STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

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

TESTIMONY OF HAROLD MCGOWEN

ON BEHALF OF

NEW MEXICO OIL AND GAS ASSOCIATION

August 8, 2025

TESTIMONY OF HAROLD E. MCGOWEN III, PE

I. INTRODUCTION AND BACKGROUND

My name is Harold E. McGowen III. I am the founder, President, and Chief Executive Officer of Navidad Energy Advisors (NEA), and have served in those capacities throughout the firm's 12-year history. My business address is 16421 FM 344 West, Bullard, TX 75757. My curriculum vitae is attached hereto as **Appendix A**.

I hold a Bachelor of Science Degree in Mechanical Engineering from Texas A&M University. I am a registered Professional Engineer in Texas (License No. 66419) and a member of the Society of Petroleum Engineers, the National Academy of Forensic Engineers, and the American Society of Safety Professionals. I have also completed extensive post-graduate technical continuing education over the years, including fifteen hours of Industrial Engineering, TEEX Phase I and Phase II Environmental Site Assessment Training, numerous Petroleum Engineering and related continuing education courses and energy industry executive education coursework in Strategic Leadership, Energy Finance, and Business Strategy at Southern Methodist University's Cox School of Business.

I have served as the President and CEO of multiple upstream exploration and production companies, including Navidad Resources, Inc., Navidad Resources, LLC, and Navidad Resource Partners, LLC. In these roles, I executed full-cycle acquisition, development, divestiture, and decommissioning programs, including plugging and abandonment (P&A) and surface restoration activities. This includes plugging numerous wells, re-entering wells that had been previously plugged by other operators, and directing U.S. Securities and Exchange Commission (SEC) compliant reserve audits that included economic modeling of P&A obligations. At Navidad

Resources, LLC, I raised and deployed over $75 million in equity and negotiated numerous joint development agreements, scaled production from zero to over 5,700 barrels of oil equivalent per day (BOEPD), and achieved a compound annual growth rate over three years of about 100% during the peak growth period of that company.

Most recently, as CEO of Navidad Resource Partners, LLC (NRP), I led the execution of a multi-well, full-field horizontal development program in the Brookeland Austin Chalk Field in East Texas. From 2017 through 2024, the project was capitalized at approximately $100 million and began with the successful Hancock 1H "proof of concept" well, which confirmed virgin reservoir pressure, high oil and NGL yield, and validated our geologic, reservoir, and completion models. Building on that success, I oversaw the drilling and completion of ten horizontal wells, each with a capital cost of approximately $18.5 million. The development also included the design and buildout of critical water infrastructure and natural gas processing and takeaway systems. As part of this project, I evaluated the potential of reentering and/or repurposing multiple legacy wellbores to facilitate delineation of the potential of our mineral acreage position. I managed all aspects of the project through its full-cycle execution, including well design, field planning, operations management, reserves evaluation, and ultimately, the successful divestment of the asset. The sale of NRP's oil and gas assets in early 2025 marked the successful culmination of our strategy to de-risk the position, demonstrate repeatable performance, and create significant value for our private equity investors, while maintaining a strong track record in environmental stewardship and operational safety.

I have been recognized for both technical leadership and business performance throughout my career. In 2013, I was named one of the Top 15 Best CEOs of Medium-Sized Producers by the

Texas Independent Producers and Royalty Owners Association (TIPRO). Under my leadership, the oil and gas exploration and production companies I founded were honored four times in the Texas A&M University "Aggie 100" ranking of the fastest-growing Aggie-led businesses, earning the #1 spot in 2012, #4 in 2013, #3 in 2014, and #9 in 2023. These distinctions reflect a sustained track record of innovation, operational excellence, and entrepreneurial success in the upstream oil and gas industry.

Alongside my work running oil and gas companies, at NEA, I have built a multidisciplinary technical advisory firm that offers services to private equity investors, oil and gas exploration and production companies, and legal professionals. At NEA, I lead and manage a team of reservoir, drilling, production, geology, and data engineers and analysts, providing engineering due diligence, reserves evaluations, expert witness services, and forensic investigations as required by the needs of our clients.

Additionally, I have published and presented extensively on horizontal drilling, underbalanced and managed pressure drilling, complex reservoir development, parent-child well interference, and upstream oil and gas project management. I have presented at industry conferences throughout my career, including the Society of Petroleum Engineers (SPE).

I have served as an expert witness or technical advisor in approximately forty (40) cases, have been deposed more than twenty (20) times, and have provided sworn testimony under cross-examination in three federal court trials, one arbitration, and one regulatory hearing before the Texas Railroad Commission (RRC). In the RRC proceeding, I supported the successful petition to revise the Fort Trinidad/Eastham Field Rules through data-driven, statistical reservoir analysis. I have studied and dealt with regulatory issues from the perspective of an Oil and Gas Operator throughout my career, including dealing with Federal and State of Texas environmental regulations specific to the Upstream Oil and Gas Industry; however, I have not previously testified before the New Mexico Oil Conservation Commission (Commission).

Throughout my 40-year career, I have been directly involved in the planning and execution of plugging operations on approximately 100 wells consistent with the requirements of the Texas RRC. I have also evaluated, re-entered, and re-purposed numerous inactive/marginal and previously plugged and abandoned wells in order to execute production and/or recompletion operations. My expert testimony/litigation support has included patent disputes involving P&A technologies, as well as litigation centered on well-plugging operations.

II. PURPOSE OF TESTIMONY

I have reviewed the proposed amendments authored by the Applicant, the Western Environmental Law Center ("WELC"), particularly **Sections 19.15.2.7, 19.15.5.9, 19.15.8.9, 19.15.9, and 19.15.25 of the New Mexico Administrative Code (NMAC)**.[1]

It is my understanding that, like the mission established for the Texas Railroad Commission, the New Mexico Legislature established the Oil Conservation Division (the "Division" or "OCD") to promote the responsible development of the state's oil and gas resources, prevent the waste of hydrocarbons, protect correlative rights, and safeguard public health and the environment.[2]

It is my understanding that New Mexico collected $11.5 billion in revenue from the oil and gas

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[1] NMOGA reserves the right to comment on any proposals later filed in this rulemaking proceeding by the New Mexico Oil Conservation Division ("OCD"), or any other party or intervenor.

[2] *See* N.M. Stat. Ann. § 70-2-11 (2025) (codifying the authority and functions relating to the Oil and Gas Proceeds Oversight and Accountability Commission), available at *Justia – N.M. Stat. Ann. § 70-2-11*.

industry through a combination of taxes and land income for fiscal 2023 (12 months ended June 30, 2023)[3], with an additional $1 billion going to local governments. It is further my understanding that the direct collections from oil and gas made up 20 percent of the state's revenue for the general fund during the recent period and were expected to increase to 23 percent by the end of fiscal 2025. My research indicates that the combination of direct and indirect collections from oil and gas brought contributions to the general fund to 35% in fiscal 2023. The state has used the additional revenue to expand its operating budget, fund capital projects, and increase monies to state investment accounts. Moreover, based on December 2023 estimates, each additional million barrels of oil production was projected to contribute roughly $6.9 million, and every extra 10 billion cubic feet of gas was projected to yield about $4.8 million to the state budget.

It is my understanding that the New Mexico Legislature intended the OCD to strike a balance, ensuring environmental protection while facilitating efficient and prudent resource recovery that maximizes the economic value of New Mexico's natural resources for the benefit of the economy of New Mexico and its citizens.[4]

I will be explaining the issues I have identified in WELC's proposal, within the framework of the stated mission of the OCD, from an oil and gas operator's perspective, and as compared to other jurisdictions. I will demonstrate that these proposed changes will drive a significant amount

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[3] Faubion, J. (June 11, 2024). Oil and Gas Revenue to the State of New Mexico (p. 5). Legislative Finance Committee, New Mexico Legislature.

[4] *See* Michelle Lujan Grisham, *Oil Conservation Division Director – Office of the Governor* (2025) (stating the OCD's goals "to promote balanced, consistent, fair, and transparent regulation of the oil and gas industry, to prevent the waste of oil and gas resources within the state, to protect the correlative rights of resource owners, to foster efficient development, and to protect human health and the environment").

of capital investment in oil and gas development out of New Mexico and into other states (like Texas) where conditions are more favorable. That is, if New Mexico's harsher bonding rules discourage local oil and gas acquisitions, divestitures, drilling, and production activity, oil and gas development will shift to other U.S. states and/or the U.S. will be forced to rely more on imported oil, with neither of these outcomes benefiting New Mexico.

