carbon Expo in 2022. Followed with two webinars and Carbon Expo 2023.

- Partnered with Carbon Tracker Initiative to publish studies of the ability of oil companies to pay for decommissioning. Cited and quoted as an expert by news organizations.
- Active volunteer with SPE's Gaia Section and Annual Technical Conference.

Training and teaching

- Developed and teach five industry courses to hundreds of professionals through American Association of Petroleum Landmen, SAGA Wisdom, PHDwin, and Texas Christian University (below).
- Formal and informal mentoring of young professionals.

Litigation support

- Quantified and testified about market value of royalty interests in three states.
- Consulting expert to defendants in nine-figure breach of contract claim concerning shale development.
- Testifying expert on drainage and damages in south Texas reef field.
- Testifying expert in class-action lawsuit over unplugged wells.

Adjunct Professor
TEXAS CHRISTIAN UNIVERSITY 2019 – present

Designed and teach *Petroleum Engineering for Managers* and *Subsurface Engineering and the Cost of Carbon* for its nationally ranked Energy MBA program and served or participated with related Advisory Boards.

Founder, President, and Chief Technical Officer
FIADOR RESOURCES, Fort Worth, TX 2017 – 2021

Created and led team of four in start-up gas production company. Led initial round of private fund-raising to pursue by-passed pay in the Fort Worth Basin. Initiated play concepts and led interdisciplinary team in regional studies of multiple plays. Developed strategic commodity price thesis. Co-led private equity raise and solicitation and negotiation of an unmarketed asset sale. Led operations to test zones and to plug wells.

Reservoir Engineering Manager, Member of Management Committee
JETTA OPERATING COMPANY 2013 – 2015

Led up to seven interdisciplinary teams and analyses of 11 plays plus acquisition opportunities, including both conventional and unconventional assets. Active member of corporate management team. Responsibility for corporate reserves quantification. Mentored junior reservoir engineers and created training program.

Selected highlights:

- Guided strategic exit from drilling programs to Austin Chalk and Woodford plays.
- Identified previously misunderstood reservoir dynamics, and thus upside potential, in fields such as a fractured carbonate, a gravity drainage dolomite and an abandoned waterflood.
- Simulated potential for horizontal well drilling to thin oil rims to avoid ill-advised development strategy.
- Performed six types of engineering analyses to justify recovery from Third Bone Spring play, followed by profitable divestiture.
- Explained anomalous historical behavior of the Delaware Mountain Group to accurately forecast previously unexpected acceleration of decline.

Executive Vice President
THE STRICKLAND GROUP 2001 – 2013

Company co-founder and executive committee member. Oversaw growth from nine employees to 25. Involved in all strategic and management decision-making.

Consulted on projects across two dozen basins in the United States and internationally. • Projects in the billions of dollars. • Diverse issues such as field development and valuation. • Clients from every corner of industry, up to international majors, national oil companies, and government agencies. • Analyses successfully defended against rebuttal and cross-examination.

Selected highlights:

- Conducted dozens of analyses of the Barnett shale since 2003 and ten other shales. *Post mortem* analysis of a $500 million bankruptcy explained the failure of a multi-basin exploration strategy.
- Organized expert team appointed by International Centre for Expertise to explain the failure of a massive gas re-injection project in north Africa and to provide guidance for future development.
- Delivered comprehensive technical due diligence for Japanese conglomerate in a series of proposed acquisitions in the Eagle Ford shale totaling over $3 billion. Client made acquisition at much less than initial offer price.
- Advised the SEC during its investigation of Shell's 25% reserve write-down (2004) and the class-action plaintiff's attorneys for El Paso's 40% reserve write-down (2004). Both reached settlement.
- Supplied analysis and deconstruction of government witnesses related to liability and discharge volume for the Macondo blowout. Final judgment concurred with our opinion.
- Assisted clients in acquisitions and divestitures in negotiated and auction settings and regularly prepared fair market value analyses.
- Managed a non-op drilling fund in the Barnett Shale (acquisition, development, and sale of interests). Created engineering insight and spearheaded fund-raising efforts for multiple projects.

Shareholder, Engineering Consultant
CAWLEY, GILLESPIE & ASSOCIATES, INC. 1995 – 2001

Engineering and litigation support for operators and contested settings from state court to international arbitrations. Specialized in probabilistic methods, pressure transient interpretation, reserves determination, and reservoir simulation. Awarded partnership within three years.

EDUCATION, TRAINING

JOHNS HOPKINS UNIVERSITY, Washington, DC 2023

School of Advanced International Studies, Master of Arts in Sustainable Energy, GPA 3.87

- Research on gas flaring and venting in Texas
- Research on decommissioning liabilities and associated cash flows in California
- Kellogg Morgan Stanley Sustainable Finance Challenge *Finalist* (March 2022) for new venture to large-scale promote carbon sequestration

TEXAS A&M UNIVERSITY, College Station, TX

B.S. Petroleum Engineering, Graduated *Magna Cum Laude* with University Honors 1994

- *Outstanding Achievement Award*, College of Engineering
- 197 total credit hours, including study abroad
- Phi Kappa Phi Honor Society, Pi Epsilon Tau petroleum engineering honor society
- Walter W. Lechner Fellowship and departmental scholarships
- Various officer positions in student organizations, including President of Residence Hall of the Year and Columnist for *The Battalion*
- Summer internships at ARCO, Chevron and Cawley, Gillespie & Associates.

DENMARK'S INTERNATIONAL STUDY PROGRAM, Copenhagen 1995

International Business

Industry courses on topics including Hydraulic Fracturing, Risk Analysis, Reserve Definitions, Magnetotellurics and others.

AFFILIATIONS & VOLUNTEERING

Registered Professional Engineer, State of Texas #87866

Society of Petroleum Engineers, 25-Year Member, Circle of Honor

- Distinguished Lecturer 2024-2025, *Economic Surprises of Late-life Production*
- Sustainable Development Technical Section Program Vice-Chair AND Gaia Talks Vice-Chair, 2024 to present
- Sustainable Development Technical Section Committee, 2021 to present
- Advisory Board Member, Management and Information, *2019 to 2020*
- Specialty Coordinator, Assistant Specialty Coordinator (Management and Information), *2018 to 2019 ATCE*
- Program Committee Member, Chairman (Ethics, Training and Professionalism), *2016 to 2017 ATCE*
- Program Committee Member, *2013 and 2014 Unconventional Gas Conference*

Society of Professional Evaluation Engineers, Member

American Association of Petroleum Geologists, Member

Society of Independent Professional Earth Scientists, Member

TCU Ralph E. Lowe Energy Management Program, Advisory Board Member, *2019 to 2021*

Lubbock Gas Gathering, Advisory Board Member, *2015 to 2018*

Renaissance Vision (charter school), Board Member, *2012 to 2013*

Various churches home group leader, Sunday school teacher, committee member and/or founding member

Boy Scouts of America, Assistant Scout Master, Troop 43, *2012 to 2015*

TECHNICAL PUBLICATIONS

Strickland, R.F., Purvis, Dwayne C., Alexander, R.A., Quinn, M.A., *Coupling Probabilistic Methods and Finite Difference Simulation: Three Case Histories* paper SPE 38777 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, TX, October 1997.

Purvis, Dwayne C., Strickland, R.F., *Problems Reconciling Probabilistic and Deterministic Reserve Classifications and Evaluations* paper SPE 68591 presented at the SPE Hydrocarbon Economics Evaluation Symposium, Dallas, TX, April 2001.

Purvis, Dwayne C., "Reserves", *Encyclopedia of Petroleum Engineering*, 2001, 2008.

Purvis, D. C., *Judgment in Probabilistic Analysis* paper SPE 81996 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO, October 2003.

Nickle, Brad, Purvis, Dwayne C., Strickland, R.F., *Resolving the Nightmare of Performance Reporting and Portfolio Management – A Web Based Approach* paper SPE 95164-PP presented at the SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, TX, April 2005.

Strickland, R., Purvis, D., and Blasingame, T., *Practical Aspects of Reserve Determinations for Shale Gas* paper SPE 144357, Presentation at the SPE North American Unconventional Gas Conference and Exhibition, The Woodlands, TX, June 2011. (reprinted in *Journal of Petroleum Technology*, January 2012).

Purvis, D. and Kuzma, H., *Evolution of Uncertainty Methods in Decline Curve Analysis* paper SPE 179980, Hydrocarbon Economics and Evaluation Symposium, Houston, TX, May 2016. Also presented to SPE section in Fort Worth (September 2016)

Purvis, D., *The Practice of Decline Curve Analysis*, paper SPE 179979, Hydrocarbon Economics and Evaluation Symposium, Houston, TX, May 2016. Also presented to SPE sections in Oklahoma City (August 2016), Dallas (April 2017), Wichita Falls (October 2017), and Midland (March 2018); and to Dallas Geological Society (January 2017).

Purvis, D., *A Proposal for "Holdback"*, research white paper published and distributed online. www.purvisenergyadvisors.com December 7, 2021.

Purvis, D., *Economic Yardsticks for the End of Economic Life: Holdback and Its Adjuncts,* paper SPE 2210226, SPE Annual Technical Conference and Exhibition, Houston, Texas, October 2022.

Purvis, D., *Policy Options to Fund Decommissioning of Aging Oilfield Infrastructure.* Poster presented at the American Geophysical Union (December 11, 2024).

Purvis, D., *Scoping the Issue of Unplugged Wells: Well Count, Status, Ownership, and Policies.* Poster presented at the American Geophysical Union (December 11, 2024).

PRESENTATIONS, WEBINARS & PANELS

Strickland, R.F., Chong, E. and Purvis, D.C., *Finite Difference Simulation of the Barnett Shale* presented at the Barnett Shale Symposium II, Dallas, TX, June 2005.

Purvis, Dwayne C. and Strickland, R.F. *Barnett Shale—Was It Worth It?*. presented at the Unconventional A&D – 2008 Round Table, Denver, CO, March 2008.

Strickland, R., Purvis, D., and Blasingame, T., *Practical Aspects of Reserve Determinations for Shale Gas*, Presentation at the Eastern Section AAPG Meeting – Classic Rocks, Cleveland, OH, September 2012.

Purvis, D. with Dr. Curtis Whitson, *Practical Aspects of Shale Reserves*, presented at SPE sections in San Antonio (October 2015), Midland (November 2015), Wichita Falls (December 2015), Austin (January 2016), Fort Worth (February 2016), Bartlesville (February 2016), and Oklahoma City (October 2016).

Purvis, D., *Evaluation of Shale Reserves and Resources in US Acquisitions*, presented to SPE Calgary Section, CA, January 2016.

Purvis, D., *Evolution of Probabilistic Decline Curve Analysis*, presented at SPE section Reservoir Studies Group in Oklahoma City (August 2016) and the SPE section in Fort Worth (September 2016).

Purvis, D., *Caveat Emptor in Acquisitions*, presented at SPE sections in Oklahoma City (August 2016), Dallas (December 2016), Austin (February 2017), Denver (March 2018) and at SM Energy internal conference (August 2018).

Purvis, D., *Ethics of Brinkmanship*, presented at SPE section in Wichita Falls (November 2016), Gulf Coast Section Members in Transition (December 2017), and Dallas chapter of SPEE (November 2018).

Purvis, D., *Decline Curve Analysis, Year-end Reserves and Ethical Pitfalls*, presented to the Society of Independent Professional Earth Scientists, Fort Worth chapter (January 2017).

Young, J. and Purvis, D., *Changing Rules of Oil and Gas Reserve Audits*, presented to the Oklahoma City chapter of SPEE (October 2017).

Purvis, D., *Myths and Misunderstandings of Reservoir Engineering*, presented at SPE section in Dallas (October 2017), Austin (November 2017), Denver (March 2018), and Fort Worth (May 2018); to Dallas Geological Society (November 2017), to New Orleans Geological Society (January 2018), and to SIPES in San Antonio (March 2018).

Purvis, D., *The Economics of Shale Plays*, presented at AAPL Field Landman Seminar (Fort Worth, June 2018), Fort Worth Petroleum Accounting Society (November 2018), and Society of Petroleum Engineers (Dallas, December 2018).

Purvis, D., *Engineer as Craftsman*, presented at SPE sections in Dallas (June 2018), Wichita Falls (December 2018), and Fort Worth (May 2019) and at the SIPES section in Oklahoma City (January 2019).

Purvis, D., *Geologic Components of Shale Production*, presented at AAPG SWS Annual Convention, Dallas, TX (April 2019), Petroleum Engineers Club of Dallas (November 2019).

Purvis, D., *Making Cash Flow*, presented at AAPL National Convention in Pittsburgh (June 2019), Young Professionals in Energy (Fort Worth, October 2019), Council of Petroleum Accounting Societies (Dallas, January 2020; Fort Worth, February 2020), Desk & Derrick (Dallas, February 2020), AAPL continuing education webinar (May 2020 and June 2021), and Dallas AAPL (October 2021).

Purvis, D., *New Dynamics of the Natural Gas Market* presented at private company (August 2019), Society of Independent Professional Earth Scientists (Fort Worth, September 2019), Dallas Geological Society (September 2019), East Texas Association of Professional Landman (November 2019), Society of Petroleum Engineers (Fort Worth, October and December 2019; Dallas, February 2020). Revised and updated delivered to national convention of Society of Independent Professional Earth Scientists (Fredericksburg, June 2021), Fort Worth Society of Petroleum Engineers (September 2021), Tyler SPE (December 2021), Houston Society of Professional Evaluation Engineers (December 2021), Fort Worth ADAM (January 2022).

Purvis, D., *Reading the Signs of Shale Declines* presented at Society of Independent Professional Earth Scientists (Midland, November 2019).

Purvis, D., *Value Proposition and Overview of PTA, RTA* and *Risk Factor for Productivity Loss* presented at webinar panel discussion hosted by Reservoir Data Systems and SAGA Wisdom (May 2020).

Purvis, D., *Risks and Opportunities Created by Shutting In* presented for the Dallas chapter of SIPES (May 2020) and for the Dallas section of Society of Petroleum Engineers (May 2020).

Purvis, D., *COVID, Climate, and Careers: A look at a changing industry* presented for the Fort Worth section of SPE (September 2020), Dallas section of COPAS (Oct 2020), Fort Worth chapter of AAPL (October 2020), Fort Worth chapter of SIPES (October 2020), the Petroleum Engineers Club of Dallas (October 2020), Mississippi Area Petroleum Landmen (November 2020), COPAS minor societies (November 2020), Washington D.C. and Wichita Falls of section of SPE (December 2020), Dallas and Midland sections of SPE (January 2021), and the Oklahoma City chapter of SPEE (January 2021).

Purvis, D. and Sabatka, S., *Log analysis and dynamics of the southern Delaware Mountain Group*, presented at AAPG SWS Annual Convention (Fort Worth, June 2021), Dallas Geological Society (October 2021), Fort Worth Geological Society (November 2021).

Purvis, D., *Winning Strategies for the Next Decade*, presented at Dallas Society of Petroleum Engineers (September 2021), Dallas Council of Petroleum Accounting Societies (September 2021), SIPES Symposium (October 2021),

Tyler ADAM (October 2021), Dallas Association of Professional Landmen (October 2021), Tyler ADAM (October 2021), Fort Worth COPAS (January 2022), Midland Society of Professional Evaluation Engineers (January 2022), Wichita Falls Society of Petroleum Engineers (March 2022)

Jacks, D. and Purvis, D., *Annual Ethics Meeting: Ethics of ARO*, Oklahoma City SPEE (November 2021).

Purvis, D., *Tales of Holdback*, presented at Petroleum Engineers Club of Dallas (February 2022).

Panelist, Operator Roundtable, *SPE/ICOTA Well Intervention Conference and Exhibition* (February 2022).

Purvis, D., *Lessons from CarbonExpo*, Society of Independent Professional Earth Scientists (Dallas, March 2022).

Purvis, D., *Bridges and Gaps: From Upstream to CCS*, presented at SAGA Wisdom's *Sokkvabekkr* conference (Fort Worth, April 2022).

Purvis, D., *Honest Inquiry: An engineer's look at climate science*, SPEE (Denver, April 2022).

Purvis, D., *Frank Dialogue on the Energy Transition*, presented at Dallas Society of Petroleum Engineers (August 2022), COPAS National Convention (October 2022), AAPL National Meeting (June 2023), AAPL Southwest Land Institute (August 2023).

Purvis, D., *A New Economic Yardstick for Today's Late-life Production: Holdback*, presented at the National Capitol section Society of Petroleum Engineers (August 2022), East Texas Society of Petroleum Engineers (September 2022), COPAS Dallas Chapter (October 2022), Petroleum Accounting Society of the Permian Basin (October 2022), COPAS San Antonio chapter (November 2022), webinar *101 Uses for a Dead Well* hosted by CarbonExpo (November 2022), AAPL Tulsa section (November 2022), COPAS Austin chapter (January 2023), ADAM Tyler (February 2023), SPE Dallas (March 2023), PPDM Midland (April 2023), SIPES Dallas (September 2023), SPE Oklahoma City (September 2023), PPDM National Convention (September 2023).

Purvis, D., *The Next U.S. Oil Boom is #Counterstream*, presented at Ft. Worth section Society of Petroleum Engineers (September 2022), Oklahoma City Society of Petroleum Evaluation Engineers (September 2022), Austin SPE (October 2022), COPAS National Convention (October 2022), Austin section of SPE (October 2022), COPAS/PASPB Midland (April 2023).

Research Presentation: Event Horizon: A Case Study of Holdback and the Point of No Return for Decommissioning Upstream Oil and Gas "Assets", webinar hosted by Carbon Tracker, panelist (September 14, 2022).

Purvis, D., *To Define the Problem of "Orphan" Wells*, presented to OKC Professional Petroleum Data Management (December 2022), PPDM DFW Energy Data Workshop (February 2023), PPDM New Data Ecosystem Expo (Houston, May 2023).

Purvis, D., *Dimensions of the Energy Trilemma*, SPE Fort Worth (November 2023).

Purvis, D., Stogner, Sarah. *Managing Zombie and Orphan Wells*, webinar hosted by COPAS—San Antonio (Remote, February 2024).

Purvis, D., *Context of Orphan and Idle Wells*, presented at the American Association of Petroleum Geologists' Orphan, Abandoned, Idle, and Marginal Wells Conference (Pittsburgh, February 2024).

Purvis, D., *The Future of Low-Producing Wells, The Good, The Bad and The Ugly*, presented at North American Petroleum Accounting Conference (Dallas, May 17, 2024).

Purvis, D., *Abandonment Costs: What PRMS and Other Standards Do and Don't Say,* webinar hosted by Purvis Energy Advisors (May 22, 2024), presented again by SAGA Wisdom (starting June 2024).

Purvis, D., *Public Blame, Private Pain, and New Growth: The Last 10 Years and the Next*. Webinar hosted by COPAS—Dallas Section (Dallas, October 2024).

Purvis, D., *Economic Surprises of Late-Life Production,* presented at the Society of Petroleum Engineers - Distinguished Lecturers Tour, New Orleans (November 12, 2024), Jackson (November 13, 2024), Shreveport (November 14, 2024), San Antonio (January 7, 2025), Gillette (January 14, 2025), SPE LIVE (online, January 22, 2025), Dubai, Northern Emirates (April 9, 2025), Dhaka, Bangladesh (April 10, 2025), Seria, Brunei (April 14, 2025), Kuala Lampur, Malaysia (April 15, 2025), Sarawak, Malaysia (April 16, 2025), Singapore, Singapore (April 17, 2025) Khartoum, Sudan (online, April 30, 2025).

Purvis, D., *Dormant to Dynamic: Breathing Life into Old Wells.* Webinar hosted by COPAS—National (Online, November 19, 2024).

Purvis, D, *Funding Options for Orphan Wells and for Avoiding Orphan Wells*, presented at the American Association of Petroleum Geologists' Orphan, Abandoned, Idle, and Marginal Wells Conference (Tulsa, February 2025)

Purvis, D., *Technologies and Practices for Plugging Oil and Gas Wells*, invited presentation to a committee of National Academies of Science and Engineering (Online, March 2025).

ARTICLES

Articles in the Journal of Petroleum Technology, flagship periodical of the Society of Petroleum Engineers https://jpt.spe.org/author/dwayne-purvis-p-e

Purvis, D., *Honest Inquiry: An engineer's look at climate science*, Journal of Petroleum Technology (April 2022).

Purvis, D., *Using Holdback to Avoid the Closing Cash Flow Trap*, Carbon Tracker blog (May 24, 2022).

Purvis, D., *Preparing to become a manager*, guest column published in *The Way Ahead*, SPE magazine for young professionals (May 2017).

Purvis, D., *How to Meet Declining Oil Demand*, Journal of Petroleum Technology (June 1, 2021).

Purvis, D., *Venting and the Moral Case for Fossil Fuels*, Journal of Petroleum Technology (December 1, 2021).

Purvis, D., *The Coming Boom in the "Counterstream" Business*, Journal of Petroleum Technology (January 12, 2022).

Purvis, D., *Oil & Gas: Villain, Victim or Hero?*, CarbonExpo (March 2022).

Purvis, D., *The Virtue in Virtue Signaling*, Journal of Petroleum Technology (March 15, 2022).

Purvis, D., *Path of Honest Inquiry Leads to Truth About Climate Science*, Journal of Petroleum Technology (April 19, 2022).

Purvis, D. and Schuwerk, R, *Event Horizon: A Case Study of Holdback and the Point of No Return for Decommissioning Upstream Oil and Gas "Assets"*, Carbon Tracker Initiative (July 2022).

Purvis, D., *New Realities of Mature Production Require New Economic Yardsticks*, Journal of Petroleum Technology (December 26, 2022).

Purvis, D., *There Will Be Blood: Decommissioning California's Oilfields*, Carbon Tracker Initiative (May 2023).

Purvis, D., *Our Texas Weather Has Changed Forever*, op-ed Dallas Morning News, (August 17, 2023).

Purvis, D., *Shale Boom Foretells Energy Transition*, Journal of Petroleum Technology (November 16, 2023).

Purvis, D. *"Decommissioning Costs Make Producing Projects Uneconomic".* JPT.spe.org (December 3, 2024).

Other articles on OilPrice.com (http://oilprice.com/contributors/Dwayne-Purvis/articles)

Other articles on LinkedIn (https://www.linkedin.com/in/dpurvispe/recent-activity/posts/)

TRAINING COURSES & WORKSHOPS

Purvis, D., *Ethics and Shale Reserves*, workshop offered through SPE Calgary Section, CA, January 2016.

Purvis, D., *Engineering Methods and Advanced PHDwin* two-day training course presented in Houston (October 2016), Dallas (November 2016), Oklahoma City (January 2017), and Houston (March 2017 & November 2017).

Purvis, D., *Creating and Defending Shale Reserves in PHDwin* one-day training course presented in Dallas and Oklahoma City (October 2017); Midland, Austin, and Houston (November 2017); Midland and Denver (March 2018).

Purvis, D., *Understanding Petroleum Economics* one-day training course prepared and presented for AAPL in Fort Worth (August 2018), Washington, PA (January 2019), Birmingham (March 2019), Anchorage (April 2019), Midland (July 2019), Fort Worth (November 2019), Houston (February 2020), Tulsa (February 2020), webinar (June 2020, September 2020).

Purvis, D., *Decline Curve Analysis, Reserves, and Economics for Shale* a three-day online training course delivered through SAGA Wisdom training platform. (released winter 2021).

Purvis, D., *Welcome to PHDwin 3.0*, a two-day training course delivered online through SAGA Wisdom. (released spring 2022).

Purvis, D., *Reservoir Engineering Past and Present*, Southwest Section of the American Association of Petroleum Geologists (one-day training on reservoir engineering, Abilene, January 2024).

Purvis, D., *Petroleum Engineering for Non-Technical Professionals*, in coordination with Energy Conference Network (one-day industry overview, Bakersfield, March 2025).

CONFERENCES & PANELS HOSTED

Carbon Expo 2022 and *Carbon Expo 2023* by Purvis Energy Advisors, host and moderator (March 2022 and March 2023).

Climate Week NYC – Stranded Assets and Stranded Liabilities: The fossil fuel industry is failing to save for retirement, seminar hosted by Carbon Tracker, speaker and panelist (September 21, 2022).

Orphan & Idle Wells Colorado by Energy Conference Network, moderator (Denver, March 2024).

2nd Annual Orphan & Idle Wells Texas by Energy Conference Network, Moderator (Houston, October 2024).

Decarbonization Congress by Gulf Coast Section and Sustainability Technical Section both of SPE, led panel session (February 2025)

Orphan & Idle Wells – California by Energy Conference Network, moderator (Bakersfield, March 2025).

MEDIA APPEARANCES AND MENTIONS

Print / Online:

- Rassenfoss, Stephen, *Fixing Old Wells Can Add Cheap Barrels, But a Worker Shortage Is Limiting Growth*, The Way Ahead (March 28, 2022).
- Bowlin, Nick, *How oil companies endlessly avoid cleanup costs*, High Country News (July 19, 2022).
- Olalde, Mark, *Oil giants sell thousands of California wells, raising worries about future liability*, LA Times (October 27, 2022).
- Bowlin, Nick, *Colorado Seeks Payments for Oil & Gas Cleanup*, Capital & Main (January 11, 2023).
- Olalde, Mark, *It Will Cost Up to $21.5 Billion to Clean Up California's Oil Sites. The Industry Won't Make Enough Money to Pay for It,* ProPublica (May 18, 2023).
- Holland, Bill, *Calif. taxpayers could pay billions of dollars to plug oil wells – study*, S&P Global Market Intelligence (May 18, 2023).
- Drane, Amanda. *Texas oil wells are leaking toxic waste, and no one wants to pay for it*, Houston Chronicle (July 17, 2023).
- Fassler, Joe. *How the Oil Industry Indefinitely Delays Cleaning Up Oil and Gas Wells in California*, Desmog.com (February 6, 2024).
- Hutchinson, Drew, Magill, Bobby. *Failed Oil Well Plugs Are Silent Polluters That No One Watches*, Bloomberg Law (March 13, 2024).
- Sonntag, Zackary. *The Big Horn Basin has thousands for unplugged oil wells*, Caspar Star Tribune (April 4, 2024).
- Richards, Heather. *Wyo. wells show scale of public land cleanup cost — report,* Politico Pro (April 4, 2024).
- Bowlin, Nick, Olalde, Mark. *Oil Companies Must Set Aside More Money to Plug Wells, a New Rule Says. But It Won't Be Enough.,* Pro Publica, Capital & Main (April 22, 2024).
- Maio, Pat. *Wyoming Oil And Gas Producers Blast Report They Should Pay $900M For Bonding*, Cowboy State Daily (April 22, 2024).
- Baddour, Dylan. *Water is bursting from another abandoned West Texas oil well, continuing a troubling trend*, Texas Tribune (June 11, 2024).
- Fassler, Joe. *"Why Colorado's Celebrated Oil Well Cleanup Reforms Face a $3 Billion Shortfall"*, Desmog.com, Rpt. In The Guardian (June 26, 2024).
- Jaffe, Mark. *"Most Colorado oil and gas wells do not generate enough cash to ensure they will be cleaned up, study says"*, The Colorado Sun (June 27, 2024).
- Bowlin, Nick. *"Colorado's oil and gas rules put taxpayers at risk, according to study"*, High Country News (June 28, 2024).
- Pskowski, Martha. *"A Legal Fight Over Legacy Oil Industry Pollution Heats Up in West Texas"*. Inside Climate News (August 6, 2024).
- Garcia, Antonio. *"Millions of Orphan Oil Wells Are a Ticking Timebomb for the U.S."*. Oilprice.com (September 23, 2024).
- Foehringer-Merchant, Emma. *"As a Major California Oil Producer Eyes Carbon Storage, Thousands of Idle Wells Await Cleanup"*. Inside Climate News (December 12, 2024).

- Baddour, Dylan. *"'Drill Baby Drill': Texas City Approves New Site for Fracking Near Daycare and Schools".* Inside Climate News (January 29, 2025).
- Drane, Amanda, Ghisolfi, Caroline. "*Bipartisan bill to cap unplugged Texas oil wells could create up to 150,000 new jobs*". Houston Chronicle (April 10, 2025).

Radio appearances:
- *Who Will Pay to Take California's Defunct Oil Wells Offline?,* Forum from KQED San Francisco (May 18, 2023).
- *AirTalk with Larry Mantle,* LAist 89.3 FM (May 18, 2023).
- *After discovering old oil and gas wells leaking on their land, one West Texas ranch owner aims to hold companies accountable,* Marfa Public Radio (August 6, 2024).

Podcast appearances:
- Tripping over the Barrel, *Catching up with Big Perv* (October 2021).
- Energy Transition Solutions with Joe Batir, *The Energy Transition through the Eyes of a Petroleum Engineer* (December 2021).
- Tripping over the Barrel, *A Short with the Carbon Capture Captain* (February 2022).
- Oil & Gas Accounting Podcast, *Holdbacks are a Possible Solution to Plugging Liabilities* (March 2022).
- Energy Transition Solutions with Joe Batir, *Why Energy Transition is an Opportunity for Oil and Gas with Dwayne Purvis – Ep 82* (February 2023).
- What the Funk?, *DP3, the CarbonExpo King* (March 2023).
- Energy Transition Talk, *Ep 6|What is the Future of Oil and Gas?* (December 2023).
- Environmental Video Library with OTA and IPAA, *Orphan, Shut-In Wells: What type of exposure are we facing?* (September 2024).
- Oil and Gas Upstream with Elena Melchert. *Dwayne Purvis, Purvis Energy Advisors | Ep. 288* (February 2025).

Television appearances:
- Brock, Hannah. *Special report: The cost of aging oilfields,* CBS7 (June 10, 2024).

(end of document)

EXHIBIT 30

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC **CASE NO. 24683**

DIRECT TESTIMONY OF DWAYNE PURVIS, P.E.

Table of Contents

BACKGROUND AND QUALIFICATIONS 2

SUMMARY OF TESTIMONY AND OPINIONS 5

OVERVIEW OF THE ORPHAN WELL PROBLEM 7

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS 31

19.15.2.7.M(2) NMAC – Definition for Marginal Well 31

19.15.8 NMAC – FINANCIAL ASSURANCE 33

19.15.8.9.C NMAC – Active Wells 38

19.15.8.9.D NMAC – Marginal Wells and Inactive Wells 47

19.15.8.9.E NMAC – Inactive Wells 69

19.15.8.9.F NMAC – Additional Financial Assurance 70

19.15.8.9.G NMAC – Inflation Adjustment 71

19.15.9 NMAC –WELL OPERATOR PROVISIONS 73

19.15.9.9.B NMAC – Plugging and Abandonment Plan 75

19.15.9.9.C(6) NMAC – Certification 86

List of References 87

BACKGROUND AND QUALIFICATION

Q: Please state your name.

A: Dwayne Christopher Purvis

Q: What is your current employment?

A: I serve as the Principal Advisor of consulting firm Purvis Energy Advisors which I founded in 2015.

Q: What is your educational background?

A: I earned a bachelor's degree in petroleum engineering from Texas A&M University in 1994, and I earned a master's degree in sustainable energy from Johns Hopkins University's school of public policy in 2023. I am also a registered professional engineer in the state of Texas and have been for a couple decades.

Q: Would you please describe your work background with particular attention to your experience working on financial assurance for oil and gas operations and the risks of inactive and orphaned wells.

A: For 30 years, I have worked as a petroleum reservoir engineer. Most of that time I worked as a consultant, though I also worked for some years in private oil companies. The job of a reservoir engineer is to determine how much oil and gas will be produced in the future, how to produce more, and how much that production is worth considering volumes, prices and costs. Reservoir engineering is the technical discipline most closely involved with strategic planning for an oil and gas company.

I have performed reservoir engineering work on fields all over the United States and in a number of foreign countries. I have, for example, certified reserves as an independent third-party evaluator, prepared and presented expert testimony on reserves and value, and evaluated

reserves, purchases, and sales for internal company use. I have worked conventional fields since 1995 and shale fields since 2003. I have worked on issues of oil and gas value for operating companies, mineral owners, governments, investors, litigants and others. I am active in many professional societies including the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. I also teach petroleum engineering, and reserves evaluation for the American Association of Petroleum Landmen, for a major training company called Saga Wisdom, and previously for a nationally ranked energy MBA program at Texas Christian University.

While I continue to perform reserve evaluations and acquisition analysis for some clients, the majority of my work in the last five years has pertained to end-of-life issues faced by oil companies as their fields mature. I have written white papers and technical papers on the principles of late-life economics, and the Society of Petroleum Engineers recently asked me to present that work in its Distinguished Lecturer program. Besides my engineering work for private clients, I have previously published studies of late-life, state-level economics in California, Colorado, Ohio, Pennsylvania, West Virginia, and parts of Wyoming. I have organized, hosted, spoken at, and attended a large number of conferences on the issue of unplugged wells, which has gained attention inside the industry. Outside of the oil and gas industry, my work has frequently been cited or quoted in news articles about aging infrastructure and how to pay for its decommissioning. A list of my technical publications, articles, media appearances, and presentations is provided in my curriculum vitae, attached as Applicants' Exhibit 29.

Q: Is Applicants' Exhibit 29 an accurate copy of your curriculum vitae?

A: Yes.

Q: You stated your professional specialty is reservoir engineering. Could you please

briefly describe the services you provide oil and gas companies as a reservoir engineer and the ways these companies rely on your expertise?

A: Reservoir engineers have the job of determining how much oil and gas will be produced, how much it is worth, and how to produce more. Reservoir engineers like me determine the value of oil and gas companies' largest asset, namely their reserves. The results of my kind of work become the basis for corporate, tactical and strategic planning, as well as for key elements of public reporting.

Q: What documents and data have you reviewed in preparing your testimony?

A: I have reviewed oil and gas operations data in New Mexico available through web queries and an application programming interface both of the Oil Conservation Division (OCD or Division) as well as similar data from a commercial data vendor called WellDataBase; various public reports and presentations made by regulatory agencies such as the OCD, and the Energy, Minerals and Natural Resources Department more generally, the Legislative Finance Committee of New Mexico, Tax Revenue Office of New Mexico, the State Land Office of New Mexico, the Interstate Oil and Gas Compact Commission (IOGCC), and the Railroad Commission of Texas, and various other regulatory agencies; U.S. Securities and Exchange Commission filings of some oil and gas companies with concentrated operations in New Mexico or the Permian basin more broadly; and academic literature and other public research studies, including some of my own work described above. A more detailed list is attached to my testimony.

Q: Have you reviewed other states' regulatory requirements governing the financial assurance requirements for oil and gas wells?

A: Yes, I have studied and written about financial assurance policies in several jurisdictions in detail and reviewed others' policies in summary.

SUMMARY OF TESTIMONY AND OPINIONS

Q: Can you please summarize the testimony and opinions you will give in your testimony?

A: A failure to plan is a plan to fail. This adage generally represents the fundamental flaw that risks many oil and gas wells in New Mexico becoming orphaned and, as such, to create financial and safety liabilities for the State, its taxpayers, surrounding communities, and the environment. The rules proposed by Applicants are designed to motivate oil and gas operators to have and execute a plan to fulfill their well decommissioning obligations before the revenue from their well production becomes insufficient to cover those costs. These rules are necessary because the nature of oil and gas economics in concert with New Mexico's existing rules create little obligation that ensures operators are planning for decommissioning and because existing incentives favor delaying decommissioning and ultimately increase the risk of orphaning. There is no single rule or policy solution that can entirely protect the State from the range of financial and physical risks posed by the dynamics unique to different wells and operation strategies from idle and micro-producing wells to brand-new shale wells. Moreover, there is no rule that adequately limits the State's current financial exposure without some impact to and realignment within the upstream oil and gas industry. Multiple strategies must be employed. Applicants' proposed rules offer a conservative but effective approach to limit the State's financial exposure in a way that will have little impact on overall oil and gas production in the state.

Regarding **19.15.2 NMAC – Definitions:** My testimony focuses on the proposed definition for "marginal well." The definition of this new category was proposed by OCD and adopted by Applicants. Based on my experience in the industry and analysis of the definition, marginal well is defined to capture wells that are especially likely to have marginal economics

and, therefore, pose a risk to an operator's ability to finance decommissioning obligations. The definition's dual criteria of volume and time make it doubly conservative. I support the new rules as proposed.

Regarding **19.15.8 NMAC – Financial Assurance:** In terms of decommissioning and reclamation costs of upstream oil and gas operations in New Mexico, the state is facing a liability growing past $22.3 billion. The proposed rules in this section would help reduce the risk to approximately 11% or $2.4 billion of that liability primarily by increasing the one well bonding amount, by applying that single-well bonding for wells that add the most risk to operators' well portfolios, and by requiring full assurance for all wells in portfolios of concentrated risk.

The former is necessary because under the current rules, one well bonding covers only a fraction of the cost it takes OCD to plug a well, and my analysis of historic and industry trends leads me to conclude that the price trajectory for plugging wells is likely to continue upwards. The latter is required to address the unintuitive and deceiving nature of oil and gas economics, which can result in a well(s) producing oil and gas and generating revenue (appearing to be a valuable asset), when in actuality the current and expected revenue cannot cover the inevitable cost to decommission.

I explain the surprises of late-life economics, the concept of holdback, and how they demonstrate the need for operators to have long-lead plans for decommissioning their whole portfolio. My analysis of New Mexico's major oil and gas basins identifies those wells that would be identified as marginal or inactive (including wells in approved and expired temporary abandonment) under the proposed rules and demonstrates that based on their age and production, these wells present the most immediate risk of orphaning to New Mexico and, thus, a need for greater financial assurance. While these wells present the greatest risk to New Mexico, they

represent less than a tenth of the state's wells. My analysis demonstrates that the proposed financial assurance rules are reasonable and conservative, and it is my opinion that operators who have planned and are prepared to satisfy their decommissioning obligations will be able to accommodate the new requirements. I do support the proposed rules.

Regarding **19.15.9 NMAC – Well Operator Provisions:** My testimony focuses on the proposed rules requiring compliance certification in a change of operator request and requiring a plugging and abandonment plan in a well transfer request. In my experience, operator changes and well transfers are moments of discrete risk to the State because when wells change hands, they can move from better capitalized companies to less capitalized companies. Accordingly, the State has a duty to protect the public interest from changes in operator and well transfers that would place wells in the hands of new operators at risk of being unable to meet their decommissioning obligations. The proposed rules' compliance certification and plugging and abandonment plan requirements provide OCD tools to better assess a new well operator's risk to the state and the discretion to limit that risk to the state. Both requirements are reasonable and appropriate and are representative of industry-standard information any good actor in oil and gas would be able to provide. I am in full support of the proposed rules.

OVERVIEW OF THE ORPHAN WELL PROBLEM

Q: Let's define some terms that you use in your analysis of plugging regulations nationally and in New Mexico. What is an orphan well?

A: An orphan well is a well for which the state has become responsible for decommissioning. The statutory requirement on oil and gas companies to plug, remediate, and sometimes restore wells at the end of their life is long-standing and well known. But sometimes a company abandons that responsibility, and the well becomes a ward of the state.

In many states "orphan well" is a defined term, but not in the law or regulations of New Mexico. For purposes of my testimony, I use the word to mean that the OCD has identified the well in a spreadsheet it designates its "Master Orphan List." Almost all of the wells on that list are already subject to a final order giving the OCD the right to plug the well. As discussed more below, such an order often comes at the end of a lengthy transition period of enforcement. In other jurisdictions, the term is applied earlier in the process of enforcement.

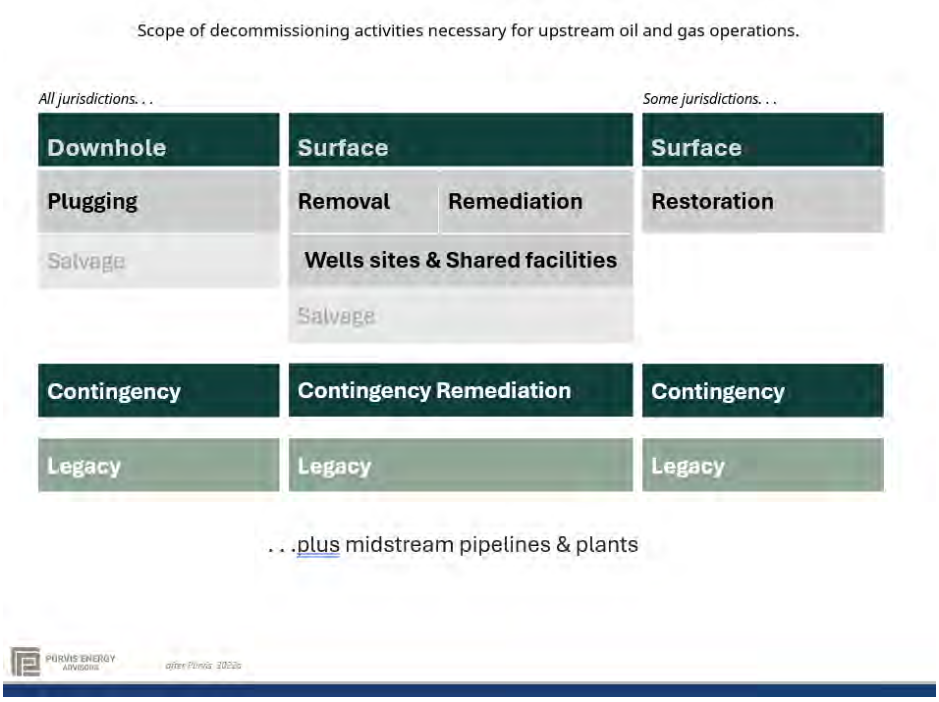
Q: Similarly, please define the terms "plugging" and "abandoned."

A: "Plugging" and "abandoned" can be used in different ways. Strictly speaking, "plugging" refers to the downhole operations to obstruct the wellbore and prevent the undesirable flow of hydrocarbons and oil field brines, but sometimes the same word is used imprecisely or confusingly as shorthand for the full scope of cleanup work.

"Abandoned" can indicate outright opposite conditions. When non-industry people say "abandoned," they use the word in the same way as they might describe an old building—present but neglected and derelict for lack of use. In the oil and gas industry, the same word usually pairs with "plugged" and means that the well and well site have been properly cleaned up.

More precise terms make for better communication. "Decommissioning" refers to the entire process of cleanup. New Mexico, like every other state that I know of, requires that well bores be plugged, surface equipment be removed, and sites be remediated of any remaining pollution. In some jurisdictions as in New Mexico, a third step is also required, namely "restoration" or "reclamation" to return the surface to its pre-drilling conditions.

The figure below helps to explain the difference between just "plugging" and "decommissioning."



When New Mexico or another state assumes responsibility for oil and gas infrastructure that its industry owners have walked away from, it assumes responsibility for the full scope of decommissioning, not just downhole plugging operations. Although we talk about orphan "wells," the wellbores are only one part of the infrastructure that must be decommissioned. Decommissioning also includes removal, remediation, and (sometimes) restoration of tank batteries, shared facilities, and perhaps flow lines or gathering lines and lease roads.

Planning for how to pay for the full scope of decommissioning requires planning for two other issues. First, the costs of decommissioning are systematically higher than the known, planned operations. Decommissioning has the same kind of lower probability risks of high-side cost as other projects but more extreme. In drilling, for example, a well will occasionally cost 20% or 50% more than expected, but there is no situation in which the well can be drilled for 50% less than expected. This is the inherent lop-sided risk. But in decommissioning projects, the risk is greater. For example, instead of 20% or 50%, a well might cost 20 times or even 50 times

as much as expected to decommission. Contingency costs significantly increase the overall cost of large decommissioning projects above the work known and planned for at the beginning.

Second, pollution is sometimes created or first discovered after the initial decommissioning. Companies generally retain liability for cleanup that comes later, but the public may still become responsible.

Q: Mr. Purvis, are current oil and gas regulations nationally and in New Mexico generally adequate to ensure appropriate and timely plugging of oil and gas wells?

A: No. Without reforms, the public of New Mexico will either bear the cost of decommissioning more orphan wells, or it will bear the cost of not cleaning up existing pollution and preventing future pollution.

Most wells plugged to date have been plugged by industry, not by public funds. Until the last few years, the public money to clean up orphan wells in New Mexico came from a portion of the severance taxes on the oil and gas industry itself set aside in the Reclamation Fund. However, the scope of the problem has grown nationally to the point that federal funds, paid by federal taxpayers, are now being used to plug orphan wells in New Mexico.

But past is not prologue. The current reality and extrapolation of current trends show that the population of orphan wells is likely to increase significantly in the future, and the state and the public face the risk of much greater costs properly borne by industry.

Before the shale revolution opened up a new class of geologic resources, U.S. oil and gas production reached its annual peak in 1970. With massive government intervention and fresh highs for oil price, the drilling pace peaked in the 1980s. Near the launch of the shale revolution in the mid to late 2000s, drilling was only continuing in less than half of the 36 productive basins in the country.

The legacy oil and gas fields (including kinds we historically called both "conventional" and "unconventional" like the coalbed methane in the San Juan Basin) are generally quite old. Production has declined for decades, the pace of wells being shut in has been accelerating since about 2009, and there is practically no drilling going on in the country except for horizontal drilling to shales and other very low permeability reservoirs.

The situation in New Mexico is not unique. Many states and other jurisdictions have applied similarly inadequate regulatory tools as New Mexico to manage the risk of orphan wells, and, as a result, are reaping the same kinds of outcomes. Many states and other jurisdictions have serious problems with their inventory of idle and defunct oil field infrastructure.

By my analysis, there are just shy of 2 million wells still unplugged onshore, half of those standing idle and about 80% of the active wells producing at stripper rates. The vast majority of U.S. onshore wells are aging, legacy wells making little money or unable to make money at all from operations.[1]

I have personally studied the financial situation of the oil and gas industry in a number of states. Some states face the same dichotomy as New Mexico: a population of young and profitable shale wells alongside a larger population of old and impecunious legacy wells. States not resurrected with shale development have only legacy wells. My macroscopic analysis shows that—even if the regulatory rules were changed instantly so that all free cash flow was spent on decommissioning—most of the legacy wells in California, Colorado, Ohio, Pennsylvania, West Virginia, and many in Wyoming would still not make enough money to fund the cleanup.[2]

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[1] Purvis, Dwayne. 2024. "Scoping the Issue of Unplugged Wells: Well Count, Status, Ownership, and Policies." *AGU Annual Meeting* (Washington D.C.), December.

[2] Purvis, Dwayne. 2023. *There Will Be Blood: Decommissioning California's Oilfields*. Carbon Tracker Initiative; Purvis, Dwayne. 2024a. *Little Big Horn: How a Bonding Proposal Can Fall Short*. Carbon Tracker Initiative; Purvis, Dwayne. 2024b. *Rocky Mountain Highs and Lows: Decommissioning Colorado's Two Oil Industries*. Carbon Tracker Initiative; Purvis, Dwayne,

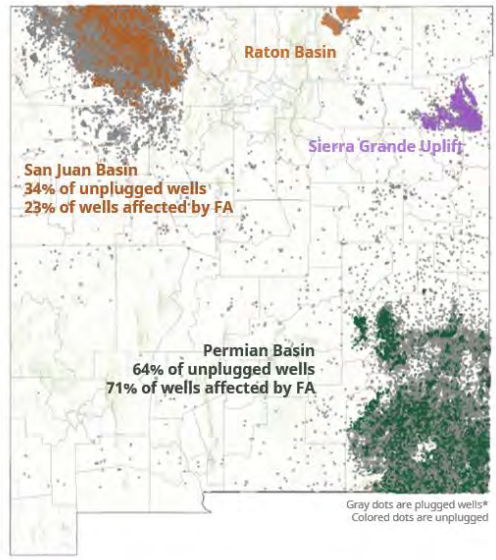
Nationally, the pace of orphaning has accelerated, but the current inventory of still-unplugged orphan wells exceeds the entire catalog of orphan wells plugged over decades of state-run plugging programs. More importantly, production continues to decline, and wells continue to be shut in. The larger issue is the impending liability of aging and depleting legacy wells; liability is accumulating while the value is depleting.

Q: Can you give the Commission some background information on the well count and production in New Mexico?

A: Sure. I have prepared three exhibits to help characterize the industry in New Mexico and to help frame the discussion. Applicants' Exhibit 31 shows the location and counts of oil and gas wells drilled in New Mexico as of June 2025, broken down into major regions with unique character. The number is always changing, but I find about 63,000 wells (along with their sites and facilities), that will need to be decommissioned.

and Ted Boettner. 2025a. *Filling the Hole, Part 1: The Problem*. Johnstown, PA.

Applicants' Exhibit 31: Plugged and unplugged wells in New Mexico as of June 2025.



Basin	Plugged*	Unplugged Total	Unplugged active	Unplugged not active
Permian	35,661	**39,929**	36,850	3,079
San Juan	12,941	**21,219**	20,370	849
Raton	116	**861**	837	24
Sierra Grande	643	**711**	698	13
Other	312	-	-	-
	49,673	**62,720**	**wells to be plugged**	

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* Not all plugged wells are fully remediated.

Applicants' Exhibit 32 provides more detail, which becomes relevant as we discuss more details. For now, it is worth noting that a majority of wells are inactive or low producers.

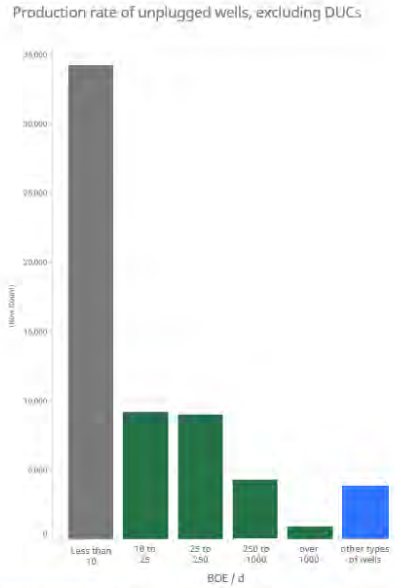
Applicants' Exhibit 32: Subdivisions of unplugged wells in New Mexico.

Unplugged wells by activity

BOE/d	Total	Types Producers	Types Other	% of Total
less than 10	**34,238**	34,238	-	55%
10 to 25	**9,187**	9,187	-	15%
25 to 250	**9,008**	9,008	-	14%
250 to 1000	**4,270**	4,270	-	6.8%
over 1000	**921**	921	-	1.5%
Other	**5,096**	1,303	3,793	8%
Total	**62,720**			

Wells in not-active categories per OCD*

Aging**	Temp Abandon Approved	Expired	Inactive	Orphan
0 to 1 yr	184	68	773	0
1 to 2 yrs	118	41		55
2 to 5 yrs	171	54	868	191
5 to 8 yrs	35	26	613	194
8 to 10 yrs	8	15	203	66
> 10 yrs	1	33	771	440
no data	40	0	-	2
Statewide	**557**	**237**	**3,228**	**948**



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*Some wells in more than one category indicating no activity.
**Aging since last production for Orphan and Inactive. For TA aging since approved or expired respectively.

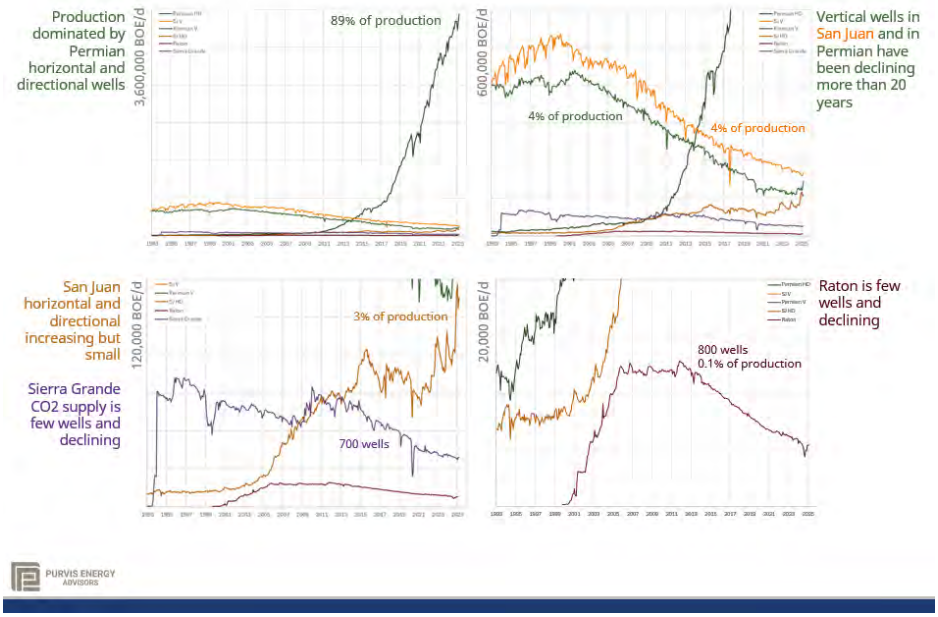
Historically, the terms “stripper” and marginal have often been used interchangeably, but they are not quite the same. The term “stripper” refers to low production rates while “marginal” refers to low profits on that production. In New Mexico, a stripper well is defined as a well that produces less than 10 barrels of oil equivalent per day (BOE/d).

The tally of not-active wells in Applicants’ Exhibit 32 above, relies on the records and designations of the OCD, including in its Master List of Orphan Wells which is Applicants’ Exhibit 55. It should be noted that some wells appear in more than one not-active category shown on this exhibit. For example, orphan wells generally qualify as Inactive and sometimes are temporarily abandoned. My quantification of not-active wells does not include wells that have been plugged but are not fully remediated at the surface.

Of the wells still needing funds to be decommissioned, 6% stand inactive as designated one way or another by the OCD, and 55% are producing less than 10 BOE/d. As my testimony will show later, many of those late-life wells are avoiding the label “inactive” but producing especially small volumes. My testimony will also show that one group of companies own the high-producing wells while a different group owns the mass of low-producers.

Lastly for this initial orientation, Applicants’ Exhibit 33 shows four graphs of the same production data in New Mexico, each progressively focused on smaller levels of production.

Applicants' Exhibit 33: History of daily production in New Mexico in six categories for major divisions among basins and types of wells shown on four vertical scales.



Statewide production is divided into six groups, one for each of the two minor areas (Raton and Sierra Grande) and two for each of the two major basins (Permian and San Juan), distinguishing between horizontal wells and vertical. The top left shows all six histories, but most are compressed at the bottom of the chart because the horizontal drilling in the Permian Basin so uniquely dominates the current production.

In the upper right is the first zoom in, showing the bottom one-sixth of the previous graph. This view shows how *vertical* wells in the San Juan and Permian Basins form the next tier of production, how they have been declining already for about 25 years, how they are now producing only about a quarter of their peak, and how *horizontal* production in the Permian is now dozens of times larger than either.

The graph in the lower left zooms in again to the bottom fifth of the previous graph to show the character of two more subsets. The carbon dioxide (CO2) supply wells of the Sierra Grande Uplift have been declining for most of the past 30 years and continuously for 15 years

following a brief period of redevelopment. In the San Juan Basin, horizontal well drilling has continued and increased production. Though notable for the fact of its success, the number of wells and the volumes are still a small fraction of the state's overall production.

The lower-right graph demonstrates the history of the Raton Basin, containing a small number of low-producing wells. In aggregate, they have declined more than 50% since 2012. These graphs are foundational to understanding the significant number of late-life wells that currently exist in New Mexico, which is relevant because late-life, low-producing wells are the kinds of wells at risk of becoming orphans.

Q: Are orphan wells a problem for the State of New Mexico and taxpayers, and, if so, can you please describe the scale of the problem?

A: Orphan infrastructure is harmful to the state and to the public because of historical and potential future pollution. The requirement for oil and gas companies to decommission their infrastructure has existed for some time because of the well-established fact that oil field locations can remain polluted by historical spills and the recognition that unplugged wells risk creating additional pollution. Existing pollution from historical spills affects the value, use, and environment at the location. In some cases, surface pollution can seep down into—and pollute—subsurface reservoirs of drinking water. Without effective plugging of the wellbore, additional oilfield fluids, including natural gas, oil and oilfield brine, can potentially move through the open borehole to fresh groundwater zones, the surface, or the atmosphere.

To remediate and avoid the public price of pollution takes money that is supposed to come from the companies that financially benefitted. The legal framework to pay for the full scope of decommissioning differs in New Mexico and depends upon the mineral ownership. Under the Commission's rules, the state does not require financial assurance if a "well is covered

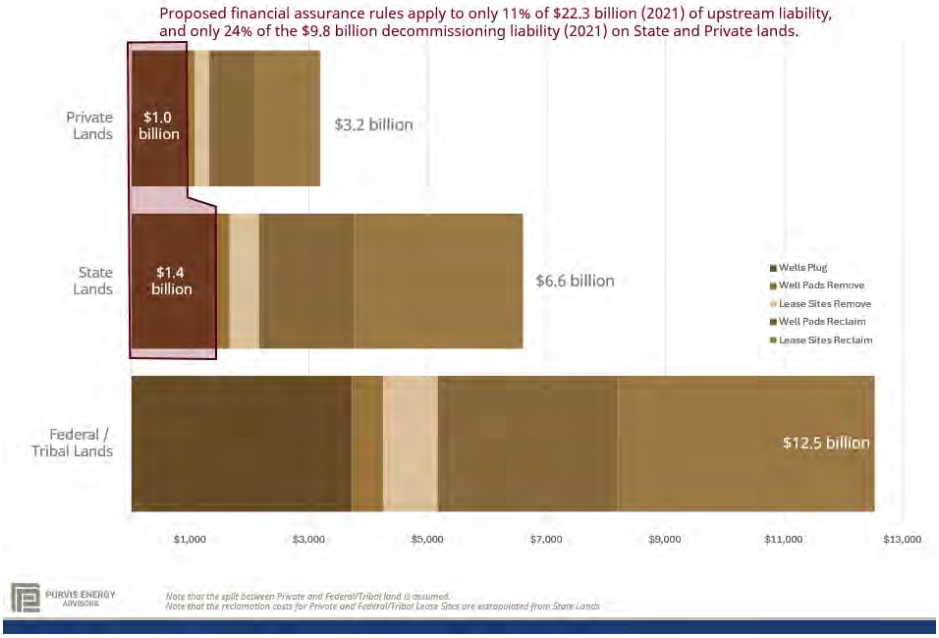
by federally required financial assurance," 19.15.8.9.A NMAC, which means that OCD does not require financial assurance on wells subject to federal mineral leases. Although, working with the U.S. Bureau of Land Management, OCD does exercise jurisdiction over inactive federal wells and has plugged orphaned federal wells.[3] And cleanup on state lands and federal lands may fall first to previous owners, to the extent they still exist, before falling to the public.

As I understand it, the Commission uses the Reclamation Fund for the full scope of decommissioning tasks and may use the funds for cleanup on state and federal lands, but the proposed rules deal only with downhole costs of wells and only for a fraction of the wells in the state. Applicants' Exhibit 34 summarizes the magnitude and relative proportions of this full scope of decommissioning costs for the upstream oil and gas industry.

Vertex Resources Services (Vertex) is a decommissioning contractor active in New Mexico, and in 2021 it prepared an estimate of the full scope of decommissioning costs on state lands and, in most cases, for the state as a whole. Each color represents a different kind of cost estimated by Vertex, and each bar shows a separate regime for enforcing accountability. Some assumptions required the estimation of costs not explicitly broken down for private and federal lands, and Vertex describes their figures as Class V estimates, which are actionable but uncertain. The area highlighted in red shows the fraction of the total liability intended to be protected by the current proposal.

[3] *See* Applicants' proposed 19.15.25.13.E NMAC (Apps' Ex. 1-E), relating to placing wells in temporary abandonment status, which provides that the timeframes in that section "shall be implemented consistent with any applicable federal requirements."

Applicants' Exhibit 34: Total decommissioning and reclamation cost of upstream oil and gas operations in New Mexico after Vertex 2021 not adjusted for subsequent inflation.



Vertex's work implies that the total cost of decommissioning the upstream infrastructure in 2021 and at 2021 prices was over $22 billion. At the time, it reported a 90% confidence range of -30% to +50%. Since then, service costs have increased significantly.

By comparison to the $22 billion contemporaneous estimate, the Reclamation Fund raises and spends only tens of millions each year, and the proposed rules address only 11% of the total liability and only 24% of the costs on state and private lands. The rules do not protect the costs of surface removal, remediation or restoration of well sites or shared facilities. What's more, Vertex estimated the cost of decommissioning pipelines in the state to cost an additional $3.4 billion for typical decommissioning or $20.3 billion for full removal.

As it stands, the Reclamation Fund has an opportunity cost. If funds were not dedicated to cleaning up industry's responsibility, then the same revenues could be used for other costs currently covered by other tax revenue. But more to the point, the approaching liability of an aging industry is orders of magnitude larger than the Reclamation Fund and an order of

magnitude larger than the costs addressed in this rulemaking.

Q: If orphaning of oil and gas infrastructure is a problem that the state wants to avoid, then it would be helpful to understand how orphaning occurs. Would you please explain how wells and related infrastructure can become the responsibility of the state?

A: The short version is that wells and infrastructure are orphaned when oil and gas companies accumulate the liabilities and run out of money to pay them. Inherent market dynamics tend to push oil and gas fields into this position, so the job of preventing orphaning falls to the regulator.

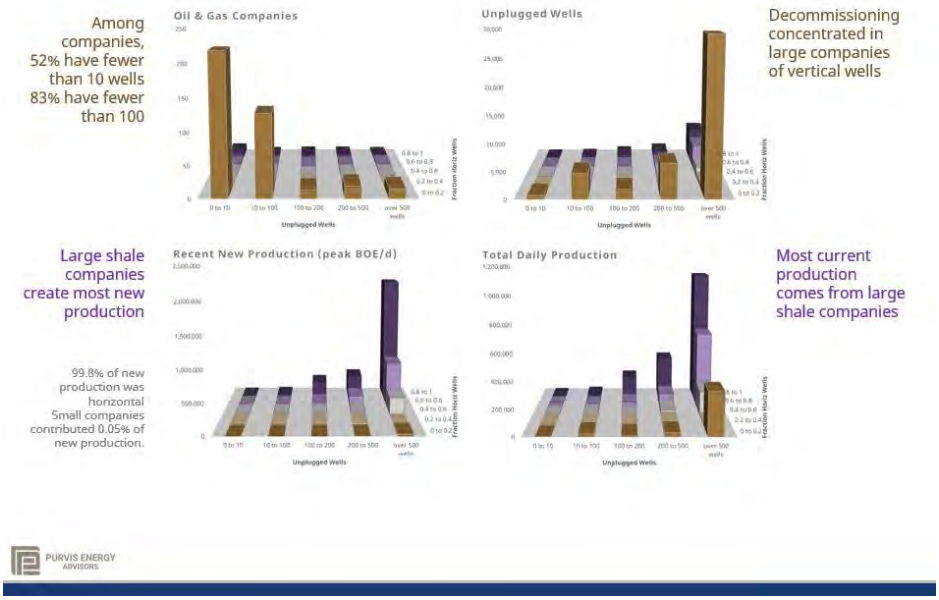
By definition, decommissioning costs for a well or a field must be paid after profits from production have ended. So, an oil and gas company must either have saved money from historical operations to meet its final obligations, or it must take money from other still-profitable operations. In my experience working with oil companies for decades and talking with them expressly about these issues for several years, it is extremely rare for an oil company to save money in advance to pay for its ultimate decommissioning liability. In fact, most companies do not decommission their wells promptly after production ends. Instead, companies prefer to delay spending capital for which there is no financial return and to maintain the minor option value of an unplugged well. Market dynamics include little or no incentive to decommission infrastructure, and current regulatory processes allow operators to accumulate the liabilities.

