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' SUBMISSION OF FILING REBUTTAL TESTIMONY AND EXHIBITS

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 file Rebuttal Testimony and Exhibits 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 rebuttal testimony, their qualifications including a description of their education and experience, and the approximate time to present a summary of the witness's rebuttal testimony: All witnesses' full rebuttal testimony and qualifications are set forth herein as follows:

a. Rebuttal testimony of Thomas Alexander is Applicants' Exhibit 73 and his resume is Applicants' Exhibit 2; the approximate time for a summary of his testimony is 30 minutes.

b. Rebuttal testimony of Dwayne Purvis, P.E., is Applicants' Exhibit 74 and his curriculum vitae is Applicants' Exhibit 29; the approximate time for a summary of his testimony is 30 minutes.

c. Rebuttal testimony of Peter Morgan, J.D., is Applicants' Exhibit 81 and his resume is Applicants' Exhibit 14; the approximate time for a summary of his testimony is 30 minutes.

d. Rebuttal Testimony of Adam Peltz, J.D., is Applicants' Exhibit 82 and his resume is Applicants' Exhibit 57; the approximate time for a summary of his testimony is 30 minutes.

4. Any proposed modifications to the proposed rule change with reasons for adopting the modifications: Applicants' proposed modifications are set forth in Applicants' Exhibit 72 and their reasons for adopting the modifications are set forth in their exhibits, a list of which appears below, and in their Prehearing Statement, filed August 8, 2025.

5. All exhibits the person plans to offer as rebuttal exhibits in the hearing: Applicants' list of rebuttal exhibits is set forth below. The exhibits are attached and are uploaded to the shared WELC folder in this matter on the EMNRD CentreStack Platform. Applicants provide a Bates stamp number for each exhibit to facilitate accessing the exhibits.

Exhibit No.	**Exhibit**	**Bates Stamp No.**
72		0949
72-A	Apps' Proposed 19.15.2 NMAC	0950
72-B	Apps' Proposed 19.15.5 NMAC	0963
72-C	Apps' Proposed 19.15.8 NMAC	0969
72-D	Apps' Proposed 19.15.9 NMAC	0974
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73	Rebuttal Testimony of Thomas Alexander	0985
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75	Graphic: Resource categories of technical uncertainty/project maturity	1111
76	Graphic: Resource categories of technical uncertainty/project maturity, including definitions	1113

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Power and Light, San Juan Citizens Alliance, Sierra Club, and WildEarth Guardians

Certificate of Service

I certify that on September 19, 2025, I served by a copy of this pleading by emailing and by filing a copy in the shared WELC folder in the EMNRD CentreStack platform the following via email:

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EXHIBIT 72

EXHIBIT 72-A

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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

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APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC
[Filed with Rebuttal Testimony 9/19/25]

(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.

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(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.

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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,

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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

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[Filed with Rebuttal Testimony 9/19/25]

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.

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[Filed with Rebuttal Testimony 9/19/25]

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".

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC
[Filed with Rebuttal Testimony 9/19/25]

(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]

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.2 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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
72-B

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.5 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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 19.15.27.8.A 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

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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
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APPLICANTS' PROPOSED AMENDMENTS TO 19.15.8 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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:

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[Filed with Rebuttal Testimony 9/19/25]

(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. Each operator with a marginal well or wells shall annually review the number of marginal wells registered to the operator and shall update the one well plugging financial assurance by May 1 of each year.

(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 financial assurance in the form of a single instrument. ~~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.

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[Filed with Rebuttal Testimony 9/19/25]

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 72-D

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.9 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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 authorized official ~~officer, director, or partner~~ that the new operator is not subject to any forfeiture demands from any state or federal agency, has not forfeited financial assurance to any state or federal agency, and does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~in compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~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 has forfeiture demands from any state or federal agency, has forfeited financial assurance to any state or federal agency, or has unresolved adjudicated orders or unresolved settlement agreements for any state or federal violation ~~is out of compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~each state~~ in which the applicant does business;

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(~~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

(4~~5~~) 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 new operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an authorized official ~~officer, director, or partner~~ of the new operator that the new operator is not subject to any forfeiture demands from any state or federal agency, has not forfeited financial assurance to any state or federal agency, and does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~in compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~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 authorized representative ~~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 has forfeiture demands from any state or federal agency, has forfeited financial assurance to any state or federal agency, or has unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~is out of compliance with federal and state oil and gas laws and~~

~~regulations~~ in any domestic jurisdiction ~~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
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APPLICANTS' PROPOSED AMENDMENTS TO 19.15.25 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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, and any information requested by the division. The final determination may be appealed pursuant to 19.15.4 NMAC. Applications shall ~~to~~ demonstrate beneficial use of a well or wells and the operator shall provide any information requested by the division. Such documentation may ~~shall~~ include:

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APPLICANTS' PROPOSED AMENDMENTS TO 19.15.25 NMAC
[Filed with Rebuttal Testimony 9/19/25]

(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~~ A plugging and abandonment plan as described in 19.15.9.9.B NMAC~~.~~; and

(4) Other relevant information requested by the division.

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~~11 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~~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]

APPLICANTS' PROPOSED AMENDMENTS TO 19.15.25 NMAC
[Filed with Rebuttal Testimony 9/19/25]

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

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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 73

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**

REBUTTAL TESTIMONY OF THOMAS M. ALEXANDER

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INTRODUCTION

Q: Please state your name.

A: Thomas Alexander.

Q: Did you provide direct testimony in this matter?

A: Yes. My direct testimony is Applicants' Exhibit 3.

Q: Are your qualifications and background set forth in that testimony?

A: Yes, on Bates stamped pages 0043-47 of Applicants' Prehearing Statement, and my resume is Applicants' Exhibit 2.

Q: At the outset, do you have any general comments about the direct testimony filed by the other parties in this matter?

A: Yes, I'd like to point out that the proposals from the Oil Conservation Division ("OCD") mirror Applicant's proposals. Applicants and OCD proposals are in concert because Applicants' counsel reached out to OCD to work with us on rule changes that would best meet the statutory goals of the Oil and Gas Act and the rules of the Oil Conservation Commission ("Commission") to prevent waste and protect the State against the risks of orphan wells.

Both parties worked hard to craft solutions that are consistent with the Oil and Gas Act, are reasonable, and address the very serious risks to the State and nearby communities of orphan wells. As a result, Applicants adopted many of OCD proposals and OCD adopted many of Applicants' proposals. Similarly, Applicants reached out to the State Land Office to discuss our proposals, and the Commissioner "strongly supports" Applicants' proposals. SLO Prehearing Statement at 1.

The risks of orphan wells were recently documented by the New Mexico Legislative Finance Committee ("LFC") in a recent report on orphan wells in New Mexico, which is Applicants' Exhibit 4. *See* LFC, Policy Spotlight: Orphaned Wells, June 24, 2025 [Apps' Ex. 4]. According to LFC, the State faces plugging and remediating roughly **2,100 wells**, being required to plug **an additional 3,000 at-risk wells**, and a potential liability of **$700 million to $1.6 billion**. *Id.* at 1. Orphan wells risks also have been documented by the State Land Office and OCD.[1]

Despite recognition across New Mexico of the risks posed by orphan wells, industry

[1] *See, e.g.,* 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 [prepared for NM State Land Office], https://www.nmstatelands.org/wp-content/uploads/2021/05/NM-Assurance-Assessment-May-FINAL.pdf; Vertex Resources, Inc., New Mexico Oil and Gas Liability Assessment, Mar. 2021 [prepared for NM State Land Office]; NM Energy, Minerals and Natural Resources Dept. Orphan Wells Spotlight, June 2025; NM Energy, Minerals and Natural Resources Dept., Agency Bill Analysis 2024 Regular Session, HB133, Jan. 18, 2024, https://www.nmlegis.gov/Sessions/24%20Regular/AgencyAnalysis/HB0133_521.pdf.

parties New Mexico Oil and Gas Association ("NMOGA") and Independent Petroleum Association of New Mexico ("IPANM") offer no effective regulatory solutions to these identified problems. They reject all of Applicants' and OCD's proposals – and offer little in the alternative to sufficiently address the pressing problem the State confronts.

It is also well worth noting that we reached out to industry on a number of occasions seeking meetings to discuss our proposals and differences in an attempt to reach some reasonable compromises. They refused to meet, except for once, which essentially was a non-event. After reading the testimonies of the expert witnesses for NMOGA and IPANM, it became abundantly clear to me that had we met, we could have likely hashed out a number of of differences and saved everybody, most pointedly the Commission, a lot of time and effort.

OXY USA, Inc. ("OXY") was the only industry party to negotiate with Applicants and OCD. As a result of these good faith negotiations, OXY, OCD, and Applicants were able to reach agreement on several OXY proposals, which are outlined in Applicants' Exhibit 1 [Sub] (replacing Applicants' Exhibit 1). The agreed upon amendments are set forth in proposed 19.15.9.8 & -.9 NMAC and 19.15.25.9 NMAC. Applicants also agreed to changes requested by OXY in the marginal well provisions at 19.15.8.9.D NMAC, even though OXY opposes the marginal well provisions. The changes represent amendments OXY requested if the Commission adopts Applicants' marginal well proposals.

Instead of taking a slash and burn approach, OXY took a more measured approach – adopting a good number of Applicants' and OCD's proposals and offering alternative proposals of its own. I appreciate the more considered approach.

The Commission should not maintain the *status quo*, as NMOGA and IPANM essentially recommend. It is clear that the existing rules have not kept pace with current day realities of oil and gas production and the indisputable risks of wells becoming orphaned. The risks of orphan wells to nearby communities and the potential liability facing the State require regulatory action.

19.15.2 NMAC – GENERAL PROVISIONS FOR OIL AND GAS OPERATORS

Q: Thank you Mr. Alexander. Let's now turn to Applicants' specific proposals. Witnesses for NMOGA object to Applicants' proposed definition for "beneficial use" and "beneficial purposes" at 19.15.2.7.B(7) NMAC: Felix Test. at 2-5 [NMOGA Ex. B]; Arthur Test. at 4-7 [NMOGA Ex. C]; McGowen Test. at 9-10 [NMOGA Ex. D]; Sporich Test. at 2-5 [NMOGA Ex. E]. The proposed definition is:

> **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.

NMOGA witnesses object that Applicants' proposed definition is too limiting and excludes beneficial use activities such as secondary and tertiary recovery and geothermal use. E.g., Felix Test. at 3-5, 8; McGowen Test. at 9; Sporich Test. at 4. What is your response?

A: This is not accurate. NMOGA witnesses misconstrue the definition. The proposed definition is clear that the examples of beneficial use set forth -- production, injection, and monitoring – **are not exclusive**, but are merely examples. That is very clear by looking at two words, "such as", in the body of the text above. Moreover, the particular examples set forth are taken **directly** from the existing definition of "inactive well" at 19.15.7.2.I(4) NMAC which means a well "not being used for beneficial purposes such as production, injection, or monitoring . . . ." Applicants' proposed definition -- which is a well "being used in a productive or beneficial manner" -- would include secondary and tertiary recovery, geothermal use, and other uses, just like the current definition for "inactive well" includes those uses. The proposed definition for "beneficial purposes" and "beneficial use" is not at all limiting but includes productive activities such as those suggested by NMOGA's witnesses.

If NMOGA had wanted to expand the examples of productive uses, it could have discussed that with Applicants' counsel and avoided this particular dialogue.

Similarly, NMOGA witness Andrea Felix's claim that the definition does not allow for case-by-case determinations of beneficial use is simply incorrect. Felix Test. at 3. The definition is **exceedingly broad** and intentionally so – covering any well "being used in a productive or beneficial manner." The only limiting provision in the definition "does not include use of a well for speculative purposes." It is this language that NMOGA and IPANM object to strongly.

Q: Yes, NMOGA witnesses object that the term "speculative" is overly vague and a determination whether a beneficial purpose or use is "speculative" is subjective and arbitrary. *E.g.,* Felix Test. at 3; Arthur Test. at 5-6; Sporich Test. at 4; Emerick Test. at 14 [NMOGA Ex. 7]; *see also* Ezzell Test. at 46 [IPANM Prehearing Statement]. What is your response?

A: Use of the term "speculative" is not subjective or arbitrary. The dictionary definition of "speculative" is "based on a guess and not on information."[2] Therefore, operators must show that a well "is being used in a productive or beneficial manner" based on information, not guesswork. This is a reasonable showing that any prudent operator should be able to make.

Applicants propose use of the term in proposed 19.15.25.9 NMAC – establishing rebuttable presumptions of beneficial use" – and in proposed 19.15.25.13 NMAC – establishing procedures for placing wells in temporary abandonment ("TA").

In the context of 19.15.25.9 NMAC, an operator may rebut a presumption of no beneficial use by demonstrating the well has "beneficial use." The demonstration required in that

[2] Cambridge Dictionary, https://dictionary.cambridge.org/us/dictionary/english/speculative.

section to demonstrate beneficial use, therefore, must be based on information, not a guess. If a well has future utility and the operator has sufficient capital to plug and abandon ("P&A") the well, an operator should be able to provide a factual basis for that demonstration.

According to Harold McGowen, operators are "constantly evaluating" their wells' financial performance, including analyzing:

> . . . each assets' [sic] production rates, revenue potential, operating costs, perceived **future** potential, and regulatory liabilities, and then either retaining those perceived to be the most valuable or divesting (selling) or plugging those that appear to no have **future** potential or that are expected to underperform or somehow misalign with core capital deployment priorities of the company.

McGowen Test. at 101 (emphasis added) [NMOGA Ex. D]. Therefore, according to Mr. McGowen, operators should have a factual basis to demonstrate the well has future utility. They don't have to guess or rely on conjecture. But, based on the facts, if a well has no future utility, it should be properly plugged and abandonment and the site remediated. It's as simple as that.

An example that I used in my direct testimony[3] was the attempt by operators to claim secondary and tertiary potential for oil and gas properties that now lie underneath the Denver International Airport. The operators' experts claimed all kinds of value based on multiple "ifs" that had no real factual or operational basis to be ascribed to the lease that the City and County of Denver wanted for the new airport. Our evaluation on behalf of the City and County was for proved producing (oil and gas reserves that based upon geological end engineering data are known to be economically viable and are currently producing) and some amount of behind pipe (oil and gas reserves that by geological and engineering data are known to be producible and economically viable but currently not producing) as I recall only. The decision went in our favor

[3] Alexander Test. at 0066 [Apps' Ex. 3]. The page number refers to the Bates stamped page numbers in my testimony.

as the thin veil the operators' experts threw up was rejected. I also stated that I 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 development of other 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).[4]

In the context of 19.15.25.13 NMAC, an operator must show that a well has future "beneficial use" in order for OCD to authorize that it be placed in TA status and not plugged and abandoned. Again, this demonstration must be based on information, not guesswork. Proposed 19.15.25.13.A and -B NMAC, give a number of examples of "information" that OCD may use to determine if a well has future beneficial use. Operators, as Mr. McGowen states, are constantly evaluating the productivity and profitability of their wells, and this is a factual demonstration they should be able to make. If a well has no future utility, it should be plugged and abandoned and the site remediated.

Ms. Felix suggests that a well has beneficial use if there is some use "in the future," not currently known, based on technology that has yet to be invented. Felix Test. at 3. That is no definition at all. Under her formulation, **all** wells would have beneficial use, forever. But, as any prudent operator knows, if there is no factual basis to assert that a well has present or future use, the well should be plugged and abandoned. This is simple common sense.

Q: NMOGA witnesses object to the proposed definition because they are concerned the definition will "conflict" with use of the terms in other Commission rules. *See* Arthur Test.

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[44] *Id.*

at 6-7; McGowen Test. at 9. What is your response?

A: As set forth in my direct testimony, the terms "beneficial purposes" and "beneficial use" are used in the Commission's rules and are critical terms, but have no definition.[5] I cite to numerous places in the Commission's rules where one of the terms is used.[6] While both Dan Arthur and Mr. McGowen claim there could be confusion among use of the terms, they do not explain what the confusion possibly could be. Mr. Arthur's three examples of where the terms are used are from existing 19.15.25.8.B(2) NMAC (requiring plugging and abandonment or applying for TA governing for a well "no longer usable for beneficial purposes"); 19.15.25.12.A NMAC (requiring an operator to return a well to "beneficial use," P&A, or re-apply for TA status); 19.15.2.7.I(4) NMAC (defining "inactive well as one "not being used for beneficial purposes such as production, injection, or monitoring . . . ."). In each of these contexts, the terms mean the same thing, and Applicants' proposed definition fits all contexts perfectly. There is no confusion or ambiguity.

Q: IPANM witness T. Calders Ezzell, Jr., objects to use of the term "beneficial use" because it is not a concept used in New Mexico in the oil and gas arena. Ezzell Test. at 46-55. What is your response?

A: I have not worked in New Mexico, and therefore I cannot comment on its usage in New Mexico. I can say that, first, the terms "beneficial use" and "beneficial purposes" are commonly used (or at least inferred) in all oil and gas producing states in which I've worked. Second, the terms are used throughout the Commission's rules.[7] Most prominently the term is used in

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[5] Alexander Test. at 0065.
[6] *See* Alexander Test. at 0065 (citing 19.15.2.7.I(4) NMAC; 19.15.25.8.B(2) NMAC; 9.15.25.12 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).
[7] *See* n.4 above.

existing 19.15.2.7.I(4) NMAC, defining “inactive well” as a “well that is not being used for beneficial purposes,” and in existing 19.15.25.8.B(2) NMAC. The latter section requires a well “that is no longer usable for beneficial purpose” to be plugged and abandoned or placed in TA status. The terms’ usage in the Commission’s rules are consistent with my understanding of the term and is consistent with the definition proposed by Applicants which is a well being used in a productive or beneficial manner, but does not include use of a well for speculative purposes.

Mr. Ezzell objects to use of the term “speculative.” As stated above, “speculative” is used in Applicants’ proposed definition consistent with its dictionary definition, meaning based on information, not a guess. For purposes of Applicants’ proposals, operators would be required under proposed 19.15.25.9 NMAC (presumptions of no beneficial use) and 19.15.25.13.A and -B NMAC (approved temporary abandonment) to demonstrate productive use of a well based on information, not conjecture. Any prudent operator will have sufficient technical and administrative data and information not only to describe a well’s history and current state, but also information pointing to possible future uses, be it recompletions, deepening or other uses described in the various testimonies. Again, I say, this is real data and not guessing or hoping that something heretofore unknown and unexpected is going to come down the road any day now or may come down the pike in the next decade.

Q: Mr. Ezzell also objects to using the term beneficial as too constraining on an operator’s ability to extract the resource, innovate, and wait for technological advances. Ezzell Test. at 46-50. What is your response?

A: Mr. Ezzell notes a number of things. He claims that drilling through cement plugs set across every potentially productive zone is not economic and so the well is lost forever if plugged. That’s simply not true at all. In my field experience, drilling through one or more cement plugs and/or cast iron plugs is really no big deal. It takes no time and effort at all -- a day or two at most. I would add that if the "economics" of reentry can't stand that sort of expense, the project is basically not worth pursuing at all. As a side note, I learned early on that re-entering a well is very risky if you aren't dead sure how it was plugged. There's no telling what you might find downhole and if the proposed project can't stand the cost of a fresh wellbore, then go find something else to do.

Mr. Ezzell makes a valid point when he discusses the issue of multiple wells on a lease, one of which is productive and thus holds the lease and the economics are favorable. I can imagine there are a number of examples such as this, especially in unitized situations. These situations are worth discussion (had IPANM and NMOGA made the effort to discuss their concerns with us). His comments about issues surrounding other working interest owners (having to make proposals and obtain consent) is true and I've dealt with that in a number of cases. The solution is simple in that the proposer of a capital investment can take the opposing parties' non-consent out of the project and they then generally back-in after payout times one or two times depending upon the operating agreement. Most all the time, good operating agreements provide reasonable mechanisms to handle situations like this.

Now, Mr. Ezzell goes into some discussion about technology improvements and other sorts of atypical uses. I don't believe anything Applicants propose in the definition excludes **any** viable and data supported idea or use at all, be it in a disposal well, a rancher's water well, carbon capture or whatever. The point to be made again and again is to show evidence to support the beneficial use and then get on with it. There is no justification for just sitting on a well year after year after year after year, hoping some new idea might emerge.

Q: NMOGA witness Clayton Sporich objects to the definition of beneficial purpose/use

as inconsistent with OCD guidance on use of the term in Parts 27 and 28 of 19.15 NMAC, regulating venting and flaring of gas, found at OCD's Notice of Rule Interpretation Waste Rule Beneficial Use of Lost Gas for Purposes of Natural Gas Management Plans and Monthly Reporting (Sept. 6, 2022) ("OCD Notice").[8] Sporich Test. at 3. What is your response?

A: That notice states:

> . . . OCD's interpretation of beneficial use under parts 27 and 28 includes alternative uses of gas produced on a lease that:
> - Occurs on-lease; and
> - Relates to, or enhances, existing or typical oil and gas production activities.

OCD Notice at 1. OCD's interpretation for purposes of Parts 27 and 28 is not inconsistent with Applicants' proposed definition, which is "a well that is being used in a productive or beneficial manner such as production." To the extent the Commission believes there is any inconsistency, Applicants' proposed definition could be limited to application to Parts 8 and 25 of 19.15 NMAC.

Q: NMOGA offers the following definition for "beneficial purposes" and "beneficial use" in 19.15.2.7.B(7) NMAC:

> <u>**(7) "Beneficial purposes" or "beneficial use"** means that a well is being used, or is reasonably expected to be used, in a productive, operational, or regulatory capacity consistent with its intended purpose. This includes, but is not limited to, production, injection, monitoring, regulatory compliance, or participation in reservoir management, pressure maintenance, or infrastructure optimization programs.</u>
>
> <u>In determining whether a well is being used for beneficial purposes, the Division may consider operational records, production or injection history, regulatory filings, and operator-submitted plans or supporting documentation. The Division shall provide the operator a reasonable opportunity to demonstrate beneficial use prior to making any contrary determination.</u>

[8] https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/9-6-22-NOTICE-Waste-Rule-Interpretation-Beneficial-Use.pdf.

Use of a well shall not be deemed non-beneficial solely because: It has produced or injected below a specific volumetric threshold; It has been temporarily inactive due to maintenance, market conditions, infrastructure limitations, or field-wide optimization; It is not producing in paying quantities on a standalone basis but contributes value to a unitized or pad-level operation.

Use of a well for speculative or indefinite purposes with no planned operational role may be deemed non-beneficial after consultation with the operator.

What is your opinion of NMOGA's proposed definition?

A: First, and interestingly, NMOGA proposing a definition for "beneficial purposes" and "beneficial use" contradicts its claim that defining these terms will "conflict" with use of the terms in other Commission rules.

Second, as stated above, Applicants' proposed definition is clear that the examples of beneficial use given -- production, injection and monitoring – are **not** exclusive, but are examples, examples taken directly from the existing definition of "inactive well" at 19.15.7.2.I(4) NMAC, cited above. The definition proposed by Applicants -- which is a well "being used in a productive or beneficial manner" -- would include examples from NMOGA that represent productive use of a well including injection, disposal, and carbon capture. I am not opposed to including additional examples of productive use of the well to the definition. Again, these are provisions that I believe industry parties should have discussed with Applicants to try to find agreement.

Third, the bulk of NMOGA's proposed definition, however, is not workable. Most of the "definition" is not definitional, but regulatory. The first paragraph is somewhat definitional but the last three clearly step off into a regulatory context. That is, the "definition" sets forth regulatory requirements. Definitions should not set forth substantive regulatory requirements. Those requirements – including the information OCD should consider when determining beneficial use -- should be set forth in the body of the rules.

Moreover, most of NMOGA's so-called "definition" are aimed at undermining Applicants' definition of beneficial use – which includes that future use cannot be "speculative" and – Applicants' presumption of no beneficial use at newly proposed 19.15.25.9 NMAC. For the reasons I support Applicants' proposed definition of beneficial purposes/beneficial use discussed in my direct testimony and in this rebuttal testimony, I disagree with NMOGA's proposed "definition."

Q: Witnesses for NMOGA similarly object to combining the definitions for "approved temporary abandonment," "temporary abandonment," and "temporarily abandoned status" at 19.15.2.7.A(13) NMAC as confusing. Arthur Test. at 22-24; McGowen Test. at 41-42; Sporich Test. at 13-14. Applicants proposed the following:

> **19.15.2.7.A(13) "Approved temporary abandonment<ins>,</ins>" <ins>"temporary abandonment," or "temporarily abandoned status"</ins>** 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.~~

What is your response?

A: While NMOGA witnesses claim combining the definitions can have "wide-ranging effects" on other Commission rules and creates "unnecessary confusion," they don't explain how that is even so. *See* McGowen Test. at 41; Arthur Test. at 22. Again, in my direct testimony, I cited to numerous places in the Commission rules where the three terms are variously used.[9]

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[9] *See* Alexander Test. at 0063 n.7 (citing 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")).

NMOGA witnesses give no example where there is any confusion among these terms. That's because there is none.

If a well is in "temporary abandonment" or in "temporarily abandoned status," that means the well is in **approved** TA status. The current definition for "temporary abandonment" or "temporarily abandoned status" – which "means the status of a well that is inactive" – is actually **not** accurate. All TA wells are a **subset** of "inactive" wells, but they also have been **approved by OCD** to remain inactive during the TA period and have met the requirements for TA status in 19.15.25.13 & -14 NMAC.

As Applicants' Exhibit 7 demonstrates, according to OCD's Inactive Well List (dated 7/3/25), there are over 3,700 wells on the inactive list: over 400 are in TA status, over 150 are in expired TA status, and over 3,200 wells are inactive and have never been placed in TA status. "Inactive" is **not** synonymous with "temporary abandonment" or "temporarily abandoned status."

Q: NMOGA witness Mr. Arthur objects to defining the three terms together stating that,

> **WELC proposes amending 19.15.2.7(A)(13) NMAC to expand the existing definition of "Approved Temporary Abandonment"—which currently refers to the status of an inactive well approved under 19.15.25.13 NMAC and compliant with 19.15.25.12 through 19.15.25.14 NMAC—to incorporate two newly defined terms: "Temporary Abandonment" and "Temporary Abandonment Status.**

Arthur Test. at 22. What is your response?

A: Mr. Arthur is incorrect that the terms "temporary abandonment" and "temporary abandonment status" are "newly defined terms" proposed by Applicants. As discussed above and in my direct testimony, those terms are already used in the Commission's rules (at existing 19.15.2.7.T(3) NMAC) and, reading those terms in context, they carry the same meaning as "approved temporary abandonment." *See* n.6 above; Alexander Test. at 0063 n.7. In fact, Mr. Arthur acknowledges that "there is no meaningful distinction between the terms." Arthur Test. at 23.

Q: NMOGA witnesses object to Applicants' proposed new definition for "expired temporary abandonment" and "expired temporary abandonment status" in 19.15.2.7.E(8) NMAC. Arthur Test. at 24-25; McGowen Test. at 42-45; Sporich Test. 15-17. That proposal provides:

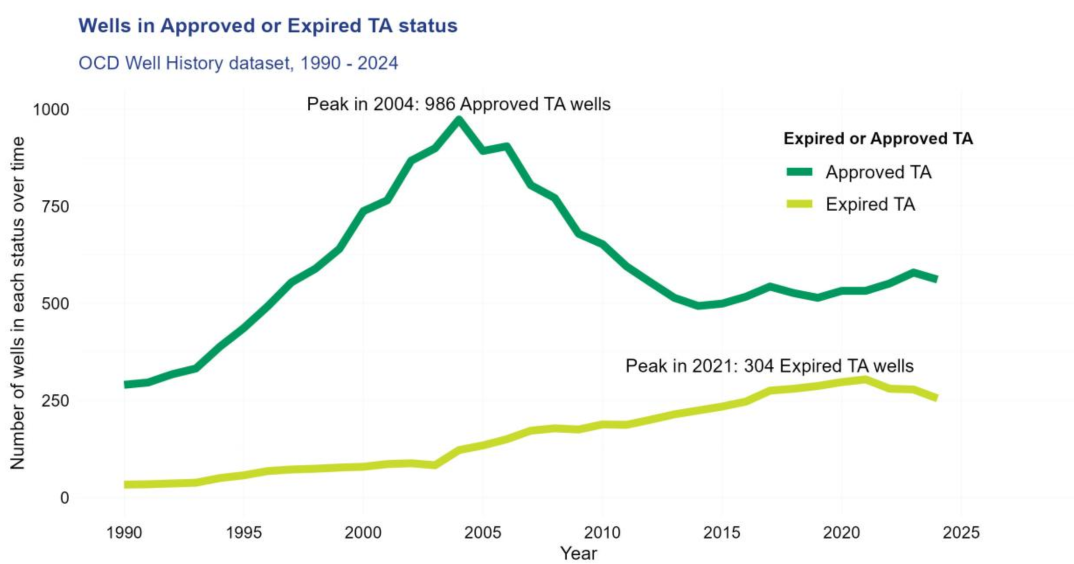
> **19.15.2.7.E(8) "Expired temporary abandonment" or "expired temporary abandonment status"** means the status of a well that is inactive and has been approved for temporary abandoned status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 NMAC through 19.15.25.14 NMAC.

What is your response?

A: NMOGA witnesses' main objection to the proposed definition is that it ties a well in expired TA status to non-compliance. However, a well in expired TA is status is **necessarily** out of compliance with the Commission's rules at 19.15.25.13.A NMAC because the operator has not renewed TA status, **as required**, after a term of temporary abandonment has expired. It is nonsensical and disingenuous to claim otherwise.

Moreover, the terms "expired temporary abandonment" and "expired temporary abandonment status" need to be defined because Applicants propose using those terms both in proposed 19.15.25.13 NMAC, relating to TA requirements, and 19.15.8.9 NMAC, relating to financial assurance. For clarity of the meaning of these terms in these two sections, the terms need to be defined.

One more point about expired TA wells: the number of expired TA wells has increased over time, as demonstrated by Applicants' Exhibit 11, below. These wells by definition are out of compliance. These are high risk wells because of the length of time they have been inactive (generally speaking, at least six years) and they are non-compliant with the Commission's rules. The upward trend is concerning, and all the more reason to strengthen regulatory solutions.



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

Apps' Ex. 11

Q: Ms. Felix objects that the definition for expired TA is vague and ambiguous. Felix Test. at 14. What is your response?

A: I disagree. There is nothing unclear about the definition. OCD approves a well for TA for a certain term under existing 19.15.25.12 and -13 NMAC. When that term expires, an operator must P&A the well, put it back to beneficial use, or apply for a new TA approval under existing 19.15.25.12.A NMAC. If the operator does not take one of those three actions, the well is in expired TA status and the operator is out of compliance. There is no ambiguity.

Furthermore, OCD currently routinely makes determinations that wells are in expired TA status and identifies expired TA wells on its Inactive Well List that is updated daily.

19.15.25 – PLUGGING AND ABANDONMENT OF WELLS

19.15.25.8 – Wells To Be Properly Abandoned

Q: NMOGA witnesses object to Applicants' proposed amendments to 19.15.25.8 NMAC. Those amendments are:

> **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.

First, what is your response to NMOGA witnesses' objection to amending the 90 day "grace period" to apply for TA or P&A to 30 days?

A: Mr. McGowen objects to changing the "grace period" from 90 to 30 days to apply to the division to place a well in TA or P&A a well as too short. McGowen Test. at 46-61; Arthur Test. at 15; *see also* Wallace Test. at 10 [OXY Ex. B]. He complains that "a well must either be permanently abandoned or formally put in TA status" within 13 months of no production. *Id.* at 52-35. But Mr. McGowen misreads Applicants' proposal and does not appreciate how the process currently works.

First, Mr. McGowen misreads the plain language of Applicants' proposal. The proposal allows an operator 13 months to **"apply to the division"** to place a well in TA status, **not** to have completed the process to place a well into TA status with 13 months.

Second, Mr. McGowen focusses in particular on the time that it takes to properly P&A, stating that it takes "months to a year" to complete the process for P&A and therefore permanent abandonment takes more than 13 months. *Id.* at 46-48. However, as I understand it, Applicants' proposed amendments do not change current OCD practice in which operators regularly take more than the required time (now 15 months) to allow an operator to plug a well.[10]

This would have been easy for NMOGA to clarify. However, as discussed, while Applicants' reached out to industry parties many times to discuss their proposals, no industry party except OXY engaged in negotiations.

Based on my decades of experience in the field, it is reasonable to require operators either to apply for TA status or make a determination to P&A a well within 13 months of non-production. It really boils down to a simple question: is an operator proactive or reactive? Prudent operators will certainly know a well or wells are in the final stages of productive life as well as being candidates for some form of other beneficial use. An operator doesn't wake up one day and all of a sudden have a bunch of wells that need to be plugged. If an operator does, that operator shouldn't be in the oil and gas business. I read with interest Mr. McGowen's accounting of the plugging process and while I don't conceptionally disagree with all the facets he brought forth for getting a well plugged, he appears to say that it's more or less normal to take months and years to plug a well. That is simply not my experience. I guess if everything that could go wrong, did go wrong, then perhaps that could happen.

As a last note: what's the big difference between 30 days and 90 days? Based on my experience, I believe the 30 day time period is reasonable for the reasons stated. However, if NMOGA and IPANM are adamant that operators need the extra 60 days to figure out whether to place a well in TA status, P&A the well, or go back into production, then so be it. Just get it done

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[10] As Mr. McGowen notes, the Commission's rules give an operator one year after completing plugging operations to clear and restore the site. 19.15.25.10.D NMAC.

properly and safely in a reasonable time and coordinate with OCD and avoid unnecessary delays. Again, this is an issue that would have been worth discussing with Applicants and OCD.

Q: NMOGA objections to deleting the word "continuously" from 19.15.25.8.B(3) NMAC so that provisions reads: "a period of one year in which a well has been ~~continuously~~ inactive." McGowen Test. at 59-61, 64-69. **Mr. Arthur objects this amendment will lead to "premature plugging," Arthur Test. at 15, and in a similar vein, Mr. McGowen objects the deletion will undermine "responsible stewardship" of "still viable and potentially profitable wells." McGowen Test. at 59-60. What is your response?**

A: Yes, NMOGA and IPANM both strongly object to deleting the word "continuously" from the regulatory requirements for identifying an inactive well. Applicants proposed deleting the word "continuously" after discussions with OCD technical staff who confirm there are operators who "game" the system by producing or claiming production for a very short period to avoid the requirement to P&A or place a well in TA status after 12 months of non-production and thereby avoid the financial obligations each requires. And if an operator is using this loophole to avoid their obligations under Commission rules, this is a well at increased risk of becoming orphaned. Applicants' proposal addresses these problems. The requirement that a well be "continuously" "inactive" for 12 months should not be used to inappropriately delay placing a well in TA or plugging it and thereby creating greater risk for the State.

We can assume that OCD will use sound professional judgment to determine if a well that has been "inactive" for 12 months is truly inactive according to the Commission's rules, that is, a well that is not being "used for beneficial purposes." 19.15.2.7.I(4) NMAC. The claim that OCD will require premature plugging infers that OCD will be unreasonable in its assessment. But we can assume that OCD technical staff are aware of potential well and operator issues that are most concerning, have the technical and administrative skill and knowledge to assess whether a well is inactive, and will work with an operator to assess whether a well is truly "inactive." I've discussed my experience with making decisions to plug wells regarding the time and effort that it takes. No one wants a viable well -- used for any beneficial use -- to be plugged prematurely and to speculate that OCD will force premature closure of wells seems unfounded.

I note that **neither NMOGA nor IPANM offers a constructive solution to the problem identified**, that is, operators who go back into production or claim production for a very short time to avoid their obligations under the Commission's rules to place in an inactive well into TA or P&A. If they have an alternative proposal, they should offer it. But taking advantage of a loophole in the language of the Commission's rules should not be allowed: it creates a risk to the State that an operator is avoiding its liabilities, that the operator will orphan the well, and the liabilities will fall to the State.

Q: Mr. Gowen claims that Applicants' proposal "would create a 'rebuttable presumption' that any well inactive for more than 13 months is out of compliance with the rule." McGowen Test. at 58. Is this claim accurate?

A: No, this is not accurate. Mr. McGowen is mixing up Applicants' proposed amendments to 19.15.25.8 NMAC with Applicants' proposed new section 19.15.25.9 NMAC, creating a rebuttable presumption of no beneficial use for oil and gas wells that produce less than 90 days and less than 90 barrels of oil equivalent ("BOE") in a 12 month consecutive period. Applicants' proposed amendments above to 19.15.25.8 NMAC do not change the requirements of or impact 19.15.25.8.B NMAC except to change the "grace period" from 90 to 30 days.

Q: Ms. Felix claims that a "single day of non-use scattered throughout the year could trigger regulatory obligations, discouraging operators from maintaining marginal but

viable wells and potentially leading to premature abandonment." Felix Test. at 33. What is your response?

A: Ms. Felix, like the others, have misinterpreted the point concerning deletion of the word "continuous." The simple point here is that operators "game" or take advantage of the system as is to avoid necessary P&A, conversion to TA or returning a well to profitable production. The "game" is to reset the inactivity clock by "producing" a well for a day or so. OCD knows this happens and the deletion of the word "continuous" helps to solve this problem. So, a single day of non-use though the course of a year is not going to trigger any regulatory obligations, much less lead to premature abandonment. Her assertion simply is hyperbole.

19.15.25.9 NMAC – Presumptions of No Beneficial Use

Q: After negotiations with OXY, Applicants propose to amend 19.15.25.9 NMAC – Presumptions of No Beneficial Use, correct?

A: Yes, that is correct. I participated in one of those discussions, which included OCD, and all three sets of parties came to agreement on changes to Applicants' original proposal.

OXY supports establishing the rebuttable presumptions of no beneficial use with the modifications below. Wallace Test. at 11. The agreed-upon changes are set forth below, are highlighted in yellow, and are reflected in Applicants' Ex. 1 [Sub]. These same changes are reflected in OXY Exhibit 1.

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, and any information requested by the division. The final determination may be appealed pursuant to 19.15.4 NMAC. Applications must ~~to~~ demonstrate beneficial use of a well or wells and the operator must provide any information requested by the division. Such documentation ~~shall~~ may 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~~ A plugging and abandonment plan as described in 19.15.9.9.B NMAC; and

(4) Other relevant information requested by the division.

Q: What is the basis for these changes:

A: OXY witness Tiffany Wallace sets forth the basis in her testimony for the changes. Wallace Test. at 11, ¶¶ 49-52. In her opinion, establishing the rebuttable presumptions "is an efficient way to address wells whose level of activity or production raises concerns about whether those wells continue to serve a potentially beneficial purpose." *Id.* I support her rationale. In general, the changes allow OCD to request and obtain all information that it needs to assess beneficial use, but does not mandate that an operator provide certain information during each OCD determination of beneficial use.[11]

Q: NMOGA witnesses raise various objections to this proposal, which was initially

[11] OXY does object to defining "beneficial purposes" and "beneficial use." Wallace Test. at 11-12, ¶ 12. I disagree with OXY on this point for the reasons stated above.

proposed by OCD based on staff's experience in the field. What is your response?

A: NMOGA witnesses object to establishing rebuttable presumptions of no beneficial arguing that setting specific production and time period thresholds to establish a rebuttable presumption are "too rigid and not operationally realistic." Felix Test. at 6-7; Arthur Test. at 8-9; McGowen Test. at 10-19; Sporich Test. at 6.

I disagree. The thresholds for production wells – 90 BOE **and** 90 days of production in 12 months – and for injection wells – 100 barrels of fluid **and** 90 days of injection – are **highly** conservative. For production wells, that means production of roughly **0.25 BOE per day** which in almost all circumstances, after tax, royalties, and operating expenses, is not economic based upon reasonable product prices. The recent LFC report on orphan wells deemed wells at or below **2 BOE per day** problematic and observed that at this level of production, the average well is plugged and abandoned. LFC, Policy Spotlight: Orphaned Wells, pp. 4, 21.

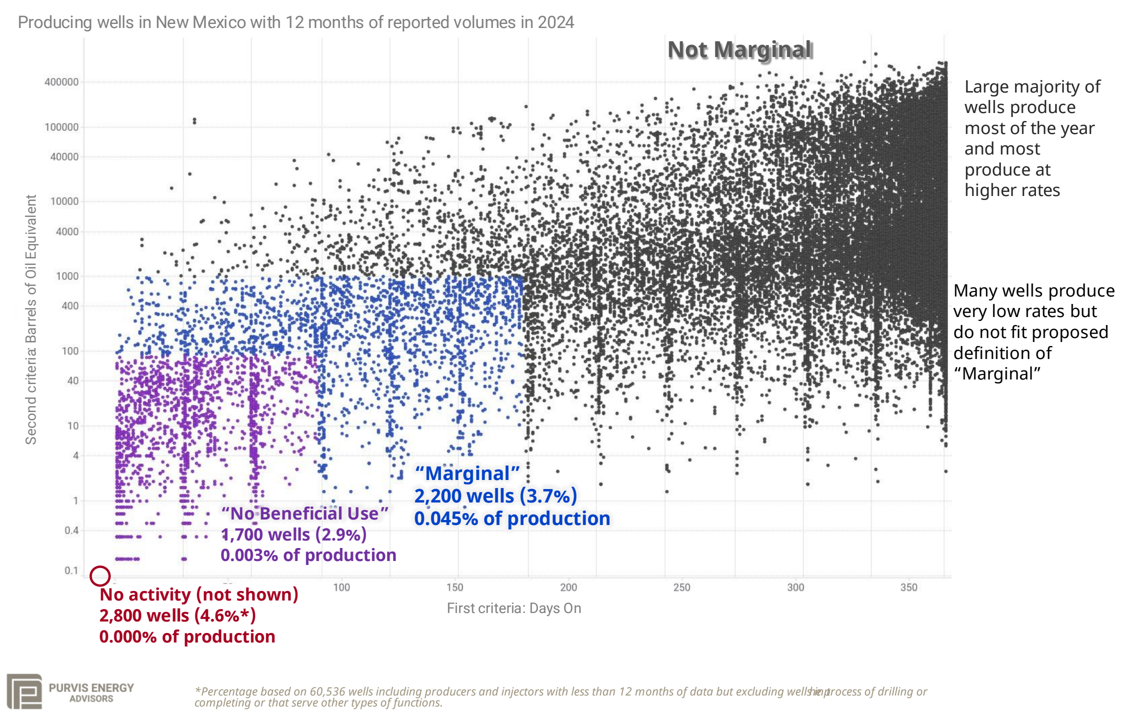
The fact is, if a well is not producing or injecting at that level, that well is limping along and is in trouble. The math is simple: 0.25 BOE per day is 7-8 BOE per month and, at $65 per barrel, yields about $490 per month. After taxes and royalties, you're down to approximately $355 per month. There's no way one can operate profitably like this. What about maintenance? What about keeping the lease safe and tidy? What about having capital for a repair or workover? What about paying other operating expenses such as chemicals, fuel, a pumper, insurance? The list could go on.