I will demonstrate how these proposed changes would force operators to prematurely or arbitrarily plug valuable wellbores, many of which required millions of dollars of capital to drill, complete, and equip, and cannot be replaced without similarly large new investments. From an engineering and economic standpoint, this outcome is wasteful, runs counter to the Legislature's intent, and undermines responsible energy development.

My testimony addresses the proposed rule changes in six key areas:

1. **Defining Beneficial**: I will critique the proposed definitions and thresholds for "Beneficial Purpose" or "Beneficial Use," and presumptions of no beneficial use they would trigger, which are overly simplistic and do not reflect operational reality. Relying on arbitrary production or injection volumes to determine whether a well has "beneficial use" could lead to the unnecessary plugging of wells that could otherwise be reactivated, recompleted, or used for secondary recovery, geothermal energy, or environmental monitoring.
2. **Unnecessary Temporary Abandonment (TA) and Casing Integrity Requirements**: I will assess the proposed changes to the Temporary Abandonment (TA) program, including inflexible timelines and redundant casing integrity log requirements. These changes disregard the substantial capital investment already made in each well and the mechanical safeguards that are already in place under OCD's existing TA approval framework.

Moreover, these changes will undermine regulatory trust and compliance. I will show how penalizing operators who have followed OCD's current TA procedures, by treating properly approved and mechanically sound TA wells as liabilities, sends a harmful message: that even compliance with state-approved procedures offers no protection against retroactive financial penalties. This undermines regulatory certainty and discourages cooperation, innovation, responsible field management, and ultimately investment in the development of the state's oil and gas.

3. **Detrimental Permanent Plugging and Abandonment (P&A) Requirements and Timelines:** Instead of promoting responsible resource management, the proposed changes to P&A requirements and timelines would penalize prudent practices aimed at responsible compliance, discourage reinvestment in marginally producing wells, and increase the risk of unnecessary well destruction, which would harm both economic recovery and environmental reuse potential. Notably, the proposed regulations would assume that after 13 months without production (12 months idle plus a 30-day reduced compliance period), a well must either be permanently abandoned or officially transitioned to TA status to remain legally idle. This introduces the risk that wells awaiting repairs, workover equipment, or shut-in due to pipeline issues or commercial reasons could automatically be classified for abandonment based on arbitrary timing rather than engineering judgment. I anticipate the changes as proposed will lead to premature P&A, counteracting broader resource conservation goals.

4. **Financial Assurance (FA) to Secure Permanent P&A and Reclamation:** I will analyze the proposed changes to bonding requirements and show how the dramatic increase in

financial assurance per well, particularly for low-production and temporarily abandoned wells, would stifle transactions, block repurposing opportunities, and potentially lead to less responsible oil and gas production and more orphaned wells, not fewer.

5. **Broadening the Definition of Marginally Defined Wells While Increasing Their Financial Assurance Requirements**: New Mexico's oil and gas landscape is diverse and full of marginally producing wells that serve long-term strategic functions. The proposed new definition of "Marginal Well," while intended to flag truly uneconomic wells, risks encompassing too many productive or strategically maintained wells, with negative economic and environmental consequences. Additionally, misclassification of a well as marginal has serious financial assurance impacts under the other proposed regulations.

6. **Restrictions on Asset Transfers and Operator Registration**: I will explain how the proposed transfer restrictions and bonding triggers for changes in operator status would create unnecessary barriers to transactions and capital formation. This would reduce the pool of responsible operators willing and able to assume stewardship of aging wells and hinder the long-standing practice of transitioning marginal assets to operators best positioned to maintain or repurpose them. I anticipate these changes would also deter capital and operators from the state.

In conclusion, the proposed amendments, while rooted in concerns over environmental risk and orphan wells, are overbroad, misaligned with field and business realities, and counterproductive to the Legislature's original mandate for the OCD. The cumulative effect of these changes would be to increase waste, reduce investment, and prematurely eliminate valuable infrastructure that could otherwise be repurposed or returned to beneficial use.

A more constructive path forward would retain OCD's existing performance-based framework while allowing for targeted improvements that support environmental protection without destroying capital, impeding transactions, or penalizing compliance. I urge the Commission to consider a more balanced and risk-based approach that honors the Legislature's intent while ensuring New Mexico's energy resources are managed wisely and responsibly.

III. TESTIMONY

A. Proposed New Definition of Beneficial and Related Presumption Using Misleading and Unrealistic Thresholds

1. "Beneficial Purpose" or "Beneficial Use" Definition – Proposed 19.15.2.7(B)(7) NMAC

WELC proposes to add a definition for "Beneficial Purposes" or "Beneficial Use" under 19.15.2.7(B)(7). To date, the industry has operated without a formal definition of these terms or "beneficial." I am concerned that defining these terms now will conflict with their use in other existing OCD regulations, including "Approved TA" under existing 19.15.25.12 NMAC and the proposed amendments to the same. Reviewing NMOGA operational witness Dan Arthur's testimony and regulatory analysis further supports the position that defining these terms or "beneficial" will potentially conflict with their current use in Title 19 of the NMAC, especially if narrowly defined.

WELC proposes to define "Beneficial Purposes" or "Beneficial Use" as "an oil or gas well that is being used in a productive or beneficial manner, such as production, injection, or monitoring, but does not include use of a well for speculative purposes." WELC's reference to speculative purposes is subjective and invites inconsistent enforcement or litigation. It also could be interpreted as excluding enhanced oil recovery (EOR) projects, geothermal, monitoring, injection, seismic, and other regulatory or reservoir management uses, which are effectively excluded.

2. *Proposed "Presumptions of Beneficial Use" Provision*

i. *Rebuttable Presumption of No Beneficial Use – Proposed 19.15.25.9 NMAC*

WELC also proposes a presumption that a well is not capable of beneficial use provision under a new 19.15.25.9 NMAC, if the following "90-Day Criteria" are not met:

- Production wells would be presumed to have no beneficial use if, during the consecutive twelve-month period, there was (i) less than ninety days of production and (ii) less than ninety total BOE or a volume that the operator can demonstrate produces in paying quantities (PPQ).
- Saltwater disposal (SWD) and injection wells would be presumed to have no beneficial use if, during any consecutive twelve-month period, there was less than ninety days of injection and less than one hundred barrels (bbls) total injected.

Introducing specific annual time/volume thresholds is too rigid and not operationally realistic, particularly for wells with variable production and maintenance downtime or those waiting on infrastructure. I reviewed Dan Arthur's testimony and agree with his opinion on this issue as well. Use of rigid presumptions could force premature P&A, thereby increasing costs and reducing revenues to royalty and interest owners. WELC proposes to introduce these same 90-day/90 BOE or 90-day/100 bbls thresholds for beneficial use (but both during a consecutive twelve-month period), but under a separate and new 19.15.25.9 NMAC (specific to presumptions of no beneficial use), proposed by WELC alone and discussed below. The concerns I raise next apply equally to OCD's definition of "Beneficial Use/Purpose" discussed here, and WELC's presumption of no beneficial use regulation discussed below, *see infra,* Part III.A.2.i.

If either of the 90-day criteria is met, it would trigger a rebuttable presumption that a well is not capable of beneficial use, which WELC's 19.15.25.9 NMAC also sets forth the process for rebutting. The same concerns regarding the misleading and unrealistic 90-day criteria introduced under OCD's version of beneficial in its proposed 19.15.2.7(B)(6) NMAC, which I discuss immediately above, *see supra,* Part III.A.1.iii., apply to WELC's proposed presumption provision under a new 19.15.25.9 NMAC.

But under WELC's proposed presumption provision, the presumption would 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.

WELC's proposed 19.15.25.9(D) NMAC goes on to set forth the procedure for rebutting the presumption. Operators would have just thirty (30) days from receipt of a preliminary determination from OCD that a well or wells are not being used for beneficial purposes to apply for administrative review; such applications must include documentation demonstrating: the well is reasonably projected to PPQ; the operator maintains adequate capitalization or reasonably projected revenue sufficient to meet all reasonably anticipated P&A and environmental liabilities (not inclusive of any financial assurance required); and any other relevant information requested by the OCD (including a P&A plan).