If liabilities continue to accumulate, they can eventually outweigh the assets of remaining production. If an oil and gas company continues to reinvest its profits successfully then it might take a long time for accumulated historical liabilities to outweigh current assets. The problem lies in the fact that most companies are only depleting their fields, not reinvesting in new ones.

Applicants' Exhibit 35 shows the bifurcation of the industry in New Mexico. A relatively

small group of companies are actively drilling, and they are dramatically increasing the headline oil and gas production from the state. On the other hand, a much larger population of wells predate the shale revolution and have been depleting for many years. The large majority of oil companies focus on these mid- to late-life fields. In some cases, they are trying to mitigate the decline with on-going projects, but mostly they focus on reducing costs.

Applicants' Exhibit 35: Four measures of the size and impact of oil and gas companies grouped by size (based on wellcount) and relative proportion of vertical and horizontal wells.



In all four of the bar charts, producing companies are grouped into the same bins based on their size and the constitution of their portfolios. From left to right, companies are categorized based on the number of unplugged wells that they bear responsibility for with small companies on the left and large companies on the right. From front to back, they are categorized by the fraction of their wells which are horizontal. In front are portfolios dominated by vertical wells, while portfolios of horizontal wells reside in the back. The height of the bars in each graph represents a different measure of each group of companies.

Three clusters of companies are pretty cleanly separated from each other. The top left

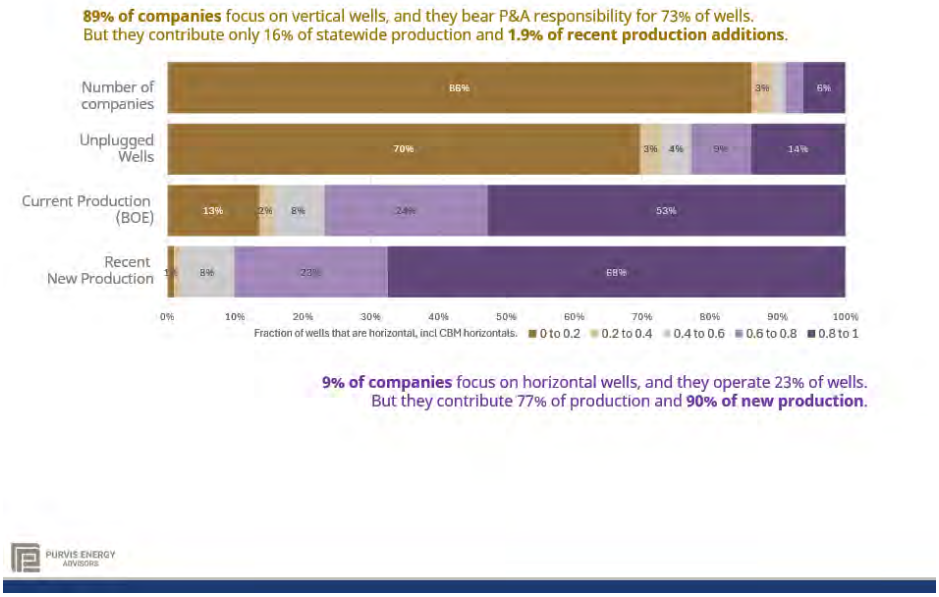
graph counts the number of companies in each group, showing that small companies of vertical legacy wells make up by far the largest population of corporate entities. The upper right graph contrasts the magnitude of the corporate entities as measured by unplugged wells. By far, the largest concentration of unplugged wells, read "decommissioning liability," is concentrated in large companies of legacy wells.

But the bottom right graph contrasts the value of the portfolios by showing the magnitude of production. Production and its associated cash flow concentrate in large companies of much more productive horizontal wells. There are few companies with portfolios balanced between high and low producers within the state.

The last graph in the lower left shows the relative contribution to new production in the last five years. It shows still greater concentration of value creation in large shale companies. In the last five years, only 0.2% of new production did not come from horizontal wells, and small companies contributed 0.05% of new production. There is practically no such thing as a small company that drills shale wells.

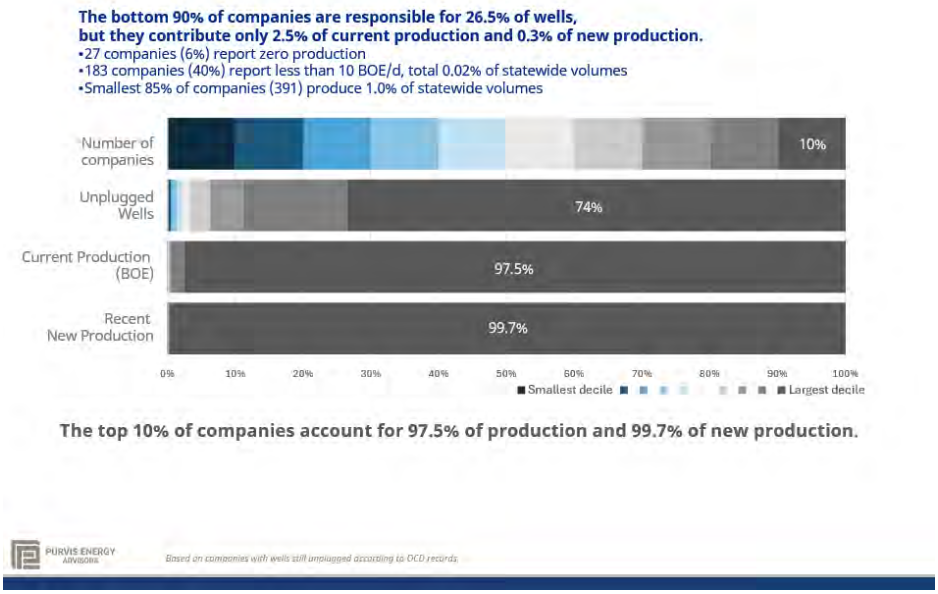
Two more exhibits show the same disparities among portfolios but in a different way. Applicants' Exhibit 36 shows how the nature of the portfolios vary, and Applicant's Exhibit 37 shows how the size of the companies varies.

Applicants' Exhibit 36: Relative measures of oil and gas companies grouped by the nature of their portfolios.



The colors in Applicant's Exhibit 36 correspond to the colors in the four-part bar chart in Applicants' Exhibit 35. Portfolios of legacy vertical wells are shown in brown and portfolios of horizontal wells are shown in purple. Each of the four bars compares a different measurement of the portfolios. In the first bar, the two segments showing portfolios dominated by vertical wells show that over 89% of corporate entities operate legacy portfolios, and the second bar shows that 73% of the current plugging liability sits in portfolios of legacy wells. The last two bars show that this large population of legacy portfolios contribute only 16% of current production and only 1.9% of new production. At the other end of the spectrum, the 9% of companies that focus mostly or heavily on horizontal wells contribute 77% of total production and 90% of new production.

Applicants' Exhibit 37: Relative measures of oil and gas companies grouped by size as measured by current production.



Applicants' Exhibit 37 is configured the same way but uses a new color scheme to indicate the size of the company. The first bar shows how each color applies to a different decile of company sized ranked on the number of unplugged wells. It shows just how little most companies are. The top 10% of companies account for 74% of wells, 97.5% of current production, and 99.7% of new production. In other words, if 90% of the companies responsible for unplugged wells in the state were to instantly disappear, the state would lose only 2.5% of its current production and 0.3% of production growth.

Q: How does a well or field progress through its lifecycle before it gets into the position of becoming an orphan?

A: As a field progresses through its life cycle from discovery to decommissioning, the strategies for making money also evolve. The lifecycle begins with geologic exploration then delineation and characterization, and it ends with cost reduction and operating efficiency. Fields begin with more resources in place than at any other time in their life, and wells start their life at

the highest production they will ever experience. Early in life, strategies focus on maximizing profits, but as production declines year over year, margins thin, and profits taper. Late in life, as opportunities for new recovery are exhausted, the strategy turns exclusively to cost reduction. Operations can continue for many years with marginal economics while the field is financially fragile, susceptible to unexcepted costs, inflation, and normal commodity price swings.

Sometimes an oil company will hold the field through multiple business strategies, but more often fields move to companies with more suitable specialties. In the last half of life, these fields (including their attendant and approaching decommissioning liabilities) move to companies who specialize in cost-reduction, often smaller companies, as demonstrated empirically above.

Except for a couple of situations in which production may temporarily increase, production systematically and consistently declines from its initial rates, and monthly operating profits also suffer secular decline. Early in a well's life, its monthly revenue is often 10 times as great—or more—than its monthly costs to operate, but the slowdown of produced volumes is also greatest in the early years. In terms of absolute volume, the slow-down of produced volumes is less later in the life of a well. Eventually, though, monthly net revenue no longer pays for the incremental cost of operations, and we call this the "economic limit" of production. Unless something changes to improve the situation, operating expenses—and thus operations themselves—are no longer justified by revenues. Continued operations, at this stage, mean intentionally losing money.

By the time that net revenues at normal prices are only twice as much as monthly costs, a well is within striking distance of its economic limit. This is not a formal or industry-recognized threshold but my rule of thumb based on decades of evaluations. I observe that commodity

prices can swing by a factor of two, and a downcycle could completely shut-in production. Second, I observe that wells often end their lives when something breaks, and the cost of repair exceeds the cash flow it would restore.

One might assume that any well that is producing is making money, and that the well is active because the cost of operations are justified by the revenues generated. That is not always true because there are also other economic drivers in play. Setting aside the nature of economics of groups of wells, companies sometimes deliberately operate wells at a loss. The operator may believe or hope that economics will improve—that the price of oil may increase or the cost to operate may reduce. A company operating wells at a loss may also want to maintain its rights to produce from the land so that it can conduct some other operation in the future. Land that is held by legacy production from vertical wells might be redeveloped, for example, with horizontal drilling.

Companies can also operate wells at a loss in order to delay decommissioning liabilities. In New Mexico, a well can stand idle for 15 months before it must be either temporarily or permanently plugged (except for a small number exempted by the current rules, *see* 19.15.5.9.A.(4) NMAC), and both types of plugging require time and especially money. It is cheaper to operate a well at a loss than to plug and abandon it. In fact, the discrepancy is usually so large that operating permanently at a loss is still cheaper than decommissioning. A small monthly operating loss can be financially more favorable than paying the large capital cost of decommissioning. In other words, economic realities can favor producing wells below their economic limit. I characterize these as "life support" wells. They should be dead, but the operator is keeping them pumping.

When wells do cease operations, they usually are not plugged promptly; it is common for

wells to be shut in for a period first. The term "shut-in" generally means that a well is capable of production (or injection) but is not producing (or injecting) at that moment. It is common for wells to stop producing for a number of months and later to be reactivated or to alternate intermittently between activity and inactivity, generally indicating a well that is struggling to produce economically. And regulations in New Mexico allow wells 12 months to restore production and three months of grace period to apply for a longer period of temporary abandonment. By the time a well has been inactive for 15 months, it is unlikely to be restarted in the future. If it is restarted, its incremental production is likely to be small compared to historical production. Both of these conclusions comport with my experience and observation but are quantified empirically in the testimony of Applicants' expert, Adam Peltz.

After activity has ceased and a well remains unplugged in violation of New Mexico rules, it generally takes a good deal of time and resources from the OCD to move a well through the process of enforcement into its own control and responsibility. Designating a well as inactive can trigger a sequence of events that leads to orphaning. But limited resources mean that the OCD only pursues enforcement against a fraction of the wells in violation and eligible for enforcement. As a matter of fact, data from OCD's inactive well list, previously discussed by Applicants' expert, Tom Alexander, in his direct testimony, show that the vast majority of wells on OCD's inactive well list—over 85%—are currently out of compliance with the Commission's rules.[4] By analogy to my experience and knowledge with Texas well decommissioning, not every single well subject to enforcement becomes an orphan, but practically all do. For this transition period from the triggering violation marking neglect by the operator to the final order consummating the state's control, we can use the term "end-of-life enforcement" or more

[4] On July 3, 2025, 3,234 inactive wells out of a total of 3,765 inactive wells were out of compliance. *See* Alexander Direct Test. (Apps' Ex. 3).

figuratively "foster care."

Q: In your role as a consulting reservoir engineer, what financial and economic concepts do you apply when analyzing an operator's decommissioning obligations?

A: Effective policy to prevent the orphaning of oilfields requires an understanding of the present reality of how much wells are producing and of the large- and small-scale economics channeling that reality as described above. Policy needs also to account for the unintuitive financial realities during late-life production. In my practice, I use a concept I call "holdback" to analyze an operator's decommissioning liabilities.

My engineering practice, my research, and fundamental economic theory show that it is possible for a well or a field to generate significant cash flow each month, to forecast a positive net present value, and still to be unable to pay for its decommissioning. In my experience, decommissioning at today's prices can commonly equal the cash flow from the last 10 to 15 years of operations in a field. Which is to say, providing for decommissioning and protecting against orphaning require long-term thinking and a different kind of economic yardstick.

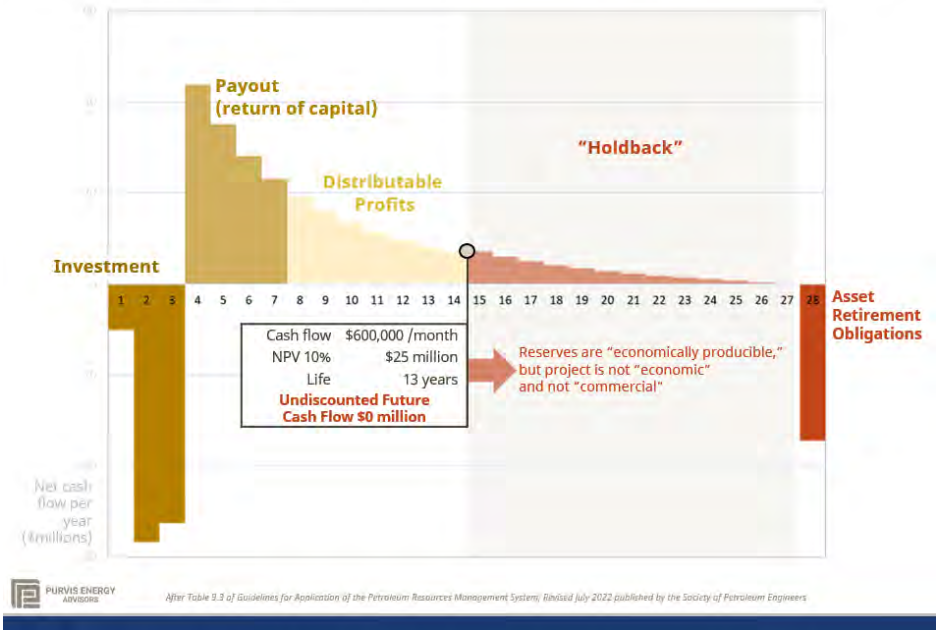
The concept of "net present value" dominates the analysis of investments of all kinds, reducing projected future values to a smaller value today to account for the delay and risk of returns. The same concept is commonly applied to decommissioning liabilities despite the fact that decommissioning is not an investment and is not uncertain. Decommissioning is literally burying money in the ground; the so-called "time value of money" does not create a preference for decommissioning sooner than later. Decommissioning is 100% guaranteed to come due at some point, and the cost is much more likely to be higher in the future than it is now.

When planning puts these costs at the end of profitable operations, then the cost of the liability suffers more discounting than all of the forecasted profits which come first. So, even

when the undiscounted cost of the liability equals the undiscounted cost of forecasted profits, the net present value stays positive. Discounting reduces the liability more than it reduces the profits. The guaranteed and likely inflating liability is reduced more than the uncertain, financially fragile profits from operations.

Applicants' Exhibit 38 demonstrates these concepts using a schematic of cash flow taken from the engineering literature, specifically from an example of how to apply economic evaluation criteria published by the Society of Petroleum Engineers, with my labels and coloring added.

Applicants' Exhibit 38: Schematic of cash flow for a hypothetical oil and gas project to demonstrate the economic concepts of payout and holdback.



A project starts with the negative cash flow associated with the capital investment, in this case a small offshore platform. Operating profits begin with production, and the first funds to come in are considered as replacement of the money invested. At the point when the project has returned the amount of money invested, reservoir engineers say the project has "paid out." Payout is the point in time when accumulated cash flow equals the capital that has been invested.

Proceeds after that point represent profits on the historical investment, and those are projected to last another 20 years in the published example. Asset retirement obligations, i.e. decommissioning, is quantified and included in the initial evaluation, expected to be incurred in year 25 after the start of production.

The problem arises in year 12 of production, labelled as year 15 of the project in the graphic. At this point in time, more than half of the life remains, the project is still generating $600,000 of operating profit every month, and its net present value discounted at 10% (including decommissioning costs) is still $25 million.

It looks like a valuable asset, but the total projected cash flow is zero. The years of projected operating profits equal the projected cost of decommissioning. If a company were to pay $25 million for the field, operate the well according to plan, and then pay for decommissioning, then it would lose $25 million dollars for its many years of work. All of the operating profits that came in the door during operations would go back out of the door at the end of operations.

As I said, I call this breakeven point "holdback," the point when capital to be spent equals remaining cash flow analogous to the investment measure "payout" but in reverse. At the point of holdback, undiscounted future cash flow is zero. After that point, the total is negative.

The current version of the industry standards for evaluations acknowledges the significance of this point though without identifying it as such. The *Petroleum Resources Management System* is created and endorsed by major professional societies, and it is the industry benchmark standard for evaluation practices. The current version, last updated in 2018, does not define holdback, but it does unambiguously define other terms that correspond to and affirm the significance of that point in time. A project is only called "economic" when

undiscounted future cash flow is positive. That is, a project is called "economic" only if it will cost less than it makes. And if a project does not qualify as "economic," then it does not qualify for the higher standard as "commercial." Instead of describing a late-life project as "economic," the standards define "economically producible." It can be economically justified to conduct the operations past the point when the project is itself an economic venture.

This is the pivotal reality that the Commission must bear in mind. Projects and whole portfolios can be upside down and destined for orphaning long before production ends.

For a deeper explanation and demonstration, the Commission can review my technical paper on the subject attached as Applicants' Exhibit 54 and can consider that similar business and financial dynamics play out in other industries, which can serve as examples of what to do and what not to do. For example, West Virginia faces a surfeit of abandoned mine lands left on its doorstep by bankrupt coal companies, and California is home to orphaned windmills from the first wave of renewable energy in the early 1980s. The nuclear power industry, however, does not orphan its power plants because operators are required regularly to prove that they have the funds available for decommissioning.

Q: Given your review of financial assurance requirements generally and your understanding of the financial situation needing assurance, what would you recommend?

A: As I explained, the inherent natural market dynamics strongly motivate companies neither to pay nor save for the liabilities but instead to pass along aging fields (and their approaching liabilities) to companies with the same economic incentives but less financial wherewithal to meet statutory demands.

In the face of these economic drivers, regulators commonly use two key mechanisms to prevent orphaning: They manage how long wells are allowed to sit idle, and they get from the

operator some form of financial guarantee that money will be available to complete well decommissioning, if the company ceases to exist. The public is impacted when these two guardrails fail.

To whit, wells are orphaned when companies' do not have enough cash flow, and orphaned wells become a burden when the guarantees and other recourse fall short of actual costs.

If you want to avoid orphaning, then it is best to interrupt the natural market dynamics that motivate companies not to pay for or save for liabilities earlier in the production life of a well rather than later. The cost of decommissioning is small or very small compared to the initial cost of drilling and completing a well, and a newly completed well almost always produces at the highest rate it ever will. Consequently, the financial significance of decommissioning and the risk of orphaning is extremely low early in the life of a successful well. Initial completion is the least impactful point in time at which to fund decommissioning and avoid orphaning, but the point of holdback arrives surprisingly early.

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS

Definition for Marginal Well

Q: Let's turn to Applicants' proposed amendments to Commission rules. Beginning with 19.15.2 NMAC – General Provisions for Oil and Gas Operators, Applicants propose to add a new definition for "marginal well" at 19.15.2.7.M(2) NMAC. What is the purpose of this new definition?

A: "Marginal well" is a new category of financial assurance initially proposed by OCD, based on their staff's experience with high risk wells. OCD proposed the provisions for defining this new category in 19.15.2.7.M(2) NMAC and proposed increased financial assurance amounts

for these wells in 19.15.8 NMAC in its February 12, 2025 Redline Proposal (Apps' Ex. 5) submitted to all parties in this proceeding. Applicants adopted OCD's proposals. As a general matter, the changes in Part 2 help to create the framework of definitions deployed later in the procedural parts of the rule. Applicants' proposed definition of "marginal well" is:

> **19.15.2.7.M(2) "Marginal well"** means an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period.

This definition uses a measure cognizant of current reality to create a new category of financial assurance, which is especially likely to represent wells with marginal economics. At the limits, it captures wells that produce less than 5.6 BOE/d over half the year or an average of 2.7 BOE/d over a full year. However, the fact that both volume and time criteria must be met means that the definition is doubly conservative and impacts fewer wells than alternative criteria.

A well is not considered "marginal"—and not subject to the corresponding increased accountability—if it operates more than 180 days out of 365, regardless of how little it produces by those operations. For example, a well that produces only 5 BOE but operates for 181 of the 365 days in a year to report those 5 BOE is not categorized as "marginal" and not subject to increased accountability.

Conversely, a well is not categorized as "marginal" regardless of how little it operates if the total volume is high enough. A well that cannot or does not produce for 298 days of the year but produces 15 BOE/d for 67 days also does not require increased accountability.

Q: What is the basis for the proposed definition of "marginal well"?

A: Based on my professional experience, I find these thresholds to be conservative. I am highly confident that wells producing below these dual thresholds present a risk to the operator's portfolio and thus contribute to the risk of orphaning. I have used several analyses to test and to

validate my judgment, which are discussed in detail below on the section on 19.15.8 NMAC – Financial Assurance.

19.15.8 NMAC – FINANCIAL ASSURANCE

General Overview

Q: Mr. Purvis, before you discuss Applicants' specific proposals to amend 19.15.8 NMAC – Financial Assurance, please discuss the role of financial assurance in general and the problems that arise when financial assurance is inadequate. Let's begin with why adequate financial assurance is an important component of effective oil and gas regulations?

A: The first wells I know of to have been orphaned by their operator were located near Oil Creek, Pennsylvania in the late 1860s less than a decade after the first commercial oil well in the U.S. was drilled there. Of course, there were no standards for plugging wells until much later. In the early and middle parts of the last century regulators in separate U.S. jurisdictions began creating and improving rules for how wells are plugged, when they are plugged and how the plugging can be financially assured. Since about the middle of the last century, regulators have widely required some form of financial guarantee that companies will perform the plugging required of them under state law and regulations. The idea is that the oil or gas company owes a duty of cleanup to the state, and the state wants some kind of assurance that the obligation will be met.

But the financial assurance was initially less important because states also did not allow wells to stand idle indefinitely. By the 1980s, most jurisdictions gave oil companies only a few months to a couple of years to either reactivate or plug their wells. In Texas, for example, a

permit was required to allow a well to stand idle more than three months, and that permit only allowed wells to be shut-in a maximum of 12 months.[5]

The oil price collapse of 1986, however, triggered a new trend of relaxing regulations. It was believed that oil prices would return to elevated prices, and no one wanted to plug a bunch of wells that they believed would come back to life with prices in a few years. So, many regulators across jurisdictions changed the rules to allow wells to stand idle longer. By the 1990s in Texas, wells were allowed to stand idle indefinitely as long as they passed simple integrity tests every five years.

Regardless of the rules about letting wells stand idle and unplugged, financial assurance remains a second key part of an effective regulatory framework. As I've said before, the overall lifecycle of the legacy U.S. industry has now reached its last stage, so the pattern of orphaning during previous and more financially secure stages has limited applicability. Still, history shows a long track record of numerous wells orphaned to the care of states without the operator having met their decommissioning obligations. Historically, 5% of U.S. onshore wells documented as plugged were orphans plugged by state agencies. The pace of orphaning nationally continues to grow, but the pace of state agency plugging has not grown as fast. More orphan wells exist unplugged today than have been plugged in the history of these public programs, many dating back decades. Today's orphans constitute 7% of the unplugged well inventory in the U.S. and 15% of idle wells.[6]

The amounts of financial assurance required and the forms of the guarantee accepted both vary among jurisdictions. The most common type is called a "bond," but it is not a deposit or an

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[5] Railroad Commission of Texas. (n.d.). *Texas RRC History of the Railroad Commission 1980 1999*. Retrieved May 31, 2017, from http://www.rrc.state.tx.us/aboutus/history/history19801999/

[6] Purvis, Dwayne. 2024c. "Scoping the Issue of Unplugged Wells: Well Count, Status, Ownership, and Policies." AGU Annual Meeting (Washington D.C.), December.

insurance policy. In this industry, "bond" means a pledge, and it functions like a bail bond. The oil or gas company pays a third-party to act as a guarantor for the face value of the bond. Like a co-signor on a loan, the bond company promises to pay the value if the company does not.

In exchange for its services and risk guaranteeing the sum, the bond company requires a fee, which is usually 1% to 5% of the face value of the bond, renewable each year. In addition, if the bond company thinks that the company may default and put them at risk, then they may require collateral from the company. In the most extreme case, the bond company may decide that the oil or gas company is so likely to default that the bond company will not co-sign for the bond, unless the oil or gas company puts the full value of the bond into an account held by the bond company.

Q: Would you summarize why the current financial assurance regulations expose the state and the public to financial risk from orphaned wells?

A: To be clear, rules about financial assurance and other enforcement mechanisms are a second choice from a policy perspective. The first, best, and most efficient choice is to create a set of rules that prevent the need for the state to get involved with doing the plugging. Other parts of the proposed rules address this primary strategy.

As it stands now, the financial assurance rules currently on the books in New Mexico are, in theory, part of the set of protective measures. In practice, however, they are so weak that they are rendered irrelevant, leaving a gap that exposes the state and the public to the financial risk of orphaned wells, particularly as the bulk of the wells in the state deplete and decline to the end of their economic life.

To understand how current financial assurance rules expose the public to risk, we first need to understand how it fits with other policy measures to protect the public from the cleanup

costs of former profit centers.

First, many wells in New Mexico are drilled on state or federal lands and subject to those leases. State and federal authorities have, especially in recent years, successfully pursued previous operators of the wells and, by the terms of their leases, required them to decommission the orphaned infrastructure. Of course, this process takes a good deal of time, effort and money, particularly for the state which has had to file dozens of lawsuits to require predecessor companies to shoulder the responsibility.[7]

Second, as discussed, a portion of state severance taxes on oil and gas production are routed into the state's Reclamation Fund which is then used to pay for the decommissioning of orphaned wells and facilities. As with enforcing predecessor liability, the process of orphaning and plugging is slow and time-consuming.

These first two mechanisms have been effective in the cases that OCD has pursued, but the time, difficulty, and cost mean that the agency can take on only a small portion of the evident need. As described above, thousands of wells are currently standing idle longer than they are allowed and waiting on enforcement.

In theory, the plugging bonds posted by oil companies could be claimed by authorities to help pay for cleanup. However, the value of the bonds is so low compared to the difficulty of making the claim that, in fact, the so-called financial assurance is almost no assurance at all. OCD collects very little money from financial assurance bonds. I do not see any dynamics that will change this fact in the future. Already the need for protection of the public has far surpassed the other mechanisms. Without reform, the current financial assurance policies will continue to

[7] Gilmore, Nicholas. n.d. "State Land Commissioner Turns to Courts to Force Oil Well Cleanup." *Santa Fe New Mexican*. Accessed August 1, 2025. https://www.santafenewmexican.com/news/local_news/state-land-commissioner-turns-to-courts-to-force-oil-well-cleanup/article_265e2a13-0dbd-4be8-a171-3000a70e427d.html.

be worthless in the face of liability and risk which continue to increase depletion and cyclic commodity prices.

Q: Would you summarize how Applicants' proposed amendments to the Commission's financial assurance requirements are tailored to protect New Mexico from wells at the greatest risk of orphaning?

A: The proposal targets the greatest risk by setting a more reasonable per-well value, by requiring greater assurance from those portfolios with concentrated risk, and by trying to prevent manipulation to avoid the protections.

The categories that require single well financial assurance in proposed 19.15.8.9.D and E NMAC are based on the experience of OCD staff in the field and are supported by the data I have developed or reviewed. Extra protection targets portfolios containing a higher concentration of impending liabilities and thus implicitly at higher risk of not being able to fund them. And the proposals that allow OCD to more closely scrutinize well transfers at proposed 19.15.9.9 NMAC allow for a more diligent and comprehensive review when liabilities are transferred from one portfolio to another so that companies cannot intentionally lay off their responsibilities to operators lacking the ability to abide by the law.

I support the rules as proposed, though I regard them mostly as modest and conservative. I note that there are some limitations to the protections provided (ways that the protections could fail or be avoided), but they do provide additional protections.

I observe that tightening regulations now to provide more protection in total in the medium and longer term comes at the cost of wider impact in the short term. The lack of reform to financial assurance until now has created a backlog of current liabilities, and any change in accountability on oil and gas companies will create distress for some companies. The financial

stress it creates will be experienced, however, by companies that have not planned to meet their decommissioning obligations and who remain unable to meet them.

Specific Provisions

Active Wells

Q: Turning to 19.15.8.9 NMAC – Categories and Amounts of Financial Assurance for Well Plugging, what amendments do Applicants propose to financial assurance requirements for active wells at 19.15.8.9.C NMAC?

A: Applicants propose:

> **19.15.8.9.C. Active wells.** An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsections D and E of 19.15.8.9 NMAC in one of the following categories:
>
> **(1)** a one well plugging financial assurance in the amount of $150,000 per well. ~~;25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or
>
> **(2)** a blanket plugging financial assurance in the amount of $250,000 ~~following amounts~~ covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC.~~:~~
>
> ~~(a) $50,000 for one to 10 wells;~~
> ~~(b) $75,000 for 11 to 50 wells;~~
> ~~(c) $125,000 for 51 to 100 wells; and~~
> ~~(d) $250,000 for more than 100 wells.~~

This provision increases the amount of third-party assurance required for the company to continue operating the well to $150,000 for a single well bond and to $250,000 for all blanket bonds for active wells. It simplifies this part of the regulations so that companies with only one well will have to post $150,000, and all other companies would post $250,000 of third-party, co-signor guarantee.

The $150,000 remains below the single-well actual cost of downhole plugging for the orphan well program. However, the Oil and Gas Act's statutory cap of $250,000 for blanket bonding means that the single-well financial assurance requirement will not have wide effect, as

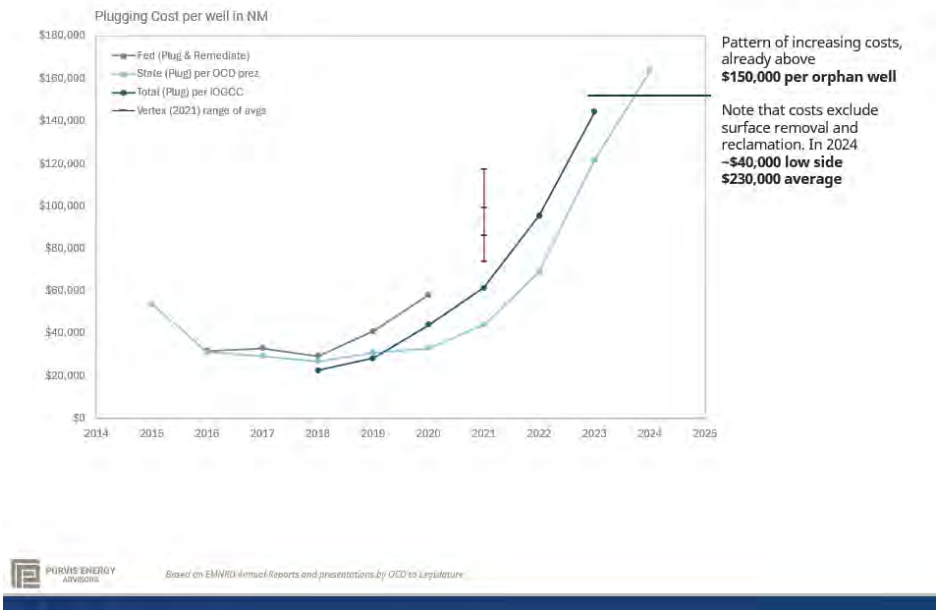
most wells reside in large company portfolios of 400 wells or more, thus qualifying for the blanket bond. Given this dynamic, the $250,000 blanket bond cap means that the bond required for active wells under the proposed rules will cover a small fraction of the actual costs owed by most companies.

Q: What is the basis for amending the one well plugging financial assurance amended to $150,000 per well?

A: As described above, the figure of $150,000 more closely aligns with actual and estimated costs of downhole plugging for which the state needs to protect itself. Notably, the financial assurance in this provision of the proposed rule and authorized under the Oil and Gas Act does not cover other costs, such as surface remediation and restoration, that create financial liabilities that the state also needs to protect itself from.

My research has found two sources for the cost of downhole plugging, namely the estimate made by decommissioning contractor, Vertex, described at the beginning of my testimony and the records of the costs incurred by the Division's orphan well program. Both costs are summarized in Applicants' Exhibit 39 below.

Applicants' Exhibit 39: Historical costs of downhole plugging for orphan wells in New Mexico.



The lines with circular data markers, showing a progression over time, represent actual out-of-pocket costs per well. The vertical red line with dashes for data markers represents the range of downhole plugging cost estimates made by Vertex in 2021 for wells statewide. Notably, the average plugging cost estimated by Vertex exceeds the contemporaneous actual cost of the program, but it is most salient that actual plugging costs per well paid out of pocket by the OCD have increased and already exceed $150,000. Actual recent costs for downhole plugging have run, on average, over $160,000.

The graph also shows that program costs in New Mexico have increased significantly in recent years, and I have observed similar patterns of increasing costs across several jurisdictions. Evidence points to several causes, and looking forward, many of those issues are likely to persist. For example, though overall oil field inflation has slowed down more recently, there is significant risk of renewed inflation from federal executive policies. Plus, the increased demand for decommissioning services is likely to continue to push costs. On the other hand, the industry

is not researching or developing technological innovations that would reduce costs. On balance of these and other forces, the strong weight of probability is for costs to continue to increase.

It is worth noting again what this figure does *not* consider. The graph does not include the cost of surface removal and reclamation, nor the administrative cost to the state. The most recent reports say that the low side costs run $30,000 to $50,000 per well, that the high side can run into the millions, and that the average runs about $230,000 per well.[8]

Both these downhole and the surface costs reported are only out-of-pocket costs paid by the state to vendors. The state must plan and supervise the work. I understand that there are no separate accountings for such costs in New Mexico, but a recent audit of the orphan well program in Ohio found that the internal labor cost of the regulator was about $17,000 for each orphan well plugged at an out-of-pocket cost of about $60,000.[9] This one analogous figure points to an internal cost equal to 28% of the contracted cost. Thus, average plugging costs with low side surface cleanup including supervision and administrative time runs over $250,000 per individual well.

It is true that the historical portfolio of costs is not a random sample across the state and may be biased toward more expensive wells. On the other hand, it is very likely that enforcement will continue to focus in the future on the same kinds of wells and sites as it has in the past. Most of the historical plugged orphans were located in the Permian Basin, and given that the states bonding rules do not overlap federal bonding rules, 71% of the subject wells are in the Permian Basin. I expect that the OCD will continue to plug the same kinds of wells in the foreseeable future as it has in the recent past. Thus, to the extent that the state will require bonds

[8] Davidson, X., Dodson, E., & Joyce, S. (2025). *Fiscal Impact Report HB0481*. And EMNRD. (2024). *ANNUAL REPORT 2023*.

[9] Farber, K. (2022). *Orphan Well Program Performance Audit, August 2022*.

to cover the costs of orphan wells, it is likely to continue needing about the same amount of money per well in the future. The financial assurance policy is meant to protect the state, so the amount of protection should be the amount of risk to the state. This $150,000 flat bond does not reflect how costs could vary among basins, types of wells or ages of wells, but it is grounded in reality and conservative compared to the full cost.

Q: What is the basis for amending the blanket bond financial assurance to $250,000 for all wells owned by an operator?

A: The reasoning for the $150,000 single-well bond applies in multiples to the $250,000 bond for two or more wells. The figure is close to the current downhole actual cost for a single well, which is the best data available, as I just explained. But financial assurance comparable to single well costs is spread across the liability for multiple wells. Limiting the blanket bond to a single tier of wells owned by an operator (i.e. two or more), allows for the greatest amount of per well financial assurance allowable under current law as I understand it, even if the figure is low when spread over large numbers of wells.

Q: On a standalone basis, how would this change affect the protection afforded the state and the cash flow of the companies?

A: This one provision on a standalone basis does not have much effect. The $150,000 bond would affect approximately 116 corporate entities, but these are responsible for 0.2% of wells in the state and 0.03% of the state's production. And a corporate entity with a single well probably doesn't provide enough work to keep even a single person busy full time.

The $250,000 bond would affect the rest of the companies operating in the state, and it would increase their costs, but bond insurance costs are a very minor portion of the costs of an oil and gas company.

From the perspective of the state, the total dollar value of bonds across the state would go up by a percentage that seems significant except by comparison to absolute value of the cost that remains unprotected.

Q: What impact do you anticipate this proposal would have on operators?

A: By themselves, the increase of bonds to $150,000 and $250,000 across the board will have little effect just because the costs are so small. A 3% premium, for example, would cost each company either $4,500 or $7,500 per year. Impacts become greater for companies that must single-well bond economically risky wells, such as marginal or inactive wells, or for all wells in portfolios with concentrated risk. So let me take this opportunity to offer a framework to consider the scope of potential consequences of requiring higher quality operations from oil companies.

In theory, any increase in costs can trip a well or company over the edge into bankruptcy, but only to the degree that they are already operating close to the edge. New Mexico like other states includes a community of so-called "stripper well operators" who make their living producing wells near the edge of profitability from month to month, who are experts at minimizing costs.

This class of operators should be not conflated with the much broader term of "independent" operators. "Independent" applies to companies that operate only upstream production as opposed to integrated oil companies which also operate refineries and retail outlets for their refined products. The term includes but does not mean small companies. Many large companies like Permian Resources and Hilcorp qualify as independent.

At any scale, a prudent operator abides by the laws and regulations and makes plans to abide by the law and regulations. Oil and gas companies, including stripper well operators, are

well aware that they will eventually be required to plug their wells and clean up their sites. This has been a requirement for decades. There is no surprise that someday they will be required to come out of pocket to pay for the retirement of their wells.

A prudent company with viable plans to meet its legal obligations will, as a result, have the means now either 1) to pay a fraction of the costs as assurance or 2) if it turns out to be lower, the whole of the cost to perform the legal obligation. If paying a fraction of the cost now puts a company into bankruptcy, then the company cannot be expected to be able to pay the full cost in the future after further production decline. Those companies that may be at risk of going out of business due to increasing accountability for financial assurance are companies that have knowingly put themselves in the position of being unable to meet their legal obligations. Bankruptcy is a natural consequence, accelerated perhaps but not created by the proposed rules.

For its part, the state also will have to live with the natural consequences of not having enforced tighter rules in the past. The question of policy is always the question of the greatest public good, and the question becomes which is better for the state: immediate orphaning but less total cost, or more total cost over a longer period as more wells become unable to pay their obligations.

At this point, I cannot say precisely how many companies are not prepared for the increased accountability, how each will exercise the range of options available to them, or how many will go out of business. But I can say that the companies at risk are the ones whose loss will be missed least. Applicants' Exhibit 37 above ranks and groups operating companies by size and demonstrates that the smallest companies in the state contribute little production to energy supply or economic activity. More importantly, they contribute practically nothing to ad valorem and severance taxes and practically nothing to drilling new supply.

This fact is also demonstrable from the experience of other states increasing their financial assurance requirements. Academic research has examined the effects of increased financial assurance in Texas and in North Dakota.[10] The following is an extended quote from a policy paper I co-authored earlier this year.

> "Boomhower (2019) examined the effects of increased bonding in Texas in 2012 but especially in 2002; Lange & Redlinger (2019) examined the effects in 2012 of increased bonding and other costs in North Dakota. Both studies support the conclusion that these policies have little effect on overall production.
>
> Boomhower provides an economic rationale for what to expect. He explained how bankruptcy law creates an economic advantage for small firms able and willing to compromise environmental protections, making them 'judgment-proof' and creating a distortion in the market. Forcing more costs onto these structurally-advantaged companies should offset the advantage and send some out of business. However, his theory also predicts that the best producing wells in their portfolios should be transferred to larger companies.
>
> The empirical data bore out both of these predictions. He observed that a number of small firms shut down after an increase in bonding requirements took effect but that most of their production was transferred to larger operators. The production that was shut-in was trivial to overall supply. On the other hand, the pace of well orphaning fell sharply, if temporarily, and the pace of citations by the state regulator for environmental violations also fell significantly. The companies that remained were better corporate citizens, at least in the short term. In the author's words:
>
> - 'About 5 percent of producers left the market immediately. These exiting firms were small and had poor environmental records.'
> - '. . .[T]he primary effect of the policy was to reallocate wells from small to large producers. The bond requirement moved about 4 percent of wells operated by the smallest 80 percent of firms to new operators. Another 1 percent of the wells operated by these firms were shut

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[10] Boomhower, J. (2019). *Drilling like there's no tomorrow: Bankruptcy, insurance, and environmental risk*. American Economic Review, 109(2), 391–426. https://doi.org/10.1257/aer.20160346; Lange, I., & Redlinger, M. (2019). *Effects of stricter environmental regulations on resource development*. Journal of Environmental Economics and Management, 96, 60–87. https://doi.org/10.1016/j.jeem.2019.04.006.

down, primarily representing low-producing wells where social cost. . .is most likely to exceed social benefit.'

- 'Environmental outcomes improved sharply.'
- '. . .[C]lear evidence of an approximately 70 percent decrease in orphan wells. . .'

Lange & Redlinger (2019) built off of Boomhower and undertook a study of a change in bonding and, especially, the cost of handling drilling waste in 2012 in North Dakota.

When the new rules were passed, industry decried the burden. The president of the North Dakota Petroleum Council objected, 'They are the most onerous regulatory changes we've ever seen.' He specifically complained that the regulations are 'now overly burdensome and among the most stringent and costly in the nation,' with an estimated cost of up to $400,000 per well. The regulator's assistant director agreed they were 'the most significant changes we have made in the 31 years I've been with the Commission.'

Lange & Redlinger (2019) looked back at the two years of activity after the change compared to the prior two years, and in order to normalize for other factors, the authors compared activity around the state's border with Montana which did not have a corresponding change. Thus rigorously controlled for other variables, the authors conclude:

- 'Results find no statistical change in the pace of drilling wells after the [North Dakota] regulations came into effect.'
- 'The reduction in production for small operators in [North Dakota] after the regulation went in effect, relative to production in [Montana], is about 0.5%. The reduction in production from small operators seems to be coming from operator exit.'

The authors found that 8% of operators exited, but still the effect on drilling and production was trivial at best. What is more, the authors also corroborated a statistically significant reduction in the number of environmental incidents in North Dakota as was documented in Texas. They write without caveat:

- 'The regulation is associated with a level shift down in the number of incidents that occur while drilling, which is consistent with higher bond requirements encouraging better safety and exit of relatively unsafe operators.'"[11]

[11] Purvis, Dwayne, and Ted Boettner. 2025b. *Filling the Hole, Part 2: The Solution*. Ohio River Valley Institute, Johnstown, PA.

Marginal Wells and Inactive Wells

Q: What amendments do applicants propose to the financial assurance requirements for the new category of marginal wells and for inactive wells at 19.15.8.9.D NMAC?

A: Applicants propose:

19.15.8.9.D. Marginal wells and inactive wells. Notwithstanding the provisions in Subsection C(2) in this Section:

(1) As of the [effective date of amendments] a transferee operator shall provide a one well plugging financial assurance of $150,000 for each marginal well prior to transfer.

(2) Beginning January 1, 2028, an operator shall provide a one well plugging financial assurance for each marginal well.

(3) An operator with over 15 percent or more of their wells in marginal or inactive well status, or a combination thereof, shall provide a one well plugging financial assurance in the amount of $150,000 for each well registered to the operator until the percentage of the operator's marginal and inactive wells is decreased below 15 percent.

(4) An operator may furnish all necessary one well plugging financial assurance in the form of a single instrument.

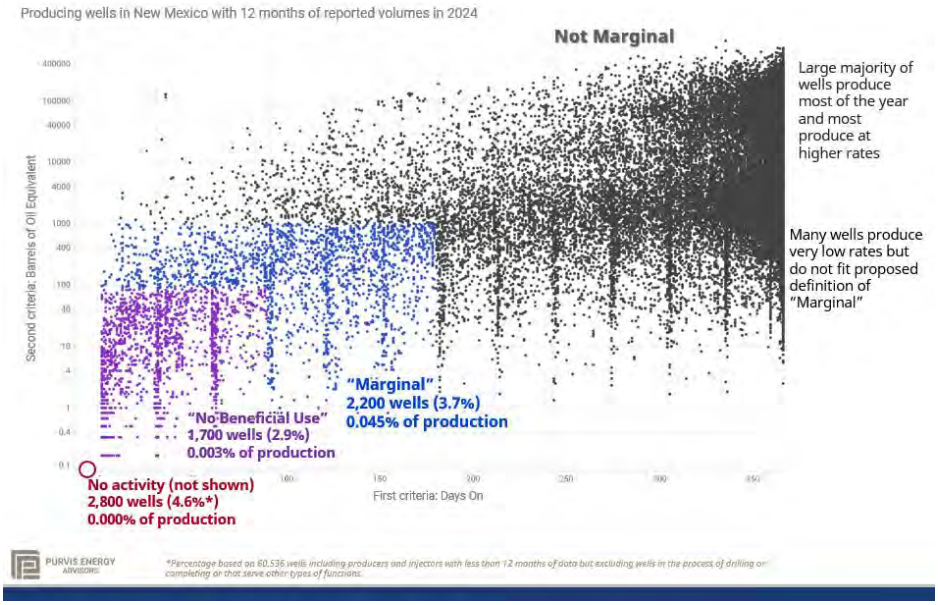
Q: What is the basis for the new category of marginal wells?

A: As I said, "marginal well" is a new category of financial assurance initially proposed by OCD based on their staff's experience with high risk wells. OCD proposed the provisions for 19.15.8.9.D NMAC in its February 12, 2025 Redline Proposal (Apps' Ex. 5), and Applicants have adopted these proposals. This new category is defined in such a way that it includes wells that are highly likely to generate only marginal or negative profits from operations.

To test this definition, I first considered how these definitions would apply to the wells currently producing in New Mexico. Each dot on Applicants' Exhibit 40 represents a single well with 12 months of production volumes and producing days reported to the OCD during 2024. The x-axis represents the first of the two criteria, namely the number of days reportedly active. The y-axis is logarithmic and shows the total volume of equivalent oil produced. In order to

qualify as "marginal" or as "no beneficial use," a well must fall in the lower left quadrant, both with few days of production and low volumes produced.

Applicants' Exhibit 40: Production vs days of activity of wells in New Mexico during 2024.



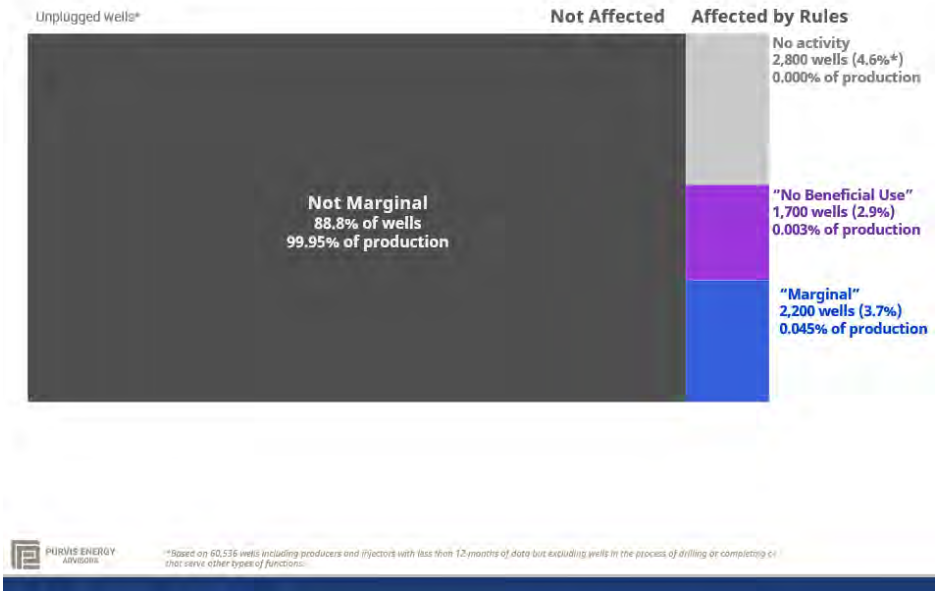
Wells with no activity do not appear on the graph because zero production is not shown on the y-axis, but a red circle indicates the approximate location of wells with no activity or production. Shown in purple are wells that meet the dual criteria of no beneficial use. Wells that meet the separate criteria for marginal are shown in blue. The categories are separate, not overlapping.

Using objective and available data self-reported by the operators to the Commission (plus some correction for wells that reportedly produced, for example, 36 days in a single month), I find that only 2,200 wells met the dual criteria for "marginal," constituting 3.7% of wells and less than 1/20th of 1% of the state's production during 2024. "No beneficial use" wells are less significant still.

I also note that a large number of wells produce less than 1,000 BOE in the year but more than 180 days. In the most extreme case, one well is reported to have produced every day of the year but only to have made 3 BOE. Still, this well does not qualify as "marginal" under the proposed definition.

My next two exhibits show this dynamic more clearly. Applicants' Exhibit 41 shows the New Mexico well counts in the various categories, but this one scales the criteria to the number of months for which production was reported by the operators in 2024. It shows that 88.8% of the wells and 99.95% of the production during 2024 would not be subject to the increased accountability that follows from the proposed definitions. I performed the same test for four previous calendar years and found the results substantially the same.

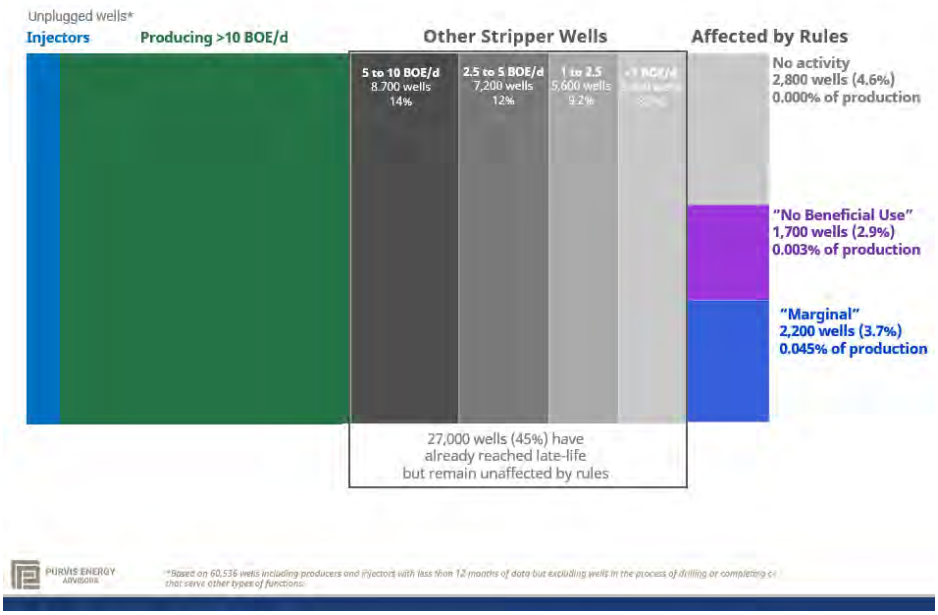
Applicants' Exhibit 41: Treemap of area representing numbers of wells in each category.



Q: Does this mean that nearly 90% of the state's wells are financially secure?

A: No, it does not mean that only a few wells are near their economic limit. It means that the proposed definitions are conservative. Applicant's Exhibit 41 further breaks down the wells in the state by recent production rate.

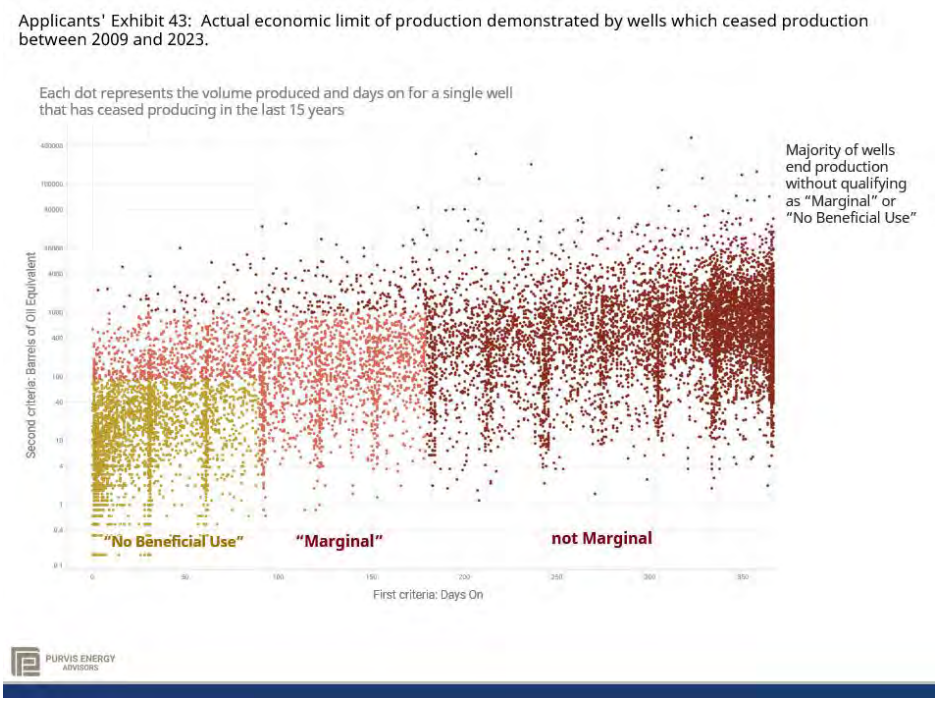
Applicants' Exhibit 42: Treemap of area representing numbers of wells in each category, with further detail on wells that do not qualify as "marginal."



The four new vertical segments represent another 44% of the wells that qualify as stripper wells, in addition to the 11% which also qualify as not active, no beneficial use, or marginal. Plus, it may be noted that several thousand wells operate as injectors, usually not generating cash flow at all. As shown also before, the scope of low-value wells is much larger than the defined categories.

Finally, to test the proposed definitions, I examined wells that had demonstrated the actual economic limits to production. A well stops being economically marginal when it stops producing. The rates at which historical wells have stopped production demonstrate the economic limit to production, the lower limit to marginal production. Applicants' Exhibit 43

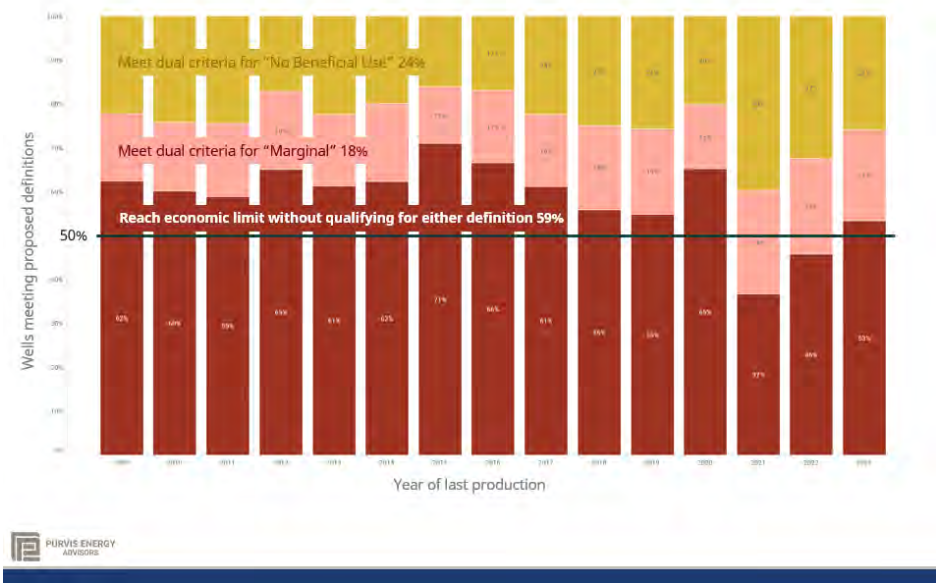
shows the actual limit to economic production demonstrated by wells in New Mexico from 2009 to 2023.



As before, each dot represents a well and its total days of activity and total production reported by the operator during its final 12 months of production. That is, I looked at the final month that production was reported for a well and counted back another 11 months. Regardless how many times a well may have been inactive and restarted, the graphic measures the absolute final 12 months of recorded operations. All of the wells have not produced for at least 15 months, and most have not produced for many years.

The colors mark the same boundaries for marginal and no beneficial use shown before. And as before, it is obvious that many wells end their economic lives without qualifying under the proposed rules as having become "marginal". Applicants' Exhibit 44 shows that dynamic better.

Applicants' Exhibit 44: Proportions of wells which qualified as "no beneficial use" and "marginal" at the point that production is known to have ceased.



Each bar represents the year of last production, and each bar is scaled to 100%. The colors correspond to the previous exhibit. Over the last 15 years, only 24% of wells that have ended production qualified as no beneficial use at the time their economic lives ended. And only 18% qualified as marginal. By contrast, 59% of wells proved to be uneconomic when they still produced so much that they did not qualify as marginally economic under the proposal.

The demonstrated end to production has changed some over time and does vary some between basins, but the evidence remains clear. The proposed definitions apply to fewer wells than are, in fact, economically marginal.

Q: Are low-producing wells risky wells? Do wells meeting the proposed definition for marginal wells which require increased financial assurance represent increased financial risk to the state?

A: Yes, I conclude that wells meeting this category represent a financial risk, but the process is a little indirect. That is the reason for other proposed provisions.

Production volume and production time are reasonable proxies for the remaining value of a well, and all of the information I considered points to the fact that wells meeting this category are financial risky. But first let me define what I mean by "risky" and how that relates to "wells" so that we can unpack how this category fits into the larger picture.

The risk of orphaning exists at the level of a company or, still more precisely, a portfolio. In theory, decommissioning an individual well at the end of its life could be funded by other wells in the portfolio. Wells are not orphaned individually; they are orphaned in groups together with their related surface infrastructure at the point that the entire company ceases to function.

Individual wells do contribute risk to the risk of a portfolio as whole and can thus be called "risky." When a well crosses over into the period of holdback, then it is by definition no longer capable of funding its own decommissioning. Again, by definition, a well in holdback is a net liability to cash flow over the life of the portfolio and thus a risk. In fact, I'd argue that the risk of orphaning is significant far before the point of holdback because, in my experience, companies are not, in fact, holding funds back but continuing to distribute operating profits past the point of holdback.

As I said before, inactivity and low production are both strongly correlated to the expectation of future operating profits and thus can serve as proxies for wells that are likely to add risk to a portfolio. The question becomes what level of production to choose for this purpose. As I discussed and demonstrated earlier, the proposed definition for "marginal well" is quite conservative compared to more protective levels it could legitimately be set to.

Lastly, this definition offers the advantage that it does not require an interpretation by the regulator of current economics. It relies on information already self-reported by operators on a

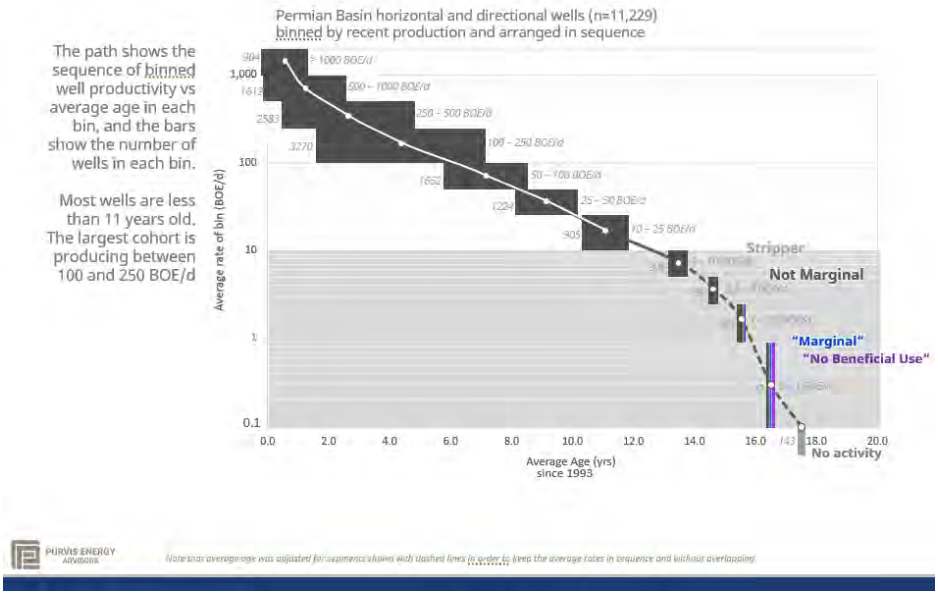
monthly basis. As such, the OCD will be capable of efficiently and objectively applying this definition.

Q: At what rate do wells become a burden and risk to portfolio and thus to the state?

A: Thank you for asking, let's do be clear about this. The analysis above demonstrates when wells have ended production, but a well becomes a financial burden in a portfolio many years before production ends. As demonstrated in the schematic example of holdback before, marginal late-life production drags out for years without creating much profit, and the cost of decommissioning is significant by comparison to late-life operating margins. I have not attempted to calculate the point of holdback for each individual well in the state, but I can say that most wells are within or fast approaching the demonstrated end production and thus are likely within holdback. That is, large portions of wells in the state are probably net liabilities or approaching that point rapidly

Applicants' Exhibits 45 to 50 demonstrate this systematic risk by looking at the four most significant regional subsets of wells discussed before. Applicants' Exhibit 45 pertains to horizontal and directional wells in the Permian Basin. It is a histogram of well count binned by current rate but arranged in a progressive sequence to show scale and time. The length of each bar represents the number of wells, the vertical range of each bar covers the rates it includes, and the bar is positioned over the average age of the wells in the group measured since the first digital data available in 1993. The vertical axis shows current rate on a logarithmic scale, and the horizontal axis shows the age of the wells. It should be noted, though, that lines shown as dashes indicate the use of a different x-axis position, so that the graph functions like a traditional rate-time graph used to forecast production with the bars showing the relative maturity of the population of still-unplugged wells.

Applicants' Exhibit 45: Permian Basin horizontal and directional wells binned by daily production rate and positioned over average rate and average age for each bin.