If a well is producing at this level and there's nothing in the immediate future that adds value, it's done. This is not a case of premature abandonment, the well is simply done and it's time to move on rather than walk away and leave it to another operator or the State to plug and clean up.

I reiterate that the LFC report stated specifically that the average production rate of 2 BOE per day is the point at which, and below, wells in New Mexico are plugged in recent years. *Id.*

While OCD staff proposed these criteria based on their experience in the field, Applicants' experts have tested the criteria looking at the data, and the data substantiate my view that these criteria are highly conservative. Looking at Applicants' Exhibit 40, developed by Applicants' expert Dwayne Purvis, P.E., the Commission can see that production wells that meet the two criteria for presumption of no beneficial use comprise only **2.9% of the state's active wells, or 1,700 wells,** accounting for only **0.003% of production** in the state.

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



Wells meeting both criteria are the most marginal of wells, and applying agency scrutiny to whether these wells are truly "active" and whether the operator has the financial capacity to plug and abandon wells that they themselves are not generating sufficient revenue to meet plugging and abandonment obligations is entirely appropriate and is in fact prudent, and should help prevent wells from being orphaned and from becoming a liability of the State. Clearly, this class of well in New Mexico warrants additional regulatory scrutiny and is not in a position to be able to generate enough revenue to eventually fund their own end-of-life plugging and site restoration.

Q: NMOGA witnesses object that the presumption bypasses individualized well evaluations and risks premature abandonment of wells that may retain economic or operational value. Felix Test. at 6[12]; Arthur Test. at 9. And, similarly, NMOGA witnesses object that individual presumptions undermine field-level economics and reservoir management. Felix Test. at 6-7; McGowen Test. at 14-15; Arthur Test. at 42. What is your response to these objections?

A: A number of NMOGA witnesses voiced concern over assessing individual wells vs. leases with multiple wells on them. I stand firm on my stance expressed above concerning the propriety of assessing wells with minimal production over a minimal production period as having no beneficial use.

NMGOA's concerns however appear to center around **inactive** wells that may be used for secondary or tertiary recovery, including enhanced oil recovery ("EOR"), or for geothermal energy. However, those **inactive** wells are not subject to the presumptions of no beneficial use.

[12] It's not clear whether Ms. Felix understands that the rebuttable presumption is triggered for production wells that have produced less than 90 BOE **and** produced less than 90 days over a 12 month period. It appears she that may believe the rebuttable presumption is triggered only by the 90 day threshold. Felix Test. at 5-6.

Only **active production and injection wells** are subject to those presumptions. NMOGA, therefore, does not need to be concerned with how the presumptions of beneficial use impact inactive wells that may be targeted for secondary or tertiary recovery. Those wells would be subject to the Commission's current rules regarding TA status in existing 19.15.25.12 NMAC and Applicants' proposed 19.15.25.13 NMAC (but not the presumptions of no beneficial use provisions in proposed 19.15.25.9 NMAC). When I discuss proposed 19.15.25.13 NMAC below, I discuss potential differential treatment for wells that may be used for secondary or tertiary recovery.

Q: Along this same vein, Mr. Arthur complains that the rebuttable presumption assesses only whether a well is producing and does not take account of other beneficial uses such as secondary and tertiary recovery. Arthur Test. at 13. What is your response?

A: This seems like an odd objection. As stated above, the presumptions of no beneficial use apply only to **active production and injection wells**. The presumptions do not apply to inactive wells or wells that are active and are being used for other purposes. If an operator wants to use a well of set of inactive wells for secondary or tertiary recovery, the provisions of existing 19.15.25.12 NMAC or proposed 19.15.25.13 NMAC, governing approved temporary abandonment, apply.

Q: Mr. McGowen objects that the rebuttable presumption means an operator is "guilty until proven innocent" and "ignores valid economic, technical, and operational reasons for temporary inactivity." McGowen Test. at 13. What is your response?

A: I strongly disagree. That a well is operating so few days and producing so little oil or gas provides a more than legitimate factual basis for the State to be concerned whether it is a candidate for P&A or abandonment by the operator. The operator is not "guilty:" the well itself is highly problematic, and it's appropriate for OCD to inquire whether the well has beneficial use and to seek justification from the operator why the well should not be plugged and abandoned.

The proposal in no way "ignores" valid data that the well is productive and the operator does have the ability to P&A. To the contrary, the proposal gives the operator a full opportunity to demonstrate that the well has beneficial use and the operator has the financial capacity to P&A. The presumption is rebuttable with facts and data within the operator's control.

I would also remind NMOGA that the operator has an avenue for appeal as provided in 19.15.25.9.D NMAC in 19.15.4 NMAC. NMOGA witnesses seem to ignore this provision.

Q: NMOGA witnesses object that a 30 day period is too short to submit the required documentation after notice from OCD it has preliminarily determined the well has no beneficial use. McGowen Test. at 101; Arthur Test. at 8; Sporich Test. at 7-8. What is your response?

A: According to Mr. McGowen, operators are "constantly evaluating" their wells' financial performance. McGowen Test. at 101. This is my experience as well. Any prudent operator will have well files, production data, pressure history, maps, and the like that can tell the well's story. Additionally, if there is any other potential beneficial use, the operator would have that available. This 30 day period is not proposed as a time to "dream up" some esoteric idea to keep an otherwise defunct well in operation to avoid the cost of P&A or TA. Therefore, operators should have the information required by 19.15.25.9.D NMAC readily available. Based on my experience, I believe 30 days is a reasonable period. That said, as I understand it, OCD can extend the time period for submission of information if appropriate.

Moreover, Applicants' proposed time periods for submission of information are provisions which could have and should have been discussed with Applicants by industry parties to try to reach agreement. Instead, industry parties chose not to negotiate and have brought what might be unnecessary objections to the Commission.

Q: Mr. Arthur claims that the rebuttable presumption can lead to "premature plugging." Arthur Test. at 13-14. What is your response?

A: I disagree. I have discussed the various provisions proposed in 19.15.25.9 NMAC, presumptions of no beneficial use. To summarize, 19.15.25.9.A NMAC stipulates a level of production that has been discussed as uneconomic at roughly 0.25 BOE per day over 90 days within a 12 month period, and I won't restate that reasoning. In so far as production over time goes, this represents a well that is of no beneficial use. Section 19.15.25.9.B NMAC represents similar thresholds for an injection well. Section 19.15.25.9.C NMAC exempts new wells that await completion. In my direct testimony I discussed examples in which it was not uncommon to drill a number of wells on a pad and to accomplish the completion of those wells *en mass* at a later date for efficiency purposes or awaiting infrastructure development, for example. Section 19.15.25.9.D NMAC gives the operator full opportunity to demonstrate to OCD that the well has beneficial use and the operator has a viable plan to P&A and, and importantly, includes an appeal process via 19.15.4 NMAC. With all that, I don't agree at all that the proposal could lead to premature abandonment. The operator – operating the most marginal of wells -- is given clear performance standards to establish beneficial use, and a process to appeal, all of which in my opinion is more than sufficient to protect against premature closure of a well.

Q: Under Applicants' proposal, to rebut a presumption of no beneficial use, an operator must provide documentation that the well is projected to produce in paying quantities and that the operator is adequately capitalized or has sufficient revenue to meet all P&A and environmental liabilities. NMOGA witnesses object that the concept of

"paying quantities" is not individual well-specific but is a lease-wide concept and therefore the requirement as written doesn't make sense. McGowen Test. at 14-15; Arthur Test. at 9-11. What is your response?

A: I think the point about assessing paying quantities at the lease level vs. the individual well has some merit. Considering assessing whether an individual well is producing in paying quantities, it's a relatively straightforward analysis whether the well's net revenue consistently exceeds the operating costs. In general, this does not include the cost to drill and complete the well. Embedded in whether a well is producing in paying quantities is the reasonably prudent operator rule. The reasonably prudent operator standard is a test to assess whether the lessee operates with the same level of care, skill, and diligence that a reasonably prudent and experienced person in the same field would exercise under similar circumstances. The standard includes consideration of the interests of both the lessee (including working interest owners) and the lessor. Paying quantities can be applied to both single wells and at lease level in my opinion. So, NMOGA's point about assessing paying quantities lease level has merit and, again, I believe this is an issue NMOGA should have raised before the hearing with Applicants and OCD. I note NMOGA offers no constructive alternative language in its proposals.

Q: NMOGA witnesses object that assessing presumptive beneficial use over a 12 month period is too short for adequate assessment. NMOGA recommends using a three to five year period. McGowen Test. at 16-17; Arthur Test. at 8-9. What is your response?

A: Aany prudent operator will know their well or wells intimately insofar as production, pressure, geology, lease provisions, reservoir character, and other characteristics go. A prudent operator would also be aware of any other potential beneficial uses available. This information should be readily available to an operator for a well that produces less than 90 BOE in less than

90 days over 12 month period, and I see no reason to add to another three to five years of evaluation and assessment. Doing so, in my opinion, smacks of unnecessary delay and kicks the can down the road for a well or wells to continue to decline, become a greater liability, and become the responsibility of the State. The three to five year period NMOGA seeks is available in a TA application and, as mentioned before, there is available an appeal process for an OCD determination of no beneficial use.

Q: NMOGA witnesses claim use of the rebuttable presumption can result in "[m]andatory disclosure of proprietary data." McGowen Test. at 18-19; Felix Test. at 6; *see also* McGowen Test. at 26-29 (raising concerns about disclosure of confidential information during TA application process under proposed 19.15.25.13.A & B NMAC).

A: In their objections, Mr. McGowen and Ms. Felix did not cite to the authority that the New Mexico Energy, Minerals and Natural Resources Department ("EMNRD") has under NMSA 1978, § 71-2-8, which **requires** EMNRD to keep confidential the "provisions of any confidential contract or any other confidential information" received from a third party. Violation of that provision is a misdemeanor. Therefore, OCD must keep confidential any legitimate proprietary information or risk legal action. Time and again NMOGA and IPANM witnesses claim that Applicants' proposals will expose confidential business information. But this is just not so. EMNRD's statutory authority already protects such information.

In my experience, this type of confidentiality mechanism works very well. When I was with Southwestern Energy Company ("SWN") and we made our Fayetteville Shale discovery, we were at the state oil and gas regulatory commission many times for untold hours. With hundreds of thousands of acres under lease, we were adamant that proprietary and highly sensitive business confidential information – including logs, tests, maps, seismic information --

be kept confidential to protect our investment. There was already a regulatory mechanism in place to do that and it was extended appropriately. So, New Mexico, as stated above, has a similar vehicle and any concern over confidentiality should be satisfied by that as well as holding hearing wherein the public, that has standing, may attend. In those case, if confidential information must be discussed, that propriety information can be kept confidential.

Q: NMOGA witnesses object that use of the rebuttable presumption can trigger the legal obligation to apply for TA or P&A a well. McGowen Test. at 19-20. What is your response?

A: Under Applicants' proposal, a final determination by OCD that a well has no beneficial use would then require the well to be plugged and abandoned. The purpose of newly proposed 19.15.25.9 NMAC, creating rebuttable presumptions of no beneficial use, is to identify "active" wells that no longer have beneficial use and present a risk to the State, and therefore should be plugged and abandoned by the operator. If, after an operator has submitted information regarding the well's utility and the operator's financial capacity to P&A and address environmental liabilities, OCD finds the well has no beneficial use, the operator would be required to P&A the well.

<u>19.15.25.13 NMAC – Approved Temporary Abandonment</u>

Q: Applicants propose amendments to existing 19.15.25.12.A NMAC -- now proposed 19.15.25.13.A and -B NMAC -- which provide:

> **19.15.25.~~12~~.<u>13.</u>A** The division may place a well in approved temporary abandonment for a period of up to five years <u>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</u>

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.

OXY does not oppose Applicants' proposal "to require operators seeking approved temporary abandonment to explain the purpose of the request, the future use of the well, the period needed for that future use and related information." Wallace Test. at 13, ¶ 57. However, OXY objects to having to produce on a "mandatory" basis the list of information in proposed 19.15.25.13.A that OCD may request.[13] What is your response?

[13] This list is: 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.

A: I appreciate OXY's general support for the proposal in proposed 19.15.25.13.A NMAC and understand its concern, however, OXY is misreading the proposal. The list of information to which OXY objects is **not** information that an operator is **mandated** to provide to OCD; the list represents **examples** of information OCD **may** request if appropriate. Applicants' proposal is clear that "[t]he 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 . . . ." (Emphasis added.) However, any information from the list is to be submitted only if "the division determines [it's] appropriate . . . ." The entire list of information is not required for each submission. All that said, I have no objection to adding language further clarifying that providing the entire list of information is not mandatory.

Q: OXY proposes to modify proposed 19.15.25.13.B NMAC in various ways, including deleting a time limit on renewal of TA status to two years and instead not placing any time limit on a second renewal. *See* OXY Ex. 1. What is your response?

A: I disagree strongly with any proposal to allow a well to remain in TA status indefinitely with no periodic administrative review that the well has beneficial use. Even under the Commission's current rules, TA status cannot continue indefinitely and must be renewed every five years. OXY's proposal would weaken already weak rules and give operators little or no incentive to properly plug and abandon a defunct well after a second renewal. Even OXY witness Kelly Montgomery states that OCD should grant extensions to TA status in "appropriate intervals with supported and approved plans and well testing." Montgomery Test. at 3, ¶ 15 [OXY Ex. 3]. OXY's proposal to allow a well to remain in TA status indefinitely would take the

State backward, not forward.

Q: OXY witnesses specifically object to requiring wells in TA status to go back into use or be plugged and abandoned after the second TA term for wells to be used for enhanced recovery because those well fields take "many years" to develop. Montgomery Test. at 1-3. What is your response?

A: I understand OXY's concern, in that, as an example, development of a limited number of EOR projects could legitimately extend more than the one year of inactivity and seven years of temporary abandonment authorized by Applicants' proposals in 19.15.25.13.A & B NMAC. Any extension, however, beyond the eight years, should be limited in scope (say to EOR/secondary and tertiary recovery), limited in time, subject to periodic administrative review by OCD, and based on solid engineering, technical, and economic information not on guesswork, hunches, speculation or the like. Any such text must be carefully crafted to avoid any kind of loophole leading to abuse. However, although OXY, NMOGA, and IPANM all complain about the eight year deadline, none attempts to craft a serious alternate proposal that would circumscribe any exception to the very few instances to which a legitimate exception could apply. As such, devoid of a specific and reasonable proposal, Applicants' and OCD's proposal is a well formulated and defensible position to address the risk to the state.

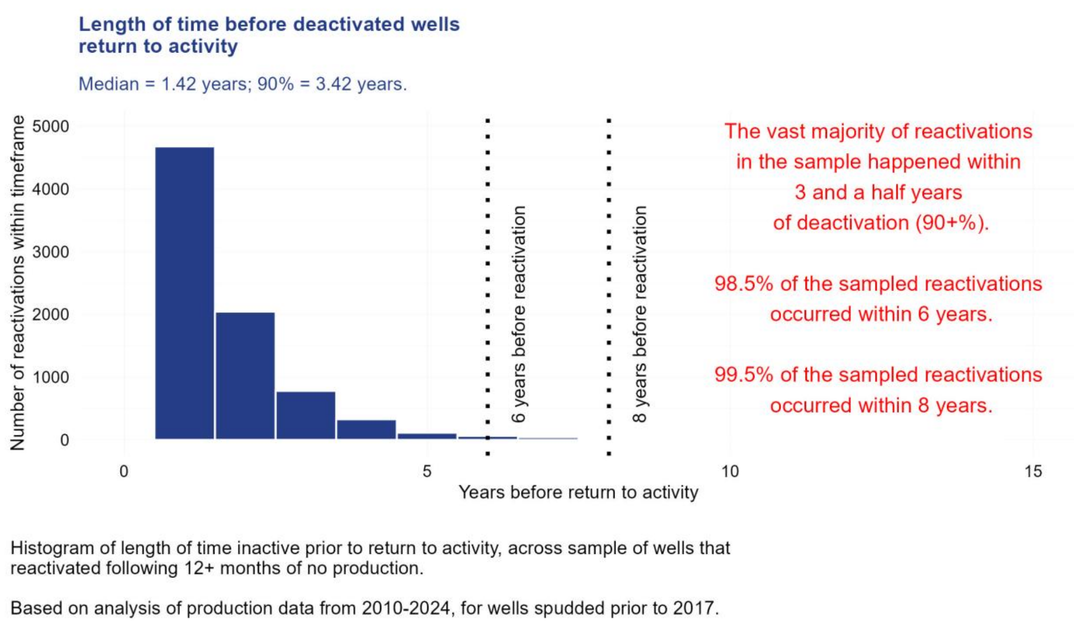
Q: NMOGA witnesses object that the timelines for allowing a well to stay in TA status are too compressed and do not comport with the economic and logistical realities of operating a well. McGowen Test. at 23-25. What is your response?

A: First, NMOGA's witnesses appear to misapprehend Applicants' proposed timelines in 19.15.25.13.A and -B NMAC.[14] However, Applicants' proposal is that an operator would be

[14] *See, e.g.,* McGowen Test. at 23 (the "intent" of Applicants' proposals "is to force a decision

allowed to maintain an inactive well for **eight years**: 12 months of inactivity (+30 days to apply for TA or submit a notice to P&A), five years in initial TA status, and two years in TA status following a public hearing.

Second, while NMOGA witnesses assert that Applicants' proposed timeline would interfere with operators' ability to re-activate wells, the actual well data from New Mexico does not support this claim. The data show that, in Applicants' Exhibit 13, after eight years of inactivity, only **0.5%** of the sampled inactive wells were reactivated. Even after six years of inactivity – the point at which a public hearing would be held – only **1.5%** of the wells were reactivated.



Apps' Ex. 13

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

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point at five years".); *id.* at 53 (Applicants proposed a "shortened 2-year initial TA (versus 5) if they can prove future use, extensions in 1-year increments up to 5 years total idle time . . . .").

wells that have been inactive for eight years to be plugged or go back into use is entirely reasonable based on New Mexico specific data (with a caveat referring to my testimony above regarding a narrowly tailored extension based in limited circumstances).

Q: NMOGA witnesses object that Applicants' proposal would "require operators of wells in expired TA status to reapply for TA or permanently P&A." McGowen Test. at 24. What is your response?

A: My response is that is correct, and that operators with wells in expired TA status should have already reapplied for TA. A well that is in expired TA status is out of compliance with the Commission's rules at existing 19.15.25.12.A NMAC because the operator has not timely applied to extend the TA period. Not only should non-compliance with this critical provision be remedied, but non-compliance with such a critical provision is a red flag that the operator is a greater risk to the State of orphaning the well. If an operator can't be bothered by following the rules and renewing TA status, can that operator be expected to properly P&A when appropriate? Non-compliance is an early warning sign that the State should take notice of. Applicants' proposal – to allow wells in expired TA status to apply to renew TA status – is generous in my view.

Mr. McGowen raises concerns about the "hundreds of wells" in expired TA status that would be required to P&A and the logistical problems that would created. McGowen Test. at 24. These concerns are overblown in my opinion. First, there are approximately 155 TA wells (as of 7/3/25). *See* Apps' Ex. 7. Second, under Applicants' proposal, an operator with an expired TA well has the opportunity to demonstrate that the well has beneficial use under proposed 19.15.25.D(3) NMAC. If it has beneficial use, it may remain in TA status up to two more years. If it does not have beneficial use, then the well rightly should be plugged and abandoned. While

Mr. McGowen raises concerns about a flood of applications to P&A, OCD will be charged with implementing these requirements -- which OCD actually supports -- and to work responsibly and diligently to ensure that both plugging and abandonment and extending TA status are handled appropriately without threats to the environment, as Mr. McGowen predicts. I would add that particularly since OCD supports these measures, it is not probably appropriate for NMOGA, IPANM or others to presume that OCD is not capable of handling its charge. This comment applies to the many other proposals to which NMOGA and IPANM object based on OCD's inability to implement.

The State also currently faces a **major** compliance problem with inactive wells, as demonstrated by Applicants' Exhibit 7, which is an analysis of OCD's Inactive Well List.

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

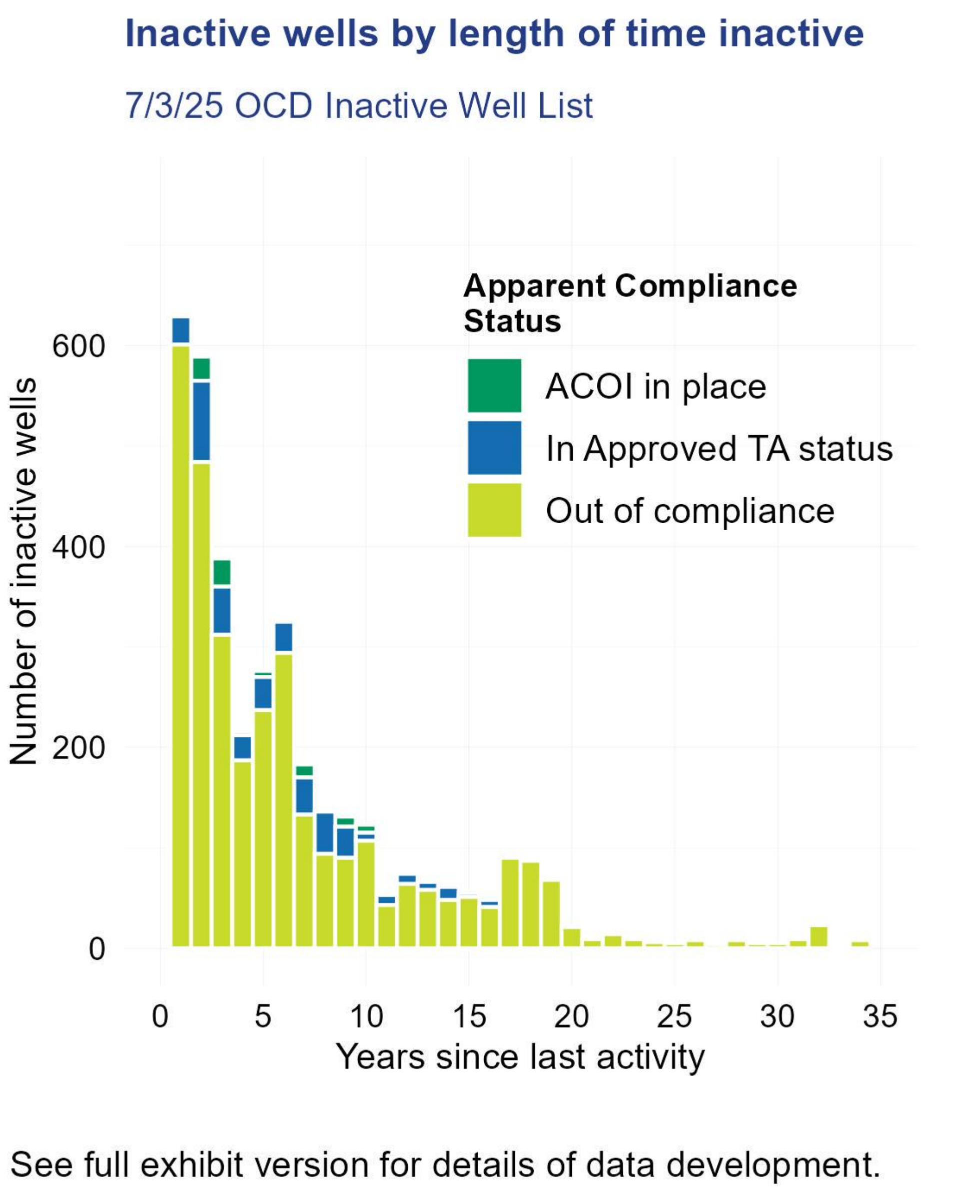
Exhibit 7 shows that on that day, there were:

- 3,765 inactive wells,
- 419 wells in approved TA status,
- 155 wells in expired TA status, and

- **3,234 wells that were out of compliance**.[15]

Only **11%** were in approved TA status while a whopping **86%** of the inactive wells were out of compliance, most of which never went into TA status in the first place. LFC recognized the problem finding that ". . . virtually all wells on the inactive list are eligible for enforcement action . . . ." LFC Policy Spotlight at 18. Applicants' Exhibit 10 below graphically demonstrates the magnitude of the compliance problem the State faces with inactive wells.

[15] These wells are out of compliance with the requirements to plug and abandon or place a well in approved temporary abandonment in existing 19.15.25.8 and -12 NMAC. Most but all of these wells are also out of compliance for purpose of the compliance determination in 19.15.5.9 NMAC.



Apps' Ex. 10

Yet, no NMOGA or IPANM witness recognized the very serious compliance issue the State faces -- with thousands of inactive wells across the State out of compliance -- or recommended any change in rule to address it. Instead of raising every possible objection to

Applicants' proposals to address this alarming non-compliance, NMOGA and IPANM, in my view, should be working with OCD and Applicants to strengthen the Commission's rules to help solve a problem that, according to LFC, puts the State at risk for an estimated at **$700 million to $1.6 billion**. LFC, Policy Spotlight: Orphaned Wells, p. 1. Simply -- how can NMOGA and IPANM seriously ignore this. It makes no sense at all.

These wells are out of compliance with the requirements to plug and abandon or place a well in approved temporary abandonment in existing 19.15.25.8 NMAC. However, some of these wells may meet the current criteria for a compliance determination under 19.15.5.9.A(4) NMAC. That provision allows a certain number of wells to be out of compliance with the requirements of 19.15.25.8 NMAC and still qualify for a compliance determination under 19.15.5.9.A NMAC.[16] It might seem non-sensical to allow non-compliance to qualify as compliance, but that's what 19.15.5.9.A(4) NMAC allows. Applicants propose to delete this loophole and, OXY, at least has not objected.

Interestingly, **almost two-thirds -- 62%** -- of the 350 operators with wells on OCD's Inactive Well List **are out of compliance with 19.15.5.9.A(4) NMAC**, as shown by Applicants'

---

[16] 19.15.5.9.A(4) provides:

19.15.5.9 COMPLIANCE:

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

. . .

(4) 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:

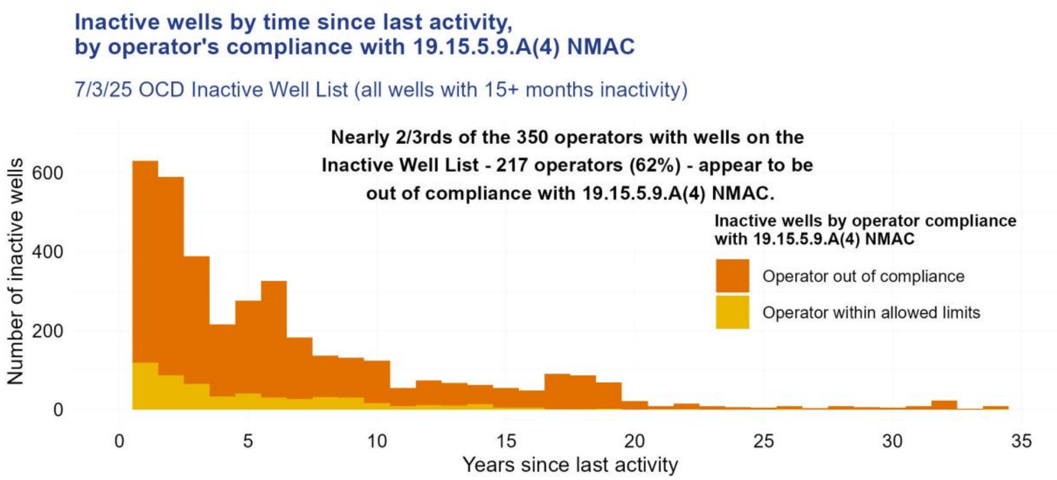
(a) two wells or fifty percent of the wells the operator operates, whichever is less, if the operator operates 100 wells or less;

(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.

Exhibit 83 below. That is, these operators have more wells that should have been plugged or placed in TA under the loophole created in 19.15.5.9.A(4) NMAC.



Data reflect wells included in search results from OCD Inactive Well Search tool as of July 3, 2025.
'Years since last activity' reflects full 12-month years since last reported production date, for wells inactive 15+ months.
'Operator compliance' refers to compliance with NMAC 19.15.5.9.A(4), based on total wells as calculated from OCD's wellhistory dataset.
Assessment steps are described in full in the full-page version of this exhibit.

Apps' Ex. 83

These data further demonstrate the magnitude of non-compliance with the Commission's current rules to plug inactive wells. Increasing the financial assurance for these high-risk wells should incentivize operators to plug them when appropriate.

Q: NMOGA witnesses complain that operators would need to show future use to keep a well in TA. McGowen Test. at 29. What is your response?

A: It is accurate that, under Applicants' proposed amendments for 19.15.25.13.A and -B NMAC, operators must show future beneficial use. Requiring such a showing, which other states do, is one of the principal requirements of Applicants' proposed amendments. If a well has no future utility, it should be plugged and abandoned. Otherwise, the longer a well with no future use sits idle, the more likely it will become the State's responsibility to P&A and remediate.

Q: NMOGA witnesses the information required to demonstrate a well has future utility is vague, rigid, and excessive. McGowen Test. at 27-29; Felix Test. at 35-36; Arthur Test. at 16. What is your response?

A: I disagree. The proposed provisions are not vague, rigid, or excessive. As discussed above, Applicants propose the operator demonstrate "the well will be used for beneficial use" within the requested TA period and the demonstration 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," other information OCD determines appropriate, which may include various identified types of information. The showing required to demonstrate future utility of a well is straightforward and seeks information that any responsible operator should have. Similarly, the types of information that OCD may request, if appropriate, are specific and are relevant to a determination of future use of a well.

If an operator wants to extend the five year TA period, the operator must have a health and safety plan, which is appropriate if a well will be in TA status for an extended period because of failure and contamination increases with time.

The demonstrations proposed to be placed in and to extend TA status are appropriate and require information that an operator should already either have or have access to. Again, the information is simply that information needed to justify the request. No one is going to be asked to go out and shoot miles and miles of 3D seismic imaging just come up with the data needed to adequately defend the request.

Q: NMOGA witnesses claim the required demonstration that a well has future beneficial use could require disclosure of confidential or proprietary information.

McGowen Test. at 26-29; Felix Test. at 35-36; Arthur Test. at 16. What is your response?

A: I addressed this concern earlier: in his objections, Mr. McGowen did not cite NMSA 1978, § 71-2-8, which **requires** EMNRD to keep such information confidential or risk legal action. There **is** a mechanism in place to protect the confidentiality of legitimate confidential business and proprietary information.

Q: Ms. Felix claims that "requiring mandatory reapplication for approved temporary abandonment upon expiration would flood" OCD with paperwork. Felix Test. at 36. What is your response?

A: The Commission's current regulations currently require reapplication to extend TA status. *See* 19.15.25.13.A NMAC. Applicants' proposals do not change this requirement.

Furthermore, as I have observed, there is compliance problem with operators meeting the requirement to reapply to extend TA status as well as moving hundreds of wells from inactive to TA status. The problem is not with OCD being able to necessarily handle applications for TA or TA extension, but with countless operators being out of compliance and essentially ignoring established regulations which in my view is totally unacceptable. I can tell you in my company, SWN, if we carried on like that, heads would have rolled. No question about it.

Q: NMOGA witnesses object to allowing "interested persons" without traditional "standing" to intervene in a hearing before OCD to extend TA status under proposed 19.15.25.13.B NMAC because of potential added expense, delay, uncertainty, and risk. McGowen Test. at 25; Felix Test. at 36; Arthur Test. at 16; Sporich Test. at 18. What is your response?

A: Whether a well should be plugged and abandoned is an important issue to the public; the impact is not limited to neighboring properties who may be directly affected. If a well is not timely plugged and abandoned, public health and the environment can be threatened. If a well is orphaned, it becomes the State's responsibility to undertake the work to P&A and to finance that work. Inactive at-risk wells are a public issue and a serious nuisance , and the public should have a right to participate in the decision to extend TA status. The hearing provision allowing interested persons to participate promotes government transparency and public participation in a matter of public importance and, in my opinion, should be adopted by the Commission.

Q: OXY objects to setting a time limit of three years for existing inactive wells to be able to apply for TA status. Proposed 19.15.25.13.D(1) NMAC 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.

OXY recommends this provision be changed to allow wells in inactive status -- no matter how long -- either to be placed back into production or apply for TA status. What is your response?

A: I don't agree with OXY's proposal. I believe that a well that has been in inactive status for a lengthy period of time should be required to plug and abandon. If a well has been in inactive status for more than three years (without an agreed upon compliance order), it has been out of compliance with the Commission's rules for three years. That is already a red flag the well is at risk. As shown by Applicants' Exhibit 13, after a well has been inactive for more than three years, the chance of it being reactivated is small, approximately 11%. The data do not support the well will be reactivated after a three years of inactivity (and out of compliance). And there is no good justification for allowing a well that has been inactive for extremely long periods, 10 years or more, not to plugged and abandoned. Those wells (and operators) are flagrantly out of compliance and at high risk of becoming orphaned and the responsibility of the State and no operator should be rewarded for such outrageous behavior.

19.15.25.15 NMAC – Demonstrating Mechanical Integrity

Q: NMOGA witnesses object to Applicants' proposed amendments to 19.15.25.15 NMAC (existing 19.15.25.14 NMAC), which add additional requirements to the mechanical testing requirements for TA wells as unnecessary, costly, and inconsistent with regulatory norms. McGowen Test. at 29-41; Felix Test. at 38-39; Arthur Test. at 17-22. Applicants propose adding the following requirements:

> **19.15.25.~~14.~~15**
> **A.**
> . . .
> (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.
> . . .
> **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.

What is your response?

A: These additional requirements were initially proposed by OCD technical staff. In general I agree with the requirement but I believe there ought to be a variance provision as well.

Passing a pressure test as described is in order, of course. However, it is just one data point and who's to know if there will be a mechanical failure five minutes later. A caliper log and casing integrity log will help not only OCD, but the operator as well, know if there is a developing problem with the casing and to be wary of resting alone on a one point in time pressure test. I read with interest Mr. McGovern's testimony pointing out the measurements and their strengths and weaknesses and don't disagree, having run many myself as an operator. By the way, the results aren't that difficult to interpret.

I think there is a good case to be made for wells that might not really need the additional data from those logs. Wells that are relatively young and aren't in areas with specific and historical corrosion issue might be exempt. This is yet again a situation that could have been discussed and a negotiated compromise likely reached. But as I've said before, NMOGA and IPANM refused to meet and talk about issues such as this, so they just want to outright try to deny the additional requirement, which in my view could be very beneficial to know more about the critical mechanical state of a well. Knowing this kind of information might help prevent an unanticipated failure leading to an uncontrolled release of wellbore fluids which is unacceptable. It might also give the operator ample warning of a potential failure thus giving the opportunity to repair the well before it becomes a problem, particularly if NMOGA and others succeed in denying that plugs be left in the hole during TA.

Furthermore, just because, as Mr. McGowen says, running these logs is inconsistent with regulatory norms, doesn't mean it does not have merit. Mr. McGovern's position (and others) is exactly like saying, "well, we've never done it this way before, therefore, let's don't do that." If I've heard that once in the oilfield, I've heard it a thousand times. Had SWN and my team had that kind of attitude, the Fayetteville Shale would never have been discovered much less become as profitable as it was.

In the case of the extra logs, I do recognize that there are cases where it would likely be overkill. I recommend working collaboratively to develop an exception or variance based on well-reasoned facts but keep the requirement because there will be numerous situations in which having the data is proper and may well avoid a bad situation from developing. This applies especially to older wells, constructed with standards and materials not up to par with what we know today.

Q: Ms. Felix objects to requiring a bridge plug or packer to remain in place during TA because it could create safety and monitoring issues and, if they fail, they can create more risk than they prevent. Felix Test. at 38-39. What is your response?

A: The answer to this issue is simple. In my experience drilling out cement plugs and cast iron bridge plugs is no big deal if you know what you are doing and the casing is in good shape. I can't count the number I have either done or been responsible for doing. Drilling out packers and retrievable bridge plugs is a bit more of an issue but certainly doable. There are situations, like offset operations in a zone, where one would definitely want a zone more secure than just hydrostatic head and a shut-in master and/or wing valve. What if the cement sheath is not good and a channel exists? Offset operations in another zone could communicate with the zone to be TA'd. The situations are numerous that favor a more secure method of TA. I saw in the few C-103's submitted for TA in which operators proposed leaving the plugs anyway, and therefore it's not a novel concept in New Mexico and it's certainly more safe that leaving the hole open with only fluid backpressure as the primary barrier between surface valving.

Certainly, if one wanted to monitor the zone being TA'd, having a plug in place is an issue. But wouldn't you cover the zone with fluid for back pressure? If not, is Ms. Felix suggesting that to TA, just shut in the wing valve and master valve, which would be insufficient? I'm not sure what kind of monitoring is being alluded to.

However, let's discuss development of a way to address this issue. If the operator can provide legitimate, fact-based information in support of not leaving a plug in the hole, then OCD can evaluate the proposal and make a determination.

Q: According to Mr. Ezzell, "[p]roperly equipped, inactive wells that are periodically checked do not pose any immediate threat to public health and welfare." Ezzell Test. at 48. What is your response?

A: As a general comment, Mr. Ezzell's statement has some legitimacy. However, it absolutely does not apply to all wells and reliance upon it could prove dangerous. On a number of occasions I have pointed to the potential issues with older wells, especially if little or nothing is known about the primary (or secondary) barriers. Mr. Ezzell assumes a well is "periodically checked." . What is periodically? The Commission's current TA rules do not require periodic checking except every five years upon renewal of TA status. That is not sufficient to check for malfunctions of the casing and environmental contamination. What is being checked? Are there homes, schools, businesses near the well? Is the well on a lease with several other wells? What zone or zones are we talking about? Are there any corrosive zones in the well? Are there under and over pressure zones? Literally, books are written and records are replete with examples of wells gone bad that were considered "safe." In my experience as Vice President in charge of Health, Safety and Environment for nearly four years at SWN (plus close to 37 years in other operations), I learned to take nothing for granted. The showings Applicants propose for a well to be placed in TA status and to extend TA status and the additional safeguards recommended in proposed 19.15.25.14.B(2) NMAC (ensuring no air emissions) and in 19.15.25.15 NMAC (mechanical integrity) much better ensure that TA wells will not pose a threat to the environment, "public health and welfare" than the Commission's current rules, and I strongly recommend their adoption as an experienced health and safety professional in the field.

This concludes my rebuttal testimony, which is accurate to the best of my knowledge.

/s/ Thomas Alexander September 17, 2025
Thomas Alexander Date

EXHIBIT 74

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

REBUTTAL TESTIMONY OF DWAYNE PURVIS, P.E.

Table of Contents

Apps' Ex. 74

INTRODUCTION

Q: Please state your name.

A: Dwayne Purvis.

Q: Did you provide direct testimony in this matter?

A: Yes. My direct testimony was previously submitted as Applicants' Exhibit 30.

Q: Are your qualifications and background set forth in that testimony?

A: Yes, on Bates stamped pages 0689-91 of Applicants' Prehearing Statement, and my resume is Applicants' Exhibit 29.

Q: Did you review references for your rebuttal testimony?

A: Yes, they are listed at the end of my testimony.

OVERVIEW OF INDUSTRY DIRECT TESTIMONY

Q: Have you reviewed the written testimony of industry witnesses submitted at the same time as your testimony?

A: Yes, I read or reviewed the direct testimony of witnesses from all participants including from the New Mexico Oil and Gas Association ("NMOGA"), Independent Producers Association of New Mexico ("IPANM"), and OXY USA, Inc. ("OXY").

Q: At a high level, what most stood out to you about the submissions?

A: There were certainly a lot of experts and a lot of points of contention, but three themes stood out to me.

It seems to me that many of the arguments boil down simply to the assertion that the proposal is not how things have been done in the past, that the proposal represents big changes. The vigor of the arguments almost seems to imply that the oil industry cannot adapt to higher standards to meet the current day realities. Second, the bulk of the arguments against the proposals focus on claims about the *cost* of the proposals to the industry and thus indirectly to the state. Third, they raise many potential problems with the specifics of how Applicants' proposals would be implemented.

But most significant to me was the paucity, even the near absence, of arguments by NMOGA and IPANM experts that a change in financial assurance is needful. (OXY seems to acknowledge the need that has been identified by the Oil Conservation Division ("OCD") and other agencies in the state government.)

<u>Changes from historical practice</u>

Q: In your opinion, do Applicants' proposed changes deviate from historical practice, and does that matter?

A: The proposals do differ from historical practice in many ways. As I said in my direct testimony, I see the changes primarily as increased accountability. They are intended to deviate from historical practice in order to achieve a better outcome.

I do think that the upstream oil industry is great at solving problems, but only the problems that they need to have solved. Of course, the easiest and best way to solve the problem of increased requirements is to prevent them, hence the present dispute. But if reforms are made, then I believe that the industry at large has the skill, will, and motivation to adapt to regulatory changes. In fact, research into an economic theory called the Porter hypothesis has showed that stricter environmental regulations often *cause innovation*. (Zhang 2024) Regulations make it necessary to find a solution that had not been found under previous requirements.

It is easy to see how an industry long accustomed to having a generous range of options could feel like a loss of options is bias or even oppression by the regulator. I agree that the proposals deviate, that they tighten options available to industry, but I see that fact as inherently neutral, a fact which should be evaluated on merits with today's knowledge not dismissed because of yesterday's assumptions.