The 30-day response window is too short and operationally unworkable. As written, it is unclear when notice is triggered or even if notice is required. There is a lack of clarity on who makes the preliminary determination based on a presumption of no beneficial use, how it is communicated, and whether the thirty days is tied to the presumption or formal notice. To comply, operators would be required to continuously monitor for OCD administrative determinations or presumptions and respond within 30 calendar days—a timeframe that is particularly burdensome for legacy wells, marginal producers, or recently acquired assets undergoing evaluation.

The proposed window fails to account for the real-world complexities of field operations. Preparing a technical response often requires coordination across disciplines (engineering, regulatory, land, legal), retrieval and review of historical well files, and a field condition assessment to develop a justified path forward. This may include scheduling casing integrity tests, contracting service providers, securing permits, and mobilizing equipment—activities that inherently involve lead times well beyond 30 days, especially in remote areas where contractor availability is limited and supply chains are stretched. For wells recently acquired in a transaction, operators may not yet have full access to historical data or site conditions, making immediate analysis difficult.

Requiring a rapid turnaround on a potentially ambiguous administrative finding places operators in the untenable position of either rushing inadequate responses that lack proper engineering basis or diverting critical resources away from other ongoing compliance and field operations. In either case, the likely result is inefficiency, increased costs, and a higher chance of error or oversight—without any corresponding benefit to environmental protection or regulatory effectiveness. A more reasonable approach would be a structured and clearly communicated notice process followed by a response window of 90 days, allowing for proper evaluation, scheduling, and compliance without unnecessarily disrupting field operations or jeopardizing beneficial reuse opportunities.

Additionally, rebutting the presumption requires unwarranted disclosure of proprietary data in the form of private technical information, development strategies, planned technology applications, tribal knowledge known only to the operator, financial models, cost structures, and revenue projections, and evidence of capital adequacy, thereby creating new confidentiality and litigation risks. Even once the operator files its application in response, OCD can demand any relevant documentation, which creates an added risk of inconsistent enforcement and regulatory overreach. Adding to this burden, operators typically face a 30-day response deadline for such data requests, often without clear guidance on scope or format, forcing hurried assembly of complex documents, diverting key technical, legal, and financial resources, and increasing the chance of errors. These tight timelines and expansive recordkeeping requirements can overwhelm smaller operators, trigger procedural objections or penalties, and prove unworkable in practice for operators of all sizes.

In short, a rebuttable presumption (guilty until proven innocent) that a well is not capable of beneficial use based solely on short-term production thresholds is arbitrary and unfairly shifts the burden of proof onto compliant operators, ignoring valid economic, technical, and operational reasons for temporary inactivity.

ii. Risks and Potential Impacts of Using the 90-Day Criteria

a. Setting 90-day/90 BOE or production in paying quantities for producing wells or 90-day/100 bbls for SWD or injection wells during any twelve-month period is arbitrary, unrealistic, and risks premature P&A of beneficial wells

Setting 90-day/90 BOE or production in paying quantities ("PPQ") for producing wells or 90-day/100 bbls for SWD or injection wells during any twelve-month period is arbitrary and unrealistic. For non-SWD/injection wells, 90 BOE per year (0.25 BOE/day average) is arbitrary and may exclude viable wells in EOR projects, low-decline stripper wells, or temporary shut-ins due to market, weather, or infrastructure outages. A well with intermittent output of say 0.5 BOE/day over part of the year may still deliver substantial net cash flow if its lifting costs are low. Classifying it as non-beneficial simply due to the arbitrary BOE threshold penalizes economically sensible operations. The thresholds fail to recognize broader beneficial uses and legitimate operational roles; EOR, geothermal, monitoring, injection, seismic, and other regulatory or reservoir management uses are effectively excluded. Use of the criteria as proposed could force premature P&A, thereby increasing costs and reducing revenues to royalty and interest owners.

b. Reference to production in paying quantities (PPQ), which is typically a lease-wide economic concept, so applying it on a well-by-well basis is misleading and burdensome

WELC's proposal expressly references PPQ. But not all valuable wells satisfy PPQ requirements (i.e., EOR, geothermal, monitoring, etc.). PPQ, a fact-specific term of art rooted in law, is grounds to refute the presumption.

Under industry custom, and as used in other states' oil and gas regulatory frameworks, such as Texas and Oklahoma, PPQ is a lease-wide economic concept, not determined on an individual well basis. Texas courts generally hold that PPQ requires the well to yield a profit after operating and marketing costs and assess the "reasonably prudent operator" standard over a flexible, reasonable period.

Applying the PPQ standard on a well-by-well basis is misleading and burdensome. If the Commission adopts PPQ as a part of the regulatory threshold, it may create conflict with existing fee or state leases for wells, trigger lease termination litigation by lessors or third parties, expose proprietary economic data, and potentially impact markets or competitive positioning. In turn, this creates potential for lease disruption and industry instability.

c. Production determinations made on a well-by-well basis disrupt multi-well pad economics, lease-level reservoir management, and can force premature P&A of marginally producing wells that support larger operations

Fourth, production determinations made on a well-by-well basis disrupt multi-well pad economics, lease-level reservoir management, and can force premature P&A of marginal wells that support larger operations. In New Mexico, pad and unit-level development is standard practice; that is, wells are managed collectively to optimize spacing, pressure management, shared surface facilities, and other infrastructure, and throughput. A well that appears idle on its own may still be critical to pad-level EOR, pressure support, or monitoring. Declaring it non-beneficial based on that single well's output undermines unit-wide development strategies and may conflict with federal lease terms that recognize lease-level beneficial use under unitization. Accordingly, unitization and lease-wide operations are not adequately addressed. Similarly, the presumption ignores federal and fee lease terms, many of which recognize beneficial use at the lease level, not on an individual well basis.

d. Risk that "no beneficial use" determinations, or even administrative presumptions, could become evidence in lawsuits alleging lease expiration or abandonment

The proposed regulations also create legal exposure for operators due to the risk that "no beneficial use" determinations, or even administrative presumptions, could become evidence in lawsuits or claims by others alleging lease expiration or abandonment, or unreasonable operations. This could destabilize existing contracts, particularly where operations or development plans preserve leases. Once leases are lost within what was formerly a "Held by Production" unit, putting the unit back together again may not be possible, or the cost may be prohibitive, effectively disrupting orderly development of the remaining oil and/or natural gas reserves remaining under the acreage. Moreover, this could create a cloud on the title of the oil/gas property, making it difficult or impossible for a new (and most likely better capitalized) operator to take over ownership and re-purpose the subject well-bores on the acreage.

a. The 1-year period is too short, not realistic or workable from an operations standpoint or for the investment cycle, and should be extended to five years

Based on my field experience, a one-year period to determine beneficial use is not realistic considering real-world infrastructure and market constraints, like time awaiting gas takeaway or for infrastructure buildout and lease negotiations. Instead, five years should be used to mirror the maximum approved temporary abandonment period, which WELC does not oppose.

In many areas of New Mexico, especially in unconventional plays, wells are sometimes drilled in advance of gathering systems, gas processing capacity, or compression infrastructure. These midstream projects can take 18–36 months or more to design, permit, fund, negotiate, and acquire right-of-way agreements, and build, often involving multiple parties and regulatory steps. Similarly, negotiations to secure new acreage or consolidate leasehold positions can take years to finalize, particularly when title issues or competing mineral owners are involved.