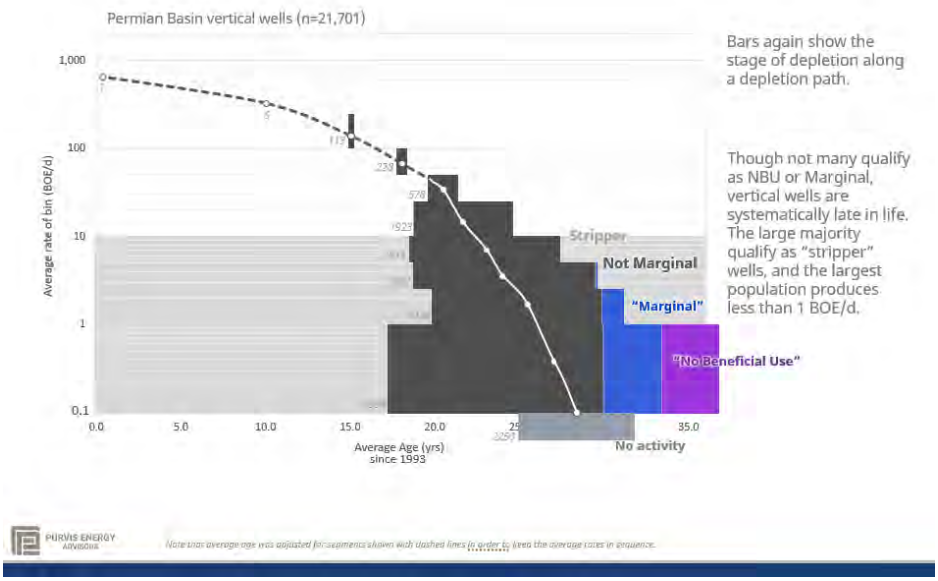
As a well begins production it starts at the upper left of the graph, and it moves to the right and down as it depletes. The colors correspond to the well categories defined earlier such that bars for not-marginal wells are shown in dark gray. Farther along the trajectory, wells currently qualifying as no beneficial use are shown in purple, and wells defined as marginal are shown in blue. No activity wells are shown in gray below the scale. The area of the chart representing stripper wells making less than 10 BOE/day is shown in a light gray. The dashed lines show that I have stretched out the age of these last few categories when, in fact, the average age is more similar than shown.

Historically, horizontal wells have ended production around 10 BOE/d, but as the bars indicate the largest group of wells are still producing between 100 and 250 BOE/d. As the wells age, that peloton of wells can be expected to deplete along the trajectory traced by the population of older analogs, and the bulk of horizontal wells will approach their economic limit starting

about 10 years from now. Of course, as I discussed earlier, many wells turn financially upside-down years before it turns off entirely.

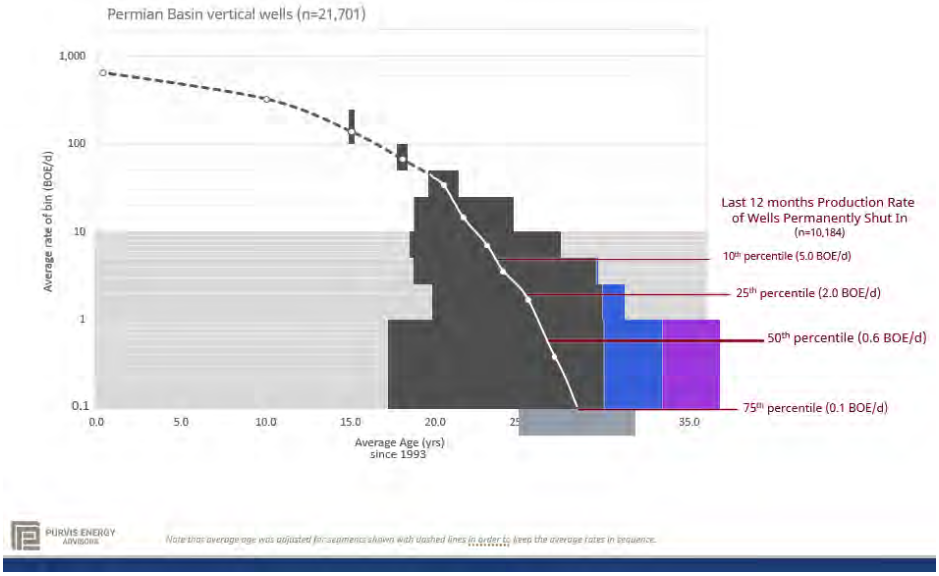
Applicants' Exhibits 46 shows the same kind of graph but for vertical wells in the Permian. These are still unplugged wells among a group whose production peaked around 2001. In this case, there were so few high producing wells that I had to overlay an interpretation of age on the high producers. The large majority of the wells fall within the definition of stripper wells, and the largest population is currently producing less than 1 BOE per day operated.

Applicants' Exhibit 46: Permian Basin vertical wells binned by daily production rate and positioned over average rate and average age for each bin.



More to the point, Applicants' Exhibit 47 overlays on actual current production rates the rates at which analog wells have stopped producing, which was presented earlier in Applicants' Exhibit 43.

Applicants' Exhibit 47: Comparison of binned Permian Basin vertical wells to final rates of production demonstrated in the basin.

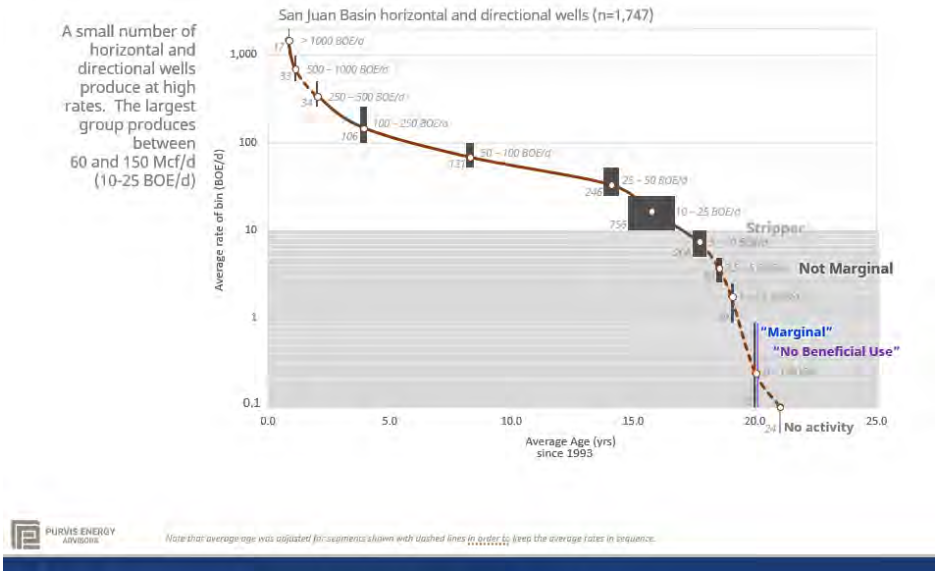


The red lines mark the rates at which remaining value for wells in New Mexico between 2009 and 2023 has proved to be zero. Ninety percent of now-dead wells produced down to rates below 5 BOE/d but only 25% produced less than 0.1 BOE/d. To be clear, the largest bin represents wells producing between 0 and 1 BOE/d, but the graph depicts the bin down only to 0.1 BOE/d. In fact, many unplugged wells are already producing less than 0.1 BOE/d over the year.

Based on a sample of more than 10,000 dead wells, I can say that the nearly 22,000 remaining wells are systematically producing within the same range of rates at which their sibling predecessors ended their financial lives. Though still operating and though mostly not qualifying under proposed definitions, this group of wells is systematically at or near the economic limit of production.

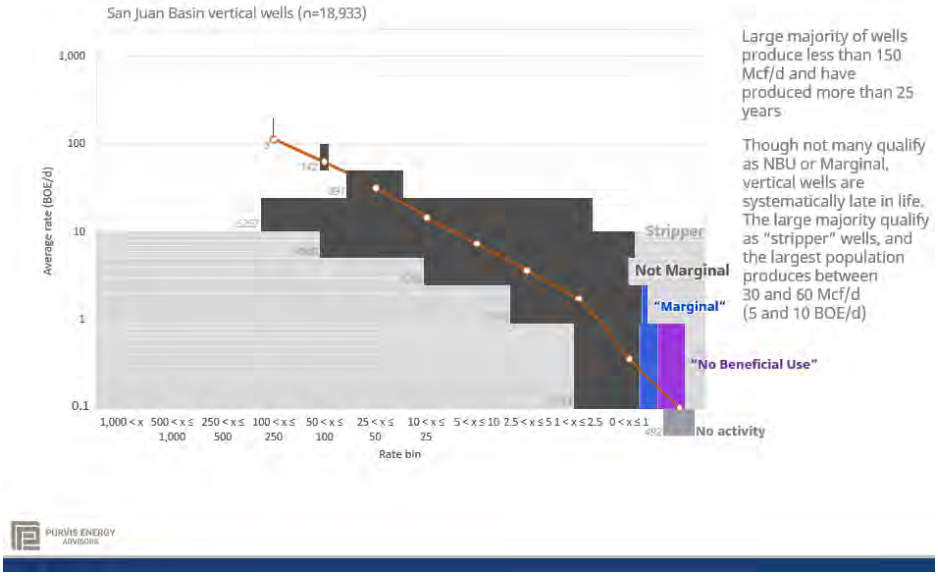
Applicants' Exhibit 48 shows the same kind of analysis for the relatively small number of horizontal and directional wells in the San Juan Basin. In this case, the bulk of the wells produce between 10 and 25 BOE/d, and the steep downturn implies the economic limit of production.

Applicants' Exhibit 48: San Juan Basin horizontal and directional wells binned by daily production rate and positioned over average rate and average age for each bin.



More importantly and more concretely, Applicants' Exhibits 49 and 50 represent the population of vertical wells in the San Juan Basin. In this case, too many of the wells predate 1993, causing the bins of production to stack. To address this, the x-axis represents bins for the current producing rates. The bulk of the unplugged wells produce between 5 and 25 BOE/d.

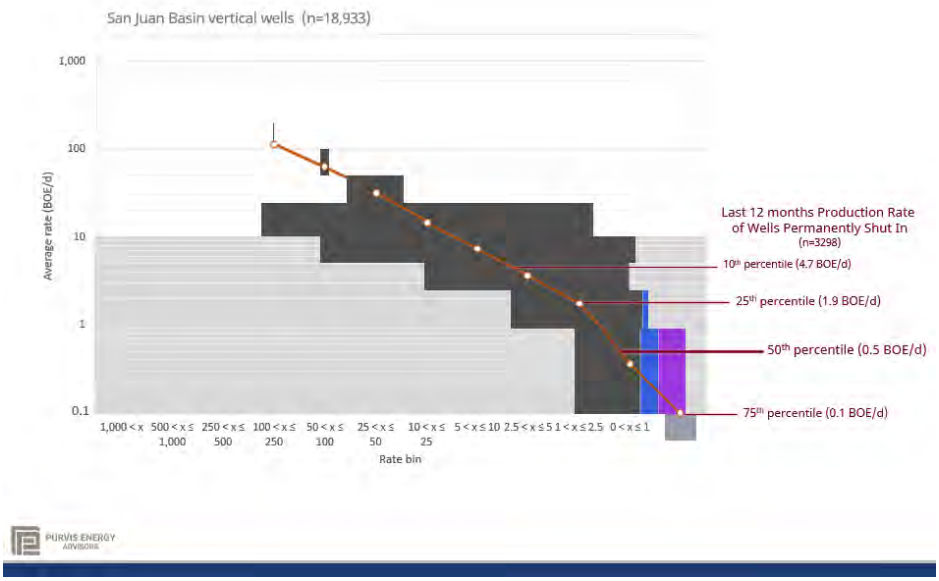
Applicants' Exhibit 49: San Juan Basin vertical wells binned by daily production rate and positioned over average rate and bin range.



Applicant's Exhibit 50 shows how these current rates compare to over 3,000 wells that have already ceased production. In this case, the peloton of wells is still producing above the demonstrated limit to economic production, but they are also producing at low rates and are continuing to deplete. Thousands of wells representing nearly 40% of the population have already depleted into the range of historical economic limits. This second largest population of wells is also systematically at or approaching the economic limit of production.

Wells become a pure cost / risk when they stop producing, and tens of thousands of wells in the state are currently producing at rates similar to that at which nearby wells have stopped producing.

Applicants' Exhibit 50: Comparison of binned San Juan Basin vertical wells to final rates of production demonstrated in the basin.



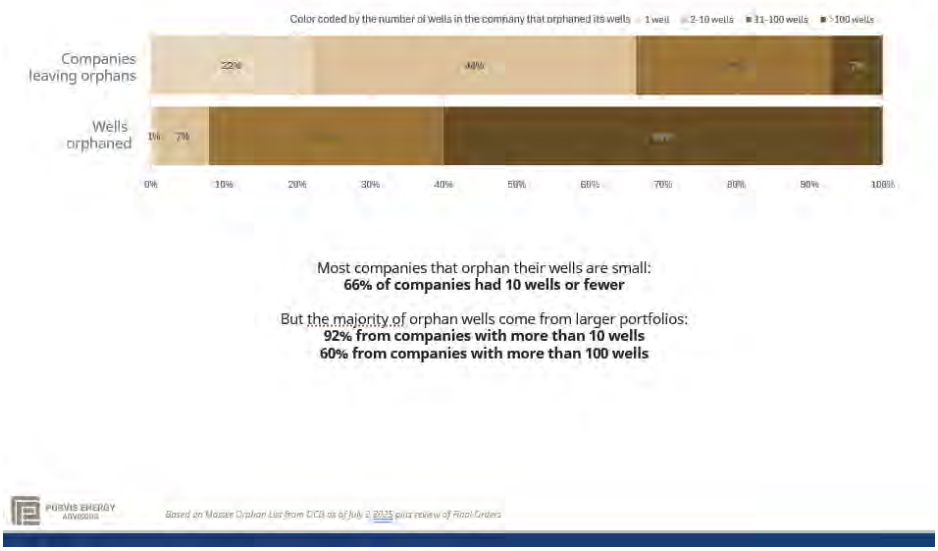
Q: Financial assurance regulations in New Mexico have long allowed for blanket bonds covering a smaller portion of the decommissioning costs for companies with larger portfolios of wells. Are larger portfolios less risky than smaller ones?

A: Yes and no.

In the short term, larger portfolios have more flexibility to adapt and keep operating. However, in the long term what matters is the systemic, correlated risk of a portfolio. It is diversity, not size, that provides financial resilience. As demonstrated above, portfolios in New Mexico, and indeed in most of the country, tend to concentrate on similar wells, either horizontal or vertical but not often a balanced combination of young and old wells.

Looking again to the in-state history for guidance, this kind of systematic risk shows up in the wells that have already been orphaned as summarized in Applicants' Exhibit 51.

Applicants' Exhibit 51: Size of recent portfolios orphaned in New Mexico.



The exhibit relies on the OCD's Master Orphan List but supplements with my own review of final orders. It groups the orphaned wells into portfolios and shows the relative proportions of small and large portfolios. The first bar looks at the history of orphaning from the perspective of the number of companies that have orphaned their wells, and it shows that most of the operators orphaned 10 wells or fewer each. Only 7% of companies orphaned more than 100 wells.

The second bar is more relevant. It shows where the orphan wells came from, and 92% of orphan wells come from portfolios with more than 10 wells. Several companies have recently orphaned hundreds of wells at once, so 60% of the wells ever orphaned in the state came from companies that failed with more than 100 wells.

Applicants' Exhibit 35 above shows how the largest concentration of wells in the state reside in large portfolios of legacy wells.

Q: Based on historic well production data, how many existing wells in New Mexico

would be categorized as marginal under the proposed rule?

A: Without trying to quantify how operators will handle their portfolios in the next couple of years before this comes into effect, I can reiterate that the category of marginal currently applies to only a 3.7% of wells in the state.

Q: What is the basis in 19.15.8.9.D(1) NMAC for proposing that operators provide financial assurance of $150,000 per marginal well prior to transfer the financial assurance of $150,000 for marginal wells take effect immediately?

A: This is also an OCD proposal that Applicants have adopted. The justification for the per well financial assurance in this Subsection D is the same as the justification offered above for Subsection C above.

In my opinion, it is reasonable and appropriate to require review and greater assurance at transfer—a point in time when high risk wells are sometimes transferred to less financially capable operators—and to make that requirement effective immediately. Often wells, including ones that remain assets and others that have become net liabilities, change hands from more to less capitalized companies. As I described before, this is the nature of specialization. And transferring a well can be a step change in orphaning risk as wells move from one portfolio to another.

The change needs to be made effective immediately in order to reduce the opportunity for companies to avoid increased accountability by rearranging their portfolios to isolate assets from liabilities and increase the probability and timing of orphaning.

Q: What impact do you anticipate this proposal would have on operators?

A: To the extent that companies are transferring wells defined as marginal, they are very likely transferring net liabilities. If there is enough value left in the package of wells to pay for

the decommissioning, then getting a third-party guarantor for the bond amount on a stand-alone purchase should not be financially prohibitive. If the receiving company has enough other assets that it can afford to plug wells already past the point of holdback, then those other assets can be used to fund the financial assurance.

To the extent that net liabilities were transferred in the past to undercapitalized companies, transfers will diminish. The provision would prevent the transfer of wells to operators who would like to take a gamble on their ability to increase production and don't have the funds to cover a failed bet.

However, one major gap remains in the proposed rules about increased assurance at transfer. The rule applies at the transfer of operatorship between companies and not to the change of ownership or leadership at companies. Transferring wells and fields between operators has and does happen, but in recent years I have observed that companies have more often transferred an entire company or subsidiary than in the past. Changing the ownership of the company has many of the same effects as changing the ownership of the wells. Transfer by corporate ownership moves wells to a company with different credit worthiness, different assets and liabilities on its balance sheet, different portfolio of production, and different management which can have a different strategy and different track record of regulatory compliance. The proposed rules on transfers may leave open an easy pathway to eschew the intended oversight and protection.

Besides the loophole for corporate transfers, the proposed rules also protect the public by creating a strong incentive for oil and gas companies to perform the decommissioning work as it comes due and not to accumulate liabilities to be orphaned en masse. Theory and history both

show that free market dynamics promote the accumulation and orphaning of liabilities, so counterincentives (i.e. incentives to do the right thing) created by policy are necessary.

Q: What is the basis 19.15.8.9.D(2) NMAC for proposing that operators provide financial assurance of $150,000 for all other marginal wells after January 1, 2028?

A: This is another OCD proposal that Applicants have adopted. The basis for requiring one well financial assurance is that a marginal well is very likely to have passed its holdback and is unable to fund its own decommissioning. If a well has little or no cash flow remaining, then it is a net liability, and it is reasonable and appropriate to ask for financial assurance against a net liability. The basis for delaying implementation until 2028 is to allow companies time to adapt to the change.

As I've said, the proposed rules do not change the ultimate decommissioning expectation that prudent operators should have been planning for. Moreover, serious efforts to increase accountability have been common knowledge in the state for a number of years. This specific proposal was first proposed by OCD in February 2025, and then formally proposed by Applicants in April 2025. If a final rule including this amendment is published next year, then the application of the rule to all individual marginal wells will not apply for nearly another two years.

Operators will have had years to exercise a number of options to prepare for the increased financial assurance. If operators with marginal wells confirm there remains known upside value to their wells, they can restore or improve production. If the potential value of restoring or improving production is small, those operators can save the proceeds of operations to fund financial assurance. If there is no opportunity at all, then they can pay the cost of decommissioning and not have to fund any kind of financial assurance.

Q: What impact do you anticipate this proposal would have on operators?

A: The effect of the change in accountability will depend on whether and how companies have planned for their decommissioning costs. Responsible and well-capitalized companies should be able to handle the new accountability just fine. Other companies may use the several years of grace period as an opportunity to take as much profit as possible and intend to orphan the remainder at the time that more bonding is required.

It should be expected that some companies will double-down on the same strategy and will exploit remaining years of operations. A company knowing that it will not be able—or willing—to meet the new financial demands can operate "like there is no tomorrow." It could stop plugging any wells, stop preventative maintenance, allow spills and releases, and take home as much of the revenue as possible before the deadline.

Allowing companies a couple of years to come into compliance provides an accommodation to oil and gas companies but also increases the risk to the state.

Q: What is the basis in 19.15.8.9.D(3) NMAC for requiring operators, whose marginal or inactive wells, or a combination thereof, make up more than 15% of their total well ownership, to provide $150,000 for each of their wells, until their share of marginal and inactive wells decrease below 15%?

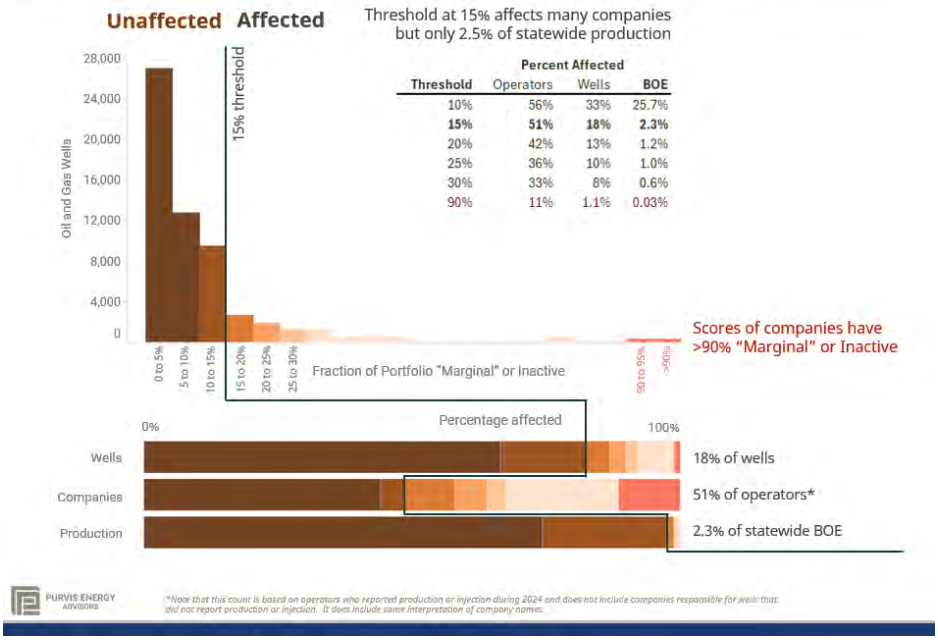
A: There are two reasons for requiring a $150,000 bond for all wells in the company when marginal wells plus inactive wells exceed 15%. The first is to protect the state against portfolios which already have a concentration of the most at-risk kinds of wells. The second is to provide motivation to companies to responsibly manage their portfolio of wells—to produce them efficiently and effectively, to capture opportunities in a timely fashion, and to pay decommissioning costs as they come due—in order to avoid the cost of full financial assurance.

This rule creates a bright line above which the cost of required financial assurance increases by about six or seven times. It is a significant increase, but financial assurance is also generally a small component of the total cost of operating. In my opinion, most companies should be able to stay close or below the 15% threshold, if they are actively managing their wells to prevent waste and actively plugging wells without clear economic prospects.

Q: What impact do you anticipate this proposal would have on operators?

A: Applicants' Exhibit 52 shows how this provision affects the industry in New Mexico.

Applicants' Exhibit 52: Distribution of the concentration of marginal and inactive wells in oil and gas company portfolios and the combined size of portfolios above a range of thresholds.



The histogram at the top of the exhibit shows how wells are concentrated in different portfolios. I have calculated the concentration of inactive, no beneficial use, and marginal producing wells in the portfolio of each reporting company, then binned the companies by their concentration. The height of each bar represents the total number of wells owned by companies with such a concentration. The first and tallest bar on the left shows that the large groups of wells in the state reside in portfolios made up of less than 5% of marginal or inactive wells. Of

course, this is according to the strict, conservative definitions proposed. At the far right, shown in red, are wells in portfolios of 90% or more marginal or inactive wells.

In this histogram, I observe a step-change at the proposed 15% threshold. The industry is mostly managing to keep the portfolio proportions below 15% of the defined thresholds on its own accord.

The three bars at bottom show different ways to understand the proportional split of the industry above and below the proposed 15% threshold. Each bar is a different measure, the colors in the bars correspond to the colors in the histogram, and the line marks the same division above and below 15% in both visualizations.

The first bar, like the histogram, represents the unplugged wells in the state. It shows that 82% of the wells in the state reside in portfolios that would be unaffected by the rule, and the last bar shows that these unaffected portfolios are responsible for 97.7% of production in the state. Conversely, the rule would affect companies responsible for only 18% of wells but only 2.3% of production.

That is not to say that the rule would provide coverage for 18% of the wells because the increased assurance would not be required on wells already covered by federal financial assurance.

The middle bar shows a contrasting measurement. The rule would affect more than half of the corporate entities active in the state. The paradox between the 51% of companies affected and the 2.3% of production affected was explained at length above. *See* Applicants' Exhibits 35 and 37. There are a large number of very small corporate entities.

The table in the upper right provides more quantitative detail for the results of defining the threshold differently. A lower threshold, of course, has greater effect, and a looser threshold

has less effect. The table also shows the extreme end of the range. 11% of companies manage portfolios up 90% or more of marginal or inactive wells. It should be noted that the graph does not include a number of other companies without any producing wells and which are not making reports to show the fact of zero production. Taken together there are dozens of oil and gas companies in the state whose portfolio of responsibility consists of 90 to 100% marginal or inactive wells.

Q: Why do Applicants propose giving an operator the option of furnishing a single financial instrument to satisfy multiple one well financial assurance requirements under 19.15.8.9.D(4) NMAC?

A: This amendment proposal is a matter of efficiency that, in my judgment, would be welcomed by all parties. The bonding company, the operator, and the regulator would be able to handle only one document instead of many.

Q: Do financial instruments exist for operators to secure financial assurance for marginal wells under 19.15.8.9.D(1) – (2) NMAC and an operator's portfolio of wells under 19.15.8.9.D(3) NMAC?

A: Bonding instruments certainly exist. The number of companies that offer the plugging bonds has diminished in recent years, and anecdotally they have been requiring more collateral, even up to 100% of the value of the bond when they judge the buyer to be too big a risk.

If an oil or gas company can supply 100% of the value of the bond, then the bonding company collects a premium with no risk of loss. It is hard to imagine that financial companies would not stand in line for this business. The primary question is not whether the financial services are available but whether oil and gas companies are in such poor financial condition that

a financial services company would require collateral and whether companies are in such bad shape that they cannot fund the required collateral.

Inactive Wells

Q: What amendments do Applicants propose to the financial assurance requirements for inactive wells and wells in approved and expired temporarily abandoned status at 19.15.8.9.E. NMAC?

A: Applicants propose:

> **19.15.8.9.E.~~D.~~ Inactive wells and wells in approved and temporarily abandoned status.** An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years,~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC, in one of the following categories:
>
> **(1)** a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or
>
> **(2)** a blanket plugging financial assurance equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E~~D~~ of 19.15.8.9 NMAC.~~:~~
>
> ~~(a) $150,000 for one to five wells;~~
> ~~(b) $300,000 for six to 10 wells;~~
> ~~(c) $500,000 for 11 to 25 wells; and~~
> ~~(d) $1,000,000 for more than 25 wells.~~

Q: What is the basis for requiring either a one well plugging financial assurance at $150,000 per well or a blanket plugging financial assurance, covering all wells of the operator subject to Subsection E of 19.15.8.9 NMAC, equal to an average of $150,000 per well?

A: The idea is that inactive and approved and expired temporarily abandoned (TA) wells present a risk similar but likely greater than those of marginal wells discussed above.

Marginal wells operate and earn some revenue, perhaps a small profit or maybe a small loss. Inactive and TA wells are not generating any revenue at all, but they still require small, ongoing costs to monitor, insure, and maintain the wells.

The mechanical configuration of inactive status is similar to the configuration of marginal status, requiring the same work plan to plug, though the inactivity may have allowed greater deterioration and thus more contingency cost.

Q: What impact do you anticipate this proposal would have on operators?

A: My discussion above considered the effects of the definition of "marginal" and of the effects of the allowable threshold of marginal and inactive wells. As before, the requirement will cost operators some more money for the opportunity to let their wells stand idle. The cost will be more significant proportionally, of course, to a well producing nothing than to one barely making profit each month. And, of course, it will have the biggest effect on companies with the highest proportion of inactive wells. As described in Applicant's Exhibit 52, many corporate entities "operate" mostly or only inactive wells.

Additional Financial Assurance

Q: What amendments do Applicants propose to 19.15.8.9.F. NMAC?

A: Applicants propose:

> **19.15.8.9.F.~~D.~~** Operators who have on file with the division a blanket plugging financial assurance that does not cover additional wells shall file additional one ~~single~~ well plugging ~~bond~~ financial assurance for any wells not covered by the existing blanket plugging financial assurance ~~bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978. ~~or in the alternative, may file a replacement bond.~~

Q: What is the basis for this amendment?

A: The changes to terminology for financial assurance instruments are editorial to keep the terminology consistent within the rule.

The provision subjecting 19.15.8.9 NMAC to limitations in the Oil and Gas Act in NMSA 1978, 70-2-14 acknowledges the limitations in the act, including the limitation on blanket bonds of $250,000.

Inflation Adjustment

Q: What amendments do Applicants propose to 19.15.8.9.G. NMAC?

A: Applicants propose:

> **19.15.8.9.G**. On January 1, 2028 and on January 1 of each successive year, the division may adjust the financial assurance amounts provided by Subsections C(1), D, E, and F of this Section by multiplying the financial assurance as of January 1, 2027 by a fraction, the numerator of which is the consumer price index ending in September of the previous year and the denominator of which is the consumer price index ending September 2026; provided that any financial assurances shall not be adjusted below the minimum amounts required in Subsections C(1), D, E and F of this Section as a result of a decrease in the consumer price index. By November 1, 2027 and by November 1 of each successive year, the division shall post on its website the financial assurance requirements in Subsections A through E of this Section for the next year. As used in this section, "consumer price index" means the consumer price index, not seasonally adjusted, for all urban consumers, United States city average for all items, or its successor index, as published by the United States department of labor for a 12 month period ending September 30.

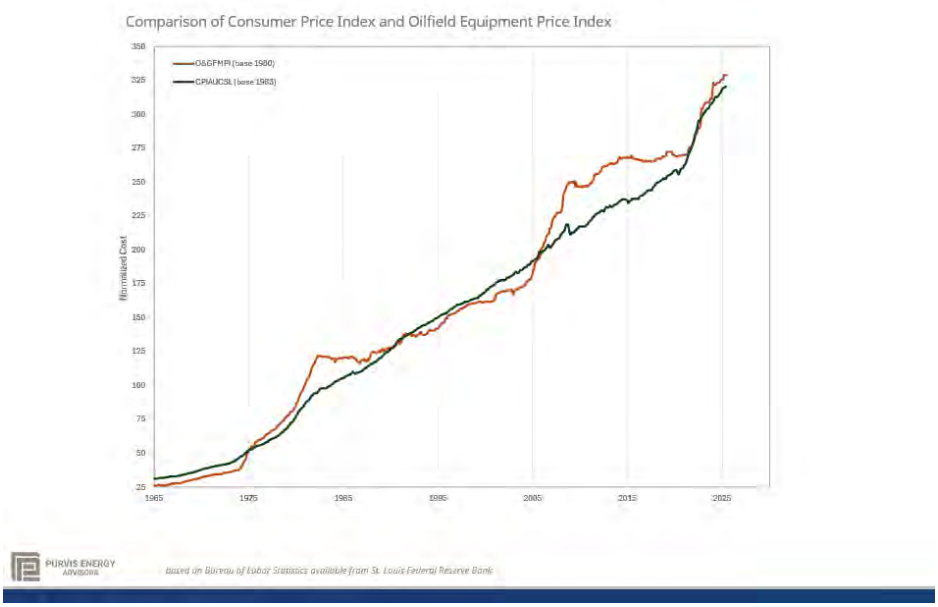
Q: What is the basis for the amendment to allow the division to adjust the financial assurance amounts according to the consumer price index?

A: Costs are not static in the oil field any more than in the rest of the economy, especially in recent years. If financial assurance does not increase with actual costs, then the relative value of the financial assurance erodes, and the state becomes more financially exposed. In some jurisdictions, like federal lands, bonding was not updated for many decades and had become quite small. Keeping pace with consumer inflation is a reasonable way to protect the state against the inevitable increase of costs over time. As proposed, adjustments to the financial assurance amounts to account for inflation are limited to those in 19.15.8.9.C(1), D, E and F

NMAC – for marginal wells, inactive wells, and approved and expired TA wells—and excludes the financial assurance amount in 19.15.8.9.C(2) NMAC in recognition of the statutory cap of $250,000 on blanket bonds for active wells. The proposal avoids the necessity of holding repeated rulemaking hearings to adjust financial assurance to account for inflation by tying the bond amounts to the consumer price index (CPI).

The question becomes how well future costs of decommissioning will track the consumer price index (CPI). Applicants' Exhibit 53 addresses that question by looking at how well the CPI has tracked oilfield inflation in the long term.

Applicants' Exhibit 53: Historical inflation of oilfield costs compared to consumer prices.



In theory, decommissioning costs are a subset of oilfield costs, and oilfield costs sit within the context of the overall economy in the same way that consumer prices do, even though oilfield costs and decommissioning costs have particular supply and demand issues.

In practice, three datasets about oilfield inflation are available for examination: qualitative data gathered by surveys of oil companies conducted by the Dallas branch of the

Federal Reserve, cost indices calculated and reported by S&P Global, and subsets of cost indices reported by the U.S. Bureau of Labor Statistics along the variations of the consumer price index.

I compared the multiple indices over multiple time frames, partly because each begins at a different historical date, but Applicants' Exhibit 53 above offers the best summary. The shorter time series of Dallas Fed and S&P Global data are broadly consistent with the longest set of oilfield data, namely the oil and gas field machinery and equipment manufacturing price index. Oilfield costs tend to inflate more unevenly, with more periods of higher inflation. But in the last decades, the data suggests that oilfield costs overall have demonstrated about the same trend as consumer prices.

Q: What is the basis for prohibiting the adjustment of financial assurances below the minimum amounts required in Subsections C(1), D, E and F of this Section as a result of a decrease in the consumer price index?

A: The notion of decreasing decommissioning costs doesn't have much relevance. Oilfield costs generally can swing high and low over the period of a few years, but the smoothed long-term trend does not show sustained downward trends. The data does not demonstrate significant trends of downward prices for decommissioning, and for a multitude of reasons, I do not expect the cost of decommissioning to decrease in the future.

19.15.9 NMAC –WELL OPERATOR PROVISIONS

General Overview

Q: Mr. Purvis, before you discuss Applicants' specific proposals to amend 19.15.9 NMAC – Well Operator Provisions, please summarize why rules that govern the transfer of oil and gas wells between operators are important to limiting risk to the public.

A: Limitations on transfer are commonly accepted across jurisdictions. Of twenty-three state

regulators, including New Mexico, who responded to a 2018 survey by the IOGCC, all but one required a review of the receiving company though with a wide range of rigor. The justification is clear and widely accepted.

When oil and gas wells change hands, they move from the context of one portfolio to another and from one set of managers to another. Importantly, wells can move from better capitalized companies who explore and drill wells to less capitalized wells focused on maximizing existing wells.

Sometimes companies hold assets from drilling through decommissioning, but it is much more common for larger companies to sell projects in mid or late life to companies that specialize in optimizing cash flow rather than developing new projects. Many receiving companies try to mitigate the decline of mature fields, but others focus only on reducing costs. Either way, the kinds of companies that own and optimize aging legacy fields are generally not the kinds of companies that reinvest in drilling. So, the wells transferred tend to be closer to the point of holdback, and they tend to move from stronger portfolios to weaker ones.

Companies buying late-life assets and using late-life strategies are often private companies less known to the public. They necessarily focus on reducing costs, and that can often mean less regulatory compliance. In other words, as smaller and private companies, they have less exposure to public opinion and less to lose. A different set of managers in the new company responding to a different set of market forces may make different strategic choices about performing decommissioning obligations. In my experience and observation, these stripper well operators tend to have worse operational track records of compliance. The analysis of changed financial assurance rules in Texas and North Dakota discussed above demonstrated this effect. Increased accountability caused fewer environmental violations.

The transfer itself has no intrinsic value to the state. The state must weigh a hypothetical value from the possibility of increased or prolonged production by a smaller company against the possibility of more regulatory violations and ultimately of orphaning.

Plugging and Abandonment Plan

Q: What amendments do Applicants propose to the requirements for proposals to transfer oil and gas wells to a new operator at 19.15.9.9.B NMAC?

A: Applicants propose:

> **19.15.9.9.B.** The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an officer, director, or partner of the new operator that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a plugging and abandonment plan; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator. The plugging and abandonment plan shall be certified by an officer, director, or partner of the new operator and shall demonstrate that the new operator has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells to be transferred in light of all the operator's assets and liabilities. The division may request the operator to provide additional information including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics report, records of the operator's historical costs for decommissioning activities, estimate of the operator's decommissioning obligations, and history of inactive wells and returning wells to production.

Q: What is the basis for requiring that operators certify their compliance with laws and regulations in other states when requesting a change of operator?

A: The existing rule requires only two documents from the companies involved in the transfer, namely a request form and evidence of the rights of the new operator. With this information, the OCD cannot perform any due diligence to vet the risks of a new operator.

The proposed rule requires disclosure on four additional topics so that OCD can better protect the public interest. Three of these changes for additional review parallel information that may be relied upon by OCD for operator registrations in 19.15.9.8.B NMAC. This amendment adds a review of regulatory compliance in other states and puts the onus on the applicant to provide the evidence.

Similar to a credit report, I deem the track record of the quality of operations to be an indicator of likely future quality. A company's track record in other jurisdictions can provide the same kind of information as its tract record in New Mexico which is already a part of the transfer review. When the transferee has not operated in New Mexico before, out-of-state operations provide the only possible review of past performance.

The provision puts the onus of evidence on the company seeking the right to operate the wells, but that burden is trivial, especially by comparison to the value of the acquisition which often runs in the millions to hundreds of millions of dollars. The applicant does not need to marshal any kind of evidence to submit to OCD. It needs only to present a signed "certification," and the company should know whether or not it is in compliance.

It is also worth noting what is not included. The self-declaration of compliance pertains only to the company seeking the right to operate. This change does not require a declaration about overall compliance of related companies, owners, or management.

I find it reasonable and appropriate to ask a company, wanting to operate in New Mexico, to vouch for itself that it has complied with regulations in other states. In fact, the rule still

leaves avenues open for demonstrably bad actors to take over operations in New Mexico, as discussed earlier.

Q: What is the basis for requiring, during a change of operator request, that operators certify their compliance with Subsection A of 19.15.5.9 NMAC?

A: It allows the OCD a view of the in-state performance of companies related through ownership, control, or corporate structure with little burden on the applicant, and I find it to be reasonable because companies under the same control are likely to behave similarly. The proposed rule is also appropriate because I find that a large number of companies operate in New Mexico through multiple related companies.

I closely reviewed the information available from the OCD about companies possessing licenses to operate in the state, comparing names, addresses and phone numbers plug considering public information on mergers and acquisitions. Relying most heavily on the contact information for the companies, I found that the majority of companies and the majority of wells in New Mexico seem to be part of a family of corporate entities. My analysis is not strict proof but still a strong indication that 42% of wells have sibling companies with sibling wells managed by the same people at the same company offices.

Q: Mr. Purvis, Mr. Morgan provides testimony in support of the proposed amendments to 19.15.9.9 NMAC, and I would like you to focus your testimony on the proposal in 19.15.9.9.B NMAC requiring a new operator to submit a plugging and abandonment plan to OCD prior to a well transfer. What is the purpose of a plugging and abandonment plan?

A: The purpose of a plugging and abandonment plan is to make sure that funds will be available when the liability comes due. Specifically, to compare the cash flow to the eventual

obligation and to determine when and where the money will come from.

To be clear, this is ultimately a question about the company's portfolio and not the specific project being transferred. Regardless of the relative cash flows in and out for the individual property, funds could still be fluidly diverted to or from other parts of the portfolio in a way that renders more or less risk for the one part of the portfolio being transferred. On the other hand, if a project joining a portfolio has a viable plan for decommissioning, then it is not adding risk to the portfolio. That is, if a viable plan cannot be made for the wells being transferred, then they are a net liability, and they increase the risk of orphaning in the destination portfolio.

Q: What is the basis for requiring, during a change of operator request, that a new operator provide a plugging and abandonment plan?

A: The most unique and significant changes in Subsection B of 19.15.9.9 NMAC is the requirement that an operator provide and justify a plan to decommission its wells from the point in time when it first takes responsibility for them.

The basic idea is the old adage that a failure to plan is a plan to fail. Or, as Stephen Covey taught us, we should begin "with the end in mind." The change is an obvious and basic point of accountability, asking only for something that should already exist.

Before consummating a transaction and transfer of operations, companies almost always make cash flow projections decades into the future, and they almost always perform due diligence on the properties to make sure they understand what they are buying. Oil and gas companies understand in general how production declines, margins thin, and prices swing. For a specific acquisition, engineers like me make quantitative projections of every element of cash flow into the future based on history, science, expertise, and judgment. We project when, based

on the best available data, production will end and, thus, when decommissioning costs will come due. Such reserves and economics calculations are fundamental.

There is no scenario in which the wells and other infrastructure will not need to be decommissioned. The only question is when. The costly cleanup requirements at retirement are long-standing and universally known. There is no ignorance among operators. Of the many changes proposed to the rules, none change the existence nor the quantum of end-of-life obligations.

So in theory, the proposed rule requires only disclosure of a plan that should already exist. A good actor—one who intends to comply with the law—should have a plan to comply with the law built into its acquisition analysis.

It is true that oil and gas companies often make acquisitions with the hope and intent to improve production or to sell again before decommissioning costs are paid, but this does not change the need for a demonstrable plan for decommissioning. Intent for improvement and/or sale can fall through, but decommissioning costs don't fall through. A failure of a company's hopes and intentions can leave the public at risk.

If a purchaser's plan for the properties does not include plans to pay for decommissioning, then it is presuming upon the state to take responsibility if its plans fail—the new operator makes the public the guarantor of its own private obligation and underwriter of its risk-taking. If the regulator does not have the right to review the purchaser's financial plan to pay its obligations, then the purchaser can force the increased financial and environmental risk of failure onto the state without the state's consent. The public, in the form of the regulator, should to my way of thinking have a say in whether or not a transfer increases the financial risk to them.

While requiring financial assurance provides some protection to the state, there needs to

be multiple layers of protection. Any single layer can fail to accomplish its purpose, and the financial assurance layer covers at best only a fraction of the total cost of decommissioning, as presented in Applicants' Exhibit 34 above. The requirement for a plugging and abandonment plan adds an extra layer of protection against an operator orphaning its wells and leaving the state to expend time, effort and administrative resources on plugging and remediation.

And the increase of financial risk in a transfer is more than theoretical or anecdotal. If the purchaser cannot demonstrate a viable plan to pay for the decommissioning, then by definition the properties are at risk of orphaning. The question then becomes whether that risk is less after the sale than before.

It is possible that the purchaser might have a stronger portfolio than the seller and be better able to meet the obligations. In this scenario, the OCD can still approve the transfer. In the scenario of a transfer to a less capitalized company, the OCD has the authority to prevent a high risk transfer, to keep the obligation within the company better able to meet the obligation, and thus reduce the risk of unmet, orphaned obligations.

Q: What is the basis for requiring, during a change of operator request, that the operator demonstrate, in a plugging and abandonment plan, it has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the wells or well to be transferred in light of all the operator's assets and liabilities?

A: The proposed amendment prescribes the scope of the necessary demonstration. The phrase "has and will have" prescribes the timing, and the phrase "in light of all of the operator's assets and liabilities" prescribes the breadth.

As explained already, the risk of orphaning exists at the corporate or portfolio level, not the level of individual wells or groups of wells. It only makes sense to evaluate the plugging and

abandonment plan across the whole breadth of the corporate portfolio.

As for timing, the ability to defer decommissioning costs makes it equally necessary to prescribe a demonstration of present and of future ability to pay. The public does not need assurance merely that the costs can be at the time of transfer because the costs are not paid at that time.

If a company does not have the ability at the time of transfer to pay its statutory asset retirement obligations, then it certainly presents significant risk. That is, if its obligations exceed its assets, then the risk of orphaning is significant. Some companies might speculate that they will be able to meet their lawful decommissioning obligations at some point in the future because they intend to drill more wells. Speculation as to a future ability of a company to pay these obligations requires both a change in economics and a company's willingness to redirect resulting profits from new investments toward the upside-down obligations.

As for the future, it would be simple, and indeed could be expected, that a company would have the ability to abide by the law now but not in the future. Oil and gas companies are not required to save the necessary funds in advance nor to perform the work promptly when a well stops production. Consequently, the proceeds of operations can be distributed to owners well past the point of holdback, and a corporation with plenty of funds now might still orphan its entire portfolio after it depletes. Requiring a company to demonstrate its plan to be able to pay in the future is less restrictive and less prescriptive than alternate rules such as requiring the entire funding up front.

Q: What is the basis for authorizing the OCD to request additional information from the operator regarding its plugging and abandonment plan?

A: The list of information that may be requested provides insight to the kinds of analysis

deemed necessary to meet the prescribed scope of proof. I'll talk through each type of information identified in the proposed rule individually, though the OCD may also request information not on the list.

Corporate credit ratings represent a third-party evaluation of a company's overall ability to pay its debts. They rely heavily on corporate financial statements, and some other jurisdictions already require or may review credit ratings before allowing a transfer.

Corporate financial statements provide first-hand documentation of financial health which can then be examined in more detail. These become needful to get the same kind of insight to companies too small to be rated by a reputable agency. Other states, such as Michigan and Alaska consider credit ratings and/or financial statements.[12]

Together, credit ratings and financial statements provide an accessible and high-level picture of a company's current financial health. And they do so at little or no incremental cost to the applicant because one or both should already exist in the normal course of business.

But again, most plugging liabilities won't be paid immediately. The next couple of items begin to dig deeper into the future of the company's financial strength.

Long-term liabilities, such as but not only asset retirement obligations, are commonly not clear in financial statements, which is why other financial documents and reports are needed to assess these liabilities. Generally Accepted Accounting Practices (GAAP) in the U.S. allow companies to report asset retirement obligations (AROs) more than five years in the future without rigorous quantification and only after discounting to the present time. Current operations are often projected to last more than five years, and costs can be scheduled years after the end of production. In my experience, AROs can and are most commonly reported under

[12] Interstate Oil and Gas Compact Commission. 2018. *Transfer of Infrastructure and Liabilities-Assessment Criteria and Considerations Toolbox for State and Provincial Regulators*.

GAAP as opaque, discounted figures.

Of course, orphaning is a question of contemporaneous future flow of actual dollars, not of hypothetical discounted dollars today. The State of New Mexico will still be around more than five years from now when economic operations end, and it will still have the same interests in decommissioning. So, the most relevant future dynamics are not captured by financial statements. Information about long-term liabilities is the first half of the equation when looking at a company further into the future.

Reserves and economics (R&E) reports provide the second half of the equation when looking further into the future. Reserves still in the ground are the largest and most fundamental asset of an upstream company, and many standards already exist to quantify future volumes and related cash flow for investors. A reserves and economics report uses historical performance, petroleum engineering, and knowledgeable assumptions to project the costs and revenue of operations decades into the future to the end of economic life.

Such an analysis is so basic to running an oil or gas company that companies routinely prepare them at least once a year and commonly more often than that. Public companies are required to publicly publish the results of R&E analysis, and banks require the same kind of reports about the collateral for their loans. Many petroleum consulting firms make a business of creating such reports as independent third parties or as auditors of internal calculations, but practically every oil and gas company maintains its own internal calculations for planning and decision-making.

By their nature, they show the timing and amount of incoming cash flow as well as the timing of the economic limit to production which precedes decommissioning, all of which are relevant to determine whether a company will have the means to decommission when the time

comes.

The last few items on the list of possible requests allow the OCD to investigate one level deeper into the basis of the assumptions made in the longer term AROs and cash flows of requests above.

Records of the operator's historical costs for decommissioning activities provide concrete evidence of the future costs. Actual costs are more reliable than estimates alone, to the extent that they can include the inevitable pattern of "unexpected" cost overruns. It is possible to cherry-pick which costs are shown just as it is possible to cherry-pick which wells are plugged so that historical data shows only wells without mechanical problems. Still, an estimate of future costs should begin with the historical track record.

An estimate of the operator's decommissioning obligations would build from the historical track record to compile a complete cost including for shared facilities which will not be decommissioned until the end of the life of the field.

As discussed earlier, a company intent on meeting its obligations would already have quantified them and used historical costs in the process. To the extent they have not done so, OCD's ability to request this information in the proposed rule serves to improve the company's plans and diminish the probability of orphaning. This is a reasonable and appropriate requirement.

Lastly, a history of inactive wells and returning wells to production provides a perspective on the assumptions about future operations made in the reserves and economics report. The historical performance provides a baseline, a sense-check for operations about the future. In my experience, oil and gas companies do not normally keep records of inactivity and reactivations as such, but they do keep the requisite information readily available.

In my opinion, it is reasonable for a regulator to ask for these kinds of information to perform its duty to protect the state. It is all the same kind of information that an investor or lender would request to evaluate risk, and the kind of information that the state should request to evaluate its risk.

In fact, one state already does take the opportunity to ask these questions. Alaska's regulations allow for deep financial review of both the seller and the buyer in a transfer, including the kinds of information requested above.[13] Proposed rules for New Mexico are less incisive than Alaska in that it does not ask for the same information on the seller.

Q: What is the basis for requiring, during a change of operator request, an operator's officer, director, or partner certify its plugging and abandonment plan?

A: This requirement is to provide a measure of accountability. Accountants sometimes sign attestations about financial statements. Petroleum engineers sometimes sign and seal attestations about reserves and economics reports. Executives of public companies must sign attestations about their public filings including financial statements and engineering reports and summaries of business plans and risks. This proposal does something similar.

It asks the leadership of the company which is responsible to execute the plans to attest to the feasibility and intent of a plan that involves large capital expenditures. Without this attestation, the company could submit a plan that is nothing more than a pie-in-the-sky hope or a feasible plan which they have no intent to follow. And without the signature of leadership with authority to commit the capital, the plan has little meaning. It is not unlike other situations that require leadership review and signature for reporting and for capital spending, and like those

[13] International and Legal and Regulatory Affairs Committees. (2018). *Transfer of Infrastructure and Liabilities-Assessment Criteria and Considerations Toolbox for State and Provincial Regulators*. Interstate Oil and Gas Compact Commission. And Feige, C. (2020). *Letter from Commissioner of the Department of Natural Resources to Legislative Resources Committees*.

other situations, it gives the counterparty confidence in the declarations.

Certification

Q: Proposed 19.15.9.9.C(6) NMAC provides:

> **C.** The director of the director's designee may deny a change of operator if:
> . . .
> **(6)** the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

What is the basis for authorizing OCD to deny a well transfer if an operator's plugging and abandonment "disclose[s] a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC"?

A: To protect the public interest, a decision will have to be made. This provision gives the OCD the ability to exercise its expert and informed judgment in the same way that all manner of other regulators do. I find it better and more effective to leave the process to expert judgment than to write a prescription without experience. The rules are designed to give OCD the information it needs to make a considered determination whether to approve a transfer. Again, the point of well transfer, is a critical point in the life of a well and transfers merit heightened scrutiny to protect the state against orphan wells and their concomitant risks.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Dwayne Purvis, P.E. August 7, 2025
Dwayne Purvis, P.E. Date

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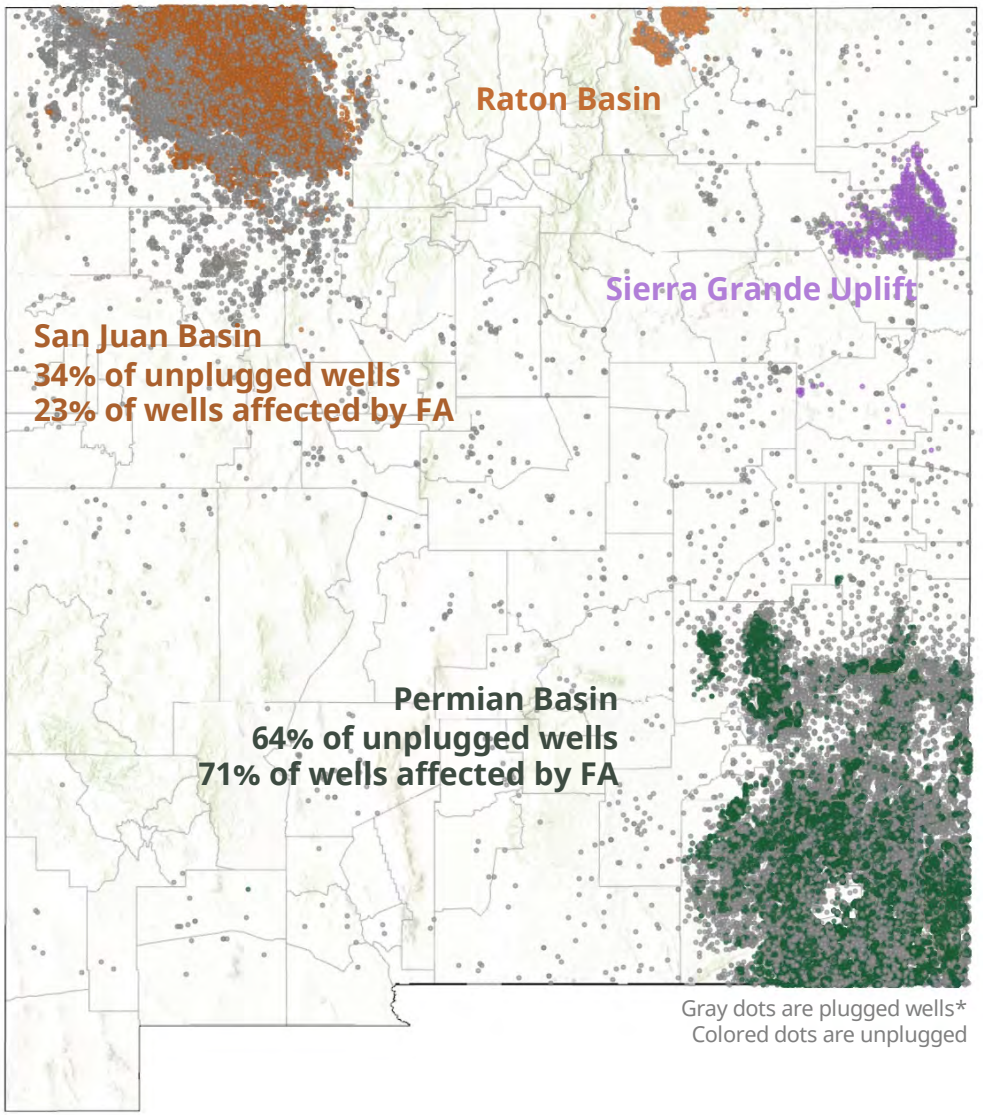
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EXHIBIT 31

Applicants' Exhibit 31: Plugged and unplugged wells in New Mexico as of June 2025.



Basin	Plugged*	Unplugged Total	active	not active
Permian	35,661	**39,929**	36,850	3,079
San Juan	12,941	**21,219**	20,370	849
Raton	116	**861**	837	24
Sierra Grande	643	**711**	698	13
Other	312	-	-	-
	49,673	**62,720**	**wells to be plugged**	

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** Not all plugged wells are fully remediated.*

EXHIBIT 32

Applicants' Exhibit 32: Subdivisions of unplugged wells in New Mexico.

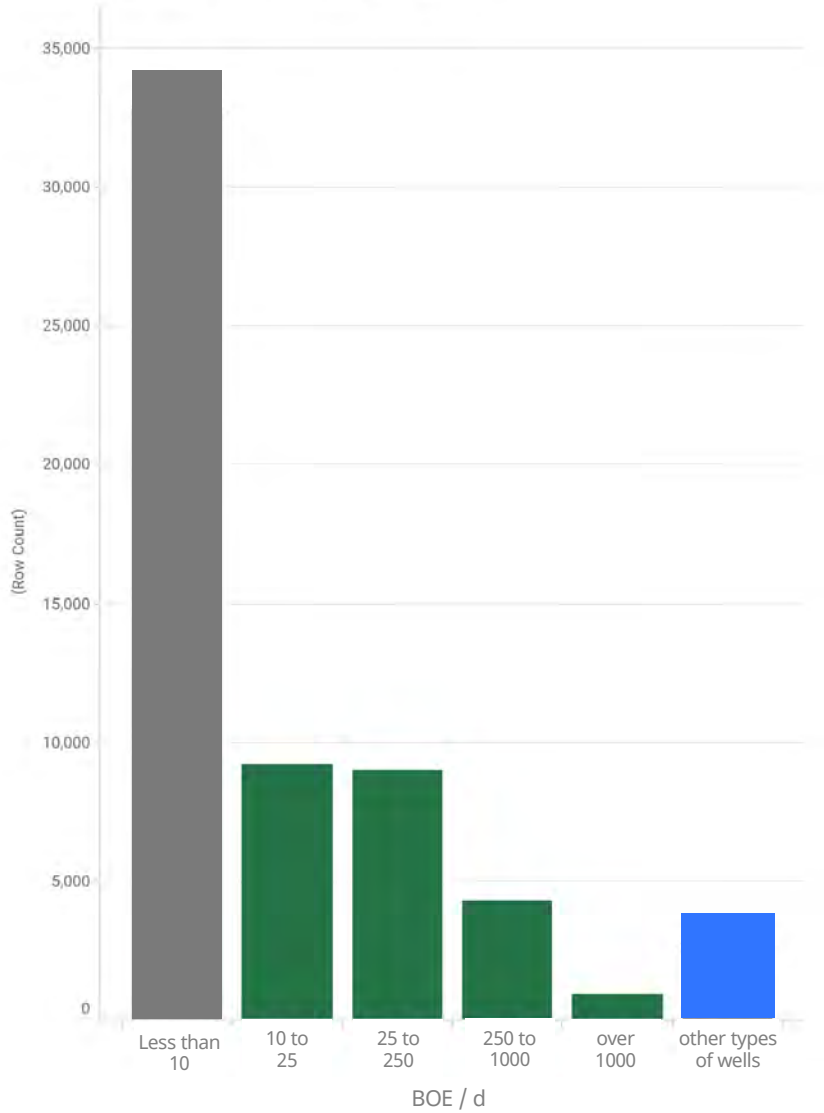
Unplugged wells by activity

BOE/d	Total	Types Producers	Types Other	% of Total
less than 10	**34,238**	34,238	-	55%
10 to 25	**9,187**	9,187	-	15%
25 to 250	**9,008**	9,008	-	14%
250 to 1000	**4,270**	4,270	-	6.8%
over 1000	**921**	921	-	1.5%
Other	**5,096**	1,303	3,793	8%
Total	**62,720**			

Wells in not-active categories per OCD*

		Temp Abandon		
Aging**	Approved	Expired	Inactive	Orphan
0 to 1 yr	184	68	773	0
1 to 2 yrs	118	41		55
2 to 5 yrs	171	54	868	191
5 to 8 yrs	35	26	613	194
8 to 10 yrs	8	15	203	66
> 10 yrs	1	33	771	440
no data	40	0	-	2
Statewide	**557**	**237**	**3,228**	**948**

Production rate of unplugged wells, excluding DUCs



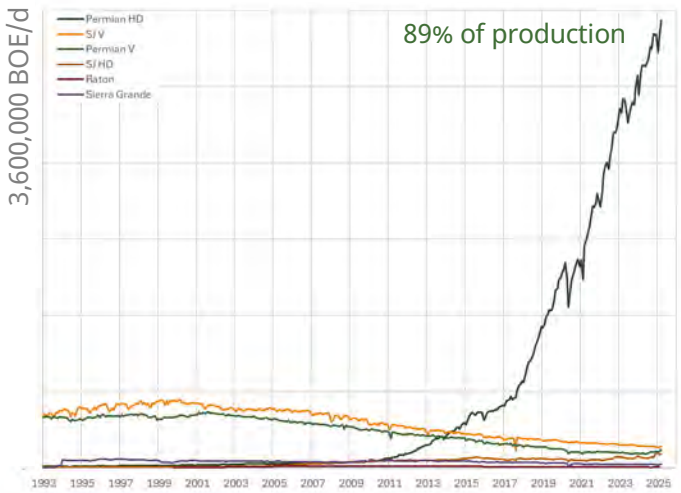
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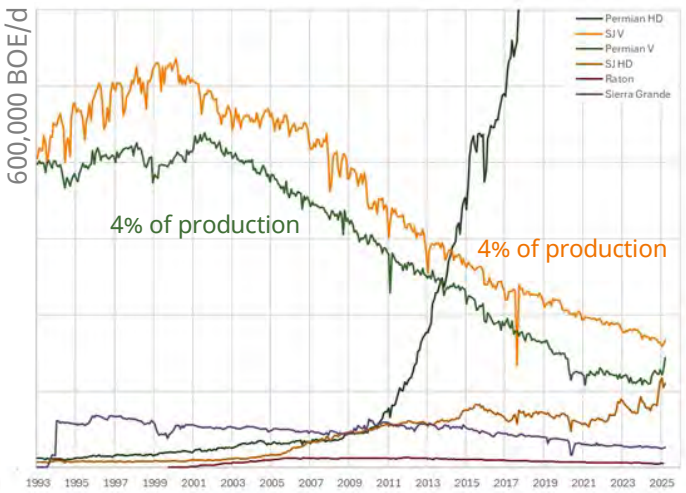
*Some wells in more than one category indicating no activity.
**Aging since last production for Orphan and Inactive. For TA, aging since approved or expired respectively.

EXHIBIT 33

Applicants' Exhibit 33: History of daily production in New Mexico in six categories for major divisions among basins and types of wells shown on four vertical scales.