<u>Cost to the industry and the public</u>

Q: What is your response to industry's objections based on the cost to the industry and to the public?

A: I struggle to imagine any regulation on any industry that does not come with a cost to that industry; regulation hardly seems necessary in the presence of existing financial returns. But the question facing regulators is whether the regulation is in the public interest, looking at the balance of public costs and benefits, not merely investor returns.

As I said in my direct testimony, the insufficiency of financial assurance has been allowed to grow so large already in New Mexico that there is no course correction that will not create painful costs for the industry in the short term. But right now, the state and nearby communities are bearing the risks and costs of inadequate financial assurance and are facing a much greater risk in the future. The Oil Conservation Commission ("Commission") needs to supervise the oil and gas industry not for the public good not over the next couple of years but for the remaining decades of its lifecycle.

Q: We will talk more about specifics claims of industry experts, but what are your observations about the overall evidence supporting those arguments about those costs?

A: On both short and long time frames, industry arguments emphasize conceptual costs but without quantification. That is, they discuss assumed directional effects with little or no facts, figures, or analysis to support the significance or even, in some case, the existence of the cost. In the same way that correlation is not causation, direction is not magnitude, and salience is not significance.

Q: Why does this matter?

A: Policymaking must balance benefits and costs, and the Commission in this case should evaluate the nature and magnitude of the costs—not just their possible existence—to strike the best balance.

While industry witnesses do not quantify the costs, they do claim or imply that there will be dire consequences for oil and gas companies in New Mexico if Applicants' proposals are accepted. Words like "small," "significant" and "meaningful" have little meaning without context and supporting evidence. The sums involved run into the 10s or 100s of billions of dollars, and the largest companies are about five orders of magnitude larger than the smallest. Something significant on an absolute scale can be minute or even trivial on the scale of the whole.

Q: Do you believe the financial consequences to industry from the proposed increases to financial assurance will be severe?

A: Yes and no. As I said in my direct testimony, the consequences will be severe to some companies, but I still don't see any evidence that consequences would be severe for the industry as a whole or for the State of New Mexico.

The companies most affected will be those who have positioned themselves near the edge of insolvency and, simultaneously, have not saved the money necessary to fund their statutory obligations. Companies that have made or still can make appropriate plans for their obligations should be able to meet the increased accountability. As for the secondary consequences to the public of the primary consequences on companies, the effects should be expected to be small. The same impecuniosity that puts some companies at risk means that they contribute little to energy supply and to the local economy.

The bigger answer, though, is no. While there will be consequences to segments of companies based own past choices, my analysis shows that the consequences will not be nearly as severe to the industry as a whole as argued or implied in some of the testimony.

How the accountability is implemented

Q: What is your response to industry experts' objections that Applicants' proposed rules are difficult or impossible to implement?

A: The testimony does wrestle with a dilemma faced by anyone trying to formalize and codify ideas into enforceable laws or regulations, specifically the tension between the need to be clear, explicit and uncomplicated and the need to be flexible, widely applicable, and forward-compatible.

It is an interesting paradox that sometimes industry witnesses criticize the proposals as too vague and sometimes as too specific, either taking too much time to apply or being too rigid. In some cases, when the proposals are written to emphasize the principles more strongly in order to provide flexibility, industry witnesses object that the proposals are too vague to apply or too burdensome to perform. When other proposals include clear, explicit, concrete specifications which are efficient to apply, industry witnesses object the proposals are too prescriptive or too restrictive or too rigid.

Some policies specify which solutions much be used, some specify which outcome must be obtained, and some specify the principles that must be applied. I think that principal-based rules are the most flexible and the most effective assuming they are administered with integrity. They may cost more time and effort to implement, but given the billions of dollars of liability that should be properly managed in New Mexico, the decision consequences are vastly more costly than a flexible decision process. In this case, it seems to me to be penny-wise and poundfoolish to risk the effectiveness of the desired outcome in order to minimize the process. More simply, higher quality decisions require and deserve more intensive processes.

Q: How do those principles apply to the current situation?

A: In my opinion, the Commission should write the new regulations within the bounds of its statutory authority to create the greatest net benefit to the public, and it should write the specifics of the regulations to consider how behaviors, knowledge, and the industry itself will evolve. The policies should be simple and clear without significantly compromising effectiveness now or in the future.

<u>Need for change to financial assurance requirements</u>

Q: If good policy balances public benefits and costs, then what did you find in the direct testimony from industry organizations about the public interests that the financial assurance proposals are intended to address?

A: I found precious little argument from industry that New Mexico's system of financial assurance does *not* need some kind of reform. The problems with historical financial assurance are widely understood. A number of states have made reforms or are considering reforms, and a number of state agencies have examined the needs for a change in New Mexico. Though emphasizing mechanisms of unquantified costs to the public, experts offered by industry say little about public need and interests. I find only three, modest arguments about this side of the scale.

Mr. George Sharpe, at 6, testifying on behalf of IPANM based on his decades of experience within Merrion Oil & Gas concluded,

> *[T]he rule is unnecessary because most operators are reputable operators like Merrion who plug their uneconomic wells on an ongoing basis. Rules are already in place to address the bad actors who let their wells languish and it is difficult to envisage any of those operators changing their behavior based on this proposal.*

The argument is pure opinion, subjective and anecdotal and not a suitable basis to deal with a multi-billion dollar risk.

Mr. Dan Arthur, at 30, on behalf of NMOGA offers a similar opinion but with only a single, dubious point of evidence and still seems to concede the need for some kind of reform.

> *In practice this risk appears to be consistently low. OCD has only pursued forfeiture on one (1) bond in the last five years. . . . [I]n my opinion, there are better, more tailored ways to decide on appropriate levels of financial assurance.*

As other testimony addresses with firsthand knowledge, the lack of forfeiture has more to do with the insufficiency of the bonds than the lack of need.

The most specific evidence against the need for reform comes from IPANM witness Dr. Robert Arscott who cited three academic papers to arrive at the conclusion that setting financial assurance below actual cost "can be" a net benefit to the public. What seems to be the best-supported argument against higher bonding arrives at the mere conclusion that it is *possible* that setting bonding below the expected costs creates more social benefit.

Dachis (2017) cited by Dr. Arscott concludes more precisely:

> *First, we recommend the province introduce an upfront bonding requirement. However, this bonding requirement should be less than the full expected liability cost.*
>
> *Second, once a well enters the inactive phase, the province should require companies to hold insurance to cover the cost of cleaning up the well.*

Boomhower (2019) cited by Dr. Arscott about the experience in Texas is also clear:

> *The introduction of an insurance requirement [in Texas in the early 2000s] caused producers to internalize a greater share of environmental costs through premiums paid to private insurers. Reducing firms' ability to avoid liability through bankruptcy caused an immediate change in industry composition. About 5 percent of firms, especially small firms and firms with poor environmental records, left the industry. Production was reallocated from small to large producers. Very low-producing projects, which were most likely to have been socially inefficient after considering environmental costs, were shut down. However, the overall rate of oil and gas production in the industry was unaffected.*

> *The results suggest that by screening out firms and wells that insurers perceived to be high risk, and increasing accountability for remaining firms, the bond requirement mitigated the harmful incentive effects created by bankruptcy protection. A back-of-the-envelope comparison of the value of avoided environmental damages and compliance costs suggests that the policy yielded substantial welfare gains.*
>
> *[I]t seems likely that somewhat higher bond requirements could yield further benefits given that Texas' requirements are still below potential damages.*

Dr. Arscott did not cite the more extensive literature cited by Dachis (2017) or published subsequently. For example, about Pennsylvania:

> *The results of the cost benefit analysis suggest that current bonds are too low. By setting bonds to closely match reclamation costs, Pennsylvania would have to give up relatively little to prevent taxpayers from bearing reclamation and environmental costs. . . . Increasing bonds to match the best estimates of reclamation costs is likely to create a socially desirable outcome. . . . In the majority of plausible scenarios, these benefits outweigh the wages and royalties paid to state residents that would be forgone if operators respond to increased bonds by drilling fewer wells. (Harleman 2018)*

Or about Alberta:

> *If decommissioning costs are not being internalized, the development of oil and gas reserves would be at a rate above what is socially optimal. The policy implication would be to create stronger mechanisms to internalize the costs of decommissioning. One such mechanism is to increase bonding requirements, which are arguably too low at present. This article demonstrates that in designing policies to decommission oil and gas wells, unnecessary weight has been placed on not jeopardizing production. (Muehlenbachs, 2015)*
>
> *This implies that wells are typically left suspended not because of the option to reactivate, but rather to avoid costly environmental obligations. . . . Thus, the regulatory requirement (or lack thereof) is introducing a high risk of potential future liability for both the industry and taxpayers as most of these suspended wells are not assets. . . .*
>
> *The paper summarized here demonstrates that policies for plugging and abandoning oil and gas wells in Alberta are biased towards inexpensive potential restart rather than environmental protection or remediation. (Muehlenbachs, 2017)*

Or about national bonding policy:

> *Although they have important limitations, bonding requirements are well suited for*

> *addressing many of the relevant environmental risks and are effective . . . . Bonds provide a source of funds for cleanups when necessary and, more importantly, an incentive for producers to make efforts to avoid environmental damages altogether.*
>
> *[I]n theory, negotiating bond amounts on a well-by-well basis could lead to more efficient bond amounts, in practice it adds to the overall economic cost of bonding requirements because it causes the diversion of resources to non-productive uses, such as negotiating with regulators over bond amounts. (Davis, 2015)*

Or about the experience in North Dakota:

> *In discussing the rule changes, the president of the North Dakota Petroleum Council stated "They are the most onerous regulatory changes we've ever seen," and considered North Dakota's regulations "now overly burdensome and among the most stringent and costly in the nation."*
>
> *Results find no statistical change in the pace of drilling wells after the ND regulations came into effect. This result is consistent across multiple specifications, including different bandwidths and functional forms of the data. Production of oil did not on average decline with the imposition of the ND regulations, however the distribution of production amongst firms did change.*
>
> *The reduction in production for small operators in ND after the regulation went in effect, relative to production in MT, is about 0.5%. The reduction in production from small operators seems to be coming from operator exit.*
>
> *Taken together, these results imply that. . .the regulation had little, if any, impact on drilling and production. . . . (Lange and Redlinger, 2018)*

I continue to opine based on my review of the situation in New Mexico that protecting the public from future orphaning of oilfield infrastructure requires at least a change in the system of financial assurance.

APPLICANTS' PROPOSALS

19.15.2.7.B(7) NMAC – Definition of Beneficial Purposes and Beneficial Use

Q: Let's now consider the specific proposals put forth by Applicants in order of how they appear in the rules. Applicants' proposal creates a definition for "beneficial purposes" and "beneficial use" then uses that definition in requirements for plugging and abandonment or temporary abandonment in Part 25, with potential implications for

increased financial assurance in Part 8. In your view, does it make sense to identify extremely low producing wells as wells which, presumptively, have no beneficial use?

A: Existing rules in New Mexico require a well to be plugged or temporarily abandoned within 12 months of last activity without regard to the significance of the preceding activity (with a three month grace period). Consequently, companies can currently side-step the rule with a technicality; they can operate the well for a trivial number of days with trivial production so that activity is non-zero.

In order to accomplish the purpose of the existing rule, it does make sense to me to close that loophole.

Q: The proposed definition for "beneficial use" provides:

> **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.

NMOGA and IPANM witnesses object that the term "speculative" is overly vague and a determination whether a beneficial purpose or use is "speculative" is subjective and arbitrary. Arthur Test. at 4-7 [NMOGA Ex. C]; McGowen Test. at 9-14 [NMOGA Ex. D]; Sporich Test. at 2-5 [NMOGA Ex. E]; Emerick Test. at 298-303 [NMOGA Ex. F]; Ezzell Test. at 42-44 [IPANM Prehrg. Stmnt.]. What is your response?

A: In general use, the word "speculative" does not have a quantitative meaning, but I don't think that renders it entirely subjective or arbitrary. I interpret "speculative" to mean the absence of information to justify a reasonable expectation for success, and that seems to me like a reasonable standard.

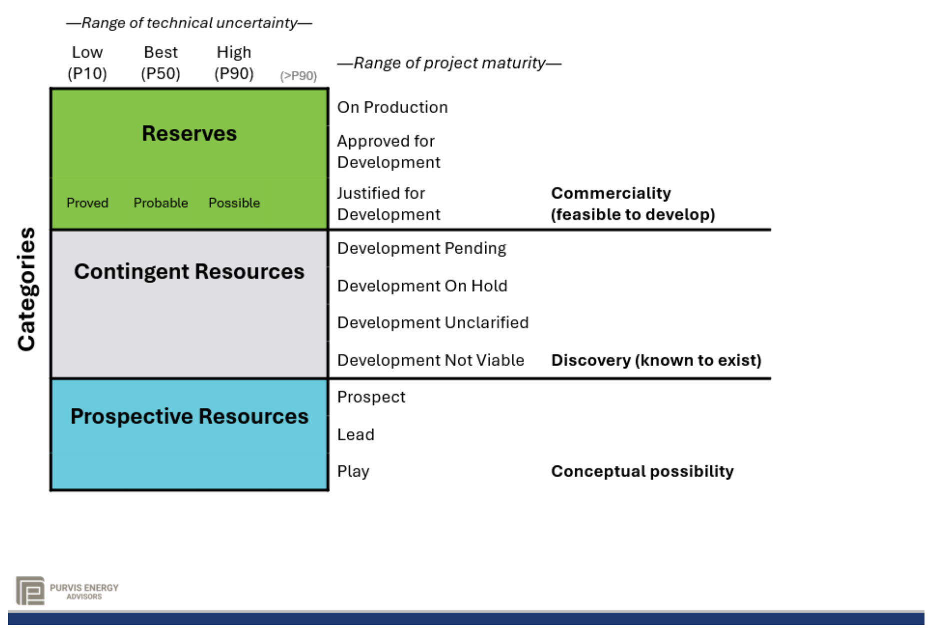
The benefit of being less specific is being more flexible. The more specifics prescribed in the regulations, the less they can adapt to changing technology or other conditions. Explicit prescription could also be called “rigid,” and the more specifics included the more research must go into the formulation now in order not to be “arbitrary.” Perhaps the difficulty is the reason why the people making the objections seem not to offer a better alternative.

If the Commission wanted to be more specific but still principle-based, then the rules could be guided by the Petroleum Resources Management System (“PRMS”, *Petroleum Resources Management System, Revised June 2018*). This system for the classification and quantification of resource volumes has existed for decades and been regularly refined and expanded. It is created by the Society of Petroleum of Engineers in consultation with and endorsed by every major professional society for oil and gas in the United States and beyond: Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, American Association of Petroleum Geologists, World Petroleum Council, and European Association of Geoscientists & Engineers. The classification system relies on principles and their judicious application that are well-defined and well-known.

Applicants’ Exhibit 75 below summarizes the key boundaries in the classification system. If a field has not been discovered yet, then the estimates of potential recovery are called “Prospective Resources.” At one point in time, they were called “Speculative Resources,” and this end of the range is speculative. Once a field has been proved to exist, the volumes of potential recovery are called “Contingent Resources,” and many project move through this category quickly. Recovery passes into the category of “Reserves” when they are determined to be “commercial.” That is, the company has a “firm intention to proceed with development within a reasonable time-frame” because the project has met multiple criteria including technical maturity, operational feasibility, economic viability, financial feasibility, legal and regulatory permission, and internal justification.

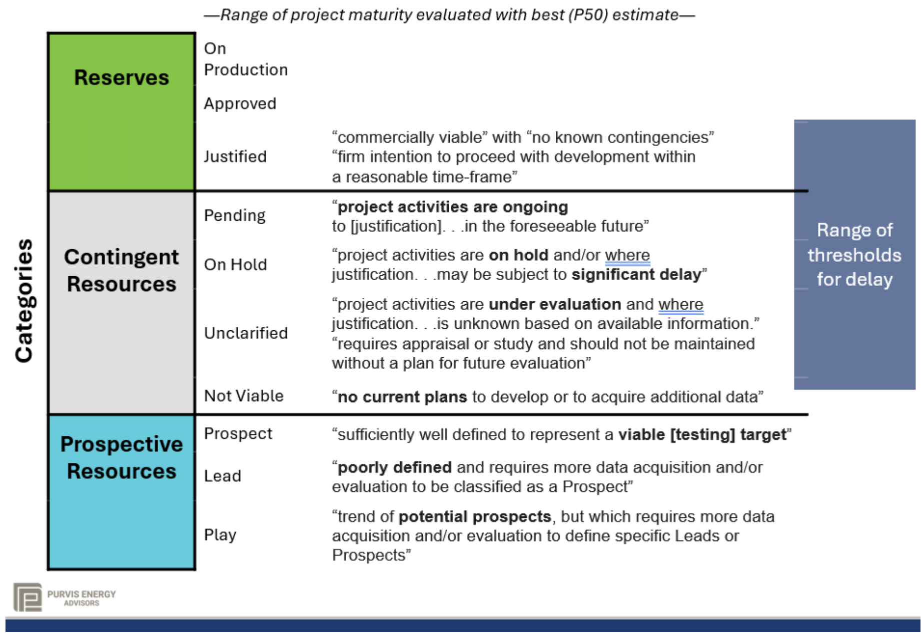
These two bright lines—discovery and commerciality—separate the categories relevant for this discussion. And it is this middle stage of maturity which could be used by the Commission as the criterion for beneficial use. (Of course, the project maturity framework would apply not just to the production of hydrocarbons but also electricity generation or energy storage as some concepts envision.)

Applicants' Exhibit 75: Resource categories and subdivisions of technical uncertainty and project maturity.



If a project is merely conceptual like Prospective Resources, then it is clearly speculative. If the company has fully evaluated and intends promptly to execute a project with a wellbore like "Reserves," then the wellbore clearly has beneficial use. The middle area is "Contingent Resources," meaning that the project is not proceeding because of "one or more contingencies" related to the commerciality criteria. Applicants' Exhibit 76 below adds the descriptions of the relevant sub-categories of project maturity.

Applicants' Exhibit 76: Resource categories and subdivisions of technical uncertainty and project maturity, including definitions.



The maturity sub-categories are differentiated first by the status of evaluation work and second by the outlook for successful justification and use. If development is deemed "Not Viable," then I would call it "speculative" under Applicants' proposal. Like Prospective Resources, the possibility of creating value still exists, but in the context of these regulations, the remoteness renders the hypothetical possibility less important than the need for plugging and abandonment. At the other end of the range, if a project is being evaluated and is expected to justify action in the near future ("Pending"), then I would say that the project has beneficial use under the proposal.

The real debate occurs when evaluation has stopped ("On Hold") or the multi-criteria justification looks dicey ("Unclarified"). The Unclarified sub-category should be temporary, not chronic. So, it could be used to justify beneficial use but only long enough to allow for the necessary scope of evaluation. More broadly, the question of speculation for projects On Hold or Unclarified pivots on the probability of the project becoming justified in the future, that is, the collective probability of passing all the criteria into action. Section 2.1.2.1 of the PRMS reads in part:

> *Commerciality is achieved with the entity's commitment to the project and all of the following criteria:*
>
> *A. Evidence of a technically mature, feasible development plan.*
>
> *B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.*
>
> *C. Evidence to support a reasonable time-frame for development.*
>
> *D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. . . .*
>
> . . .
>
> *G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming. . . .*

That is to say, commerciality requires having clear plan of what to do, enough confidence in the technology to do it, the ability to do it operationally, sufficient economic returns, the capital necessary, and the intent to use that capital. The more contingencies remaining unresolved, the less likely the aggregate probability of development.

Among these, the economic criteria cover such a wide range of possibilities that the PRMS defines terms to further clarity in Section 2.1.3.7:

> *Economically Viable Contingent Resources are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the [other] commercial criteria defined in Section 2.1.2.*
>
> *Economically Not Viable Contingent Resources are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.*

For a project to qualify as Reserves, it must be economic under *current* conditions, but Contingent Resources can be called "economically viable" if they would be economic under "*reasonably forecasted conditions*." That is, if commodity prices would have to increase dramatically to meet investment criteria, then the contingent project is "not economically viable."

Building on this system of classification, the Commission could cite the PRMS as guidance, or the Commission could apply the principles: A potential use is not speculative if the use is fully evaluated or actively being evaluated, is economically viable in the most likely scenario of performance, and uses a technology sufficiently mature such that the operator can and would execute the project within a reasonable time.

19.15.25.9 NMAC – Presumptions of No Beneficial Use

Q: Applicants' proposed 19.15.25.9 NMAC, establishing rebuttable presumptions of no beneficial use, provides:

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.

Under Applicants' proposal, to rebut a presumption of no beneficial use, an operator must document that the well is projected to produce in paying quantities and that the operator is adequately capitalized or has sufficient revenue to meet all plugging and abandonment ("P&A") and environmental liabilities. NMOGA witnesses object that the concept of "paying quantities" is not individual well-specific but is a lease-wide concept and therefore the requirement doesn't make sense. McGowen Test. at 14-15; Felix Test. at 6-7 [NMOGA Ex. B]; Arthur Test. at 9-12. What is your response?

A: The phrase "producing in paying quantities" is certainly used in mineral leases, and, in that context, it does in my experience apply at the lease level. That does not mean, however, that the same phrase cannot be applied to individual wells in this separate context.

It is standard practice to project production, costs, and economic life for each well separately and independently, so it comports with standard practice as written. Moreover, it is simple to make an economic calculation instead at a lease level and to calculate when an individual well is no longer contributing to lease-level economics, *i.e.*, when it is no longer "producing in paying quantities" considering its contributions and costs at a group level. Among the specialized "reserves and economics" software programs, the oldest does not have this feature, but the most common and fastest-growing programs do. Regardless of which method is used, making an actionable calculation of whether a well is making or losing money is a basic function of running an oil company, one that should be readily available.

If the testimony is arguing generically that a well losing money still could have other beneficial use, then I do agree. However, the presumptions of no beneficial use apply only to active production and injection wells. They do not apply, for example, to inactive wells. Therefore, industry's concerns that the presumptions of no beneficial use will prevent inactive wells being used for secondary or tertiary recovery are unfounded because the well could be converted to inactive, with increased protections, and preserved for other possibilities.

Q: Objecting to what NMOGA witness Andrea Felix characterizes as the "well-by-well presumption" for no beneficial use, she argues Applicants' proposal ignores the "interplay between multiple wells." Felix Test. at 6-7 "viable wells—including those used in enhanced oil recovery (EOR), cyclic operations, pilot testing, or temporarily shut-in for maintenance" or "wells, some of which may be cycled on and off or used intermittently" and "examples like shut-ins for pad drilling or offset frac protection"; ***see also*** **McGowen Test. ait 17-18 ("legitimate operational practices, such as lease-level cycling, pad-wide downtime, or strategic shut-ins.") What is your response?**

A: Again, the presumptions apply only to active production and injection wells. Wells deemed to have no beneficial (active) use can be converted to inactive wells and preserved, with protections, for their option value including secondary or tertiary recovery. They do not apply to inactive wells slated for secondary or tertiary recovery.

To the extent NMOGA's arguments apply to active production and injection wells, there certainly are legitimate reasons to temporarily shut in a well (for less than the 12 or 15 months before becoming "inactive"), but those reasons in my experience do not approach the threshold defined for the rebuttable presumption of no beneficial use. I did not observe any evidence presented with the objection that temporary shut-ins for development management would trigger the rebuttable presumption provisions. Instead, my own experience is that these kinds of operations occur on a minority of wells and for periods of weeks to months.

To reiterate, the rebuttable presumption of no beneficial use has *dual* criteria which must *both* be met: less than 90 days of operation out of the last 365 days AND less than 90 barrels of oil equivalent. A productive well shut in even for a few months while frac'ing a group of offset wells would easily avoid both criteria.

What is more, the designation of no beneficial use can be rebutted with evidence. If a case does exist in which the dual criteria improperly categorize a well, then it should be simple matter to demonstrate the unique situation and avoid any undue consequences.

Q: NMOGA witnesses object that assessing presumptive no beneficial use using a 90-day production criterion is too rigid and fails to account for wells in temporary non-productive status and object that assessing beneficial use over a 12-month period is too short for adequate evaluation. NMOGA recommends using a five-year period. McGowen Test. at 16-17; Arthur Test. at 8-9. What is your response?

A: To be clear, it is not a 90-day evaluation period; it is a 90-day threshold in a 12-month evaluation period. As I said above, temporary shut-ins do not often last 265 days AND produce less than 1 barrel of oil equivalent ("BOE") per day when they are active. The definition is quite restrictive. Plus, if the rule of thumb does turn out not to apply, the label can be appealed if an operator disagrees with OCD's final determination.

Wells may be strategically shut-in due to commodity prices, but those kinds of shut-ins are indefinite. They will be reactivated *if* commodity prices improve sufficiently. In the meantime, the use is contingent on circumstances changing. And this is the kind of situation in which beneficial use can be rebutted by, as I suggest above, demonstrating that the well is economically viable with reasonably forecasted prices.

I see no evidence presented, and I know of no reason, that the presumption of no beneficial use is more appropriately determined over a three- or five-year period. Plus, I do not see an alternative proposal for thresholds that should be used with a three- or five-year period.

By comparison, the data I have developed and related testimony by Applicants' experts show that the presumption of no beneficial use criteria are quite strict and do not often result in false designations. My analysis shown in Applicants' Exhibit 44 shows that about 76% of wells stop production at levels *above* the no beneficial use criteria. That is, the criteria only correctly flag uneconomic wells about a quarter of the time, and 75% of the time the flag renders a false negative.

Dr. Arscott performed a converse analysis related to the much less restrictive definition of "marginal" wells. (To be clear, applicants do *not* propose that marginal wells should be presumed not to have beneficial use and plugged; the proposal for marginal wells is that they be subject to a one well financial assurance of $150,000.) As described more below, he found that 80% of wells that met the marginal well criteria did not return to "meaningful production." If fewer than 20% of wells under the much looser criteria made "meaningful" volumes after designation, then it stands to reason that a the much tighter criteria for no beneficial use will have a much lower incidence of meaningful production. (Though it would have been easy to reproduce the same calculation with the no beneficial use criteria, the results of that analysis are not presented.)

19.15.8.9 NMAC – Categories and Amounts of Financial Assurance

19.15.8.9.C Active Wells

Q: Applicants propose in 19.15.8.9.C(1) NMAC a one well plugging financial assurance of $150,000 for active wells and in 19.15.8.9.C(2) NMAC a blanket plugging financial assurance of $250,000 for all active wells of an operator. NMOGA and IAPNM raise many

objections to these proposals. Before addressing specific objections, what is your basis for support these proposals?

A: As I said before, I believe that the state needs more protection than it has. I do think that the proposal as written will increase financial assurance, though incompletely.

The question comes back to how to be effective given what is known and what is not known while balancing flexibility and simplicity in implementation. Other experts would like to see single-well bonding values more tailored to individual well or operator characteristics, though the alternatives are vague and disconnected. They call these "risk-based" measures, but many of them are better described as "cost-based." Many have intuitive appeal, and a couple of concepts are already incorporated into the existing proposal. The main problem of alternatives lies in the lack of available data to do the tailoring. Ironically, some of the alternative proposals would involve methods and consequences to which industry objects in other contexts.

The existing proposal for $150,000 per well is well founded in data, an average cost across the state dominated by costs for the Permian Basin where the rule is predominantly applied. Other direct testimony does almost nothing to expand the base of information on which to refine the bonding value or to add flexibility. Testimony does offer some personal experience and some aging information from other states. Because the required work for plugging does vary depending on well characteristics, local geology, and requirements of the jurisdiction and because the cost of those services varies with time and across basins, the information about costs at other times and in other states do not help to quantify costs in New Mexico.

Still, there may be ways that single-well bonding could be tailored. Though the evidence is modest or even limited, single-well bonding amounts could reasonably be more flexible to depend upon basin and/or depth if done carefully within the scope of available data.

Q: Witnesses for IPANM object to the one well bonding financial assurance of $150,000 based on anecdotes of lower plugging costs to operators to P&A in areas like the San Juan Basin. Andrews Test. at 2; Sharpe Test. at 5. What is your response?

A: The purpose of financial assurance is not to make money available to private companies to do the work but to make money available to the OCD. So the cost to industry is not the relevant cost information for purposes of determining operators' financial assurance; they won't be doing the work. It is the cost to OCD that is the relevant cost information.

Evidence of older costs from different states has by comparison no probative value to understand the average cost to OCD in New Mexico in the future. Testimony agrees that costs have been increasing and that characteristics of the wells and regulatory standards vary significantly. Costs documented in years past in other basins reduce almost to trivia.

My direct testimony acknowledged that current decommissioning costs will be less on average in some areas of New Mexico than others. But, obviously, to decide how best to set variable values requires information on how those costs vary between regions and across well characteristics. The proposal as written relies on what is still the best available data; direct testimony presented by industry provides little additional insight.

Concerning the Permian basin which holds 71% of the wells subject to the $150,000 bonding value for a single well (see Applicants' Exhibit 31), I did not find any new evidence in the direct testimony to contest directly the estimate of the cost of plugging to OCD. The $150,000 relies on a large and recent sample of actual costs. The OCD's records of costs in the Permian Basin include hundreds of wells over a number of years, And these are slightly higher than the average cost of about $163,000 documented by the OCD. The bonding value of $150,000 is thus *less* than the demonstrated cost in the Permian.

Concerning the 23% of wells subject to the same $150,000 bonding value but situated in the San Juan Basin with its different average characteristics, industry testimony provides slim insight to refine an estimate, even using operator cost data instead of OCD's cost data. IPANM witness Vern Andrews observes that his most recent two shallow, under-pressured wells cost $50,000 each to plug, abandon, and reclaim. He does not explain what fraction of the wells in San Juan are analogously shallow and not located on tribal or federal land. Even if the information came from an appropriate and homogeneous group of wells, the sample size remains too small to understand how much the average cost will exceed the most common cost.

Separately, Mr. Sharpe offers his own estimate that in the San Juan basin shallow wells run about $35,000 for plugging, but moderate depths run "$80,000 to $85,000 to plug and abandon, if no extensive remediation work is required." He does not, however, explained how less common high-side cases impact the average, explain how many wells in San Juan fit into his two groups, explain how his cost estimates have changed over time, explain how cost vary with other characteristics, explain whether they are subject to state bonding requirements, nor provide the data to allow such deeper understanding. The incremental evidence points only vaguely to a variation from the Permian Basin and not to a clear alternative value.

The records of OCD provide a larger and more explicit dataset than either of these anecdotes to understand average costs in the San Juan basin. From 2023 to 2025, the state plugged 15 wells in the San Juan Basin at an average actual cost of $93,000, and they came in an average of 14% below the pre-work estimate (which was based on site-specific information) of $111,000. By comparison, the estimated plugging cost using site-specific information in the Permian basin in the same time frame was $134,000, but that sample set of 193 wells came in higher than estimates as is more statistically likely, specifically 16% higher. (As demonstrated below in Applicants' Exhibit 77, the full data set indicates an average overrun of at least 25%.) Setting aside the stochastic variance of actual to pre-work estimates, the expected scope of work in the San Juan basin was only 17% lower than the average in the Permian basin.

An additional set of analytical estimates can also be used to estimate the relative difference in costs among basins, namely the Vertex Resources cost estimate made for the State Land Office in 2021. (New Mexico Oil and Gas Liability Assessment, 2021) Appendix B to its report breaks down the cost calculations by county among 12 models of various well design and shows the number of wells of each design.

Based on Vertex's analysis, the weighted average cost of plugging wells on state lands in Rio Arriba and San Juan Counties (San Juan Basin) average 19% less than the weighted average in Lea, Eddy, and Chavez Counties (Permian Basin). More interestingly, the Vertex study shows the 10th percentile of estimated cost in the San Juan counties was only 9% less than the average cost. Which is to say, fewer than 10% of wells in the San Juan counties were more than 26% below the average cost in the Permian. Still more simply, Vertex estimated that only a small fraction of wells in the San Juan counties (and subject to the increased financial assurance) would cost significantly less to plug than the average in the Permian counties.

These two independent sources—OCD's actual cost and Vertex's estimated costs—do show some difference on average between the San Juan and Permian basins, but only differences of 17% and 19% based on well characteristics. The proposed $150,000 per well is already a blended average between the two basins, partially splitting the difference between the basins.

Q: More generically, NMOGA witnesses Mr. Arthur and Ms. Felix object to Applicants' proposed financial assurance requirements for active wells, arguing that they abandon risk-based financial assurance requirements and tiered blanket bond financial

assurance. Arthur Test. at 26; Felix Test. at 15. What is your response?

A: Let me address tiered blanket bonds first, then the broader principle of "risk-based" financial assurance.

The proposal does abandon tiered bonding based on company size which is the way things have been done in the past, but that only makes sense. First, as I demonstrated in my direct testimony, the systematic risk of low production applies to both large and small companies. Large companies of low producers have more flexibility, can delay longer, but have the same systematic risk. To whit, more orphan wells in New Mexico have come from large companies than small. Second, the maximum value of generic bonding ($250,000) is unreasonably low compared to actual costs needing financial assurance but is, as I understand it, limited by statute. It does not make sense to me to have a tier of bonding lower than the statutory maximum of $250,000 except hypothetically in very limited circumstances of operators.

Experts presented by industry organizations prefer "risk-based" values of bonding instead of a "rigid" or "crude" $150,000 applied to all wells despite the complexity, burden or OCD "discretion" (Arthur Test. at 51) that would come with more sophisticated systems. To be clear, though, their proposals are mostly better described "cost-based" than "risk-based" because most pertain to the cost of orphaning rather than to the probability of orphaning.

The question of setting more tailored, cost-based well bonding values returns to the question again turns to questions of effectiveness, simplicity and flexibility. (First, of course, is legality, but I have not found any assertion that the Commission is legally bound to the standard of "risk-based.") If effectiveness could be maintained and flexibility paid for, then a more differentiated system could be justified. However, I have not found and industry has not presented sufficient data to be sure that the tailoring would effectively serve the intended purpose. As importantly, the alternatives are mostly too vague to evaluate concretely and not organized into a cohesive, actionable counterproposal.

Following are all of the various, piecemeal ideas offered by NMOGA witnesses to better tailor single-well bond values followed by my observations about each.

- **"Production" (Felix Test. at 15), "asset maturity" (Arthur Test. at 51):** This idea is, indeed, a risk-based idea; plus it is consistent with the proposed rules. The single-well bonding value is already risk-based in that applies only to wells demonstrably close to the end of their economic lives, close to the point in time when the obligations comes due but without the inherent wherewithal to perform. In fact, the empirical evidence shows that the risk mostly begins earlier than the maturity/production quantified in the proposal. I find no other specific proposals in the direct testimony from industry about how to tie single-well bonding to production or asset maturity, but a more appropriate risk-based rule would, in my opinion, apply to higher, earlier production rates.

- **"Well condition" (Arthur Test. at 51) or "known well integrity issues" (McGowen Test. at 90):** It is easy to observe that wells with known integrity issues are expected to cost more to plug. The problem lies in the knowing and in the costing. Integrity issues are often not known in advance of plugging, and they do not often exist early in the life of a well when cash flow remains high. So the trigger for more bonding risks coming too late to be effective. Bonding on the basis of well condition could have more merit if industry were willing to conduct regular and reliable integrity testing on active wellbores. But industry's objections to other proposals on well integrity portend an unwillingness to gather the data necessary to make this idea work.

Most importantly, even if well integrity issues occurred and were found early enough to successfully increase single-well values, the question of *how much* remains. I know of no data that could form the foundation for a reliable rule about how much to change the single-well bonds when an integrity issue is discovered.

Actually, as Applicants' proposal stands, it does about the best that can be done with the available data. By using an average cost to the state, it incorporates a form of average well condition. It incorporates a kind of average risk to all wells.

- **"Well type (e.g., producers vs. injectors)" and "age" (McGowen Test. at 90):** Unlike well integrity issues, these risk factors are knowable in advance, and they do have some relationship to costs because they correlate to increased incidence of integrity issues. However, my research shows that what information does exist about the relationship between type, age and cost shows only weak correlations. Scaling with type or age might improve the bond value on average, but that it would not address the chief complaint by industry experts; bonding would still end up being higher or lower than actual costs for most wells.

More importantly, that correlation remains not known. No data has been presented that could be used to translate well type or age to an appropriate dollar-amount of increased bonding. An effective policy to quantitatively scale bonding to the possibilities of higher costs would require a quantitative basis for the relationship.

- **"Well depth" (Arthur Test. at 27, 49; McGowen Test. at 70, 71, 90, 112):** This is the most concrete and practical of the alternatives presented in direct testimony. Among the collection of correlations of cost studied in the literature, depth is the strongest of the weak correlations. Still, no evidence has been presented on how quantitatively to scale costs with depth in New Mexico as a whole or in any of the four unique regions. The correlation is likely to be weak, with many wells above or below the trend line. Still, without data, attempting to make the bonding more accurate turns into an exercise of guesswork.

- **"Demonstrated plugging costs" (Arthur Test. at 51) and "plugging cost variability" (Arthur Test. at 49)**: It is not clear to me what Mr. Arthur means by these two recommendations or how it differs from concepts already in the proposal. If he means that the single-well bonding should be tied to actual costs rather than hypothetical estimates, then I agree, and the proposal already does that (subject to the discussion above about the small difference in the San Juan basin).

If he means that the single-well bonding should consider the variability of final costs based on the range of contingencies, then proposal already does that by including cases with those overruns.

If he means that the bond value should reflect variability of individual well characteristics like depth, type and age, then the recommendation to consider variability ends up in conflict with the recommendation to use "demonstrated" costs. There is not enough information available to quantify the relationship of costs to well characteristics as described above.

- **"Operator history" (Felix Test. at 15), "compliance history" (Arthur Test. at 49) or "operator compliance history" (Arthur Test. at 51):** This idea has some intuitive sense, but it also suffers limitations of timing, enforcement, and quantification.

I accept the theoretical premise that companies with more violations of operational regulations today are more likely ultimately to orphan their wells in the future and more likely to suffer mechanical failures. As a directional correlation to present risk, I see the value.

The indicator probably arrives too late to be effective. Operational violations often come from cost-cutting, and cutting operating costs is the last stage of the lifecycle. A well loses the ability to fund its own decommissioning– adding to risk – many years before it struggles to pay operating costs. I worry that the increase would not happen in many cases because, as many experts testify about the current proposal, companies would go out of business before securing the higher bonding value. Ironically, the proposal would probably end up like the current proposal, falling preferentially on less capitalized (read "smaller") companies to which many testifiers object with regards to other proposals.

What is more, drawing a boundary this way invites manipulation. A company could prioritize operational compliance still without planning for decommissioning. They could avoid the trigger of increasing assurance without decreasing the actual risk of orphaning.

Getting increased financial assurance after, rather than before, a manipulable correlate of risk thus appears to fail the test of effectiveness, to repeat the same mistakes of past policy.

On top of the structural problems, the idea remains an unquantified hypothesis. Other than research in other states that showed a decrease in environmental violations (or increased environmental effort) after an increase in bonding amounts, I do not know of data in other states or in New Mexico that could quantify a risk-premium or a "safe-driver" discount. Again, policy to tailor the costs fails for lack of evidence of how to do the tailoring.

Lastly, and about as equally damning for the concept, is the difficulty of creating a policy to provide sufficient, reliable data on which to make the judgment. Applicants' proposal calls for exactly this kind of review of operational history when granting the right to operate wells in the state. Although I find the requirements reasonable and practical, participants from the industry have objected stridently to the difficulty and depth of the review.

The specific alternatives scattered in other testimony are either already built into Applicants' proposal, or they cannot be applied effectively or quantitatively.

Q: You stated that the proposal for single-well bonding value does address some variability of costs. How is that?

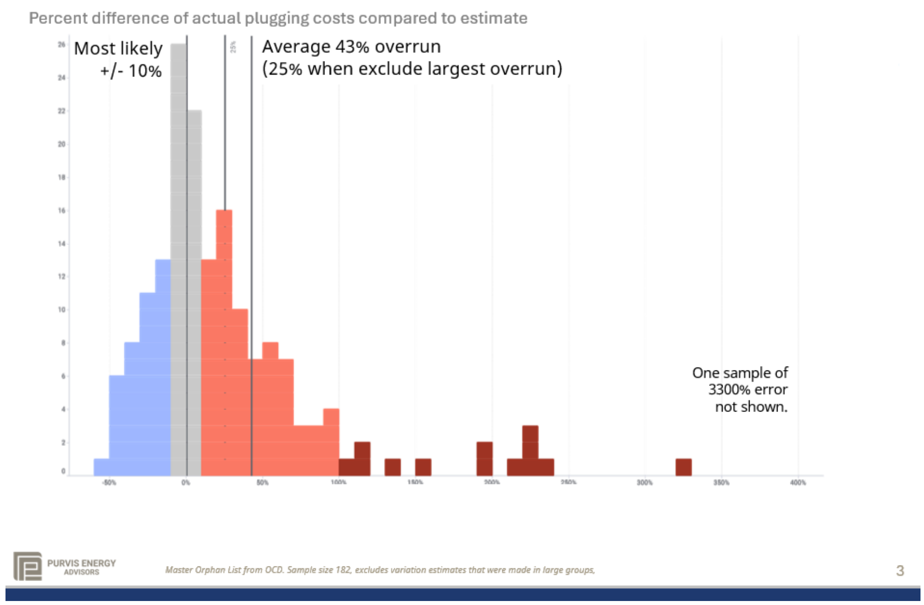
A: The proposal uses a single bonding value, not a variable value. But that single value does incorporate several kinds of variations, including one seemingly overlooked in the discussion by other experts.

The cost for each of the segments of decommissioning work—downhole plugging, as well as surface removal and remediation and surface restoration—is driven by three factors: the planned scope of work, the cost of services, and the additional unplanned work that turns out to be required. The planned scope of work depends in part on the well design and history and in part on local geology, such as uphole zones that need to be isolated. The specifics of well design can vary widely, but there tend to be patterns within a basin. Plus, service costs tend to vary somewhat from basin to basin. These seem to be the kinds of variability that other experts find important to consider in setting a bonding value, and these are the kinds of costs averaged across the state to set the assurance value.