The investment cycle for oil and gas development is not linear or rapid. Hanging onto future inventory of projects is critical for sustained viability. Operators frequently evaluate project economics across multiple sections, waiting for commodity prices to stabilize at a level that makes the project viable, service costs to come down, or adjacent well performance to justify full-scale development. For example, it is common in my experience to shelve a drilled but uncompleted well or shut in an underperforming zone while planning a recompletion or re-frac program, sometimes dependent on the results from offset operators or larger joint ventures. These types of staged developments or prudent staggered risk management strategies don’t align with a compressed one-year beneficial window under the 90-Day Criteria as proposed. The 90-Day Criteria could disrupt project continuity and penalize sound long-term planning.

b. Minimizes flexibility for operators with long-term development plans

In my professional opinion, it would also lead to more premature plugging and wasted capital, particularly in smaller fields where smaller operators are often the only ones willing to take a risk on marginal or complex assets. I’ve seen firsthand how responsible operators can take older or idle wells and turn them into productive assets years later with the right timing, technology, or partnerships. I have spearheaded these types of projects myself. This is part of what keeps the industry dynamic and innovative; those second-look opportunities are often where breakthroughs happen.

iii. Risks and Potential Impacts of Adopting Proposed Presumption Provision

Application of the presumptions of no beneficial use based on the flawed 90-Day Criteria would create numerous new risks and unintended outcomes.

a. Premature classification of compliant wells as liabilities

The proposed presumption of non-beneficial use after limited production fails to account for legitimate operational practices, such as lease-level cycling,[5] pad-wide downtime, or strategic

[5] “Operators frequently engage in lease-level cycling, a common field practice where production is strategically rotated among multiple wells on the same lease to manage infrastructure constraints, optimize fluid handling, or preserve reservoir energy. More likely than not, such cycling results in individual wells producing fewer than 180

shut-ins. More likely than not, applying this presumption will result in premature classification of compliant wells as liabilities, raising due process concerns and distorting long-term development economics.

b. Mandatory disclosure of proprietary data

Small entrepreneurial operators are often the driving force behind the discovery of untapped potential that others overlook. These operators thrive by combining hard-earned field experience with relentless curiosity and technical rigor. They excel at identifying overlooked value through a blend of insightful subsurface geologic mapping, statistical production analysis, and historical pattern recognition. Armed with a nuanced understanding of local geology, well performance trends, and operational nuances, they are often able to spot opportunities that others overlook.

These nimble operators are willing to chase subtle trends in well logs, drilling data, production data, or unique structural interpretations, and other clues that may signal bypassed pay zones, compartmentalized reservoirs, or under-stimulated intervals. They may creatively apply newer technologies to revitalize existing wells, increase recovery, and unlock stranded hydrocarbons from legacy infrastructure. Often, the insights that spark a new project arise not from a single breakthrough or from accepted industry viewpoints but from the cumulative intuition gained over decades of hands-on operations and iterative testing.

Through a combination of local knowledge, ingenuity, and the motivation to pursue ideas unproven by precedent, small operators routinely turn marginal wells into profitable ventures.

days per year without reflecting disuse or diminished value—misclassifying these wells could lead to unjustified regulatory penalties and premature bonding requirements."

Their success is rooted not just in what they know, but in how they look at old problems with fresh eyes. Every new project begins with a contrarian insight: that something valuable lies hidden in plain sight, waiting for someone with the right tools, mindset, and tenacity to bring it to fruition.

It is unrealistic to expect time-constrained regulatory staff with limited resources and diverse responsibilities, who are not directly engaged in day-to-day exploration for oil and gas, to quickly recognize and fully appreciate the evolving and innovative techniques operators may propose to extract additional resources from existing wells. Moreover, the ideas that these entrepreneurs have developed, and would necessarily have to make public, are definitely trade secrets that are the one competitive advantage many of these operators have. In addition, the rebuttal documentation required could impact credit evaluations or operator liquidity. I discuss my concerns surrounding the mandatory disclosure of confidential and proprietary data in more detail below. *See infra,* Part III.B.2.

c. Presumption of no beneficial use, if not refuted, can trigger the legal obligation to apply to TA or properly P&A a well

The presumption is especially concerning due to the possibility that if a presumption of no beneficial is not refuted, the preliminary determination could become a determination of no beneficial use, which under existing 19.15.25.8 NMAC is currently one of the trigger events mandating the legal obligation to properly plug and abandon a well, *see infra*, Part III.C., or apply for approved temporarily abandoned status, *see infra*, Part III.C.

B. Proposed Changes to Temporary Abandonment (TA) of Wells and TA Permitting

New Mexico's current regulatory framework for Approved Temporary Abandonment (ATA) under 19.15.25 NMAC establishes a structured, safety-focused process for idling wells while protecting public health, freshwater, and the environment.

1. Current Requirements and Mechanical Integrity Testing for Approved TA Status under Existing 19.15.25 NMAC

The Division currently allows wells to be placed in ATA status for up to five years, but only under specific conditions that include a full demonstration of mechanical integrity in line with the U.S. Environmental Protection Agency (EPA) standards under 40 C.F.R. §146.8(c).

i. "Approved Temporary Abandonment" – Existing 19.15.25.12 NMAC

Under existing 19.15.25.12 NMAC, operators may apply to place a well in "Approved Temporary Abandonment" (Approved TA) status for a period of up to five years, subject to renewal or reclassification (i.e., return to beneficial use or full plugging and restoration) before expiration. Operators are limited to the number of TA wells they may hold: (A) one well if operating five or fewer wells; or (B) up to one-third of their well count (rounded to the nearest whole number) if they operate more than five. 19.15.25.12 NMAC. This limits the potential for large numbers of idle wells accumulating under a single operator.

ii. "Request for Approval and Permit for Approved Temporary Abandonment" – Existing 19.15.25.13 NMAC

To secure ATA status under the existing version of 19.15.25.13 NMAC, an operator must:

- Submit Form C-103 outlining the proposed temporary abandonment procedures;
- Wait for division approval before conducting any work.
- Provide 24-hour advance notice to the OCD district office before starting field operations;
- Demonstrate mechanical integrity for both internal and external components of the well;
- Provide financial assurance in compliance with the inactive and certain TA wells statuses under existing 19.15.8.9(D) NMAC; and

- Comply with the technical standards of 19.15.25.14 NMAC, including pressure testing and logging.

19.15.25.13(A)-(E) NMAC. Once approved, the division sets a specific expiration date (maximum five years from issuance). 19.15.25.13(F) NMAC.

iii. "Demonstrating Mechanical Integrity" – Existing 19.15.25.14 NMAC

Under existing 19.15.25.14 NMAC, internal mechanical integrity must be demonstrated via one of the following options:

- A cast iron bridge plug set within 100 feet of the uppermost perforation or casing shoe, with a 500 pounds per square inch (psi) pressure test for thirty (30) minutes and a maximum allowable pressure drop of 10%;
- A retrievable bridge plug or packer, with the same pressure and time requirements; or
- By showing that the well has been completed for less than five years and remains unconnected to a pipeline.

19.15.25.14(A)(1)-(3) NMAC.

During testing, all casing valves must be opened, any pressure changes or flow must be reported immediately, and the well must be topped off with inert fluid before being left unattended. Pressure tests must be recorded using a chart recorder (two-hour clock, 1,000 psi spring, calibrated within six months). 19.15.25.14(B)(1)-(2) NMAC. Logs and charts must be signed by witnesses and submitted with OCD Form C-103, Sundry Notices and Reports on Well.[6] External mechanical

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[6] *Sundry Notices and Reports on Wells*, New Mexico Oil Conservation Division, New Mexico Energy, Minerals and Natural Resources Department, available at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/C-103-1.pdf.

integrity must be demonstrated using any EPA-approved method under 40 C.F.R. § 146.8(c). 19.15.25.14(C) NMAC (2025). These include:

- Temperature logs;
- Noise logs;
- Radioactive tracer surveys;
- Oxygen activation logs;
- Cementing records (where applicable); and
- Other EPA-approved diagnostics.

Each method must confirm no significant fluid movement behind casing or between strata that could jeopardize underground sources of drinking water. The division requires that no integrity test or log be older than 12 months at the time of application. 19.15.25.14(D) NMAC (2025).

iv. Existing TA Regulations Integrate EPA Standards and Require "Demonstrating Mechanical Integrity" Using EPA-Approved Methods

Under current regulations (19.15.25.14(C) NMAC), operators may demonstrate external mechanical integrity using EPA-approved methods listed under 40 C.F.R. § 146.8(c). This provision allows pressure testing, pressure monitoring, and cementing records to serve as the primary evidence of annular isolation. More advanced diagnostic tools, such as temperature logs, noise logs, or radioactive tracer surveys, are only required if these initial methods indicate a possible integrity issue or if cementing records are inconclusive.