Production dominated by Permian horizontal and directional wells

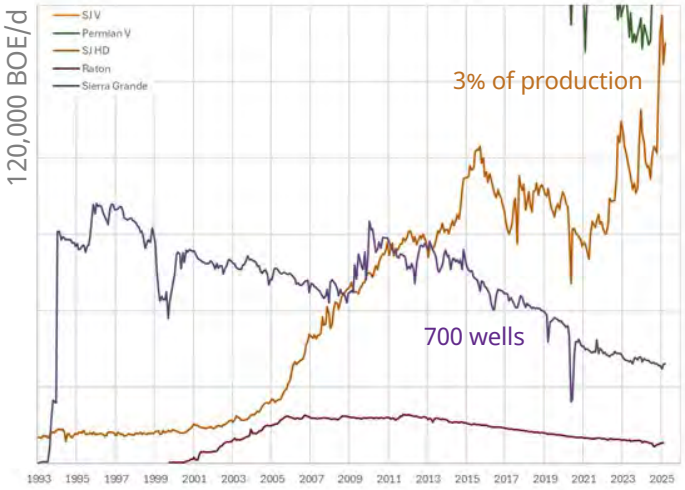


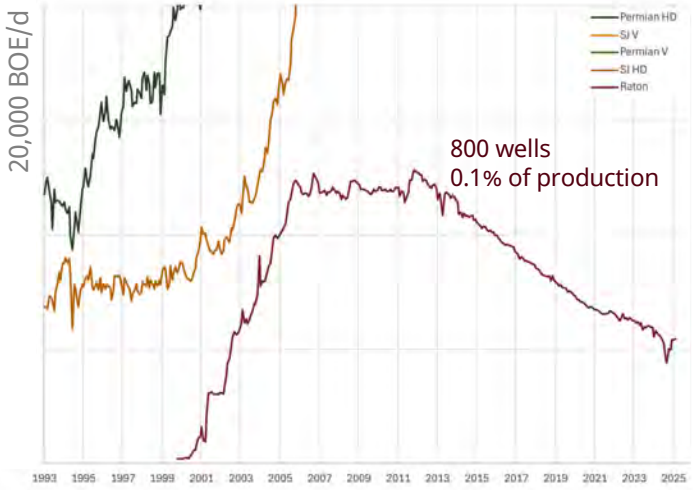


Vertical wells in San Juan and in Permian have been declining more than 20 years

San Juan horizontal and directional increasing but small

Sierra Grande CO2 supply is few wells and declining



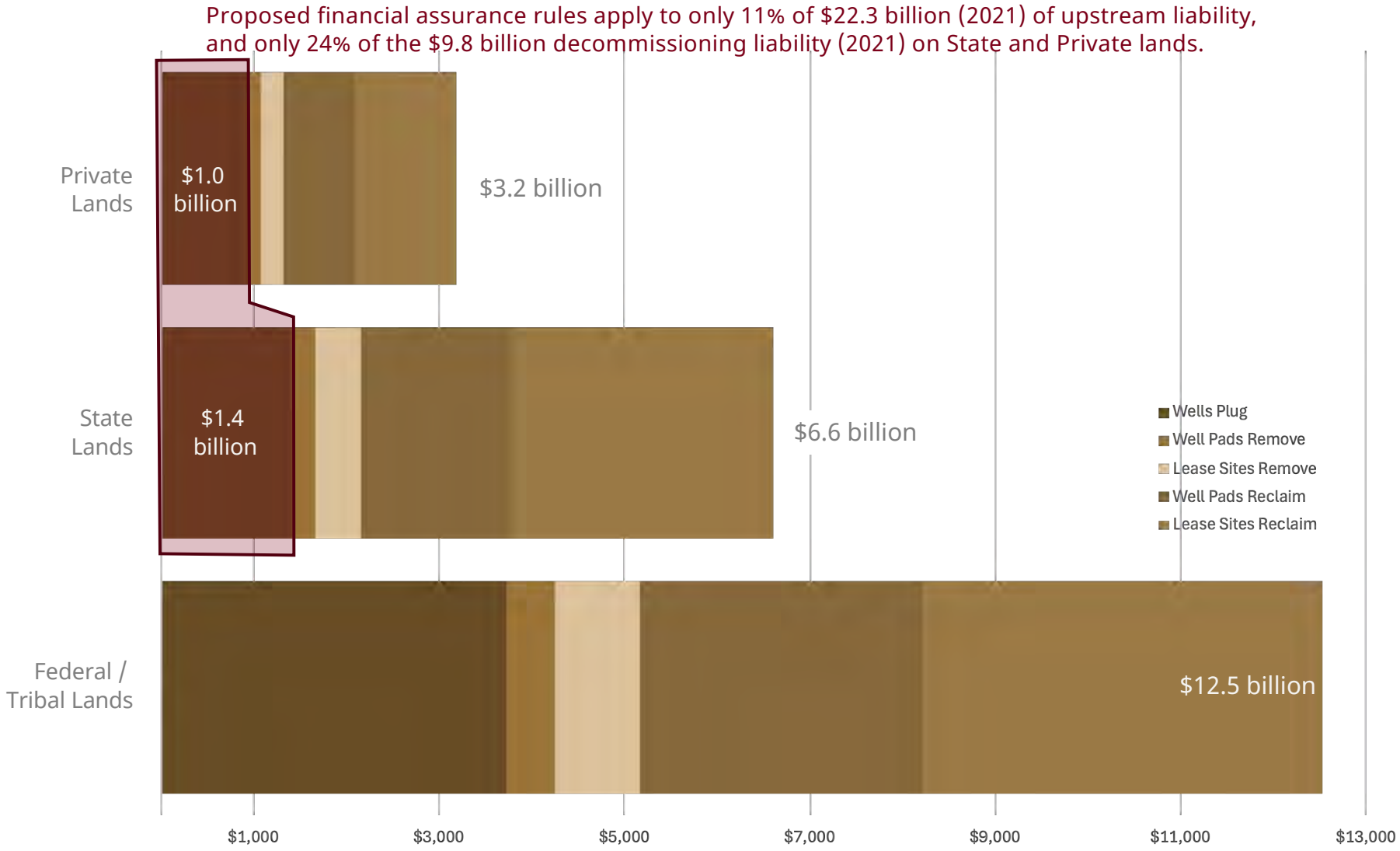


Raton is few wells and declining

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EXHIBIT 34

Applicants' Exhibit 34: Total decommissioning and reclamation cost of upstream oil and gas operations in New Mexico after Vertex 2021 not adjusted for subsequent inflation.



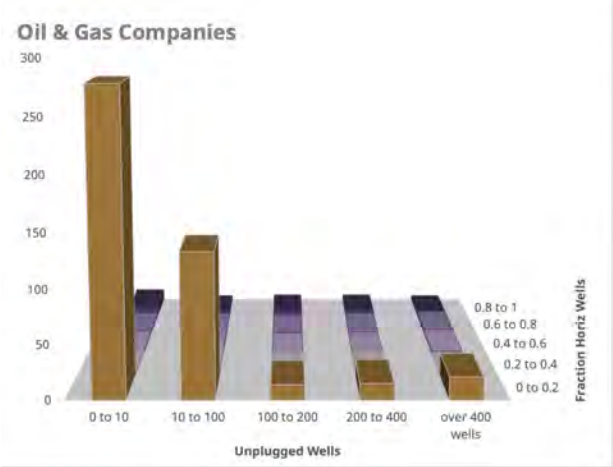
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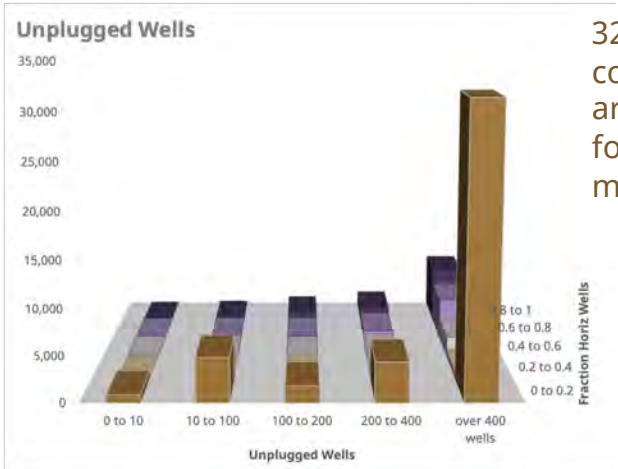
Note that the split between Private and Federal/Tribal land is assumed.
Note that the reclamation costs for Private and Federal/Tribal Lease Sites are extrapolated from State Lands

EXHIBIT 35

Applicants' Exhibit 35: Four measures of the size and impact of oil and gas companies grouped by size (based on wellcount) and relative proportion of vertical and horizontal wells.

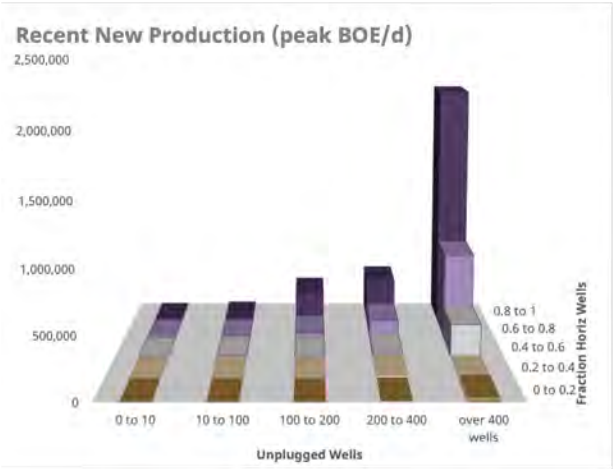
Among companies, 57% have fewer than 10 wells 85% have fewer than 100

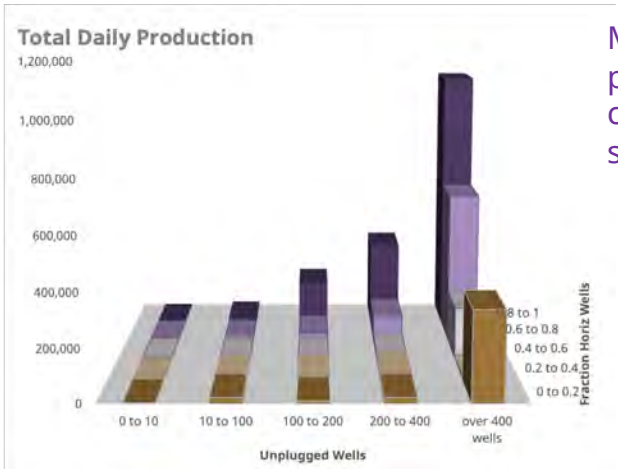




32 largest companies (6%) are responsible for 73% of wells, mostly not shale

Large shale companies create most new production





Most current production comes from large shale companies

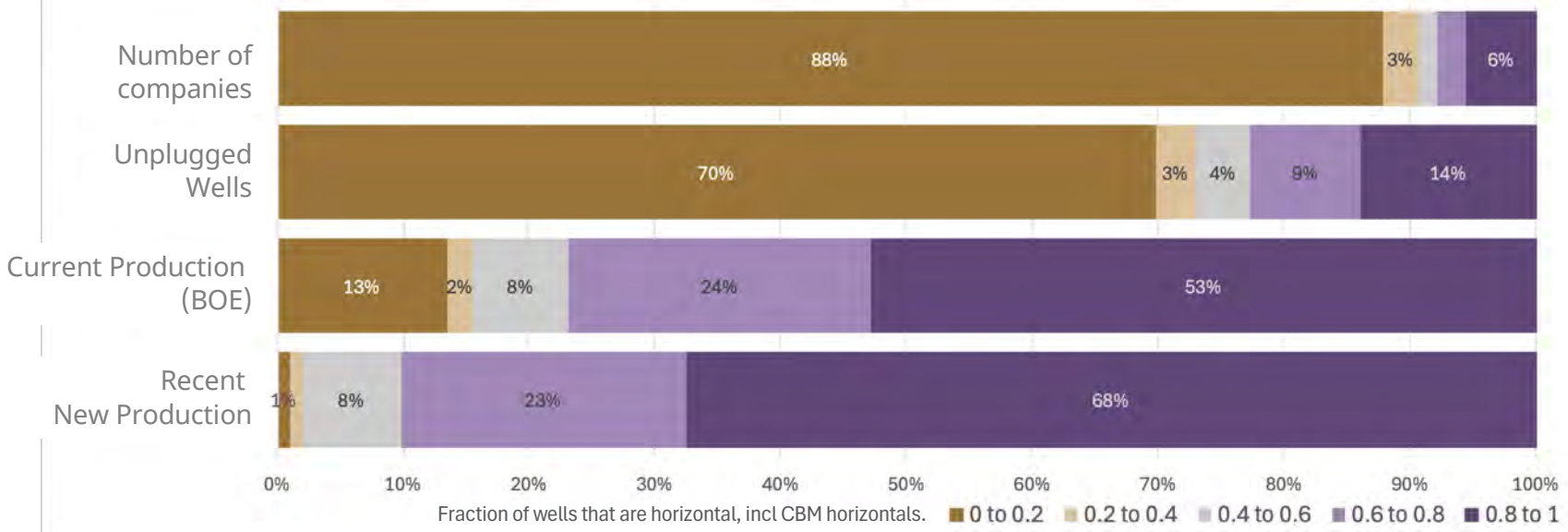
99.8% of new production was horizontal
Small companies contributed 0.05% of new production.

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EXHIBIT 36

Applicants' Exhibit 36: Relative measures of oil and gas companies grouped by the nature of their portfolios.

91% of companies focus on vertical wells, and they bear P&A responsibility for 73% of wells.
But they contribute only 16% of statewide production and **1.9% of recent production additions**.



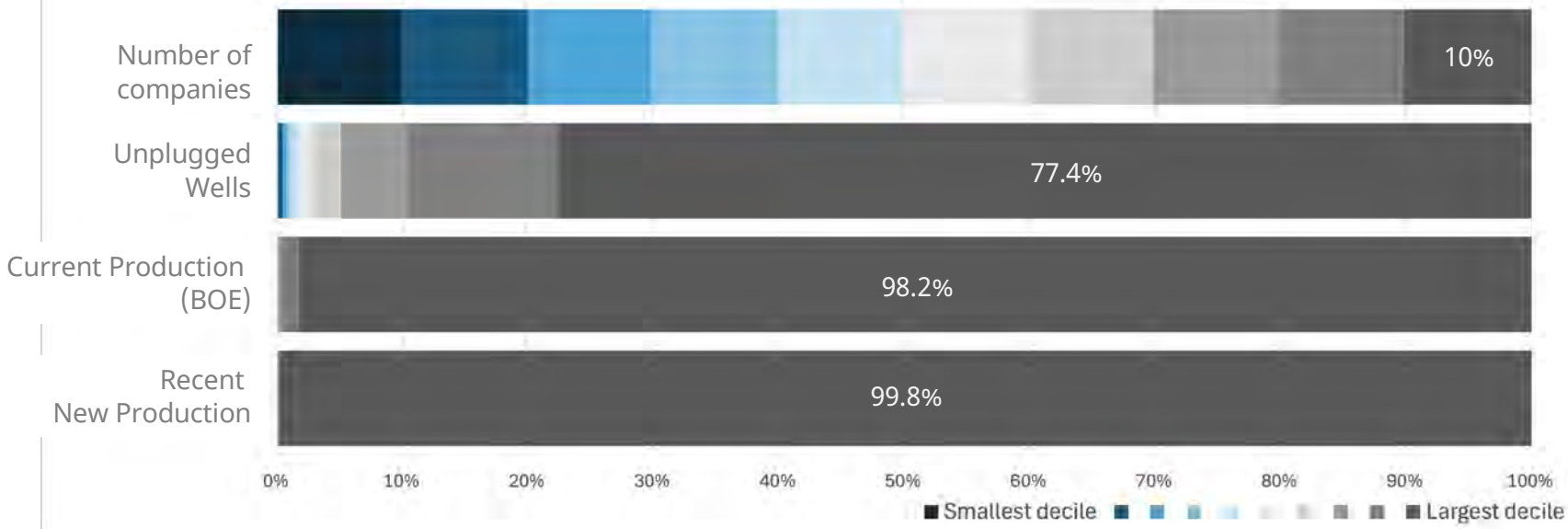
8% of companies focus on horizontal wells, and they operate 23% of wells.
But they contribute 77% of production and **90% of new production**.

EXHIBIT 37

Applicants' Exhibit 37: Relative measures of oil and gas companies grouped by size as measured by current production.

The bottom 90% of companies are responsible for 22.6% of wells, but they contribute only 1.8% of current production and 0.2% of new production.

- 75 companies (14%) report zero production
- 244 companies (47%) report less than 10 BOE/d, total 0.02% of statewide volumes
- Smallest 85% of companies (446) produce 0.7% of statewide volumes



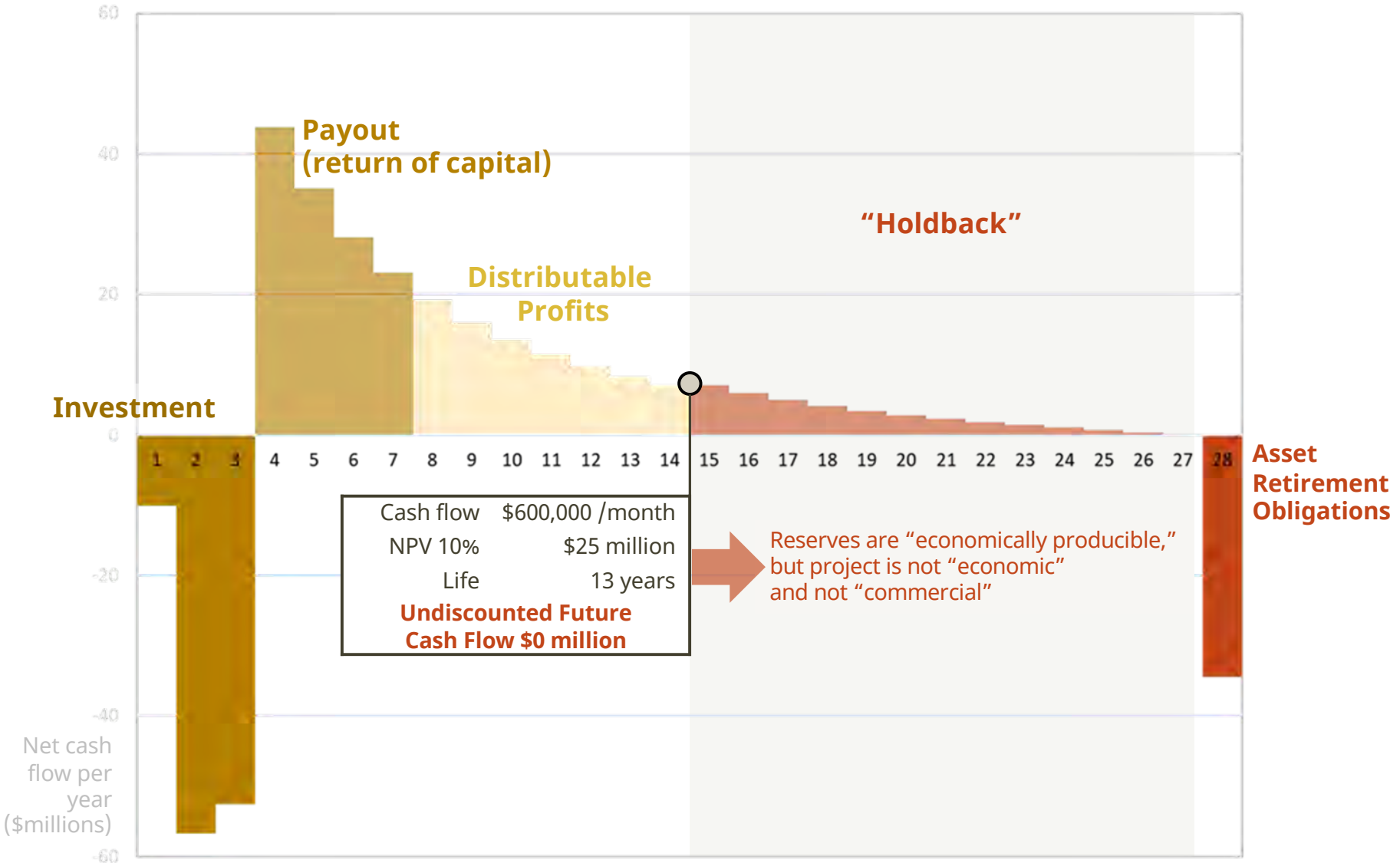
The top 10% of companies account for 98.2% of production and 99.8% of new production.

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Based on companies with wells still unplugged according to OCD records.

EXHIBIT 38

Applicants' Exhibit 38: Schematic of cash flow for a hypothetical oil and gas project to demonstrate the economic concepts of payout and holdback.

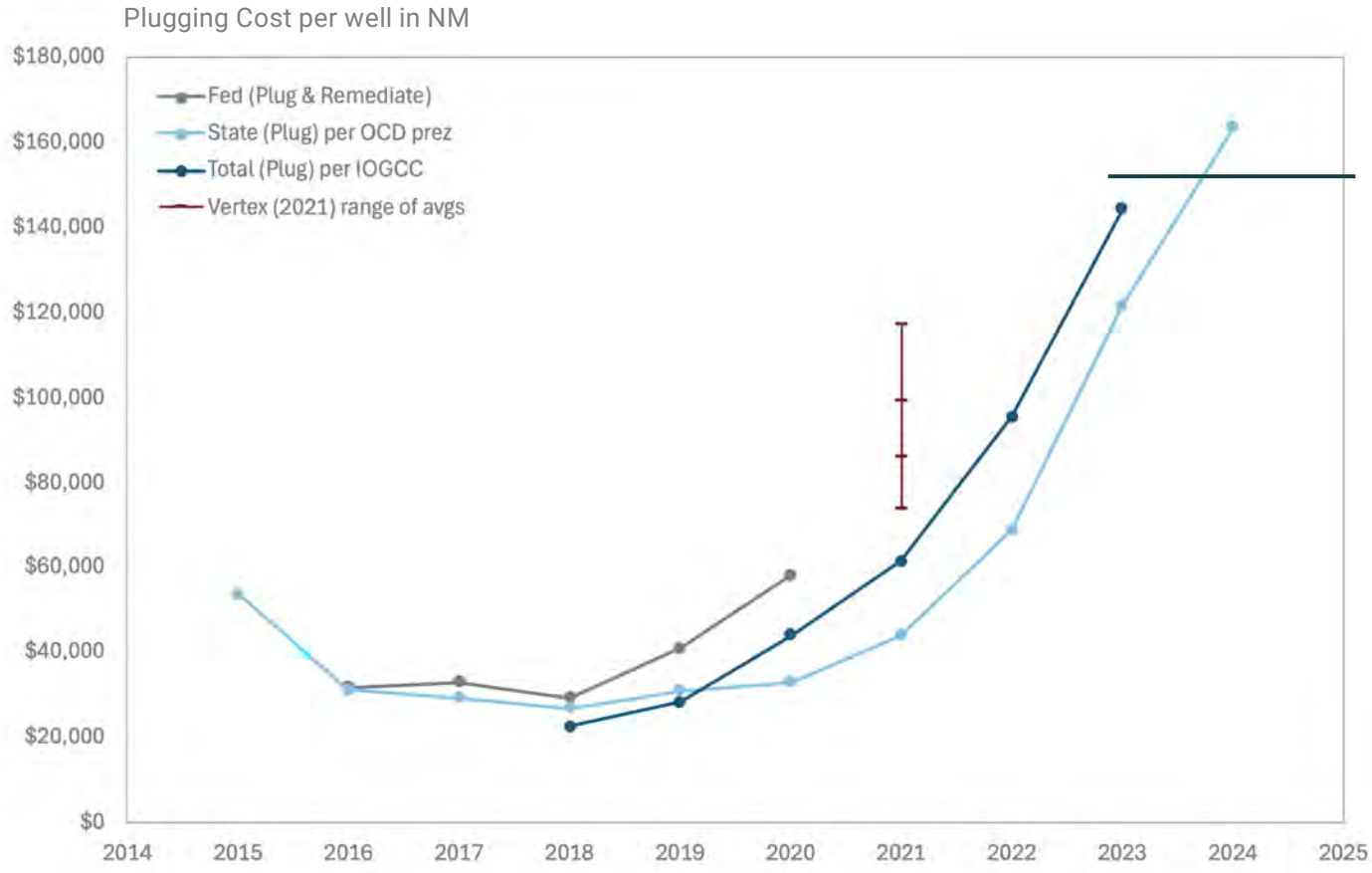


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After Table 9.3 of Guidelines for Application of the Petroleum Resources Management System, Revised July 2022 published by the Society of Petroleum Engineers

EXHIBIT 39

Applicants' Exhibit 39: Historical costs of downhole plugging for orphan wells in New Mexico.



Pattern of increasing costs, already above **$150,000 per orphan well**

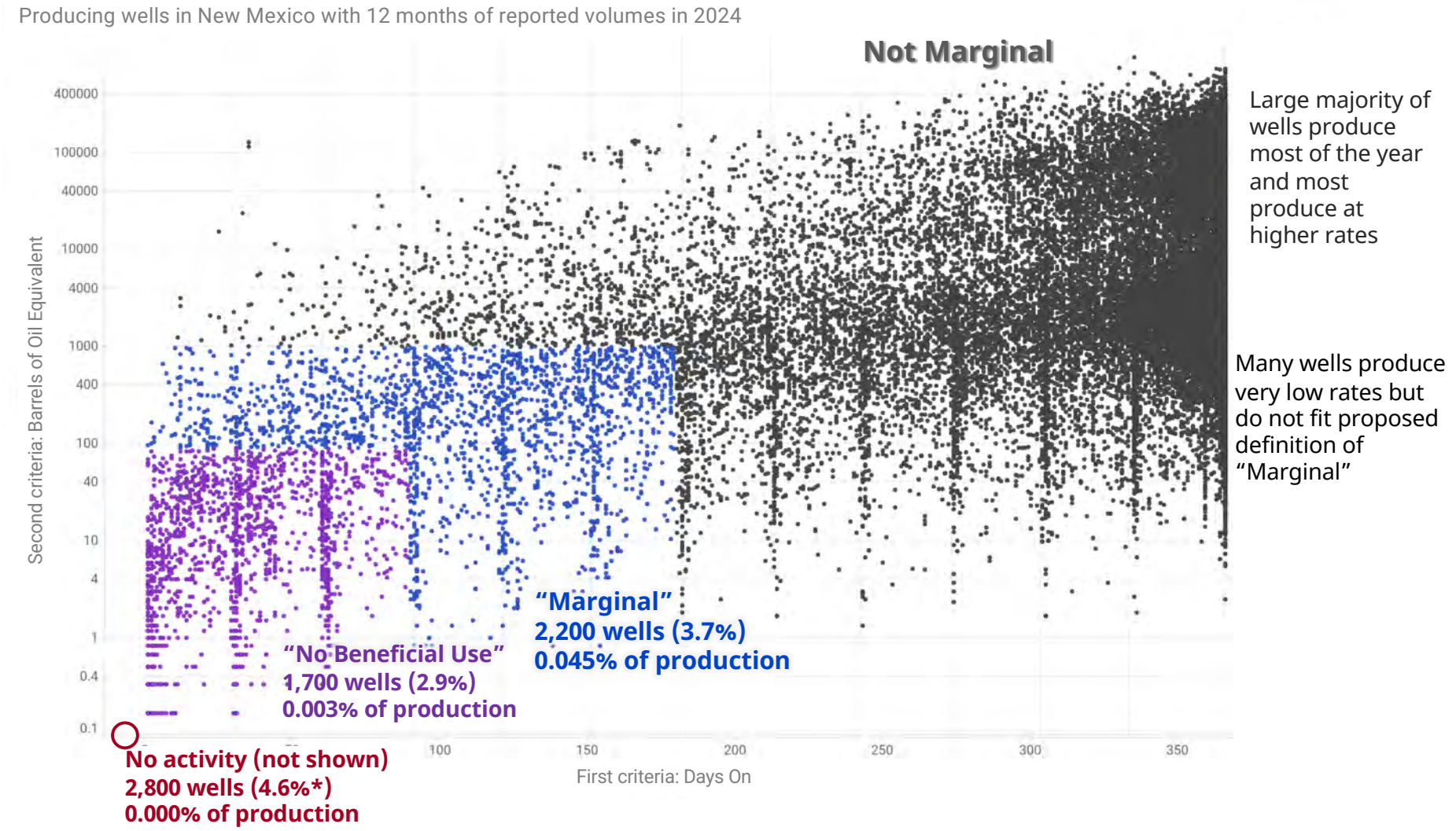
Note that costs exclude surface removal and reclamation. In 2024 **~$40,000 low side** **$230,000 average**

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Based on EMNRD Annual Reports and presentations by OCD to Legislature

EXHIBIT 40

Applicants' Exhibit 40: Production vs days of activity of wells in New Mexico during 2024.

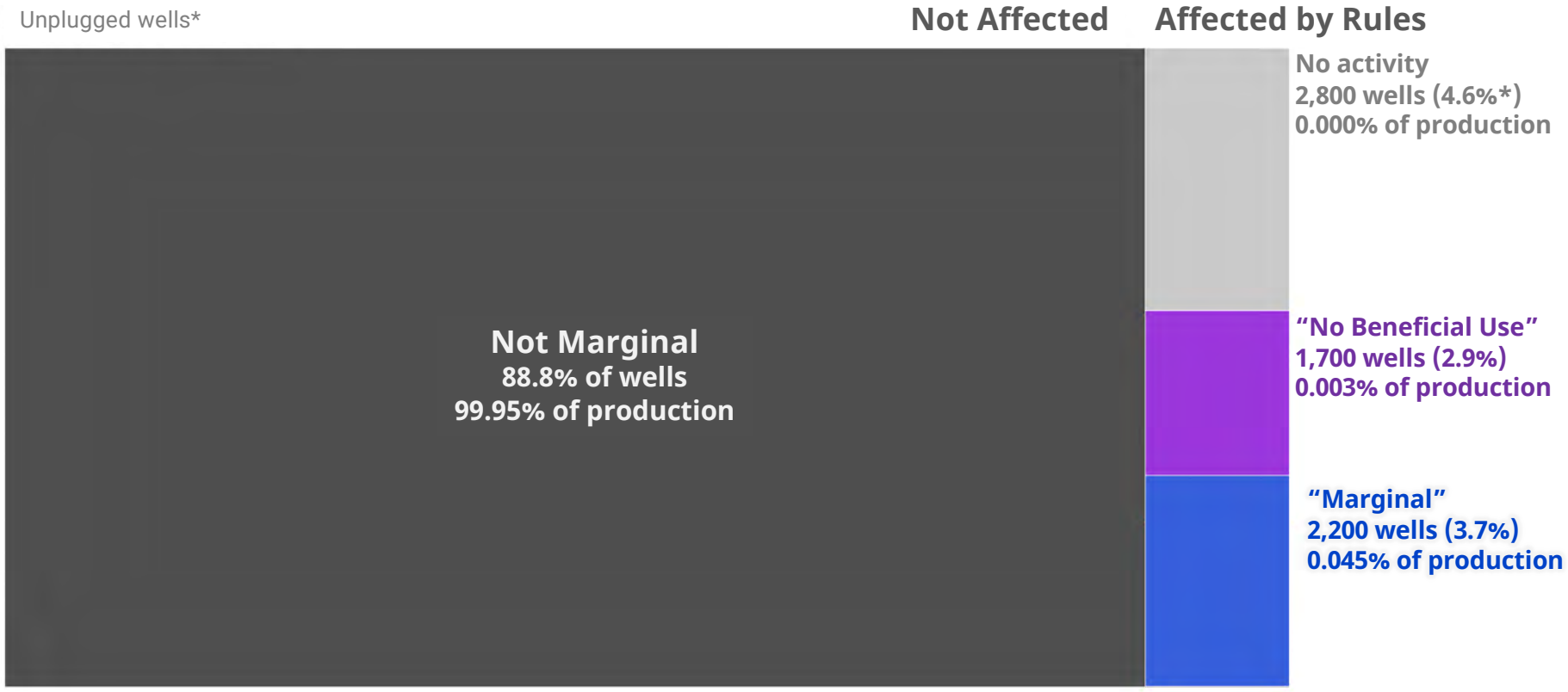


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**Percentage based on 60,536 wells including producers and injectors with less than 12 months of data but excluding wells in the process of drilling or completing or that serve other types of functions.*

EXHIBIT 41

Applicants' Exhibit 41: Treemap of area representing numbers of wells in each category.

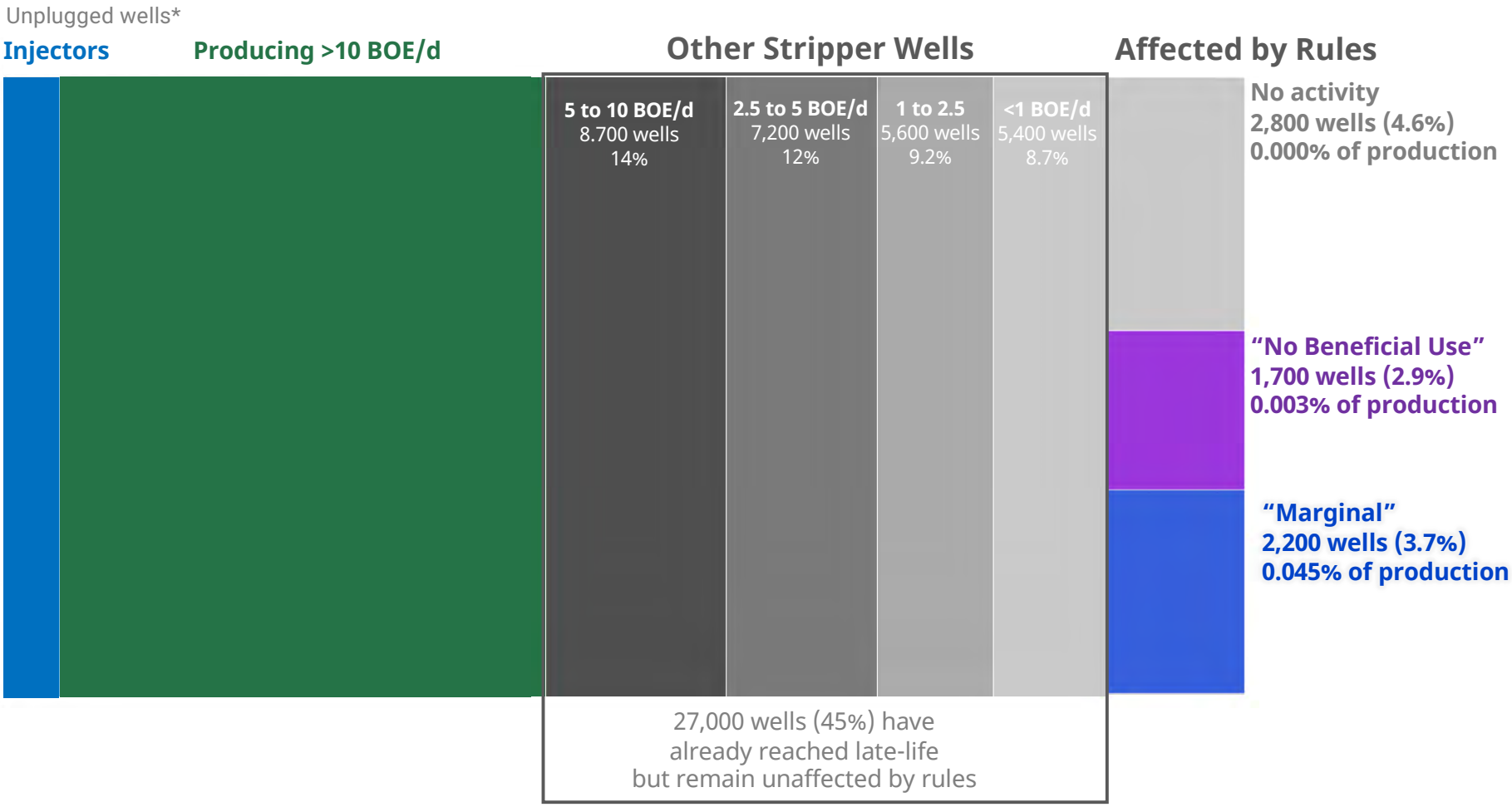


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*Based on 60,536 wells including producers and injectors with less than 12 months of data but excluding wells in the process of drilling or completing or that serve other types of functions.

EXHIBIT 42

Applicants' Exhibit 42: Treemap of area representing numbers of wells in each category, with further detail on wells that do not qualify as "marginal."



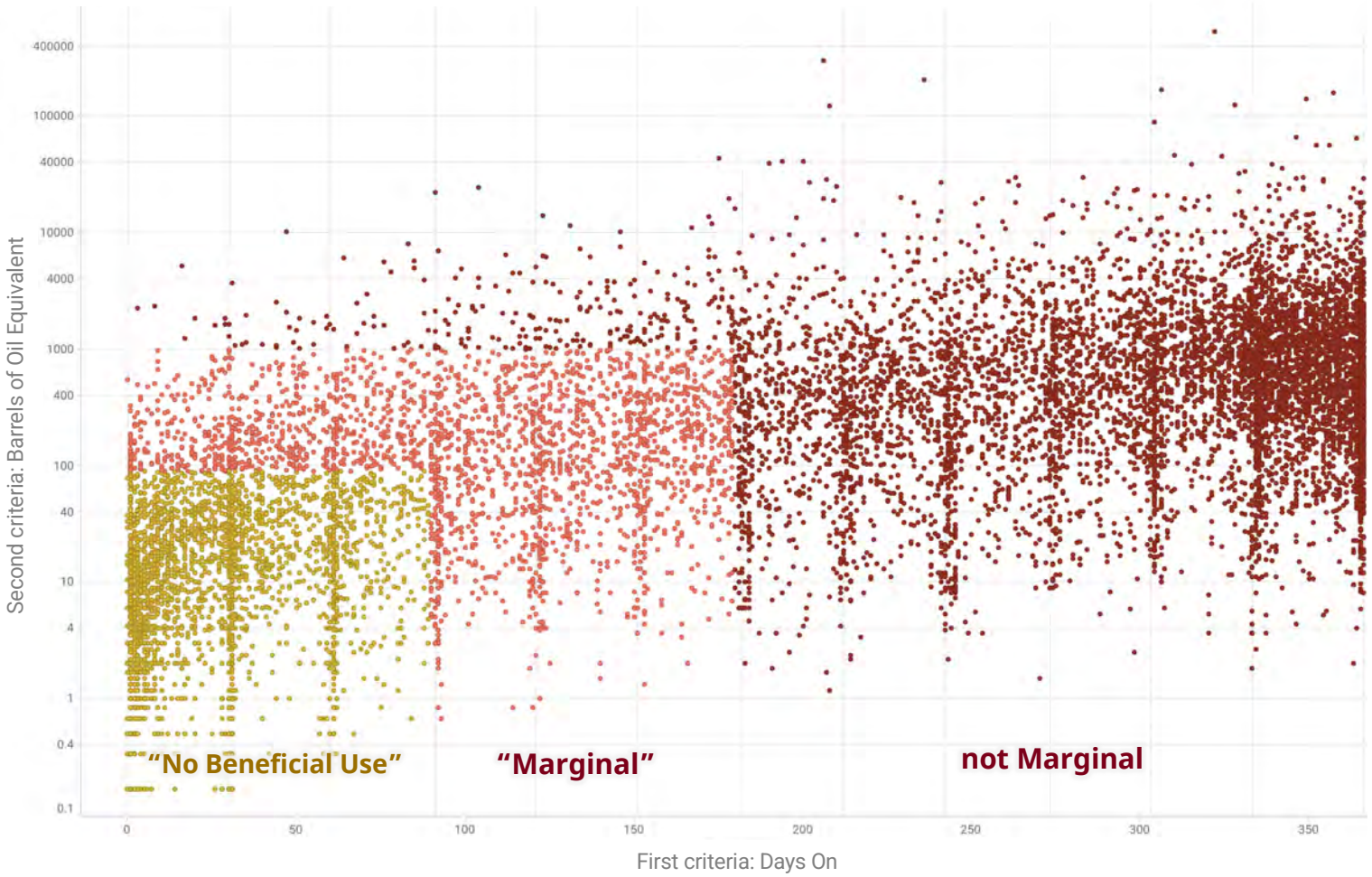
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**Based on 60,536 wells including producers and injectors with less than 12 months of data but excluding wells in the process of drilling or completing or that serve other types of functions.*

EXHIBIT 43

Applicants' Exhibit 43: Actual economic limit of production demonstrated by wells which ceased production between 2009 and 2023.

Each dot represents the volume produced and days on for a single well that has ceased producing in the last 15 years

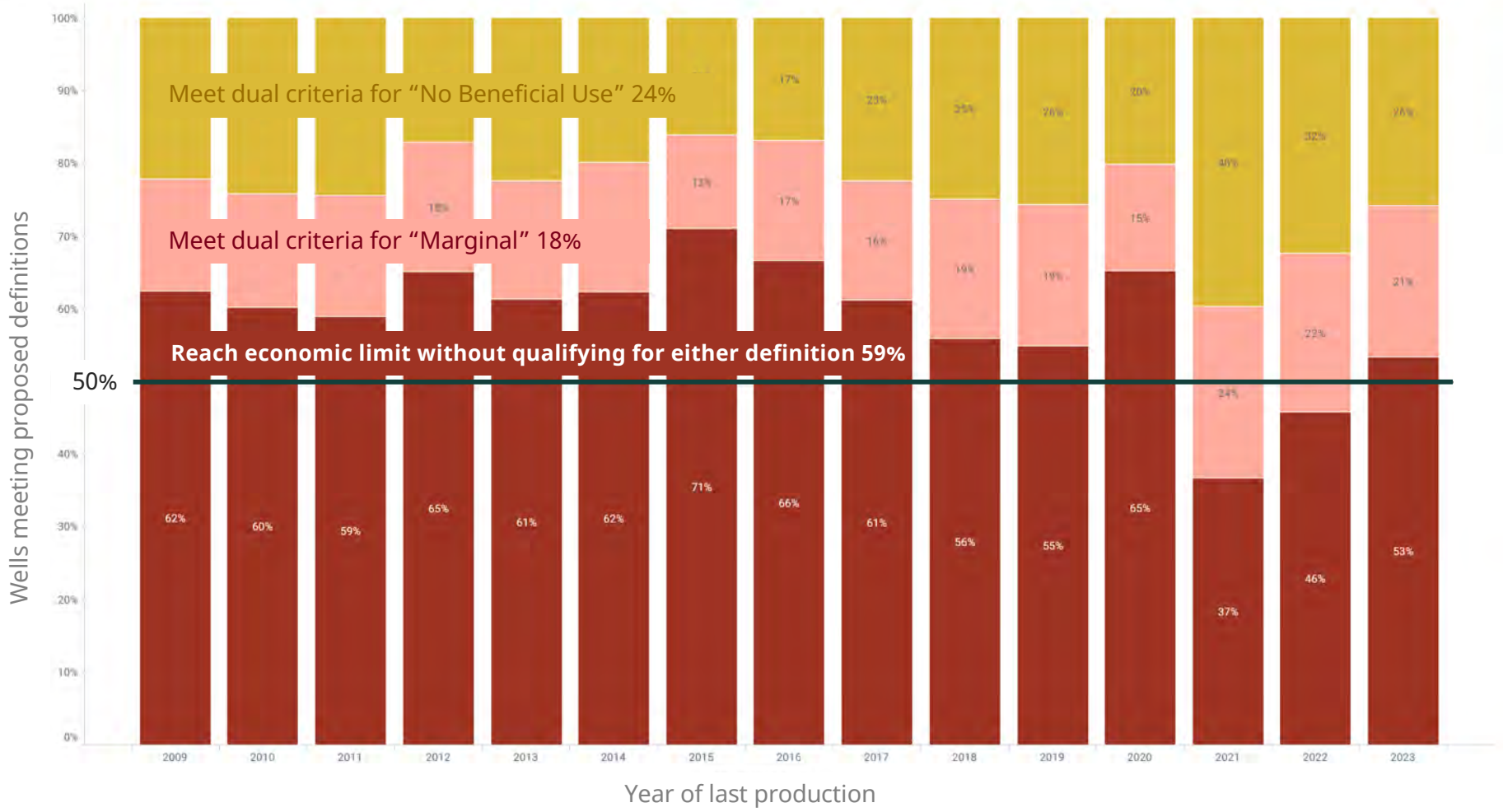


Majority of wells end production without qualifying as "Marginal" or "No Beneficial Use"

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EXHIBIT 44

Applicants' Exhibit 44: Proportions of wells which qualified as “no beneficial use” and “marginal” at the point that production is known to have ceased.



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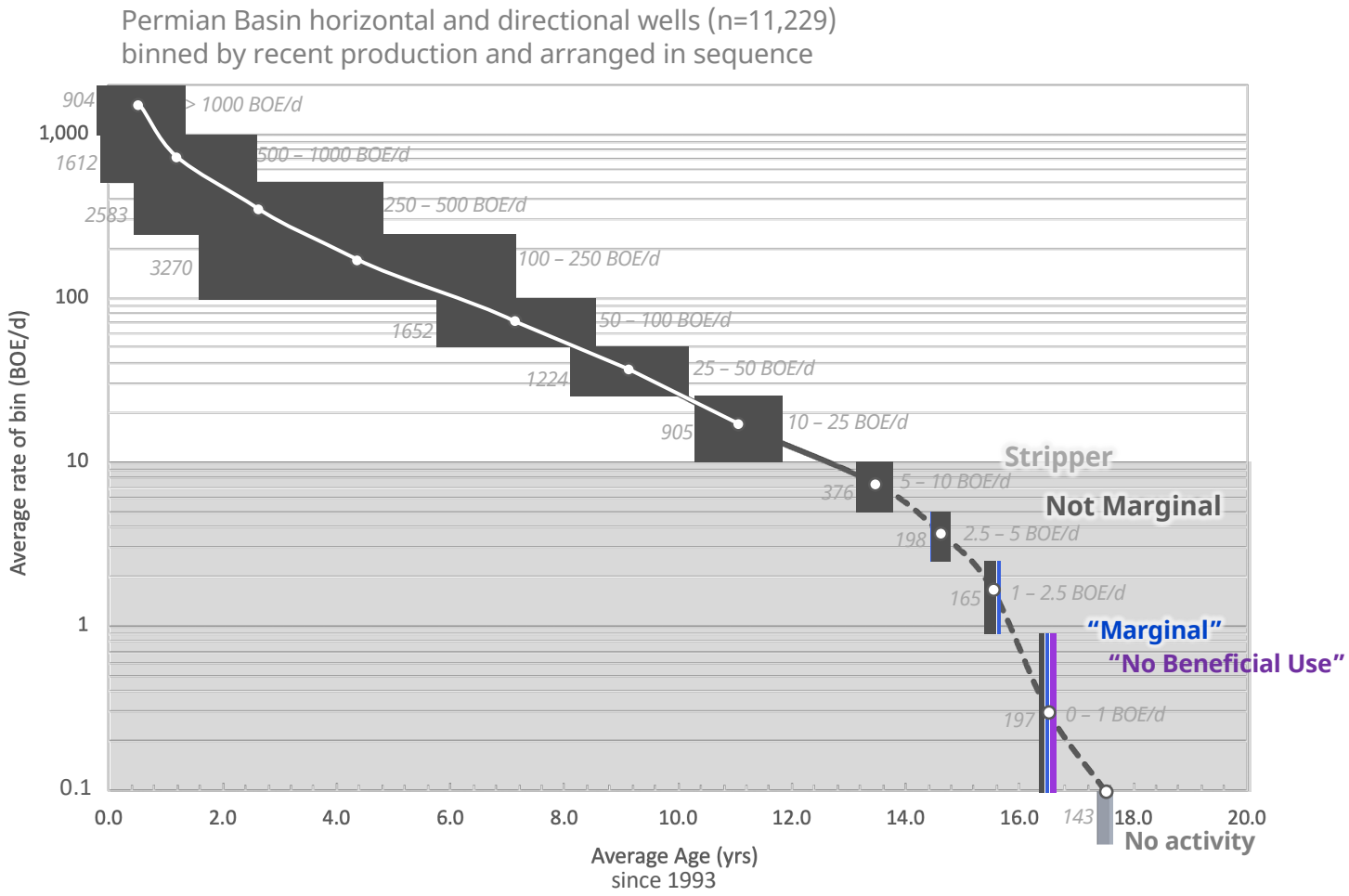
Apps' Ex. 44

EXHIBIT 45

Applicants' Exhibit 45: Permian Basin horizontal and directional wells binned by daily production rate and positioned over average rate and average age for each bin.

The path shows the sequence of binned well productivity vs average age in each bin, and the bars show the number of wells in each bin.

Most wells are less than 11 years old. The largest cohort is producing between 100 and 250 BOE/d

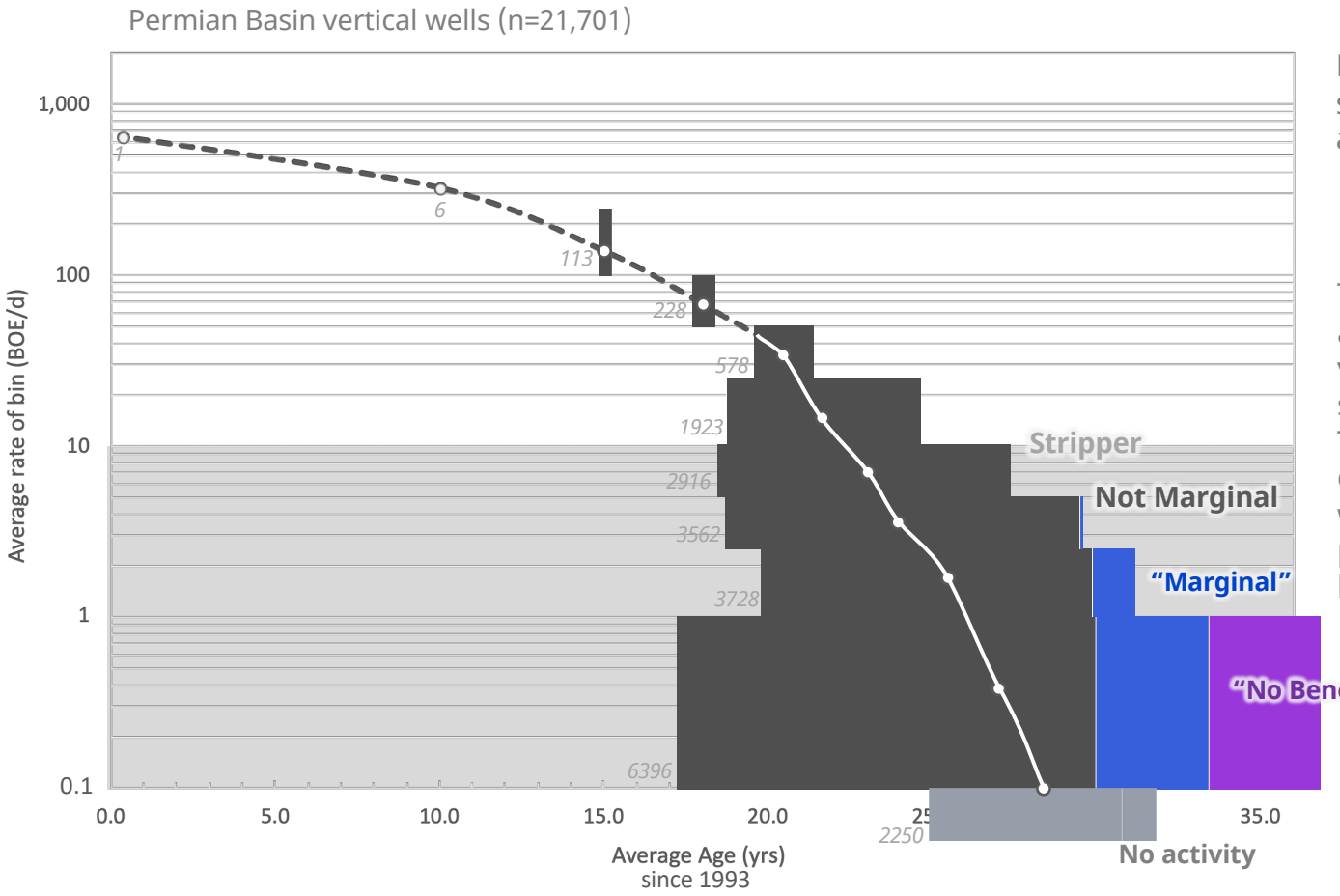


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Note that average age was adjusted for segments shown with dashed lines in order to keep the average rates in sequence and without overlapping.

EXHIBIT 46

Applicants' Exhibit 46: Permian Basin vertical wells binned by daily production rate and positioned over average rate and average age for each bin.



Bars again show the stage of depletion along a depletion path.

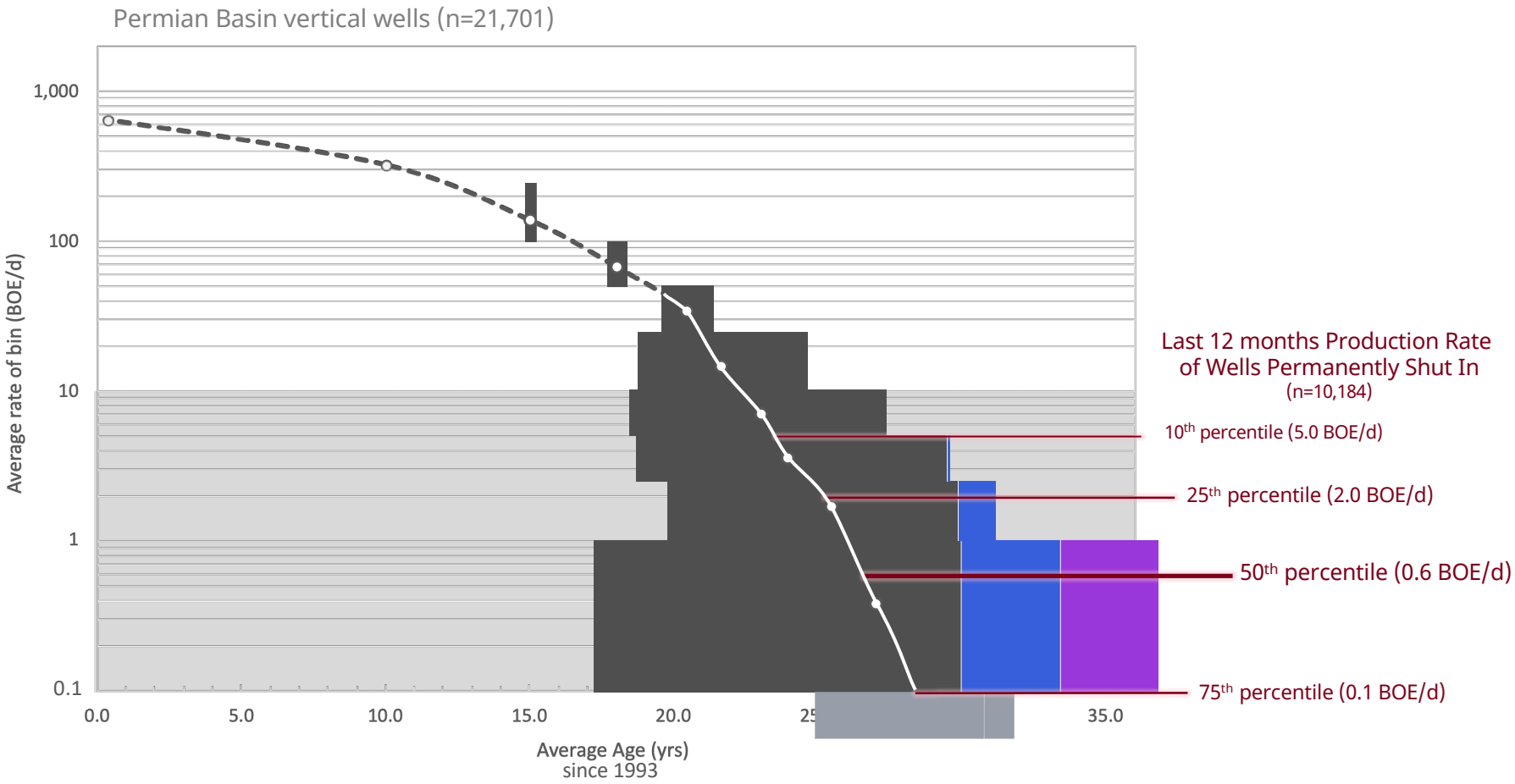
Though not many qualify as NBU or Marginal, vertical wells are systematically late in life. The large majority qualify as "stripper" wells, and the largest population produces less than 1 BOE/d.

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Note that average age was adjusted for segments shown with dashed lines in order to keep the average rates in sequence.

EXHIBIT 47

Applicants' Exhibit 47: Comparison of binned Permian Basin vertical wells to final rates of production demonstrated in the basin.



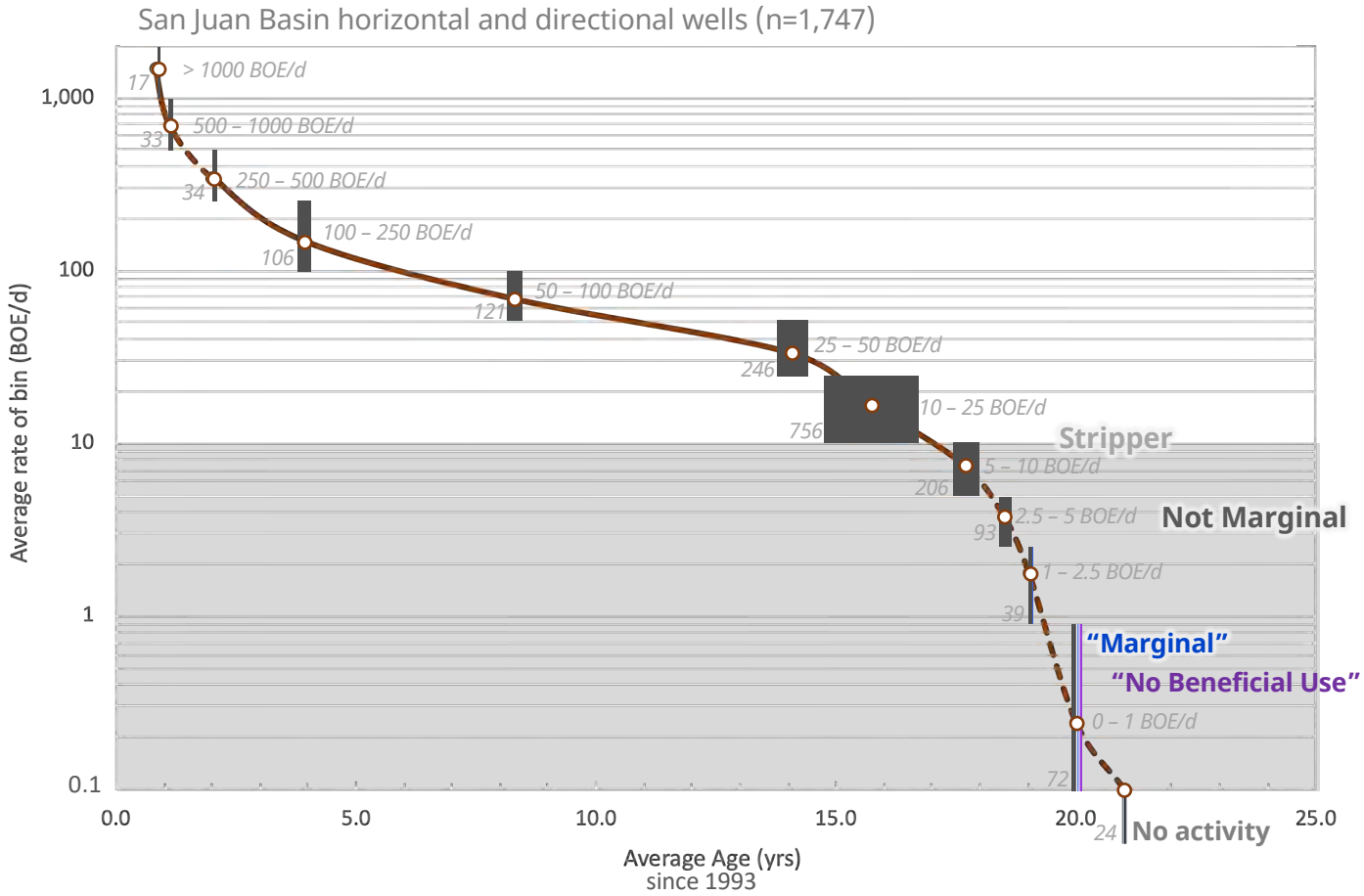
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Note that average age was adjusted for segments shown with dashed lines in order to keep the average rates in sequence.

EXHIBIT 48

Applicants' Exhibit 48: San Juan Basin horizontal and directional wells binned by daily production rate and positioned over average rate and average age for each bin.

A small number of horizontal and directional wells produce at high rates. The largest group produces between 60 and 150 Mcf/d (10-25 BOE/d)

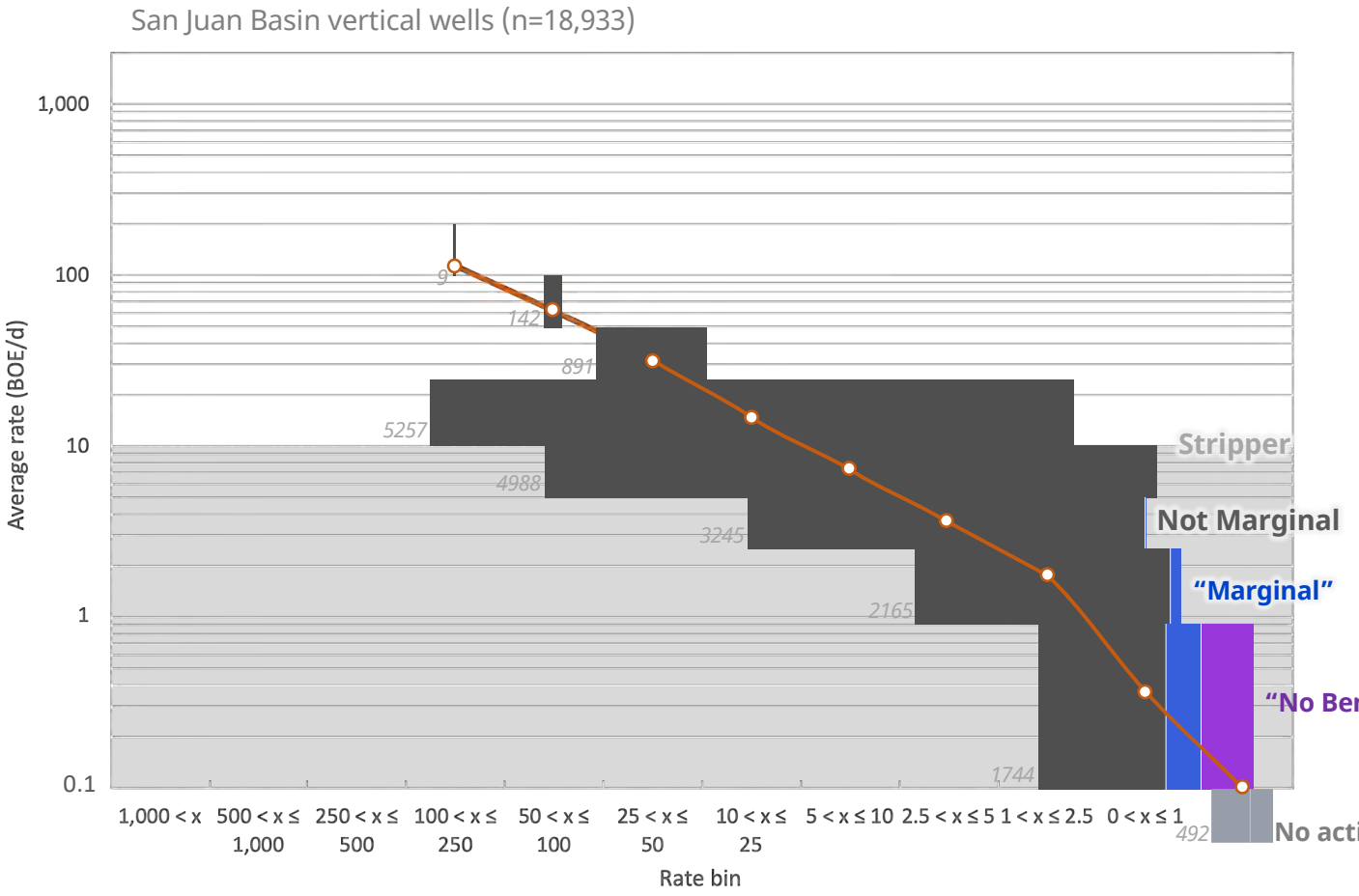


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Note that average age was adjusted for segments shown with dashed lines in order to keep the average rates in sequence.

EXHIBIT 49

Applicants' Exhibit 49: San Juan Basin vertical wells binned by daily production rate and positioned over average rate and bin range.