The last part of the cost equation, however, is also important and is considered in the setting of the single-well bonding value but not addressed as such by other participants, namely unplanned work. We do not know exactly what the contingencies will be in advance, but theory and historical data show that it should be expected and that it is significant.

Applicants' Exhibit 77 below shows the actual downhole plugging costs for wells in the orphan well program compared to detailed pre-work estimate for 182 wells. The histogram shows the relative frequency of percentage over/underruns observed in the program.

Applicants' Exhibit 77: Variance of actual downhole plugging costs to estimates shows long high-side tail.



The two gray bars represent actual costs within +/-10% of the estimate, and the estimate should have included known issues that would make the baseline higher than for a generic estimate well without known issues. Compared to the predicted scope of work considering known issues, blue columns represent actual costs below estimates, and shades of red represent cost overruns. The mode (most likely) of the distribution occurs around the estimated cost, but the average is significantly higher. On average across the program, the actual cost turned out to be 43% higher than the estimated cost. One case in particular drives the average overrun, demonstrating how long that high side risk tail is.

Whatever other kinds of variability the Commission incorporates into single-well bonding values, they should consider the average of the distribution of costs and not the most likely or most common cost.

Q: Witnesses for IPANM and NMOGA object to Applicants' proposed one well

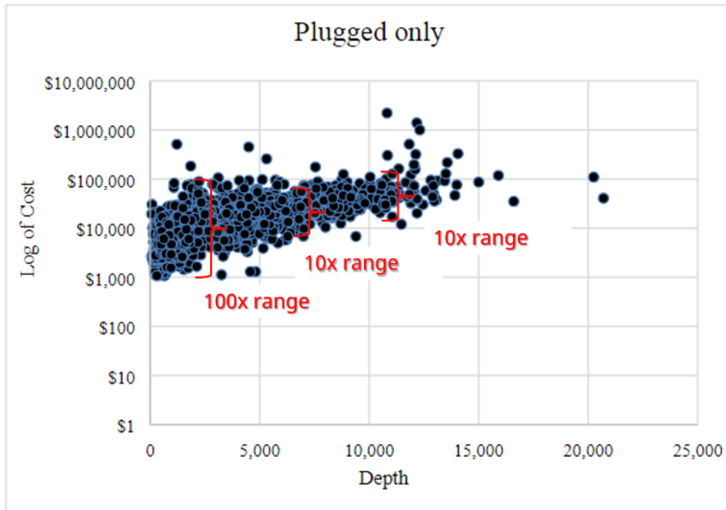
bonding financial assurance because it is not based on site-specific criteria, such as well depth. Sharpe Test. at 5; Felix Test. at 18; McGowen Test. at 77-85. What is your response?

A: As I said above, correlation of cost to depth has a theoretical foundation, but it remains unquantified. Instead, the arguments rely on patterns demonstrated in the academic literature from other regions, especially a paper by policy research analyst Dr. Daniel Raimi and his co-authors published in 2021. The paper has value in showing that costs systematically vary with certain well characteristics and location but not in quantifying those for today or for New Mexico. The data in that study is also useful to demonstrate how well characteristics only correlate roughly to costs, so the issue of too much or too little bonding would remain after adjustment.

They assembled thousands of data points across five states and many years. The costs were normalized to 2018, before the recent inflation and rendering their data on the absolute value of the work not analogous to today's costs. Of the thousands of data points, only 158 costs came from New Mexico, and these costs averaged almost twice as much as the cost of their reference case, demonstrating again the lack of analogy across states. Their research attempted to reproduce the diverse data set with a model of six variables, and they achieved a correlation coefficient of 0.69.

As for the single variable of depth, Applicants' Exhibit 78 below shows the relationship between plugging-only cost and well depth in dataset across locations. Brackets shown in red are overlaid to show ranges of 10x and 100x in the raw data.

Applicants' Exhibit 78: Figure S2 of Raimi 2021 showing the relationship of the logarithmic of plugging-only cost against the depth of the wells in a sample across five states with brackets to show ranges of 10x and 100x.



The relationships they calculated pertain mainly to regions other than New Mexico, and the relationship to depth alone is real but also weak. Depth alone leaves an uncertainty of 10x to 100x at most depths. So, the Raimi analysis has no quantitative value for the relationship to depth in New Mexico, and it suggests that whatever relationship does exist is likely to include a wide range of uncertainty.

It may also be noted that the authors observe that the national shortfall of financial assurance is largely driven by the use of blanket bonds and recommend against those. They further observe that "plugging costs are strongly skewed to the right," meaning that they have a long high-side tail of uncertainty.

As I said before, a more sophisticated and applicable cost-estimation system could be created for the State of New Mexico. It could be based on well-specific criteria like the model used in California, or it could be based on similarity to model wells like the model used by Vertex in its study for the State Land Office. But tailoring the model would require extensive data, probably from industry, about actual costs followed by a statistical and modeling exercise by the OCD. The results would still leave a good deal of variability and uncertainty. But without the data and analysis specific to New Mexico, adding consideration for well-specific criteria remains an exercise in guesswork.

19.15.8.9.D Marginal Wells and Inactive Wells

Q: Based on OCD's recommendation, Applicants propose a new category of well for purposes of financial assurance, "marginal wells." A marginal well is "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." Proposed 19.15.27.B(7) NMAC. The proposed financial assurance requirements at 19.15.8.9.D NMAC, including newly proposed language that is highlighted that was added at OXY's request, are:

> **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. Each operator with a marginal well or wells shall annually review the number of marginal wells registered to the operator and shall update the one well plugging financial assurance by May 1 of each year.
>
> **(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.

NMOGA, IPANM, and OXY witnesses object to this new category of financial assurance. Before you discuss their specific objections, what is the basis for your support for 19.15.8.9.D(1) and (2) NMAC, requiring single well bonding for marginal wells of

$150,000?

A: I do not think it is controversial to assert again that the less money a well makes on a month-to-month basis, the greater financial risk it represents. It makes most sense to me to have full financial assurance in place before a well crosses the point of holdback, while there is still significant remaining cash flow. It makes perfect sense to me to require financial assurance for the decommissioning capital by the time a well is barely meeting its month-to-month operating costs, analogous to the recommendation in Dachis (2017) cited by Dr. Arscott. If the operator demonstrates the ability to fund the decommissioning when required, the risk to the operator's portfolio is neutralized. Then the question becomes how to determine that economic limit to production and how close to that limit the threshold for additional assurance should be, given that the limit varies a good deal.

Q: NMOGA and IPANM witnesses object that the definition for marginal well is arbitrary, does not align with operational reality of marginal well production, and misclassifying wells as "marginal" could have negative impacts. What is your response?

A: I agree that the word "marginal" refers to a financial condition not an absolute production rate, and I agree that the production rate that causes the financial condition does vary because operating costs vary. The variations create complications for defining a policy of increased financial assurance late in life. Better would be requiring sufficient financial assurance earlier in life. Later in life is less effective and more problematic to implement. But the worst option at this point is not to try to do define a threshold for increased assurance.

On the most flexible and accurate end of the scale, the Commission could pass a rule to require a use of a well-by-well analysis of net cash flow. It could require an accounting of operating costs for each well from oil and gas companies, or it could require an accounting of net cash flow. Then the Commission could require OCD to make its own, independent and informed judgment about when a well is marginal enough to require additional financial assurance.

Without utilizing operating costs as an input, the policy needs to rely on production rate (and perhaps commodity prices). So the question becomes how to set a production rate threshold that is reasonable and how it should vary with qualitative indicators of cost and with commodity prices., It seems unlikely that operators would willingly submit the data, and it seems unlikely that either operators or the OCD would want to expend the resources that it would take to implement such a flexible, tailored analysis.

Applicants' proposal uses a single figure statewide without regard to commodity prices, but it does so conservatively. That is, the definition applies less often than the condition is true. Applicants' Exhibit 40, which I developed, shows that the definition for marginal wells (separate from wells of o beneficial use) applies to about 2,200 wells or 3.7% of total wells in the state. More to the point, my analysis at Applicants' Exhibits 43 and 44 show that nearly 60% of the wells in the state (fewer in recent years) pass their economic limit at rates above those formalized in the proposal. A marginal flow rate with some monthly profit should be greater than the final rate of zero or negative profit. Instead, the rate of marginal cash flow is set below the rate of zero or negative cash flow.

As I said before, Dr. Arscott's analysis showed the other side of the coin, specifically that 80% of the wells that meet the threshold subsequently produce less than 1,000 barrels of oil equivalent and thus do not return to "meaningful production." His data also shows another 11% produced subsequently less than 5,000 BOE. It should be noted, too, that his analysis included spring of 2020 when large-scale shut-ins were triggered by the COVID demand crash and that his flag as marginal is evidently performed on a rolling basis, not an annual basis.[1] Both of these elements of the methodology likely make his calculations yield a higher rate of improper classification. Yet, I interpret his work to say that the designation as "marginal" is proved correct 91% or more of the time.

It would be possible to define a flow rate for additional financial assurance with greater detail and empirical foundation using data like that I presented in Applicants' Exhibit 47 and 50, namely the actual final production rates of thousands of wells that have unambiguously stopped production. The definitions of marginal and presumptive no beneficial use combined apply to only a small fraction of the wells at the low end of the range of empirical economic limits. If the Commission wanted to set a more realistic volume threshold, it could observe empirically that the median final production rate is about 2 BOE per day[2]--without regard to days of activity--and thus choose this or a higher rate as the threshold for increased financial assurance.

Q: IPANM witness Mr. Ezzell states that identification of marginal wells should be assessed over "a few years" rather than a 12 month period. Ezzell Test. at 34. What is your response?

A: First, he objects that the criteria would be set on a "rolling basis" evaluated each month while I understand it to be applied once a year and thus triggering less often.

Second, his conclusion appears to be subjective and qualitative. As I discussed above, I am satisfied that evidence proves the rule is conservative, meaning that it will apply less often than would be appropriate. In principle, intentional short-term shut-ins rarely extend more than

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[1] At OXY's request during negotiations, Applicants and OCD agreed to add language, highlighted above, to the marginal well proposal allowing for annual review of the number of operators' marginal wells, for the administrative convenience of operators and OCD.
[2] Ironically, the rates are similar for vertical wells in both the San Juan and Permian basins.

half a year and, in practice, most wells stop producing at rates significantly higher than defined.

Q: Witnesses for IPANM, NMOGA, and OXY object to Applicants' proposed definition of "marginal well" and Applicants' proposed financial assurance requirements for this category of well because it would cause wells that would otherwise be able to produce economically to be "prematurely" plugged. Mitchell Test. at 3-4 [IPANM Prehrg. Stmnt.]; Sharpe Test. at 3; Harvard Test. at 7-9; McHugh Test. at 11 [IPANM Prehrg. Stmnt.]; Felix Test. at 27-28; Arscott Test. at 8-11; Wallace Test. at 4 [OXY Ex. B]. What is your response?

A: To be clear, the arguments made by various experts pertain to two different mechanisms to shorten production: first, an increase in operating costs that increases the break-even production rate and shortens life, and second an increase in required collateral which an operator cannot meet and provokes bankruptcy including the subset of wells still operating profitably. Concerning the first mechanism, the mechanism exists in theory. Setting aside that the reality that the end of productive life often does not resemble the theory, the theoretical effect is minute, and calling that effect "premature" incorporates value judgment.

The incremental cost of bonding premiums is incurred to better protect the public, as part of higher-quality operations. Like car insurance, I find financial assurance to be an appropriate cost necessary to responsible, high-quality operations. An earlier date for the end of production is not necessarily a "premature" date. I would argue that the earlier date is a fully mature date for a high-quality, responsible operation.

Setting aside the value-judgment, the magnitude of the change is minor. For an operator who has the means of paying the decommissioning, the incremental cost of financial assurance is not higher than the annual fee of the bond, less if the financial assurance is self-financed. Even a large increase on a small fraction of the total cost is still minor. The cash cost of operating, not opportunity cost, is the relevant measure. Dr. Arscott reports from his discussions with operators about the two most common types of wells:

> *Monthly operating expenses for gas wells were reported to range from . . .$3,500 - $5,000 for coalbed methane wells. Oil wells were reported to carry higher operating expenses of up to $14,800 per month.*

Q: IPANM witness Mr. Andrews claims that many gas wells in the San Juan Basin can produce economically for years at low volumes because of lower overhead costs, and that Applicants' proposed financial assurance rules would incentivize plugging wells prematurely, leaving and wasting hydrocarbons in the ground. Andrews Test. at 2-3. Similarly, NMOGA witness Mr. Arscott objects to Applicants' proposed financial assurance requirements for marginal wells by presenting examples of historic wells that might have been plugged prematurely, if Applicants' proposed rules had been in place. Arscott Test. at 13-17. What is your response?

A: In my opinion, the incentives work in the opposite direction.

First, the anecdotes of production histories offered by Mr. Arscott are only marginally probative. In a state that has drilled more than 120,000 wells, it is possible to find examples of most any possible scenario. Dr. Arscott's more comprehensive analysis of marginal wells discussed above quantifies more comprehensively that subsequent production is minor in the large majority of cases.

Second is the question of interpreting how Applicants' proposals would play out in scenarios where more upside does exist as in these hand-picked examples. The proposal does put an additional cost on maintaining an inventory of wells for their future option value, and companies can exercise (buy) that option up to a point under the proposal. When the cost does not appear justified by the future potential, the rules create motivation to plug. If the company thinks that there may be profitable opportunities, then the incentive works the other direction. The increased cost of waiting motivates the company to evaluate and perform the work sooner rather than later.

Q: IPANM witness, Mr. Kyle Armstrong, objects to Applicants' proposed definition of "marginal well" and Applicants' proposed financial assurance requirements for this category of well because it would limit opportunities for uphole development of existing wells by incentivizing early plugging. Armstrong Test. at 8-9 [IPANM Prehrg. Stmnt.]. What is your response?

A: The argument does not make sense to me. Mr. Armstrong's objection is that waiting instead of acting promptly might slightly improve his cash flow (because he has "more urgent" projects or because he wants a lower cost by contracting more work at the same time). Setting aside the relative frequency of the scenarios and the relative cost in competition, it seems to me that the policy works in just the opposite direction. It adds motivation to develop more promptly and thus serves the purposes of the OCD.

Q: Witnesses for IPANM and NMOGA object to Applicants' proposed rule at 19.15.8.9.D(3) NMAC, initially proposed by OCD, which provides:

> **(3)** An operator with over 15 percent of their wells in marginal or inactive 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.

IPANM and NMOGA witnesses raise many objections to this proposal. Before you address specific objections, what is the basis for your support for this provision?

A: The risk of orphaning exists at a portfolio level. The provisions for increased financial assurance for individual wells does partially address the risk, but as I've said, the definition of marginal well is conservative. The idea of requiring financial assurance for an entire portfolio based upon the configuration of that entire portfolio makes good sense to me.

Q: IPANM and NMOGA witnesses claim that this proposal is arbitrary and lacks a risk-based foundation. Ezzell Test. at 58; Felix Test. at 13, 30. What is your response?

A: Once again, the question seems to become a balance of considerations in deciding how to implement a legitimate protection.

The proposal is based on risk. There can be no serious argument that the risk of default does not increase as production in the portfolio decreases. An operator with 100% marginal wells presents more risk than one with 0% marginal wells. And I've demonstrated that a company with 0% marginal wells could still be operate 100% of their wells on the edge of profitability. Increased bonding from companies with lower production is certainly a risk-based concept. The question is how to encode that relationship into increased financial assurance. Applicants' proposal draws a line at 15%.

Least arbitrary would be setting the trigger for financial assurance based on the projected production, costs, and cash flow from each company separately. Each year a company could submit its capital plan for decommissioning and evidence that it is willing and able to perform the plan.

But if the policy is going to operate on the basis of information already publicly available, then it could be based on average rate (as in Colorado) or proportion of low-producing wells as proposed here. It could be scaled upwards with multiple tiers, or it could have only a single upper tier as proposed. Regardless of which of these designs is chosen, the thresholds will end up being indirect (volumes or categories of volumes instead of actual costs and projected cash flows) and imperfect.

As it is defined, the proposal does have a steep cliff of increased financial assurance when 15% of the portfolio is marginal and/or inactive, *i.e.*, is operating below the empirically observed average economic limit. As shown Applicants' Exhibit 52 which I developed, this step-change affects only 2.3% of statewide production, attesting to the small value to the state exposed to the change. At the same time, I calculated that the threshold affects 18% of wells and 51% of operators (who report non-zero activity in 2024). The discrepancy between volumes and wells attests to the idea that the threshold does, indeed, preferentially affect low-producing portfolios of greater risk.

The evidence for that specific value of the threshold, however, remains imprecise. As I observed in my testimony, there is a natural break in the portfolios at 15% when measured by well count. Other measurements of the portfolios do not show the same step-change at 15%, but they do all show rapidly decreasing incidence of portfolios above thresholds of 15% to about 30%. A threshold of 20% would affect 13% of wells in the state instead of 18%, and a threshold of 25% would affect 10% of wells.

Some of the examples by other experts show how the change of status of a single well could hypothetically precipitate a multiplication of the necessary financial assurance. The math is correct, but the import is not significant. Companies with fewer than 10 wells (and more susceptible to single-well changes) represent a minute proportion of production/tax revenue. Plus, based on my analysis presented previously in Applicants' Exhibit 52, already 55% of companies with fewer than 100 wells operate above the 15% threshold, immune to the effect of a single-well change. So the import of the argument is minimal to the state's calculus.

Q: Mr. Ezzell claims, taking a hypothetical 100 well area that is to be unitized, that "about 75% of the wells will be injectors and, therefore, definitionally marginal wells under

the proposed rulemaking," which would add about $11.25 million to the cost of bonding. Ezzell Test. at 54. What is your response?

A: I think Mr. Ezzell misreads Applicants' proposal for marginal wells. The proposal applies *only* to production wells. It does *not* apply to injection wells. Therefore, his concern is unfounded.

That said, there is reason to expand the definition of marginality to address other kinds of wells. My analysis shows that if the same days of activity and barrels of fluid were applied to injectors, then the definition would apply to just a couple of percent of the injectors in the state.

<u>19.15.8.9.E Inactive Wells and</u>
<u>Wells in Approved and Expired Temporarily Abandoned Status</u>

Q: Applicants propose a one well plugging financial assurance of $150,000 for each inactive well, including all wells in approved and expired temporary abandonment. Before you address specific objections, what is the basis of your support for this proposal?

A: An inactive well is generally a pure liability, offset only by the option value of future use. It is the kind of well that weighs most heavily on a portfolio. This idea provides assurance at the point when it is most needed.

Q: NMOGA witnesses Ms. Felix and Mr. Emerick object to Applicants' proposed one well bonding and average-based blanket bond rules because they claim these requirements will be too administratively burdensome for operators. Felix Test. at 17, 22, 30; Emerick Test. at 10-11. What is your response?

A: It is obviously true that arranging more bonding will require some paperwork, and new paperwork is likely going to feel inconvenient. The question is the significance.

By comparison, operators are already required to get increase their financial assurance at the time a well is placed in temporary abandonment. The current proposal clarifies and ensures that this requirement includes all inactive wells and expired temporary abandonment wells, that combined make up a majority of wells on OCD's inactive well list. The proposal also allows for a single instrument to cover the group of wells each at the same, fixed cost. If an operator wishes to avoid the small incremental cost of maintaining the option value of the wellbore, then they can plug the well. Incurring incremental mid-year bonding requirements already exists, and it is already a strategic choice within the control of the company.

Plus, my experience gives me faith that the oil industry and the financial markets can adapt.

Q: NMOGA witness, Mr. Arthur, objects to Applicants' proposed financial assurance requirements for inactive and temporarily abandoned wells, which provides:

> **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.~~

Mr. Arthur claims that the average blanket financial assurance rule creates a "moving target" and that the abandonment of risk-based rules will drive business and tax revenue out of the state. Arthur Test. at 27. What is your response?

A: Already wells that have been inactive for 12 months must be placed in temporary abandonment or plugged (within 90 days). And under the existing rules, operators must file increased financial assurance *prior* to OCD approval of placing a well in temporary abandonment.[3] There is no good reason to change that existing requirement, as Mr. Arthur appears to suggest.

Moving wells in and out of temporary abandonment does make the bonding required change over time. But the principle is already accepted, plus the operator has control over how it changes. It is the operator's choice to place an inactive well in temporary abandonment or plug it. I have every confidence that the oil industry can continue to work with this "moving target."

Q: Similarly, Mr. McGowen claims the logical and economic flaws of Applicants' proposed financial assurance rules are revealed through his "Larger Well-Count Operator" scenario, which he argues shows that the proposed rules ignore different operator risk profiles and create regulatory prejudice. McGowen Test. at 112-14. What is your response?

A: In this example, Mr. McGowen objects to the cliff of financial assurance required at 15% marginal and inactive wells category. He first objects to the inflexibility, arguing that there is no grace period for compliance and that the threshold does not consider the different mechanical and financial risk inherent to different well conditions. A more complicated system could be created, but then it would add more cost and complexity to execution, a cost rejected by Mr. McGowen with regard to other provisions. Of course, the boundary is clearly defined in

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[3] Section 19.15.25.13.E NMAC provides that, "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."

advance, and operators have control of how close to that boundary they operate. Operators have the agency to create their own "grace period" by managing their portfolio to create margin from the boundary.

Mr. McGowen further complains about combining marginal and inactive wells because they represent different degrees of risk -- that a marginal well is "actively monitored" while an inactive well is "unmaintained." I'd argue that a prudent operator should still be monitoring and maintaining inactive wells, even if less frequently. More importantly, two categories are closely similar or even overlapping in a financial sense, and it is the financial risk the rule is meant to protect.

Next, Mr. McGowen objects that the rules make responsible operators like himself the victims of bias and prejudice.

> *The proposed rules reflect a troubling bias that paints all operators with the same brush, reinforcing a narrative that . . . every operator is a potential bad actor. It creates a form of regulatory prejudice that substitutes blanket suspicion for measured risk-based oversight.* (McGowen Test. at 114.)

Applicants' proposals increase accountability for all operators, using a uniform set of standards across the board regardless of size. And those standards are based on the reality that inactive and marginal wells carry greater risks to the state which should be accounted for in with financial assurance.

Given the large scale of the decommissioning that will become necessary and given the systematic lack of preparation by the industry for this impending cost, the "blanket suspicion" to which Mr. Gowen objects seems to me like objective and appropriate risk-management, even if "good actors" don't like being lumped in with "bad actors."

Rather than a single set of rules, maybe Mr. McGowen would prefer a regulatory system that tried to identify "good actors" and "bad actors" and created different standards for each group. Perhaps, as I've said before, regulators could enforce accountability by examining each company's plan and means for decommissioning by looking at company-wide liability and future cash flow. Such a system could in theory target financial assurance most specifically and most justifiably on companies presenting the most risk.

(As an aside, as I said in the opening of my direct testimony, this one rulemaking addresses only a fraction of the overall decommissioning liability in the state for which companies are not saving in advance. Financial assurance on other aspects of decommissioning is advisable.)

Finally, Mr. McGowen observes that the 15% threshold "introduces severe financial strain and risk, especially for small and mid-sized operators who lack immediate access to multi-million-dollar surety instruments." It is not clear to me whether Mr. McGowen believes that the surety can be obtained but not "immediately," or whether it cannot be obtained at all. As I said before, I have faith that the financial market will write instruments that make money for them. To the extent that surety or any other option for financial assurance is not available to the company, it indicates the likelihood of future default. Which is to say, arguing that some companies cannot provide assurance is tantamount to confirming the risk and the need for financial assurance, buttressing the argument for a change in the system to prevent other companies declining into the same high-risk condition using a uniform standard of accountability

<u>19.15.8.9.G NMAC – OCD Discretion for Adjustment with Consumer Price Index</u>

Q: NMOGA witnesses object to Applicants' proposed rules that would grant OCD discretion to adjust the financial assurance amounts in Part 8 according to the consumer price index ("CPI") because surety markets don't operate on CPI schedules. Felix Test. at 25; McGowen Test. at 73-78. What is your response?

A: I have observed in federal and other jurisdictions that the lack of inflation adjustment allowed the value of the financial assurance to erode significantly, and I don't think that the actual cost of plugging will systematically diminish in the future. Oilfield costs will remain more volatile than other kinds of costs and may temporarily trend downward but also can swing up quickly. So the question again becomes how best to implement an adjustment, not whether to do it.

The figures could be adjusted ad hoc every few years has they have been in the past. Ad hoc could be effective, but it hardly seems efficient. For simplicity and reliability, an escalator could be tied to an independent measure of inflation, but none of the measures are precisely on-point. Also, some measures of escalation may not be available in the future. Of the options available, I find the Consumer Price Index to be a reasonable choice, though the Bureau of Labor Statistics producer price index for Oil and Gas Field Machinery and Equipment Manufacturing may be a closer tie to the vagaries of this precise cost.

Plus, the fact that the cost escalation is discretionary (on top of the fact that the proposed values are starting below recent actual costs) provides another mechanism for managing the bonding value.

Q: NMOGA witnesses object to Applicants' proposed rules granting OCD discretion to adjust the financial assurance amounts in Part 8 according to the CPI" because yearly inflation updates would make long-term capital bonding difficult. Felix Test. at 25; McGowen Test. at 73-78. What is your response?

A: In my experience, contracts with third-party guarantors of financial assurance run only one year at a time, with the coverage and the cost revisited each year. Already the rest of the proposed revisions require annual review and potential changes to the bonding amounts and thus new or incremental contracts. The main drivers of increased bonding (individual wells becoming marginal and the growing concentration of marginal wells in a portfolio) can both be predicted with the same reserves and economics forecasts that companies already create and use as a standard practice for planning years in advance.

I don't see that optional inflation adjustments creates new burdens, much less ones that cannot be overcome by a creative and financially motivated market.

General Industry Objections to 19.15.9.8.9 NMAC – Categories and Amounts of Financial Assurance for Well Plugging

Possibility of alternative models

Q: IPANM witnesses Mr. Bradley and Mr. Gilstrap opine that better models of financial assurance regulations to address the risk of orphan wells are found in Kansas, Oklahoma, and in the context of subsurface tanks in the gas station industry. Bradley Test. at 5; Gilstrap Test. at 7-8. What is your response?

A: Other models do exist, not just in the downstream oil and gas industry but also in other industries like nuclear power and coal mining. Some work well, some not. And I can see the value in a more proactive, comprehensive plan. But alternatives seem academic at this point because there is not a concrete proposal to evaluate as an alternative.

I recommend that the Commission take action now to reform the system before it considers deeper, structural changes to the funding model in the future.

Alleged disruption of transfers

Q: NMOGA and IPANM witnesses object to Applicants' proposed financial assurance rules, arguing that the rules would burden and disrupt the transfer of wells from larger operators to smaller operators despite indications that shale production has likely peaked in New Mexico. McGowen Test. at 95-99, Armstrong Test. at 2-3; Murphy Test. at 11-12

[IPANM's Prehrg. Stmnt.]. What is your response?

A: Applicants' proposed revisions to the transfer provisions are intended to protect the state against high-risk transfers. The proposed provisions will disrupt the status quo to a certain extent, but the proposed revisions reflect in my opinion a reasonable and effective approach to protecting the state against the potential liability which all parties seem to recognize.

It should also be noted that the records of the OCD already show a dramatic slowdown in the pace of transfers over the last 30 years. As discussed below about the falling number of companies operating in the state, the dynamic is probably driven by overlapping dynamics. It is not strict proof of future trends, but the pattern does demonstrate that development has proceeded in the state with fewer transfers under existing rules. I have not heard and do not see any cause for objections to the historical downward trend.

<u>**Alleged significance of "small" operators to New Mexico**</u>

Q: NMOGA witness, Mr. McGowen also objects to Applicants' proposed financial assurance requirements, claiming that the rules are flawed in logic and economic impact, when viewed through Mr. McGowen's "Small Well-Count Operator" scenario. McGowen Test. at 108-12. What is your response?

A: As I said before, companies with fewer than 10 wells are numerous but account for very little production (0.2% of production and 0.05% of recent new production) or revenue to the state. Plus, my analysis shows that already more than half of companies with fewer than 10 wells operate above the 15% threshold, immune to the effect of a single-well change. What he calls "flawed in logic and economic impact" I call inconsequential.

Q: IPANM witness, Mr. Gilstrap, claims that Applicants' proposed financial assurance rules disproportionately target small operators. Gilstrap Test. at 10. What is your

response?

A: As I said above, to the degree that there is disproportionate impact, it follows from disproportionate risk. Objection to disproportionate impact is implicit admission of disproportionate risk.

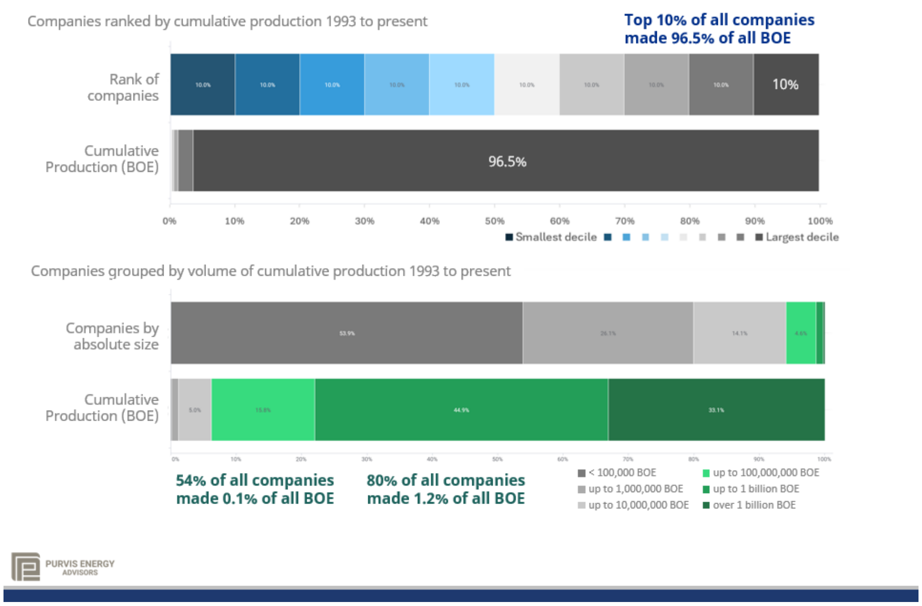
Q: IPANM witnesses, Sam Bradley and Mark Murphy, opine that small operators provide a vital service and contribution to New Mexico, Bradley Test. at 6; Murphy Test. at 11-12, claiming that the rules will result in small operator bankruptcies, increased well orphaning, reductions in economic revenue and jobs to New Mexico. *See also* Gilstrap Test. at 7; Sharpe Test. at 6-8; McGowen Test. at 115-119; Felix Test. at 19. What is your response?

A: This is a common trope, often perpetuated with a definitional misunderstanding, that is not supported by empirical data.

First, we need to be clear about the word "small." I use that term to indicate diminutive size measured by wells and/or production volume, but the term in often wrongly conflated with "independent." As I said in my direct testimony, "independent" oil and gas companies are differentiated from to "integrated" companies by the fact that they do not own and operate many refineries or gas stations. "Independent" companies like those represented by IPANM can be quite large, like private company Hilcorp Energy Co. or public Burlington Resources Inc. (acquired by ConocoPhillips Co. in 2006) which still ranks among the largest producers in the history of the state. Small companies fall under the label as "independents" but only as a sub-set.

Applicants' Exhibits 36 and 37 from my direct testimony examine the current significance of genuinely small companies. Applicants' Exhibit 79 below expands the analysis to measure the significance of small companies over the last 31 years.

Applicants' Exhibit 79: Proportion of cumulative oil and gas production 1993 to present contributed by companies of various sizes.



The pair of bars at the top shows the contributions of total production based on relative size. The top 10% of companies by cumulative production have contributed 96.5% of BOE production from 1993 to 2024. Historically, smaller companies have contributed 3.5% of production, but that figure fell to 2.5% in 2024 (see Applicants' Exhibit 37). The contributions of small companies are not just small, they have become less than they were historically.

The second pair of bars groups companies based on an absolute, not relative, volume of production contributed to the state. The categories are quite broad because companies vary in size over about five orders of magnitude. It shows that the smallest category of companies constitute 54% of the corporate entities but have contributed 0.1% of production from the state. Combining the two smallest categories show that 80% of companies have historically contributed 1.2% of cumulative production.

Certainly there are instances of small companies making outsized contributions, but those are the exception, not the rule. And, after many decades of looking for new ideas, the pool of opportunities for redevelopment and out-sized contributions is necessarily shrunken. For many years now, what opportunities do remain are mostly pursued by companies backed by private equity with the means to provide the assurance necessary in order to take the risk.

The consequences of protecting the state against orphaning will be painful to individuals and individual companies who have taken a position at the edge of profitability without the means of paying for decommissioning, but increased protection remains good policy.

Alleged loss of innovation

Q: NMOGA witness, Mr. McGowen objects to Applicants' proposed financial assurance rule for marginal and inactive wells for a number or reasons including that the proposed rules would constrain entrepreneurial flexibility and innovation, discourage risk-taking, and constrain the conversion of marginal and inactive wells "into industry-transforming assets." McGowen Test. at 99-108. Similarly, IPANM and NMOGA witnesses claim that the proposed financial assurance rules for marginal wells would limit operators' ability to use technological innovations to revitalize old field and would make new production methods, such as unitization for purposes of secondary or tertiary recovery, impossible or cost prohibitive. Arscott Test. at 11-13, Ezzell Test. at 50-55. What is your response?

A: This commentary by Mr. McGowen represents alarm without quantification. I see some of the same dynamics, but I see their significance differently. Most marginal, inactive or low-producing wells do not become the hotbed of innovation, a Phoenix rising from the ashes. It happens, but it is the exception. And the impact of those will be minor.

Most small companies and most companies focused on "mature" fields specialize in operations, not re-investment. The companies can be tenacious and hard-working, creative and even ingenious, but not innovative. A cost-reduction strategy is not compatible with developing and testing new technology. Some succeed better than others, but none have a unique, proprietary advantage over the crowd.

The minority with Phoenix strategies require capital, and most such strategies have long been backed by well-capitalized private-equity firms. The gambles will still be made by companies with new ideas, but the rules help to make sure that the companies are betting with their own money instead of unilaterally forcing the state to shoulder the risk of loss. As I explained above, the extra cost affects investment in the long-term only to the extent that it pushes expected returns below an investment hurdle.

(It should also be noted that, even while companies will continue trying new ideas, the significance to the state will continue to decline because opportunities systematically decrease as basins mature. A few years ago, a conventional field for sale came across my desk. It was operated by the third company that had attempted an “acquire and exploit” strategy. (They had not succeeded.) And exploration for legacy types of fields has all but ended, stopping the pipeline of redevelopment options. The shale revolution kicked off a new Hubbert curve of resources, but there is no further prospect for another class of resources. Meanwhile, shale drilling locations are being exhausted, companies are laying off people, professional societies are contracting rapidly, and primary research in oil and gas production is down by about half. (Fahes, 2024) Not that new ideas and new successes don’t happen; just that their role has been and will continue to diminish.

<u>Alleged reduction of working capital</u>

Q: IPANM and NMOGA witnesses object to Applicants’ proposed financial assurance rules because they claim that the proposed increase to bonding requirements will tie up

money that could be used for other industry operations. Gilstrap Test. at 6-7; Felix Test. at 19. What is your response?

A: Most salient to me about this line of logic is the tacit admission and confirmation of the root issue creating the need for reform. By objecting to the difficulty of meeting the accountability of financial assurance, experts from both the surety market and from operating companies tacitly confirm that companies do not have the money necessary to pay for the decommissioning of their wells, and the argument about tying up capital goes further to admitting that they do not have a viable plan to pay for decommissioning.

If a company does not have and cannot borrow capital today to cover the *fraction* of decommissioning cost related to their least productive wells (or in fewer case for all of their wells when risk is concentrated), then it is unlikely that they will have the capital required to decommission *all* of their fields after they further deplete and cease production.

As I've said repeatedly, there is by definition no profit left at the end of the life of a field, so for the kinds of companies that specialize in late-life production, the kinds more likely to be subject to greater financial assurance, the only option to fund the complete liability is to set aside the funds years in advance.

What is more, when the industry organization objects to "tying up" funds in collateral accounts for bonding against the final capital requirements, then it is as much as admitting that its members do not intend to save the necessary capital to be prepared for the final costs. That is to say, that a company that intends to pay for its decommissioning costs should not complain about having money tied up because that is the only prudent strategy for compliance, whether in bond collateral or a separate account makes no difference. For companies focused on depleting assets yet still unwilling to set aside funds from ongoing operations, there is no viable plan to meet their obligations to the public under the law.

Setting aside the inherent necessity of tying up funds and the admission that companies have not and intend not to do so, the same money could in theory be used for other kinds of capital investments, and the hypothetical question becomes one of the significance of the reduction in funds in the context of their business strategy and opportunities.

Funds saved for future capital obligations compromise current capital investments only to the extent that the company is capital-constrained. That is, if a company has more opportunities for investment than it has capital for investment, only then will the set-aside reduce capital investment.

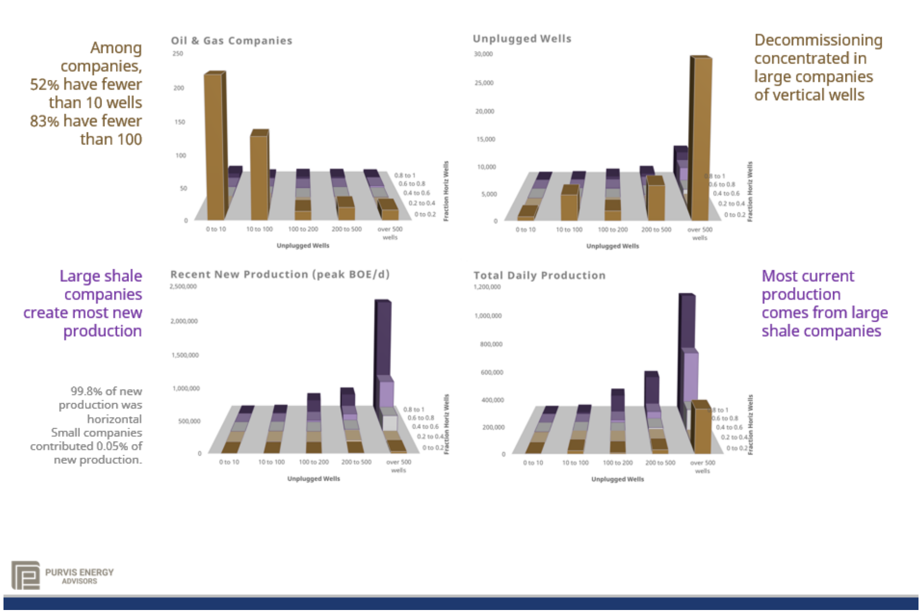
When a company buys a field for the purpose of redevelopment, they have an idea and a supply of capital. As I said, I have observed that the large majority of such companies have been backed by private equity investors responsible for hundreds of millions or more commonly billions of dollars of capital available. Aside from private equity, there are other sources of capital looking to invest in oilfield opportunities. Though certainly less than in the past, bank loans and private investors still supply capital to oil and gas companies.

Companies focused instead on cost reduction and incremental improvements have little capital largely because they require little capital. In either generalized scenario, companies with decommissioning risk are not likely to have more opportunities than capital they can raise.

Further setting aside the limited scenarios of capital constraint newly imposed by the needs of financial assurance, we can get a sense of the hypothetical impact by examining the historical capital investments made by companies most likely impacted by the proposed rules.

The analysis I presented in Applicants' Exhibit 35 is copied below for ease of reference. Every company falls into the same bin in each of the four graphs, but the height of the bars in each version measures a different aspect of the group of companies. The front two rows of companies (shown in brown) represent companies of all sizes with portfolios of at least 60% vertical wells, and thus older and less productive and more likely subject to increased bonding requirements. And the two rows on the left hand side represent the smallest companies, those with less than 100 wells, which are also more likely to be subject to increased bonding. The graph in the lower left represents the contributions to new production over the last five years measured by peak production.

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.



Considering first the small companies of all the kinds of portfolios, the far left row of columns representing all companies with 10 wells or fewer contributed 1/20th of 1% of the production in the state from new wells. Adding in the second row to measure all companies with fewer than 100 wells, the figure increases to 14/20th of 1% of new production. Considering portfolios of all sizes focused on vertical wells without regard to increasing access to capital with size, the analysis shows that companies with greater than 80% vertical wells contributed 1.0% of new production, and companies with greater than 60% vertical wells contributed 1.9% of statewide production from new wells. That is to say, that if the change in rules caused all drilling to stop from 94.8% of companies, then 97.5% of the drilling in the state would continue unaffected.

This sense-check of the capital needs of smaller and non-shale companies does not include other kinds of capital investments; the data is not available. The data in the exhibit show the significance of their existing production. The 94.8% of companies that are small or focused on vertical wells currently contribute 16.3% of production. Losing the ability to perform any kind of workover or other capital project on existing wells would not cause production to immediately cease but instead to decline in aggregate more rapidly than in the past. So this hypothetical maximum loss to the state to be weighed against the value of decreased orphaning would top out at a few percentage points each year from a base of 16.3% of production.

Other experts do raise a legitimate question about the need to spend the money to do the work before money (if any) held as bonding collateral is released. A bank might lend to an oil and gas company with the same collateral account, but I have not observed a solution to the cash flow paradox in the field. This issue, however, does not mean that financial assurance should not be increased as proposed. It just means that a smaller problem will need to be solved to implement a larger solution.