New Mexico's adoption of 40 C.F.R. § 146.8(c) reflects a prudent, risk-based approach to environmental protection. Operators are not required to run expensive logs by default, but rather to escalate testing only when justified by preliminary findings. This approach aligns with the EPA's original intent: staged verification, not mandatory use of advanced tools in every case.

A well that passes pressure testing, has adequate cementing records, and shows no signs of leakage or communication should be considered compliant under both state and federal rules. Requiring further logs in such cases offers minimal environmental benefit and imposes unnecessary cost. Moreover, properly maintained and regularly tested TA wells may pose less risk than actively producing but unmonitored low-rate wells. Penalizing operators for maintaining TA wells in compliance with approved procedures contradicts both the letter and spirit of the regulations. To be consistent with the current application of EPA's 40 C.F.R. § 146.8(c), more advanced diagnostic tools, such as caliper logs and casing integrity logs should only be required if pressure monitoring and/or pressure tests indicate a possible integrity issue with the casing, and even then as a precursor to potential remediation of the problem.

2. Changes Proposed to Approved TA Provision – Proposed 19.15.25.13 NMAC

The amendments to existing 19.15.25.12(A) NMAC proposed by WELC would require operators to justify a well's future use to obtain approval from OCD, and impose excessive and burdensome documentation requests as a part of that process. The proposed amendments to existing 19.15.25.12(B) NMAC would then limit extensions beyond the initial approval period to two years. WELC's amendments would recodify these requirements and more under 19.15.25.13.

These are major changes from the current rules, which technically allow rolling five-year renewals indefinitely. The intent is to force a decision point at five years: either return the well to beneficial use or plug it, unless a regulator finds good cause to allow it to remain idle longer.

v. Comparison to Other Jurisdictions

Texas does not impose a hard cap on shut-in duration but instead requires periodic reporting and compliance with mechanical integrity standards. Similarly, Wyoming allows TA status in five-year increments with extension possibilities, and Colorado's rules allow for extended shut-in if certain conditions are met, including mechanical integrity and field development plans. The key theme across these jurisdictions is maintaining regulatory oversight while still allowing operators the flexibility to manage their wells in accordance with economic and logistical realities. New Mexico's current five-year period is well-aligned with this principle and should be preserved.

vi. Mandatory Reapplication for Expired TA Wells Could Be Interpreted As Requiring Immediate P&A of Hundreds of Wells

The proposed amendments would also require operators of wells in expired TA status to reapply for TA or permanently P&A. The mandatory reapplication for expired TA wells could be interpreted as requiring immediate P&A of hundreds of wells, creating regulatory and operational bottlenecks, especially if all such applications flood OCD at once, a conceivable outcome of the proposed WELC/OCD regulations. This would place enormous pressure on a limited number of service rigs, cementing contractors, and OCD field staff, resulting in delays, rushed abandonment operations, and inefficient sequencing of regional projects. Worse, many of these wells may be sitting in strategic locations awaiting gas takeaway infrastructure, finalizing unitization agreements, or aligning with broader leasehold and pooling strategies. Denial of TA status under these conditions would not just kill future production potential, it could also disrupt carefully negotiated deals, trigger lease expirations, and discourage responsible field planning. Rather than preserving resources or protecting the environment, the result may be rushed, suboptimal plug jobs and forfeited reserves that would otherwise have been safely and economically recovered.

vii. Creating Hard Cutoffs for TA Eligibility is Shortsighted

The proposed amendments create hard cutoffs for TA eligibility based on inactivity as well; after seven cumulative years in TA, the initial 5-year maximum plus a maximum of 2-year extensions) pursuant to WELC's revised proposed amendments. Oil and gas development is not an assembly line of widgets; it's a dynamic process that depends on timing, creativity, and judgment. Experienced operators do not guess, and just because they are waiting does not mean they are speculators. Prudent operators act when economics, reservoir conditions, and technical options converge. AI-driven production optimization, machine learning, horizontal drilling, re-frac technologies, and CO_2 applications are improving every year, increasing the probability that today's idle well becomes tomorrow's profitable project.

viii. Unnecessarily Expands Intervention Rights Beyond Interested Parties By Broadening Categories of Persons Who Can Intervene in Routine TA Extension Request Proceedings

In addition, the proposed amendments to this rule unnecessarily expand intervention rights beyond interested parties by expanding the categories of persons who can intervene in these routine proceedings. While 19.15.4.11(A) NMAC does require standing, WELC's language suggests a broader intervention right, which exposes operators to protests on routine TA extensions; adds delay, expense, and uncertainty; and is inappropriate for a non-contested, non-permit proceeding. The proposed expansion of individuals who can protest these proceedings may inadvertently open the door for those with limited or no knowledge or expertise in the industry to disrupt existing procedural processes. This could lead to protests driven more by emotional and/or ideological positions rather than a comprehensive understanding of the technical, economic, and regulatory factors at play. As a result, it may create immense and unnecessary challenges for oil and gas operators, potentially diverting resources and attention away from more substantive issues. This will expose operators to unnecessary legal risk, and the increased possibility of protests by otherwise uninterested parties will further tax and strain OCD's already limited resources.

ix. Concerns with Requiring a Beneficial Use Demonstration as Condition for Approval or Extension of TA

The proposed amendments would further require a beneficial use demonstration as a condition for approval or extension.

a. Reality of requiring future use demonstration and confidential or proprietary documentation required to prove

Requiring an operator applying for TA status to show a credible plan for future use of the well within a reasonable time would necessarily require submission of technical and economic data, a timeline for reactivation, and even information on required casing repairs or stimulation plans to make the well viable. The absence of such a plan could lead to OCD denying TA and ordering permanent plugging and abandonment. In essence, "temporary" abandonment would need to genuinely be in anticipation of near-future use, not just a way to delay costs. This closes a loophole where wells could sit idle for many years on TA with what outside observers have deemed to be no realistic prospects.

The proposed "future use demonstration" requirement poses significant challenges for operators, especially small and mid-sized independents who rely on innovation and local insight to unlock value in idle wells. The activities required to evaluate re-purpose potential and plan a project include, but are not limited to, establishing well and reservoir conditions, conducting geostatistical analysis and comparisons to analogs, performing an economic analysis, identifying and engaging service companies/vendors, ensuring regulatory compliance, developing a detailed technical plan and procedure before implementation, and gaining partner approval. Requiring operators to submit comprehensive technical and economic plans, including stimulation strategies, innovative repair solutions, cost estimates, and timelines, effectively forces them to disclose proprietary redevelopment concepts, often hard-earned trade secrets that distinguish successful operators in the market.

Making confidential or proprietary information subject to bureaucratic approval not only risks premature disclosure but also assumes that the OCD has the time and resources to accurately evaluate complex technical plans across varied geological and economic contexts and prevent further disclosure. Operators that re-purpose wells typically fall into the "early adopter" or "innovator" category, leveraging creative strategies to unlock value from idle assets. If the regulator doesn't understand or agree with the operator's concept of future use, the well could be denied TA and ordered plugged, even if the idea has strong merit. This kind of subjective gatekeeping could stall or kill creative redevelopment opportunities and entangle well-repurposing in years of bureaucratic limbo. Instead of promoting responsible use of legacy wells, the proposal may choke off exactly the kind of innovation the industry needs.

x. Documentation Requirements are Vague, Excessive, and Will Further Infringe on Confidential and Proprietary Data

In addition, WELC would also impose extensive documentation requirements to obtain TA approval, including geological, geophysical, seismic data, economic forecasts, and detailed casing, waste, lease, reservoir, and safety plans. The generic and lengthy documentation requirements WELC proposes have no clear standard for adequacy, and the documents demanded are so excessive that they will overwhelm operators and OCD alike. Requiring such a broad amount of documentation not specific to TA status will result in procedural delays for obtaining TA approval, increased litigation, and disputes over sufficiency. It will likely result in a chilling effect on reinvestment in older wells or marginal fields because operators will face significant uncertainty over whether their investment and planning timelines will survive the unpredictable and subjective gatekeeping process. The prospect of sinking time and capital into well evaluations, recompletion designs, or leasehold strategies, only to be denied TA renewal due to unclear or arbitrarily applied documentation standards, will discourage the kind of creative risk-taking that has historically allowed smaller independents to breathe new life into older assets.