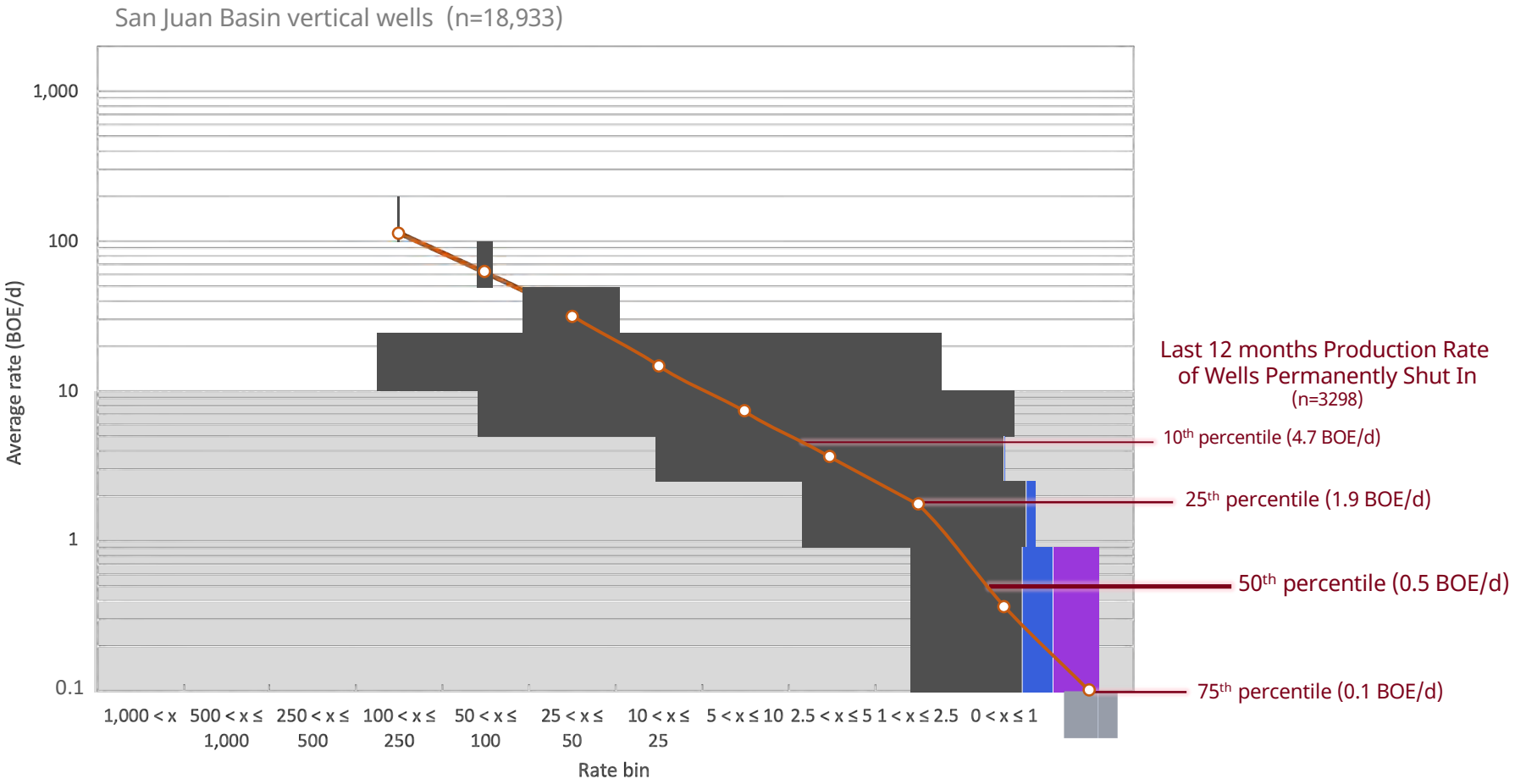
Large majority of wells produce less than 150 Mcf/d and have produced more than 25 years

Though not many qualify as NBU or Marginal, vertical wells are systematically late in life. The large majority qualify as "stripper" wells, and the largest population produces between 30 and 60 Mcf/d (5 and 10 BOE/d)

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EXHIBIT 50

Applicants' Exhibit 50: Comparison of binned San Juan Basin vertical wells to final rates of production demonstrated in the basin.

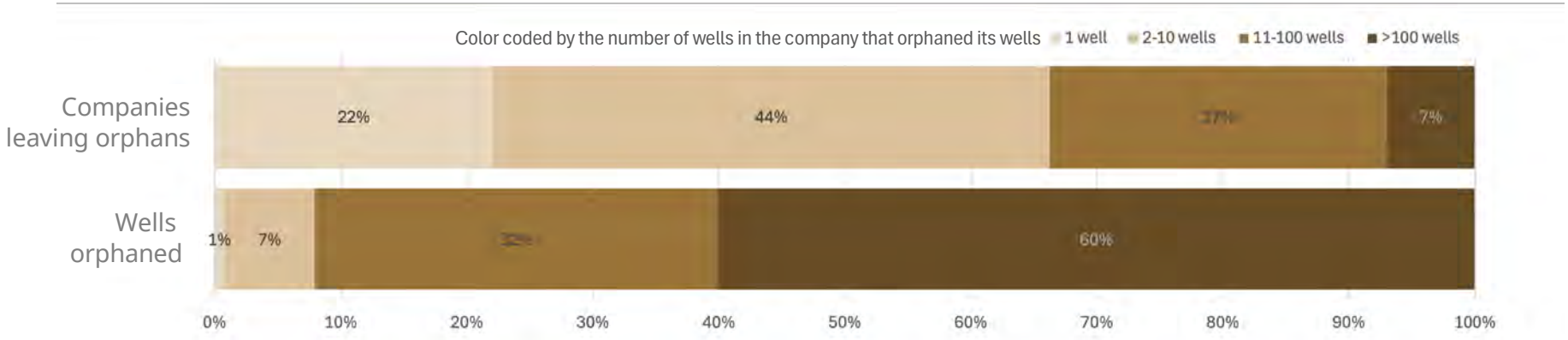


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EXHIBIT 51

Applicants' Exhibit 51: Size of recent portfolios orphaned in New Mexico.



Most companies that orphan their wells are small:
66% of companies had 10 wells or fewer

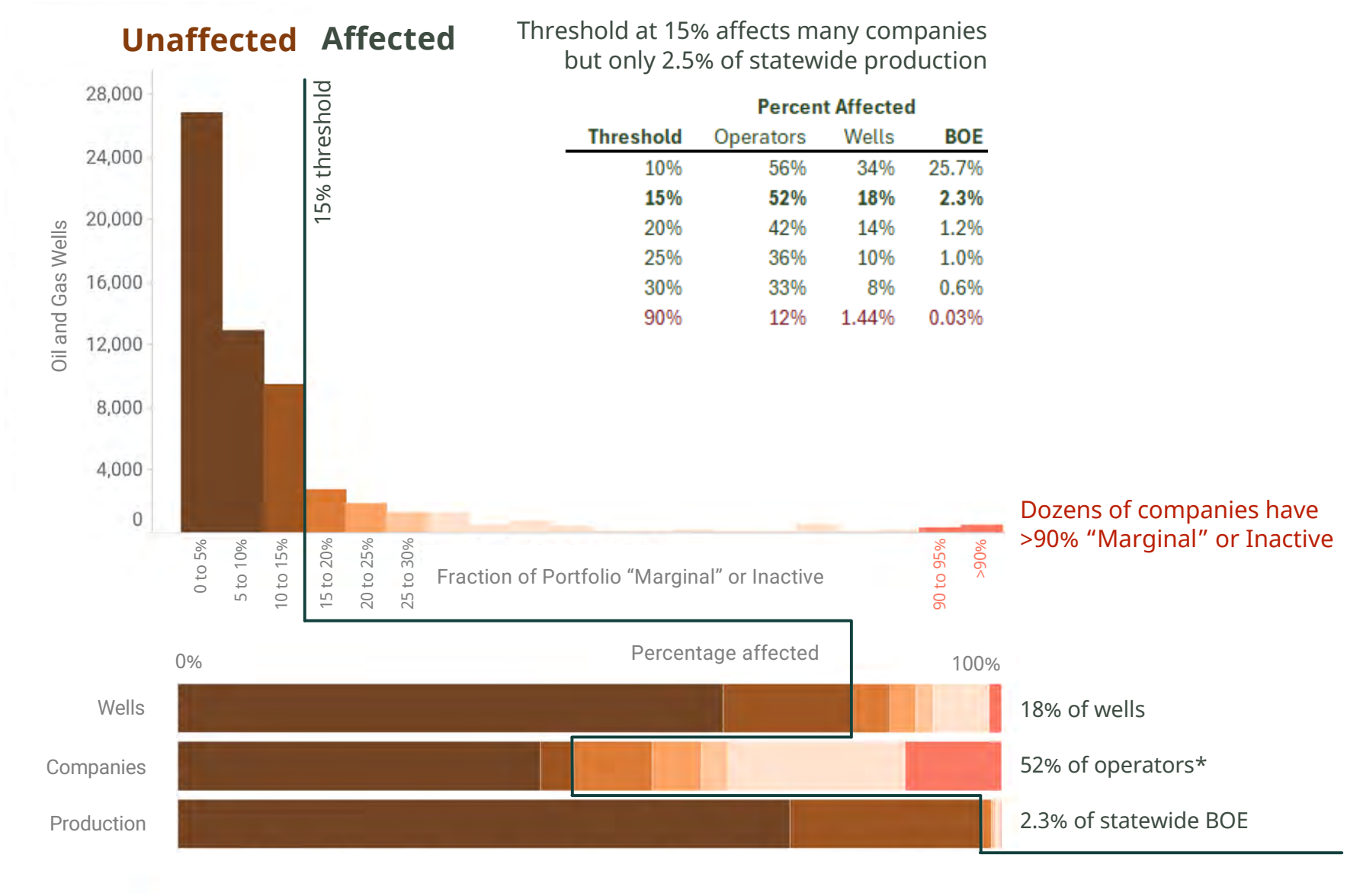
But the majority of orphan wells come from larger portfolios:
92% from companies with more than 10 wells
60% from companies with more than 100 wells

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Based on Master Orphan List from OCD as of July 2 2025 plus review of Final Orders

EXHIBIT 52

Applicants' Exhibit 52: Distribution of the concentration of marginal and inactive wells in oil and gas company portfolios and the combined size of portfolios above a range of thresholds.

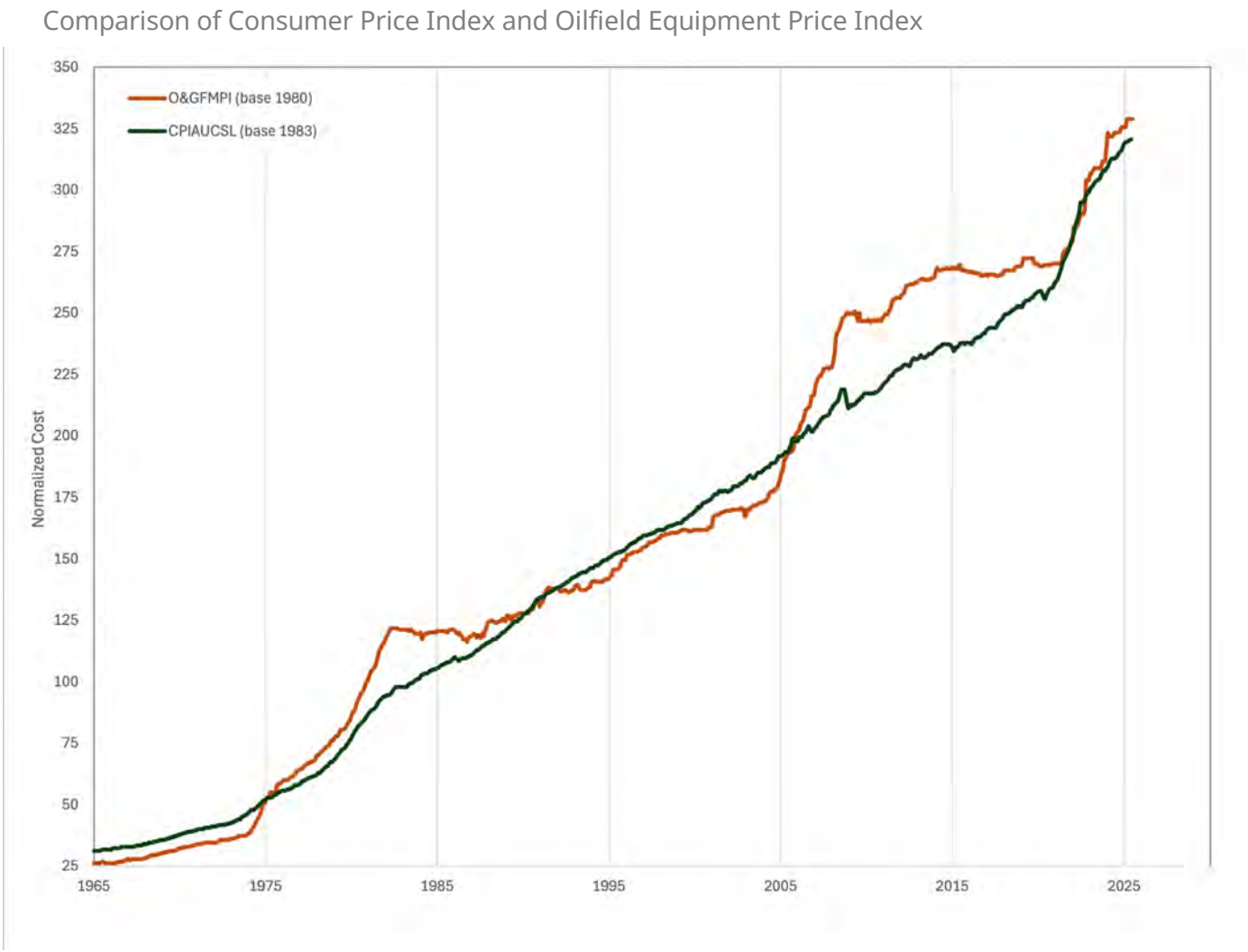


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**Note that this count is based on operators who reported production or injection during 2024 and does not include companies responsible for wells that did not report production or injection. It does include some interpretation of company names.*

EXHIBIT 53

Applicants' Exhibit 53: Historical inflation of oilfield costs compared to consumer prices.



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based on Bureau of Labor Statistics available from St. Louis Federal Reserve Bank

EXHIBIT 54

SPE-210226-MS

Economic Yardsticks for the End of Economic Life: Holdback and Its Adjuncts

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Abstract

Traditional economic measures use chiefly *net present value* to compare on-going net revenue to plugging liabilities and other retirement liabilities, but operators onshore in the US plan to pay for plugging costs from *cash flow*. Liabilities have accumulated and continue to accumulate as operators defer plugging. At the same time, production declines, and cash flow tapers and becomes riskier.

When retirement liabilities become significant compared to thinned cash flow, traditional yardsticks obscure the risk of ultimate insolvency. Future cash flow becomes insufficient to fund liabilities years before the present value flags the inversion. Recognizing the *cash* shortfall – which can occur surprisingly early when liabilities are allowed to accumulate – can fundamentally change the way the investment is viewed, valued, and managed.

Planning, therefore, requires new economic yardsticks to characterize the nature of cash flows with large retirement obligations, what can be called "holdback" and its adjuncts. These yardsticks look differently at the timing and risk of asset retirement obligations, namely backward from the end of the projection. "Holdback" is analogous to payout but in reverse from the end of economic life. Related measures similarly use other conventional yardstick concepts in reverse to characterize the situation more fully and to help an operator avoid orphaning its abandonment liabilities to be paid by taxpayers.

Introduction

The basics of cash flow analysis for acquisitions and portfolio assets have been established for decades, and asset retirement obligations ("AROs") have been deemed mostly trivial. In fact, no major industry publication has standardized their inclusion, much less their treatment. Landmark papers about evaluations in the oil industry don't even mention AROs (Garb 1985, Garb 1988, Garb 1990), the Petroleum Resource Management System published by the Society of Petroleum Engineers mentions AROs only briefly and only in the context of a development decision (SPE 2011), and the Society of Petroleum Evaluation Engineers do not address the treatment of AROs either in monographs (SPEE 2002, SPEE 2018) or in recommended evaluation practices. The guiding principles of all three, however, imply the necessity of including costs material to the economics. Indeed, professional and regulatory ethics require protection of the safety and

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welfare of the public (TBPELS 2020, SPE 2013), and it seems incongruous to stamp a cash flow analysis that does not include retirement costs necessary to protect the public.

For decades starting in the middle of last century, Texas and other states required wells to be plugged promptly after they ceased production, and federal regulations still require plugging within two years. Following the price crash in 1986, however, most states created an alternative option allowing wells to sit inactive indefinitely as long as they do not demonstrate a downhole failure of integrity. Statutes still require that the operator eventually plug the wells according to regulatory code and remove surface equipment, but the operators have for the last 35 years often warehoused old wells instead of plugging and abandoning them. Subsequent regulatory changes requiring a minimal portion of an operator's inactive wells to be reactivated or plugged have done little to abate the growing inventory of retirement obligations.

While the liability accumulates from shutting in wells, production also declines. The timing of the final retirement costs also draws closer, and the net cash flow progressively thins until margins pinch to zero and trigger the payment of accumulated costs. Thinning cash flows and accumulating liabilities can cause AROs to equal the entire projected net cash flow for the last years or even decades of a project, yet many private evaluations for acquisitions or internal planning do not include AROs. Some practitioners do include them, and both U.S. securities regulations and formalized accounting standards require the inclusion. Still, the results are reported as discounted present values and thus distort or conceal the reality of *undiscounted* liabilities from operators and investors. Other industries certainly bear large liabilities at the end of project life, but my research has not uncovered any unique or suitable economic yardsticks used to examine the issue of large liabilities at the end of economic life.

Background

Meaning of Asset Retirement Obligations

To be clear, AROs include more than just the sum of planned costs of plugging each well. Operators are obligated to redress both the downhole and the surface, and each area includes planned costs, contingency costs, and remediation costs all offset by any salvage value. The distribution of actual costs to plug wells includes a long high-side tail related to unexpected problems and to repairs, and this tail for on contingencies shifts the average cost for a program of plugging above the most common, planned cost per well. In addition, removing surface equipment for a single well at the end of the life of that well is commonly inexpensive, but removal of satellite or central facilities at the end of life for the field can be quite expensive. Lastly, environmental and property laws also require remediation of any downhole or surface pollution. Though they may occur uncommonly, they can be uncommonly expensive when they do. On the other idea of the retirement ledger sits salvage value, chiefly any downhole tubulars plus artificial lift equipment.

Beyond these universal considerations, some leases like those to the U.S. federal government may require restoration of the surface including pads, flowlines, and roads. These costs can also run high. Lastly, it is worth noting that an operator may continue to bear liability for repair and clean-up of problems created or found in the future.

Accumulating and approaching AROs

Onshore U.S. production first peaked in 1970, but the peak of drilling still remains the first half of the 1980s. Many wells pre-dating modern record-keeping remain unplugged or even orphaned. Among drilled since 1970, the cohort from the early 1980s are now approaching 40 years old, and a second large cohort is about 15 years old. Production has spiked from the shale revolution. On the other hand, shale production also falls much faster than from millidarcy reservoirs, and production has widely underperformed expectations.

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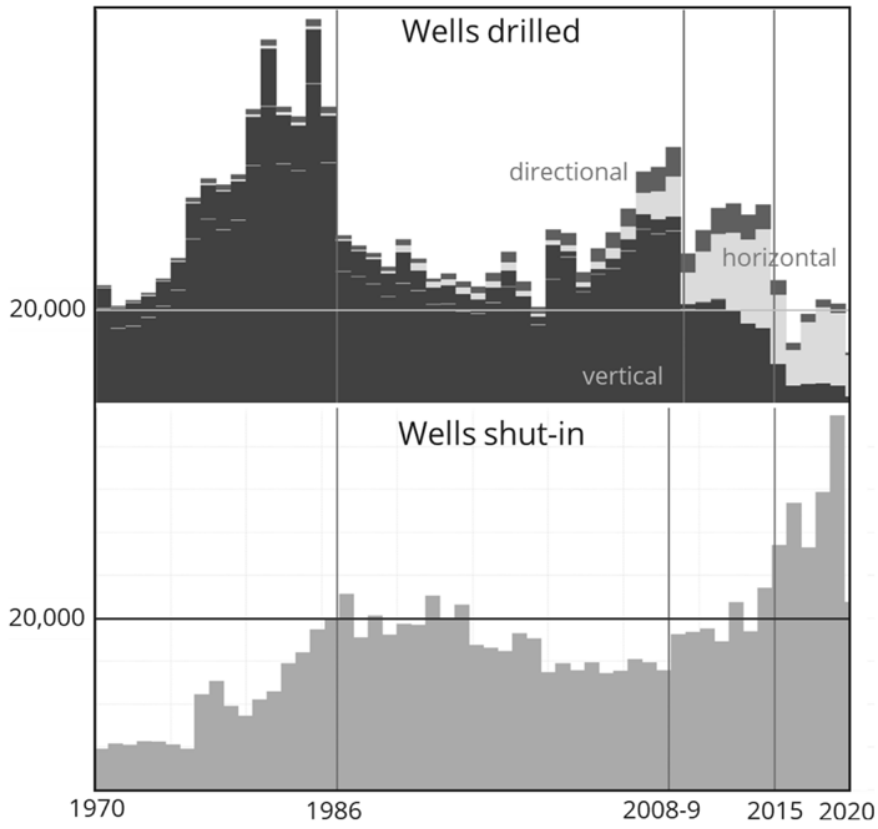


Figure 1—Wells drilled and wells shut-in onshore contiguous U.S. each year from 1970 to 2019.

Within limitations in the available information about well status, my research shows that about half of those wells drilled since 1970 are already idle, that 80% or more of active wells qualify as marginal producers (also EIA 2022), and that the number of wells shut in each year has been rising since 2009. In fact, since 2015 more old wells have been shut in each year than new wells drilled. Among both vertical and horizontal wells, the population is systematically bearing down on their retirement obligations. More importantly, field development patterns and corporate strategies create a strong correlation of well maturity within leases (as they are contracted with owners), assets (as they are often transacted) and portfolios (as they are owned).

Narrowing margins and increasing uncertainty

Unlike many other industries, production and thus revenue from upstream oil and gas assets decline dramatically from first production to last. Idealized projections used for planning and investments show revenues declining over years or decades until they fall below the more stable level of operating costs; margins slowly pinch to zero. The plugging costs which come next in the cash flow are greater than recent profits. The planned cost to retire a single well may equal the last couple of years of net revenue. As liabilities accumulate, though, the remaining active wells become responsible also to pay for the plugging of already inactive wells. In the hypothetical limit, the last well in a field or lease would bear the costs for all of the wells and surface facilities. At a field or lease level, it is possible to calculate the date when all projected net revenues equal projected AROs.

However, the net revenues at the end of economic life are riskier than suggested by idealized, deterministic projections. Margins depend on production volumes, commodity prices, and operating costs. As revenues converge with costs, small changes in the input assumptions are amplified to larger changes in margins. For example, in my experience a 15% change in costs can reduce projected net cash flow by 60%, and a change in decline from 7% to 5% can decrease value by the same 60%. Net cash flow becomes much more uncertain and more volatile. What is worse, the production becomes more erratic and less predictable

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late in life, opening the inherent uncertainty of this input. Price expectations change, volume forecasts evolve, and real-world variations in either can unexpectedly trip an economic limit and forfeit all expected future profits.

Historical and current treatment

Operators onshore U.S. are not required to set aside the cost of plugging their wells; they expect instead to pay the costs from cash flow of other assets. Operators purchase annual plugging bonds from a third-party guarantor, effectively one-year term life insurance for plugging. These state bonding regulations can be circumvented easily enough, and federal lands require a set-aside much less than the total cost of abandonment and restoration.

Nevertheless, operators and their evaluators of onshore wells have historically not included plugging costs in their projections and thus not in their planning. They assumed that salvage value would entirely or mostly offset out-of-pocket costs, neglected contingencies and shared facilities, and observed that the costs were so distant in the future that they had little effect on the plans or present values. In today's oilfield, though, none of those assumptions can be relied upon.

Having not maintained on-going plugging programs, liabilities have accumulated. Aging of wells, especially inactive ones, increases the risk of complications, repairs, and cost overruns. Aging of equipment has reduced its value, and changing markets for used equipment have kept values mostly down. Except a recent upcycle in the value of used tubulars, these dynamics do not compensate for each other; they compound.

Certain applications do require the inclusion of AROs, but a recent survey among the Society of Petroleum Evaluation Engineers found that only 56% of respondents believe that AROs should always be included in evaluations. (SPEE 2022) Bidders have risked the Winner's Curse long before the complication of insidious retirement costs, but today 44% or more of evaluators risk purchasing a cash-flowing liability.

Analysis

In this new reality of accumulated and correlated retirement obligations supported by declining production, the first step to improve decision-making is to include reliable estimates of the liabilities, but that step is not enough. Then the cash flows need to be examined with new yardsticks besides those built on present value.

Shortcomings of existing yardsticks

Econonic yardsticks characterize the shape and proportions of the full array of future cash flows with simple, single figures, and the standard set of measurements describes well the common situation of initial capital outlays followed by on-going revenues. The current situation, especially when evaluating assets already owned, reverses the situation: revenues come first, and capital follows. The reversal causes capital to be discounted and thus ironically *inflates* traditional yardsticks of value. What is more, the inflation of value increases as the capital outlay approaches.

Figure 2 below shows a schematic of the net present value (NPV) of an oil and gas asset vs discount rate, and the value is normalized to the undiscounted value. Adding AROs, as demonstrated in the second line, decreases the undiscounted value, but the discounting applied to the liabilities reduces the impact on the present value at 10% (PV10%). If AROs are assumed to be incurred at the end of economic life, then they necessarily suffer more discounting than all the revenues, and the effect of including AROs diminishes with increasing discount rate. If the asset is purchased, then both lines shift downward to cross a value of zero at the discount rate defined as the rate of return. Thus, the three main net present value yardsticks – such as PV10%, rate of return, NPV at risk-adjusted rate – often don't show much influence from AROs.

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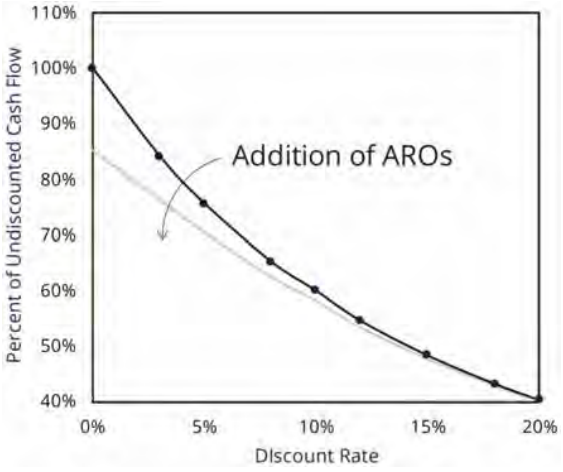


Figure 2—Effect on net present value of adding AROs to cash flow at the end of life.

This downward trend of NPV with discount rate persists for the whole life of the project when there are no end-of-life capital expenses. The values become smaller, but discounting producing the same, customary trend since the future includes only revenues and no net outlays. Hoewver, as shown in Figure 3, adding AROs to the cash flow fundamentally changes the behavior of the NPV trend as the end of life approaches.

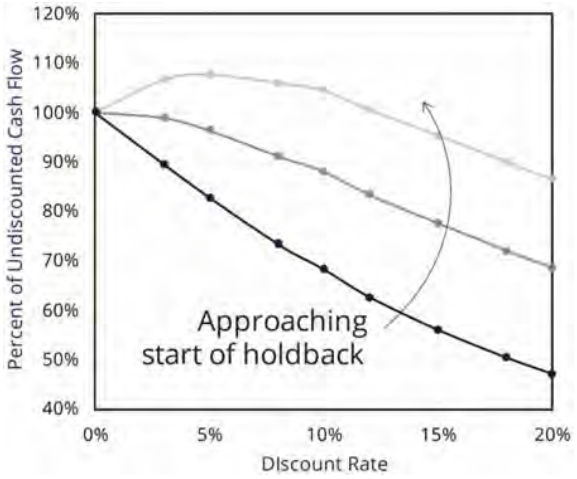


Figure 3—Effect of proximity of AROs on net present value before the start of holdback.

The present value does decrease, but the relationship of present value to discount rate *improves*. PV10%, for example, is higher than it had been as a proportion of undiscounted cash flow. If the property were to be purchased for the same proportion of undiscounted cash flow, then it would suggest a *higher* rate of return. What value is returned comes back faster. As the liability continues to approach, undiscounted value drops, and present value becomes *greater* than undiscounted value. Net present value remains positive even when the future capital requirements are greater than the sum of all projected net revenue. As stated above, all end-of-life liabilities are – by definition – discounted more heavily than all of the profits during the life of the asset.

Figure 4 demonstrates the same dynamic more concretely by tracking both undiscounted and discounted values as a project approaches its projected and unchanging date of abandonment. The graph on the left shows how the present values diminish with higher discount rates and how this relationship persists through the end of life when there are no concentrated costs at the end. When costs are included (right side), the standard relationship of lower values at higher discount rates holds only to a point. The relationship reverses

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late in life; higher discount rates calculate *higher* values. The undiscounted cash flow falls faster than discounted figures, and the PV10% becomes greater than the total of all future undiscounted cash flow. PV10% remains positive for a couple of years even after total cash flow turns negative. All else equal, the same inversions play out earlier and more slowly in assets with lower declines.

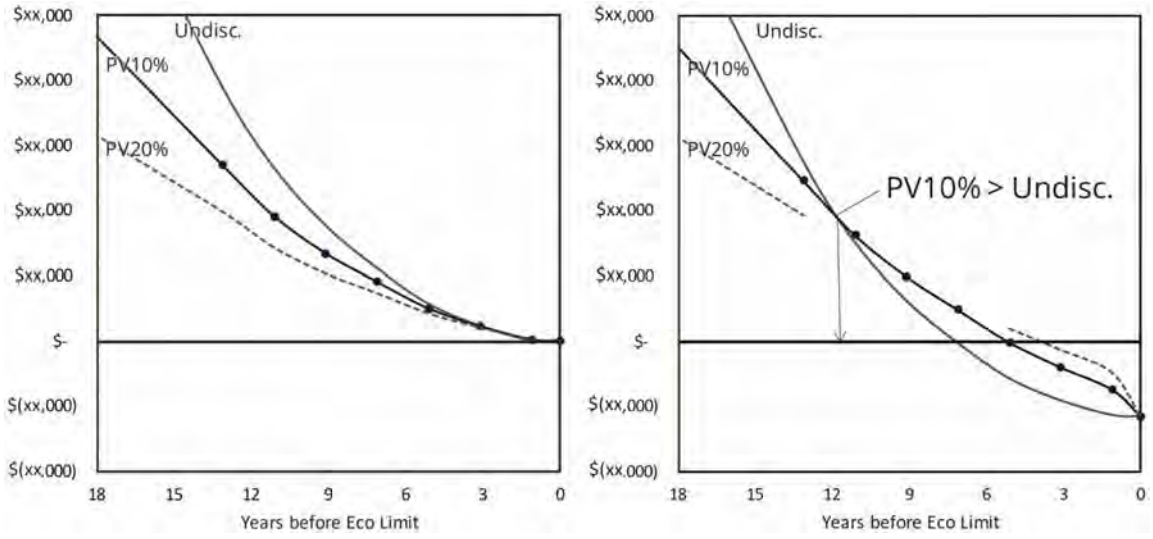


Figure 4—Future net cash flow at various discount rates as a field approaches its economic limit without and with substantial AROs.

The inversion means that using higher discount rates to account for risk actually backfires. A higher discount rate of 20% can be used as a "risk-adjusted discount rate" (RADR) to reduce the value, but it is in fact, the last figure to show a negative value. In this example, an RADR treatment of end-of-life uncertainties calculates a positive value for nearly 10 years after total future net cash flow is projected to be negative.

Other conventional yardsticks – namely, return on investment (ROI) and discounted return on investment (DROI) – have the potential to signal the coming problem. However, some practitioners and some software include only *initial* investments in the denominator. AROs still affect cash flow returns in the numerator, but excluding the firm capital obligation of AROs with other investments in the denominator inflates the appearance of return, and as above, discounting the return in the numerator creates the same effect of camouflaging a liability as an asset.

Setting aside the real-world risk inherent to projections which discounting is meant to address, net present value yardsticks paint a distorted picture of value sometimes as early as 10 or 20 years before the end of economic life. At first, discounting gradually accounts for risk less effectively. At some point, discounting reports values greater than all future income, and then present value remains positive after the "asset" becomes a net liability. By the time that discounted figures show a negative value, the project is far more upside-down on a cash basis than a discounted basis.

Case studies explored in other references (Purvis 2021) demonstrate the obvious risks of how these facts of the conventional calculations can mislead operators and investors. In one case, a large portfolio of fields with decades of economic life remaining calculated only five years of distributable life before all proceeds would need to be spent on plugging. In a second case, a small lease cash flowing tens of thousands of dollars per month with high and backwardated prices calculated only seven months of distributable life before AROs equaled all remaining projected profits.

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New Yardsticks without discounting

Asset retirement obligations are less uncertain than profits; they are fixed legal and ethical compulsions though still with some uncertainty in the price tag. To bring the situation into focus first requires removing discounting on those certain costs. "Holdback" and related measures take that step.

Holdback functions like payout in reverse: that period when the total net cash flow equals the cost of retirement. Like payout, holdback is not a business plan but merely a measurement. This is the period of time when all projected net revenues would need to be set aside (either used or "held back" but not distributed to owners) to pay for the costs of abandonment.

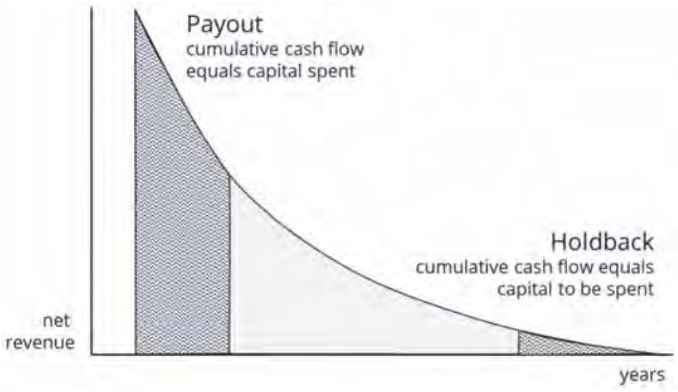


Figure 3—Schematic of payout and holdback.

The complement to holdback is "distributable life:" that period of time between the as-of date and the start of holdback. Distributable life is the more important measure for investors since it describes the amount of time when they could – according to idealized projections – expect to capture a return from the asset.

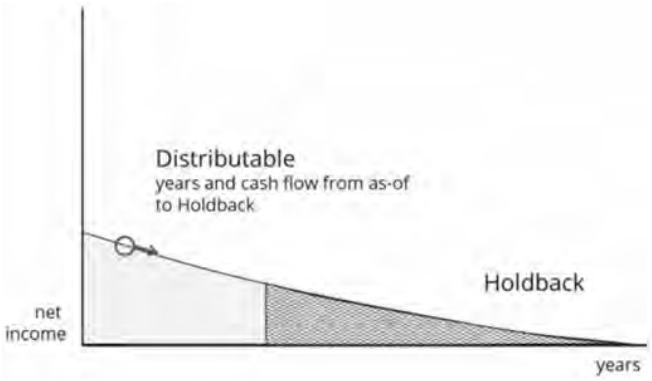


Figure 4—Schematic of distributable cash flow and holdback.

Counting the years of distribution and holdback, though, does not translate directly to dollars, so "holdback coverage" or "cash coverage" measures the relative proportion of total undiscounted future net revenue to the cost of abandonment. It reads and works like ROI but can be applied to assets after the an initial purchase cost. For new acquisitions, return on investment can be labeled instead as "return on investment, retirement" or "ROIR" to state explicitly the inclusion of AROs.

Lopsided risk, Additional yardsticks

The primary purpose of discounting in oil and gas is to account for the inherent uncertainties, but revenues and liabilities have different uncertainties. The yardsticks above neglect the differential risk, but two additional and more sophisticated yardsticks can account for it.

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Retirement liabilities suffer less uncertainty than other parts of the cash flow, and that uncertainty presently leans toward higher costs. Though the scope of work might increase in future, the scope cannot be expected to decrease from the established standard of past decades. The unexpected costs of repairs and remediation necessarily correlate to age of the equipment and their operation, continuously growing. The macroeconomic cost of services and equipment to conduct the operations may vary, but oilfield services and plugging in particular have been in such low demand in recent years that future costs are more likely to be higher than lower. All of these dynamics suggest that AROs should not be discounted; incorporating uncertainty might suggest instead that costs be inflated.

By contrast, as discussed above, late life revenues suffer more inherent risk than most parts of life. In fact, evaluators will sometimes recognize the project-specific risks with discount rates from 12 to 18% on producing assets (SPEE 2022) and anecdotally sometimes a little higher.

To put the two – investments and net revenues – on comparable risk-adjusted footing, an evaluator can consider "discounted holdback" and "discounted holdback coverage." Discounted holdback measures the time for which discounted revenues equal undiscounted (or perhaps inflated) liabilities, and discounted holdback coverage measures the ratio of the discounted revenues over undiscounted capital. Discounted holdback coverage is equivalent to discounted return of investment when there are no initial costs and can be calculated the same way. Discounted holdback, though, requires a more unusual procedure to isolate the point of equivalence. Appendix A includes more information about how to calculate holdback and discounted holdback.

It may be noted that none of these parameters inflated the monies "held back." That is, none assume that set-aside money is invested to earn a return before being used to settle the liability. The implication of inflating net revenues to the abandonment date does not make sense for either a business or economic standpoint. By the time holdback begins, the liabilities are commonly current; an inventory of inactive wells stands ready for abandonment. If the money were invested instead, expectations would be low since principal needed to pay near-term liabilities deserve low-volatility, low-return investments. Meanwhile, aging of equipment can be expected to slowly increase the liability. Gamesmanship risks not being able to pay obligations and offers the potential to gain only the difference between market returns and liabilitiy growth.

Conclusions

The maturity of U.S. onshore production means that the welfare of both investors and the public requires explicit management of retirement liabilities. A change in regulation and practice 35 years ago has now accumulated decades of asset retirement liabilities, and about half of all onshore US wells are currently inactive waiting to be plugged. Though some portfolios include younger and higher rate wells, and the large majority of active wells qualify as "stripper" or marginal producers near the end of their economic life. The age of the wells can be expected to increase costs, and final retirement will include removal of shared facilities, remediation, and in some case restoration. Large and growing retirement liabilities correlate strongly within assets and within portfolios governed by corporate strategies.

Existing economic yardsticks fail to meaningfully characterize cash flows that include a large capital expense at the end of economic life because discounting distorts and conceals the significance of AROs even when liabilities exceed all projected future net revenues. New yardsticks better describe the situation and thus lead to better planning and better protection for both investors and the public:

- **Holdback:** that period of time during which all of the net cash flow would need to be "held back" to fund retirement obligations. Equivalent to yardstick "payout" but in reverse, first the net cash flow then the capital expense.
- **Distributable life:** the complement of holdback, that period of time between the present and the start of holdback during which net cash flow could theoretically be distributed.

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- **Holdback coverage or cash coverage:** For an asset already owned, the ratio of total future net cash flow divided by the total asset retirement liability.
- **Discounted Holdback:** Same concept as Holdback except that the inherent risk in the net cash flow is treated with traditional discounting. That period of time during which *discounted* net cash flow equals undiscounted retirement liabilities.
- **Discounted Holdback Coverage:** Same concept as Holdback Coverage except that the numerator of the ratio is discounted to account for inherent risk.
- **Return on Investment, Retirement "ROIR":** To evaluate a purchase rather than an asset already owned, retirement obligations should be included along with the purchase price in the calculation of Return on Investment ("ROI"). To state explicitly that retirement costs are included, the return on investment can be labeled ROIR.

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Appendix 1:
Calculation of yardsticks

Since holdback and discounted holdback function like payout and discounted payout in reverse, they can be calculated using the same procedure but moving backwards in time from the end of economic life instead of forward through time from the as-of date. However, holdback can also be calculated more simply.

The calculation requires first an array of future net revenues excluding AROs. (It can, however, include development capital and resulting income as discussed more below.) Secondly, create a reverse cumulative of the array by either 1) summing all figures after that point in time, or 2) starting at the end of economic life, moving backward in time accumulating a running total. Holdback occurs at the earliest point in the cash flow projection that the reverse cumulative equals the liabilities.

Discounted holdback uses the same procedures but applies discounting to the reverse cumulative at a rate consistent with its inherent risks. For each period, the reverse cumulative is the discounted sum of all figures after that point in time. It can also be calculated with a running total moving backward in time by applying a discount factor to the running total in each step before adding the revenue from the current period.

Holdback can alternatively be calculated by first subtracting the total ARO from the total undiscounted future net revenue without AROs to determine the total distributable cash flow. The first date when the forward cumulative revenues equal distributable cash flow marks the date of holdback. (No analogous shortcut exists for discounted holdback.)

As with other economic yardsticks, these can be calculated for wells, leases, assets, and portfolios. They can be calculated for producing assets as well as combinations of reserve classes. It should be noted, though, that variation in timing can create novel situations with more than one solution to the timing of holdback depending upon how the calculation is made.

For example, one large asset may trigger its plugging while a second large asset continues generating cash flow to pay for the retirement. As the second asset continues producing, it will return to distributable cash flow then eventually reach its own separate holdback period. If AROs are "scheduled" for the calculation of holdback, then the first occurrence of the equivalence is the more informative measure. If AROs are "lumped" (treated as grand total for the calculation of holdback), the resulting calculation date can be different again.

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EXHIBIT 55

This exhibit is the OCD Master Orphan Well List (7-2-25) which is an Excel spreadsheet filed in the WELC shared folder in ENMRD CentreStack

EXHIBIT 56

ADAM PELTZ

apeltz@edf.org • +1 212-616-1212

SUMMARY

- Environmental and energy law attorney and public interest advocate with focus on carbon sequestration, oil and gas, and other subsurface energy development and impacts
- Admitted to practice law in New York State

EXPERIENCE

Environmental Defense Fund: Legal Fellow, 2011-2012, Attorney, 2012-2017; Senior Attorney, 2017-2022; Director & Senior Attorney, 2022-present

- Extensive work on carbon capture and sequestration, orphan wells, and oil and gas well integrity management
- Led effort to secure $4.7 billion in federal funding to plug and remediate orphaned oil and gas wells
- Manages state legislative and regulatory advocacy on secure geologic storage of CO2
- Leads multiple workgroups of the Interstate Oil and Gas Compact Commission's update of its model CCS statute
- Volunteer on Non-Federal Lands Subcommittee of the CEQ CCUS Non-Federal Lands Permitting Task Force
- Provisional Committee Member of National Academies Committee on Technologies and Practices for Plugging and Remediating Orphaned and Abandoned Gas and Oil Wells, 2024-2025
- Served as Chair of the Interstate Oil and Gas Compact Commission's Energy Resources, Research and Technology committee (2021-2023) and Vice Chair (2019-2021)

EDUCATION

Boston University, 2008-2011

School of Law: *Juris Doctor* granted May 2011, GPA: 3.80, graduated magna cum laude

- Honors: Paul J. Liacos Distinguished Scholar (ranked 4 out of 276 students for 2009-2010 Academic Year)
  Articles Editor, *International Law Journal*

Graduate School of Arts and Sciences: *Master of Arts* in International Relations granted May 2011, GPA: 4.0

Graduate Institute of International and Development Studies (IHEID), 2010

University of Chicago, 2001-2005

Bachelor of Arts with Honors in Political Science and International Studies awarded June 2005, GPA: 3.5

University of Dar Es Salaam, 2004

SELECTED PUBLICATIONS

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EXHIBIT 57

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

IN THE MATTER OF PROPOSED AMENDMENTS TO 19.15.2, 19.15.5, 19.15.8, 19.15.9, AND 19.15.25 NMAC **CASE NO. 24683**

DIRECT TESTIMONY OF ADAM PELTZ

Table of Contents

BACKGROUND AND QUALIFICATIONS ……2

SUMMARY OF TESTIMONY AND OPINIONS ……4

OVERVIEW OF ORPHAN WELL PROBLEM ……..…7

19.15.2 NMAC—GENERAL PROVISIONS FOR OIL AND GAS OPERATORS ……..34

19.15.8 NMAC—FINANCIAL ASSURANCE ……..37

19.15.8.9.C NMAC – Active Wells ……37

19.15.8.9.D NMAC – Marginal Wells and Inactive Wells ……...……40

19.15.8.9.E NMAC – Inactive Wells and Wells in Approved and Temporarily Abandoned Status ……53

19.15.8.9.F & -G NMAC ……..60

19.15.9 NMAC—WELL OPERATOR PROVISIONS ……60

19.15.25 NMAC—PLUGGING AND ABANDONMENT OF WELLS ……..64

List of References ……75

BACKGROUND AND QUALIFICATIONS

Q: Please state your name.

A: My name is Adam Peltz.

Q: What is your current employment?

A: I am a director and senior attorney at the Environmental Defense Fund ("EDF").

Q: What is your educational background?

A: I have undergraduate degrees in political science and international studies from the University of Chicago, and a master's degree in International Relations and a law degree from Boston University.

Q: Would you please describe your work background with particular attention to your experience working on financial assurance for oil and gas operations and the risks of inactive and orphaned wells.

A: Since 2011, I have worked nationally on local environmental impacts of oil and gas development, with a focus on well integrity, as well other aspects of subsurface energy development like underground injection control, underground natural gas storage, and carbon sequestration. Since 2020 in particular I have focused heavily on the topic of orphaned and abandoned wells.

Working closely with Senators Luján of New Mexico and Cramer of North Dakota, the Interstate Oil and Gas Compact Commission ("IOGCC") and the Independent Petroleum Association, I helped conceive and strongly advocated for the passage of the Revive Economic Growth and Reclaim Orphan Wells Act ("REGROW Act"), which provides $4.7 billion to states, Tribes and federal land management agencies to plug and remediate orphaned and abandoned wells across the U.S., as well as resources to the U.S. Department of Energy, including Sandia

and Los Alamos National Labs, to develop techniques to find and characterize undocumented orphan wells. The legislation includes incentives for states to reduce future orphan well burden through legislation or rulemakings (like this one) that address financial assurance, idle well management and well transfer; upgrades to technical plugging rules; and providing federal matching funds for state expenditures on orphan well plugging that exceed a historical baseline. The legislation was adopted as part of the 2021 Infrastructure Investment and Jobs Act, a.k.a. the Bipartisan Infrastructure Law. New Mexico has so far received $55.5 million from that funding and is eligible to receive another $111.8 million.[1]

I am currently engaged in legislative or rulemaking activities on financial assurance, idle well management and well transfer in Louisiana, Texas, Oklahoma, and Utah in addition to New Mexico. I am overseeing a research project in Pennsylvania to find undocumented orphan wells (which likely number 300,000-700,000 in western Pennsylvania alone)[2] through instrumented surveys including drone-mounted and backpack magnetometry and car-based methane/ethane detection.

I serve on a National Academy of Science consensus study on orphan well plugging. My team has convened a session at the American Geophysical Union's annual meeting on orphan and abandoned wells three years running. With the American Association for the Advancement of the Sciences ("AAAS"), I have put on a symposium about the promises and pitfalls of carbon

[1] Apps' Ex. 4, N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells at 11-12 (2025), https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf.

[2] *See* Interstate Oil & Gas Compact Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 15 (2024), https://oklahoma.gov/content/dam/ok/en/iogcc/documents/publications/Orphan%20Wells%20Revised.pdf.

credits for well closure, and have been a long-time supporter and participant of AAAS's orphan well experts' group. During my time as chair of the IOGCC's Energy Resources, Research and Technology committee, I worked with the Society of Petroleum Engineers to put on a webinar series about oil and gas issues relevant to state oil and gas regulators, including several sessions about orphaned oil and gas well issues.

EDF's economics team and I have produced analyses of the likely fate of well populations in six states including New Mexico, delineating orphan risk, transfer risk and low risk wells through 2050; and idle well historical analyses and job creation potential from plugging and remediation in Louisiana and Texas. I am a co-author on several peer-reviewed papers on various aspects of orphaned and abandoned well inventorying and impacts, which are cited in my resume, which is **Applicants' Exhibit 56**.

Q: Is Applicants' Exhibit 56 an accurate copy of your resume?

A: Yes.

SUMMARY OF TESTIMONY AND OPINIONS

Q: Have you reviewed any documents in preparing the testimony you will be giving today?

A: Yes, a List of References I reviewed is attached at the end of my testimony.

Q: Can you please summarize the testimony and opinions you will give in your testimony?

A: Yes. I will provide testimony and opinions on the Applicants' proposed amendments 19.15.2 NMAC, 19.15.8 NMAC, 19.15.9 NMAC, and 19.15.25 NMAC. Specifically, I will cover the following areas:

First, a definition of "marginal well" should be added to 19.15.2.7.M(2) NMAC to

identify wells at greatest risk of being orphaned due to their reduced production and revenue. "Marginal wells," as proposed by the Oil Conservation Division ("OCD") and adopted by Applicants, are wells that produce less than 180 days and produce less 1,000 barrels of oil equivalent ("BOE") per day over a 12 month period. This proposal accords with recommendations from the New Mexico Legislative Finance Committee ("LFC") in its recent report, Policy Spotlight: Orphan Wells (June 24, 2025), attached as Applicants' Exhibit 4.

Second, given the cost of well-plugging to the agency, current financial assurance amounts are hardly adequate. Thus, the financial assurance amounts in 19.15.8 NMAC should be increased to $150,000 per well or $250,000 blanket financial assurance (the latter of which is a limit imposed in the Oil and Gas Act, which is woefully inadequate).

Third, I recommend increasing financial assurance amounts to essentially full cost bonding for "marginal wells" at $150,000 per well. Increasing financial assurance for these high-risk wells is at the heart of Applicants' proposal. These low-producing wells are at high risk of orphaning and as such should have individual well assurances that can cover the cost of plugging each well. Additionally, Applicants proposed that the full cost bonding requirements for marginal wells go into effect immediately for marginal wells that will be transferred. The point of transfer has historically been an area of abuse—the updated language is more protective and ensures wells are not transferred to avoid liability.

Fourth, 19.15.8 NMAC should be updated to have increased financial assurance for inactive and approved and expired temporarily abandoned wells—wells that are at a very high risk of orphaning—to properly reflect the financial risk they pose to the state. The updates would include $150,000 per well or blanket assurance that averages $150,000 per well. As noted above, this better reflects current agency costs for plugging and is similar to other state regulatory

updates. The Legislature already recognizes that inactive wells pose a greater risk to the state by setting a floor, not a ceiling, of $50,000 for a blanket bond for temporarily abandoned wells.

Fifth, as noted above, well transfers can be used by operators to escape liability, so updates to 19.15.9 NMAC would require full compliance with state and federal law before transfer. Specifically, there is also a requirement that operators create a plugging and abandonment plan prior to transfer to ensure the logistical and financial burdens of plugging are properly considered and not just ignored. As part of these changes, I recommend that OCD be given more discretion to deny a change of operator for specific reasons relating to lack of compliance. Non-compliance in some areas can indicate non-compliance elsewhere and this amendment allows OCD more oversight to protect the state from abuse.

Sixth, Applicants propose that 19.15.25 NMAC be updated to require operators to demonstrate that a well has future beneficial use prior to placing it in temporary abandonment ("TA"). If a well has no future utility, the well should be plugged and abandoned and the site should be remediated. In addition, the timeline and conditions for TA status renewal is expanded to provide more regulatory guardrails to prevent perpetual TA status by limiting term renewals, requiring explanations for future use, and allowing conditions to protect human health and the environment.

Relatedly, Applicants propose new language in 19.15.25 NMAC that addresses beneficial use. OCD proposed and Applicants adopted a proposal to establish presumptions of no beneficial use to identify very low-producing wells that are highly unlikely to be generating sufficient revenue to pay for plugging and abandonment and site remediation. These are oil and gas wells that have produced for less than 90 days and less than 90 BOE per day over a 12 month period. These amendments provide an avenue for operators to rebut findings of no beneficial use. But if

the operator cannot make that showing, the well must be plugged. This provision, while conservative, allows OCD to identify wells that operate on the very margins and are at high risk of becoming orphaned.

OVERVIEW OF ORPHAN WELL PROBLEM

Q: Mr. Peltz, when you refer to "orphan wells," what do you mean?

A: Generally speaking, orphan wells are non-producing, unplugged oil and gas wells with no solvent responsible party able to pay for plugging and remediation costs, and thus clean-up responsibility falls to the state. New Mexico does not have an official definition for orphan wells – however, in 2024 IOGCC[2] defined orphan wells as idle wells for which the operator is unknown or insolvent and the OCD provides the following: "This term is not expressly defined under New Mexico regulations. However, if a well has been inactive for one year, enforcement action is taken. If the operator fails to bring the well back into compliance, the well is deemed to be orphaned and the OCD may plug the well. If no funding is available from the operator or well financial assurance, the OCD can use the reclamation fund to plug the well and restore the site."[3] The LFC's policy spotlight on orphaned wells from June 2025 recommends that the Legislature consider "Amending statute to define 'orphaned' and 'abandoned' wells, aligning the definitions with their common use in the oil and gas industry and clarifying that 'orphaned' wells are oil and gas wells for which the state has pursued and received plugging authority."[4]

Q: Can you please briefly describe the orphan well problem facing oil and gas producing states, including New Mexico; the role states play in taking on responsibility for orphan wells; and the potential harm to public health and the environment from orphan

[3] *Id.* at 60.
[4] Apps' Ex. 4, N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells at 2.

wells?

A: When an oil and gas well reaches the end of its productive life, it needs to be properly sealed to prevent negative impacts on the surrounding environment and human health. Unplugged wells can have a host of disastrous consequences—they emit methane, a powerful greenhouse gas; they contaminate groundwater with toxic chemicals; and as a result, negatively impact nearby communities' health and economy. When wells are unplugged, no longer actively producing, and have no solvent operator responsible for them, they become orphan wells. This problem is why we are here today—New Mexico, along with many other states, faces a growing population of orphan wells that are threatening the health of communities and the environment, as well as posing a massive economic burden on the state. This is because the problem of orphan wells often falls on the state to clean up. Thus, reforming New Mexico's regulations is necessary.

The LFC agrees with us. In April of this year I was contacted by the LFC to support its work producing a report on New Mexico's growing orphan well problem, and I gave a presentation to the LFC in May on the work I have been leading at EDF addressing orphan wells across the country. In June, the LFC published its report that gives a comprehensive overview of orphan wells in New Mexico,[5] which I will summarize.

The LFC's goal with this report was to assess the current scope of the problem, with a focus on the environmental, health, and safety impacts of orphan wells, and given the scope of the problem, evaluate the adequacy of the state's regulatory framework to address current orphaned wells and prevent future orphaning.[6] As part of this, the LFC also estimated the state's future liability from orphan wells. The scope of the liability is dramatic, and underscores the

[5] Apps' Ex. 4, N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells.
[6] Apps' Ex. 4, *id.* at 2.

need for the changes we are proposing. Currently, orphan wells will cost the state more than $200 million, but future liability costs range from as "low" as $700 million, to as high as $1.6 billion.[7] For a state whose budget just recently broke $10 billion,[8] this is unsustainable, and reforms are needed now.

The LFC makes several recommendations for both the Legislature and the Energy, Minerals, and Natural Resources Department ("EMNRD") to address this problem. The LFC's regulatory recommendations accord with our proposals below in several ways. First, the LFC recognizes the importance of defining low-producing wells, or what we are calling marginal wells, because they are at high risk of orphaning and require additional regulatory oversight[9]—we agree and propose a definition in 19.15.2.7.M(2) NMAC. Second, given that high-orphaning risk from these wells, the LFC has also proposed that operators or owners of these wells secure *individual* well assurance instead of blanket bonds to recognize the financial costs posed by these wells[10]—we also agree. This is why we are proposing the changes to 19.15.8.9.D NMAC. Third, the LFC also noted that regulatory oversight is needed for all well transfer to reduce owners and operators being able to escape liability,[11] something we also address in Applicants' proposed changes. The LFC also makes other important programmatic suggestions to EMNRD as well as to the legislature to address the orphan well problem that are beyond the scope of the rulemaking here. However, clearly LFC has recognized that orphan wells pose a great threat to New Mexico and this rulemaking is a critical, important first step to protecting New Mexico's people, climate, and

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[7] Apps' Ex. 4, *id.* at 1-2.

[8] Austin Fisher, *Majority of New Mexico's Annual Spending Passes Governor's Veto Test*, SourceNM (April 11, 2025), https://sourcenm.com/2025/04/11/majority-of-new-mexicos-annual-spending-passes-governors-veto-test/.

[9] Apps' Ex. 4, N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells at 23.

[10] Apps' Ex. 4, *id.* at 37.

[11] Apps' Ex. 4, *id.*

environment from orphan wells.

Q: Mr. Peltz, can you briefly describe national trends in the regulation of oil and gas that influence the timely and sufficient plugging and abandonment of oil and gas wells?

A: Yes. The very first plugging rules came into being in Pennsylvania, Texas, and Oklahoma in the late 1800s and early 1900s, several decades after the first oil and gas wells were drilled in Pennsylvania.[12] Historically, most states did not assiduously enforce plugging requirements, and many still do not – though every oil and gas state has long required operators to plug their non-producing wells. The IOGCC has long tracked this issue through a series of reports beginning in the early 1990s. In a 2019 report, as conversations about what was to become the REGROW Act started taking place, IOGCC tracked over 56,000 documented orphan wells in thirty states.[13] Once states saw that the REGROW Act was in fact likely to pass, state oil and gas agencies scrambled to document their orphan wells because their share of the $4.7 billion was predicated in part on their *documented* orphan well population.[14] As a result, by the time states had to express an intent to apply for "formula" grants to the U.S. Department of the Interior, the count was up to 125,000.[15] In the latest IOGCC report, the count is 141,000.[16]

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[12] Nat'l Petroleum Council, Plugging and Abandonment of Oil and Gas Wells 5-7 (2011), https://www.npc.org/Prudent_Development-Topic_Papers/2-25_Well_Plugging_and_Abandonment_Paper.pdf; Interstate Oil & Gas Compact Comm'n, A Study of Idle Oil and Gas Wells 21 (2000), https://oklahoma.gov/content/dam/ok/en/iogcc/documents/publications/produce_or_plug-2000.pdf. The early plugging rules were to protect production, not the environment.

[13] Interstate Oil & Gas Compact Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 12.

[14] *See* Senators Lujan & Cramer, REGROW Act 2021, https://www.lujan.senate.gov/wp-content/uploads/2021/04/REGROW-Act.pdf.

[15] Jade Boutot, Adam S. Peltz, Renee McVay & Mary Kang, *Documented Orphaned Oil and Gas Wells Across the United States*, 56 Env't Sci. & Tech 14228, 14228 (2022), https://doi.org/10.1021/acs.est.2c03268?urlappend=%3Fref%3DPDF&jav=VoR&rel=cite-as.

[16] Interstate Oil & Gas Compact Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 3 (2024).

Some states have also estimated their undocumented orphan well population, which can include unplugged wells believed to have been drilled but whose locations have not been identified, or wells where there does not appear to be a solvent operator of record but the state has not gone through its internal verification process and placed these wells on an orphaned well plugging list. Such wells are estimated to total up to 800,000 in the latest IOGCC report— but that total excludes some states like Texas that likely have thousands of undocumented orphan wells.[17] Nearby Oklahoma alone is believed to have over 300,000 undocumented orphan wells.[18] The true national number of inactive, unplugged wells with no responsible party able to pay for closure and remediation is unknown but could be as high as two million.[19]

Unfortunately, this is not just a historical problem. Currently in the United States, operators orphan wells at the rate of hundreds to thousands a month across thirty states. And even in states that annually fund plugging wells – like Texas, which spends over $30 million a year[20] – orphan well populations tend to stay stable because operators are orphaning wells as quickly as states can plug them. For example, Texas' investment of over $30 million per year[21]

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[17] *Id.* at 6, 15.

[18] Ismot Jahan et al., *Data-driven Estimates of Undocumented Orphan Oil and Gas Wells With Implications to the Environment*, 97 Sci. Of the Total Env't 178746 (2025), https://doi.org/10.1016/j.scitotenv.2025.178746.

[19] *See* Adam Peltz, *Plugging Orphan Wells Across the United States,* EDF (Oct. 14, 2021), https://www.edf.org/orphanwellmap.

[20] *Texas Has Thousands of Abandoned Oil and Gas Wells. Who is Responsible for Cleaning Them Up*, J. of Petroleum Tech. (May 19, 2025), https://jpt.spe.org/texas-has-thousands-of-abandoned-oil-and-gas-wells-who-is-responsible-for-cleaning-them-up; Interstate Oil & Gas Compact Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 18 (2024) (noting a range of $25 million to $35 million between 2018 and 2023 which does not include remediation costs).

[21] Interstate Oil & Gas Compact Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 16.

kept the listed orphan well population averaging around 6,500[22] wells in any given year since 2009; this low average obscures the plugging by the state of over 18,000 orphaned wells during that same timeframe.

The low average also belies the dramatic increase in the state's population of idle wells (wells that are inactive and have an increased risk of becoming orphaned). As noted by the Texas Railroad Commission ("TRRC"), inactive wells in Texas have increased by over a third since 2015, from around 115,000 reported in FY2015 to over 155,000 in FY2024.[23] Non-orphaned idle wells in Texas technically have a solvent operator, or at least an operator who files annual reports indicating they still exist. However, neither the state nor the public knows whether those operators have set aside the billions of dollars that inevitably will be needed to plug those wells. States face a similar risk from growing populations of submarginal wells – wells producing less than 1 BOE per day. The U.S. Energy Information Administration ("EIA") reported well over 300 thousand such low-producing wells nationally as of December 2024.[24] While the Texas situation is starker than New Mexico's today, this is not an exoneration of New Mexico's oil and gas industry and regulatory approach, but instead a cautionary tale that can be avoided with reforms consistent with the Revised Application in this matter.

Over the past several years, state legislative and rulemaking activity has rapidly increased in an effort to bend the curve on the orphan wells epidemic and protect taxpayers, public health

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[22] Annual orphaned well populations reported by the Texas Railroad Commission range from 5,636 to 8,347 between August 2009 and August 2024, averaging 6,570. *See* Railroad Comm'n of Tex., Oilfield Cleanup Program Annual Report (2024), https://www.rrc.texas.gov/media/iadli5ig/2024-oilfield-cleanup-program-annual-report-final.pdf.

[23] *Id.* at 4; *see* Railroad Comm'n of Tex., Oil & Gas Div., Oil Field Cleanup Program Annual Report – Fiscal Year (2015), https://portalvhdskzlfb8q9lqr9.blob.core.windows.net/media/31235/ogrc2015.pdf.

[24] U.S. Energy Info. Admin, U.S. Oil and Natural Gas Wells by Production Rate at 14 app. B, tbl. B44 (2024), https://www.eia.gov/petroleum/wells/.

and safety, local property values, as well as to ensure the geologic integrity of the surrounding area. This is partially due to unprecedented public scrutiny on the issue --which long flew below the national radar -- after passage of the REGROW Act. Now the problem of orphan wells is in local, state and national news on a near-daily basis. The issue resonates with the public who understand the basic imperative to require operators to clean up after themselves, and do not look kindly on how the richest industry in the world so frequently ignores its closure and remediation obligations. Generally, there is substantial public support, including bipartisan support,[25] for holding oil and gas companies responsible for clean-up instead of taxpayers, as EDF[26] and other polling shows.[27]

Additionally, in some neighboring jurisdictions to New Mexico, like Texas and Oklahoma, the consequences of unremediated legacy drilling are becoming very visually evident and expensive.[28] On the Texas side of the Permian Basin in particular, after deep injection of oil and gas wastewater caused a politically unacceptable swarm of earthquakes,[29] operators began injecting in shallow zones, causing a spate of blowouts in old wells that has regularly made the news[30] and led the TRRC to seek $100 million from the legislature to deal with blowout

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[25] *See* Blair Miller, *Montana Poll Finds Support for New BLM Oil and Gas Rules*, Daily Montanan (Aug. 16, 2024), https://dailymontanan.com/2024/08/16/montana-poll-finds-support-for-new-blm-oil-and-gas-rules/.