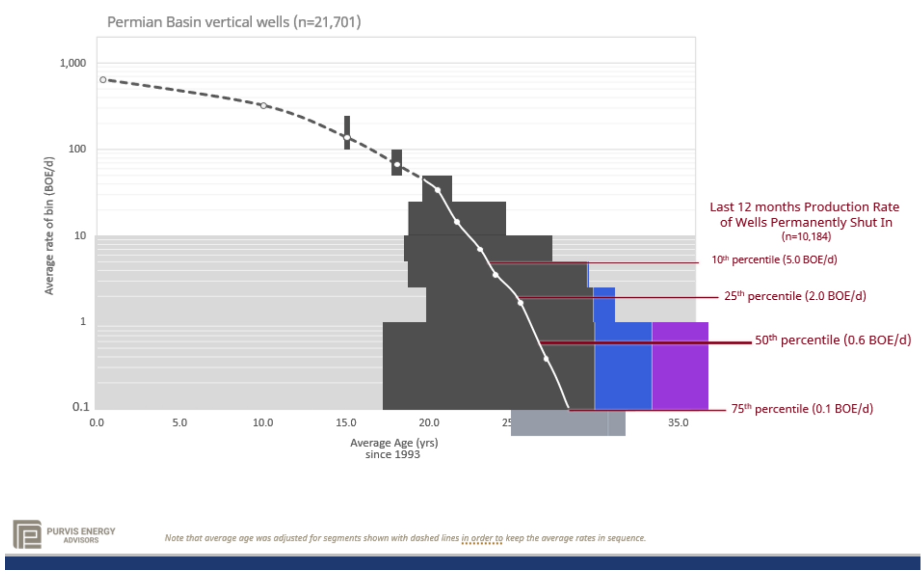
<u>Alleged loss of operators leaving the state</u>

Q: IPANM witness, Mr. Murphy claims that Applicants' proposed financial assurance rules for marginal wells would end most if not all responsible, independent operators, including stripper well operators, in New Mexico, despite claims by IPANM witness, David

Mitchell, that stripper wells can break even at 2 BOE/day. Murphy Test. at 4, 9-10; Mitchell Test. at 2. What is your response?

A: When Mr. Mitchell opines that "a lot" of oil wells can "break even" at two barrels of oil per day, "depending on the market [price]," he corroborates my observation that many wells currently operate at or below their economic limit and thus represent significant liabilities. Below shows the distribution of vertical wells by current rate in the Permian basin compared to historically demonstrated economic limits previously presented as Applicants' Exhibit 47.

Applicants' Exhibit 47: Comparison of binned Permian Basin vertical wells to final rates of production demonstrated in the basin.



It shows that nearly half of the vertical wells in the oily Permian basin (in the two lowest-rate bars) already operate at or below the rate at which Mr. Mitchell asserts that "a lot" of wells can manage to pay for expenses on a month-to-month basis. It is a large liability, but because the production is so low, still a minute contribution to the public good.

Q: NMOGA witnesses, Mr. Arthur and Ms. Felix, object to Applicants' proposed financial assurance requirements for active wells, arguing that they abandon risk-based

financial assurance requirements and tiered blanket bond financial assurance and claim these proposals will drive business and tax revenue out of the state. Arthur Test. at 26; Felix Test. at 15. What is your response?

A: Your question has two parts, first about whether a different structure for bonding would be less onerous and second whether the proposal as it stands is so onerous that it would drive the oil business out of the state.

As I have said, I do not see a way to protect against larger, longer-term orphaning without provoking an uptick of orphaning in the short term. The increase in protection could be smaller and have fewer consequences. Continuing the use of blanket bonds could reduce the temporary uptick, but it would leave the larger issue unaddressed and thus fail their purpose. Large companies can better manage cash flow and delay than smaller companies, but risk ultimately pertains to the profitability and management of the portfolio and not to its raw size. My direct testimony showed, for example, that most orphan wells came from operators with more than 100 wells.

As I discussed above, an alternative structure that required less financial assurance for wells that cost less to decommission could theoretically reduce inefficiencies. The data does not exist for such a "risk-based" system, and what data does exist suggests only modest differences in average cost. In my opinion, a truly risk-based system would require much more financial assurance than the current proposal. My direct testimony explained that the risk of orphaning increases with proximity to the economic limit and that far more wells already produce close to their economic limit than are covered by the proposal. The proposal addresses only part of the risk faced by the state.

Ignoring whether the proposal creates too big a change or not enough compared to alternatives, the question remains whether or not the change is large enough to drive companies and activity out of the state of New Mexico and, if so, how much.

Q: NMOGA witnesses argue that changes could drive investment out of state and could drive oil companies out of the state to more permissive jurisdictions. Felix Test. at 9; Arthur Test. at 27-28, 38; McGowen Test. at 8, 117. What is your response?

A: Let's first discriminate between two dynamics: reduction in capital investment for development and reduction in companies operating marginal wells.

I have talked above about the ways the costs affect existing operators of marginal wells, and about the significance of the production associated with wells affected by Applicants' proposals. The purpose of the proposals is to protect against under-capitalized companies taking over wells and not being able to decommission them, which experts admit does happen. Many companies operate marginal wells, though some better than others. Transfers to underfunded companies need to be addressed, and companies that exit instead of comply help support the public good by leaving the operations to better-managed companies.

Ms. Felix focuses on, and Mr. McGowen mentions, a second possible scenario for companies operating marginal wells, one in which the new operator improves production:

> *Acquisitions of distressed and legacy assets from less capitalized market participants to better capitalized market participants would face additional hurdles.* (Felix at 9)

> *[T]he onerous bonding requirements proposed. . .will make transactions less competitive. . .jeopardizing deals that might otherwise benefit both the industry and the state.* (McGowen at 117)

I do not find estimates from either about how often such transactions occur, but Ms. Felix's explanation includes the larger answer: A company wanting to significantly redevelop a field requires capital. Such a "better capitalized market participant" should be in a position to fund also the necessary assurance.[4]

Whether new investments are made by buying and redeveloping or by drilling, the effect on investment in the state is not as simple as portrayed. It is easy to think about business generally leaving one jurisdiction for a less costly alternative, and that theory of tax competition may have some merit for businesses like manufacturing which must bring supplies to the plant. But that is not the way the oil and gas business works, either in theory or as demonstrated in empirical studies.

Oil companies can leave the state, but oil fields cannot. Commodity prices may rise and fall, but oil in place does not move in and out with the financial tide. If development activity does decrease temporarily, the resources in the ground will remain unchanged. As long at the geology remains or becomes economically viable to develop, there is no paucity of oil and gas companies available to produce them.

If one company does not develop them now, then another company can develop them now or in the future. There remain hundreds of companies in New Mexico and hundreds more in adjacent states. Oil companies are not like technology firms with proprietary or exclusive advantages that cannot be reproduced. Information is widely available, techniques are widely shared through professional societies, and technology is widely shared through service contractors. Companies can differentiate themselves with expertise and diligence, but then as now, opportunities left behind by some invite others to develop the expertise and reap the benefits.

[4] Alternatively, if the Commission wanted to create still more flexibility (and more work), then it could add a review also of the selling company, as Alaska and several Canadian provinces do, in order to allow for the scenario in which the buyer is more financially capable but still not able to post the proportion of final costs required.

Production from New Mexico will be impaired only to the extent that the marginal increase in costs tips the balance and causes resources to become unprofitable to develop. That is, if the extra costs cause the projected returns to fall below the minimum threshold for investment.

As I demonstrated before, development activity and production in the state are now heavily dominated by horizontal drilling, and I see no reason to think that the change in bonding would have a meaningful impact on the state as a whole. Most of the rest of the state has been explored and exploited for decades, leaving fewer and fewer of the best opportunities. Most affected would be the least valuable (normally the least productive) projects. If some resources are pushed below an economic threshold, then the significance of the potentially by-passed value to the public must still be weighed against the increased cost of decommissioning more orphan wells which is far more concrete.

Beyond the economic theory, the issue of competition for development of resources has been studied in the context of relative severance taxes and other regulations. On balance, those studies show little or no net gain from lowering the costs on companies. Besides the several studies cited in response to Dr. Arscott above, Brown (2018) looked at cross-border differences in U.S. severance taxes from 1981 to 2015:

> *Our core econometric results show that oil drilling is inelastic with respect to severance taxes with an elasticity about -0.2 to -0.4.*
>
> *The response to a change in tax paid per barrel of oil is inelastic, implying that an increase in the tax rate per barrel leads to increases in tax revenue. The policy implication is that state governments should use caution when considering the use of lower tax rates to attract more drilling from neighboring states.*
>
> *These results are robust to interstate spillovers, other state regulations, and econometric specification. They imply that using state tax rate decreases to incentivize investment may lead to losses of government revenue.*

Castillo (2021) attempted to take economic theory about mineral taxation politics into the real world of South American mining:

> *Results indicate a surprisingly small average impact [of profit-based royalties] on grassroots exploration. . . .The absence of geographical spillovers not only supports these estimated effects but also suggests that neighboring countries do not need to engage in harmful tax competition.*

And Black (2018) looked closely at the theory and its application to Pennsylvania's "impact fee":

> *The reticence to tax the industry stems from the expectation that higher state taxes will cause energy firms to invest less. Less investment is not a problem from an [economic] efficiency standpoint–it simply indicates that some wells become uneconomical if firms must pay the well's full cost, assuming that the tax represents the well's social cost.*
>
> *If the supply of acreage for drilling is fairly inelastic. . .the tax or regulation will have little or no effect on industry investment.*
>
> *A related literature considers how taxes on oil and gas production in particular affect exploration and production. This literature suggests that production is insensitive to marginal changes in tax rates. . .. All of the studies cited, however, base their conclusions on simulations.*
>
> *. . .Pennsylvania introduced a per-well Impact Fee despite concerns that it would discourage industry investment. Using a quasi-experimental design and data that nearly cover the universe of leases and wells in Pennsylvania, Ohio, and West Virginia, we find little to no declines in well permitting or drilling occurred in the most geologically similar subsample.*
>
> *If, however, profit-seeking investors eventually cause all profitable acreage to be developed, retroactive application of the Fee merely delays leasing and development. Moreover, if the supply side of energy markets tends to over-invest in times of high prices, thus sowing the seeds of an eventual price collapse, the delay in leasing and development could improve efficiency by shifting some development to a higher-price period.*

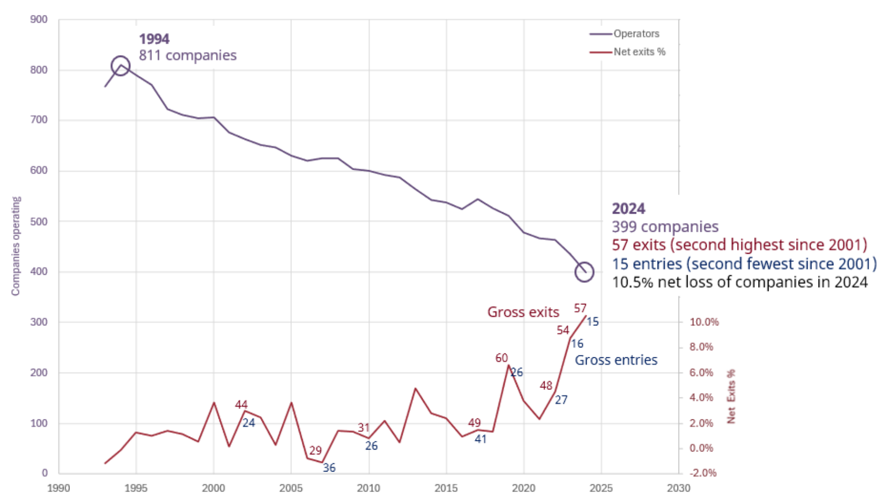
Q: Other experts imply or state that the loss of companies operating or willing to operate in New Mexico is fundamentally a loss for the state. For example, Mr. McGowen at 130 offers, "This is yet another example of a policy that could drive capital and operators out of New Mexico, ultimately causing oil and gas production and associated tax revenue to decline rapidly." What is your response?

A: As described above, the increased cost changes investment decisions in the short term only to the extent that they change the returns relative to alternative investments available to the company, and they change investments in the long-term only to the extent that they cause the returns to fall below a minimum investment threshold.

As I see it, the policy objective is neutral to the number oil companies operating in the state; the policy objective is the financial responsibility of whatever population exists. More to the point, the history of New Mexico breaks the presumption that more companies mean more production.

Applicants' Exhibit 80 below shows the history of oil companies active in the state each year from 1993 to 2024 in purple using the left axis. The red line shows the net percentage exits from the state against the right axis, and labels on selected points show the gross number of companies starting and ending operations.

Applicants' Exhibit 80: Number of operators active in the state on long-term decline and accelerating in recent years.



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The number of oil companies operating in New Mexico has neatly halved in the last 30 years, and the pace of net departures from the state has accelerated in about the last 10 years. Last year saw a net loss of 10.5% of oil companies in the state due to the second fewest entries and second most exits in over 20 years. Meanwhile, I have not heard and do not see any complaint about the number of companies in the state. And production continues to grow.

The overall steadiness of the trend probably results from overlapping dynamics of market prices and geologic maturity, and it is not strict proof of future trends. It does, however, show unambiguously that the number of companies is likely to decline regardless of financial assurance policy and that, historically, having fewer operating companies has not created an issue for the state.

Q: IPANM witnesses, Mr. Bradley and Mr. Gilstrap, opine on the negative consequences of recently promulgated financial assurance regulations in Colorado, including that orphan wells increased, statewide total financial assurance decreased, and small operators left the state. Bradley Test. at 2-4; Gilstrap Test. at 7-9. What is your response?

A: Last year I researched and published a 56-page analysis of the financial assurance situation in Colorado. (Purvis, 2024) I also observed financial assurance did decrease attesting to the failure of the process meant to accommodate all parties by creating a tiered and layered system.

For most wells, the new rules set in 2022 required bonding of $130,000 per well. I observed that, more than two years after the start of implementing the new rules, "37% of the listed operators targeted have not even responded to the multiple demands of the regulator, and another 10% have responded but not complied." The number of wells affected, though, was much smaller. Unresponsive operators represented only a little over 1000 wells, and noncompliant operators represented about 2,800 additional wells. Mr. Armstrong thrummed the proportional increase of orphans in the state, but still "the number of orphaned wells reported by COGCC [increased]. . .to 941. . ."[5] in a state with nearly 48,000 unplugged wells.

Notwithstanding the experience of Mr. Bradley having partially left the state, I have not observed a decrease in drilling activity nor in acquisitions and divestitures nor a mass orphaning of wells. On the other hand, my analysis also demonstrated the on-going risk to the taxpayers of the state.

> *Legacy areas range across 30 counties and include more than 27,000 wells, 57% of the statewide total. In these areas, we estimate a decommissioning cost of $4.0 to $5.0 billion but only about $1 billion of remaining cash flow. It is unreasonable to expect or hope that future production can pay for asset retirement, even if every future dollar of projected profit were dedicated to decommissioning. (pg 1)*

From the experience of Colorado I conclude not that increasing financial assurance caused a net loss of public good but that increasing financial assurance failed to increase the public good but by doing too little.

<u>**19.15.9.9 NMAC – Change of Operator**</u>

Q: In 19.15.9.9.B NMAC, Applicants propose requiring additional safeguards for the state at the point of well transfer to which NMOGA and IPANM witnesses raise many objections. Before you discuss their specific objections, what is your basis for supporting Applicants' proposals to require an operator to submit a plugging and abandonment plan that meet the Commission's requirements at 19.15.25 NMAC and demonstrating the operator is financially capable of carrying out that plan?

A: This appears to be one of the questions about which there is consensus about a need but difficulty in codifying. For example, Mr. McGowen validates the need when he

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[5] The number of unremediated sites associated with these wells and wells already plugged downhole increased to 2000.

observes that transfers to impecunious operators occur often:

> *"Operators regularly shed marginal or aging wells. . ." (pg 105)*
>
> *"[T]hese burdens will hit small and mid-sized operators the hardest, especially those who specialize in extending the life of older wells or acquiring marginal assets. . ." (pg 117)*
>
> *"These companies typically have limited capital resources. . .. They may have plans to re-purpose wells, but they do not have the ability to bring the capital intensity required to plug and/or re-purpose many wells in a short timeframe." (pg 117)*

Given that the wells are barely making money ("marginal") and that the operators do not otherwise "have the ability. . . to plug . . . many wells in a short timeframe," they may not have the ability to plug all of the wells even in a long timeframe. This is the issue of holdback discussed in my direct testimony.

Mr. McGowen goes on to assert that the transferred wells might be rejuvenated or re-developed (although "re-purposed" is a misleading term to use), but he does not discuss the probability of success. If a smaller company takes on a new field but does not succeed, then the risk of orphaning increases because the recipient does not have, as Mr. McGowen explains, the same "capital intensity" to pay the final liability from other assets. Hence, such a transfer to a less-capitalized company represents an increase in the risk of orphaning to the public fisc.

For my part, I agree that wells and their associated liabilities are often transferred to less capitalized companies. And I observe that the probability of rejuvenating a field has long been modest and declines with age. So, some sort of accountability at the point of transfer will help to ensure that the gamble taken by the buyer is made with the companies' own money and not with the public's, that the company bears the risk of failure and not the state's orphan well program.

The question becomes how to manage transfers, whether a more clear and rigid rule or a more vague and flexible process. I recommend flexibility.

Transfers of mid-or late-life fields from more-capitalized companies to less are only one kind of transfer that occurs. The range of possible scenarios is quite broad. Neither regulators nor lenders have figured out a simple, reliable, universal measurement to evaluate the risk of orphaning.

We do know that the risk of orphaning occurs at the portfolio level and that it occurs late in life, after it is too late to get more money from the fields. So evaluating the risk requires understanding all of a company's portfolio and years into the future. Of course, making such projections involves uncertainty, so the question becomes one of a minimum safety margin. A clear, explicit standard could be specified in New Mexico rule, but the industry has not created or adopted a consensus of how much risk or uncertainty should be accepted or how to measure it. Hence the value of flexibility.

I do agree that a clear and explicit standard would be preferable, except that maintaining efficacy with a clear standard would raise more protest. Given the nature of the liabilities—specifically, their being paid after the end of economic life—and the difficulty of simplification, I support the broad and flexible process embodied in the proposal.

It should be noted that there is one solution that is much more clear and explicit and noninvasive for the benefit of industry while also more protective for the public but industry has vehemently objected: some form of guarantee for the full cost of decommissioning required in order to allow the transfer. It can be done, and it would be effective. California has implemented a kind of this requirement, and I'm told that sellers of fields are sometimes voluntarily purchasing such a guarantee from OneNexus before transferring wells to small companies.

But I suspect that industry would prefer a flexible process to a fully effective one. In lieu of full cost guarantee at transfer, a flexible but comprehensive diligence process is the next best compromise I see. Plus, it resembles an established process long used within the industry.

Some mineral leases, more commonly those of large and sophisticated landowners, give the lessor the right to disallow the transfer of wells on its property to a new operator. In my experience, the provision allows the landowner to approve or deny a transfer in its reasonable but sole discretion. Such a right is broad but well-established and long-standing in the industry. The proposal gives analogous discretion to the OCD to protect against high risk transfers.

Q: NMOGA does propose adding certain requirements for new operators to provide information to OCD prior to well transfer. In proposed 19.15.9.9.B NMAC, NMOGA proposes a new operator must provide:

- **Certification that the new operator is in compliance with applicable federal and state oil and gas laws in jurisdictions where it operates,**
- **Certification that the new operator can meet the plugging and abandonment requirements for the wells to be transferred in accordance with 19.15.25 NMAC, and**
- **A brief summary of the new operator's current asset retirement obligations specific to the State of New Mexico.**

NMOGA, however, does not propose that any of this information can provide a basis for a denial of transfer. What is your response to NMOGA's proposal?

A: This counterproposal could be read as implied agreement about the relevance of the kinds of information sought in Applicants' proposal, but the scope of data is so abbreviated as to be easily manipulated. More importantly, without the ability to act on it, the information is virtually useless, voiding the utility of disclosure .

Limiting the disclosure to current companies in current compliance with laws could be interpreted to mean that a company could not disclose a long history of enforcement actions if none rose to the level of violations of law and/or if all were, at that moment in time, resolved. Or, a management team with an abysmal record in Texas could create a new legal entity in New Mexico and honestly certify a clean bill of compliance.

A certification that a company can meet its decommissioning obligations is necessarily limited to the date of the certification. Setting aside that NMOGA's proposal asks for trust ("certification") without verification, the certification says nothing about the ability to pay the costs in the future. The costs are not due in the future, not at the time of the declaration.

The company's current obligations within the state are only a fraction of one side of the two sides of the balance of considerations. It says nothing of the company's other liabilities like bank debt, long-term contracts, or decommissioning obligations in other states. And it does not provide any sense of scale about whether the asset side of the balance sheet will suffice to meet the liabilities side.

NMOGA's alternative proposal fails the first principle of good policy: it would not be effective.

Q: NMOGA witness, Ms. Felix, claims that Applicants' proposal to require a plugging and abandonment plan at 19.15.9.9.B NMAC as part the requirements for approval of well transfer is unclear. Felix Test. at 55. What is your response?

A: Applicants' proposal requires a transferee to certify that it "has and will have the financial ability to meet the plugging and abandonment requirements of 19.15.25 NMAC." In service of effectiveness, this phrase intends to close two loopholes in time and scope that NMOGA's alternative would create: not just what the costs are, but how they compare to the assets; not just now but also in the future when the costs are actually paid.

In service of flexibility, the standard of evidence required could also be called vague or unclear. I do not see how to prescribe a sufficiently reliable, fixed standard without incurring more urgent objections. As I said before, the full cost of decommissioning could be placed in escrow. Or, the regulations could require that future cash flow from Proved reserves equal at least 150% of obligations and then specify parameters for all of the kinds of inputs required for the calculation. The regulations would be clear but rigid, and the debate over appropriateness of the clearly fixed standards could drag out indefinitely.

On the other hand, the general kind of evidence required is obvious and easily accessible. A comprehensive and cogent plan for decommissioning should be part and parcel of operations for a prudent operator who intends to abide by the law. Future cash flow of operations projected in a reserve report is standard practice. If the cost of decommissioning has not been estimated, then it should be. The requirement is simply to show how these two basic functions fit together.

Q: IPANM witness Jim Winchester objects to Applicants' proposed requirement that operators requesting a transfer of wells provide OCD a plugging and abandonment plan because such a plan will not represent how an operator's financial position can change over time. Winchester Test. at 4 [IPANM Prehrg. Stmnt.]. What is your response?

A: Plans certainly change over time, but that does not make the demonstration or attestation useless. His objection does, however, beg the question of the need for still greater assurance or greater disclosure.

The risk of financial failure systematically (though not universally or uniformly) increases with time as the properties deplete. A viable plan at transfer does not prevent orphaning, but the lack of a viable plan represents substantial risk to the state.

When a viable plan cannot be demonstrated, companies may still reduce costs and extend the life of wells to increase cash flow, but that extension occurs to the thinnest margins of the lifecycle. Sometimes a company can find or create significant new value, but often they don't. If the operator takes over a field without a viable plan for decommissioning, then it is asking taxpayers to underwrite its gamble. The owners would keep the upside of success, and the public pays the downside cost of failure.

More concretely, for an operator to succeed in paying its obligations at the end of life when it cannot demonstrate a viable plan today requires two extraordinary sacrifices from the operator. First, the transferee must dedicate all of the existing cash flow for the remainder of the projected life to paying for the retirement obligations (up to the cost of retirement). Then, the company would have to make investments knowing that part of the returns must also be routed to the projected funding gap. It seems unlikely that a buyer would be willing to dedicate not only all future cash flow but also part of any investment returns to paying someone else; I've never seen such a thing.

Mr. Winchester does make a good point that an operator could demonstrate a viable retirement plan today then merely not perform it. The company could send proceeds out of the company to owners instead of sending proceeds to meet their statutory obligations.

The real solution to Mr. Winchester's objection is stricter, not looser, oversight. The Commission could require full funding at the drilling of the well, or it could require payments during the life of a well with make-up payments for wells already substantially depleted. Or the Commission could require annual attestation or annual justification by the operator of a viable plan to met the full obligation.

This concludes my rebuttal testimony, which is accurate to the best of my knowledge.

<u>*/s/ Dwayne Purvis*</u> <u>September 18, 2025</u>
Dwyane Purvis Date

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EXHIBIT 75

Applicants’ Exhibit 75: Resource categories and subdivisions of technical uncertainty and project maturity.

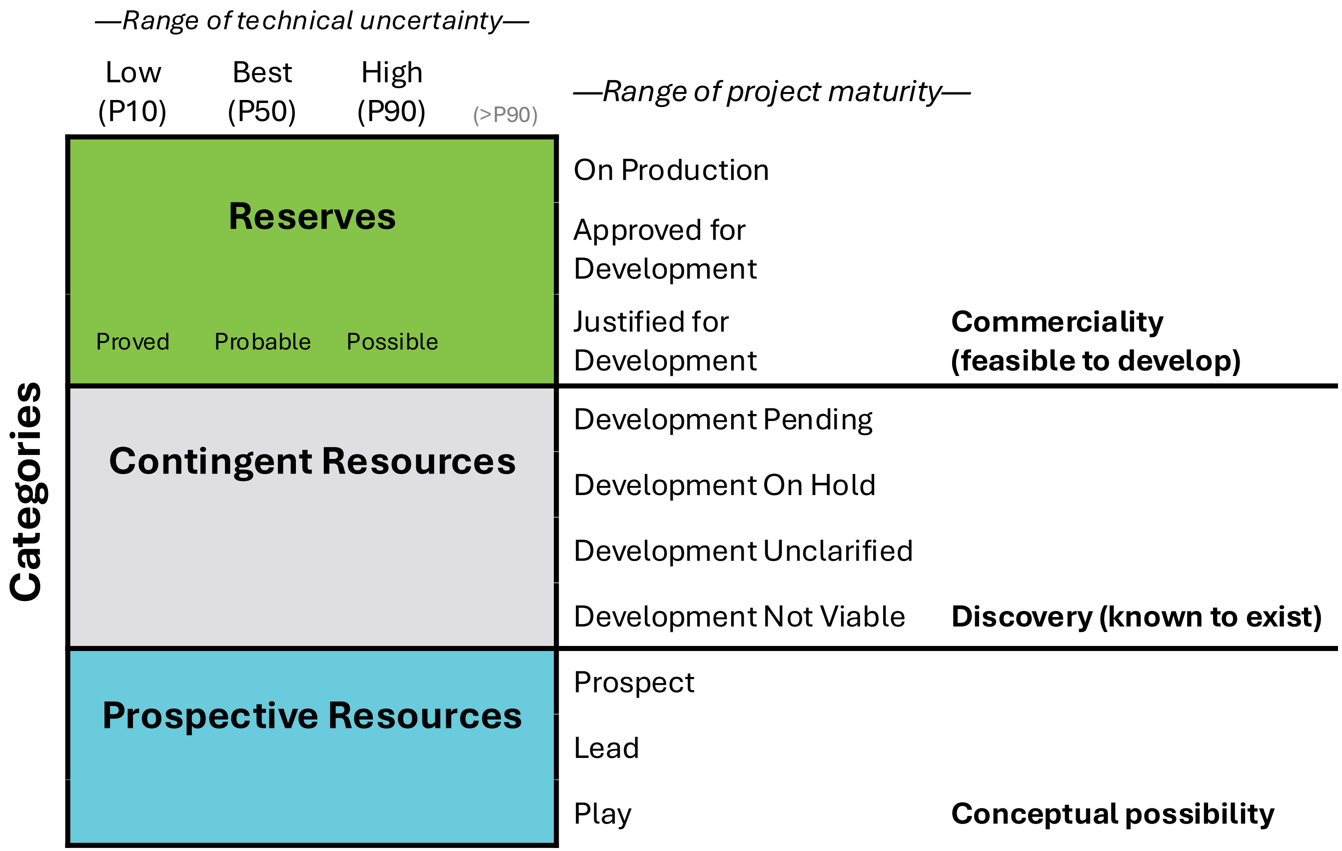

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EXHIBIT 76

Applicants' Exhibit 76: Resource categories and subdivisions of technical uncertainty and project maturity, including definitions.

—Range of project maturity evaluated with best (P50) estimate—

Categories			
Reserves	On Production		
	Approved		
	Justified	"commercially viable" with "no known contingencies" "firm intention to proceed with development within a reasonable time-frame"	Range of thresholds for delay
Contingent Resources	Pending	"**project activities are ongoing** to [justification]. . .in the foreseeable future"	
	On Hold	"project activities are **on hold** and/or where justification. . .may be subject to **significant delay**"	
	Unclarified	"project activities are **under evaluation** and where justification. . .is unknown based on available information." "requires appraisal or study and should not be maintained without a plan for future evaluation"	
	Not Viable	"**no current plans** to develop or to acquire additional data"	
Prospective Resources	Prospect	"sufficiently well defined to represent a **viable [testing] target**"	
	Lead	"**poorly defined** and requires more data acquisition and/or evaluation to be classified as a Prospect"	
	Play	"trend of **potential prospects**, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects"	

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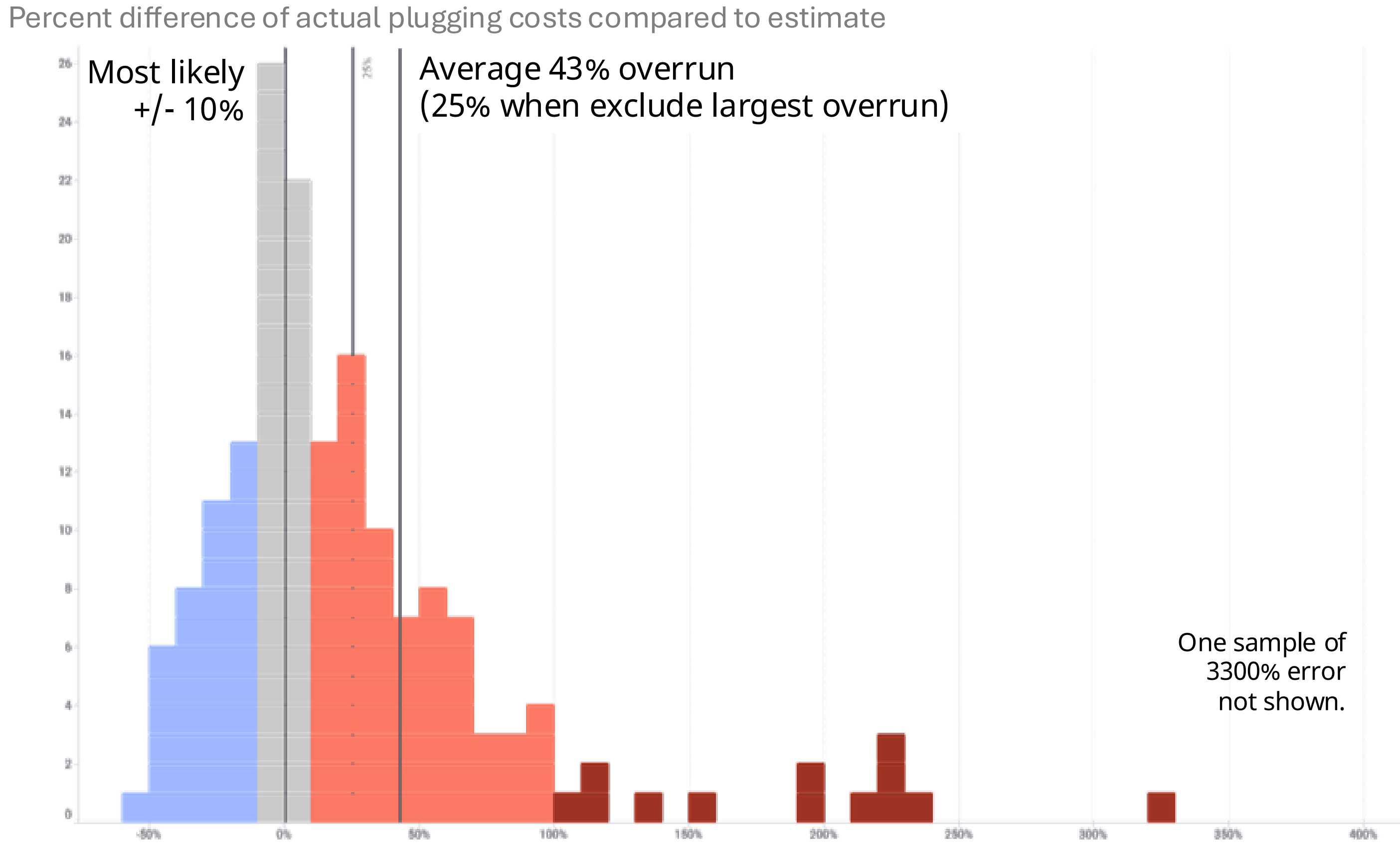
Apps' Ex. 76

EXHIBIT 77

Applicants' Exhibit 77: Variance of actual downhole plugging costs to estimates shows long high-side tail.



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Master Orphan List from OCD. Sample size 182, excludes variation estimates that were made in large groups,

EXHIBIT 78

Applicants' Exhibit 78: Figure S2 of Raimi 2021 showing the relationship of the logarithmic of plugging-only cost against the depth of the wells in a sample across five states with brackets to show ranges of 10x and 100x.

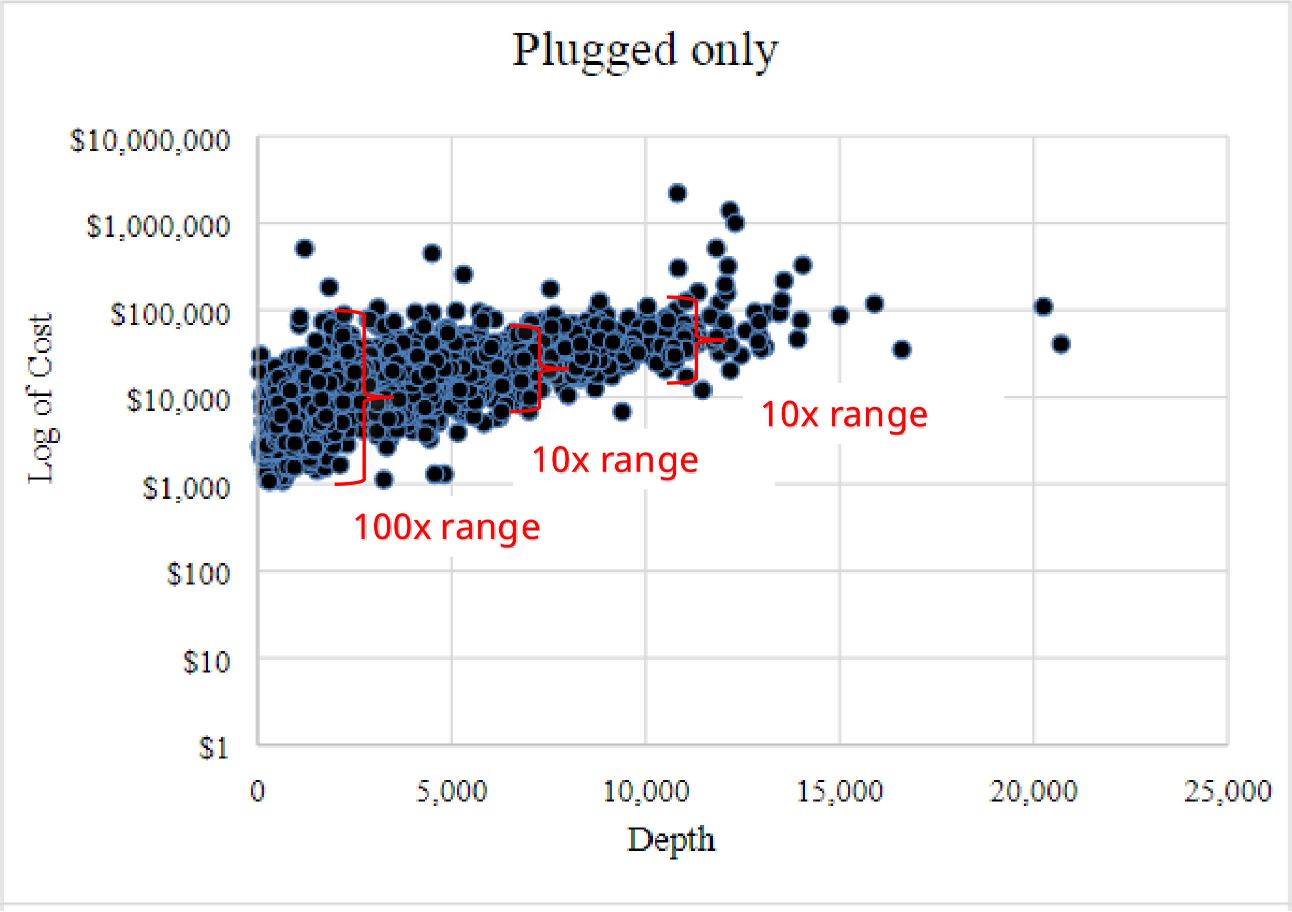

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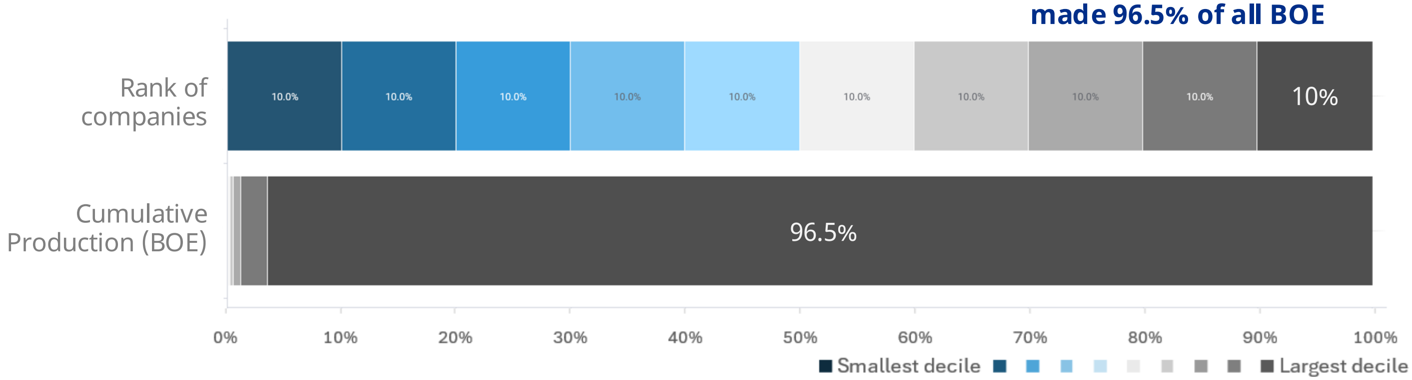
EXHIBIT 79

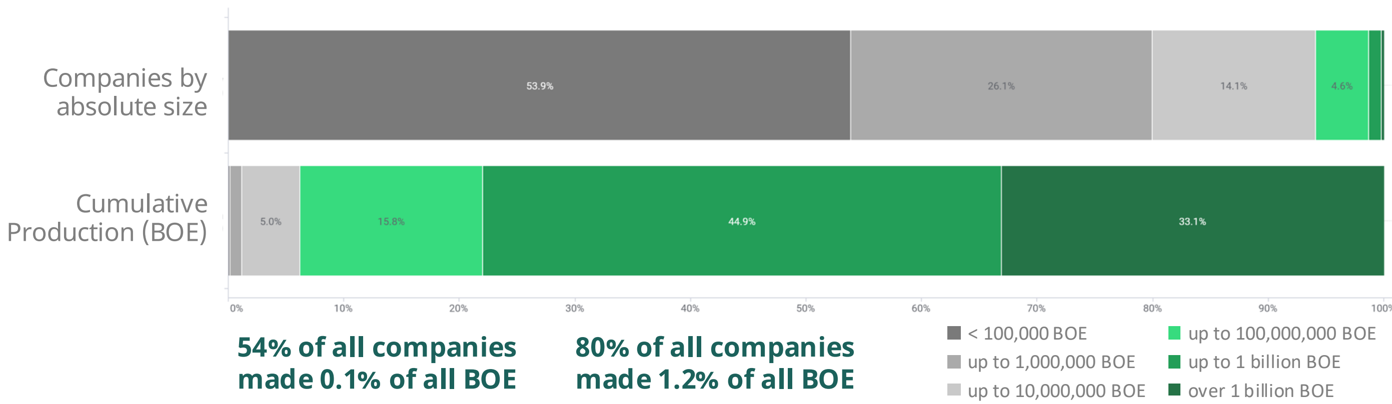
Applicants' Exhibit 79: Proportion of cumulative oil and gas production 1993 to present contributed by companies of various sizes.

Companies ranked by cumulative production 1993 to present

Top 10% of all companies made 96.5% of all BOE



Companies grouped by volume of cumulative production 1993 to present



54% of all companies made 0.1% of all BOE

80% of all companies made 1.2% of all BOE

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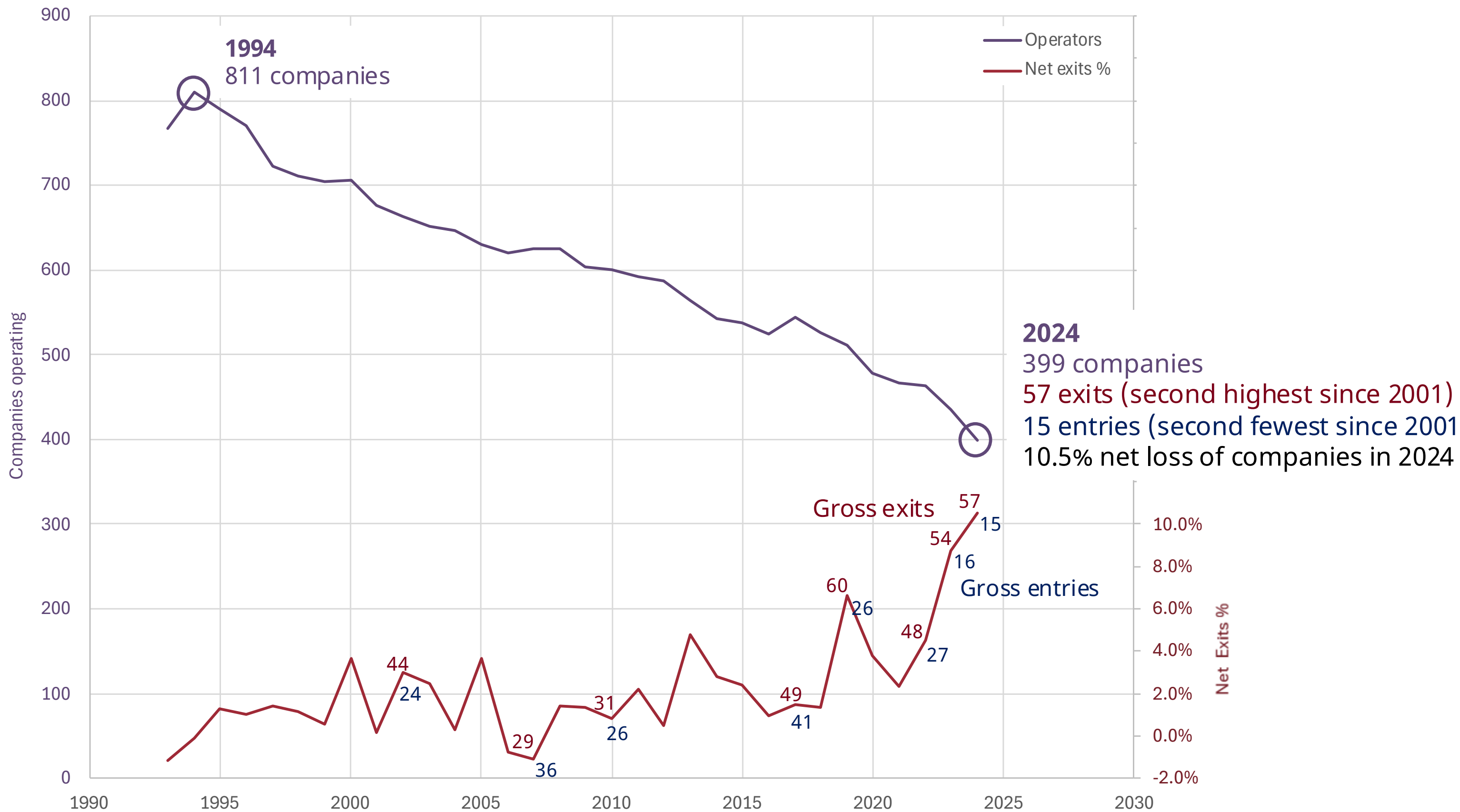
Apps' Ex. 79

EXHIBIT 80

Applicants' Exhibit 80: Number of operators active in the state on long-term decline and accelerating in recent years.