The rule should establish exactly what documentation is required to prove TA status eligibility and allow OCD to request further documentation as needed, as is the case in numerous other jurisdictions, including Texas, Wyoming, and Colorado, each of which retains flexibility for case-by-case review but does not burden operators with sweeping disclosure obligations at the front end of TA applications. These states recognize the need for clarity, proportionality, and administrative efficiency in regulating idle wells.

Furthermore, many of the document types demanded contain confidential and/or proprietary information that is not uniformly available. In my professional opinion, forced disclosure of otherwise protected information oversteps OCD's regulatory role and creates risks like unintended public release of trade secrets, strategic business plans, reservoir modeling, and offset development timing. While this is true for any sized oil and gas company, for smaller and mid-sized companies, which often rely on differentiated insights and timing to compete, these disclosures could expose their competitive edge, impair negotiations with mineral owners or midstream companies, and even give rival operators an unfair advantage. In the oil patch, information is king for large, mid-sized and small companies alike, and competitors will quickly swoop in to capture prospects or opportunities if they have insight suggesting promising action or imminent development in the area. There is also the risk that, once submitted, sensitive information could be subject to open records requests or become discoverable in litigation, even if never directly cited by OCD in a decision. This goes far beyond what is necessary for the Division to regulate wellbore integrity and environmental protection. Further, I have reviewed Dan Arthur's expert testimony, which strengthens the position against the proposed rules.

xi. Strict Implementation Schedules for All Well Types

If adopted, operators will likely be given an implementation schedule to bring existing inactive wells into compliance with the changes. Notably, proposals included phasing in the new TA limits for wells already inactive: e.g., wells inactive >5 years might not be eligible for any TA renewal under the new rule and would need plugging on a set schedule.

Importantly, the proposals remove considerable flexibility that operators had through TA. For example, currently, a well can sit idle if the operator periodically obtains TA status (even if the well has no imminent or obvious re-purposing planned). Under the new rule, that would be much harder; an operator would have to show future use or face plugging after a maximum time. Additionally, OCD signaled it will more aggressively enforce the timelines, aided by the rule changes that create completely subjective non-compliance thresholds, e.g., the 13-month presumption a well must be temporarily abandoned or properly plugged and abandoned, *see infra,* Part III.C.2.

3. Proposed Changes to the Requirements for Demonstrating Mechanical Integrity When Requesting Approved TA Status – Proposed 19.15.25.15(A)(4)-(5) NMAC

WELC proposes adding two new subsections (4) and (5) under the mechanical integrity testing requirements currently set forth in 19.15.25.14(A)(1)-(3) NMAC, applicable to obtaining and maintaining TA status. As proposed by WELC, the existing and new requirements would be moved to and codified under 19.15.25.15(A)(1)-(5) NMAC.

Based on my field experience, the standard industry practices for demonstrating mechanical integrity are pressure testing of the casing with inert fluid after setting a bridge plug or packer near the top of the producing interval, along with visual inspections, fluid level checks, and casing valve monitoring.

According to 19.15.25.14 NMAC, current through Register Vol. 36, No. 6, March 25, 2025, to achieve ATA Status for a well 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.

These tests, conducted under controlled pressure for a defined time with minimal pressure drop, are reliable, widely accepted across jurisdictions, and already sufficient to establish wellbore integrity. As explained below, the heightened requirements proposed by WELC are excessive and do not provide value sufficient to justify the added obligations.

i. New Requirement that Isolation Device Must Remain in Place for Duration of TA Creates Risk of Conflict with Downhole Safety, Maintenance, and Testing

Specifically, under a new subparagraph (4), WELC would require that any isolation device used to conduct mechanical integrity testing, i.e., the bridge plug or packer, must remain in place for the duration of TA. This may conflict with operational safety or prevent monitoring by restricting access to the interval below the plug, making it impossible to run a temperature log, fluid level tool, or pressure gauge downhole. The isolation device requirement could also hinder re-entry or maintenance during TA by obstructing wireline or coiled tubing operations, making it harder to remediate issues or prepare for recompletion. In deep wells, bridge plugs or packers left in place for years can also degrade or seize, increasing the risk of fishing jobs, stuck tools, or milling operations that raise costs and risks for future re-entry. Moreover, placing metal or elastomeric mechanical devices across old perforations or casing shoes for extended periods can increase stress on casing, especially if there are existing corrosion risks or micro-annuli, creating unintended well integrity hazards. In my professional opinion, there is no operational or safety justification for requiring permanent in-place bridge plugs or packers unless specific issues are detected during testing. Temporary mechanical isolation is sufficient for demonstrating integrity.

While permanent isolation devices set inside casing, such as bridge plugs, are generally robust enough for long-term placement, prudent engineering practice dictates periodic evaluation (and possibly replacement) to assess their continued effectiveness. The rubber elements can degrade, particularly in older wells with continued pressure and temperature exposure. Removing and replacing these types of downhole isolation devices during re-entry for permanent plugging may require milling which poses mechanical risks. For example, in a worst-case scenario, milling might result in accidental sidetracking out of the casing, drastically increasing abandonment costs, or even making complete plugging below the milling point impracticable.

ii. New Caliper and Casing Integrity Log Requirements Disregard Costs and Set No Criteria for What is Passing

Oil and natural gas wells are constructed using long strings of concentric ferrous tubular casings (pipe), with the innermost generally being production tubing. Being ferrous materials these tubulars are susceptible to corrosion. Caliper logs along with casing integrity or casing inspection logs, including ultrasonic and electromagnetic (EM) tools, are sometimes deployed to evaluate tubular corrosion and assess well integrity for intervention planning and mitigation. Corrosion is inferred through measurements of internal diameter and/or wall thickness.

- Mechanical (finger) caliper logs provide profiles of the internal surface of the pipe, but only for the single tubular string into which the tool is deployed. They measure internal diameter but cannot detect wall loss.
- Ultrasonic tools can measure both internal diameter and wall thickness, but in wells with multiple concentric strings, wall thickness measurements are limited to the innermost string.

- Electromagnetic tools, such as flux leakage or eddy current devices, detect magnetic flux anomalies associated with pitting, holes, and corrosion, but again are effective only for the inner string where the tool is positioned.

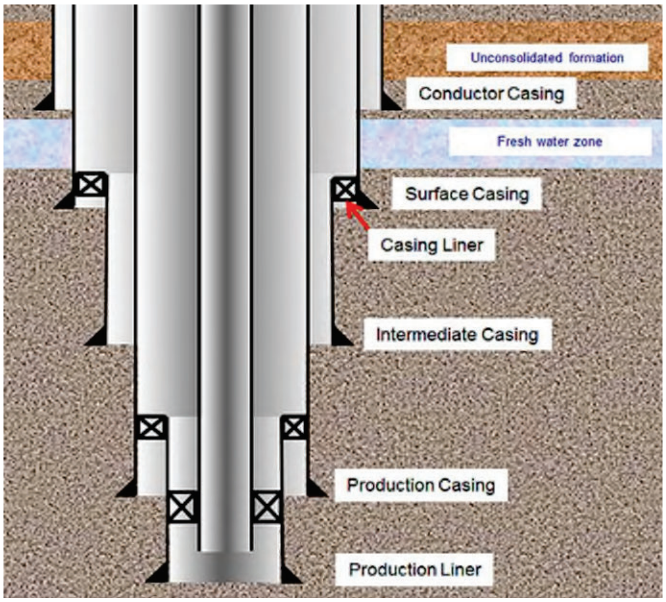

Figure 1 - Wellbore Diagram Showing Concentric Casing

Wells may be constructed with various layers of concentric casing strings, with the number being driven by local conditions, with deep wells in complex, less stable geologic strata requiring numerous concentric casing string as shown in the figure below,[7] or only three strings (only conductor pipe, surface casing and production casing) in shallower wells drilled through less complex, more stable, geologic strata.

None of the casing inspection tools (caliper, ultrasonic, or EM) that are commonly used and are readily available to operators are designed to evaluate outer casing strings in multi-string well

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[7] Basic Understanding of Oil Well Casing and Tubing https://www.drillingformulas.com/basic-understanding-of-oil-well-casing-and-tubing/.

configurations. For example, if production casing is being inspected in a well, it blocks access and signal transmission, making it impossible for the typical caliper, ultrasonic, or EM tools typically available to operators to assess the condition of surface or intermediate casing.