[26] Apps' Ex. 58.

[27] Colo. Coll., State of the Rockies Project: Support for Conservation Remains High in the West Despite a Rise in Other Concerns, New Poll Finds at 3 (Feb. 15, 2023), https://www.coloradocollege.edu/other/stateoftherockies/_documents/2023-poll-data-and-graphics/ccpoll%202023%20national%20release.pdf.

[28] S.B. 1150, 89th Legis., 2025 Reg. Sess. (Tex. 2025).

[29] Erin Douglas, *Earthquakes in Texas Doubled in 2021. Scientists Cite Years of Oil Companies Injecting Sludgy Water Underground*, Tex. Trib. (Feb. 8, 2022), https://www.texastribune.org/2022/02/08/west-texas-earthquakes-fracking/.

[30] *See e.g.*, Carlos Nogueras Ramos & Alejandra Martinez, "*Should we be worried?": Another Well Blowout in West Texas Has a Town Smelling of Rotten Eggs*, Tex. Trib. (Oct. 10, 2024),

expenses.[31] In response, Texas industry, led by the Texas Oil and Gas Association, developed legislation that became law in June 2025 to limit the length of time wells could remain idle.[32] This legislation required increased integrity testing of idle wells and prompted several TRRC rulemakings, as well as required an annual report to the Governor, Lieutenant Governor, TRRC Commissioners, and the Texas Legislature on the fate and trajectory of the idle well population. The TRRC will undertake rulemakings on idle well management starting in the near future – even if the end result of these rulemakings is not as ambitious as the policies delineated in this position, the fact that an industry-led bill is requiring multiple rulemakings to reduce the taxpayer and environmental risk from inactive wells in Texas speaks to a sea change on this topic, and reinforces the notion that now is the time to fix this problem in New Mexico before it gets as bad as in Texas.

Meanwhile, in Oklahoma, which likely has at least fifteen times its official count of 18,000 documented orphan wells,[33] the shallow injection of wastewater to avoid earthquakes is

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https://www.texastribune.org/2024/10/10/west-texas-well-blowout-oil-gas-railroad-commission/; Dylan Baddour & Carlos Nogueras Ramos, *Ranchers Reported Abandoned Oil Wells Spewing Wastewater: A New Study Blames Fracking*, Tex. Trib. (Aug. 7, 2024), https://www.texastribune.org/2024/08/07/texas-oil-fracking-wastewater-injection-blowouts-permian-basin/; U.S. Chem. Safety & Hazard Investigation Bd., No. 2020-04-I-TX, Investigation Report: Fatal Well Blowout at Daniel H. Wendland 1-H Well (2023), https://www.csb.gov/assets/1/6/wendland_final_report_2023-12-22.pdf; Ian Dexter Palmer, *A Serious Earthquake in the Drill Baby Drill Oilfields of Texas*, Forbes (Feb. 20, 2025), https://www.forbes.com/sites/ianpalmer/2025/02/20/a-serious-earthquake-in-the-drill-baby-drill-oilfields-of-texas/.

[31] Amanda Drane, *Leaked Memo Details $100M Emergency Request to Address Texas Oil Well Blowouts, Contamination*, Houston Chron. (Nov. 1, 2024), https://www.houstonchronicle.com/news/investigations/article/texas-regulators-seek-100m-respond-oil-well-19872200.php.

[32] S.B. 1150, 89th Legis., 2025 Reg. Sess. (Tex. 2025), https://legiscan.com/TX/text/SB1150/id/3245689.

[33] Lauren Henry, *Oklahoma Faces Costly Challenge with Over 18,000 Abandoned Oil and Gas Wells*, KTUL (Mar. 27, 2025), https://ktul.com/news/local/oklahoma-faces-costly-challenge-

causing saltwater purges, or lakes of produced water popping up around Oklahoma ranchland.[34] Certain influential state lawmakers with idled wells on their properties saw fit to toughen up Oklahoma's extremely lax approach to well closure through three measures: one sets a time limit on well idling, a second raises financial assurance amounts and eliminates financial assurance via financial statements (i.e. self-bonding), and a third appropriated millions of state dollars toward well plugging. The first two of these measures passed; the third is up for reconsideration in the second half of the current Oklahoma legislative session, which resumes next year.[35] As in Texas, these measures fall short of what could be considered optimum policy, but they speak to an increasingly universal understanding that the proliferation of uneconomic and unplugged legacy wells is bad for states and bad for the oil and gas industry

Texas and Oklahoma's legislative efforts follow on the heels of an October 2023 rulemaking in Louisiana that set limits on well idling, reduced the discretion of the Louisiana Department of Conservation and Energy ("DCE") Secretary to indefinitely renew temporary abandonment status, and instituted idle well fee that increases over time to incentivize operators to plug their wells.[36] Like similar efforts in Texas and Oklahoma, the Louisiana rulemaking falls short of solving the problem – but it is telling that every states in the highly productive south-

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with-over-18000-abandoned-oil-and-gas-wells-tulsa-money-residents; Ismot Jahan et al., *Data-driven Estimates of Undocumented Orphan Oil and Gas Wells With Implications to the Environment*, 97 Sci. Of the Total Env't 178746 (2025), https://doi.org/10.1016/j.scitotenv.2025.178746.

[34] Mike Soraghan, *Toxic, Briny Water Surfaces in Oklahoma. Is Oil to Blame?* E&E News (Dec. 3, 2019), https://www.eenews.net/articles/toxic-briny-water-surfaces-in-okla-is-oil-to-blame/#:~:text=A%20'huge'%20threat?,dropped%20in%20the%20disposal%20formation.

[35] Inactive Gas Wells, S.B. 132, 2025 Reg. Sess. (Okla. 2025); Financial Assurance Reform, H.B. 1369, 2025 Reg. Sess. (Okla. 2025). Plugging Fund, H.B. 1370, 2025 Reg. Sess. (Okla. 2025) (held over until the 2026 session).

[36] 49 La. Reg. 1679, 1746 (Oct. 20, 2023); *see also* Liz Russell, *Louisiana Finalizes Rules to Stem the Tide of Orphan Wells*, EDF (Oct. 20, 2023), https://www.edf.org/media/louisiana-finalizes-rules-stem-tide-orphan-wells.

central part of the U.S. is grappling with this issue essentially simultaneously. In the fall of 2024, the Louisiana Legislative Auditor released a pair of reports on the state's end-of-life well management. The first report found that one of the two state-run well closure funds was being used as a personal piggybank for a high-ranking official, who used the funds to buy homes instead of plugging wells – criminal charges are possible over the coming year.[37] This scandal speaks to the dangers and limitations of relying on a state fund to plug wells rather than using regulation to reduce the number of orphan wells to an absolute minimum.

The second report found that the state's regulatory approach was woefully inadequate to protect taxpayers from incurring the costs of future wells likely to become orphaned, and laid out a series of recommendations for improvement – with which the DCE largely agreed.[38] With the passage of Senate Bill 244 in the spring 2025 legislative session in Louisiana, a newly constituted agency, DCE, is empowered to pursue rulemakings along these lines.[39]

In Utah, after a legislative audit found that the state's approach to financial assurance left taxpayers with unacceptable risk,[40] the Utah Division of Oil, Gas and Mining began a multiyear

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[37] La. Legis. Auditor, Off. of Conservation: Dep't of Energy & Nat. Res., Oversight of the Louisiana Oilfield Restoration Association's Efforts to Address Orphaned Oil & Gas Wells (Oct. 2024), https://app2.lla.state.la.us/publicreports.nsf/0/ad6eb1c47f87a3cf86258bc00064c330/$file/00006297d.pdf?openelement&.7773098; Patrick Sloan-Turner, *$780k Loan, Insider Ties and No Oversight Unraveled a Louisiana Orphan Well Effort, Report Finds*, The Advocate (May 20, 2025), https://www.theadvocate.com/baton_rouge/lora-report-finds-red-flags-with-loan-and-finances/article_5a869688-b01a-4bdc-87a1-7bdf981f61ff.html.; Patrick Sloan-Turner, *Louisiana Official Got $780 for a House, Jobs for His Kids from a Firm He Oversaw, Warrant Says*, NOLA (Oct. 2, 2024), https://www.nola.com/news/la-official-probed-for-malfeasance-for-oil-well-program/article_6e297a56-2483-507d-aad2-4b8f2ebdc640.html.

[38] La. Legis. Auditor, Off. of Conservation: Dep't of Energy & Nat. Res., Progress Report: State Efforts to Address Orphaned Oil and Gas Wells at 4.

[39] S.B. 244, 2025 Reg. Sess, § 1 (La. 2025).

[40] Off. of the Legis. Auditor Gen., No. 2019-11, A Performance Audit of Utah's Oil and Gas Program (2019), https://le.utah.gov/audit/19_11rpt.pdf.

stakeholder process to modernize Utah's bonding rules with a risk-based approach.[41] After eight rounds of stakeholder feedback, the agency has landed on a proposal along the following lines: blanket bonds should be considered a privilege and not a right, and only available to solvent operators as proxied by fleet production and percentage of idle and submarginal wells in the fleet.[42] Operators eligible for blanket bonds are divided into tiers, with increasingly large per-well bond amounts as operators become riskier to the state, tied to the number of wells covered by the blanket bonds.[43] In addition, operators must provide single well depth bonds for their idle and submarginal wells.[44] Operators who do not qualify for blanket bonds must obtain single well depth bonds for all of their wells.[45] This matter is now before the Utah Board of Oil, Gas and Mining, which is collecting analytics to determine how to proceed on the rulemaking.

In addition to this spate of very recent activity, other states have been working on this issue for many years. Since 2020, California and Colorado both overhauled their approaches to financial assurance, idle well management, and well transfer.[46] California requires full-cost financial assurance for marginal wells on transfer or after workovers.[47] Colorado has created a

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[41] *Draft Bond Rule*, Utah Div. Of Oil, Gas & Mining, https://ogm.utah.gov/rulemaking-og-bond/ (last visited July 9, 2025).

[42] Performance Bonds, Utah Admin. Code R649-13 (proposed rule), https://ogm.utah.gov/wp-content/uploads/2025/03/R649-13-Bonding-Draft.pdf.

[43] *Id.*

[44] *Id.*

[45] *Id.*

[46] Andrew Gillies, *Governor Signs Bill Into Law Increasing Financial Responsibilities of Oil and Gas Well Operators*, KEYT (Oct. 10, 2023); Chase Woodruff, *Colorado Oil and Gas Regulators Approve 'Strongest in the Nation' Financial Rules*, Canary Media (Mar. 2, 2022), https://www.canarymedia.com/articles/enn/colorado-oil-and-gas-regulators-approve-strongest-in-the-nation-financial-rules. Robert Davis, *Colorado Oil and Gas Regulators Overhaul State Financial Assurance Rules*, Colo: The Ctr. Square (Mar. 2, 2022), https://www.thecentersquare.com/colorado/article_248ddcb6-9a64-11ec-8899-f34b1442ce3d.html.

[47] Cal. Pub. Res. Code § 3017(b) (2024).

multi-tier system,[48] along with a new annual orphan well fee ($225 per well per year for large operators; $125 per well per year for small operators)[49] designed to generate $10 million a year to cover expected future orphan wells.[50] It should be noted some commentators have calculated this is only a fraction of the likely capital needed given the high population of very low producing wells outside of the Denver-Julesburg Basin.[51]

Many other states have similar programs to address orphaned and idled wells. Wyoming, having already experienced a wave of mass orphaning of coalbed methane wells,[52] recently adopted a policy of essentially full-cost, single well, per-foot financial assurance for all idle wells.[53] North Dakota, which was the first state to use federal stimulus funds for orphan well plugging even before the REGROW Act,[54] similarly limits blanket bonds to seven idle wells.[55] Alabama has almost no orphan wells because of a longstanding state policy to go after all scofflaw operators regardless of likelihood of return – in Alabama, obeying the law is not optional.[56] Finally, Arkansas pioneered the concept of full-cost financial assurance for marginal

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[48] Colo. Code Regs. § 404-1:700 to 707 (2022).
[49] *Id.* § 404-1:205.
[50] Mark Jaffe, *Nearly Half of Colorado's 52,000 Wells Produce Little or No Oil. Who'll Pay to Plug Them?*, Colo. Sun (Aug. 22, 2021), https://coloradosun.com/2021/08/22/colorado-orphan-wells-cost-to-plug/.
[51] Joe Fassler, *Why Colorado's Celebrated Oil Well Cleanup Reforms Face a $3 Billion Shortfall*, DeSmog (June 26, 2024), https://www.desmog.com/2024/06/26/why-colorados-celebrated-oil-well-cleanup-reforms-face-a-3-billion-shortfall/.
[52] Dustin Bleizeffer, *Coalbed Methane: Boom, Bust and Hard Lessons*, Wyo.History.org (Mar. 29, 2015), https://www.wyohistory.org/encyclopedia/coalbed-methane-boom-bust-and-hard-lessons.
[53] Wyo. Code R. § 055-0001.3 §4 (2020).
[54] Daniel Raimi, *Plugging Orphaned Oil and Gas Wells: What We Know and Need to Know*, Resources.org (Feb. 25, 2021), https://www.resources.org/archives/plugging-orphaned-oil-and-gas-wells-what-we-know-and-need-to-know/.
[55] N.D. Admin. Code 43-02-03-15(2) (2024).
[56] *See* Ala. Admin. Code r. 9-17-23 (2024); *see also* Ala. Dep't of Env't Mgmt., Protecting Our Groundwater: Guidelines for Well Abandonment,

wells on transfer in 2018,[57] after an Arkansas Oil and Gas Commission ("AOGC") Commissioner's bad experience with unplugged idle wells on his property – AOCG regulators have shared with me that as a result new orphans have decreased, transfers to unaccountable micro-operators have decreased, and bonds held by the AOGC have gone up.

Q: Mr. Peltz, can you please describe your background working on idled and orphaned oil and gas wells in New Mexico?

A: Yes. In the run-up to the 2024 New Mexico legislative session, EMNRD convened a stakeholder process to address financial assurance and other Oil and Gas Act reform issues legislatively.[58] I facilitated the industry-NGO subgroup on financial assurance.[59] That process led to the development of some common principles, including pursuit of risk-based financial assurance. The legislative proposal on financial assurance for the 2024 legislative session aimed to increase the maximum amount of a blanket bond to $10 million to better reflect the actual risks faced by the state.[60] At the time, and now, the blanket bond financial assurance cap of $250,000 only covers the state-managed plugging of 1.66 wells, while some operators in New Mexico have over 10,000 wells.

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https://adem.alabama.gov/programs/water/nps/take/protectgw.pdf; *see also* Shelby Webb, *How the Infrastructure Law Creates State Oil Winners and Losers*, E&E News (Aug. 17, 2023), https://www.eenews.net/articles/how-the-infrastructure-law-creates-state-oil-winners-and-losers/ (discussing Alabama's approach to cracking down on operators).

[57] 118-03-1 Ark. Code. R. § B-7 (2018).

[58] Jerry Redfern, *Oil and Gas Regulatory Bills Still Alive in New Mexico Legislature*, SourceNM (Feb. 6, 2024), https://sourcenm.com/2024/02/06/oil-and-gas-regulatory-bills-still-alive-in-new-mexico-legislature/; Jerry Redfern, *New Mexico Battles to Clamp Down on Big Oil*, SourceNM (Jan. 19, 2024), https://sourcenm.com/2024/01/19/new-mexico-battles-to-clamp-down-on-big-oil/.

[59] *See* Mark Olalde, *How America's "Most Powerful Lobby" is Stifling Efforts to Reform Oil Well Cleanup in State After State*, ProPublica (June 24, 2024), https://www.propublica.org/article/oil-industry-lobbying-unplugged-wells.

[60] Jerry Redfern, *New Mexico Battles to Clamp Down on Big Oil*, SourceNM (Jan. 19, 2024), https://sourcenm.com/2024/01/19/new-mexico-battles-to-clamp-down-on-big-oil/.

Despite industry's participation in the discussions that led up to a legislative proposal put forth by the Administration, during the legislative session industry turned out strongly against it, arguing incorrectly that the law would mean all operators had to pay a $10 million bond.[61] In order to address industry concerns, the Administration offered, at industry parties' urging, a tiered approach based on well counts such that 85% of operators would be exempt from bond increases (notably *not* a risk-based approach),[62] but this was not enough for some operators, who nonetheless successfully opposed the bill.[63] Since then, I have worked with partners to better analyze New Mexico's well population and potential future risk to the state.

Q: Mr. Peltz, when did you begin working on the Revised Application now before the Commission, and what has been the nature of your participation?

A: I began working with Applicants' counsel on the initial Application in March 2024. The nature of my participation is serving as an expert witness because of my significant experience on financial assurance rulemakings in states in the region. I have consulted on the initial and Revised Applications and have participated in multiple meetings with Applicants' counsel and OCD legal and technical staff. I have reviewed and provided input into multiple drafts of the initial Application and the Revised Application that is before the Commission.

Q: Mr. Peltz, do you believe the current oil and gas regulatory framework in New Mexico is sufficient to ensure the adequate plugging and abandonment of oil and gas wells?

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[61] *Id.*

[62] *Compare* H.B. 133, 56th Legis, Reg. Sess. (N.M. 2024) (House Judiciary Committee Substitute for House Energy, Environment and Natural Resources Committee Substitute for House Bill 133), https://www.nmlegis.gov/Sessions/24%20Regular/bills/house/HB0133JCS.pdf, *with* H.B. 133, 56th Legis., Reg. Session. (N.M. 2024) (Introduced bill).

[63] Jerry Redfern, *Another New Mexico Legislative Session Ends, and Again – No New Oil and Gas Reforms*, SourceNM (Feb. 27, 2024), https://sourcenm.com/2024/02/27/another-new-mexico-legislative-session-ends-and-again-no-new-oil-and-gas-reforms/.

A: No, and I am in good company. Both the State Land Office,[64] and most recently the LFC found that taxpayer risk from future well orphaning in New Mexico is unacceptable due to insufficient regulatory policy and enforcement.[65] New Mexico has over 63,000 oil and gas wells that will eventually be retired.[66] Without an adequate regulatory framework, the orphan well problem in New Mexico will only worsen over time.[67] The LFC estimates that New Mexico is looking at a liability of $200 million to $700 million, or as high as $1.6 billion, to address current and near-term well plugging needs.[68] Given those looming costs, LFC finds that the current financial assurance requirements for operators are insufficient.[69] EDF has also projected expected bonding amounts required under New Mexico's current financial assurance rules, based on a snapshot of 2024 production across state and private lease wells; based on an estimated plugging cost of $163,000 each to plug the same set of wells, the bonding required under current rules are estimated to cover only 1-2% of the potential liability, even before necessary environmental remediation is considered.

Q: What other considerations factor into the need for increased financial assurance as proposed by Applicants?

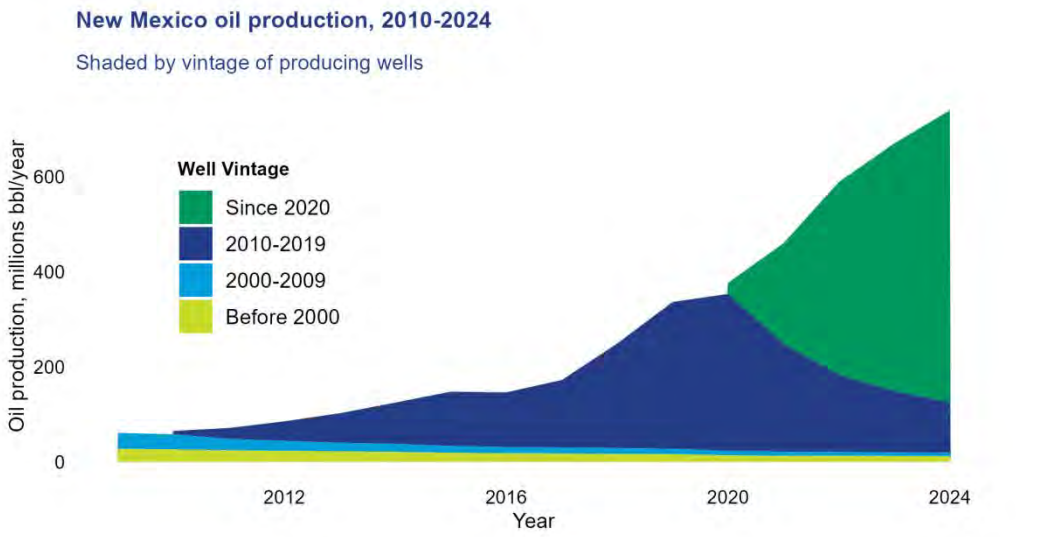
New Mexico is producing record amounts of oil and gas production. Oil production has increased exponentially since 2010, rising more than 10-fold from 66 million barrels in 2010 to 745 million barrels in 2024.[70] A look at the wells responsible for this boom in production reveals

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[64] *Bonding*, N.M. State Land Off., https://www.nmstatelands.org/bonding/ (last visited July 10, 2025) (citing Center for Applied Research Study).
[65] Apps' Ex. 4, N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells at 22, 24, 31.
[66] Apps' Ex. 4, *id.* at 1.
[67] Apps' Ex. 4, *id.*
[68] Apps' Ex. 4, *id.* at 1, 2, 15.
[69] Apps' Ex. 4, *id.* at 32.
[70] U.S. Energy Info. Admin., New Mexico Field Production of Crude Oil (Annual), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mcrfpnm1&f=a

that these record highs are driven by wells drilled within the past 10 years.

As can be seen from Applicants' Exhibit 59 below, oil production has been rising rapidly since the middle of the last decade, primarily due to the Permian shale boom. Since 2020, all of the growth has come from these newer wells, while the share of older well production has shrunk dramatically. Now, the vast majority of production in the state comes from wells spudded in just the past five years – meaning that the entire large fleet from earlier vintages are rapidly becoming unproductive and thus uneconomic – representing an increasingly large liability with increasingly less revenue to cover those costs.



Production as reported from GO-TECH annual County Production Volume downloads, 2010-2024, all counties.
Vintages derived from SpudDates reported in OCD Well History dataset, current as of 7/11/25.

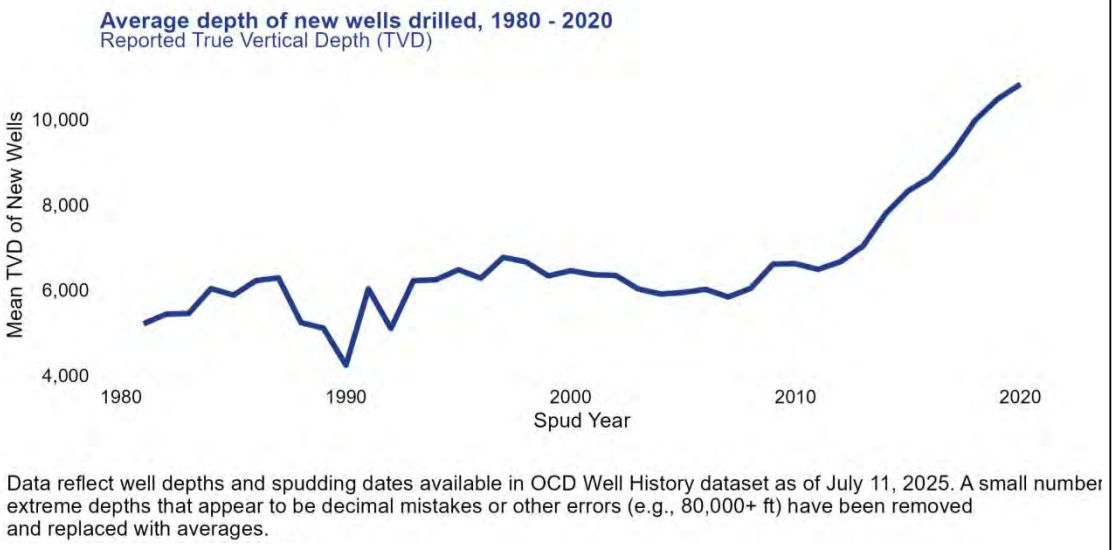
Apps' Ex. 59

The EIA's latest Short Term Energy Outlook forecasts production to be relatively flat through 2026, with long term projections of U.S. production increasing through 2027 and 2028, primarily driven by production from the Permian Basin, followed by leveling off and gradually declining

Apps' Ex. 57

production after 2028.[71] Although oil markets forecasts and projections have inherent uncertainty, all indications are that *there will never be a better time for New Mexico to strengthen its financial assurance regulations of oil and gas wells*, while markets remain strong and the industry can afford to invest in taking care of its current inventory and future legacy wells. It would be the paragon of irresponsibility to ignore the opportunity to secure legacy clean-up costs during this boom time.

With this tremendous increase in production, primarily from deep tight oil plays in the Permian Basin, has come an increase in New Mexico's average well depths: the average reported true vertical depth of newly drilled wells increased from ~6,000 feet in 2010 to around 10,000 feet by 2020, in turn reflecting higher expected plugging costs, as shown by Applicants' Exhibit 60 below.



Apps' Ex. 60

While production has boomed among a relatively small number of wells, New Mexico faces a growing population of low-production and inactive wells. EIA's 2024 annual well distribution

[71] U.S. Energy Info. Admin., Short-Term Energy Outlook at 2-3 (2025), https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

Apps' Ex. 57

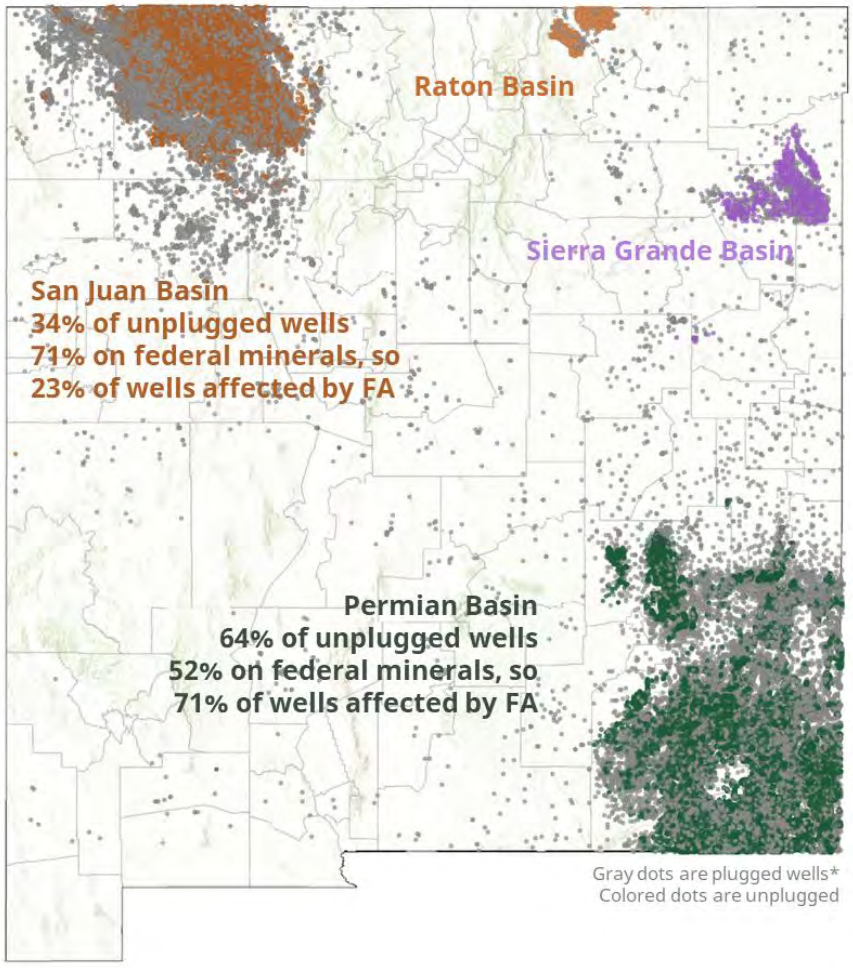
report indicates *54%* of the state's producing oil wells produce < 15 BOE/day and accounted for only *2%* of the state's annual oil production; similarly, *81%* of the state's gas wells produced ≤ 15 BOE/day, amounting to only *19%* of annual gas production.[72]

As of mid-2025, the new category of marginal wells proposed in this rule (< 2.7 BOE/day, and fewer than 180 days of activity in the past 12 months) captures an estimated 3,900 wells (inclusive of those lower-producing wells also meeting the proposed criteria for presumption of no beneficial use); together these wells amounted to around 6.6% of producing wells (including new drilling), but only produced on the order of *0.0048%* of the state's oil and gas over the preceding 12 months. While New Mexico's inventory of these low producing and legacy wells is lower than other states such as Texas, the potential liability for end-of-life closure is substantial (on the order of $636 million[73] for plugging and abandonment alone.) These marginal wells do not materially benefit the state in terms of production or revenue and are instead a growing liability. The state has an opportunity to get ahead of the curve and curtail this growing risk with updated regulations, without impact to most of the production.

[72] U.S. Energy Info. Admin, U.S. Oil and Natural Gas Wells by Production Rate at 14 app. B, tbl. B44 (2024), https://www.eia.gov/petroleum/wells/.

[73] Assuming OCD's estimate of $163,000/well for 3,900 wells yields an estimated plugging and abandonment cost of $636 million, even before other remediation costs.

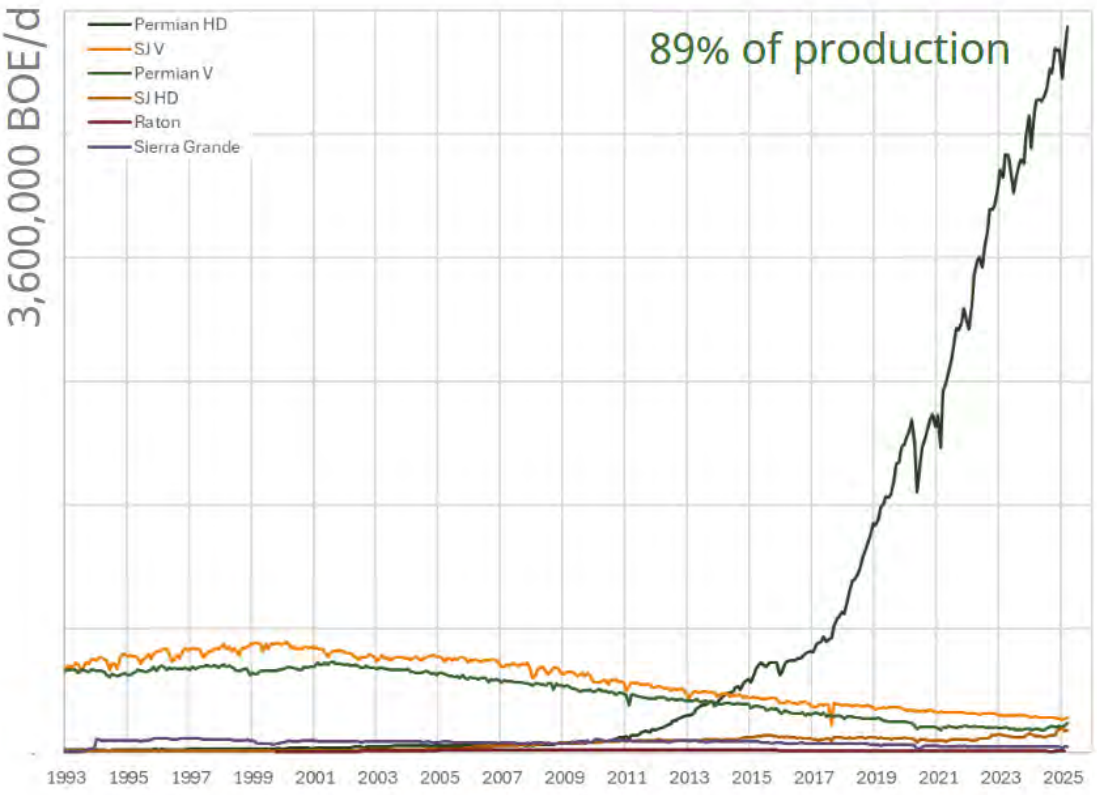
An overview of all active and inactive wells in New Mexico by Dwayne Purvis, P.E. (one of Applicants' experts), indicates the majority of current active or inactive wells that will need to be plugged are in the Permian and San Juan Basins. The table and map included here (Apps' Ex. 31) illustrate the distribution of these plugged and unplugged wells.



Basin	Plugged*	Unplugged Total	active	not active
Permian	35,661	**39,929**	36,850	3,079
San Juan	12,941	**21,219**	20,370	849
Raton	116	**861**	837	24
Sierra Grande	643	**711**	698	13
Other	312	-	-	-
	49,673	**62,720**	**wells to be plugged**	

Apps' Ex. 31

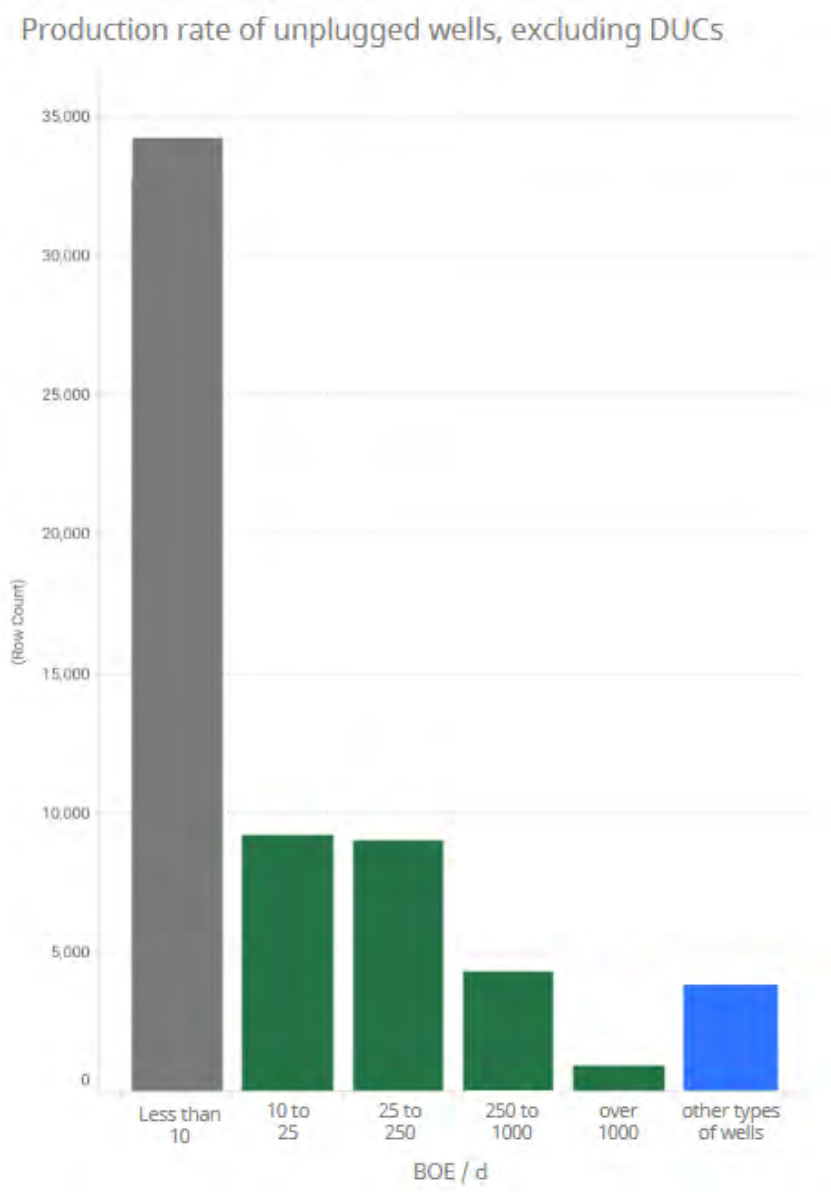
Additional analysis from Mr. Purvis (included as Apps' Ex. 33) shows that outside of the Permian Basin, and except for *horizontal* wells drilled *within* the Permian, production from most wells and regions in New Mexico is in long-term decline.



Apps' Ex. 33

And the majority of the approximately 63,000 wells in New Mexico that will eventually need to be plugged are only marginally productive, as demonstrated below in Applicants' Exhibit 32. Indeed, approximately 34,000 wells produce less than 10 BOE per day.

It should also be noted that the estimated ~63,000 wells that will need plugging is not a static number and is anticipated to grow substantially, as the Permian Basin is the only region in the U.S. with increasing production that is anticipated to continue for the near term, and

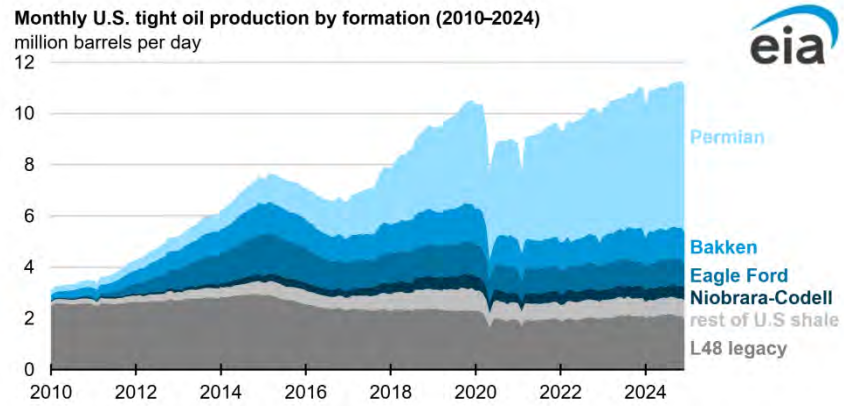


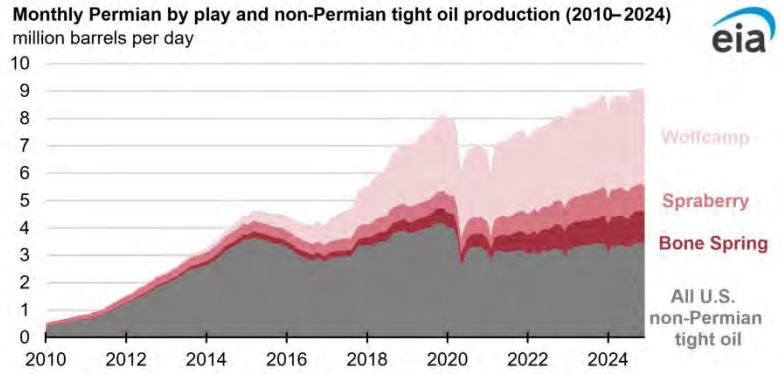
Apps' Ex. 32

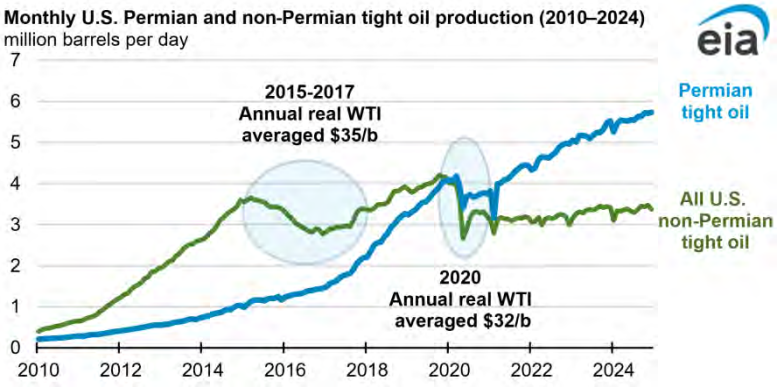
the majority of that increase is from the New Mexico portion of the Permian Basin. A recent analysis by the EIA highlighted that, indeed, nearly all of the recent and forecasted production growth in the U.S. is coming from the horizontal wells in the Wolfcamp Formation within the Permian Basin, while production from vertical wells is in decline; production from horizontal

Apps' Ex. 57

wells in other tight oil plays is relatively flat and forecast to remain flat. [74] These trends are reflected in the following three EIA figures, taken from the cited study:







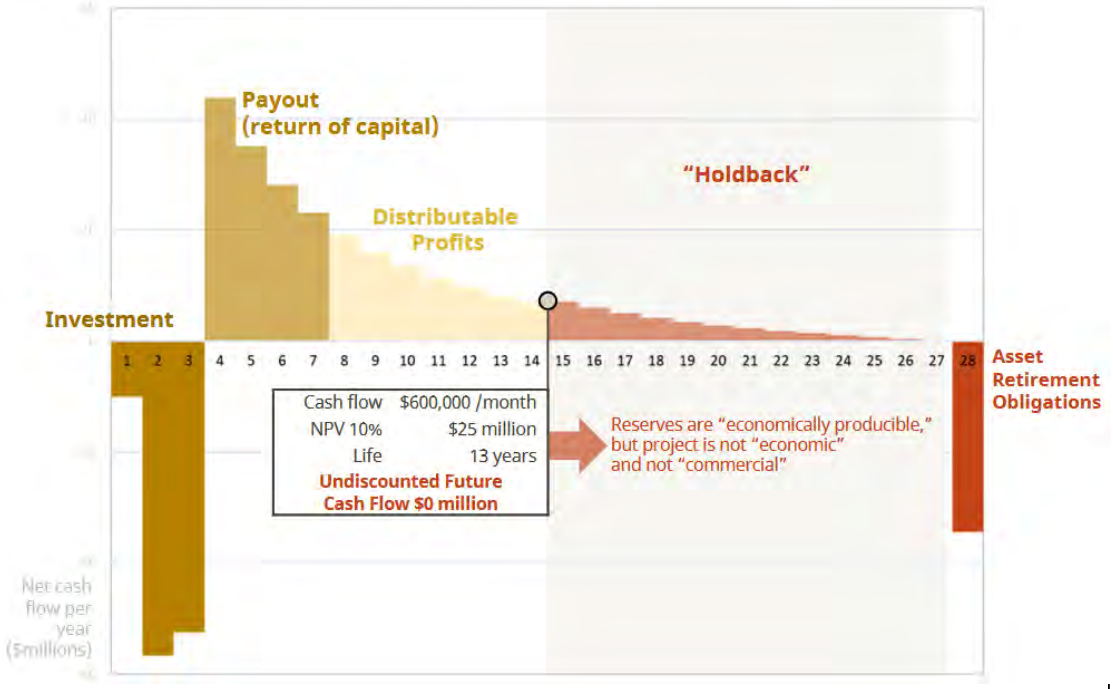
EIA 2024

[74] *Tight Oil Production in Permian Drives Growth in Onshore U.S. Lower 48 States Production*, U.S. Energy Info. Admin. (June 2, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65404.

It should also be noted that for production to remain flat from tight oil plays, new wells must be brought online continually as production from tight oil plays declines relatively quickly, and to increase production requires even more drilling and new wells to be brought online. New Mexico is producing more oil right now than most OPEC countries, and there may never be a better time for industry to adequately prepare for its eventual plugging liabilities—and for the state to begin to more effectively hold industry accountable for plugging their own wells.

Mr. Purvis's testimony (Apps' Ex. 30) clearly demonstrates through cash flow analysis that low-producing wells will realistically never generate enough revenue to cover plugging and remediation costs of those wells. The following figure from his analysis (Apps' Ex. 38) shows, for a hypothetical well, that the operator would need to retain all revenue after year 15 of production to cover asset retirement obligations:

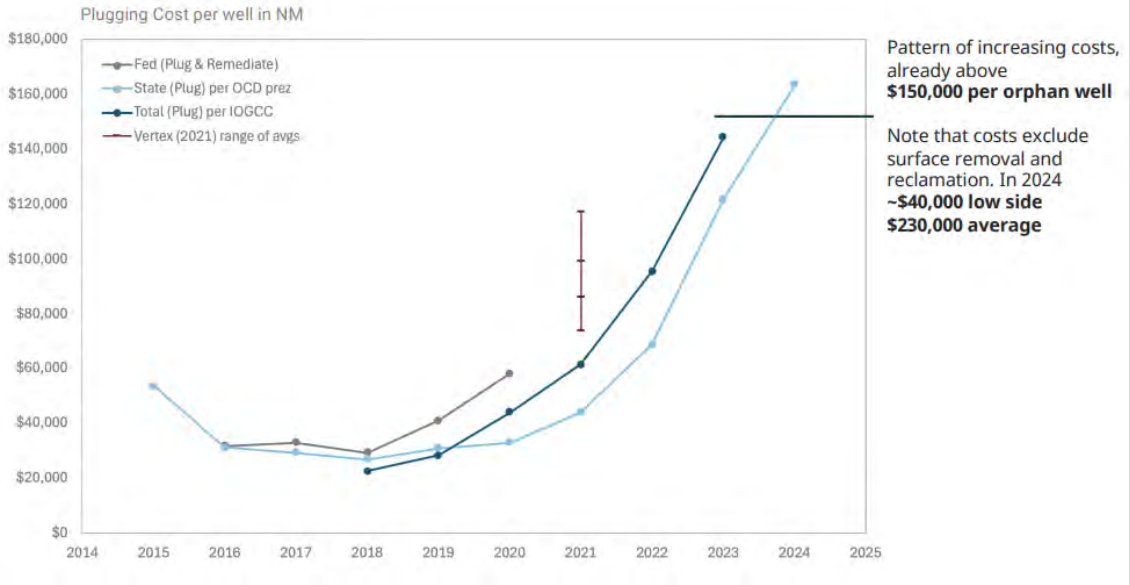
Applicants' Exhibit 38: Schematic of cash flow for a hypothetical oil and gas project to demonstrate the economic concepts of payout and holdback.



Apps' Ex. 38

Apps' Ex. 57

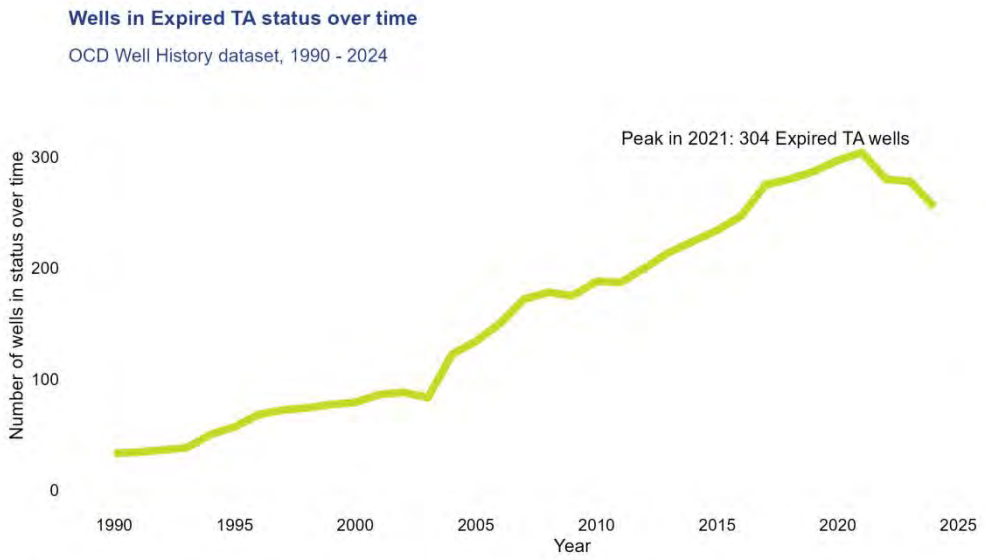
And that the average costs for plugging orphaned wells for the state have increased substantially in the past decade, as illustrated in Applicants' Exhibit 39.



Apps' Ex. 39

Q: How do wells in temporary abandonment status fit into this landscape?

A look at New Mexico's population of wells reported by OCD to be in expired TA status suggests a growing trend by operators of leaving wells in expired TA status rather than plugging them, as shown by Applicants' Exhibit 61 below. The proposed rules will go a long way towards reversing this trend.

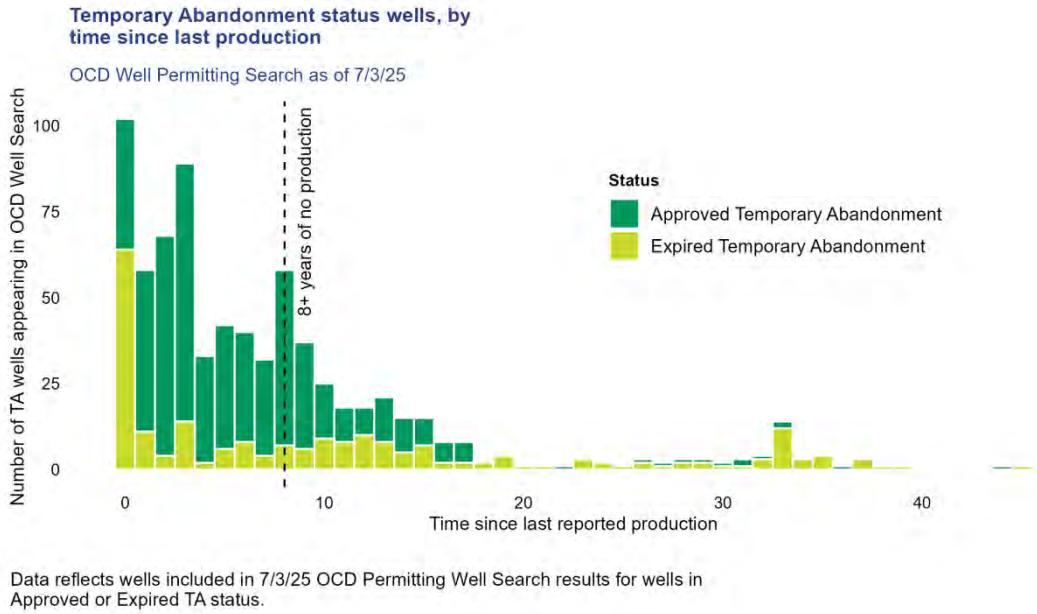


Wells reported in Expired TA status by OCD Well History dataset, current as of 7/11/25.

Apps' Ex. 61

A look at wells in approved and expired TA status shows that wells linger for years in both approved and expired TA status, and that the longer the well is inactive, the more likely it is to be in expired TA status and out of compliance with Commission rules, as shown by Applicants' Exhibit 62 below.

Apps' Ex. 57

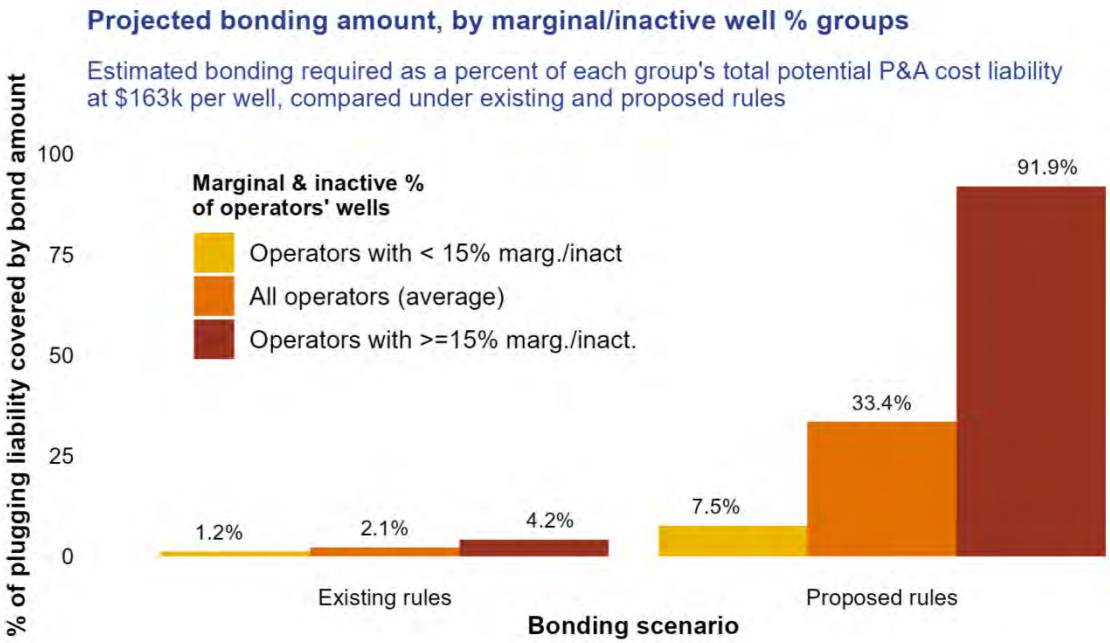


Apps' Ex. 62

An EDF analysis (Apps' Exhibit 63), estimated the total plugging liability to be $3.4 billion across New Mexico's wells with state or private mineral ownership, based on a snapshot of 2024 production levels [75]. Under existing rules, the total bonding amount estimated across all operators for this same set of wells is less than $72 million – covering barely more than 2% of the potential $3.4 billion needed to plug these wells. Under the proposed rules, estimated bonding across all operators would increase more than 17-fold to around $1.1 billion, increasing the coverage to roughly one third of the $3.4 billion. This increase in costs falls primarily on risky operators with 15% or more marginal and inactive wells, incentivizing reactivation or

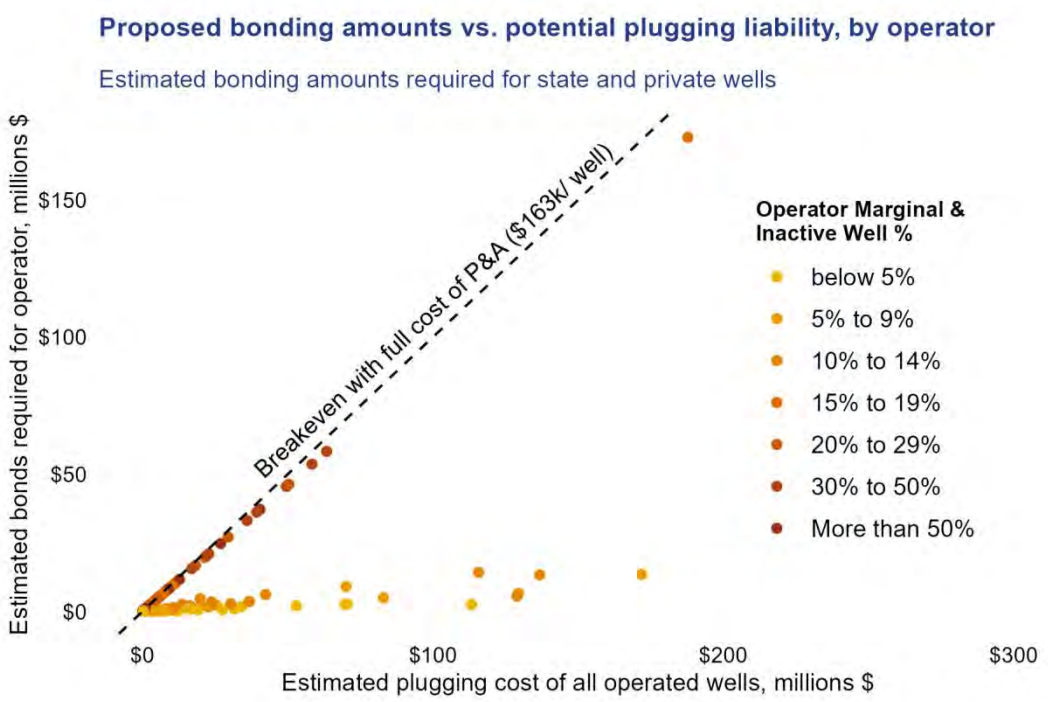
[75] This analysis reflects a filtered subset of all New Mexico wells, removing those spudded after Jan. 2024 or plugged before Jan. 2025, and limited to wells with state or private lease types (approx. 21,000 wells). Marginal/inactive well determinations were based on classifications using OCD production data obtained via GO-TECH, as well as other OCD status and activity records. Assessed percentages of marginal and inactive wells are inclusive of federal lease type wells. *See* Apps' Ex. 63 for complete details.

closure of these wells to bring operators under the threshold.



Apps' Ex. 63

As illustrated below in this scatter plot, Applicants' Exhibit 64, comparing each analyzed operator's projected bonding requirements (x axis) to projected plugging liability total for the same number of wells (y axis), the structure of the proposed rules requires operators with more than 15% marginal or inactive wells to bond all of their state and private wells at near-full cost, reflective of the higher risk these operators pose to the state's finances.



Plot of firm-level bond amounts (Y axis) versus projected plugging liabilities at $163k (X axis). A line is plotted at y=x; operators below the line are underbonded relative to potential P&A liability. Operator marginal & inactive well % based on all federal, state, and private lease-type wells; bonding costs and liabilities based on operator's state and private wells only.

Apps' Ex. 64

19.15.2 NMAC—GENERAL PROVISIONS FOR OIL AND GAS OPERATORS

Q: Mr. Peltz, turning to Applicants' specific proposals, Applicants propose changes to 19.15.2 NMAC—General Provisions for Oil and Gas Operators—and recommend adding a definition for "marginal well." What do Applicants propose?

A: Applicants propose the following definition, shown in redline:

> **19.15.2.7.M(2) "Marginal well"** means an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period.

Under this definition, initially proposed by OCD in its February 12, 2025 Redline Proposals to the parties (Apps' Ex. 5), a marginal well is one that produces for less than 180 days during a 12-

month period *and* produces less than 1,000 BOE during that same 12-month period. Over the course of 12 months, this represents daily production of 2.7 BOE.

Q: What is the purpose of this new definition?

A: This new category of financial assurance for "marginal wells" was initially proposed by OCD based on staff's experience, and Applicants adopted the proposal. Marginal wells represent a category of well that is at greater risk of becoming orphaned and therefore merits increased financial assurance to protect the state. I discuss the basis for the increased financial assurance later in my testimony discussing proposed amendments to 19.15.8.9.D NMAC – Financial Assurance. Essentially the new category of marginal wells comprises a small percentage of New Mexico's low-producing wells that are the highest risk to the state with plugging costs that far exceed present and future revenue potential.

For example: if a 1,000 BOE per year well were producing oil, its gross revenue would correspond to around $65,500 per year; if it were producing gas, its gross revenue would correspond to around $21,000 per year[76]. Nearly half of the wells that produce less than 1,000 BOE per year in New Mexico are in fact less than 1 BOE per day. At 1 BOE per day, an oil well will produce around $24,000 per year in gross revenue, while a gas well will produce around $7,800 per year in gross revenues.[77] Looking at all active New Mexico wells that produce less than 1,000 BOE per year, their total gross revenue can be estimated at around $26 million in 2024, or less than $1,300 per well on average[78]. In other words, there is a significant number of

[76] Approximation based on July 1, 2025 prices for NYMEX LS ($65.50/bbl, * 1000 = $65,500) of oil, and Henry Hub ($3.43/MMbtu; * 1.038 mcf/MMbtu [EIA conversion factor from https://www.eia.gov/tools/faqs/faq.php?id=45&t=8] * 6 mcf/boe (conversion factor from NM statute) = $21.36/BOE; X 1000 BOE = $21,360.)

[77] Using prices above, 365 days * $3.43/bbl = $23,907; 365 days * $21.36 = $7,796.

[78] Based on categorizations and totals of wells UNM's GO-TECH County Production data downloads, for 2024.

wells that are "active" in name only – and certainly not at levels that would also cover the costs to plug, abandon and remediate the site, which is estimated to average around $249,000[79].

When calculating net revenue, one must calculate expenses, which include operation and maintenance ("O&M") costs, royalties and taxes. The sum of these factors can vary dramatically between regions and operators; survey responses from the Dallas Fed Energy Survey for Q1 of 2025[80] suggest breakeven oil prices needed for existing wells to profitably produce range from as low as $4.25 to as high as $90/bbl; averages of responses received for the Permian Basin in the range from $31 to $43/bbl, and reported US non-shale averages range as high as $45/bbl .[81] Comparing these breakeven prices to the July 1, 2025 NYMEX LS oil price as a reference, these breakeven averages suggest average expenses in the range of 48% and 69% of gross revenues We might therefore reasonably expect average net revenues for our hypothetical well producing less than 1,000 BOE per day ($65,500 gross revenue) to fall in the range of only $20,000-35,000/year net revenue for oil, or $6,500-$11,000 for a 1000 BOE/year gas well. These are extremely low figures relative to plugging costs, even given that industry plugging costs are expected to be somewhat lower than average agency plugging cost of $163,000/well.

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[79] Based on $163,000/well plugging and abandonment estimate from OCD, and $86,000/site remediation cost estimate from Vertex, cited and used by LFC in the previously cited report.

[80] *See Dallas Fed Energy Survey First Quarter: Special Questions*, Fed. Rsrv. Bank of Dallas (Mar. 26, 2025),

[81] Note, these averages do not take into account the social cost of methane, which is relatively significant as low-producing wells as a class have high emissions intensity. *See New Study: Low-Producing Oil and Gas Wells Drive Roughly Half of Well Site Methane Pollution Nationwide*, EDF (April 20, 2022), https://www.edf.org/media/new-study-low-producing-oil-and-gas-wells-drive-roughly-half-well-site-methane-pollution; James P. Williams et al., *Small Emissions Sources in Aggregate Disproportionately Account for a Large Majority of Total Methane Emissions from the U.S. Oil and Gas Sector*, 25 Eur. Geosciences Union 1513 (2025), https://doi.org/10.5194/acp-25-1513-2025; Mark Omara et al., *Methane Emissions from U.S. Low Production Oil and Natural Gas Well Sites*, Nature Comm. (Apr. 19, 2022), https://www.nature.com/articles/s41467-022-29709-3.

Because of their very marginal net revenue, these wells pose a material risk of becoming orphaned. This particular cutoff was proposed by OCD and represents a production level where the risks and potential liability to the state to plug and remediate are great compared to the potential loss in production and revenue to the state.

Orphaned wells have additional costs to the state, the public, and the environment including emission of methane and toxic and hazardous air pollutants and contamination of ground and surface water.[82] The Commission's financial assurance and plugging and abandonment rules are designed to prevent the external social costs of orphaned wells.

It is worth clarifying that a well producing more than 180 days of the year but less than 1,000 BOE per year, or a well producing less than 180 days of the year but more than 1,000 BOE per year, would not be considered a marginal well under this definition. The former scenario is conservatively exempted because continuous production may be a sign of potential future productivity of the well; the latter because increased revenue reduces risk of orphaning. In other words, only those wells most at risk to the state of becoming orphaned would fall into OCD's proposed definition of "marginal well," which is used throughout the Revised Application to increase financial assurance levels and address risk.

19.15.8 NMAC—FINANCIAL ASSURANCE

19.15.8.9.C NMAC – Active Wells

Q: Mr. Peltz, Applicants propose changes to 19.15.8 NMAC—Financial Assurance—and specifically recommend changes to 19.15.8.9 NMAC which establishes "Categories and Amounts of Financial Assurance for Well Plugging," which we will address in turn. What

[82] Apps' Ex. 4, p. 4-5, 13-15; Mary Kang et al., *Environmental Risks and Opportunities of Orphaned Oil and Gas Wells in the United States*, Env't Rsch. Letters (June 20, 2023), https://iopscience.iop.org/article/10.1088/1748-9326/acdae7.

changes to Applicants propose to Subsection C, governing "active wells"?