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Apps' Ex. 80

EXHIBIT 81

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

REBUTTAL TESTIMONY OF PETER MORGAN

Table of Contents

BACKGROUND AND QUALIFICATIONS

Q: Please state your name.

A: Peter Morgan.

Q: Did you provide direct testimony in this matter?

A: Yes. My direct testimony is Applicants' Exhibit 15.

Q: Are your qualifications and background set forth in that testimony?

A: Yes, on Bates stamped pages 0287-0382 of Applicants' Prehearing Statement, and my resume is Applicants' Exhibit 14.

SUMMARY OF OPINIONS

Q: At the outset, do you have any general comments about the direct testimony filed by the other parties in this matter?

A: Significant portions of the testimony of the experts for the New Mexico Oil and Gas Association ("NMOGA") and Independent Producers Association of New Mexico ("IPANM") confirm the fundamental premises identified by Applicants that establish the need for the proposed amendments to New Mexico's oil and gas regulations to prevent the state from bearing hundreds of millions of dollars of potential liability to plug and remediate thousands of orphaned wells.[1] And yet those same experts offer no solutions in their testimony other than maintaining the broken status quo, and NMOGA and IPANM have refused to engage in good faith negotiations to address the growing problem of orphaned wells.

Industry expert testimony acknowledges that oil and gas production in New Mexico has entered its decline phase. McGowen Test. at p. 98 [NMOGA Ex. D] ("The likelihood that

[1] New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, p. 1, June 24, 2025 [Apps' Ex. 4].

Permian shale production has already peaked is more than just speculation, it is becoming the prevailing leitmotif for the industry's evolving dynamics.") This means that industry and regulators can no longer presume that new production and revenue will cover legacy cleanup costs for the existing portfolio of wells. Instead, action must be taken immediately to ensure that existing revenue from these wells is put towards satisfying these obligations.

Industry expert testimony also acknowledges that the practice of transferring low-producing wells from highly profitable initial producers to under-resourced small operators is a fundamental part of the industry's business model. McGowen Test. at p. 97 (describing "the natural lifecycle of the upstream industry, where smaller operators play a vital role in absorbing, redeveloping, and de-risking legacy assets that the larger companies no longer prioritize."); and p. 105 ("[a]s part of the ongoing portfolio rationalization in the industry, Operators regularly shed marginal or aging wells and associated non-core leases to free up capital and reduce ongoing costs, especially during product price downturns and/or capital is required for what appear to be better projects."). This process directly contributes to well orphaning in New Mexico by allowing initial operators to pocket the profits from wells' early high production, and leaving end-of-life wells in the hands of under-resourced operators most likely to orphan the wells before plugging.

By highlighting the limited cash flow and exceedingly narrow margins of the majority of New Mexico operators—those operating marginal or stripper wells—the NMOGA and IPANM experts have all but conceded that these operators have not set aside funds to cover the costs of plugging their wells and do not have the resources to satisfy those obligations. *See* Emerick Test. at pp. 4-5 [NMOGA Ex. F] ("For these sizes of operators, working capital and investment capital are generally minimal. Surety providers are far less likely to approve larger bonds when an operator's investment capital and working capital are barely adequate upon initial analysis."); Arscott Test. at p. 8 [IPANM Prehrg. Stmnt.] ("in low producing wells, . . . fixed costs are large relative to expected revenues from continued oil and gas production. Revenue from sales of oil and gas produced from a well declines over time as reserves are depleted."). The "minimal" working capital referenced here includes the capital needed to plug wells. Both NMOGA's Mr. Emerick and IPANM's Mr. Gilstrap state in their testimony that operators are unlikely to be able to satisfy surety provider requirements that they have working capital equal to 25% of a $150,000 bond. Emerick Test. at p. 3; Gilstrap Test. at p. 4. That's just $37,500 per well. Multiple industry experts cite to the Raimi et el.[2] study, which provides a national median plugging and remediation cost of $76,000. *See* McGowen Test. at p. 82 (citing Raimi: "analysis of ~19,500 wells found a median of $76k"); Arscott Test. at pp. 3 and 4 (citing Raimi). Even assuming that this figure is accurate, that means that New Mexico operators maintain working capital per well of less than half that amount (and one quarter of OCD's average cost of $163,000 per well). In other words, the operators do not have the capital to plug their wells. The only reasonable conclusion that can follow is that the cost of plugging these wells will fall to the state. Indeed, the dominant theme that emerges from the testimony of NMOGA and IPANM's witnesses is that marginal operators cannot bear the actual market costs to secure them against the risk of orphaning their wells. If the operators do not bear the costs, it is left up to the State of New Mexico to subsidize the oil and gas industry by absorbing the industry's plugging and clean-up costs. The testimony of NMOGA and IPANM's experts gives little confidence that operators of the most marginal wells have the ability to satisfy these obligations themselves.

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[2] Raimi, D., Krupnick, A.J., Shah, J.S. and Thompson, A., 2021. Decommissioning orphaned and abandoned oil and gas wells: New estimates and cost drivers. Environmental science & technology, 55(15), pp.10224-10230.

Finally, NMOGA and IPANM experts implicitly acknowledge that the surety bonding industry has concluded that under the current regime New Mexico oil and gas operators pose an extremely high risk of defaulting on their plugging obligations. *See* Gilstrap Test. at pp. 3-4 [IPANM Prehrg. Stmnt.] ("Currently, we are in one of the hardest surety markets I've experienced in my career."); Emerick Test. at pp. 2-3 ("The simple fact is that the surety market today is very demanding and difficult to navigate. . . . surety companies have become more restrictive in their underwriting guidelines to minimize the risk that a bond will be called."). Surety providers are sophisticated, profit-motivated firms. Industry acknowledges that "sureties have become far more restrictive in their underwriting guidelines in determining collateral amounts." Gilstrap Test. at pp. 3-4. Surety providers are under no illusion as to the risks posed by marginal operators. If the sureties perceive these risks, then New Mexico's regulators must also, and must take immediate action to protect the state from defaults.

Even if industry parties fail to expressly acknowledge the existence of the orphaned well crisis in New Mexico, they *have* acknowledged each of the dynamics that has led to the crisis. As they must. This means that the only question remaining for the Oil Conservation Commission ("Commission") is what steps to take to address the crisis -- a threat to the state recognized by the New Mexico Legislative Finance Committee, the New Mexico State Land Office, and the Energy, Minerals and Natural Resources Department.[3]

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[3] *See, e.g.,* 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 [prepared for NM State Land Office], https://www.nmstatelands.org/wp-content/uploads/2021/05/NM-Assurance-Assessment-May-FINAL.pdf; Vertex Resources, Inc., New Mexico Oil and Gas Liability Assessment, Mar. 2021 [prepared for NM State Land Office]; NM Energy, Minerals and Natural Resources Dept. Orphan Wells Spotlight, June 2025; NM Energy, Minerals and Natural Resources Dept., Agency Bill Analysis 2024 Regular Session, HB133, Jan. 18, 2024, https://www.nmlegis.gov/Sessions/24%20Regular/AgencyAnalysis/HB0133_521.pdf.

Apps' Ex. 81

SURETY BONDS

Q: Mr. Morgan, before we turn to Applicants' specific proposal, I'd like to do address general concerns raised by industry witnesses regarding the ability of operators to secure surety bonds under Applicants' financial assurance proposals in 19.15.8 NMAC. Witnesses for NMOGA and IPANM claim that operators will struggle to access surety bonds: Emerick Test. at pp, 10-11; Winchester Test. at p. 10 [IPANM Prehrg. Stmnt.]; Arscott Test. at p. 20. IPANM witnesses also claim that the increase in annual premiums caused by Applicants' proposed rules would be cost-prohibitive for many operators: Winchester Test. at p. 10; Gilstrap Test. at pp. 4-6. And NMOGA witnesses claim that obtaining single-well financial instruments in addition to high-volume blanket bonds will be difficult in the current surety market. Emerick Test. at p. 6. What is your response?

A: Rather than supporting an argument that New Mexico should maintain its current inadequate financial assurance requirements, this testimony from IPANM and NMOGA experts demonstrates the critical need for the state to protect itself from operator defaults. New Mexico must ask why an operator wouldn't qualify for a surety bond that covers the anticipated liability. Wouldn't the surety want to collect premiums? When determining whether to offer bonds, and on what terms, sureties consider factors such as the remaining revenue in the operator's wells, the operator's expenses, and the operator's cash reserves. If a surety declines to issue a bond, or requires higher premiums or higher amounts of collateral, that means the surety has concluded that the operator poses a higher risk of default. That should sound an alarm prompting more action from state regulators, not less. IPANM and NMOGA are asking that the State of New Mexico---rather than operators or sureties---bear this risk. That is unreasonable. These costs should not be socialized; they should be borne by industry.

Furthermore, surety providers are unlikely to treat the entire oil and gas industry as a monolith. Because surety providers weigh annual premiums against the risk of default and forfeiture, responsible New Mexico operators who can demonstrate a history of plugging wells and setting aside funds for plugging should still have ready access to the surety market. Those operators who sureties deem at risk of default will not be able to secure bonds. To the extent the proposed amendments help identify the operators with the riskiest wells, that will only assist New Mexico's responsible operators. Those responsible operators should be able to acquire wells and continue production as the highest risk operators exit the market.

Q: NMOGA witnesses claim the surety market isn't equipped to issue the volume of surety instruments that would be needed to comply with these rules: Emerick Test. at p. 12-13; Felix Test. at p. 17 [NMOGA Ex. B]. What is your response?

A: Surety bonding is a robust and sophisticated industry with hundreds of firms providing bonds for a wide range of industries, including oil and gas. There are 245 distinct surety providers on the U.S. Treasury Department's Circular 570, listing the companies vetted by the Department and deemed qualified to do business with the United States.[4] Almost all of those sureties are licensed to do business in New Mexico.[5]

Sureties are always happy to collect premiums. Sureties keep the premiums they collect, regardless of whether they ultimately pay out the bond. If the operator completes the plugging and the regulator releases the bond, the surety still keeps the collected premiums, which can be considered pure profit. Premiums are set based on a percentage of the bonded amount, so the larger the bond, the more premiums may be collected. And if the operator defaults, the surety can

[4] https://www.fiscal.treasury.gov/surety-bonds/list-certified-companies.html.
[5] *Id.*

recover the bond amount---on top of the premiums collected---by foreclosing on collateral and filing a collection action against the operator.

Given the established capacity within the surety bonding industry, and the inherent desire to collect premiums, concerns about the ability of surety providers to satisfy an increased demand for bonding are overstated.

The industry experts' dire predictions of how the surety industry may respond to the proposed amendments are contradicted by other portions of the experts' testimony. For example, Mr. Gilstrap anticipates a surety collecting $130,000 in premiums for a $150,000 bond over 25 years. Gilstrap Test. at p. 9. At that rate, a surety bond should be a highly profitable instrument for the surety industry, as the bond provider's maximum exposure would be $20,000. This means that the premiums collected from a minority of non-forfeited bonds could cover the costs of paying out other bonds. But as Mr. Gilstrap also states, the surety industry is exiting the oil and gas sector, indicating sureties' concern that the rate of operator default will be too high for the industry to bear. If true, that assessment—by sophisticated, profit motivated financial institutions—should be a major red flag for New Mexico.

To the extent none of the hundreds of surety bond providers are willing to issue bonds covering the full liability for New Mexico oil and gas operators, this should be read as a significant warning sign that the surety industry believes New Mexico operators will default on their plugging obligations. The only rational response to such a warning is for the State of New Mexico to take more actions to protect itself from this risk of default, not less. In the face of such a dire prediction, it would be highly irresponsible for New Mexico regulators to maintain the status quo, which is exactly what the industry parties are recommending.

Q: IPANM witnesses claim that alternatives to surety bonds are unworkable and tie up

operator capital that could otherwise be used for other purposes: Gilstrap Test. at pp. 6-7. Similarly, NMOGA witnesses claim that surety bonds would require significant collateral for each bond, tying up capital that could be used elsewhere: Felix Test. at p. 19. What is your response?

A: This argument is effectively an admission that under the status quo the oil and gas industry does not set aside funds during initial peak production to cover its ongoing plugging and environmental obligations. Surety providers and other providers of financial assurances determine things like collateral requirements based on their assessment of the likelihood the bonded operator will be able to meet its plugging obligations. An operator with funds already set aside for plugging, or a demonstrated history of the same, would pose a very low risk of default and therefore not be subject to onerous collateral requirements. If, on the other hand, an operator has not set aside those funds, and now cannot afford bond premiums or collateral requirements, that operator has already put itself in a position where it is extremely unlikely to be able to plug its wells. Once wells are low producing, they will struggle to cover their operating costs, let alone provide funds to pay for plugging.

Q: NMOGA witnesses recommend that the bond instrument be modified to a periodically renewable form to make it easier for operators to qualify for the bond and meet surety company underwriting guidelines: Emerick Test. at 16. What is your response?

A: This is not a serious proposal, and is not consistent with how financial assurances work for extractive industries. The obligation to plug a well attaches at the moment the well is drilled. As soon as the well is drilled, there will be a need to plug that well at some point. If the operator does not plug the well, then the regulator must do so. In order for the regulator to be assured that this plugging can be accomplished at no cost to the state, there must be a permanent, noncancellable financial assurance in place before the obligation is incurred (i.e. before the well is drilled).

Under Mr. Emerick's proposal, sureties would have every incentive to provide bonding during the first few years of a well's initial, profitable production. That's basically free money for the surety, where they can pocket the annual premium payments, while bearing essentially zero risk of having to pay out the clean-up bond. But as soon as the well's production goes down, the surety's calculus changes. As production declines, the risk of having to pay out the bond goes up. Once the initial surety cancels its bond, no rational surety would be willing to provide a replacement bond. Sureties will decline to issue replacement bonds for late-life wells. *Accord* Emerick Test. at p. 3 ("For a host of reasons, surety companies have become more restrictive in their underwriting guidelines to minimize the risk that a bond will be called."). Once the initial bond is canceled, the regulator is left with absolutely no protection (short of building a time machine and going back in time to deny the permit and prevent the drilling of the well in the first place).

<u>19.15.5 NMAC – ENFORCEMENT AND COMPLIANCE</u>

<u>19.15.5.9.A(4) NMAC – Compliance with 19.15.2.25.8 NMAC</u>

Q: Mr. Morgan, let's turn to Applicants' specific proposals, beginning with 19.15.5 NMAC – Enforcement and Compliance. NMOGA witnesses object to Applicants' proposal to eliminate current language allowing operators to have a certain number of wells out of compliance for purposes of a compliance determination under 19.15.5.9.A NMAC: Felix Test. at 47. OCD originally proposed this change, and Applicants adopted it. OCD February 12, 2025 Redline Proposals [Apps' Ex. 5]. The proposed amendment is:

19.15.5.9 COMPLIANCE

A. An operator is in compliance with Subsection A of 19.15.5.9

NMAC if the operator:

. . .

(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.~~

NMOGA witnesses state that proposed removal of the allowance for noncompliant wells is "impractical and punitive—especially for smaller operators." Felix Test. at 47. What is your response?

A: As discussed in my direct testimony, 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.[6]

Existing 19.15.5.9.A(4) NMAC allows operators to have a certain number of wells out of

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[6] 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).

compliance with the Commission's plugging and abandonment requirements at 19.15.25.8 NMAC for purposes of the compliance determination made under 19.15.5.9.A NMAC. Section 19.15.25.8 NMAC requires operators to plug and abandon a well or place the well in temporary abandonment status after 12 months of inactivity (or a determination the well has no beneficial use or 60 days after suspending drilling operations).

There is no sound policy rationale that I can think of that justifies allowing *non-compliance* for purposes of making a *compliance* determination. On its face, this makes no sense. And there is certainly no sound policy rationale for allowing operators to avoid their responsibilities to plug and abandon an inactive well or better secure the well by placing it in temporary abandonment. Wells that have been inactive for a year or more are at higher risk of becoming orphaned. The Commission's existing rule allows these at-risk wells to remain inactive *indefinitely* – with no administrative review or regulatory requirements. This loophole in the Commission's rules has no sound policy or regulatory basis and creates unacceptable risk to the state that these wells will pollute the environment and/or be orphaned.

Ms. Felix sets forth no good basis for her claim that this proposal is "impractical and punitive – especially for smaller operators" claiming the proposal ". . . disregards the realities of field operations, where minor noncompliance is often temporary and quickly resolved." Felix Test. at 47.

However, Ms. Felix misunderstands the Commission's rules. Ms. Felix presumably refers to an operator's non-compliance in the field with the plugging and abandonment requirements of 19.15.25.8 NMAC. The loophole in 19.15.5.9.A(4) NMAC however does *not* allow an operator to be out of compliance with the plugging and abandonment requirements in 19.15.25.8 NMAC. It allows non-compliance only for purposes of the compliance determinations identified above.

When an operator accepts a permit and drills a well, or when it acquires an existing well, it assumes the obligations to plug or place the well in temporary abandonment once it stops producing. This is just as true for small operators as it is for large. Applicants' and OCD's proposed amendment merely holds operators to this requirement by requiring them to maintain compliance with the well plugging requirements of 19.15.25.8 NMAC.

Q: NMOGA proposes to do away completely with requiring compliance with the Commission's plugging and abandonment requirements at 19.15.25.8 NMAC for purposes of the compliance determination in 19.15.5.9.A(4) NMAC. *See* NMOGA Ex. A. What is your opinion on that proposal?

A: I strongly disagree with that proposal. The requirement to plug and abandon or place a well in temporary abandonment after 12 months of inactivity is critical to ensuring that inactive wells don't lie idle indefinitely, pollute the environment, or threaten nearby communities, or become the responsibility of the state to clean up. I can find no good rationale in NMOGA's experts' testimony to not take account of operators' compliance with one of the Commission's most important rules when OCD makes compliance determinations under 19.15.5.9.A NMAC. NMOGA's proposal would take the Commissions' rules backward, not forward.

<u>19.15.5.9.A(5) NMAC – Compliance with 19.15.27.8.A NMAC</u>

Q: NMOGA and IPANM witnesses object to incorporation of the waste prevention requirements in 19.15.27.8.A NMAC into the 19.15.5.9 NMAC compliance standard: Felix Test. at p. 47; Sharpe Test. at p. 6 [IPANM Prehrg. Stmnt.]; Winchester Test. at pp. 2-3; Sporich Test. at p. 34-36 [NMOGA Ex. E]. The proposed amendment is:

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

<u>**(5)** currently meets the requirements of 19.15.27.8.A NMAC.</u>

NMOGA witnesses states that incorporation risks distorting "a broad policy statement into a rigid threshold for compliance," and characterize the waste prevention compliance requirement as a "high-level policy provision," rather than "a binary compliance rule," suggesting that incorporating that requirement here creates "legal ambiguity and overreach." IPANM witnesses characterize the incorporation as "redundant" and "inflexible." What is your response?

A: The requirements of 19.15.27.8.A NMAC are clearly expressed as a prohibition, with detailed provisions specifying the limited circumstances under which venting or flaring may be allowed. It is not a broad policy statement; it is a requirement.

Including the venting and flaring requirements within 19.15.5.9 NMAC is no more redundant than including the other Commission requirements in the compliance determination at 19.15.5.9.A NMAC. The general prohibition against venting and flaring methane waste is one of the Commission's most important rules. Adding it to the requirements for a compliance determination underscores its significance. 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.[7]

Operators who regularly vent and flare natural gas in violation of 19.15.27.8.A NMAC may also lack capacity to properly operate and plug their wells, and the inclusion of the reference to 19.15.27.8.A NMAC in the compliance provisions of 19.15.5.9 NMAC provides OCD with

[7] *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),

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.

<u>19.15.8 NMAC – FINANCIAL ASSURANCE</u>

Q: IPANM and NMOGA witnesses generally object to the proposed amendments to the financial assurance requirements at 19.15.8.9 NMAC: Gilstrap Test. at p. 7; Arscott Test. at p. 20; Sporich Test. at pp. 19-20; Arthur Test. at pp. 34, 43-44 [NMOGA Ex. C]. IPANM witnesses claim that the unintended consequences of the proposed amendments include premature plugging of marginal wells, bankruptcies, increased orphaning, increased bank debt, and operators exiting the state. What is your response?

A: These predictions are contrary to the actual outcomes described by Boomhower[8] and Lange & Redlinger[9] in their respective economic studies describing the effects of increased bonding in Texas and North Dakota. As described in my direct testimony,[10] those studies found no meaningful decrease in production following adoption of the increased bonding requirements. Specifically, Boomhower observed that "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."[11]

I would expect to see the same in New Mexico. Although the Texas and North Dakota laws reviewed in the two studies required bond amounts that are lower in absolute terms than the

[8] Judson Boomhower, <u>Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk</u>, American Economic Review Vol. 109, No. 2, Feb. 2019 at pp. 420-21.
[9] Ian Lange & Michael Redlinger, <u>Effects of stricter environmental regulations on resource development</u>, Journal of Environmental Economics and Management, 96, 60–87 (July 19).
[10] Morgan Dir. Test. at 0319-0322 [Apps' Ex. 15].
[11] Boomhower at p. 422.

adjusted financial assurance amounts in the proposed amendments, each law represented a significant increase compared to prior requirements. It is likely that certain high risk operators will see a decrease in access to capital and may choose to exit the market. But it's not accurate to say that the industry as a whole will be impacted in the same way. The responsible operators who remain will be able to acquire and continue producing economic wells.

To the extent any additional wells are orphaned following adoption of the proposed amendments, the changes to the regulations would not be to blame. These wells are likely already going to be orphaned, regardless of what action the Commission takes. The operators of these wells have failed to set aside the funds necessary for plugging. The only question is timing. Under the current regulations, operators are encouraged to kick the can down the road, but the outcome is always going to be well orphaning. To the extent the amended regulations accelerate this process, the amendments are merely exposing this reality, and allowing the state to take action sooner to address the need to plug those wells.

Q: IPANM's witness argues that inactive and marginal wells should be allowed to remain unplugged because it is possible that a new technological advancement could arise that would make these wells productive. Arscott Test. at p. 11. What is your response?

A: What Mr. Arscott is describing here is a gamble - a bet that technology will improve and make unprofitable wells profitable. That's fine, if all of the risk is borne by the operator. Currently, virtually all of the risk is being pushed onto the state, because if there is no new miracle technology, then that well is going to be orphaned, and the state will bear the cost. The longer a well sits inactive and unplugged, the more likely it is to be orphaned. Operators are much more likely to run out of funds and go out of business than they are to benefit from currently unknown technologic advancements. Imposing one well financial assurance requirements covering all the operator's liability puts the risk back on the operator, where it should be. If operators want to maintain the financial assurance and comply with all other requirements for temporarily abandoned wells while they wait for technological improvements, that's their choice. But they should not be allowed to put the risk on the communities, environment, and economy of New Mexico.

Q: IPANM witnesses discuss how other states have addressed financial assurance for oil and gas wells: Gilstrap Test. at p. 7-8. These examples include state-run bonding pools, OneNexus, and third-party trust or escrow accounts. What is your response?

A: Those arguments are outside the scope of the present rulemaking, because they would require amendments to New Mexico statute.

That said, I do believe that the third-party trust or escrow account approach has merit, at least for newly drilled wells. Under this approach, operators would be required to set aside a set percentage of funds each year in a dedicated, bankruptcy-remote account, until the ultimate cost of plugging each well was satisfied. As the funds in the account increase towards the anticipated cost of plugging, the amount of separate financial assurance required for each well would decrease. At year zero, when the funds in the account were at $0, the operator would be required to provide a surety bond or other financial assurance for $150,000. Assuming contribution of 10% each year, by year 5 the account would have $75,000 and the bond would be reduced to $75,000. In year ten and thereafter, the bond requirement would be $0 because the account would be fully funded. One significant advantage of this approach is that once the well's production has declined to the point where it needs to be plugged, the operator can draw down the funds in the account without having to tap into working capital.

Because this trust account approach works in concert with other financial assurances, it is not inconsistent with the amendments proposed in this current rulemaking. The Commission can adopt all of the proposed amendments now without interfering with future efforts to secure legislation providing a third-party trust or escrow account approach in New Mexico statute.

Q: NMOGA witnesses claim that NMSA 1978, § 70-2-14(A) provides OCD the authority to require single-well and blanket financial assurance "in amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance," and that the single-well financial assurance amount is not reasonable because it doesn't represent typical costs to decommission New Mexico oil and gas wells: Sporich Test. at p. 19. NMOGA witnesses also claim that the proposed rules are a "one-size-fits-all" approach, in contravention of NMSA 1978, § 70-2-14, which requires consideration of "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": Sporich Test. at 19-20. What is your response?

A: In relevant part, NMSA 1978, § 70-2-14 states that "[i]n establishing categories of financial assurance, the oil conservation [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 oil conservation division deems relevant." The listing of multiple factors, together with inclusion of the additional catch-all "such other factors as the oil conservation division deems relevant," directs the Commission to consider relevant available information. And the ultimate mandate of the statute is that the "one-well plugging financial assurance" be "sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance." The proposed amendments fully satisfy this mandate.

Under the existing regulations, one-well financial assurances are determined solely on the basis of a single statutory factor: the depth of the well. 19.15.8.9 NMAC (providing for "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"). None of the parties opposing the proposed amendments have suggested that this existing regulation contravenes the statute by focusing on a single statutory factor. Nor have any of the parties offered testimony demonstrating that the current standard of $25,000 plus $2 per foot of well depth bears any relationship to actual well plugging costs. Indeed, under that formula, a 10,000-foot well would require only a $45,000 bond, or less than one-third OCD's actual average plugging cost of $163,000.

The current approach of focusing solely on well depth fails to capture additional significant cost drivers, including the age of the well, how long since the well stopped producing, the condition of the well bore, and any challenges in accessing the well site. Those factors—including well depth—are inherently incorporated into the approach adopted in the proposed amendments, where the $150,000 one-well financial assurance is based on OCD's actual average cost of plugging wells. This approach of relying on OCD's actual plugging costs is the most effective way to ensure that the "one-well plugging financial assurance" is "sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance."

Q: NMOGA witnesses claim that OCD lacks the legal authority under NMSA 1978, § 70-2-14 to require the large blanket bonding amounts that would be required under the proposed rule: Sporich Test. at p. 20. OXY witnesses also make this same claim. Wallace Test. at 3-4 [OXY Ex. B]. What is your response?

A: Mr. Sporich, in my opinion, misreads the Oil and Gas Act's requirements. In relevant part, the act provides:

> The oil conservation [commission] **shall establish categories of financial assurance** after notice and hearing. Such categories shall include a blanket

> plugging financial assurance, which shall be set by rule in an amount not to exceed two hundred fifty thousand dollars ($250,000), a blanket plugging financial assurance for temporarily abandoned status wells, which 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.

NMSA 1978, § 70-2-14(A). The act further provides that:

> The oil conservation [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 or, at the election of the operator, may allow an operator to increase its blanket plugging financial assurance to cover wells held in temporarily abandoned status.

Id.

By its plain terms, the Oil and Gas Act authorizes the Commission to establish different "categories of financial assurance," and requires the Commission to establish three such categories:

- A "blanket plugging financial assurance" with a ceiling not to exceed $250,000;
- A blanket plugging financial assurance for temporarily abandoned status wells with a floor not less than $50,000, but no ceiling, and
- A one well plugging financial assurance sufficient to pay the cost of plugging the wells covered.

These three categories are *not* exclusive. The Commission has full authority to establish other categories of financial assurance.

In their amendments, Applicants propose that the Commission establish additional categories of financial assurance for higher risk wells: very low producing wells and inactive wells. Indeed, the Legislature has already recognized that inactive wells pose a greater risk to the state by setting a floor, not a ceiling, on blanket plugging financial assurance for wells in temporary abandonment status and requiring a one well financial assurance for wells in temporary abandonment more than two years.

Applicants' proposals do not conflict with any of the act's requirements, including the requirement to establish a "blanket plugging financial assurance" capped at $250,000. Applicants' proposal at 19.15.8.9.C(2) NMAC includes a "blanket plugging financial assurance" capped at $250,000 for active wells (similar to the Commission's current rule at 19.15.8.9.C(2) NMAC).

But in addition to establishing the required category for "blanket plugging financial assurance" capped at $250,000, Applicants – and OCD – propose additional categories of financial assurance, none of which is a "blanket plugging financial assurance," and all of which come within the Commission's authority to establish different categories of financial assurance. These categories require *one well* plugging financial assurance for marginal wells, all wells of an operator with more than 15% of its wells in marginal and/or inactive status, and all inactive wells (including approved and expired temporary abandonment wells). These one well plugging financial assurance categories do not conflict with the act's requirement to establish a blanket financial plugging assurance capped at $250,000 and are straightforwardly within the Commission's authority to establish different categories of financial assurance.

For the administrative convenience of operators, Applicants and OCD proposed in 19.15. 25.8.D(4) NMAC that, for marginal wells, an "operator may furnish all necessary one well plugging and financial assurance in the form of a single instrument." This provision, allowing operators to file a single instrument instead of multiple instruments, was included for the benefit of operators. Its inclusion does not turn the "one well financial plugging assurance" required for marginal wells into a "blanket plugging financial assurance" that runs afoul of the Oil and Gas Act. Similarly, *at the request of OXY USA, Inc.* ("OXY"), in this rebuttal filing, Applicants amended their proposal at 19.15.25.8.F NMAC to include the same allowance for the "one well financial plugging assurance" required for inactive wells. The newly added provision authorizes operators to file a "single instrument" instead of multiple instruments. *See* Apps' Ex. 72.

Allowing a single instrument instead of multiple instruments for inactive wells does not turn the "one well plugging financial assurance" required into a "blanket plugging financial assurance." There is an important distinction between a "blanket plugging financial assurance" and the allowance that an operator may satisfy its cumulative financial assurance obligations through a single instrument. Under the former, the operator is allowed to provide coverage for multiple wells at a fixed amount, such that as the number of covered wells increases, the per well coverage decreases. In contrast, under the single instrument approach the total amount of financial assurance required is calculated, including both eligible blanket financial assurance amounts, and one well financial assurance amounts, and then the operator secures a bond or other financial assurance instrument for that total combined figure. Just because an operator qualifies for use of a blanket financial assurance for some of its wells does not mean that the $250,000 cap applies to all of the financial assurances required for that operator.

<u>19.15.8.9.A NMAC -- Applicability</u>

Q: IPANM and NMOGA witnesses object to the proposed amendment to 19.15.8.9.A NMAC, which prevents drilling or acquisition until the operator has furnished the required financial assurance: Winchester Test. at p. 2, Sporich Test. at pp. 27-32. The proposed amendment is:

> **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. <u>The division shall not approve</u>

<u>and the operator shall not proceed with any proposed drilling or acquisition until the operator has furnished the required financial assurance.</u>

IPANM witnesses claim that the proposed new language is vague and broad. IPANM witnesses also claim that the proposed rule would require two operators to simultaneously bond the same well in the case of an acquisition, and that it would discourage the sale or purchase of wells in New Mexico. NMOGA witnesses claim that this would overstep OCD's authority. What is your response?

A: First, as stated in my direct testimony, this amendment does not change the current regulatory requirement or practice, but merely clarifies the rule. Section 19.15.8.9.A NMAC already requires an operator who "proposes to drill or acquire an oil, gas or injection or other service well" to furnish financial assurance to the state. That financial assurance would be due prior to drilling or acquisition. Applicants' proposed language clarifies that requirement.

Second, it's important to note that the proposed language is an addition to existing provisions pertaining to "Categories and Amounts of Financial Assurance for Well Plugging" – 19.15.8.9.A NMAC. This context is important, because Applicants' proposal relates only to the timing of the furnishing of financial assurances, and does not confer any additional authority.

Given that context, the inclusion of the proposed language is completely unremarkable and wholly appropriate. It is inherent in any financial assurance scheme that the financial assurance must be provided before the obligation is incurred. It would defeat the entire point of financial assurances were it otherwise. For example, what would happen if a well were drilled and then the operator could not secure a bond or other financial assurance? Or what if a well were transferred and the existing operator's bond released before the new operator's replacement bond were in place? In either case, OCD would be without recourse because it would be too late to undo the activity giving rise to the obligation. If the operator were not then able to provide the required financial assurance, OCD would still be responsible for covering the full plugging cost in the event of orphaning.

The language taken in context is adequately clear that this provision only applies to activities already requiring OCD approval: drilling a well or changing the designated operator. Taken in context, "acquisition" clearly means "acquisition of operating authority." The terms "acquire," "acquired," and "acquiring" already appear in multiple places within the "Financial Assurance" provisions of 19.15.8 NMAC. The stated "objective" of this section is: "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 (emphasis added); *see also* 19.15.8.9.A NMAC; 19.15.8.12.A NMAC; 19.15.8.14.A NMAC; 19.15.9.9.C(2) NMAC. This existing usage includes instances where—as with the proposed amendment—the acquisition has not yet occurred. 19.15.8.6 NMAC ("propose to . . . acquire"); 19.15.8.9.A NMAC ("proposes to . . . acquire"). In all cases, "acquire" (or its related forms) refers to an activity or proposed activity within the scope of OCD's jurisdiction: acquisition of operating authority. So, too, with the proposed amendment.

Nothing in the proposed language suggests that OCD would or could have a role in approving the sale of a well. Operators engaged in the sale of wells should, however, continue to be aware that even after a well is sold, if the parties wish to change the designated operator, that step does involve OCD oversight and review. The regulation at 19.15.9.9.C NMAC—Change of Operator—both as currently drafted and under Applicants' proposed amendments—expressly authorizes OCD to deny a change of operator under certain circumstances. The proposed amendment to 19.15.8.9.A NMAC ensures that the prior operator's financial assurance will not be released until the new operator's financial assurance is approved and the replacement bond is in place. This common sense policy keeps the risk with the transferring operator until the transaction is complete, rather than placing it on the state.

19.15.8.9.D NMAC – Marginal Wells and Inactive Wells

Q: After negotiations with OXY, Applicants propose an additional amendment to 19.15.8.9.D NMAC – Marginal Wells and Inactive Wells; is that correct?

A: Yes, that is correct. I participated in discussions with OXY and OCD, and all three sets of parties came to agreement on changes to Applicants' original proposal. OXY opposes the marginal well designation. If the marginal well designation and associated financial assurance requirements remain in the rule at Applicants' proposed 19.15.8.9.D NMAC, however, OXY would agree with this language. The agreed-upon changes are set forth below and in Applicants' Exhibit 72 and are highlighted in yellow.

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. Each operator with a marginal well or wells shall annually review the number of marginal wells registered to the operator and shall update the one well plugging financial assurance by May 1 of each year.

(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 basis for these changes?

A: OXY and other parties have expressed concerns that, as originally proposed, the amended financial assurance provisions could result in frequent fluctuations to an operator's financial assurance requirements as the operator acquires or disposes of wells, and as individual well's production changes. *See* Felix Test. at p. 17; Emerick Test. at p. 11. Parties assert that staying in compliance with the financial assurance requirements under such circumstances would be administratively burdensome for operators and for sureties and other providers of financial assurances. The proposed agreed-upon change addresses those concerns by specifying that the financial assurance for marginal wells need only be updated once per year on a predictable schedule. Although this means that some operators will not have the full amount of one well financial assurances in place for all of their marginal wells for the entire year, this is a reasonable trade-off to ease implementation of the requirement.

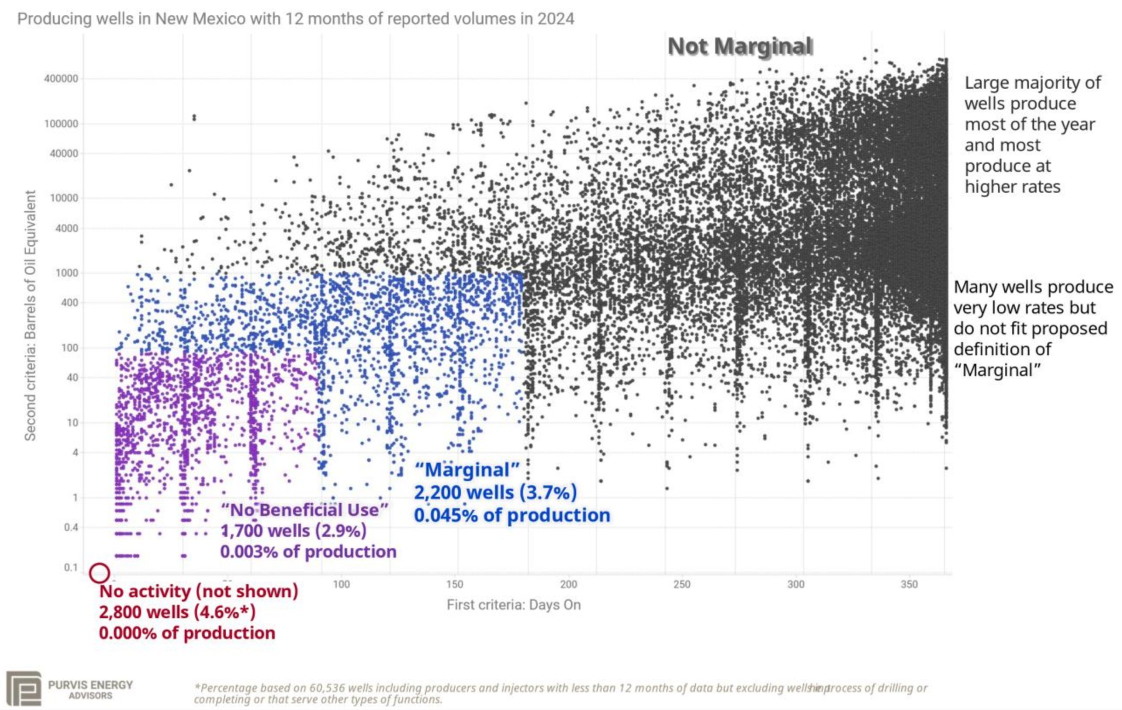
Q: NMOGA, IPANM, and OXY witnesses object to the proposed new category of financial assurance for marginal wells at 19.15.8.9.D NMAC: Wallace Test. at pp. 3-4; Gilstrap Test. at p. 3; Felix Test. at p. 13; Emerick at p. 8. IPANM and NMOGA witnesses claim that the one well financial assurance of $150,000 for marginal wells would be prohibitively expensive for many operators, if they are even able to qualify for that higher level of surety. They claim that the one well requirement may disproportionately affect smaller operators, who rely on marginal or stripper wells, which make up 54% of the oil wells and 81% of the gas wells in the state. What is your response?

A: Applicants' proposals for financial assurance for marginal wells in 19.15.8.9.D(1) & (2) NMAC and for marginal wells and inactive wells in 19.15.8.9.D(3) NMAC were initially proposed by OCD staff based on their experience in the field, *see* OCD February 12, 2025 Redline Proposals [Apps' Ex. 5], and then adopted and data-tested by Applicants. The data support OCD's field experience. This is a risk-based approach to address the category of wells at greatest risk of orphaning. It is a prudent action for the State of New Mexico to take to protect itself from the cost of plugging these wells.

At the outset, it is important to note that "marginal wells" as proposed and defined by Applicants and OCD are not the equivalent of "stripper wells." A marginal well is an oil or gas well that has produced less than 1,000 BOE and operated less than 180 days over a 12 month period. A stripper well is an oil or gas well that has produced less than 10 BOE per day over the preceding calendar year. NMSA 1978, § 7-29B-2(L); 19.15.6.7.M NMAC. Applicants and OCD are not proposing increased financial assurance requirements for stripper wells. Therefore, the proposals do not impact 54% of the oil wells and 81% of the gas wells in the state.

Second, as shown by Applicants' expert Dwayne Purvis, P.E. in Applicants' Exhibit 40, below, marginal wells make up 2,200 wells or 3.7% of all wells (exclusive of wells presumed not to have beneficial use), accounting for only 0.045% of production in the state. The category of "marginal wells" is exceedingly small and represents those wells with barely any activity. Applicants' and OCD's proposal is conservative.

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



Third, operators who cannot afford to maintain the additional financial assurances have the option of plugging wells that are already uneconomic, or of selling productive wells. This is the result that was observed in the economic studies of financial assurance increases in Texas[12] and North Dakota.[13] In those states, although some operators chose to exit the market, overall production remained consistent because producing wells were sold to other operators. I would expect to see the same in New Mexico.