While it is true that commonly used, readily, available, economical casing inspection tools can only provide quantitative corrosion evaluation in the single casing string into which they're run, and accurate inspection of outer strings requires removal of inner tubulars or alternative evaluation methods, there are more sophisticated (and more expensive) tools available. For example, the Schlumberger EM Pipe Scanner™ is claimed to not only provide a quantitative assessment of corrosion damage (metal-loss, wall-thickness) in the single string the tool traverses, it can also provide a qualitative evaluation of multiple concentric casing strings using low-frequency remote-field signals[8]. That is, while innermost strings dominate the response, Schlumberger claims that with their tool outer strings can still be flagged qualitatively for abnormal thinning or anomalies.

While it is true that advanced electromagnetic (EM) tools, such as Schlumberger's EM Pipe Scanner, can provide limited qualitative evaluation of outer casing strings in multi-string configurations, these tools remain the exception rather than the rule in field operations. Their ability to detect anomalies outside the innermost casing string represents a technical advancement over traditional caliper and ultrasonic tools, which are strictly limited to the internal diameter and wall thickness of the string they are deployed in. From a practical point-of-view, this enhanced

[8] T. M. Brill, J.-L. Le Calvez, C. Demichel, E. A. Nichols, and F. Z. Bermúdez, "Electromagnetic casing inspection tool for corrosion evaluation," in Proc. Int. Petroleum Technology Conference (IPTC-14865-MS), Bangkok, Thailand, 7–9 February 2012

capability is most relevant in offshore or high-value onshore wells where running costs and specialized personnel are justifiable.

Importantly, these more sophisticated EM tools come with significant practical limitations that make them unsuitable for widespread use in the temporary abandonment (TA) context. First, they are produced in relatively small numbers and are operated by a limited pool of highly trained wireline specialists who are often unavailable or cost-prohibitive in many U.S. land markets. Second, they are substantially more expensive to deploy than conventional logging tools, both in terms of daily service charges and post-run data interpretation, which often requires proprietary software and expert analysis. Additionally, only a handful of service providers, including Schlumberger and potentially one or two others such as Halliburton and Baker Hughes, offer EM tools capable of even partial multi-string analysis. Even then, the data on outer casing strings is inherently qualitative, not quantitative, and is heavily influenced by factors such as the centralization (or lack thereof) of the inner casing string. In practical field use, these tools can be finicky, and results are sometimes ambiguous or internally inconsistent when pushed beyond routine single-string inspection. From the point of view of prudent engineering practices, such a subjective/qualitative analysis is insufficient for condemning well to permanent P&A versus Approved TA.

Bottom line: while these advanced tools have niche value, they are expensive, scarce, require specialized personnel, and generate results that are subject to interpretation. In my opinion, based on my experience, these type tools are not well-suited for broad implementation across thousands of marginal or inactive wells in New Mexico that are candidates for Approved TA status. A mandate requiring such tools would impose an unreasonable technical and economic burden on operators without demonstrably improving environmental protection.

It is important to keep in mind that from the standpoint of parties active in the P&A of marginal or inactive oil / gas wells, such as environmental regulators, public health agencies, local water utility boards, and community stakeholders, their primary concern is the risk that inadequately TA wellbores could provide conduits for hydrocarbons (oil, gas) or saline formation fluids (brine) to migrate into underground sources of drinking water. Therefore, mandating the use of tools that do not meaningfully reduce the risk of such migration in underground sources of drinking water is counterproductive.

I have not seen any statistical analysis demonstrating that requiring caliper and casing inspection logs inside production casing in wells that are candidates for ATA is likely to significantly reduce the risk of hydrocarbons/brine leaking into freshwater aquifers. This is because the primary barrier protecting these aquifers is the surface casing, which is typically set outside the production casing. As explained above, the production casing is run inside the surface casing, or in some cases, inside the intermediate casing, which is inside the surface casing (two layers of casing). The surface casing is the first and most important line of defense against migration into underground sources of drinking water, and caliper, conventional casing inspection, and even advanced casing inspection logs are inadequate to assess the integrity of the surface casing, when they are (necessarily) run inside of production casing.

In conclusion, it is my opinion that requiring caliper and casing inspection logs for wells seeking ATA status is not technically justified and would impose significant economic and operational burdens without delivering a measurable reduction in environmental risk.

Fundamentally, practically accessible and typically used tools such as multi-finger calipers, ultrasonic, and electromagnetic (EM) casing inspection devices can only evaluate the single casing string into which they are deployed, typically the production casing. These tools are incapable of assessing the integrity of the surface casing, which is the critical barrier protecting underground sources of drinking water (USDW). In most wells, surface casing resides outside the production casing (or intermediate casing) and cannot be directly evaluated without removing inner tubulars. As a result, mandating these tools provides no actionable data on the surface casing, the primary line of defense against migration of hydrocarbons or brine into freshwater aquifers.

Despite this, the proposed rule would require logs that are expensive, logistically challenging, and technically limited. Caliper logs measure only the internal geometry of the production casing and cannot detect external wall loss or assess cement isolation. While more advanced EM tools like Schlumberger's EM Pipe Scanner™ can qualitatively flag possible outer casing anomalies, they are rare, costly, require highly skilled personnel, and would be scarce relative to a sudden increase in demand for their widespread use in thousands of wells in New Mexico. Moreover, interpretation of data on outer strings is qualitative, not quantitative, and highly sensitive to inner-string centralization. In field practice, such data can be ambiguous, inconsistent, or misleading.

By contrast, traditional annular pressure testing, already required and documented using chart recorders, is the most direct, cost-effective and practically applicable method for assessing wellbore integrity, including verifying pressure containment. Pressure tests confirm functional integrity across all concentric strings and are widely accepted by regulators in Texas, Oklahoma, and Wyoming. There is no publicly available statistical evidence indicating that supplementing these pressure tests with caliper or casing logs would meaningfully reduce the risk of fluid migration into aquifers.

Further, the proposed rule fails to establish acceptance criteria for what constitutes a “passing” casing inspection log. Without objective standards, regulatory interpretation is likely to be inconsistent, subject to dispute, and potentially lead to unnecessary delays, litigation, and permit denials based on subjective log interpretation. This introduces delays, excessive costs, uncertainty and risk into a process that is already governed by clear mechanical integrity testing protocols.

Economically, imposing mandatory logging would divert capital from higher-priority well management efforts. Typical logging runs with single-string analysis tools capability are likely to exceed $10,000 in service costs, and when tubing must be pulled to allow tool access, costs can easily exceed $20,000 per well due to rig time, tool rental, personnel, and data analysis. These are significant expenditures for marginal wells, especially when such costs do not yield actionable information about the surface casing, which is the most important line of defense against contamination of USDW. These funds would be better spent on repairing or plugging wells that demonstrably lack integrity due to pressure test results or on repurposing wellbores for alternative beneficial uses.

Operationally, New Mexico operators—particularly small independents, would face major logistical challenges in mobilizing wireline crews, coordinating rig time, and complying with expanded logging requirements. These challenges would exacerbate scheduling delays, increase costs, and overwhelm both operators and OCD staff with unnecessary data from wells that have already passed pressure testing and show no evidence of mechanical issues.

In summary, requiring caliper or casing inspection logs as a blanket condition for Approved TA status is technically unnecessary, economically burdensome, operationally unworkable, and contrary to established regulatory practices in other producing states. These logs should remain optional tools used selectively when pressure tests fail or when mechanical damage is suspected, not as a default requirement.

iii. Proposed Mechanical Integrity Requirements Undermine Operator Flexibility Granted by EPA

It is my understanding that in practice, EPA's mechanical integrity framework under 40 C.F.R. § 146.8 is built around a flexible, risk-based approach that allows operators to demonstrate external mechanical integrity (integrity of the cement job outside the targeted casing) using a range of acceptable methods, including pressure tests, annular pressure monitoring, temperature logs, noise logs, radioactive tracer surveys, and cementing records. This flexibility recognizes the diversity of well types, operational histories, and site-specific risks, particularly for Class II injection wells, where the primary concern is protection of underground sources of drinking water (USDWs).