A: Applicants propose the following amendments:

> **19.15.8.9.C. Active wells.** An operator shall provide financial assurance for wells that are covered by Subsection A of 19.15.8.9 NMAC and are not subject to Subsections D and E of 19.15.8.9 NMAC in one of the following categories:
>
> **(1)** a one well plugging financial assurance in the amount of $150,000 per well. ~~25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells~~; or
>
> **(2)** a blanket plugging financial assurance in the amount of $250,000 ~~following amounts~~ covering all the wells of the operator subject to Subsection C of 19.15.8.9 NMAC.~~:~~
>
> ~~**(a)** $50,000 for one to 10 wells; $200,000 for one to five wells; and~~
>
> ~~**(b)** $75,000 for 11 to 50 wells; $250,000 for six or more wells.;~~
>
> ~~**(c)** $125,000 for 51 to 100 wells; and~~
>
> ~~**(d)** $250,000 for more than 100 wells.~~

Q: What is the purpose of the proposed changes to financial assurance for "active wells?"

A: Applicants propose a non-substantive change in Paragraph (1), term "one well plugging financial assurance" is used for consistency with terminology in the Oil and Gas Act and within 19.15.8 NMAC.

Applicants propose two principal amendments to the Commission rules concerning "active wells," first, proposing to increase the one well financial assurance to $150,000 per well and, second, to increase the blanket financial assurance to $250,000 regardless of the number of wells owned by the operator.

As to the proposed amendment to one well plugging financial assurance in 19.15.8.9.D(1) NMAC: The Oil and Gas Act requires the Commission to establish a "one-well plugging financial assurance in amounts determined sufficient to reasonably pay the cost of plugging the

wells covered by the financial assurance."[83] Currently, Commission rules provide for a one well plugging financial assurance based on a base amount of $25,000 plus $2 per foot of the projected well depth (either true vertical depth or measured depth) depending on well directionality).[84] This formula, established in 2019,[85] is outdated and is far from "sufficient to reasonably pay the cost of plugging the wells" covered by the Commission financial assurance. For example, the average well depth in New Mexico is around 6,200.[86] Under the current rules, a one well financial assurance instrument for that well would be approximately $37,400.

According to state data, the current average cost to OCD to plug a well is between $163,000 and $167,000.[87] (This range does not include costs for site remediation, which can run into the thousands, tens of thousands, and millions of dollars; a 2021 study for New Mexico's State Land Office provided an estimate of $86,000 per well used by the LFC in its recent report on the orphaned well issue.[88]) To fulfill the statutory requirement that a one well bond be "sufficient to reasonably pay the cost of plugging" a well, Applicants propose a one well bond of $150,000, which approximates the average cost to the state. Applicants use costs to the state—not costs to industry—because it will be the state, using the available financial assurance, that will plug and abandon the well in the event of orphaning. Therefore, the cost to the state, not to operators, is the appropriate measure for financial assurance amounts. One-hundred and fifty thousand dollars is a conservative number, accounting for the fact that some wells may cost less

[83] NMSA 1978, § 70-2-14(A).
[84] 19.15.8.9(D)(1) NMAC.
[85] 19.15.8.9.D NMAC (as amended 1/15/2019).
[86] Based on average true vertical depths reported in OCD Well History dataset, as described in Apps' Ex. 60.
[87] *See* Morgan Dir. Test. (Apps' Ex. 15), which sets forth OCD and LFC information on average costs to OCD to plug a well.
[88] N.M. Legis. Fin. Comm., Policy Spotlight: Orphaned Wells.

to plug (but not accounting for the fact that some wells will cost more). Nonetheless, the average cost to the state is the best measure of what is "sufficient to reasonably pay the cost of plugging" a well.[89]

As to the proposed amendment to a blanket plugging financial assurance in 19.15.8.9.D(2) NMAC: The Oil and Gas Act sets a blanket plugging financial assurance limit of $250,000.[90] The Commission's current rules tier blanket bond amounts to numbers of wells, ranging from a bond of $50,000 for one to 10 wells to a bond of $250,000 for more than 100 wells. This tiering is outdated in light of the current costs to the state to plug and abandon. A $250,000 blanket bond does not even cover the average cost to plug two wells. Therefore, it's appropriate to bring the blanket bond amounts in line with current costs to the extent possible – however insufficient that is – and require that all blanket bonds be set at $250,000.[91]

19.15.8.9.D NMAC – Marginal Wells and Inactive Wells

Q: Turning to new language proposed for "marginal wells and inactive wells" under Subsection D, what do Applicants propose?

A: The proposed amendments are shown in redline:

19.15.8.9.D. Marginal wells and inactive wells. Notwithstanding the

[89] Applicants understand that average plugging costs for industry may be lower than $150,000, likely because when industry plugs wells, they are only recently non-productive and thus in decent shape with known well architecture and minimal damage or junk in the hole. Whereas by the time they reach the state, conditions have often deteriorated, leading to more expensive and time-consuming plugging work. Other possibilities include that state plugging jobs are more thorough because of increased inspector oversight of state-paid plug jobs. Regardless, because financial assurance only applies when the operator fails to plug their well and the state must do so in their stead, it is the cost to the state than private plugging costs that should determine financial assurance levels.

[90] NMSA 1978, § 70-2-14(A). Most obviously, a cap of $250,000 for a blanket bond that can cover hundreds of wells is woefully inadequate when the average cost to the state to plug just one well exceeds $160,000. However, the cap is set in statute.

[91] The blanket bond amount of $250,000 is not unfair to an operator with one well who may obtain a one well financial assurance in the amount of $150,000.

provisions in Subsection C(2) in this Section:

(1) As of the [effective date of amendments] a transferee operator shall provide a one well plugging financial assurance of $150,000 for each marginal well prior to transfer.

(2) Beginning January 1, 2028, an operator shall provide a one well plugging financial assurance for each marginal well.

(3) An operator with 15 percent or more of their wells in marginal or inactive well status, or a combination thereof, shall provide a one well plugging financial assurance in the amount of $150,000 for each well registered to the operator until the percentage of the operator's marginal and inactive wells is decreased below 15 percent.

(4) An operator may furnish all necessary one well plugging financial assurance in the form of a single instrument.

Q: What is the purpose of this new provision?

A: The Oil and Gas Act requires the Commission to "establish categories of financial assurance after notice and hearing."[92] "In establishing categories of financial assurance, the [commission] shall consider the depth of the well involved, the length of time since the well was produced, the cost of plugging similar wells and such other factors as the [commission] deems relevant."[93] In proposed 19.15.8.9.D NMAC, Applicants propose that the Commission establish new categories of financial assurance that target wells at high risk of becoming orphaned and operators at high risk of orphaning their wells. "Marginal wells," proposed by OCD in its February 12, 2025 Redline Proposals (Apps' Ex. 5) and adopted by Applicants in their Revised Application, represents a new category of financial assurance. This is the operational core of Applicants' proposal, and based directly on OCD's recommendations. Overall, these proposals assign full-cost financial assurance to wells and operators at highest risk of non-compliance with abandonment requirements due to the low or negative profit margins on these wells.

[92] NMSA 1978, § 70-2-14(A).

[93] *Id.* Under the terms of the act, the "oil conservation division" is charged with this responsibility and OCD and the Commission share concurrent jurisdiction over this responsibility. *Id.* § 70-2-6(B).

According to data compiled by EIA,[94] more than 60% of New Mexico's unplugged wells produced less than 10 BOE per day in 2024. These wells together produced around 1% of New Mexico's annual oil production and around 13% of the state's 2024 gas production, yet present a significant financial risk to the state in terms of plugging costs if and when these operators go bankrupt. Only a fraction of these wells is covered by the proposed definition of "marginal". For example, analysis of the state's wells by Mr. Purvis (Apps' Ex. 42**)** shows that the proposed "marginal well" definition of 1,000 BOE of annual production (or 2.7 BOE per day) and <180 days of production captures fewer than ~7% of unplugged wells (around 3,900), but less than 0.048% of total production on a BOE basis. *For comparison, 9 wells in New Mexico each individually reported more total production in 2024 than the sum of production from all of these 3,900 marginal wells combined*[95] (*see* Applicants' Exhibit 65).

I will discuss each subsection of 19.15.8.9.D NMAC, beginning with Paragraph (1), which effectively requires full-cost financial assurance of $150,000 for marginal wells prior to transfer. This requirement has immediate application. Requiring full-cost financial assurance for low producing wells was first conceived of by Arkansas in 2018, and has since been adopted by Colorado and California.[96] The theory behind such a provision is that, historically and through today, low-producing wells are transferred and sold down the value chain to increasingly poorly

[94] U.S. Energy Info. Admin, U.S. Oil and Natural Gas Wells by Production Rate at 14 app. B, tbl. B44 (2024), https://www.eia.gov/petroleum/wells/.

[95] Based on 2024 OCD production data from University of New Mexico's GO-TECH county volume downloads, a group of 9 wells were identified with total 2024 production above 750,000 (from 782,000 to over 1 million BOE); an additional 10 reported more than 700,000 BOE. These high-producing wells are all Permian Basin wells spudded since 2022. *See* Apps' Ex. 65. Compare to total annual production of 4.34M BOE/day (as reported in Apps' Ex. 33), * 365 days *0.048% = ~760,000 BOE/year total for marginal and no beneficial use wells.

[96] *See* Cal. Pub. Res. Code § 3017(b); Colo. Code Regs. § 404-1:700 to 707; 118-03-1 Ark. Code. R. § B-7.

capitalized operators until the final, bankruptcy-proof operator walks away and leaves the state holding closure responsibility. This fact pattern can occur even under good intentions, where the smaller transferee has lower operating costs and is thus able to make a profit where the larger transferor could not (although Mr. Purvis discusses in his testimony whether a profit is possible if closure costs are factored in); under bad intentions where the transferee is a purpose-built LLC designed to eliminate liability exposure for the financiers and facilitate well orphaning; or a mix of intentions.

A series of recent lawsuits on grounds of fraudulent transfer, contending that a transfer took place with the intention of relieving the transferor of liability and with the knowledge the transferee could not assume that liability, speaks to the need to protect landowners, people living in close proximity to end-of-life wells, and taxpayers from the specter of liability for transferred marginal wells.[97] The point of transfer is a critical point in time in which it is appropriate to apply full-cost financial assurance to low-producing wells because of heightened risk. It is also an opportune time because the price of decommissioning and financial assurance can be factored into the deal. An EDF analysis in 2022[98] found that 29% of producing wells in New Mexico could be categorized as facing "transfer risk" – that is, they appeared to have a negative net present value through 2050 based on forecasted production levels and operating expenses, though belonging to a relatively solvent operator. These factors increase a well's risk of being sold to an operator that may be able to continue production with lower operational costs than the

[97] *See e.g.*, Complaint at 2-6, McEvoy v. Diversified Energy Co., No. 5:22-cv-00171 (N.D.W. Va. July 8, 2022), https://climatecasechart.com/wp-content/uploads/case-documents/2022/20220708_docket-522-cv-00171_complaint.pdf.

[98] Orphan Zero: Plugging All Orphan Wells in a Timely Manner. Poster presentation for AGU Fall Meeting, December 12-16, 2022, Chicago, IL, https://agu.confex.com/agu/fm22/meetingapp.cgi/Paper/1121990

seller – but which is also implicitly less likely to be able or willing to cover all appropriate closure costs, given the expected negative future value of the asset. (An additional 6% of these wells were found to face "orphan risk" – those also having negative net present value, but operators already themselves at risk of insolvency.) This Paragraph (1) eliminates the risk of closure costs from these at-risk wells being shunted to the public, by requiring proof of ability to pay for closure before the transfer can occur.

Risk Type	Well Count	% of Wells	Operator Count	Average NPV (000's USD)
Low Risk	38,366	65%	434	$1,141.2
Transfer Risk	17,436	29%	319	-$35.1
Orphan Risk	3,525	6%	338	-$37.9
TOTAL	59,327	100%	737	$725.4

EDF, 2022

While Applicants propose that all marginal wells be subject to full-cost financial assurance, Applicants propose, in Paragraph (2) of 19.15.8.9.D NMAC, an implementation period of approximately two years, until January 1, 2028, for operators to adjust to the increased financial assurance requirements. Immediate application to marginal wells upon transfer and delayed implementation for all other marginal wells was part of the OCD's proposal, again adopted by Applicants. *See* Feb. 12, 2025 OCD Redline Proposals (Apps' Ex. 5). Requiring full-cost financial assurance for all marginal wells reflects the strong state interest in ensuring that low-profit wells have a privately-funded pathway to be plugged. Operators who believe in the long-term viability of these wells should be able to provide this financial assurance amount financed by the well's revenues. If a well is not producing enough revenue to pay for its own

plugging (or financial assurance to cover the eventuality of state plugging), it should probably not be operating given environmental, climate, and closure cost risks to the state, unless the operator is willing and able to subsidize its operational costs through other revenue sources. Alternatively, operators wishing to avoid single well financial assurance can work over or otherwise recomplete their wells to increase their production and take them out of marginal status. The delay in applicability gives operators time to increase production, transfer, or plug their marginal wells if they wish.

Paragraph (3) of 19.15.8.9.D NMAC aims to address the systemic risk posed by operators with a large proportion of their wells in marginal or inactive status or a combination of both. This proposal, initially proffered by OCD and adopted by Applicants, requires operators whose portfolio consists of more than 15% of their wells in marginal or inactive status or both, to provide full-cost financial assurance for all of their wells (not just those in marginal or inactive status). As illustrated in by the table, which is Applicants' Exhibit 66, such operators tend to have lower-than-average revenue to potential plugging liability ratios, and larger numbers of low- or non-producing wells that are likely to need to be plugged sooner. If these operators declare bankruptcy or are otherwise unable to meet their closure obligations, the sudden costs to the state may be very high.

Comparisons of operators by marginal and inactive well % group Based on activity categorization from GO-TECH production data; filtered to federal, state, and private lease type wells active for the entirety of 2024, except where noted otherwise.			
Marginal & Inactive Well % group	**All operators**	**< 15% marginal or inactive**	**>= 15% marginal or inactive**
Number of operators with state, private, and federal wells	420	160	260
% of total operators	100%	38%	62%
Number of operators with state and private wells	342	144	198
% of state and private well operators	100%	42%	58%
Total Wells (rounded to 10)	51270	36020	15250
Average wells / operator **	110	180	60
Total M/I wells **	7170	2200	4980
Average M/I wells / operator	15	11	18
Total revenues (2024), millions $	$21,040	$17,277	$3,763
Average revenues / operator, millions $	$44	$84	$14
Total revenues from marginal wells, thousands $	$22,825	$9,315	$13,511
Average revenues from marginal wells, thousands $	$49	$46	$51

Apps' Ex. 66

One recent example of this dynamic unfolded with Ridgeway Arizona Oil Corporation ("Ridgeway"), a Texas based subsidiary of a publicly traded, private equity-backed company,[99] that was unable to meet its plugging responsibility for *299 wells*, leading the state to take on $30 million in plugging liability.[100] In a settlement with the State of New Mexico, Ridgeway agreed to a $30,000 per month repayment plan, which would take more than 83 years to make the state whole if the operator is able to continue to meet its payment obligations for the next 1,000 months—far from a guaranteed outcome.[101] Per EDF's 2024 snapshot of projected bonding amounts and plugging liabilities, Ridgeway's percentage of marginal and inactive wells under

[99] *Land Owner Relations*, PEDEVCO, https://www.pedevco.com/land-owner-relations (last visited July 21, 2025); *see also About Us*, PEDEVCO, https://www.pedevco.com/about-us (last visited July 21, 2025).

[100] Jerry Redfern, *It's Settled: New Mexico to Bankroll Plugging of Oil Wells for Texas Company*, SourceNM (Dec. 22, 2023), https://sourcenm.com/2023/12/22/its-settled-new-mexico-to-bankroll-plugging-of-oil-wells-for-texas-company/.

[101] Adam Peltz & Meg Coleman, *New Mexico Can Protect Its Citizens by Closing an Orphan Well Loophole*, EDF (Feb. 6, 2024), https://blogs.edf.org/energyexchange/2024/02/06/new-mexico-can-protect-its-citizens-by-closing-an-orphan-well-loophole/.

Apps' Ex. 57

the proposed definitions was over 90%.

Another pertinent example is Diversified Energy Company PLC ("Diversified"),[102] an Alabama-based, publicly traded, private equity-backed firm that at least in 2021 was the largest operator of oil and gas wells in the country by well count, by a large margin.[103] Diversified recently acquired thousands of additional wells including many in the Permian; the Enverus PRISM database[104] reports their total well count at nearly 80,000, most of which are low- or non-producing.[105] Notably, Diversified is the most heavily shorted security on the London Stock Exchange, on the widespread belief that the company's business model is designed for near- to medium-term bankruptcy.[106] According to public filings, Diversified engages in share buybacks which benefit the shareholders but leaves the company vulnerable and unable to save the hundreds of millions of dollars[107] needed for properly plugging and remediating its well

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[102] Formerly known as Diversified Gas & Oil. *Diversified Gas & Oil PLC Announces New Corporate Name*, Diversified Energy (May 6, 2021), https://ir.div.energy/news-events/us-press-releases/detail/104/diversified-gas-oil-plc-announces-new-corporate-name.

[103] *See* Zachary R. Mider & Rachel Adams-Heard, *An Empire of Dying Wells*, Bloomberg (Oct. 12, 2021), https://www.bloomberg.com/features/diversified-energy-natural-gas-wells-methane-leaks-2021/; *E&C Democrats Demand Answers from Diversified Energy Over Concerning Environmental Liabilities That Could Results in Thousands of Orphaned, Methane-Leaking Oil & Gas Releases*, E&C Com. Comm. Democrats (Dec. 18, 2023), https://democrats-energycommerce.house.gov/media/press-releases/ec-democrats-demand-answers-diversified-energy-over-concerning-environmental.

[104] From Enverus PRISM database query for all wells operated by Diversified Energy or its rolled-up subsidiaries, as of August 4, 2025. https://www.enverus.com.

[105] Scott Waldman, *Manchin-Linked Company Could Reap Millions From Climate Law*, E&E News (Aug. 19, 2022), https://www.eenews.net/articles/manchin-linked-company-could-reap-millions-from-climate-law/.

[106] *Id. See also* Emma Powell, *Diversified Energy Puts Faith in U.S. Listing To Relights Its Fire*, The Times (Oct. 8, 2024), https://www.thetimes.com/business-money/energy/article/diversified-energy-puts-faith-in-us-listing-to-relight-its-fire-5bmj9q0d0.

[107] Ted Boettner, Kathy Hipple & Anthony Ingraffea, Ohio River Valley Inst., Diversified Energy: A Business Model Built to Fail Appalachia 27 (2022), https://ohiorivervalleyinstitute.org/wp-content/uploads/2022/04/Diversified-Energy-Report-FINAL-2-min.pdf.

population.[108] When Diversified's well population was closer to 70,000 last year, the company reported plugging an average of 190 wells a year.[109] At that rate it would take 368 years to plug all its wells – an unlikely proposition given that most of Diversified's wells are already at end of life.[110]

Diversified was the subject of at least one fraudulent transfer lawsuit in West Virginia, which has since been settled for pennies on the dollar.[111] That is, Diversified ended up paying for a fraction of alleged damages and escaped responsibility for cleaning up a vast majority of its wells in Appalachia.[112] Diversified is also the subject of an ongoing investigation from a U.S. House of Representatives subcommittee.[113] As Diversified began buying large swaths of low-producing wells in Appalachia in the mid-2010s,[114] regulators in the region were caught flat-

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[108] *See* William Lazonick et al., *Why Stock Buybacks Are Dangerous for the Economy*, Harv. Bus. Rev. (Jan. 7, 2020), https://hbr.org/2020/01/why-stock-buybacks-are-dangerous-for-the-economy; *Transaction in Own Shares*, Diversified Energy (Oct. 6, 2023), https://www.div.energy/2023/10/06/transaction-in-own-shares/.

[109] *See* Diversified Energy, 2023 Annual Report 19, https://d1io3yog0oux5.cloudfront.net/_058ef9e6bba9ffd1da1bf83cfd8d98a9/dgoc/db/604/5962/report/DEC+Annual+Report+and+Accounts+2023.pdf (average from 2021-2023 is 275/wells/yr including third party plugging or 190/wells/yr if only considering wells plugged by DGO).

[110] Ted Boettner, Kathy Hipple & Anthony Ingraffea, Ohio River Valley Inst., Diversified Energy: A Business Model Built to Fail Appalachia at 11.

[111] Complaint, McEvoy v. Diversified Energy Co., No. 5:22-cv-00171 (N.D.W. Va. July 8, 2022), https://climatecasechart.com/wp-content/uploads/case-documents/2022/20220708_docket-522-cv-00171_complaint.pdf.; *$6.5M Diversified Energy, EQT Well Plug Class Action Settlement*, Top Class Action (Feb. 16, 2025), https://topclassactions.com/lawsuit-settlements/closed-settlements/6-5m-diversified-energy-eqt-well-plug-class-action-settlement/.

[112] 3d Amended Complaint, McEvoy v. Diversified Energy Co., No. 5:22-cv-00171 (N.D.W. Va. July 8, 2022).

[113] *E&C Democrats Demand Answers from Diversified Energy Over Concerning Environmental Liabilities That Could Results in Thousands of Orphaned, Methane-Leaking Oil & Gas Releases*, E&C Com. Comm. Democrats (Dec. 18, 2023), https://democrats-energycommerce.house.gov/media/press-releases/ec-democrats-demand-answers-diversified-energy-over-concerning-environmental.

[114] *See* Ted Boettner, Kathy Hipple & Anthony Ingraffea, Oh. River. Valley Inst., Diversified Energy: A Business Model Built to Fail Appalachia.

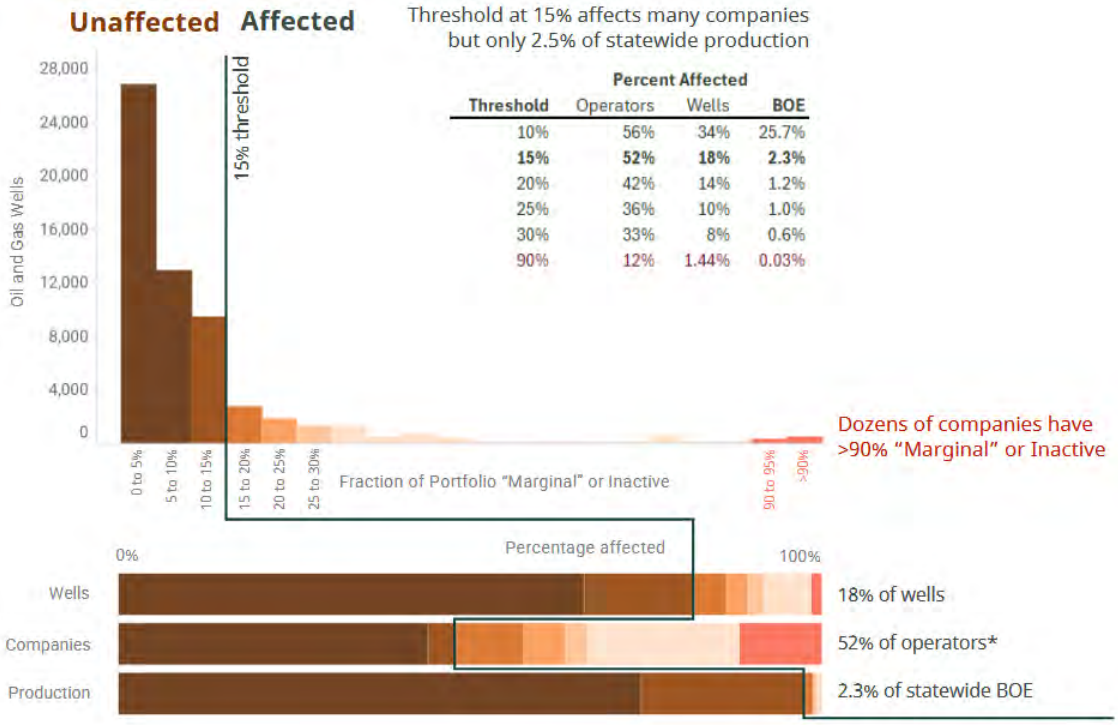
footed by their own minimal financial assurance and well transfer oversight requirements. Even in states where Diversified was acquiring tens of thousands of wells, states were only able to impose blanket bonds of $100,000-$250,000, plus additional bonds for wells out of compliance at the time of transfer – a tiny fraction of overall liability. In private conversations, Appalachian oil and gas regulators tell me the Diversified situation keeps them up at night. Paragraph (3), discussed below, is designed to guard against a Diversified scenario in New Mexico – rather timely as Diversified is actively buying wells in the state.

Paragraph (3) is patterned after a rule proposal by Utah's Division of Oil, Gas and Mining, which requires single well financial assurance for all of an operator's wells if more than 25% of their well population is idle or below 1 BOE per day, and reserves the lowest-cost "Tier" of blanket bonding for operators with less than 15% idle or below 1 BOE per day, with an additional minimum total production criterion for all of the operator's wells in the state.[115] The more stringent nature of the proposal in Paragraph (3) reflects OCD's understanding of New Mexico's landscape and operator dynamics, and is supported by assessing the characteristics of operators likely to fall above this threshold, as described below. This section creates an incentive for operators either to increase production or transfer or plug their low- and non-productive wells, all of which is in the public interest (as long as appropriate bonding is required upon transfer as well).

As illustrated by Mr. Purvis' analysis (Apps' Ex. 52 below), setting this operator threshold at 15% limits the impacts of this provision to fewer than 20% of the producing wells in

[115] See draft bond rule language and Supplemental Bonding Schedules document. Performance Bonds, Utah Admin. Code R649-13 (proposed rule), https://ogm.utah.gov/wp-content/uploads/2025/03/R649-13-Bonding-Draft.pdf; Utah Admin. Code R649-1 to -3, -8 (proposed changes), https://ogm.utah.gov/wp-content/uploads/2025/03/R649-1-2-3-8-Changes.pdf.

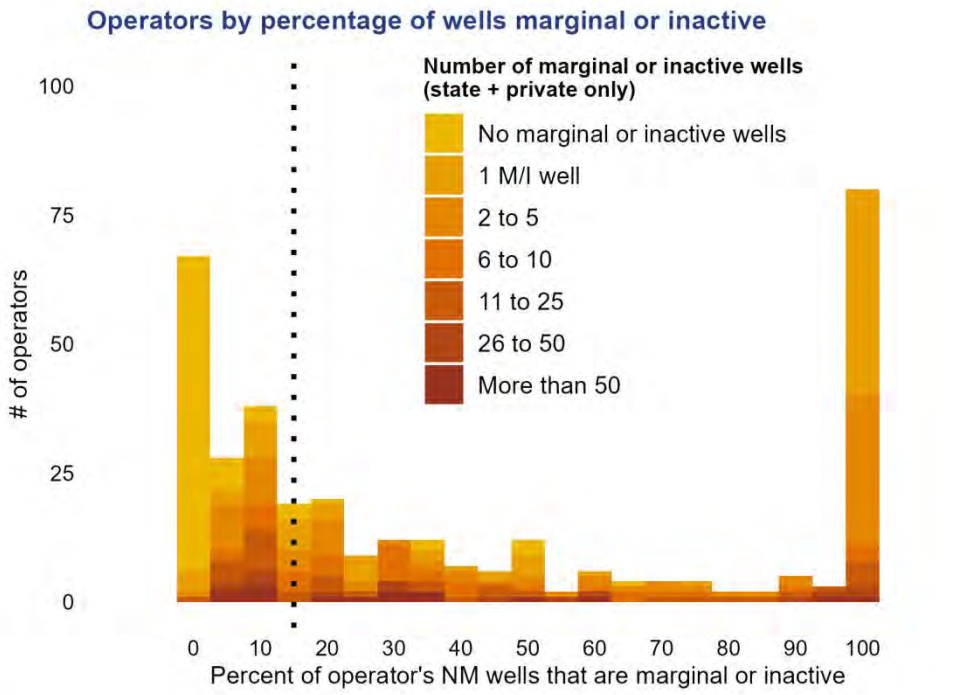
the state, associated with less than 2.5% of the state's annual production.



Apps' Ex. 52

Looking at the effect of this classification on an operator basis, around half of the operators in the state surpass this 15% threshold. A deeper look at the characteristics of the companies impacted by setting this provision to 15% reveals that many (though not all) of these companies are extremely small (operating 5 or fewer state and private wells), and in dozens of cases have only a single (marginal or inactive) well associated with them in 2024 OCD production records, suggesting their net revenues across New Mexico holdings to be very low. Applicants' Exhibit 67 below shows the distribution of operators by marginal/inactive well percent and also shades operators by absolute number of marginal and inactive wells. (Those operators with a low marginal/inactive percentage but a high absolute number of such wells are relatively large companies, while those with a high marginal/inactive percentage and a low number of marginal/inactive wells are relatively small.)

Apps' Ex. 57

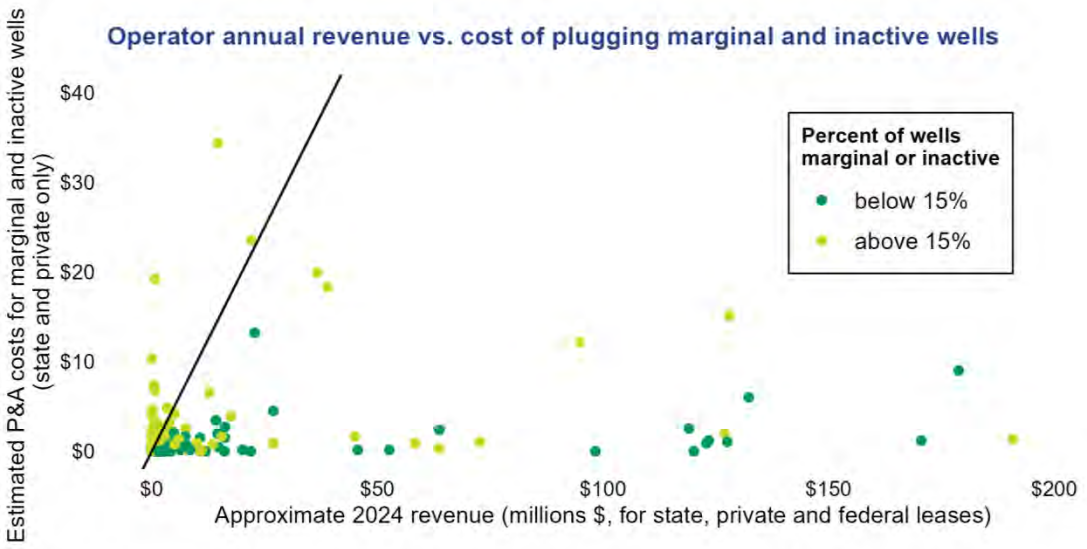


Histogram of operators included in bonding amount projections (Apps' Ex. 63), by percentage of federal, state, and private wells marginal or inactive.
Data excludes Active status wells with no production data available via UNM's GO-TECH County Production volumes.

Apps' Ex. 67

Meaningfully assessing the financial health and associated risk of operators is complex, and challenging to classify based on any single metric or regulatory threshold. However, average revenue levels can serve as a simple proxy to help contextualize an operator's likely ability to meet its expected plugging obligations. As part of analyzing expected bonding amounts and plugging liabilities for a 2024 snapshot, EDF estimated the total revenues generated in 2024 by each modeled company's state, private, and federal lease wells in New Mexico (as shown in the figure below, Applicants' Exhibit 68. These values were then compared to the expected cost for plugging their own (state and private) marginal or inactive wells, at $163,000 per well. While the 15% threshold does not perfectly split companies on this basis, only a third of the modeled

operators exceeding the proposed threshold can meet this criterion (of 2024 revenues exceeding estimated plugging liability for risky state and private well.) Meanwhile, nearly all (98%) of those operators with *fewer* than 15% marginal and inactive wells *can* meet the same criterion. This suggests that, as a group, the operators below the proposed 15% threshold are significantly more financially resilient relative to the potential financial risk they pose to the state.



Plot of firm-level plugging liability for operator's marginal and inactive wells (Y axis) versus estimated 2024 revenue, under existing rules (X axis).
A line is plotted at y=x; operators below the line generated more 2024 revenue than the expected cost of plugging and abandonment of their state and private marginal and inactive wells.
Companies with revenues above $250 million excluded for legibility of remaining data.

Apps' Ex. 68

Paragraph (4) of 19.15.8.9.D NMAC is designed for administrative efficiency: rather than requiring operators to obtain individual bonds for each well, it allows operators to roll up the costs of multiple single well bonds into a single blanket bond of the appropriate amount, which in addition to being easier to administer, is also less expensive. As operators reduce their necessary bond amount through production increases, transfers and plugging, so too will the bond premiums decrease.

19.15.8.9.E NMAC – Inactive Wells and Wells in Approved and Temporarily Abandoned Status

Q: Turning to Subsection E of 19.15.8.9 NMAC , changes are also proposed for "Inactive wells and wells in approved and temporarily abandoned status," what amendments do Applicants propose?

A: The proposed amendments shown in redline and strikeout:

19.15.8.9.E.~~D.~~ Inactive wells and wells in approved and expired temporarily abandoned status. An operator shall provide financial assurance for wells that are inactive and wells in approved and expired temporarily abandoned status, ~~covered by Subsection A of 19.15.8.9 NMAC that have been in temporarily abandoned status for more than two years,~~ or for which the operator is seeking approved temporary abandonment pursuant to 19.15.25.13 NMAC, in one of the following categories:

(1) a one well plugging financial assurance in the amount of $150,000 per well; ~~$25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells;~~ or

(2) a blanket plugging financial assurance equal to an average of $150,000 per well covering all wells of the operator subject to Subsection E~~D~~ of 19.15.8.9 NMAC.~~:~~

~~**(a)** $150,000 for one to five wells;~~

~~**(b)** $300,000 for six to 10 wells;~~

~~**(c)** $500,000 for 11 to 25 wells; and~~

~~**(d)** $1,000,000 for more than 25 wells.~~

Q: What is the purpose of these modifications?

A: The proposed changes address wells that are inactive and wells in approved and expired temporary abandonment status – wells that are inherently more at risk of becoming orphaned, and therefore need increased financial assurance to protect the State from assuming the cost to sufficiently plug and abandon these wells.

There are non-substantive amendments in Subsection E. In the first paragraph, the amendments ensure that the section is covering all non-productive wells, i.e., inactive, approved TA and expired TA wells. In Paragraph (1), the term "one well plugging financial assurance" is

used for consistency with terminology in the Oil and Gas Act and within 19.15.8 NMAC.

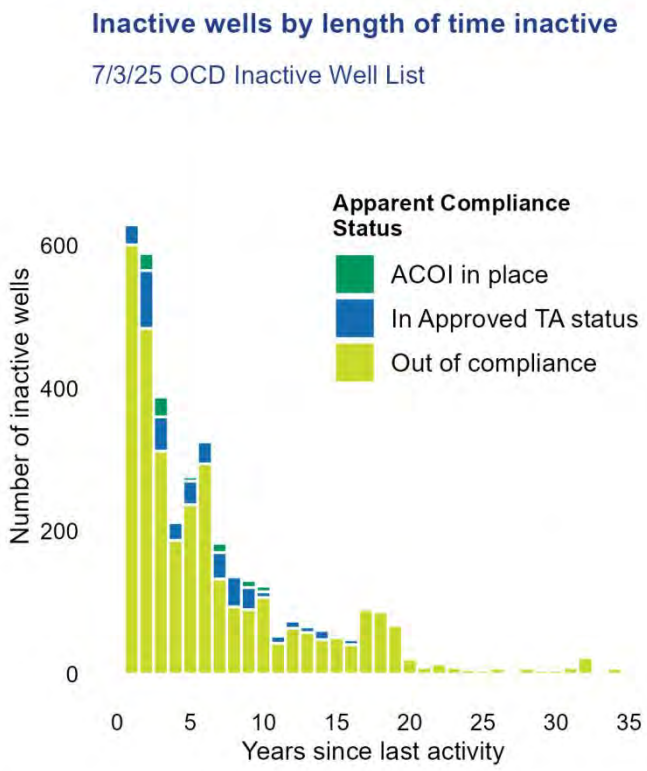
The substantive changes in Paragraphs (1) and (2) are in amounts of financial assurance coverage. As elsewhere in the Revised Application, single well financial assurance is set at approximating OCD's average cost of plugging for all wells at $150,000. A blanket financial assurance option is included for administrative and cost efficiency, as above.

Subsection D establishes "categories of financial assurance" as the Commission is authorized to do under the Oil and Gas Act. Under the act, the Commission "shall" establish by rule "a blanket plugging financial assurance for temporarily abandoned status wells" "at amounts greater than fifty thousand dollars ($50,000)."[116] And the Commission "shall require a one-well financial assurance on any well that has been held in a temporarily abandoned status for more than two years . . . ."[117] The legislature, by setting a floor, not a ceiling, on bonds for TA wells has recognized the increased risk to the State these wells represent. And, by requiring a one well financial assurance for wells that have been in TA status for more than two years, the legislature has recognized that the longer a well is in TA status, the greater the risk.

While the legislature has recognized the increased risks that come from wells in **approved** TA status, the vast majority of wells on OCD's Inactive Well List are either in **expired TA status,** or (in far more cases) are just **inactive** with no apparent formal status or other agreed compliance order. Wells in expired TA status or that are just inactive are out of

[116] NMSA 1978, § 70-2-14(A).

[117] *Id.* At the election of the operator, the Commission may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status. *Id.*



Apps' Ex. 10

compliance with the Commission's rules and therefore are inherently riskier than wells in approved TA status where operators have followed the rules of the road. As discussed by Applicants' expert, Tom Alexander, approximately 3,200 wells out of the approximately 3,700 wells on the Inactive Well List are out of compliance, totaling *86%* of the wells in inactive status. Ninety-nine percent of the 350 operators with a well on this list have at least one inactive well out of compliance[118]. The data is shown again in the figure above (Apps' Ex. 10), and the

[118] These wells are out of compliance with 19.15.25 NMAC requirements to plug and abandon (even though some of the responsible operators may not be out of compliance for purposes of the compliance determination in 19.15.5.9.A(4) NMAC).

table below, which is Applicants' Exhibit 7.

OCD INACTIVE WELL LIST (15+ months inactive)
Listed wells and apparent compliance status
7/3/25

Well Subset	No. of wells	% of total inactive wells	No. of associated operators	%
Total well count (from Inactive Well search output – appears to represent wells other than Plugged & Released, Cancelled, and Never Drilled statuses)	**74,582**	n/a	n/a	n/a
Total inactive wells (15+ months)	**3,765**	**100%**	**350**	**100%**
Total approved TA wells* on Inactive Well Search list	419	11%	89	25%
Total expired TA wells* on Inactive Well Search list	155	4%	67	19%
Total wells under ACOI** on Inactive Well Search list	99	3%	3	1%
Wells on Inactive Well Search list with unusual status (Drilled, New, or Plugged) - *excluded from total below*	13	< 0.5%	11	3%
Total inactive wells apparently out of compliance (without ACOI or non-expired TA status)* **	**3,234**	**86%**	**346**	**99%**

*The approved and expired TA status wells listed on OCD Inactive Well Search is only a subset of all wells labeled by OCD as having TA status, per OCD's Well History datafiles, and per a July 3rd search of OCD's Well Permitting Search for all TA wells.

** ACOI (Inactive Well Agreed Compliance Order) coverage was determined by the difference between wells included on 2 back-to-back queries of OCD's Inactive Well Search for wells 15+ months inactive— one set to include ACOI wells and one set to exclude them. Wells absent from the "Exclude ACOI" version of the list are presumed to have a compliance order in place.

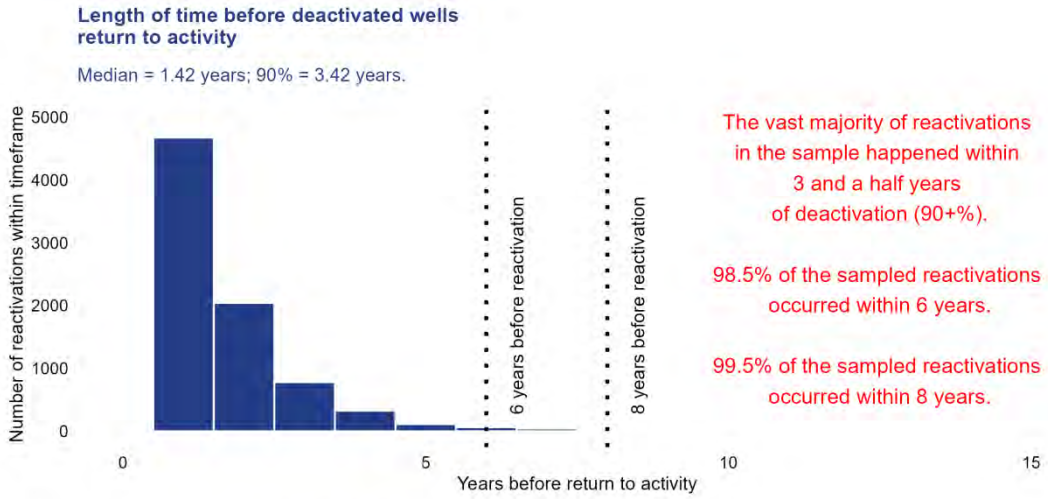
*** Some wells with an ACOI are also listed in expired TA status, so this total is slightly less than the sum of the preceding rows.

Apps' Ex. 7

It is these wells – wells in approved TA, expired TA, and inactive wells that have never gone into TA status – that by all measures are high risk and which should have full-cost financial assurance to protect the State. Requiring full-cost financial assurance for non-productive wells is increasingly common in major hydrocarbon-producing states. Wyoming generally requires full-cost financial assurance for idle wells.[119] North Dakota limits to seven the number of idle wells on blanket bonds.[120] The recently passed legislation in Texas, SB 1150, requires the TRRC to undertake rulemakings on idle wells generally and, in particular, on transfer, including considerations of financial assurance.[121]

[119] Wyo. Code R. § 055-0001.3 §4 (2020).
[120] N.D. Admin. Code 43-02-03-15(2) (2024).
[121] S.B. 1150, 89th Legis., 2025 Sess. (Tex. 2025).

Idled wells are at significantly increased risk for orphaning, since they do not produce any revenue at all. An EDF analysis of idled wells in New Mexico (*see* Applicants' Exhibit 13) found that most wells, if they are reactivated, the operators do so within 2 years, and after 5 years it is highly unlikely the well will produce again. The analysis found that for wells that were idled *and then later reactivated* between 2010 and 2024, over 90% reactivated within 3.5 years. Reactivations dropped off exponentially after only 2 years of inactivity.

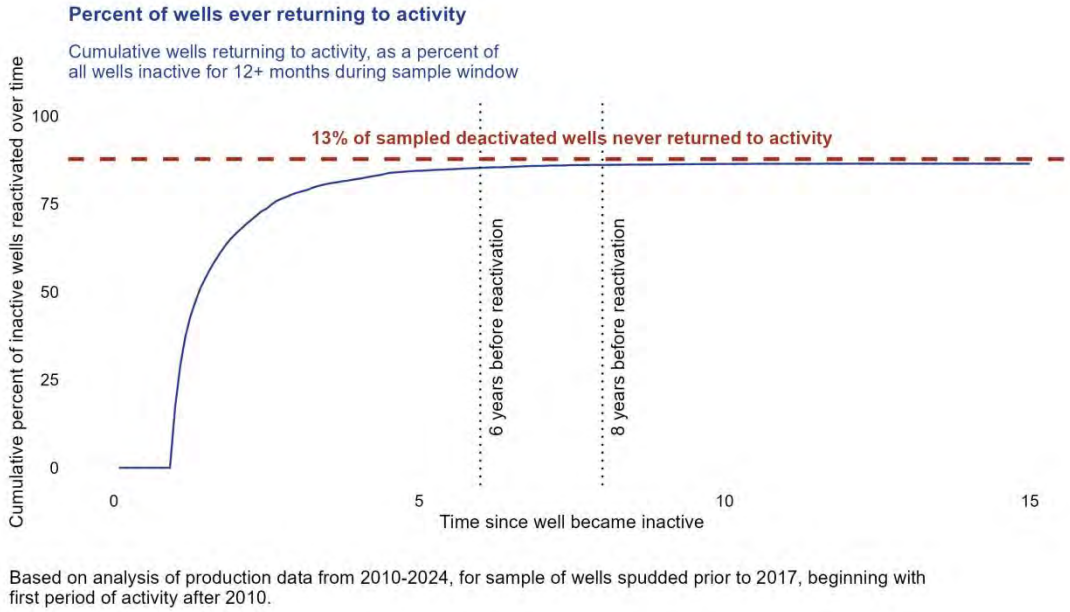


Histogram of length of time inactive prior to return to activity, across sample of wells that reactivated following 12+ months of no production.

Based on analysis of production data from 2010-2024, for wells spudded prior to 2017.

Apps' Ex. 13

Looking at all instances of wells becoming inactive for 12+ months after January 2010 (those spudded prior to 2017), 13% of the sampled wells *never* returned to activity. Of those that did reactivate, the vast majority did so within 3.5 years (90+%). Moreover, for purposes of Applicants' proposal requiring wells to be plugged after 8 eight years of inactivity, the analysis shows that functionally all of the wells that reactivated (99.5%) did so within 8 years of last activity.



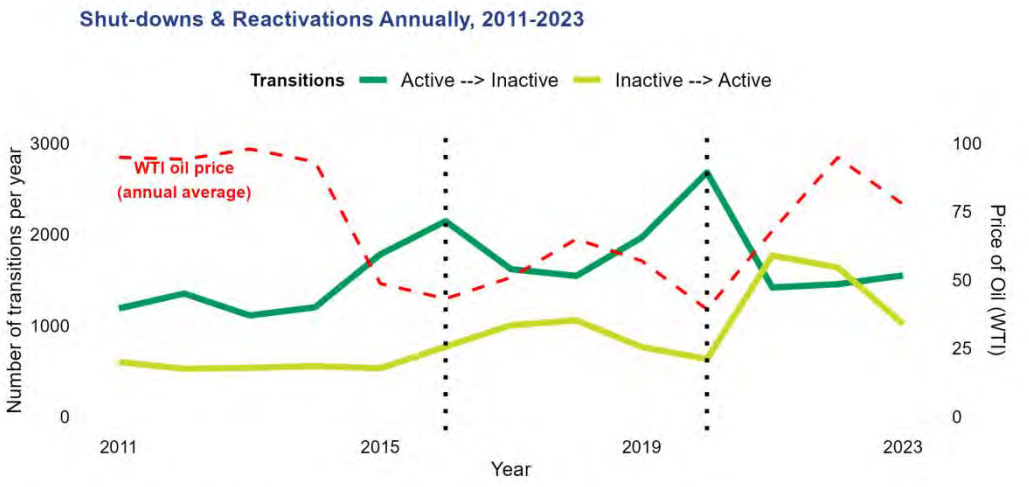
Apps' Ex. 13

The New Mexico analysis is consistent with previous EDF analysis in Texas[122] and Louisiana[123] that also found that after five years, the chance of an idle well ever returning to service is under 15%, and that post-idling production is usually only a tiny fraction of total lifetime production.

[122] Colin Leyden & Adam Peltz, *Don't Mess With Texas: Bill Begins to Tackle the Clean Up Challenge of Inactive Oil and Gas Wells*, EDF (May 29, 2025), https://blogs.edf.org/energyexchange/2025/05/29/texas-takes-a-step-forward-senate-bill-1150-begins-to-tackle-the-inactive-well-challenge/.

[123] Aaron Wolfe, Margaret Coleman, Maureen Lackner, Adam Peltz & Lauren Beatty, EDF, Louisiana's Inactive Wells: Steps Toward Improved Management (2024), http://dx.doi.org/10.2139/ssrn.5044308.

It is also worth noting that oil prices correlate with deactivations and reactivations of well production as tracked in this analysis. EDF also tracked transitions for all New Mexico oil and gas wells included in GO-TECH's County Production Volumes data (which is compiled from OCD production data), looking for all instances of wells becoming inactive for 12+ months, or returning to producing after such a 12+ month pause. *See* Apps' Ex. 69 below. When these transitions are plotted with West Texas Intermediate prices over time, price declines in 2016 (global oil supply glut, OPEC announcements, and geopolitics) and 2020 (COVID-related disruptions) correlate strongly with more wells transitioning to inactivity (green line).



Black lines drawn at 2016 (Shale bust) and 2020 (COVID-19). Increased numbers of deactivations are seen in the year of each event, with a smaller increase in reactivations lagging after (correlated to rising prices.)

Apps' Ex. 69

After each of these declines, as prices rose again, reactivations (yellow line) also increased – though fewer total wells reactivated after each price event than the number that deactivated by the low point of the price decline. Given that reduced prices represent a more significant impact for operators of low-producing wells with a higher expected ratio of costs to revenues, the wells that fail to reactivate after a sharp price decline are likely those low-

producing wells already at most risk of orphaning.

19.15.8.9.F & -G NMAC

Q: What are the proposed changes to Subsection F of 19.15.8.9 NMAC?

A: There are proposed changes under Subsection F concerning blanket plugging financial assurance.

The proposed amendments shown in redline and strikeout are:

> **19.15.8.9.F.** Operators who have on file with the division a blanket plugging financial assurance that does not cover additional wells shall file additional one ~~single~~ well plugging ~~bond~~ financial assurance for any wells not covered by the existing blanket plugging financial assurance ~~bond~~ in an amount as determined by Section 19.15.8.9 NMAC, subject to any limitations in Section 70-2-14 NMSA 1978. ~~or, in the alternative, may file a replacement blanket bond.~~

Q: What is the purpose of these modifications?

A: The terms "blanket plugging financial assurance" and "one well plugging financial assurance" are used for consistency with terminology in the Oil and Gas Act and within 19.15.8 NMAC. And the latter amendments recognize that financial assurance amounts in Commission rule must be consistent with any limitations in the Oil and Gas Act at Section 70-2-14.

19.15.9 NMAC—WELL OPERATOR PROVISIONS

Q: Mr. Peltz, Applicants propose changes to 19.15.9 NMAC—Well Operator Provisions—and specifically recommend additional requirements to 19.15.9.9 NMAC governing the "Change of Operator." What amendments to Applicants propose?

A: Applicants proposed the following amendments shown in redline:

> **19.15.9.9.B.** The operator of record with the division and the new operator shall apply for a change of operator by jointly filing a form C-145 using the division's web-based online application. If the operator of record with the division is unavailable, the new operator shall apply to the division for approval of change of operator without a joint application. The operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an officer, director, or partner of the new operator

that the new operator is in compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business; a plugging and abandonment plan; a disclosure of any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC; and a disclosure whether the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC. The new operator shall not commence operations until the division approves the application for change of operator. The plugging and abandonment plan shall be certified by an officer, director, or partner of the new operator and shall demonstrate that the new operator has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells to be transferred in light of all the operator's assets and liabilities. The division may request the operator to provide additional information including corporate credit rating, corporate financial statements, long-term liabilities, reserves and economics report, records of the operator's historical costs for decommissioning activities, estimate of the operator's decommissioning obligations, and history of inactive wells and returning wells to production.

Q: What is the purpose of these modifications?

A: Change of operator represents a critical juncture in the life of a well and a point where OCD oversight of well transfer is needed to mitigate risk to the State. The proposed certification and disclosure provisions ensure that OCD has relevant information on new operators to inform OCD approval or denial of well transfers. These additions include:

(1) information regarding compliance with 19.15.5.9 NMAC of the operator's officers, directors, partners and persons with an interest in the operator exceeding 25% for which the Commission has *already* authorized OCD to use to deny operator registrations in existing 19.15.9.8.B NMAC;
(2) additional information regarding operator compliance federal and state laws in which the operator does business, with the laws and regulations of that Applicants propose be included for purposes of both operator registration and well transfer; and
(3) a plugging and abandonment plan to ensure that the operator has and will have the financial ability to plug its wells consistent with Commission rules.

The information required is designed to create a parallel between new operator registration in 19.15.9.8 NMAC, which includes these same filings, and transferee registration. Commission

rules already authorize OCD to deny an operator registration based on current and past compliance with 19.15.5.9 NMAC by an operator's officers, directors, partners and persons with an interest in the operator exceeding 25%. The Commission has already identified such non-compliance as a risk factor relevant to operator approval in its existing regulations.[124] There is no reason why requirements for new operators and transferees should not be the same.

The new requirement that the operator certify compliance with federal law and state law in each state where the operator does business is intended to more thoroughly evaluate an operator's compliance across their operations. Regulators in other jurisdictions have recognized that operators who are non-compliant in one area or geography are more likely to be non-compliant in other matters in the future; for example, the LFC notes that regulators in Alberta include broader compliance history as among the factors for which a well transfer may be denied.[125]

Information on non-compliance is intended to help OCD assess risk. The requirement of disclosure of participation in non-compliant operations creates an incentive for compliance throughout the oil and gas industry, and helps to curb abuse by serial non-compliers from constantly starting new entities to escape non-compliance, an all-too-frequent fact patterns which I have heard anecdotally from state regulators across the country. It is worth noting that none of these factors are dispositive for transfer approval but they are factors for OCD to consider in

[124] *See* 19.15.9.8.B NMAC.

[125] The LFC's audit report notes of the Alberta Energy Regulator (AER): "Factors considered in determining whether the applicant poses an unreasonable risk and should be denied a license include the compliance history of all actors within the applicant's company (including its directors, officers, and shareholders in the province and elsewhere), compliance history of actors previously associated with the applicant, financial health of the applicant and associated entities, outstanding debts to AER or others, cancelation or reductions in insurance coverage, and any unspecified factor AER considers appropriate in the circumstances." *See* Apps' Ex. 4, p. 35.

evaluating whether a transfer is appropriate.

The plugging and abandonment plan submission requirement is designed to ensure that transferees are planning for the future plugging liabilities they will inevitably incur and have, in fact, planned. The plan is developed by the operator and OCD may seek additional relevant information from the operator. The operator's plugging and abandonment plan will help OCD make risk-based decisions about the adequacy of a transferee's ability to meet the Commission's plugging and abandonment requirements at 19.15.25 NMAC.

Q: Mr. Peltz, Subsection C of 19.15.9.9 NMAC authorizes OCD to deny a change of operator for specified reasons. What do Applicants propose?

The proposed amendments shown in redline and strikeout are:

> **C.** The director or the director's designee may deny a change of operator if:
>
> **(1)** the new operator is not in compliance with Subsection A of 19.15.5.9 NMAC; or
>
> ~~**(2)** the new operator is acquiring wells, facilities or sites subject to a compliance order requiring remediation or abatement of contamination, or compliance with 19.15.25.8 NMAC, and the new operator has not entered into an agreed compliance order setting a schedule for compliance with the existing order.~~[126]
>
> **(2)** the new operator is out of compliance with federal and state oil and gas laws and regulations in each state in which the new operator does business;
>
> **(3)** any officer, director, partner in the new operator or person with an interest in the new operator exceeding 25 percent, who is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;
>
> **(4)** the new operator is or was within the past five years an officer, director, partner, or person with an interest exceeding 25 percent in another entity that is not currently in compliance with Subsection A of 19.15.5.9 NMAC;
>
> **(5)** the applicant is a corporation, limited liability company, or limited partnership and is not registered or is not in good standing with the New

[126] Peter Morgan, one of Applicants' experts, offers testimony in support of this proposed deletion in his testimony (Apps' Ex. 14).

Mexico secretary of state to do business in New Mexico; or

(6) the certification or disclosure requirements set forth in Subsection B of this Section disclose a substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements of 19.15.25 NMAC for the well or wells the new operator intends to take over.

A: What is the purpose of these changes?

A: These new requirements include new criteria under which OCD may deny a change of operator. While the Commission has given OCD discretion to deny *operator registrations* based on operator risk factors, it has not given OCD the same discretion to deny *change of operator request*. A change of operator is not only analogous to an operator registration – because OCD is approving whether a new operator may operate a well – it is a point in time, as discussed, when the risk is heightened and requires additional scrutiny by state regulators. The amendments proposed do not require OCD to deny transfers under the circumstances listed but do authorize OCD to do so based on additional information from the operator. Proposed language sets forth a number of reasons that may rise to the level of a transfer denial corresponding to information submitted as part of a transfer request in proposed 19.15.9.9.B NMAC. Non-compliance with state and federal law, either directly or through other businesses, and substantial risk of inability to comply with closure requirements are all good potential reasons for denying a transfer.

19.15.25 NMAC—PLUGGING AND ABANDONMENT OF WELLS

Q: Mr. Peltz, Applicants propose changes to 19.15.25 NMAC—Plugging and Abandonment of Wells. The first change is to 19.15.25.8.B NMAC and proposes language regarding an application to OCD prior to placing a well in "Approved Temporary Abandonment" status. What is the purpose of this modification?

A: The proposed amendments shown in redline and strikeout:

19.15.25.8.B. The operator shall either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment in

accordance with 19.15.25 NMAC within ~~90~~ 30 days after:

(1) a 60 day period following suspension of drilling operations; or

(2) a determination that a well is no longer usable for beneficial purposes; or

(3) a period of one year in which a well has been ~~continuously~~ inactive.

Q: What is the basis for these amendments?

A: Wells cannot be placed in temporary abandonment status without approval of OCD, and the addition of "apply to the division to" makes that clear.

Applicants propose to shorten the length of time between when one of the plug-or-temporarily-abandon conditions is met, from 90 to 30 days because the well has already been inactive for 12 months, and the operator has had sufficient time to develop a plan for the well's future. The additional 60 days is not necessary.

The deletion of "continuously" from Paragraph (3) is designed to address those operators who "game the system" to avoid plugging or the well being placed into TA status by producing a de minimis amount of hydrocarbons once a year, which is contrary to good public policy because it obscures the true financial risk these wells pose to the public. This change is also consistent with Applicants' proposal in the next section – 19.15.25.9 NMAC – Presumptions of Beneficial Use – which assesses whether low producing wells operating less than 90 days per year have beneficial use.

Q: Speaking of that new section establishing presumptions of no beneficial use, what do Applicants propose?

A: Applicants' proposed amendments shown in redline:

19.15.25.9. PRESUMPTIONS OF NO BENEFICIAL USE:

A. For oil and gas production wells, there is a rebuttal presumption that a well is not capable of beneficial use if, in a consecutive 12 month period, the well has not produced for at least 90 days and has not produced at least 90 barrels of oil equivalent.

B. For injection or salt water disposal wells, there is a rebuttal presumption that a well is not capable of beneficial use if, in a consecutive 12

month period, the well has not injected at least 90 days and at least 100 barrels of fluid.

C. The rebuttal presumptions in this Section do not apply to wells that have been drilled but not completed for less than 18 months and wells that have been completed but have not produced for less than 18 months.

D. Within 30 calendar days after notice of a preliminary determination from the division that a well or wells are not being used for beneficial purposes, a well operator may submit an application for administrative review of such determination through the division's electronic permitting portal. The division shall issue a final determination based on the application and information available in division records. The final determination may be appealed pursuant to 19.15.4 NMAC. Applications to demonstrate beneficial use of a well or wells shall include:

(1) Documentation demonstrating that the well is reasonably projected to produce in paying quantities; and

(2) Documentation demonstrating that the operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all reasonably anticipated plugging and environmental liabilities of the well or wells and associated production facilities, not inclusive of any financial assurance associated with the well or wells; and

(3) Other relevant information requested by the division including a plugging and abandonment plan as described in 19.15.9.9.B NMAC.

Q: What is the purpose of this proposal?

A: Establishing presumptions of no beneficial use was initially proposed by OCD in its February 12, 2025 Redline Proposals (Apps' Ex. 5) and has been adopted by Applicants. The purpose of this proposal is to establish a class of nominally active wells whose activity levels are presumptively not economically viable and thus must be plugged. This is designed to facilitate early identification of wells posing a risk of becoming orphaned, and begin the process of ensuring that their decommissioning is paid for by the operator rather than through public funds. The threshold of 90 barrels and 90 days of production (or 100 barrels of injection) was selected as a tipping point where the social benefit of these wells continuing to produce outweighs the social risk that they will become public burdens. This proposal is established as a rebuttable presumption because of the potential fact patterns that mitigate against the risk of orphaning – operators ought to be able to make a showing that, despite their minimal production or injection,

there is good reason to keep these wells online.

"Beneficial use" or "beneficial purpose" are common industry terms. The terms are used in the Commission's rules but have never been defined. Applicants propose a definition at 19.15.2.7.B(7) NMAC to mean "an oil or gas well that is being used in a productive or beneficial manner such as production, injection or monitoring, and does not include use of a well for speculative purposes." A well has beneficial use if it remains viable for its intended purpose or is repurposed for some productive use.

The presumptions of no beneficial use are rebuttable and can be rebutted by operators with evidence that the well has beneficial use. This section is intended to identify production and injection wells that while technically "active" are producing or injecting so infrequently and at such low levels that they are not viable wells and are being kept in active status to avoid the immediate cost of plugging and remediation.

Subsection A applies to oil and gas production wells and provides that those wells that have been active for at least one quarter of the year and have produced at least 90 BOE during a year (or 0.25 BOE per day) have beneficial use. As of July 2025 this represents gross revenue of less than $6,000 for oil wells, or less than $2,000 for gas wells[127] – given that recent New Mexico oil prices fall squarely within the ranges of necessary breakeven prices reported for the Permian and other basins by respondents to the Q1 2025 Dallas Fed Energy Survey[128], wells

[127] As above, based on July 1, 2025 prices for NYMEX LS ($65.50/bbl, * 90 = $5,895) for oil, and Henry Hub ($3.43/MMbtu; * 1.038 mcf/MMbtu [EIA conversion factor from https://www.eia.gov/tools/faqs/faq.php?id=45&t=8] * 6 mcf/boe (conversion factor from NM statute) = $21.36/BOE; X 90 BOE = $1922.)

[128] Values reported by producers for Permian basin (Delaware, Midland, and Other) for breakeven prices range from $4.25 to $80. *See Dallas Fed Energy Survey First Quarter: Special Questions*, Fed. Rsrv. Bank of Dallas (Mar. 26, 2025), https://www.dallasfed.org/research/surveys/des/2025/2501#tab-questions.

producing less than 90 BOE are likely to producing below paying quantities, especially if appropriate holdback amounts to ensure coverage of future plugging and site remediation liability are fully taken into account. The threshold for this presumption is very conservative, and the process for rebutting a presumption of no beneficial use provides an opportunity for an exception to be granted for operators whose circumstances are more secure.

Subsection B applies to injection wells and saltwater disposal wells (commonly referred to as Class II wells), and provides that those wells that have injected for at least one quarter of the year and injected at least 100 barrels of fluid have beneficial use. Most Class II wells inject orders of magnitude more than this[129], and it is difficult to imagine injection volumes below 100 barrels per year for any reason other than to avoid plugging liability. Again, this threshold is very conservative.

Subsection C exempts new wells from the rebuttable presumption, giving them an opportunity to begin producing.

Subsection D sets forth the procedure for operators to rebut a preliminary finding from OCD that a well presumptively has no beneficial use. Key here is that the operator has full opportunity to rebut with relevant information and is afforded an appeal process through 19.15.4 NMAC if the operator disagrees with OCD's final determination.