Nothing in the proposed amendment targets smaller operators. Small, medium, and large

[12] 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.
[13] Ian Lange & Michael Redlinger, Effects of stricter environmental regulations on resource development, Journal of Environmental Economics and Management, 96, 60–87 (July 19).

operators are all subject to the marginal well requirements. The marginal well criteria are based on wells that have exceedingly low production and operate sporadically over the course of 12 months, not on the size of operator, *i.e.*, how many wells the operator operates. As a result of these two factors combined, these wells represent a high risk to the state no matter the size of the operator. Smaller operators should be required to comply with the same regulatory requirements as any other operator and should not be exempted. These requirements, including financial assurance requirements, are intended to protect New Mexico's communities, environment, and economy. If an operator cannot comply with these requirements, it should not be in the oil and gas business. When I go to the doctor, I expect any medical practice---whether a solo practitioner or a large corporation---to comply with all medical licensing and malpractice insurance requirements. It's the same for the oil and gas industry.

Q: IPANM witnesses claim that bonding requirements set below the expected costs of reclamation can be beneficial: Arscott at pp. 2-3. What is your response?

A: In support of this assertion, Mr. Arscott cites to a paper by Gerard, which I also discuss in my direct testimony. However, Mr. Arscott takes Gerard's comment out of context. While Gerard does say that compliance with plugging requirements "can be induced with bond levels that are below the expected reclamation costs," this is limited to regulatory programs where regulators "have the authority to block permits for any operator that has a record of noncompliance."[14]

The entire premise of Gerard's paper is that effective regulatory programs can rely on a combination of tools, including financial assurances, to ensure that operators meet their clean up

[14] David Gerard, The Law and Economics of Reclamation Bonds, Resources Policy 26 (4): 189–97, at 192. Oct. 2, 2000.

obligations. If one tool is de-emphasized (such as where a financial assurance is set at a level less than the actual cleanup cost), this weakening must be made up through the strengthening of other tools. But Mr. Arscott fails to identify other existing provisions of New Mexico's regulatory program that could make up for lower financial assurance amounts, and Mr. Arscott (and the other IPANM and NMOGA witnesses) oppose all of the proposed amendments to strengthen New Mexico's program. This includes opposition to the tool specifically referenced by Gerard, "the authority to block permits for any operator that has a record of noncompliance."

The oil and gas industry cannot have it both ways: they cannot oppose increases to financial assurance amounts while also opposing limitations on the transfer of wells. Indeed, given the scale of the orphan well problem in New Mexico, an "all of the above" approach to regulatory reform is desperately needed.

Q: IPANM witnesses object to the proposed marginal well financial assurance amendments on the grounds that the state would not access more money for plugging and abandonment, because the state rarely claims bonds: Winchester Test. at pp. 6-9; Murphy Test. at pp. 4-5 [IPANM Prehrg. Stmnt.]. What is your response?

A: It is true that under the current regulations OCD does not consistently seek forfeiture of financial assurances. However, this is actually an argument in favor of increasing financial assurance amounts to better reflect actual plugging costs. As it stands, the low amounts recoverable via forfeiture have led OCD to conclude that it is not worth the time and effort required to complete bond forfeiture. That would change if financial assurance amounts increased.

This argument also overlooks the fact that the benefit of setting financial assurance amounts at levels equivalent to plugging costs is not limited to the regulator's use of the funds.

Adequate financial assurances also provide an incentive for operators to promptly plug their wells once they are no longer economic, so as to be relieved of the carrying costs (premiums and collateral requirements) associated with maintaining those financial assurances. The New Mexico Legislative Finance Committee agrees: "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 . . . ."[15]

Q: IPANM claims that after a well enters marginal well status, there is no mechanism for the well to be released from the marginal well financial assurance requirement once it produces above the marginal well threshold: Harvard Test. at p. 7 [IPANM Prehrg. Stmnt.]; Armstrong Test. at pp. 4-5 [IPANM Prehrg. Stmnt.]; Ezzell Test. at pp. 24, 33. What is your response?

A: Nothing within the proposed definition for marginal well, or in the proposed financial assurance category for marginal wells, suggests that once a well enters "marginal well" status it must always be categorized as a marginal well. If a well produces more than 180 days, or more than 1,000 BOE within a consecutive 12 month period, it is no longer a marginal well and would not be subject to financial assurance requirements for marginal wells.

19.15.8.9.E NMAC -- Inactive Wells and
Wells in Approved and Expired Temporarily Abandoned Status

Q: NMOGA witnesses object to proposed amendments that amend financial assurance for inactive wells and wells in approved or temporarily abandoned status at 19.15.8.9.E: Emerick Test. at p. 10. The proposed amendments are:

> **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

[15] New Mexico Legislative Finance Committee, Policy Spotlight: Orphaned Wells, p. 32, June 24, 2025 [Apps' Ex. 4].

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.~~

NMOGA witnesses again claim that a one well financial assurance of $150,000 is infeasible for operators, both from a cost and availability of bonding perspective. Additionally, NMOGA witnesses claim that $150,000 is greater than the typical costs required to plug and abandon the typical onshore oil and gas well in New Mexico. What is your response?

A: Because OCD is responsible for plugging wells that have been orphaned and subject to financial assurance forfeiture, the *only* relevant figure for determining the typical cost to plug and abandon a New Mexico well is the cost to OCD. As discussed in detail in my direct testimony, 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.

To the extent witnesses for NMOGA or IPANM claim that the $163,000 is artificially high and attributable to factors that OCD is in the process of correcting (*see* McGowen Test. at pp. 87-90), that potential is already factored into the proposed amendments. The proposed amendments set one well financial assurance amounts at $150,000, not $163,000.

Q: NMOGA witnesses also claim that restrictive bonding will likely increase the orphaning of oil and gas wells, as it will push operators to walk away from marginal assets:

Felix Test. at p. 19. What is your response?

A: As expressed above, to the extent any additional wells are orphaned following adoption of the proposed amendments, the changes to the regulations would not be to blame. These wells were likely already going to be orphaned, regardless of what action the Commission takes. The operators of these wells have failed to set aside the funds necessary for plugging. The only question is timing.

Furthermore, the Commission should not allow itself to be bullied or blackmailed. The record thoroughly demonstrates the current reality that thousands of New Mexico wells are poised to be orphaned with woefully inadequate financial assurances to cover the cost of plugging. Continued inaction in the face of this crisis is no longer an option.

Q: NMOGA witnesses further claim that applicants have not demonstrated that the current blanket bonding system has failed: Felix Test. at p. 20. What is your response?

A: Blanket financial assurance is simply no longer a reasonable option for at-risk wells and operators in New Mexico, given the high risk that inactive and low-producing wells will be orphaned. As described in my direct testimony, the default amount for financial assurances should always be the amount required to plug the well. Anything less than that, including through the use of blanket financial assurances, is a benefit extended to certain low-risk wells or operators. That benefit to the operator must be weighed against the corresponding increased risk borne by the state. In New Mexico, under current conditions, the risk is simply too high for inactive and marginal wells.

Q: OXY witnesses claim that the proposed amendment to require additional financial assurance for wells that have been in temporary abandonment for fewer than two years is inconsistent with NMSA 1978, § 70-2-14(A), which authorizes increased financial assurance

"on any well that has been held in a temporarily abandoned status for more than two years." Wallace Test. at pp. 5-6. What is your response?

A: Nothing in the statute prohibits additional financial assurance for wells that have been in temporary abandonment for fewer than two years. The statute does mandate that the categories of financial assurance include a requirement for one well financial assurance for wells that have been in temporary abandonment status for more than two years. NMSA 1978, § 70-2-14 (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"). But that statement is not exclusive and does not say that the Commission may *only* require a one well financial assurance for wells in temporarily abandoned status for more than two years. Instead, the statute instructs the Commission to "establish categories of financial assurance after notice and hearing" and that "[i]n establishing categories of financial assurance, the oil conservation division 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." NMSA 1978, § 70-2-14. Those "other factors" include the factors explained in detail and supported by data by the Applicants' experts in support of the proposal to require one well financial assurances not only for wells in temporarily abandoned status for more than two years, but also "wells that are inactive and wells in approved and expired temporarily abandoned status, or for which the operator is seeking approved temporary abandonment."

<u>**19.15.8.9.F NMAC – Single Financial Assurance Instrument**</u>

Q: After negotiations with OXY, Applicants propose a new amendment to proposed 19.15.8.9.F NMAC; is that correct?

A: Yes, that is correct. As noted above, I participated in discussions with OXY and OCD, and all three sets of parties came to agreement on changes to Applicants' original proposal. OXY opposes the marginal well designation. If the marginal well designation and associated financial assurance requirements remain in the rule, however, OXY would approve this language. The agreed-upon changes are set forth below and are highlighted in yellow.

> **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 financial assurance in the form of a single instrument ~~replacement blanket bond~~.

Q: What is the basis for this change?

A: The amended proposal provides operators with the option of filing a single financial assurance instrument---such as a single surety bond---to satisfy that operator's full financial assurance obligation, including combining a blanket bond with one well financial assurances. The purpose of this amended proposal is to provide maximum administrative efficiency for the operator and for sureties and other financial assurance providers.

Q: OXY witnesses question why the last clause of this provision, which provides the option of filing a blanket bond, is eliminated in the proposed rules: Wallace Test. at 6. Does the amended proposal address this concern?

A: Section 19.15.8.9.C(2) NMAC, as proposed to be amended, provides for a blanket financial assurance for active wells and would set the blanket financial assurance amount at the statutory maximum for active wells of $250,000. Section 19.15.8.9.F NMAC addresses the situation where an operator maintains a blanket financial assurance, but then is required to provide additional one well financial assurances. Because the blanket financial assurance is already set at the statutory maximum, and cannot be increased, there would be no point in filing a replacement blanket financial assurance.

The amended proposal instead provides the option of providing a single financial assurance instrument that would allow for combining one or more blanket financial assurance with any additional one well financial assurances. This would not be a new form of blanket financial assurance, because the one well financial assurance amounts would be calculated separately based on the other provisions of 19.15.8.9 NMAC and would comply with statutory limitations. But rather than requiring operators to negotiate and keep track of multiple different financial assurance instruments, all of the operator's requirements could be satisfied by a single instrument. This simplifies the administrative process, including calculating annual premiums and collateral requirements.

Q: NMOGA witnesses object to the blanket plugging financial assurance amendment in 19.15.8.9.F NMAC on the grounds that it is redundant with 19.15.8.9.E(2) NMAC: Felix Test. at p. 22. What is your response?

A: These are distinct provisions satisfying different purposes.

Section 19.15.8.9.E(2) NMAC applies to the blanket plugging financial assurance for inactive wells and wells in approved and expired temporarily abandoned status. This form of financial assurance is not subject to the statutory cap of $250,000 for blanket financial assurance for active wells under NMSA 1978, § 70-2-14(A). Instead, it is covered by the separate statutory provision for blanket financial assurance for "temporarily abandoned status wells," which has no cap but only a floor of $50,000. NMSA 1978, § 70-2-14(A).

Section 19.15.8.9.F NMAC, under the amended proposal, provides a way for operators to satisfy both blanket financial assurance requirements and one well financial assurance requirements in a single instrument, and applies to all categories of financial assurance described in 19.15.8.9 NMAC, including forms of financial assurance that are subject to statutory caps.

19.15.8.9.G NMAC – Inflationary Adjustment Provision

Q: NMOGA witnesses object to the inflationary adjustment provision in the proposed rules at 19.15.8.9.G NMAC: Felix Test. at p. 25-26; Emerick Test. at p. 13; McGowen Test. at p. 73-74. The proposed provision is:

> **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 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.

NMOGA witnesses claim that annual inflation updates would make it more difficult to access surety bonding. NMOGA witnesses also claim that the inflationary adjustment provision is arbitrary, because applicants have not demonstrated that a broad Consumer Price Index derived from the overall economy reflects changes in plugging and abandonment costs in the oilfield: McGowen Test. at p. 73. NMOGA witnesses also suggest that if the inflationary adjustment provision is retained, it should be tied to an index specific to New Mexico: Emerick Test. at p. 13. NMOGA witnesses claim that automatic inflation adjustments may outpace the bonding capacity of surety providers in a hardening surety market: McGowen Test. at p. 73-74. What is your response?

A: Much of the opposition to this proposed amendment overlooks that the proposal expressly provides OCD with discretion to decline to adjust financial assurance amounts in any given year. The proposal says only that "the division *may* adjust the financial assurance amounts" (emphasis added). This inherent discretion is adequate to address concerns related to actual costs experienced within the oil fields, and practical considerations such as that raised by Mr. McGowen.

As to NMOGA witnesses' complaint that the Consumer Price Index does not reflect inflation in costs to plug and abandon, Mr. Purvis discussed the relationship in his direct testimony and actually graphed how well the CPI has tracked oilfield inflation in the long term in Applicants' Exhibit 53. *See* Purvis Dir. Test. at 0759-0760 [Apps' Ex. 30]; Apps' Ex. 53.

Q: NMOGA and OXY witnesses claim that the inflationary adjustment provision is outside the scope of OCD' authority: Sporich Test. at p. 26; Wallace Test. at p. 6. NMOGA witnesses claim that the provision is ultra vires, particularly as the legislature considered and rejected a similar provision in a bill proposed during the 2024 New Mexico legislative session. Both NMOGA and OXY witnesses claim that the adjustment can't apply to the blanket financial assurance provision for active wells, as the statute provides a $250,000 cap. What is your response?

A: Nothing in New Mexico statute prohibits adjustments to financial assurance amounts based on the consumer price index.

The list of statutory factors regulators are required to consider in setting financial assurance amounts under NMSA 1978, § 70-2-14(A)includes "such other factors as the oil conservation division deems relevant." Increases to the costs of labor and materials, as reflected in the Consumer Price Index, qualify as relevant factors.

The $250,000 cap on the amount of blanket financial assurance for active wells is not relevant to the proposed amendment at 19.15.8.9.G NMAC allowing for adjustments to financial assurance amounts, because the proposed language expressly *excludes* blanket financial assurances for active wells. The blanket financial assurance amount for active wells is set at 19.15.8.9.C(2) NMAC. This subsection is excluded from the list of financial assurance categories subject to the adjustments provided under 19.15.8.9.G NMAC. That provision applies only to "the financial assurance amounts provided by Subsections C(1), D, E and F of this Section."

19.15.9 NMAC – WELL OPERATOR PROVISIONS

Q: After negotiations with OXY, Applicants propose to amend 19.15.9.8 – Operator Registration and 19.15.9.9 NMAC – Change of Operator, correct?

A: Yes, that is correct. I participated in discussions with OXY and OCD, and all three sets of parties came to agreement on changes to Applicants' original proposal.

OXY supports altering the compliance provisions to replace the more general reference to "compliance with federal and state oil and gas laws and regulations" with a more specific list of actions and statuses that operators would be required to disclose and certify, and OCD would be authorized to consider. Wallace Test. at p. 7. The agreed-upon changes are set forth below and in Applicants' Exhibit 72 and are highlighted in yellow. These same changes are reflected in OXY Exhibit 1.

19.15.9.8 OPERATOR REGISTRATION:

. . .

B. Prior to commencing operations, an operator shall provide to the division a certification by an authorized official ~~officer, director, or partner~~ that the new operator is not subject to any forfeiture demands from any state or federal agency, has not forfeited financial assurance to any state or federal agency, and does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~is in compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~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:

. . .

(2) the applicant has forfeiture demands from any state or federal agency, has forfeited financial assurance to any state or federal agency, or has unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~is in compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~each state~~ in which the applicant does business;

. . .

19.15.9.9 CHANGE OF OPERATOR:

. . .

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 new operator shall make such application in writing and provide documentary evidence of the applicant's right to assume operations; a certification by an authorized official ~~officer, director, or partner~~ of the new operator that the new operator is not subject to any forfeiture demands from any state or federal agency, has not forfeited financial assurance to any state or federal agency, and does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~is in compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~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 authorized representative ~~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:

. . .

(3) the new operator has forfeiture demands from any state or federal agency, has forfeited financial assurance to any state or federal agency, or has unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations ~~is out of compliance with federal and state oil and gas laws and regulations~~ in any domestic jurisdiction ~~each state~~ in which the new operator does business;

. . .

Q: What is the basis for these changes?

A: The amended proposal makes three fundamental changes that appear and recur in the proposed amendments to sections 19.15.9.8 and 19.15.9.9 NMAC.

First, the amended proposal replaces "officer, director, or partner" with "authorized official." This provides operators with greater flexibility in determining who is most suited to provide the required certification, and accommodates a broader range of company structures and position titles while still ensuring that the operator can be held accountable for the certification.

Second, the amended proposal eliminates the phrase "is in compliance with federal and state oil and gas laws and regulations." This language was intended to be inclusive and to capture variations in state and federal programs. OXY viewed this language as overly broad and vague, and other industry witnesses in their direct testimony have also objected to this language on the same basis *See* Sporich Test. at p. 36-37; Arthur Test. at p. 47. Both the terms "in compliance" and "laws and regulations" could be read broadly in a manner that could lead to different interpretations by different operators.

Third, the amended proposal provides a list of more specific and concrete actions and statuses to narrow and focus the certification requirements on critical compliance issues. Operators would be required to certify "that the new operator is not subject to any forfeiture demands from any state or federal agency, has not forfeited financial assurance to any state or federal agency, and does not have unresolved adjudicated orders or unresolved settlement agreements for any state or federal violations."

The focus on "forfeiture demands" and actual "forfeited financial assurance" provides a very specific and easily trackable metric. No operator can claim to be unaware of a forfeiture demand or a past forfeiture, as this is a serious consequence that would be obvious and well known within a company. Forfeiture also occurs at the end of an administrative process where an operator has multiple opportunities to correct an innocent mistake or paperwork violation. The specific inclusion here therefore captures the most egregious offenses and avoids minor infractions.

Similarly, the reference to "unresolved adjudicated orders or unresolved settlement agreements" captures instances where operators have been unable or unwilling to comply with program requirements, even after being duly notified and given an opportunity to correct. Such are the operators and scenarios most likely to warrant increased attention and action by OCD, including exercise of OCD's discretionary authority to deny operator registration (under 19.15.9.8.C NMAC) or a change of operator (under 19.15.9.9.C NMAC). Circumscribing the jurisdiction where the violation occurred to "domestic jurisdiction" clarifies that only jurisdictions within the United States are included, which was Applicants' intent in its original proposal.

Q: OXY, IPANM, and NMOGA witnesses claimed that the certification of compliance with federal and state oil and gas laws in each state in which an operator does business was

unreasonable, vague, and impermissible under the statute: Winchester Test. at pp. 3-4; Ezzell Test. at pp. 55-57; Felix Test. at pp. 49-50; Arthur Test. at pp. 47-48; Wallace Test. at 8-9. Do these amendments address those concerns?

A: Yes. The amended proposal provides more specific and concrete examples of violations, and focuses on significant acts of non-compliance where operators were unable or unwilling to avail themselves of opportunities to correct the violations, and were negotiated with an industry operator.

To the extent the proposed amendments reference oil and gas statutes and regulations in other jurisdictions, this is merely to provide information to inform purely New Mexico-focused actions by OCD regarding operators seeking to do business in New Mexico. Nothing in the proposed amendments authorizes or requires OCD to take any action outside of its jurisdiction.

Q: IPANM witnesses claim that the proposed compliance provisions could lead to unfair treatment of operators based on a former employer's noncompliance: Mitchell at pp. 5-6 [IPANM Prehrg. Stmnt.]; Winchester Test. at p. 5. Similarly, NMOGA witnesses claim the proposed provisions would delay development and acquisitions, and that the proposed provisions would create barriers to entry for new capital and operators in the state, especially for transactions involving distressed or legacy assets, and that it would impair better-capitalized market participants from acquiring distressed or legacy assets from less-capitalized market participants: Sporich Test. at 42-43; Felix Test. at 9; McGowen Test. at p. 130. What is your response?

A: The parties opposing these proposed amendments fail to explain why it is in the interest of New Mexico---or of the industry itself---to facilitate the continued employment of bad actors. The proposed amendments bear only on executives or investors who have participated in companies that have accrued violations. If the industry is truly as responsible and self-policing as it so often claims, and if documented violations are truly attributable to just a small number of bad actor operators, then the proposed amendments should not materially impact the vast majority of operators. Industry participants should already be tracking this information and should already be vetting the backgrounds of executives. If industry is *not* doing that, then that fact alone---as suggested by these objections---is highly revealing and only supports the urgency of the need for greater OCD oversight.

Q: NMOGA witnesses claim that the proposed additional certifications effectively act as a prohibition on some transfers and, in so doing, violate New Mexico's ban on the impairment of obligations of contracts. What is your response?

A: OCD clearly already has authority to block the transfer of oil and gas assets, in certain limited circumstances. Under the current 19.15.9.9.C NMAC, OCD may deny a change of operator if the new operator is not in compliance with 19.15.5.9.A NMAC or if the new operator is acquiring facilities that are subject to an existing compliance order and has not entered into an agreed schedule for bringing the site into compliance. The proposed amendments provide additional grounds for OCD denial, but do not impose a new authority where one did not previously exist. Furthermore, nothing in the regulations applies to the actual sale of a well, only to the change of operator for regulatory purposes. Parties remain free to sell wells and retain the current operator.

Q: IPANM and NMOGA witnesses claim that the terms "substantial risk" in proposed 19.15.9.9.C(6) NMAC and "good standing" in 19.15.9.8.C(5) and -9.C(5) NMAC in the disclosure requirements are vague and subjective: Mitchell Test. at 6-7; Sporich Test. at 43. What is your response?

A: Existing provisions at 19.15.9.8.C and 19.15.9.9.C NMAC already authorize OCD to deny operator registration or change of operator, respectively. These are already inherently discretionary provisions and nothing in the proposed amendments changes that. The crux of any discretionary determination under 19.15.9.9.C(6) NMAC as to whether to approve or deny a change of operator would be assessment of whether the applicant poses a "substantial risk that the new operator would be unable to satisfy the plugging and abandonment requirements." Furthermore, that phrase is further modified, and made more specific, by the preceding reference to information disclosed in the certification and disclosure requirements of 19.15.9.9.B NMAC. This is not an open-ended determination, but one grounded in OCD's assessment of the information provided, and whether that information discloses a substantial risk that the new operator will be unable to satisfy the plugging and abandonment requirements.

"Good standing" is a well-defined term of art under New Mexico law. The Secretary of State's office is specifically empowered under New Mexico statute to issue a "certificate of good standing" for a corporation, limited liability company or other entity. *See, e.g.,* NMSA 1978, §§ 53-18-3, 53-19-68, 53-8-92. The inclusion of the reference to "in good standing with the New Mexico secretary of state" is a recognition that a corporation or other entity may have registered with the Secretary of State's office, but then fallen out of good standing (i.e. by failing to pay certain fees or file certain required reports). The proposed amendment merely closes that loophole by requiring that an operator be both registered *and* in good standing.

This concludes my rebuttal testimony, which is accurate to the best of my knowledge.

/s/ Peter Morgan September 16, 2025
Peter Morgan Date

EXHIBIT 82

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

REBUTTAL TESTIMONY OF ADAM PELTZ

Table of Contents

Introduction

Q: Please state your name.

A: My name is Adam Peltz

Q: Did you provide direct testimony in this matter?

A: Yes. My direct testimony is Applicants' Exhibit 57.

Q: Are your qualifications and background set forth in that testimony?

A: Yes, on Bates stamped pages 0841-0843 of Applicants' Prehearing Statement, and my resume is Applicants' Exhibit 56.

General Allegations

Q: Witness for the Independent Petroleum Association of New Mexico ("IPANM"), Mark Murphy, at 4, offers the general observation that "[i]f the Commission were to adopt WELC's changes wholesale, I feel it would be the end of most if not all responsible, independent operators in the State of New Mexico." What is your response?

A: This is neither the intent nor the likely outcome of this proposal. Responsible operators who are not, in the eyes of surety companies, at elevated risk of orphaning their wells, should continue to be able to obtain financial assurance bonds at pennies on the dollar. Moreover, if the concern is that an independent operator would no longer qualify for bonding for active wells, a number of steps could be taken: operators can minimize the number of wells for which they would need to put up $150,000 bonds by plugging idle wells; ensuring production of their marginal wells for more than 180 days per year; and reducing their populations of idle and marginal wells to below 15% threshold. Small businesses are the lifeblood of communities—at the same time, it is neither appropriate nor socially beneficial to subsidize small business operations at the expense of taxpayers and the environment by minimally enforcing plugging requirements. The reforms proposed in Applicants' proposals are risk-tailored to eliminate persistent orphan wells, and should not threaten the viability of operators who have incorporated asset retirement costs into their business models.

19.15.2.7 NMAC – Definitions

Q: The New Mexico Oil and Gas Association ("NMOGA") witness, Andrea Felix, at 27 [NMOGA Ex. B] claimed that the definition of marginal wells is too rigid and "risks

sweeping in viable, strategically managed, or temporarily offline wells, especially those shut in for maintenance, operations curtailments, or infrastructure upgrades." What is your response?

A: I would draw the Oil Conservation Commission's ("Commission") attention to the distinction in treatment between marginal wells and inactive wells. Here, the witness appears to be conflating marginal wells (as first recommended by the Oil Conservation Division ("Division") and as proposed by Applicants as those producing less than 1,000 BOE per year *and* less than 180 days a year) with inactive wells (those not producing for 12 months). Applicants' proposal allows for wells to remain idled for the reasons Ms. Felix articulated above for 8 years—a length of time beyond which, historically, virtually every well – 99.5% -- in New Mexico has returned to service or been plugged or orphaned. On this point, I reference my direct testimony at Bates stamped page 0896, including the chart as Applicants' Exhibit 13, depicting the length of time before deactivated wells in the state return to activity.

Q: IPANM witness David Mitchell, at 3, states that the definition of marginal well is overbroad and "include wells that provide economics that are better than just 'marginal' economics." What is your response?

A: A well producing less than 1,000 BOE per year and that is active for less than half the year raises significant concerns regarding the well's long-term economic viability, which is why Applicants propose a higher-cost bond at that time. Requiring a full-cost bond for marginal wells as defined reflects the increased risk to the State, and the internalization of that risk to the operators of those wells. As I understand, few production days typically indicate a steep decline in overall well performance, or an effort by the operator to manipulate that well to avoid being labeled inactive. Such wells should be put on a path for required plugging or covered by bonding amounts that ensure the ultimate plugging liability is borne by the operator and not the State. If a well is not economic enough to cover its plugging cost, is it really economic?

Q: NMOGA witness Clayton Sporich, at 9-10 [NMOGA Ex. E], claims that Applicants proposed marginal well definition has "the potential to reclassify non-marginal wells as marginal," which could be triggered "where productive wells may be misclassified because wells are often prudently shut in for the duration of nearby drilling or hydraulic fracturing," and that "this is why historically the focus has appropriately been on any particular well's *capability of production* rather than solely its actual production over a prescribed amount of time." (emphasis in original). What is your response?

A: Mr. Sporich's comment inappropriately conflates several aspects of Applicants' proposal. Marginal wells and inactive wells are two separate categories. Wells being temporarily shut in to accommodate nearby drilling or hydraulic fracturing activities likely would not even need to be converted to inactive status, which does not effectuate until 12 months of non-production (and then there's a three month grace period). Meanwhile the definition of marginal well being proposed here—less than 1,000 BOE per year and less than 180 days per year of production—is actually much more narrow than the common federal definition of marginal wells—which is less than 15 BOE per day or less than 5,475 BOE per year, with no exception for number of days producing. If anything, the proposed definition of marginal is underinclusive. Finally, production *capability* does not pay the bills or for plugging and abandonment—only actual production does.

Q: IPANM witness T. Calders Ezzell, Jr., at 44-45, raises concerns with the definition of "marginal wells" and that the definition conflicts with existing state policy concerning severance taxation and a production incentive tax exemption for a "stripper well property," which Mr. Ezzell suggests is "a legislative policy that seeks to create financial

incentives for such production restoration or workover projects" and is in conflict with the treatment of "marginal wells" under Applicants' proposal that would "saddle the operator with an additional $150,000 costs for each such marginal well." What is your response?

A: The stripper well tax policy covers wells producing under 10 BOE per day, or 3,650 BOE per year. NMSA 1978, § 7-29B-2(L). In contrast, Applicants' proposal merely puts an insurance policy on wells when production levels reach less than a third of the tax policy amount, accounting for the increased risk to the State that such wells become orphaned. While I cannot speak for the Legislature's intent relative to the tax policy, it is hard to believe the goal was to allow low-producing wells to be run into the ground, leaving clean-up liability to the public. Indeed, the New Mexico Legislative Finance Committee ("LFC") -- no stranger to New Mexico tax policy -- recommends in its recent report on orphan wells that rules be promulgated for "low-producing wells," producing less than 750 BOE per year or less than 2 BOE per day, be required to post individual well financial assurance.[1]

All that said, operators could use the taxes saved on low-producing wells to support bonding and plugging activities. Moreover, it is possible that the production restoration and workover projects subsidized by New Mexico taxpayers through the stripper well tax policy, coupled with Applicants' proposed amendments, can incentivize operators to keep wells more highly productive and thus avoid heightened bonding requirements.

Q: NMOGA witness Harold McGowen, at 125 [NMOGA Ex. D], claims that "misclassifying productive or strategically maintained wells as marginal could force operators to prematurely plug viable wells or face unnecessary bonding burdens." What is

[1] NM Legislative Finance Committee, Policy Spotlight: Orphaned Wells, pp. 2-3, June 24, 2025 ("LFC Report") [Apps' Ex. 4].

your response?

A: The structure of the Division's the marginal well definition, as adopted by Applicants—under 1,000 BOE per year *and* under 180 days per year of production—minimizes the risk of misclassification. If such wells are able to support the cost of plugging, I do not see why they would be plugged prematurely. Mr. McGowen similarly offers no support for his assertion. On the other hand, if wells within the marginal definition are not able to support the cost of plugging, then there is something wrong with the business model. In that case, bonds are, in fact, necessary to protect New Mexico taxpayers, residents, and the environment from the impact of persistent orphan wells.

Along these lines, it's important to observe that marginal wells (excluding wells with presumed no beneficial use) account for a very small number of wells in New Mexico – 2,200, a very small percent of total wells in the state – 3.7%, and an exceedingly small percent of total production in the state – 0.045%. *See* Apps' Ex. 40. The potential problem with the marginal well classification, in my view, is not that these wells are misclassified for single well full cost bonding, it is that the classification may be overly conservative and does not capture low producing wells at elevated risk for orphaning that qualify for blanket bonding capped in New Mexico by statute at $250,000.

Q: NMOGA witness Douglas R. Emerick, at 14 [NMOGA Ex. F], claims that the definition of marginal well "misclassifies wells as marginal could lead to a significant overestimation of decommissioning liability." What is your response?

A: Decommissioning liability is independent of production levels and, instead, is dependent on well depth, condition, and location. What Applicants' proposed amendments aim to address is the increasing risk that decommissioning liability falls to the public, and the definition of marginal wells (under 1,000 BOE per year *and* under 180 days per year of production) is specifically calibrated to address wells that the Division believes, based on their decades of on-the-ground experience, are at enhanced risk of orphaning.

<u>19.15.5 NMAC – Enforcement and Compliance</u>

Q: Witnesses for IPANM, George Sharpe, at 6, and Jim Winchester, at 2-3, allege that proposed changes to 19.15.5.9 NMAC, requiring operators to meet waste prevention requirements of 19.15.27.8.A NMAC as a condition of being in good standing, "would be incredibly harsh to basically pull an operator's license to operate because the operator is out of compliance with one well," and that "a single waste prevention violation would result in revocation of an operator's ability to operate any of its wells." What is your response?

A: IPANM's witnesses' concerns seem exaggerated. Under the operator registration (and change of operator) provisions, the Division *exercises discretion* whether to deny a registration (or well transfer) if an operator is out of compliance with 19.15.5.9.A NMAC. *See* 19.15.9.8.B(1), -(2) NMAC; 19.15.9.9.C(1), -(3) NMAC. Non-compliance with the criteria in 19.15.5.9.A NMAC by no means results in an automatic or mandatory denial. And Applicants do not propose to modify the Division's ability to exercise discretion. State agencies, including the Division, may not act arbitrarily or capriciously in their decision making, and I believe that Division staff, who are fully acquainted with operators around the state, would not deny a registration (or well transfer) based on a *de minimis* violation of the methane waste rule requirements at 19.15.27.8.A NMAC.

<u>19.15.8 NMAC – Financial Assurance</u>

Q: NMOGA witness Felix, at 15, claims that Applicants' proposed financial assurance amendments would require the Legislature to make statutory changes before proposed rules could be implemented. What is your response?

A: Applicants, as supported by the Division, disagree with Ms. Felix's legal interpretation of the Oil and Gas Act. As explained in more detail in my direct testimony and in the direct testimony of Applicants' expert Peter Morgan, the Oil and Gas Act requires the Commission to "establish categories of financial assurance after notice and hearing." NMSA 1978, § 70-2-14(A). *See* Peltz Dir. Test. at 0880, 0893-94 [Apps' Ex. 63]; Morgan Dir. Test. at 0319, 0324-25, 0328-30, 0341-47 [App's Ex. 15]. The marginal well (and inactive well) categories proposed by Applicants and the Division in 19.15.8.D NMAC fall squarely within the Commission's authority to "establish categories of financial assurance."

Q: NMOGA witness Sporich, at 19, claims that Applicants' financial assurance requirements "exceed OCD's limited grant of financial assurance authority under the Act, under NMSA 1978, § 70-2-14," and that "[r]etroactive applicating of these requirements could amount to a taking." What is your response?

A: As just stated, NMSA 1978, § 70-2-14 allows the Commission to "establish categories of financial assurance after notice and hearing," which is what Applicants' proposal does. As far as I know, financial assurance requirements have never been considered a taking anywhere in the country; nor have I ever heard of financial assurance grandfathering such that rates could not be raised. The fact that NMSA 1978, § 70-2-14 envisions the Commission conducting rulemakings to set amounts implies that such amounts may change, insofar as "amounts determined sufficient to reasonably pay the cost of plugging the wells covered by the financial assurance" certainly change over time.

Q: IPANM witness, Trevor Gilstrap, at 8, claims that increasing bonding does not reduce the number of orphaned wells, that "more wells will become orphaned, not less," and that "the state will see a precipitous increase in abandoned wells when smaller

operators can no longer meet or comply with New Mexico's requirements." What is your response?

A: In my opinion, if an operator cannot meet their financial assurance obligations and chooses to walk away from their legal plugging responsibility, the financial assurance obligation could not be said to have *caused* the orphaning, but merely to have revealed an inevitability. I question, in these cases, whether the operator would ever have been able to pay for plugging and remediation and whether the operator failed to internalize their liabilities as part of their business model.

The intent of Applicants' proposals is not to cause well orphaning. However, internalization of plugging and abandonment costs through the proposed rules to operators who have not been planning or setting aside funds to account for this inevitability could on the margins result in acceleration of orphaning that would have occurred eventually. But where operators do walk away, Applicants want to ensure there is as much funding in the system as possible to cover the costs the State will incur. There are other ways to do this than what we have proposed, though many such options—risk pooling, escrow accounts, sinking funds, a jumbo reclamation fund—would, in fact, require legislative action. Absent that, Applicants are left with the various forms and mechanisms of financial assurance allowed under the Oil and Gas Act, NMSA 1978, § 70-2-14, and pursued the structure of their proposals in consultation with the Division, based on the agency's on-the-ground experience, understanding of the legal requirements and limitations of the Oil and Gas Act, and best ideas to tailor financial assurance to risk.

Of note, neither IPANM nor NMOGA offers any substantive proposal to address the increasing risk to the State and the body of evidence presented—including independent reports from the State Land Office and LFC. Rather, the focus of their testimony is entirely focused on maintaining the status quo of a system that is currently leading the State to a financial cliff. LFC estimated that, in the absence of policy change, the state burden for orphan wells is between $700 million and $1.6 billion.[2] Some well operators have, in fact, been operating their businesses in a way where they have not saved up enough money for plugging and remediation, and would walk away at some point in the future regardless—Applicants' package of financial assurance proposals – all supported by OCD – will help minimize the cost to the State where that unfortunate fact pattern plays out.

Q: IPANM witness Gilstrap, at 8-9, offers the example of Colorado financial assurance rulemaking, and states that, as a result, "not only did bonding levels decrease by $4 million, the number of orphaned wells doubled in the first year, and has quadrupled to 941 orphan wells as of July 1, 2024." What is your response?

A: Colorado's financial assurance implementation has been complex and there are (at least) two different total dollar amounts to track: one is the amount required by the rules and the other is the amount Colorado has in-hand for plugging. On the first, Colorado did anticipate that the total amount required by rules might initially dip after the rules went into effect, based on which plans operators selected, with certain options having relatively low year-one amounts that would build over time. On the second amount, in April 2022 Colorado had roughly $243 million on-hand for plugging and, as of September 2025, that amount has increased to roughly $390 million on-hand for approved financial assurance plans. This, of course, is complemented by the fact that industry plugged roughly 1,600 wells in 2022, 1,800 in 2023, and 1,200 in 2024. Both of these trends are, on-balance, reducing risk to the state.

On the second topic of orphan wells, Colorado has seen an increase in wells formally

[2] LFC Report at 1.

orphaned by operators. With the financial assurance rules, Colorado also included a registration requirement that has created an opportunity to work through the entirety of Colorado's operator list and work to bring operators into compliance. The reasons operators have orphaned wells are myriad. Operators in Colorado continue to fund an Orphan Well Mitigation fund that the state has used to complement the federal spending over the last two years, and provides an industry-funded resource of around $10 million per year above and beyond severance tax revenue for the work to plug and reclaim orphaned wells.

While the complexity of the Colorado example can be expected given the magnitude of the changes undertaken, it is disingenuous to cast the state's efforts to get ahead of its orphan well problem as ineffectual, and should certainly not be used as a cautionary tale to disincentivize New Mexico from doing the same.

Q: IPANM witness Gilstrap, at 10, claims that increases in financial assurance in Applicants' proposals "disproportionately target smaller operators" and that "the vast majority of small to medium size operators will not be able to comply." What is your response?

A: The plain language of the proposal is no more discriminatory with respect to operator size than the existing requirements that operators be able to pay to properly plug and abandon their wells. The criteria for marginal wells are low production levels and sporadic operation over time – not size of operator. These two criteria apply to small, medium, and large operators. All operators in New Mexico, regardless of their size, are obligated to obey the law, and plugging and remediation requirements are sufficiently long-standing as to predate any current New Mexico operator.

Moreover, the cost of plugging a well does not scale meaningfully depending on its operator's portfolio size; barring a system in which more profitable operators take on the plugging responsibilities of other companies, the financial burden of plugging wells is always going to be a higher burden proportionally for less profitable operators with a smaller revenue stream. The flaws of the existing framework have allowed some companies to enter this market without appropriate safeguards to ensure they can meet their obligations down the line. Correcting that system may cause financial hardship for some of those operators, but the alternative is to continue to outsource their responsibilities and risks to the public.

In the context of the Environmental Defense Fund's ("EDF") bonding snapshot analysis, a look at how the 15% marginal-and-inactive-well threshold falls across operators of various size shows that around 2/3rds of operators with 50 or fewer wells appear to exceed this threshold, placing them in the higher-risk group with higher bonding requirements. Nearly half of operators with 51-500 wells fall into this high-risk category, while only 14% of operators above 500 wells do. However, this distribution reflects the reality that many small and medium-sized operators are holding a larger percentage of marginal or nonproductive wells within their portfolio. To the extent the impacts of Applicants' proposal rule fall "disproportionately" on small businesses, that reflects the fact that the majority of small to medium size operators are already at apparent risk of being unable to meet their existing future legal plugging and remediation obligations, given apparently low revenue levels for the assets they must eventually pay to plug.

Further, the requirements of the Applicants' proposals allow for bonding requirements to be met with surety bonding. In principle, the rates required to maintain these bonds should be a low annual percentage of the required total, if the surety guarantor gauges the financial health of the operator receiving the bond as sufficiently strong to meet their requirements.

In addition to estimating the bonding amounts required under the Applicants' proposed rule using a snapshot of 2024 production, EDF also estimated total revenues for each operator in the dataset, as included in Applicants' Exhibits 64 and 68 (both comparing each operator's estimated 2024 revenues to some or all of their estimated 2024 plugging liabilities). We can compare these estimated revenues with estimated costs of premiums for surety bonds for the amounts needed to meet bonding requirements for their state and private lease wells. An annual premium for an operator expected to be able to meet their responsibilities would, accordingly, be expected to fall in the range of 0.5-7%, with lower premiums around 1% for companies considered more investment-ready, and rates upward of 5% for companies deemed speculative or higher risk.[3] Applicants' Exhibit 84 below summarizes comparisons of these amounts across operator groups of different sizes.