An operator must demonstrate that the well is reasonably projected to produce in paying quantities. "Paying quantities" can generally be understood to mean that the well is turning a profit. In other words, that revenue from production exceeds the costs to operate the well. It is

[129] Average activity (oil, gas, water, and CO2, in barrels or BOE) reported across active wells labeled by OCD as injection (I), saltwater disposal (S), CO2 injection (C), or water (W) well types for the 2024 bonding snapshot (Apps' Exs. 63-64) was around 25,000 BOE for the year. Averages across further breakouts of these 5 well types ranged from 3- to 7-digit values.

my understanding that this is how OCD generally understands this phrase. Additionally, operators must show they can afford to stay in business and deal with potential problems that may arise during the life of the well, as well as the resources to properly plug and abandon the well and conduct site remediation when it is time to do so. All information required is relevant to determine whether the well in fact has beneficial use or whether the well does not, in which case it should be properly plugged and abandoned.

Q: Mr. Peltz, Applicants propose amendments to 19.15.25.13.A NMAC regarding wells in "approved temporary abandonment" status. What do Applicants propose?.

A: Applicants' proposed amendments are shown in redline:

> **19.15.25.13.A.** The division may place a well in approved temporary abandonment for a period of up to five years upon a demonstration from the operator that the well will be used for beneficial use within the approved period of temporary abandonment. The operator's demonstration shall include an explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future including supporting technical and economic data, a plan that describes the ultimate disposition of the well, the time frame for that disposition, and any other information the division determines appropriate, including a current and complete well bore diagram; geological evidence; geophysical data; well casing information; waste removal and disposition; production engineering; geophysical logs, e.g., cement bond logs, caliper logs, and casing inspection logs; and health, safety, and environmental information. If the division denies a request, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

Q: What is the purpose of these amendments?

A: This amendment requires that, for a well to be placed in approved temporary abandonment status, the operator must demonstrate that the well will be returned to beneficial use within the period of temporary abandonment. If the well has no future beneficial use, it should be plugged and abandoned.

Under the current rules, operators do not need to make any showing justifying why they

want to put their wells into TA status. That status is intended to postpone plugging liability for inactive wells until market conditions improve, the well is worked over, or some other factors will make that well economically viable in the future despite lack of production for over a year. The intention of Applicants' proposal is to require a showing along these lines to justify the risk the State is taking in allowing the well to stay open. This risk includes not only the financial burden of plugging and remediating the well, but potential air, water, and land contamination during the pendency of the TA status (hence the requirement for detailed well integrity data), as well as considerations about ultimate resource recovery from the tract and whether the well is being used to hold the lease and is stymying development of other formations in the area. The information collected in this process will help OCD plan for well plugging and remediation in case the operator orphans the well during the TA duration.

Q: Mr. Peltz, Applicants also proposed changes to 19.15.25.13.B NMAC concerning conditions for extending a well's temporary abandonment status. What are the proposed changes and the purpose of these amendments?

A: The proposed amendments are shown in redline and strikeout:

> **19.15.25.13.B.** Prior to the expiration of an approved temporary abandonment, the operator shall return the well to beneficial use under a plan the division approves, permanently plug and abandon the well and restore and remediate the location, or apply ~~for a new approval to temporarily abandon the well~~ to the division to extend temporary abandonment status pursuant to the procedures for adjudicatory proceedings in 19.15.4 NMAC. In any such adjudicatory proceeding, any interested person may intervene pursuant to 19.15.4.11 NMAC. To continue in temporary abandonment, the operator must demonstrate to the division that the well will be returned to beneficial use within the requested period of temporary abandonment. The request shall include an explanation why the well should be placed in temporary abandonment, how the well will be put to beneficial use in the future and supporting technical and economic data, a plan that describes the ultimate disposition of the well, the time frame for that disposition, and a health and safety plan demonstrating the well's casing and cementing meet the requirements of Subsections B and C of Section 19.15.25.13 NMAC and the operator has adequate monitoring procedures in place

to ensure such requirements will be met. The division shall approve, approve with conditions, or deny a request to extend the temporary abandonment. Such conditions may include conditions to protect human health and the environment. An extended term shall not exceed two additional years, upon which time the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

The proposed additional language requires a demonstration from the operator of its plan to return the well to future beneficial use. Currently, New Mexico has no time limitation on how long a well can remain in TA status, only that an application be renewed every five years. Wells that are not renewed move into expired TA status. New Mexico currently has over 800 wells[130] reported by OCD as being in approved or expired TA status; based on earliest reported date of TA status, nearly 30% of those wells have been in TA status for over five years as of July 3, and some evidently for decades. *See* Apps' Ex. 70 below.

OCD WELL PERMITTING STATUS SEARCH
All Temporary Abandonment status wells,
by time since initial entry into TA status
7/3/25

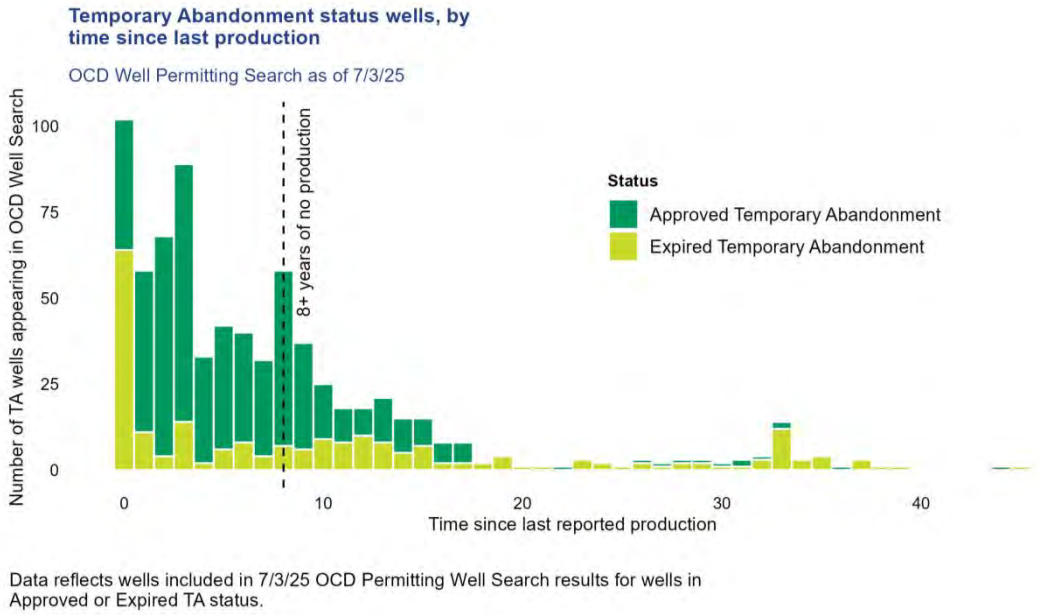
	No. of Wells	%
All Wells in any TA status, (7/3/25)	805	100%
5+ years in TA status	226	28%
8+ years in TA status	111	14%
10+ years in TA status	65	8%
15+ years in TA status	29	4%

Source: EDF analysis of wells listed by OCD as approved or expired TA; times are from first known TA date to 7/3/25

Apps' Ex. 70

[130] This data from Applicants' Exhibit 70 on TA wells is from OCD's well permitting search data. The data on TA wells from Applicants' Exhibit 7 is from OCD's Inactive Well List (filtered for wells inactive 15+ months). These data differ, as not all wells listed as having TA status are included in OCD's 15+ month Inactive List search results. Around half of the wells missing from the 15-months Inactive list were placed in TA status within the past 15 months; a portion of the remaining wells have reported production since their reported date of entering TA status, and could be erroneously classified in the database. For these analyses, OCD data was taken at face value unless otherwise noted.

Moreover, as illustrated in Applicants' Exhibits 71 and 72, nearly half of TA wells have been inactive for more than 5 years, and some have been inactive upward of 30 years.



Apps' Ex. 71

While long-term inactive TA wells are by definition technically not orphaned (because an operator of record still exists), there is little chance that such wells will ever be returned to beneficial use; as discussed previously above and shown in Apps' Ex. 13 most wells that return to activity do so within 3.5 years. This current structure of allowing indefinite TA time essentially operates an undefined subsidy from the State to the oil and gas industry, whereby operators are allowed to keep wells indefinitely open and avoid the costs to permanently plug and abandon those wells – all while creating significant additional risk that the State and taxpayers will ultimately bear those costs.

OCD WELL PERMITTING STATUS SEARCH All Temporary Abandonment status wells, by time since last production 7/3/25		
	No. of Wells	%
All Wells in any TA status, (7/3/25)	805	100%
2+ years since last prod.	569	71%
5+ years since last prod.	388	48%
8+ years since last prod.	267	33%
15+ years since last prod.	86	11%

Apps' Ex. 72

The impact of the proposed changes is to put an outside limit of eight years for wells to remain inactive. For the first thirteen months of inactivity, operators would not be required to make any special showing. Then, for five more years of inactivity, operators must provide a plausible and legitimate reason, backed by evidence, to enter TA status, as described in Subsection A of 19.15.25.13 NMAC.

Subsection B of 19.15.25.13 NMAC allows operators to request an extension of TA status for up to two additional years, upon satisfactory explanation for the extension, a showing that the well will not cause health, safety or environmental problems during the pendency of the extension, and a plan for decommissioning. As previously discussed, EDF analysis of well deactivations and reactivations between 2010 and 2024 suggests that *99.5%* of wells that are deactivated will reactivate in less than 8 years, if they are going to reactivate at all – and over 90% will do so within far less time (3.5 years of the start of inactivity.) *See* Apps' Ex. 13. Thus, for the vast majority of wells in most circumstances, it is difficult to understand, based on New Mexico data, why keeping a well inactive for more than eight years is reasonable or necessary. A well is either going to be useful in that period, or it is almost certainly not going to be useful at all.

Q: Mr. Peltz, Applicants propose additional language under 19.15.25.13.D NMAC regarding an "implementation schedule for existing wells." What do Applicants propose?

A: The proposed amendments are shown in redline:

19.15.25.13.D. Implementation schedule for existing wells.

(1) Inactive wells. Wells that have been inactive for less than three years are eligible for temporary abandonment status. Wells that have been inactive for three or more years are not eligible for temporary abandonment status.

(2) Wells in approved temporary abandoned status. Any operator of a well in temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status in accordance with Subsection B of this Section prior to the date temporary abandonment status terminates. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

(3) Wells in expired temporary abandoned status. Any operator of a well in expired temporary abandoned status as of [effective date of amendments] shall apply to the division to extend temporary abandonment status in accordance with Subsection B of this Section. Unless an operator of a well has renewed a temporary abandonment in accordance with this Paragraph, the operator shall return the well to beneficial use under a plan the division approves or permanently plug and abandon the well and restore and remediate the location.

Q: What is the purpose of these amendments?

A: The purpose is to ensure a comprehensive and consistent regulatory approach across new and existing wells, an implementation schedule is needed. The implementation schedule was proposed by OCD and is adopted by Applicants. Paragraph (1) addresses inactive wells out of compliance with current requirements to enter TA status. Wells up to three years out of compliance would have a pathway to enter TA status under this provision. Wells more than three years out of compliance would need to be returned to service or plugged. OCD staff recommended the three year time cutoff based on their experience.

Paragraph (2) addresses wells already in approved TA status. When these wells reach the end of their five year TA period, they can be returned to service or plugged, or the operator can

request two more years of TA status in accordance with 19.15.25.13.B NMAC.

Paragraph (3) allows for wells with expired TA status to re-enter compliance upon application, though for a maximum of two years before either returning to service of plugging. This is a generous proposal for wells that are out of compliance and may have been out of compliance for many years.

Q: Finally, Mr. Peltz, what amendments do Applicants propose to 19.15.25.14 NMAC?

A: The proposed amendments shown in redline:

> **19.15.25.14.B.** The division shall not approve a permit for approved temporary abandonment until the operator furnishes evidence demonstrating that the well's casing and cementing are mechanically and physically sound and in such condition as to prevent:
> **(1)** damage to the producing zone;
> **(2)** noncontainment of well bore fluids to the atmosphere or migration of hydrocarbons or water;
> **(3)** the contamination of fresh water or other natural resources; and
> **(4)** the leakage of a substance at the surface.

Q: What is the purpose of this amendment?

A: This provision adds a requirement to the showing an operator must make when it places a well in TA status to ensure that the well is not releasing methane or other constituents to the atmosphere. This provision prevents waste and protects human health and the environment. Generally, proper isolation of flow zones and the corrosive zones in the geology should prevent fluid migration of any kind outside of their intended zones.

Q: Mr. Peltz, does this conclude your testimony?

A: Yes.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Adam Peltz — August 7, 2025
Name — Date

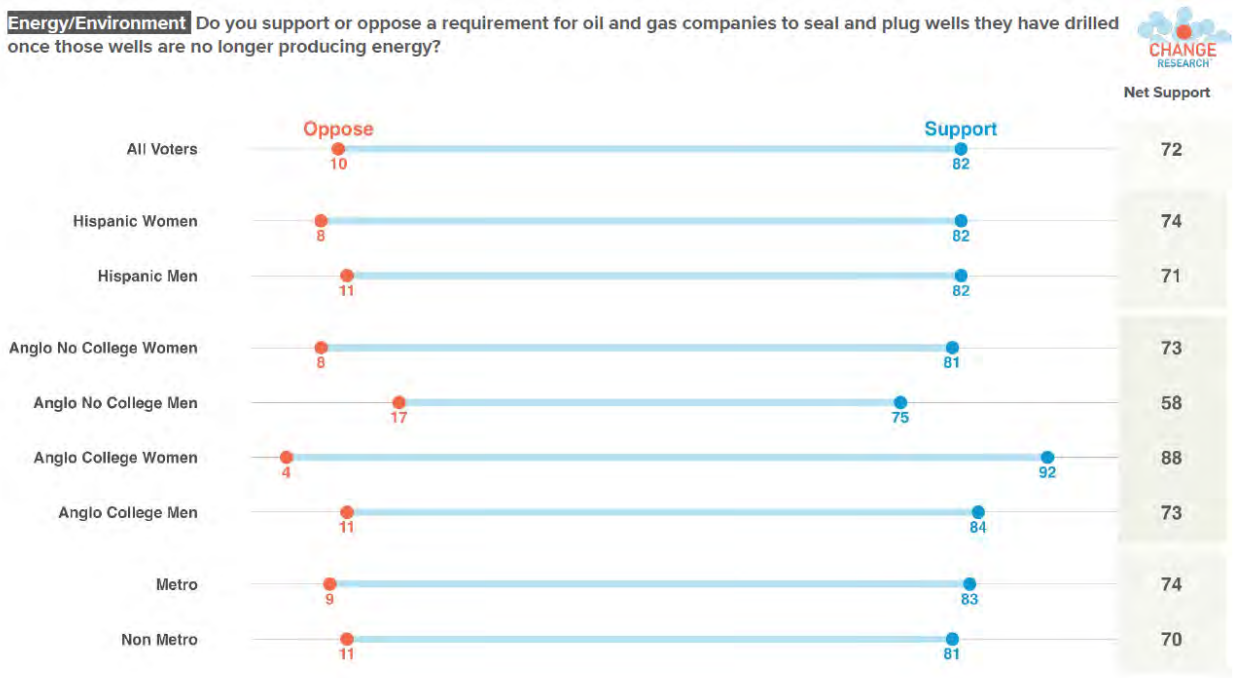
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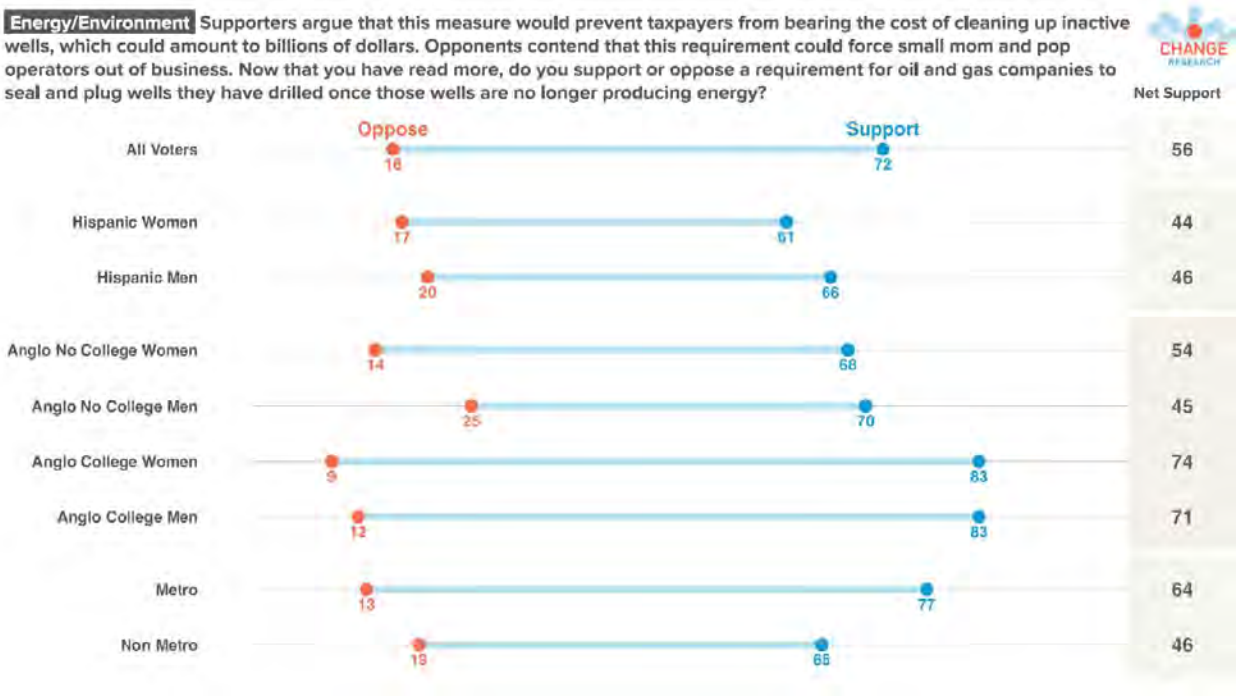
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EXHIBIT 58

Exhibit 58: Selected excerpts from Change Research polling results
(from 2025 New Mexico Landscape: Energy & Climate, Nov. 22 – Dec. 5, 2024)



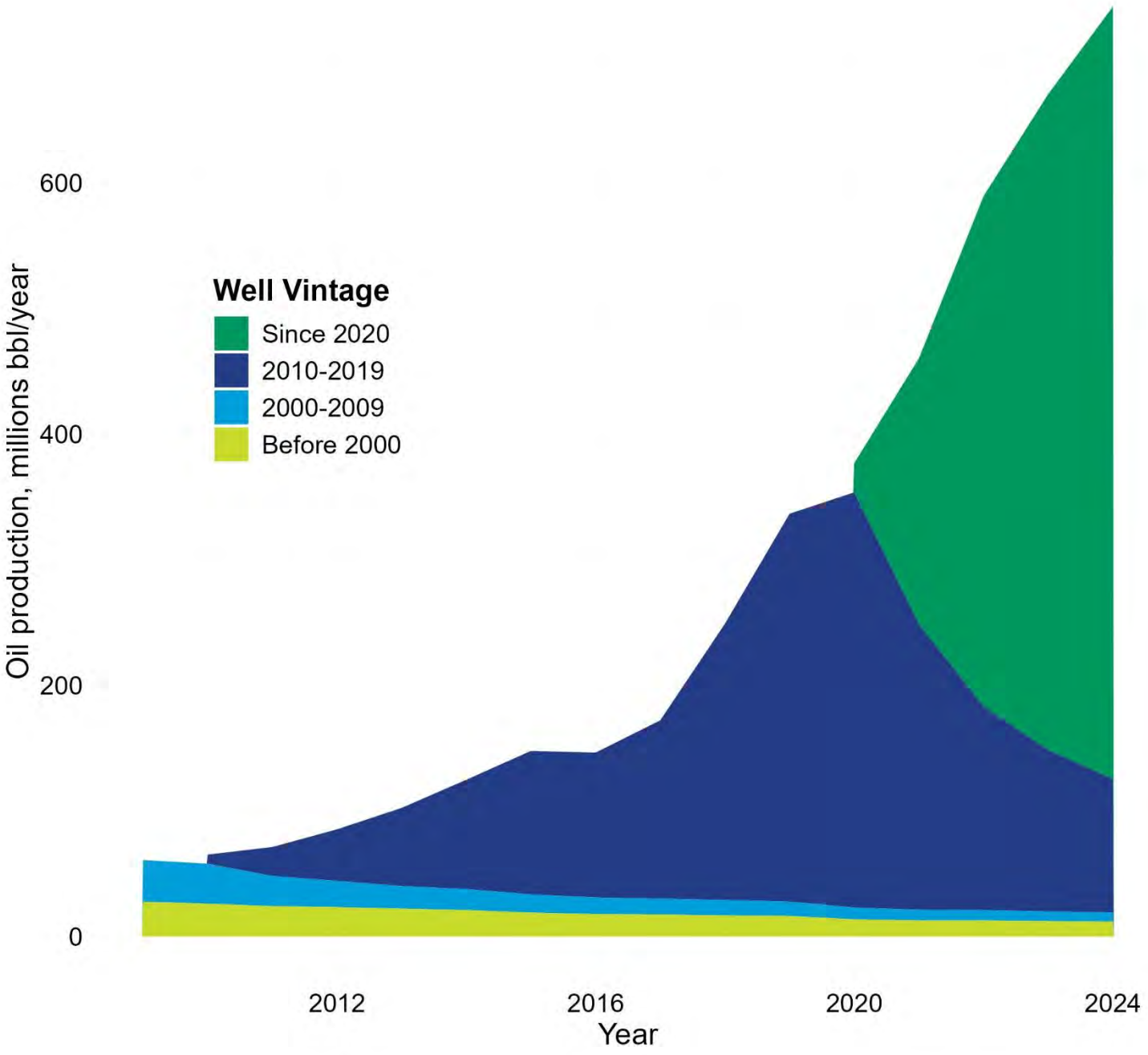


Apps' Ex. 58

EXHIBIT 59

New Mexico oil production, 2010-2024

Shaded by vintage of producing wells



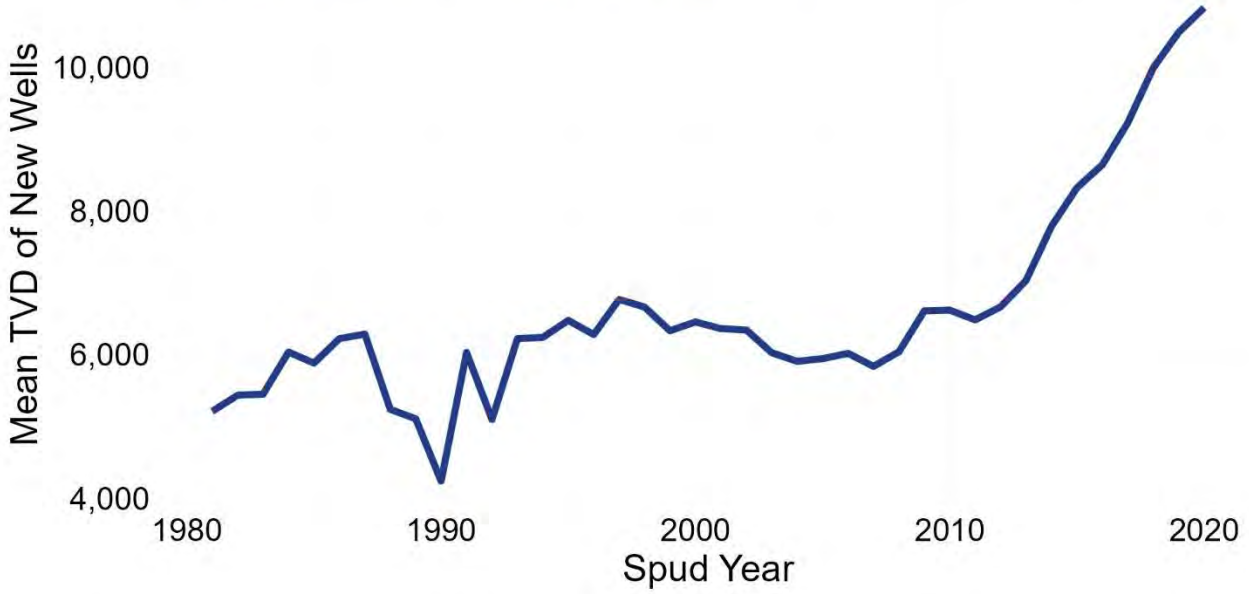
Production as reported from GO-TECH annual County Production Volume downloads, 2010-2024, all counties.
Vintages derived from SpudDates reported in OCD Well History dataset, current as of 7/11/25.

Apps' Ex. 59

EXHIBIT 60

Average depth of new wells drilled, 1980 - 2020

Reported True Vertical Depth (TVD)



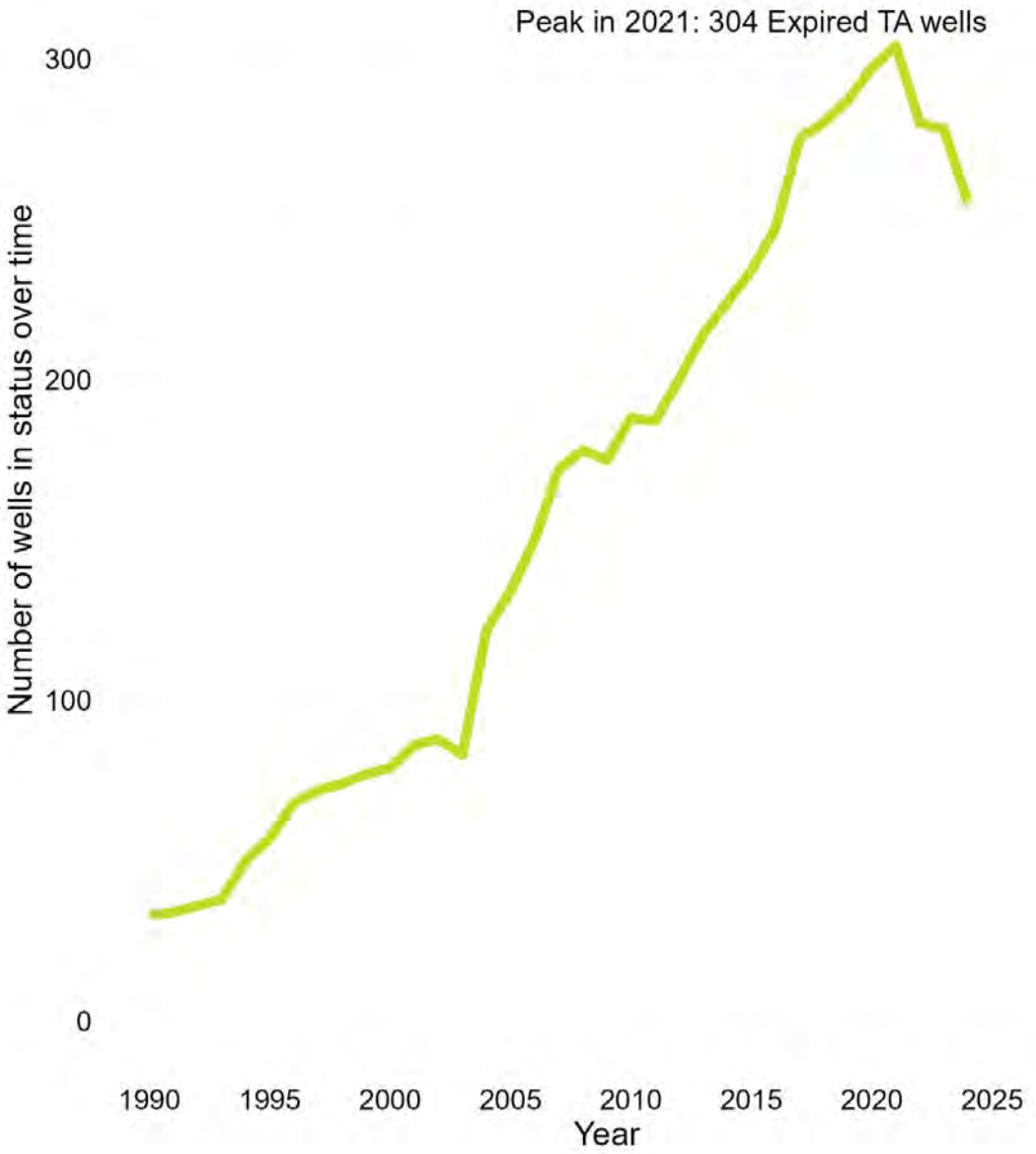
Data reflect well depths and spudding dates available in OCD Well History dataset as of July 11, 2025.
A small number of extreme depths that appear to be decimal mistakes or other errors
(e.g., 80,000+ ft) have been removed and replaced with averages.

Apps' Ex. 60

EXHIBIT 61

Wells in Expired TA status over time

OCD Well History dataset, 1990 - 2024

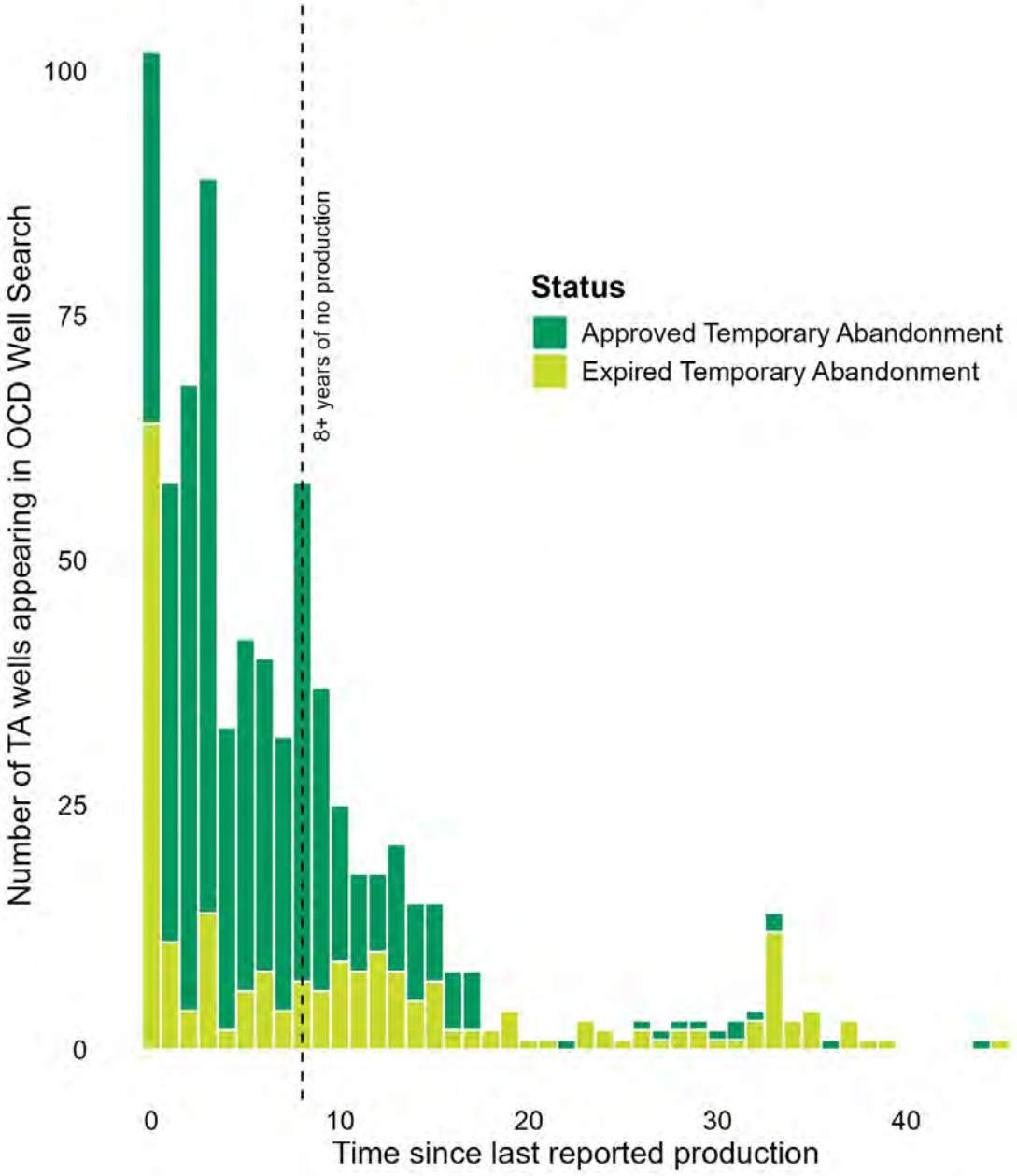


Wells reported in Expired TA status by OCD Well History dataset, current as of 7/11/25.

EXHIBIT 62

Temporary Abandonment status wells, by time since last production

OCD Well Permitting Search as of 7/3/25



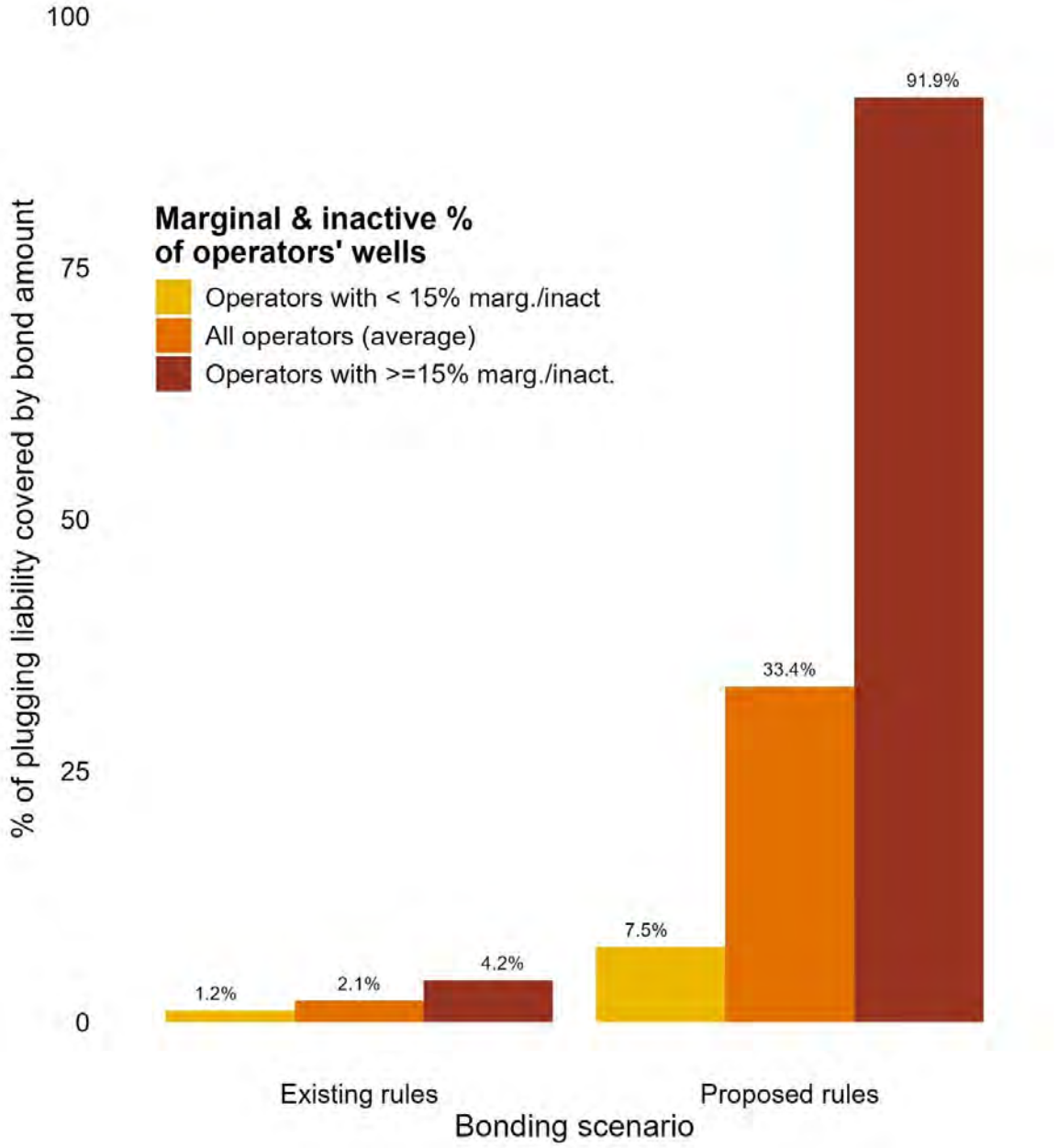
Data reflects wells included in 7/3/25 OCD Permitting Well Search results for wells in Approved or Expired TA status.

Apps' Ex. 62

EXHIBIT 63

Projected bonding amount, by marginal/ inactive well % groups

Estimated bonding required as a percent of each group's total potential P&A cost liability at $163k per well, compared under existing and proposed rules



Estimated bonding amounts required under existing and proposed rules

Using a snapshot of 2024 production and status data, EDF estimated the total bonding amounts required for all NM operators with state and private lease wells, under both existing rules and the applicants' proposed rules.

Step 1: Well categorization and filtering
Wells were first categorized according to the activity categories included in the proposal, then filtered as described below.

Data sources:

Monthly production data by well, 2010 - 2024

- Source: Annual county production volumes from UNM GO-TECH platform
- Contents: monthly reporting of oil, gas, water, & CO2 volumes (bbl or mcf); producing days per month
- Last updated July 1, 2025

OCD wellhistory data

- Source: bulk download from OCD's FTP server, .xml conversion in Excel
- Contents: status and operator changes by well, ~1900 - 2025
- Last updated July 11, 2025

Additional well descriptive data from OCD

- Source: EMNRD Water Data Act API call shared by Purvis Associates
- Contents: various additional descriptive info and event dates for each well (including last production, TA status and expiration dates, etc.)
- Last updated June 2025

Data processing:

1. A panel of production data was generated for all months between January 2022 and January 2025, with one entry for each timepoint and each API10 from the OCD wellhistory dataset.
2. Rows with a date outside of the EffDate (record effective) and RecTermDate (record termination) for each wellhistory record were excluded, providing a continuous panel with one status per well per timepoint. Missing RecTermDates were filled in from the next EffDate in sequence for each API10.
3. Total oil or gas production (in BOE) and total activity (in barrels) was summed monthly by API10; periods of activity or 12+ months inactivity were used in combination with well descriptive data to assign classifications used in the proposed rule (marginal, presumption of no beneficial use, inactive).
4. Data was restricted to 2024 only, and a snapshot of imputed activity and statuses as of ~Jan. 1, 2025, was created, in combination with wellhistory statuses of record and other well descriptive information.
5. Wells were classified on the following basis for the purpose of modeling of the proposed bonding rules, using 6 mcf/bbl to convert gas volumes to barrels:

Activity Classification	Included Well Types	Reported Activity per Year (bbl or BOE)	Reported Days Active
Active	Any	Not meeting criteria for other categories below	
• Marginal	O, G	<1000	<180
• NBU (oil and gas)	O, G	< 90	<90
• NBU (injection/disposal)	C, I, S, W, M	< 100	< 90
Inactive	Any	< 1	< 1

Additional filtering and caveats for estimated bonding snapshot:

- Wells were filtered to federal, state, and private lease types;
    - Federal wells were excluded for:
        - assessment of total required state bond amounts
    - Federal wells were retained for the purposes of:
        - assessing total 2024 revenue
        - classifying operators by the percent of their wells considered marginal or inactive (the 15% threshold)

- Wells were removed if they had statuses in the wellhistory dataset as of Jan. 1, 2025, indicating them as:
    - Already fully plugged and abandoned (Plugged(site released))
    - In process or slated to be plugged (Plugged (not released), Rec. Fund Pending, Rec. Fund Approved), or
    - Not drilled (Cancelled, Never Drilled).

- To avoid biasing wells with partial-year data availability toward lower activity classifications:
    - Wells with a recorded Plug Date prior to the end of 2024 were removed.
    - Wells with a Spud Date during or after 2024 were removed to avoid misclassifications of wells with artificially low annual activity or producing days.

- Finally, around ~2500 wells (mostly of Injection type) were listed as Active status as of January 1, 2025, but were not included in the GO-TECH production data downloads. These wells were excluded from the analysis; the impacts of this removal are modest in terms of the overall totals of estimated bonding amounts and plugging and abandonment liabilities.
    - 51 operators, most of them with only 1 recorded well, were excluded from the analysis by this choice.
    - Of the included operators associated with these excluded wells:
        - 84 of them would not have been reclassified by the inclusion of the missing wells, whether they were truly active or not;
        - 6 operators (<2% of the 342 included in the final analysis) were classified above the 15% threshold that might have been below it if all missing wells were included and were truly active
        - 24 operators (~7% of the 342 included in the final analysis) were classified below the 15% threshold but could potentially have been above it, if all missing wells were included and turned out to truly be inactive or marginal.

Step 2: Bonding amount estimates and related calculations

Estimation of bonding amounts required under existing rules:
Wells with any activity were classified as "active" for the purposes of the estimate of bonding under existing rules. All other unplugged wells were classified as "inactive".

1. **Active wells:** If an operator had only 1 active well, that well's required bond was calculated as 25,000 + 2 * bonding depth, with depth determined based on directional status in line with NMAC 19.15.8.9.C.(1) ("the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells"). If an operator had more than 1 inactive well, the following criteria for blanket bonding were used instead:

Number of active wells	Blanket bonding amount
2-10	50,000
11-50	75,000
51-100	125,000
100+	250,000

2. **Inactive wells:** Similarly, inactive wells were calculated using the same equation for only 1 inactive well, and the following criteria for blanket bonding if more than one inactive well was included:

Number of inactive wells	Blanket bonding amount
2- 5	150,000
6 – 10	300,000
11- 25	500,000
25+	1,000,000

Total bonding amounts estimated for active and inactive wells were summed for each operator.

Estimation of bonding required under proposed rules:
Estimated bonding amounts were calculated for each operator based on the activity classifications descripted in Step 1, and the following algorithm, in alignment with Applicants' proposed changes to 19.15.8.9:

1. **Active wells:**
   - For 1 active well, $150K
   - For 2+ active wells, $250,000 (blanket bond)

2. **Marginal wells:**
   - For each marginal well, $150K

3. **Inactive wells:**
   - For 1 inactive well: one bond of $150K or
   - for 2+: a blanket bond of $150K * number of inactive wells

4. **If over 15% of operator's wells are marginal or inactive:**
   - All of that operator's wells instead require full 150k, substituting the previous calculations entirely.

5. **If operator is below the 15% threshold,** then 1, 2, and 3 are summed.

Step 3: Other related calculations

Estimation of plugging and abandonment liability:
A cost of $163,000 per well was assumed, per OCD estimates referenced throughout Applicants' testimony and exhibits.

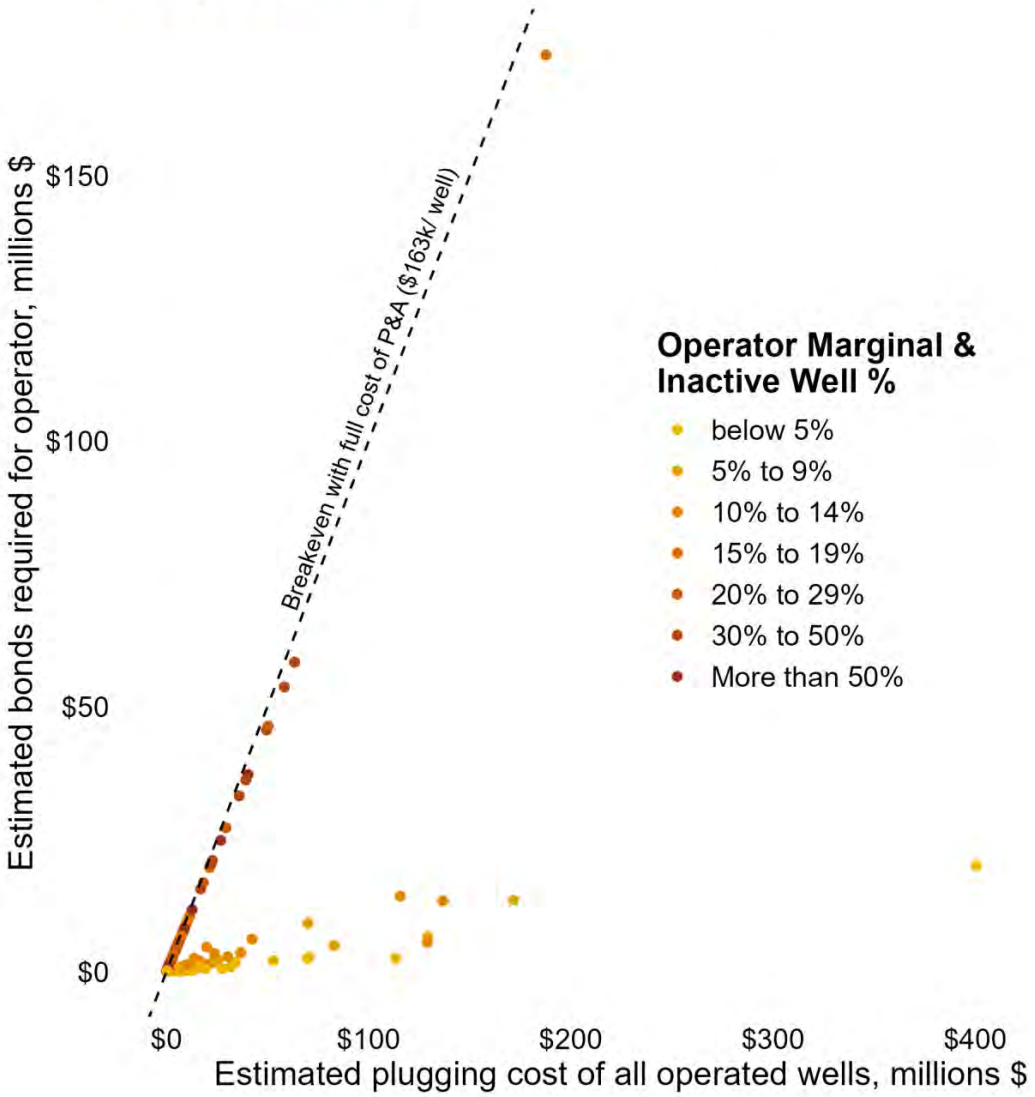
Estimation of operator gross revenues for 2024:

- Oil and gas volumes reported in 2024 GO-TECH data were summed for each operator.
- Sums for oil and for gas were multiplied by EIA monthly prices (WTI crude prices for oil, and Henry Hub prices for gas) averaged to create one annual average each for 2024.

EXHIBIT 64

Proposed bonding amounts vs. potential plugging liability, by operator

Estimated bonding amounts required for state and private wells



Plot of firm-level bond amounts (Y axis) versus projected plugging liabilities at $163k (X axis).
A line is plotted at y=x; operators below the line are underbonded relative to potential P&A liability.
Operator marginal & inactive well % based on all federal, state, and private lease-type wells; bonding costs and liabilities based on operator's state and private wells only.
One high x-axis value operator was excluded for legibility in the in-line version presented in direct testimony of Adam Peltz (App's Ex. 57).

EXHIBIT 65

List of wells individually producing more than all marginal wells in 2024						
API10	**BOE (2024)**	**Lease Type**	**Well Type**	**Spud Date**	**County Name**	**Property or Formation Description**
3002552076	1035928.5	F	O	10/31/2023	Lea	
3001550185	955547.7	F	G	1/15/2023	Eddy	
3001548907	866426.7	F	O	4/4/2023	Eddy	
3001549343	849200	F	O	4/14/2023	Eddy	
3002551956	845298	F	O	10/7/2023	Lea	
3001549344	792154.7	F	G	4/15/2023	Eddy	
3001553715	788311.8	F	G	4/21/2023	*NA*	PURPLE SAGE; WOLFCAMP
3001550040	782295	F	G	3/9/2023	Eddy	PURPLE SAGE WOLFCAMP
3001550039	781872.2	F	G	12/12/2022	Eddy	
Additional wells producing more than 700,000 BOE in 2024						
3001550199	743302.8	F	G	1/15/2023	Eddy	
3001553645	734187.2	F	O	*NA*	Eddy	
3002552244	733837.7	F	O	1/19/2024	Lea	
3002552256	723975.2	F	O	1/20/2024	Lea	
3001549349	723123.8	F	O	4/19/2023	Eddy	
3001553646	721704.2	F	O	5/6/2023	Eddy	R-22701/COMPL. POOLING ENSP
3001554048	720804.5	F	O	8/11/2023	Eddy	BONE SPRING 2
3001550042	702638.8	F	G	3/9/2023	Eddy	
3002551265	701827.5	F	O	7/12/2023	Lea	
3001553644	700877.7	F	O	*NA*	Eddy	

Table reflects reported oil and gas production volumes from all wells included in 2024 County Production volumes from UNM's GO-TECH data platform (oil in bbl and gas in mcf).

Gas volumes were converted to BOE using a conversion of 6 mcf/BOE.

Wells with incomplete 2024 data due to known Spud Date after January 1, 2024, or plugging date prior to January 1, 2025, were excluded from the search.

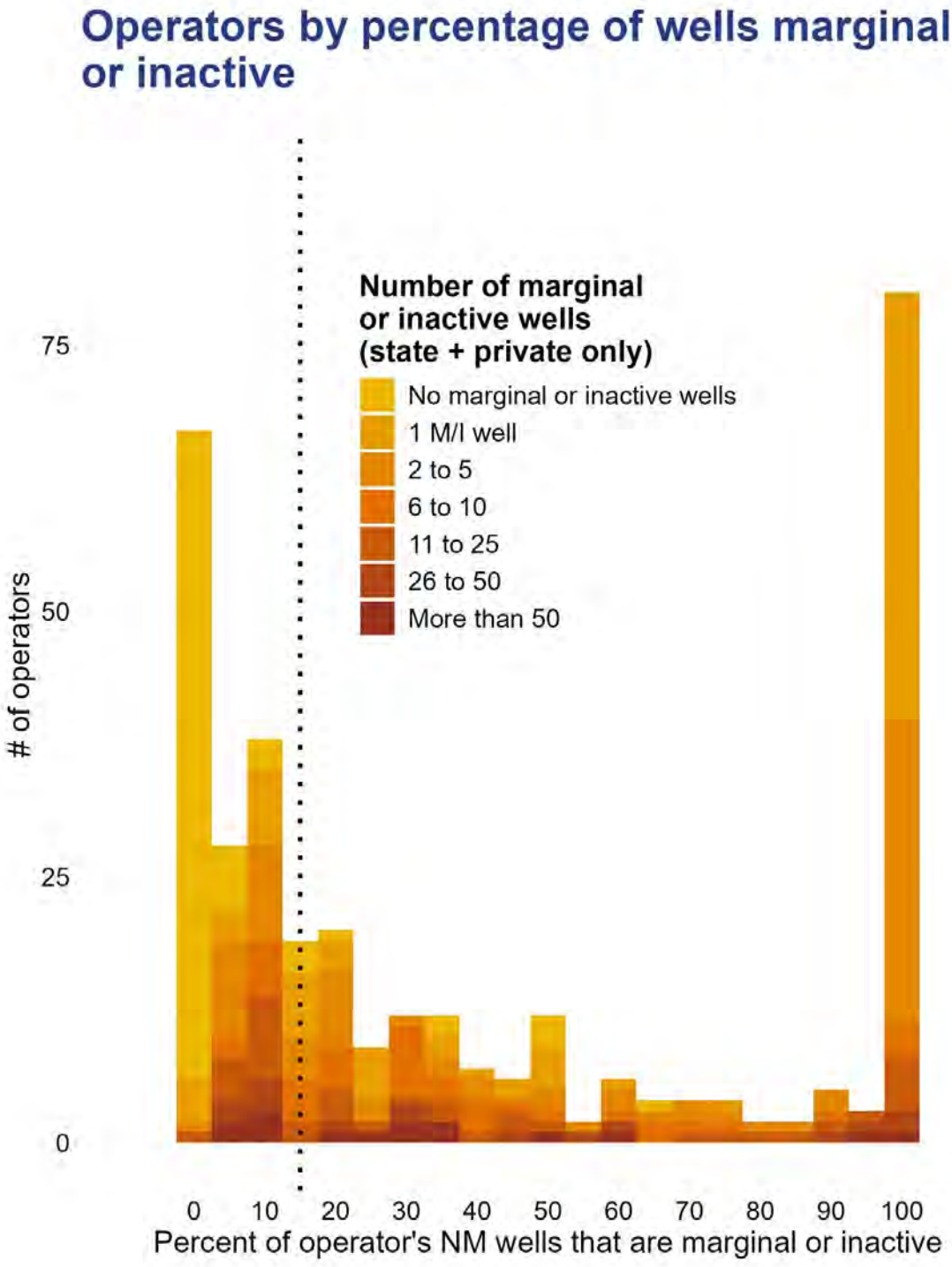
EXHIBIT 66

Comparisons of operators by marginal and inactive well % group Based on activity categorization from GO-TECH production data; filtered to federal, state, and private lease type wells active for the entirety of 2024, except where noted otherwise.			
Marginal & Inactive Well % group	**All operators**	**< 15% marginal or inactive**	**>= 15% marginal or inactive**
Number of operators with state, private, and federal wells	420	160	260
% of total operators	100%	38%	62%
Number of operators with state and private wells	342	144	198
% of state and private well operators	100%	42%	58%
Total Wells (rounded to 10)	51270	36020	15250
Average wells / operator **	110	180	60
Total M/I wells **	7170	2200	4980
Average M/I wells / operator	15	11	18
Total revenues (2024), millions $	$21,040	$17,277	$3,763
Average revenues / operator, millions $	$44	$84	$14
Total revenues from marginal wells, thousands $	$22,825	$9,315	$13,511
Average revenues from marginal wells, thousands $	$49	$46	$51

Details of activity categorization and related data filtering are documented in Apps' Ex. 63.

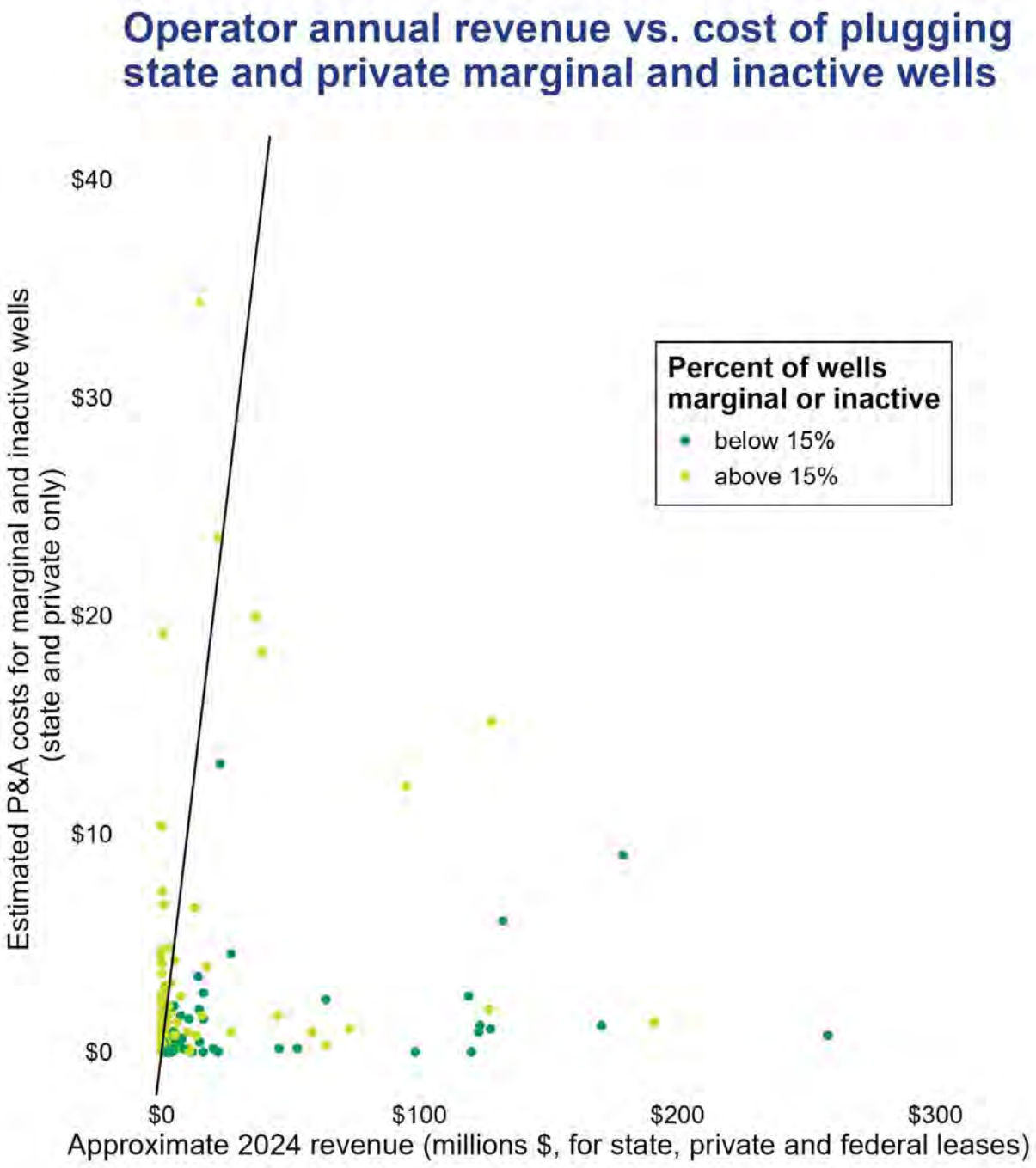
Apps' Ex. 66

EXHIBIT 67



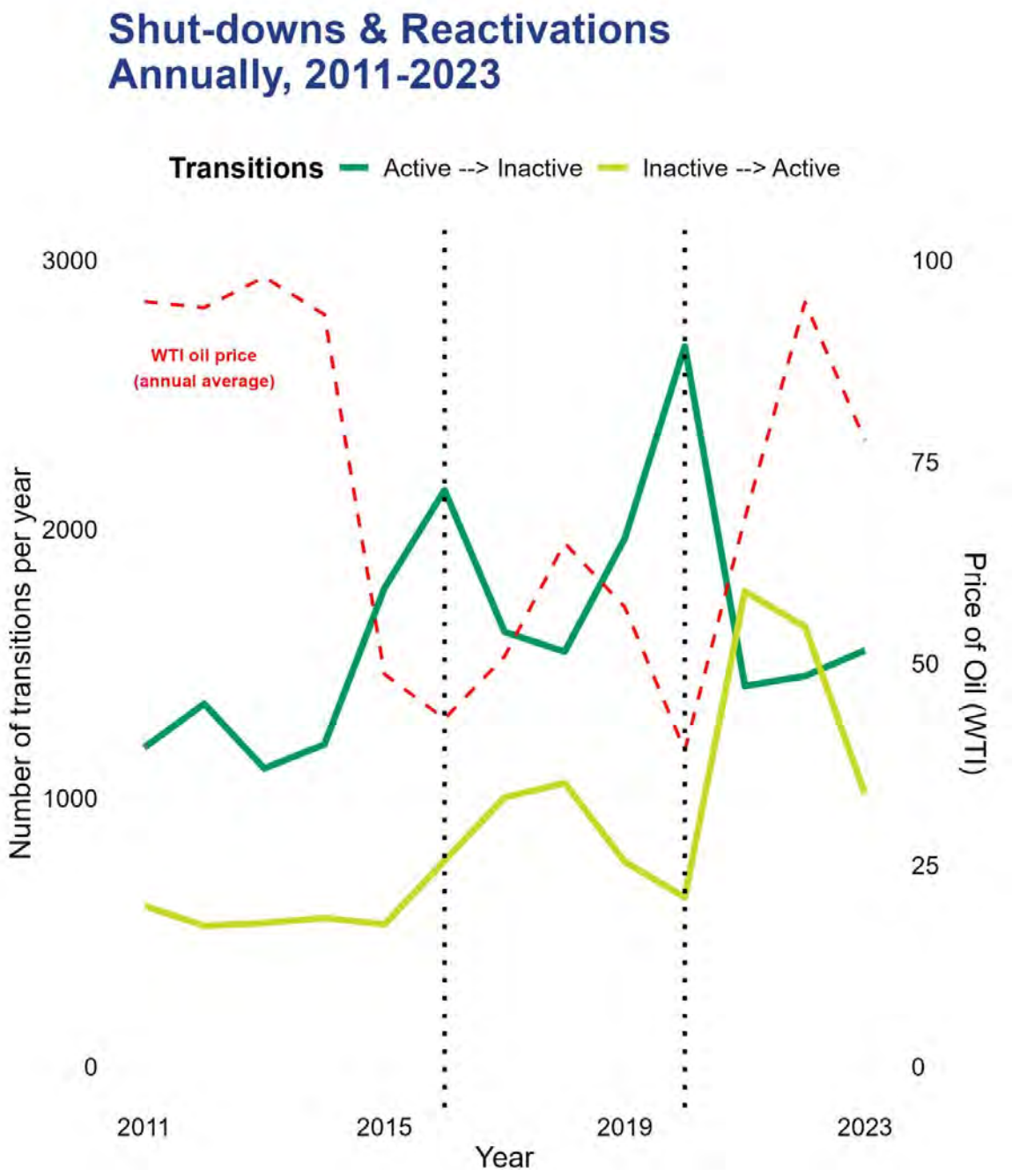
Histogram of 342 operators included in bonding amount projections (Apps' Ex. 63), by percentage of federal, state, and private wells marginal or inactive.
Data excludes Active status wells with no production data available via UNM's GO-TECH County Production volumes.

EXHIBIT 68



Plot of firm-level plugging liability for operator's marginal and inactive wells (Y axis) versus estimated 2024 revenue, under existing rules (X axis).
A line is plotted at y=x; operators below the line generated more 2024 revenue than the expected cost of plugging and abandonment of their state and private marginal and inactive wells.
Companies with revenues above $250 million excluded for legibility of remaining data.
Details of revenue and bonding calculations documented in Apps' Ex. 63.

EXHIBIT 69



Data reflect wells included in County Production data downloads from UNM's GO-TECH data platform for all counties, 2010-2024 (downloaded July 2025).
Deactivation was defined as a period of 12+ months of no reported production after known activity, while reactivation was a return to activity following a period of deactivation.
Activity determinations included reported oil, gas, water, and CO2 volumes.
Black lines drawn at 2016 (shale bust) and 2020 (COVID-19).
Increased numbers of deactivations are seen in the year of each event, with a smaller increase in reactivations lagging after (correlated to rising prices.)

Applicant's Exhibit 69

EXHIBIT 70

OCD WELL PERMITTING STATUS SEARCH All Temporary Abandonment status wells, by time in approved or expired status 7/3/25		
	No. of Wells	%
All Wells in any TA status, (7/3/25)	805	100%
5+ years in TA status	226	28%
8+ years in TA status	111	14%
10+ years in TA status	65	8%
15+ years in TA status	29	4%

Table reflects wells returned by OCD Well Permitting Search for wells in approved or expired TA status as of July 3, 2025.

Assessment of time in status based on reported TemporaryAbandonmentDate or MostRecentTemporaryAbandonmentDate from OCD well records.

Apps' Ex. 70

EXHIBIT 71

OCD WELL PERMITTING STATUS SEARCH All Temporary Abandonment status wells, by time since last production 7/3/25		
	No. of Wells	%
All Wells in any TA status, (7/3/25)	805	100%
2+ years since last prod.	569	71%
5+ years since last prod.	388	48%
8+ years since last prod.	267	33%
15+ years since last prod.	86	11%

Table reflects wells returned by OCD Well Permitting Search for wells in approved or expired TA status as of July 3, 2025.

Assessment of time since last production based on reported LastProductionDate from OCD well records.

Apps' Ex. 71