Comparisons of Operator Revenues and Bonding Amounts, by Marginal and Inactive % and Well Count Groups

Marginal and inactive wells as a fraction of total	Operator well count (inclusive of federal, state, and private wells)	Total operators in group	Total marginal and inactive state and private wells in group	Percentage of federal, state, and private wells identified as marginal or inactive	Total estimated 2024 revenue (inclusive of federal, state, and private wells) (millions USD)	Total estimated bonding liability for state and private wells (millions USD)	1% of total bonding liability, as a percentage of total 2024 revenue
above 15%	1 to 50	160	641	55%	$235	$171	0.729%
	51 to 100	14	247	46%	$147	$85	0.577%
	101 to 500	21	1087	38%	$956	$420	0.440%
	Over 500	3	473	24%	$662	$272	0.411%
below 15%	1 to 50	83	35	6%	$519	$18	0.034%
	51 to 100	17	48	7%	$1,679	$10	0.006%
	101 to 500	26	233	7%	$12,532	$39	0.003%
	Over 500	18	709	6%	$35,637	$109	0.003%
	1 to 50	243	676	37%	$754	$189	0.25%

[3] Based on estimates of surety premium rates from the Bureau of Ocean and Energy Management ("BOEM") as part of a 2023 regulatory impact analysis, we consider surety rates of 1% annually (aligned with the range for what BOEM calls "Investment grade" companies) and of 5% (at the lower end of what BOEM estimates for "highly speculative" companies.) See BOEM (2023). Risk Management, Financial Assurance and Loss Prevention (Initial Regulatory Impact Analysis). Department of the Interior. Accessed Sept. 2025 at https://www.boem.gov/sites/default/files/documents/about-boem/BOEM-2023-0027-0002.pdf at 26-27.

all operators (above + below 15%)	51 to 100	31	295	24%	$1,826	$95	0.05%
	101 to 500	47	1320	22%	$13,488	$459	0.03%
	Over 500	21	1182	8%	$36,298	$381	0.01%

Apps' Ex. 84

If we look at all operators with fewer than 50 wells as a group, 1% of the group's collective bonding liabilities amounts to about 0.25 % of their expected total revenues. (Five times this, representing a 5% surety premium instead, is still only 1.25%.) This measure varies across the group; for operators of 50 wells or fewer that are above the 15% marginal and inactive threshold, the equivalency of 1% of liability for the group is closer to 0.75% of revenue (or at a 5% premium, 3.75% of revenue), while for the same size operators below the 15% threshold, the equivalency is only 0.034% (or at a 5% premium, 0.17% of revenue). There is of course variation within these groups at the level of individual companies (especially given that some very small operators were not associated with any production or estimated revenue in the dataset, meaning that there is no revenue to divide the liability by in the calculation.) However, for the productive and financially healthy operators (those gauged to be low-risk by a bonding entity) the financial impact of an annual surety payment would likely fall well within the expected range of typical revenue fluctuations as oil and gas prices vary.[4]

Conversely, the operators who would find these increased bonding requirements burdensome are most likely those that were also already going to struggle or fail to meet their obligations for well closure. Pushing up the timeline for this eventual revelation to before the actual orphaning of these wells provides an opportunity for a different outcome, such as

[4] Based on analysis of annually averaged 1989-2025 monthly price series data from the U.S. Energy Information Administration ("EIA") , year-over-year change of annually averaged prices range from -47% to 73% for West Texas Intermediate ("WTI") oil prices, and -52% to 138% for Henry Hub ("HH") gas prices. First and third quartile year-over-year changes were -10.5 to 25% for WTI, and -16.5 to 28.7% for HH.

returning a well to production or increasing production through workover if realistically feasible, or transferring their unproductive assets to a more solvent operator who can meet the bonding needs, before its value has truly fallen to zero.

Q: IPANM witness, Robert Arscott, at 2, claims that the "optimal bond amount is often less than the expected cost of remediation," that financial assurance requirements impose costs on operators which reduce economic incentives, and that bonding below the expected cost to plug and remediate a well is socially beneficial. What is your response?

A: The proposed bond amount of $150,000 is set below the average cost to the Division for orphan well plugging, which is $163,000—notably this cost does not include remediation and restoration, which can be several times the plugging cost where there is significant soil or water contamination from salts and other chemistry in produced water. The structure of the bonding proposal does provide operators an incentive to increase production or plug low-producing wells, which is socially beneficial. Operators that surety companies do not believe are risky can get these bonds for well below face value.

Q: IPANM witness Murphy, at 4, claims that "[r]aising bond amounts does not solve the problem of orphaned wells and does nothing to protect the state against 'bad actors' who are responsible for most of the delinquency cases where abandoned wells are left behind for others to plug, reclaim, and remediate," and that the "proposal approaches the problem backwards: targeting operators at the back-half of a well's life rather than using the funds already collected over the well's entire productive lifespan to assist operators in plugging wells." What is your response?

A: The Oil and Gas Act as currently written provides a limited set of structures that can be used to protect taxpayers against the cost of orphan well plugging and remediation, and

Applicants' proposal is confined to these structures. There are other ways to solve the problems of orphan wells via reforms to the Oil and Gas Act. This includes past reform efforts such as the multi-stakeholder process that occurred in the fall of 2023 in the lead-up to the 2024 legislative session—reforms that were ultimately undermined by industry.

One way or another, solving the orphan well problem will require a lot of money from industry. Alternative mechanisms, such as efforts to socialize that cost across industry so that larger, better capitalized operators subsidize well closure for smaller operators may have merit, but that is outside the scope of what is possible in this rulemaking. Using the framework available through rule, as here, requires financial assurance levels to increase in amounts sufficient to cover costs to the State in a risk-based manner. Under Applicants' proposal, "bad actors" will quickly reveal themselves by attempting to get out of their plugging responsibilities through bankruptcy or disappearance. Hopefully the Division will be resourced to go after what assets they can, piercing the corporate veil if necessary, to satisfy plugging obligations. Whatever is left over will rely upon funding currently in the Reclamation Fund. If this drains the Fund, the Legislature could intervene to increase it through additional production taxes.

As for targeting the back half of a well's life, if we could go back in time and file Applicants' proposals 20 years ago, that would have been better! But here we are now with LFC concluding the State faces $700 million to $1.6 billion in liabilities. Neither IPANM nor NMOGA has offered any alternative proposal to address the State's looming liabilities.

Finally, Applicants' proposals aim to protect taxpayers from bad actors going forward by making it more difficult to transfer end-of-life wells to those bad actors—both through increased scrutiny on transferees and their compliance history and ability to meet regulatory obligations, and the bonding structure which disincentivizes concentrating low- and non-producing wells under limited liability companies designed to facilitate revenue dispersion to shareholders and well orphaning.

Q: IPANM witness Murphy, at 12-13, claims that New Mexico does not have an orphan well problem, and that orphaned wells do not have an impact on taxpayers except on a federal level through the orphaned well program. What is your response?

A: I disagree with Mr. Murphy. And I'm in good company: the New Mexico Legislative Finance Committee believes New Mexico has an orphan well problem. The Division alone has spent $46.4 million on orphan well plugging and remediation since 2019[5]. LFC estimates future orphan well plugging costs could exceed one billion dollars in New Mexico absent policy change. And it finds that:

> 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.[6]

Until recently much of the money spent on orphan well plugging in the state had an New Mexico taxpayer nexus—money from the Reclamation Fund is production tax revenue spent on well plugging for which industry is legally responsible, rather than on general needs like schools, emergency response, health care, and other state priorities. The $30 million that the Division is laying out to plug 299 Ridgeway Arizona Oil Corp. wells sure sounds like an orphan well problem to me. There are thousands of low- and non-producing wells in New Mexico where, if the operator did not save up the funds to cover closure, will fall on the public. The total estimated federal funds available to New Mexico is $167 million, obviously very welcome, but a fraction

[5] LFC Report at 1.
[6] LFC Report at 1.

of potential future orphan well burden. Neighboring states like Texas and Oklahoma are choking on their orphan well problems. The major difference between New Mexico and these other states is not policy, but simply where wells and associated oil and gas basins are in their development cycle. In other words, make no mistake, a massive orphan well problem in New Mexico is just down the pipeline in the absence of meaningful policy change.

Q: NMOGA witness Dan Arthur, at 33-34, claims that Applicants proposed heightened financial assurance requirements will result in "reduced access to capital for smaller or mid-sized operators, discouraged participation in asset acquisitions or farm-in agreements due to bonding burdens, premature plugging of otherwise viable wells, increased risk of orphaned wells due to operator insolvency, and consolidation of assets into fewer hands, undermining competition and local economic participation," and that this will drive away operators from New Mexico and to a different state, decreasing tax revenue and jobs. What is your response?

A: The only development of significance in New Mexico is occurring in several counties in the Permian Basin, chasing some of the most productive oil and gas reservoirs in the entire world. *The top 11 Permian wells produce more than twice as much as the bottom four thousand wells in the state*[7]. For these big Permian wells, which make money hand over fist, pre-paying plugging costs is practically a rounding error. You could put a million-dollar bond on each of these wells and operators will still be lining up to drill them. You drill where the hydrocarbons are, and they are in Southeast New Mexico. As for reduced access to capital for smaller operators—surely operators with business models that include accounting for legally required well plugging obligations will continue to have access to capital. If New Mexico wishes to

[7] Applicants' Exhibit 65.

subsidize uneconomic business models in order to boost employment, that is the state's choice, but the plugging obligations of such operators who are unable to meet individual commitments should be covered collectively by the industry in the state, and not the taxpayer. This would entail raising the severance tax and putting more of the financial burden on larger operators to cover for their smaller brethren. However, such a decision is outside the scope of this rulemaking and the authority of the Commission, which is tasked with ensuring that all operators meet their regulatory obligations to plug and abandon. Increasing financial assurance requirements, as proposed here, is one of the tools at Commission's disposal.

Q: NMOGA witness Felix, at 15, suggests that financial assurance "should be scaled based on operator size and total well count instead of on a per-well basis," and that "NMOGA supports a risk-based approach based on statistical data for orphan wells and operator default rates that can be adjusted based on operator history, production, and compliance records." What is your response?

A: I agree that risk-based financial assurance is the way to go. Applicants' proposal uses certain well production percentages as a proxy for such risk, as detailed in my direct testimony. *See, e.g.,* Peltz Dir. Test. at 0880-891. While this is not the only way to account for such risk, it is nevertheless straightforward and easy for the Division to administer.

It is worth noting that risk-based financial assurance was also the goal of the multi-stakeholder discussions in fall of 2023, but as the 2024 legislative session was under way, NMOGA demanded a very non-risked based schedule of maximum blanket bond amounts by well count only, which did not consider other factors. Nevertheless, I am eager to hear NMOGA's specific proposal on how to condition financial assurance amounts based on risk but did not see such a proposal from Ms. Felix or any other NMOGA witness.

Q: IPANM witness Arscott, at 6, claims that Applicants' proposed amendments to financial assurance requirements will lower incentives to produce oil and gas in New Mexico, and that a "one-size-fits-all approach, imposing a flat $150,000 coverage requirement on all marginal and inactive wells," ignores differences and "default likelihood among operators and the anticipated P&A costs of individual wells." What is your response?

A: In a previous answer, I addressed that the incentive to produce oil and gas in New Mexico is primarily a function of geology, and plugging obligation costs are *de minimis* compared to the significant revenues that operators are making in the Permian. Applicants' proposal does require $150,000 bonds for marginal and inactive wells, but remember that marginal wells, as defined, only includes wells producing less than 1,000 BOE per year *and* less than 180 days per year—a relatively small fraction of all low-producing wells in the state and an even smaller fraction of all producing wells in the state (3.7% excluding wells presumed not to have beneficial use). That said, there is room for the optimization of risk, including potentially by well depth and operator default risk criteria if operators were willing to provide information about assets, liability, cash flows. Applicants would welcome specific proposals from IPANM and NMOGA, but testimony thus far appears devoid of any such recommendations.

Q: NMOGA witness McGowen, at 91, states that "[g]iven the wide variability in plugging costs and the importance of well-specific risk factors, it is far more sensible to adopt a flexible financial assurance scheme rather than a 'one-size-fits-all' $150,000 per-well bond." What is your response?

A: I would ask for the witness' specific proposal for consideration, modeling and discussion. Commission rulemakings require details.

Q: NMOGA witness McGowen, at 116, claims that "heightened financial assurance requirements will have adverse effects on the flow of capital and the feasibility of transactions in the upstream oil and gas sector in New Mexico." What is your response?

A: See response to IPANM witness Arthur, above, regarding Permian production revenue and associated operations.

Q: NMOGA witness Emerick, at 16, suggests that financial assurance requirements should impose a "risk-based approach informed by statistical data on orphan wells and operator default rates," and include "a tiered bonding system adjusted for operator history, production status, and compliance record." What is your response?

A: As I've said elsewhere, Applicants' proposals related to financial assurance have accounted for risk by proxy and by setting thresholds for production, which has been supported by robust data and testimony. If industry has specific suggestions about how to implement a more fine-grained risk-based approach given existing resources at the Division, we welcome them. Applicants' proposals are attempting to solve these vulnerabilities and risks to the State, not attack the industry.

<u>**19.15.8.9.C NMAC -- Active Wells**</u>

Q: NMOGA witness Arthur, at 26, claims that Applicants' proposed amendments to financial assurance "abandons the existing risk-based financial assurance requirements for individual bonding for such active wells." What is your response?

A: The current bonding structure is not risk-based. Applicants' proposals are an attempt to bring risk into the equation. Since the Application was filed, Applicants' counsel tried diligently to meet with NMOGA and IPANM to discuss financial assurance proposals. Except for OXY USA, Inc. ("OXY"), which supports Applicants' proposals for active wells and inactive wells at

19.15.8.9.C and -E NMAC and Applicants' proposal to identify wells with presumed no beneficial use at 19.15.25.9 NMAC, no other industry party would meet with Applicants and the Division to negotiate to try to find common ground.

Q: NMOGA witness Emerick, at 6, identifies his concerns with the proposed financial assurance requirements, stating that "the majority of operators will likely have a mix of wells, with some being covered by a $250,000 blanket bond and others requiring a single-well financial assurance of $150,000," and that "obtaining numerous single well financial assurance instruments in addition to high-volume blanket bonds" would be difficult if not impossible. What is your response?

A: We agree that this is an issue, which is why the proposal is structured to allow operators to roll up all of their bonding obligations for marginal wells and inactive wells into a single instrument for administrative ease. The amount of such a roll-up bond would change over time as well counts and circumstances change (along with inflation adjustments), but there is no need for an operator to hold multiple instruments. Applicants' have offered amended proposals in Exhibit 1-C, in 19.15.8 NMAC, negotiated with OXY, consistent with this goal.

<u>19.15.8.9.D NMAC – Marginal Wells and Inactive Wells</u>

Q: IPANM witness Ezzell, at 48, states that it is his understanding that, "properly equipped, inactive wells that are periodically checked to not pose any immediate threat to public health and welfare." What is your response?

A: Wells in approved temporary abandonment ("TA") status do undergo mechanical integrity testing ("MITs") upon going into and renewing TA status, that is, at five-year intervals. However, the vast majority of inactive wells in New Mexico are not in approved TA status. As noted in Apps' Exhibit 7, on July 3, 2025, there were 3,765 inactive wells on OCD's 15+ months

Inactive Well list, of which:

- 419 wells were in approved TA status,
- 155 wells were in expired TA status, and
- 99 wells were indicated as being under an ACOI

Accounting for overlaps in these subgroups, EDF analysis of these characteristics indicate that *3,234 wells were apparently out of compliance (having neither an ACOI nor approved TA status.)* This means that only *14%* of the inactive wells were either in approved TA status or under an ACOI, while *86%* of the inactive wells were out of compliance, most of which never went into TA status in the first place. LFC recognized the problem finding that ". . . virtually all wells on the inactive list are eligible for enforcement action . . . ."[8] I am not aware of any evidence these out-of-compliance wells are, in fact, being regularly checked for integrity issues. While Commission rules are replete with express requirements to protect public health and safety, it is well understood that unplugged wells can result in significant air, water and human health impacts. *See, e.g.,* Morgan Dir. Test. at 0307-310 [Apps' Ex. 15]. Even as "properly equipped, inactive wells" can include safeguards to mitigate harms to public health, that is certainly not the status of all or even most inactive wells in New Mexico.

Q: IPANM witness Arscott, at 7, claims that Applicants' proposed amendments to financial assurance will "reduce the marketability of marginal and inactive wells" and that this will "lead operators to prematurely plug such wells." What is your response?

A: Evidence and data on the economics of marginal and inactive wells don't support the idea that such wells would be plugged "prematurely" when plugging costs and liabilities are factored in. Right now, operators can functionally indefinitely idle their wells, which means the legal requirement to plug never kicks in. If the operator has indeed saved the capital to cover well

[8] LFC Report at 18.

plugging, then the operator wouldn't plug before the well's revenue falls below its operating and maintenance costs. I posit that the Applicants' proposed rule only reduces the marketability of marginal and inactive wells to the extent that well plugging and remediation costs would be internalized to the operator, rather than externalized to the public. To me this argument sounds like, "you're hurting our business because you're not allowing us to break the law anymore." And, if anything, industry's argument supports the Commission's adoption of the proposed amendments.

Q: NMOGA witness Arthur, at 36, claims that Applicants' proposed amendments to financial assurance and the creation of a "marginal well" classification are not grounded in operational or economic context, and that "these wells often fulfill lease retention obligations and infrastructure utilization roles." Mr. Arthur continues, stating that "operators assess the economic viability of marginal wells based on a combination of leasehold economics, operating costs, projected recovery, tax treatment, and the strategic value of holding acreage or infrastructure, not simply on short-term production volumes or number of days producing." He concludes that "[i]mposing rigid thresholds ignores these economic realities and could lead to unnecessary abandonment, impairing the long-term asset value of the lease and undermining full reservoir development." What is your response?

A: First, the "marginal well" classification was first proposed by the Division staff based their lengthy on-the-ground experience dealing with end-of-life wells and their fates. Applicants' experts have supported the financial assurance proposals with data. The Division's marginal well definition of less than 1,000 BOE per year *and* producing less than 180 days a year was specifically targeted to identify the wells that are most worrisome and at risk of becoming orphaned. The Division identifies a meaningful distinction between low-producing wells that produce daily, and low-producing wells that only produce a few days a year to avoid inactive status or violation of the terms of a lease agreement.

Second, operators often use submarginal wells specifically to hold leases, in the hopes of accessing other formations over time. This practice deprives mineral owners of maximum returns and locks them into minimal royalty payments while the operator waits around for new opportunities. If an operator chooses to plug their submarginal well rather than furnish a bond to ensure that well will be plugged, eventually, with operator financing, the mineral owner then gets an opportunity to negotiate new terms for their minerals with new operators and ultimately avoids waste from indefinite idling.

Q: NMOGA witness Felix, at 14 and 30, claims that the 15% marginal well threshold for triggering mandatory one-well bonding is arbitrary, not grounded in empirical risk modeling, and "penalizes operators solely on portfolio composition, not actual compliance behavior or plugging risk." What is your response?

A: The use of any set of criteria to gauge potential risk for well bonding purposes will be imperfect, as no set of uniform rules can capture the precise nuanced reality of every single well or operator; however, picking a set of straightforward-to-administer criteria for setting bonding amounts is likely to create a more workable system to implement, avoiding the need for potentially major time or money expenditures by private and state actors alike on transaction costs and administrative overhead[9]. By Ms. Felix's proposed standard, New Mexico's existing

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[9] See discussions of bonding policy design by L. Davis (2015). Policy Monitor: Bonding Requirements for U.S. Natural Gas. Review of Environmental Economics and Policy, volume 9, issue 1, winter 2015, pp. 128–144. doi:10.1093/reep/reu015. Accessed at https://faculty.haas.berkeley.edu/ldavis/Davis%20REEP%202015.pdf , at 141.

bonding rules are arguably arbitrary as well; while they do include depth as a factor for individual well bonding only, they do not consider it for blanket bonding. But more importantly, the Commission's current rules do not consider other key factors that impact the reality of any operator's likely ability to cover its future liabilities. Adding a metric of portfolio composition as an indicator of potential financial risk represents a refinement over the existing rules, replacing the limited inclusion of depth in the existing rules as a risk indicator. Ms. Felix provides no specific proposal to better account for that risk.

While necessarily simple enough to be easy to implement, the 15% threshold *is* also supported by empirical modeling. As illustrated in Applicants' Exhibit 68[10], the 15% threshold reflects a natural breakpoint in the ratio of potential liability vs. revenue generation across the landscape of New Mexico's operators. The graph illustrates that all operators below 15% marginal and inactive wells appear to have produced at least enough revenue in 2024 to cover estimated plugging costs (though not reclamation) for at least their marginal and inactive state and private wells. Meanwhile, the only operators that fail to meet the criteria are all above the 15% threshold.[11] This suggests that portfolio composition does serve as a meaningful indicator of a structural financial risk: namely, that an operator may not be able to generate even this modest amount of gross revenue, relative to expected future costs that could fall to the state on its account. In lieu of collecting fine-grained details from each operator about their assets, liabilities, balance sheets and projections—a potential burden for operators (to which NMOGA and IPANM

[10] Apps.' Ex. 68 is the graph comparing each operator's estimated 2024 revenue (across all state, private, and federal wells) vs. the state's potential liability for all of that operator's marginal and inactive wells. These numbers are estimated for 2024 based on the assumptions and filtering for the bonding estimation analysis, as documented in Applicants' Exhibit 63.

[11] To clarify: Some (mostly larger) operators above the 15% threshold do meet the revenue criterion. But all those that fail the metric are in the above-15% category, while none of the operators below 15% fail the metric.

would surely object) -- as well as for administrators—the 15% threshold is a reasonable proxy that corresponds to a degree of structural financial risk potential across the class of operators that exceed it, but does not overly tax the Division's administrative capacity to implement.

The broader implications of selecting 15% as this limit are discussed in Dwanye Purvis's testimony, and compared to some alternative limits. Mr. Purvis shows in Applicants' Exhibit 51 a range of marginal and inactive well percentage thresholds, and the extent to which different threshold choices would impact different percentages of operators, wells, and production volumes. This empirical modeling illustrates that the selection of 15% allows the proposed rule to strike a balance between improving liability coverage for a large proportion of New Mexico's lowest-producing wells, while limiting its strongest effects to portfolios representing only a combined 2.3% of New Mexico's total oil and gas production (BOE basis).

Moreover, and in addition to addressing systemic risk, a portfolio composition metric also acts as an incentive for operators to increase their production, to plug their non-economic wells, or to transfer them to a company able to demonstrate the ability to pay for proper end-of-life closure—all beneficial courses of action (socially or economically) that may reduce the risk of eventual orphaning.

Q: IPANM witness Ezzell, at 58, claims that the 15% marginal well threshold for an operator to bond all its wells individually as arbitrary, and that there may be "an operator with a very strong balance sheet and has a significant portion of highly productive wells in its portfolio, but has marginal wells for reasons of, for instance forming a unit," concluding that such an operator "does not seem to pose any danger of default to the State of New Mexico." What is your response?

A: To say such an operator does not pose *any* danger of default to the state defies credulity—default risk is ever-present, consider black swan events like the pandemic, or major bankruptcies like Enron—things can go wrong in a hurry. If an operator with a very strong balance sheet and mostly productive wells in its portfolio acquires a significant enough number of marginal and inactive wells as part of an acquisition, that operator is well-positioned to support their bond (presumably at a discount because of their low risk), or increase production at its newly acquired wells through workovers and enhanced recovery, or to plug those wells and take them out of the risk pool entirely.

Q: NMOGA witness Arthur, at 27, claims that the average marginal and inactive well blanket financial assurance of $150,000 per well "creates a 'moving target' bonding framework" that creates internal compliance risk, abandons the existing risk-based approach, and will ultimately drive business and tax revenue out of the state. What is your response?

A: As I've stated elsewhere, I do not believe the current financial assurance program to be particularly risk-based. The financial assurance update cadence is annual, which should be enough time for all parties to calculate their obligations and adjust their financial assurance as appropriate. Given that the overwhelming majority of production comes from high-producing shale wells,[12] financial assurance obligations will not make a noticeable difference in the state's tax revenue, though it *will* make a significant difference in the state's plugging and remediation obligations.

Q: NMOGA witness Arthur, at 29, claims that Applicants proposed amendments requiring single well financial assurance "bears no relationship to risk or lived experience"

[12] *See* Applicants' Exhibit 40, showing marginal wells account for only 0.045% of New Mexico production (excluding wells with presumed no beneficial use).

that some wells "can be fully plugged and abandoned for far less than $150,000," and that "a bonding regime should take experience, risk, well characteristics, and other factors into account." What is your response?

A: Actually, the proposal is based on the experience of Division regulators, who have a wider and temporally longer aperture than the operating community, and are tasked with balancing the economic productivity of the state's resources and other factors like the environment, the climate, and taxpayer expenses. I welcome industry's demonstrations of their actual plugging cost, and hope the industry will work with the Division to lower the agency's plugging costs for orphan wells—perhaps through the industry plugging of wells before well casing or wellhead issues arise, which increase the costs to plug. Until those costs are lowered, it is appropriate to bond to the agency's actual costs for plugging. And repeating what I've said elsewhere, there is no good-faith, data-oriented, risk-based approach to financial assurance proposed by industry thus far.

Q: NMOGA witness McGowen, at 124, discusses what he describes as the importance of marginally producing wells which "produce at low but still economically viable rates, often contributing significantly to cumulative field production over long periods." What is your response?

A: Marginal wells as defined in Applicants' proposal certainly do produce oil and gas, which provides some income for the operator and any royalty. But it's also the case that these wells, producing less than 1,000 BOE per year and less than 180 days per year, amount to only 0.045% of the state's annual production (excluding wells with presumed no beneficial use). The proposal is not intended to cease production of such wells—only to ensure that their future plugging costs are fully covered. These wells in many cases are only economically viable because their large future liabilities are excluded from present-day accounting.

19.15.8.9.E NMAC -- Inactive Wells and Wells in Approved and Temporary Abandoned Status

Q: NMOGA witness Emerick, at 9, claims that Applicants' proposal "would remove risk-based individual well financial assurance and tiered blanket bonding currently in place for inactive wells and wells that have been in temporarily abandoned status" and require financial assurance that is "far greater than the typical costs required to plug and abandon the typical onshore oil and gas well in New Mexico." What is your response?

A: Existing financial assurance requirements for inactive wells are not risk-based—they are depth-based, but only if the operator obtains single-well financial assurance. Otherwise operators can obtain a blanket bond conditioned only by the number of wells covered. Many states recognize the orphaning risk inherent in idle wells, and do not allow an unlimited number of idle wells to be placed on a blanket bond, as current rules in New Mexico allow. This includes Wyoming, which has the discretion to require single-well financial assurance for each inactive well, as well as North Dakota, which limits the number of inactive wells that can go on a blanket bond. As for the cost, I discuss this elsewhere, but the $150,000 figure used is less than the Division's average plugging cost of $163,000.

19.15.8.9.F NMAC

Q: NMOGA witness Arthur, at 29, claims that Applicants' proposed amendments for incomplete blanket financial assurance under 19.15.8.9.F NMAC are "unworkable to mandate matching new wells with bonding coverage without accounting for the frequent acquisitions and dispositions in the oil and gas industry and related challenges of updating bonds as wells are plugged, sold, or transferred." What is your response?

A: If the Division cannot keep up with well transfers and well plugging, the solution is to increase the Division's funding to allow sufficient staffing to meet the size and complexity of the oil and gas industry in New Mexico, not to reduce standards in defeat. That said, the updates to financial assurance occur only annually, and at least the first cut of what needs to change could be provided programmatically by using the OCD's data management system. If the proposal is adopted and the results are truly unworkable, OCC and OCD can adjust course with input from stakeholders. But positing unworkability is not a sufficient reason not to try to solve this problem.

General Objections to Applicants' Financial Assurance and Plugging and Abandonment Proposals

Q: NMOGA witnesses Sporich, at 19, and Arthur, at 26 claim that single-well and blanket bonding amounts are not reasonable and do not represent the typical costs to decommission New Mexico oil and gas wells. What is your response?

A: The average plugging cost for the Division is $163,000—the $150,000 single well bond is below that amount. The bond is only collected and deployed if the Division is the plugger, and thus the bond amount is reasonable. There may be ways to get the Division's average costs down over time, and would encourage New Mexico operators and service companies to work with the Division in this regard. For example, a workforce development program providing training and apprenticeship opportunities for people wanting to enter well plugging and remediation careers in New Mexico would benefit employment in the oil patch, while simultaneously reducing plugging and abandonment costs. Moreover, industry plugging of wells prior to well casing and wellhead deterioration, as would be incentivized through the proposed amendments, would reduce the costs of Division plugging.

Q: NMOGA witness Felix, at 17, claims that the "proposed average-based blanket bond structure introduces a moving target that is operationally unworkable," that the "average

bond amount would fluctuate as wells move in and out of temporarily abandoned or inactive status, forcing operators to constantly recalculate financial assurance needs across dynamic well portfolios." What is your response?

A: Applicants do not propose blanket bonds for inactive wells or for approved or expired TA wells. Applicants propose single well bonding that may be bonded through a single instrument, for the convenience of operators.

Furthermore, Applicants do not propose changing *current* Commission requirements for when operators must put up bonding for inactive or TA wells. Under the current rules, operators must provide financial assurance *prior* to placing a well in TA status. 19.15.25.13.E NMAC. Applicants' proposals do not create a "moving target" that doesn't otherwise exist under existing rules. And, it certainly makes sense to require operators to provide financial assurance before they place a well in TA status. A well that can be idled indefinitely, as a well can under the Commission's current rules, is a higher risk to the state and the financial assurance securing the cost to plug and abandon should be provided upfront.

Q: NMOGA witness McGowen, at 53, claims that "there is no demonstrated correlation between accelerating P&A and improved environmental outcomes." What is your response?

A: At risk of stating the obvious, oil and gas wells pose risks to the environment. Even perfectly operated facilities inherently damage the subsurface by creating fluid conduits for flow between geological layers and the surface. One can have relatively low-emission production using electrified equipment, for example, and still never have zero emissions. Methane emissions, unless brought to near zero, can also have outsize near-term effects on the climate (and low-producing wells tend to have higher methane emissions per unit of energy production).

Produced water management, even in a no-leak, closed loop scenario, still takes energy to store, transfer and move around. Well pads induce ecosystem change. Truck traffic and pipelines to and from facilities are not impact-free even in the best of circumstances (and can be catastrophic in the worst). And noise, light and dust from operations is ever-present and impossible to fully mitigate. As a society, we've made trade-offs, accepting these impacts while trying to minimize them for the economic benefits of production, which first and foremost go to the operator and mineral owner (and in New Mexico is a major source of government revenue), and to provide needed energy and materials for as long as we use fossil fuels for those products. But we did not, as a society, agree that operators can treat their well closure obligations as functionally optional.

Turning directly to Mr. McGowen's contention: first, there is clear documentation of increased risk of environmental exposures and human health impacts resulting from unplugged or improperly abandoned wells, as noted previously (again, *see, e.g.,* Morgan Dir. Test. at 0307-310 [Apps' Ex. 15].) For environmental hazards of unplugged wells that grow more likely or more significant over time, a longer timeframe prior to plugging clearly leaves more opportunity for these contamination events to occur. We can also note that there is an entire carbon credit industry coming into being that bases the development of credits on plugging marginal wells before they are legally obligated to be plugged, and generating credits based on methane emissions avoided and unproduced hydrocarbons (minus a factor for production leakage as to new production coming online to make up for production loss from that well). I won't go into a whole exegesis on this issue, but I will say that if there were no environmental benefit from plugging those wells early, then any carbon credits generated that way would be illegitimate and worthless. There clearly is a benefit from plugging wells before the last drop of hydrocarbon is produced—the question is, how to quantify those benefits versus the costs. Applicants believe our proposals, which allow operators to continue producing pretty much indefinitely (notwithstanding the rebuttal *de minimis* production), and then allow operators to keep non-productive wells around for over eight years, strikes a more than fair balance.

Q: NMOGA witness McGowen, at 53, claims that "the push to prematurely plug wells ignores the substantial potential of properly maintained temporarily abandoned wells," and identifies New Mexico's 2025 Well Repurposing Act (HB361) as "explicitly recogniz[ing] this opportunity by creating a legal and regulatory framework to convert idle wells into geothermal energy sources, CO_2 storage sites, methane monitoring stations, and other beneficial uses." What is your response?

A: Applicants' proposal allows wells to sit inactive for just over eight years. Except in extremely limited circumstances, wells that have not been used for more than eight years will not come back into production or used for another beneficial purpose. This is supported by my direct testimony and Applicants' Exhibit 13, which demonstrates that *99.5% of inactive wells* that are reactivated do so before 8 years of inactivity.

Meanwhile, many in the advocacy community were worried that the advent of beneficial uses for wells outside of oil and gas production and waste disposal would merely serve as an excuse for operators to idle their wells forever and never plug them. I personally made the argument that these alternative uses were important to pursue, first for their potential contribution to clean energy development, and second as a potential revenue source for eventual plugging. I am disheartened, although I suppose not surprised, to see this potential weaponized by industry to avoid plugging liability. I do think the eight-year window to make use of the wells strikes the right balance here.

Q: NMOGA witness McGowen, at 61-64, discusses P&A requirements in various

jurisdictions to contrast the approach in Applicants' proposal. What is your response?

A: It is true that an absolute time limit on well idling is new and would be unique if adopted in New Mexico. As just discussed, EDF's evaluation of well idling in New Mexico found that practically all idle wells that reactivate do so within eight full years of inactivity (*see* Apps' Ex. 13), so I do not believe that there would be much practical impact, and any focus on a few hypothetical exceptions risks losing the policy forest for the trees.

It is worth noting that in the Oklahoma Legislature this year, before the Legislature settled on a ten-year idle limit with a hearing process for extensions, the original bill had an eight-year limit with no exceptions—very close to our proposal. Of note, Oklahoma likely has over 300,000 undocumented orphan wells; their documented orphan well count rose from 1,000 before the advent of the REGROW Act, and 18,000 by the time the state had to submit a notice of intent to apply for a formula grant to the Department of the Interior in December 2021.

Similarly, in Texas, the original concept for idle well time limitations in the TXOGA bill was set at ten years with limited exceptions—smaller operator associations insisted on extending that time limit to fifteen years and adding an economic hardship exception, for their support (or lack of opposition) in the Texas Legislature. Texas has an estimated 115,00 idle production wells, a striking increase from an average of around 80,000-85,000 such wells from 2000 to 2015, coinciding with the shale boom, the standing out of vertical wells impacted by frac hits, and the shift of operator focus and dollars from legacy vertical production to modern horizontal production. Notwithstanding the regulations in Texas that Mr. McGowen cites, over 59% of the idle wells in Texas have been inactive for five years or more—the majority of which will never return to service if history is any guide. Part of the legislation passed in Texas this year (SB1150) required the Texas Railroad Commission to undertake two rulemakings on idle wells, a general one revising all of rule 3.14, and a specific one handling the transfer of idle wells. In any case, New Mexico has the opportunity to learn from its neighbors, where development started much earlier, and correct for their policy failings which plague both of those states and their residents today.

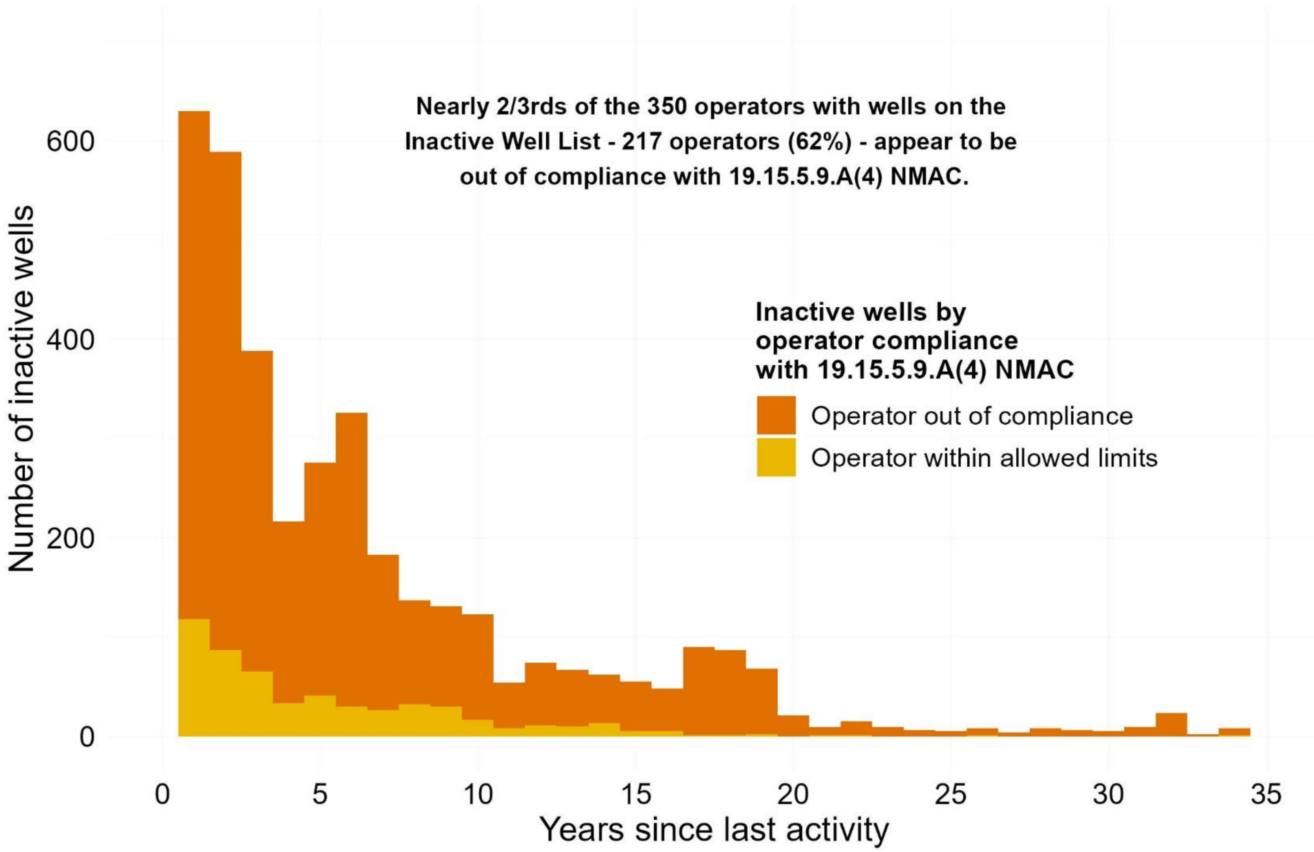
This concludes my testimony, which is accurate to the best of my knowledge.

/s/ Adam Peltz	September 18, 2025
Adam Peltz	Date

EXHIBIT 83

Inactive wells by time since last activity, by operator's compliance with 19.15.5.9.A(4) NMAC

7/3/25 OCD Inactive Well List (all wells with 15+ months inactivity)



Data reflect wells included in search results from OCD Inactive Well Search tool as of July 3, 2025.
'Years since last activity' reflects full 12-month years since last reported production date, for wells inactive 15+ months.
'Operator compliance' refers to compliance with NMAC 19.15.5.9.A(4), based on total wells as calculated from OCD's wellhistory dataset.

Assessment steps are described in full below:

1. Each well on the Inactive Wells list was assessed for apparent compliance status, as described and presented in Apps.' Exhibit 10 (Inactive wells by length of time inactive).
2. Each operator's non-compliant wells (those not in Approved TA status, or under an ACOI) were tallied.
3. Each operator's total number of wells was tallied based on the OCD wellhistory dataset, as of July 11, 2025.
   A. The wellhistory dataset was filtered to well status entries effective as of July 3rd, 2025, based on the combination of the effective date (effdate) and termination date (rectermdate) for each status entry.
   B. For wells with no termination date for more than one status entry, the effective date of the next status change was inserted as the termination date of the earlier status entry, eliminating potential double counting of API10s.
   C. Wells with a status indicating they had been cancelled (C), plugged (P), or never drilled (X) were removed.
   D. The remaining wells were tallied by operator; total well counts were then matched and joined to the Inactive Well List data by operator identification number (ogrid).
4. Based on the number of total wells, each operator was assigned an allowed number of wells based on the text of 19.15.5.9.A(4). For operators allowed the lower of 2 or 50% of their well total, well allowance numbers were rounded down (such that an allowance of 1.5 wells was treated as 1 well, and an allowance of .5 was treated as 0.)
5. Operators with more noncompliant wells on the Inactive Wells list than their allowed number were assessed as out of compliance with NMAC 19.15.5.9.A(4).

Apps' Ex. 83

EXHIBIT 84

Documentation for estimates of 1% and 5% surety premiums as fraction of revenue (Apps' Exhibit 84)

Comparisons of Operator Revenues and Bonding Amounts, by Marginal and Inactive % and Well Count Groups							
Marginal and inactive wells as a fraction of total	Operator well count (inclusive of federal, state, and private wells)	Total operators in group	Total marginal and inactive state and private wells in group	Percentage of federal, state, and private wells identified as marginal or inactive	Total estimated 2024 revenue (inclusive of federal, state, and private wells) (millions USD)	Total estimated bonding liability for state and private wells (millions USD)	1% of total bonding liability, as a percentage of total 2024 revenue
above 15%	1 to 50	160	641	55%	$235	$171	0.729%
	51 to 100	14	247	46%	$147	$85	0.577%
	101 to 500	21	1087	38%	$956	$420	0.440%
	Over 500	3	473	24%	$662	$272	0.411%
below 15%	1 to 50	83	35	6%	$519	$18	0.034%
	51 to 100	17	48	7%	$1,679	$10	0.006%
	101 to 500	26	233	7%	$12,532	$39	0.003%
	Over 500	18	709	6%	$35,637	$109	0.003%
all operators (above + below 15%)	1 to 50	243	676	37%	$754	$189	0.25%
	51 to 100	31	295	24%	$1,826	$95	0.05%
	101 to 500	47	1320	22%	$13,488	$459	0.03%
	Over 500	21	1182	8%	$36,298	$381	0.01%

Data sources:

- The dataset generated for the bonding snapshot analysis (as detailed in Applicant's Exhibit 63) was used as the basis of this table, including:
    - estimated 2024 revenues across federal, state, and private lease wells
    - estimated bonding amounts for state and private wells only
    - operator marginal and inactive well percentages (inclusive of federal wells).
    - Annually averaged EIA prices (West Texas Intermediate and Henry Hub indices)
- The same underlying data sources, filtering processes, caveats and limitations documented in Exhibit 63 thus carry forward to these data.

Data processing:

- Operators were grouped by total number of wells inclusive of federal, state, and private lease types, then further subset by whether they were assessed as below or above the 15% marginal and inactive well percentage threshold .
- Totals and sums at the level of each group were calculated through queries in R coding language.
- 1% surety comparisons are calculated as 1% of the estimated bonding liability for the group's state and private wells only (federal wells excluded), divided by estimated 2024 revenues.
- Estimates for 5% premiums included in the text of Apps' Exhibit referencing this one are based on multiplying this 1% surety equivalency by 5.

Related calculations: historic range of typical oil and gas prices variation

- Year-over-year change for each price data series was calculated as previous year – current year / previous year. Annual change ranged from -47% to 73% for West Texas Intermediate ("WTI") oil prices, and from -52% to 138% for Henry Hub ("HH") gas prices. First and third quartile year-over-year changes were -10.5 to 25% for WTI, and -16.5 to 28.7% for HH.