By contrast, the proposed OCD amendments at 19.15.25.15(4)-(5) NMAC would mandate the use of caliper logs and casing inspection logs (which speak to internal integrity, that is, the integrity of the casing itself) regardless of whether existing pressure monitoring data suggests a problem. This blanket requirement undermines the spirit of the federal rule, which, when applied to ATA status, is to escalate diagnostics only when there is data that indicates a potential isolation failure.

While EPA allows states to adopt more stringent requirements under UIC primacy, such changes should be technically justified and consistent with the flexible, performance-based nature of the federal standard. Mandating specific logs for all wells, without regard to actual risk indicators or problem identification, departs from that framework, creating unnecessary cost and complexity without clear benefit to USDW protection.

In effect, OCD is attempting to replace a performance standard (demonstrate integrity) with a prescriptive method (run specific logs). This not only conflicts with the risk-based logic behind 40 C.F.R. § 146.8, it may also create confusion for operators and regulators alike by requiring tools that were never intended to be used as blanket screening instruments.

iv. Proposed Changes Overlook Critical Differences in Risk Between Well Categories

Based on the aggressive nature of the new rules being proposed, environmental advocates seem to feel that the only safe well is a plugged one, but this overlooks critical differences in risk between well categories. A well actively producing oil or gas maintains tubing in place, carries hydrocarbons to the surface (typically up a tubing string inside of casing), and may undergo intermittent integrity checks, and cannot have casing integrity logs run while producing up tubing. These are conditions that could result in a moderate level of environmental risk. In contrast, orphaned or unapproved idle wells typically lack oversight, mechanical integrity testing, or monitoring, making them higher liabilities.

v. Bottom Line Recommendation

In short, the proposed changes to mechanical integrity testing are unnecessary, costly, impractical, and inconsistent with broader regulatory norms. The current rules already provide OCD with the authority and tools to request further testing when needed, without burdening every operator with excessive and unjustified requirements.

Accordingly, I recommend striking WELC's proposed subparagraphs (4) and (5) of existing 19.15.25.14 entirely. If changes must be made, it is my opinion that a tiered risk-based approach to evaluating mechanical integrity is more appropriate than a one-size-fits-all mandate. For example, using pressure testing alone for wells under 10 years old, requiring one integrity log for wells older than 10 years, and using two logs only for the oldest or highest-risk wells would align better with industry standards, reduce unnecessary cost, and improve compliance.

4. Applying Single Definition for "Approved Temporary Abandonment" to Three Defined Terms – Proposed 19.15.2.7(A)(13) NMAC

WELC proposes to consolidate three distinct terms, "Temporary Abandonment," "Temporary Abandonment Status," and "Approved Temporary Abandonment," under the existing definition of "Approved Temporary Abandonment" meaning: "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(A)(13) NMAC. But "Temporary Abandonment" and "Temporarily Abandoned Status" are currently defined as meaning "the status of a well that is inactive" absent any cross references to other provisions for which compliance is mandated. 19.15.2.7(T)(3) NMAC (2025).

As Mr. Arthur explains in his testimony, making changes and adding definitions can have wide-ranging effects on other parts of the administrative code which rely and reference those terms. Additionally:

i. Lumping Terms Together Ignores Important Distinctions and Results in Myopic Operational and Financial Planning

Based on my field experience and well-economics perspective, applying a single definition to all three terms is problematic. Operational clarity and financial planning suffer when the nuances of initial TA (short-term deferral of permanent P&A) versus renewal or extension TA (multi-year commitments) are ignored and instead collapsed into one generic definition. A beginner-level TA well, just coming off production, differs significantly in cost structure and risk from a well in its fourth year of TA.

Future economic and repurposing potential also diverge. A newly TA'd well might be a candidate for re-completion, CO_2 storage, or geothermal repurposing. A long-dormant TA well may no longer be economically viable. Treating both the same undermines structured decision-making.

Without a clear regulatory distinction between definitions, risk management and oversight will become opaque. For instance, an initial TA may require minimal intervention (plugging the perforations and pressure-testing), while later extensions may trigger stricter scrutiny, bonding hikes, or Commission review. Lumping these under one label removes these graduated guardrails.

ii. Regulatory Caps and Resource Allocation Depend on Clear Definitions

While simplifying terminology may seem administratively tidy, it obscures critical differences in economic context, environmental oversight, regulatory triggers, and future utility, making the proposal unworkable in practice. Regulatory caps and resource allocation depend on clear definitions. Current limits allow operators to place a fixed percentage of wells in TA. Merging all terms risks unintentionally increasing that cap or diluting enforcement thresholds, weakening environmental safeguards.

5. Adding New Single Definition for "Expired Temporary Abandonment" and "Expired Temporary Abandonment Status" – Proposed 19.15.2.7(E)(8) NMAC

Additionally, WELC proposes to add a definition for "Expired Temporary Abandonment" or "Expired Temporary Abandonment Status" under 19.15.2.7(E)(8) NMAC to mean the status of a well that is inactive and has been approved for temporary abandonment status in accordance with 19.15.25.13 NMAC, but that no longer complies with 19.15.25.12 through 19.15.25.14 NMAC.

In my opinion, this definition needs to be clarified or simplified to ensure consistency with other regulations and regulatory objectives. I recommend that the term “expired” be linked to the five-year expiration of TA status approval authorized under existing version of 19.15.25.12 NMAC. Otherwise, tying TA expiration to broad compliance issues could likely cause confusion, unjustified regulatory exposure, and operational uncertainty.

i. Assigning a Single Regulatory Definition to Two (2) Defined Terms is Problematic

This proposal to assign a single regulatory definition to two defined terms, here “Expired Temporary Abandonment” or “Expired Temporary Abandonment Status,” is problematic for the same reasons discussed above regarding the proposal to apply the single definition for “Approved Temporary Abandonment” to “Temporary Abandonment” and “Temporary Abandonment Status,” *see supra*, Part III.B.4. And again, the substantive cross references to other OCD regulations within that proposed single defined term create additional concerns. Here, the proposed definition would effectively assign Expired TA Status to wells not in compliance with existing 19.15.25.12-.14 NMAC.

ii. Tying the Expiration of Well’s TA Status to Broad Compliance Issues Under Multiple Regulations Creates Ambiguity as to When TA Status Has Expired

Sections 19.15.25.12 through 19.15.25.14 NMAC are currently administered by OCD through a relatively clear and well-functioning process. Section 19.15.25.12 defines the eligibility criteria and numerical limits for placing wells in Approved TA status (based on total well count). Section 19.15.25.13 outlines the application process, including mechanical integrity demonstrations and financial assurance. Section 19.15.25.14 defines acceptable methods for demonstrating internal and external mechanical integrity. These sections are enforced through documentation submitted on Form C-103, test charts, and chart recorder data, followed by district engineer review. In practice, OCD staff work with operators to resolve issues, and technical compliance is reviewed during field inspections or file audits, not on a daily or continuous basis.

WELC's proposal to tie the expiration of a well's TA status to broad compliance issues outlined under three separate provisions introduces excessive ambiguity as to when a TA status has expired. Definitions matter; they determine the trigger for enforcement, compliance deadlines, and operator obligations. Vague or overbroad definitions undermine regulatory certainty and increase the risk of inconsistent interpretation by district staff. Definitions should be limited, specific, and tied to material outcomes (e.g., actual expiration dates), not every administrative or technical detail of TA management. Without clarity, operators risk being penalized over transient or easily correctable conditions that do not threaten well integrity or public safety.

iii. TA Approval Process Compliance Should Not and Could Not Determine TA Status Expirations

Some of the referenced regulatory requirements do not relate to ongoing compliance. Specifically, 19.15.25.13 NMAC, which I discuss above, governs the TA approval process and is thus not a logical reference for determining TA expirations.

iv. Proposed Definition Risks Premature or Arbitrary Reclassification of Wells as Expired Due to Technicalities

Most notably, I am concerned that the definition as proposed may prematurely or arbitrarily reclassify a well as "expired" due to technicalities. Since the new definition does not account for excusable short-term non-compliance, the proposal creates the risk that a well could suddenly be considered "expired" even for momentary or minor non-compliance. In my experience as an oil and gas operator, and as someone directly responsible for managing mechanical integrity testing, documentation, and regulatory correspondence, excusable technicalities can include temporary inability to schedule a test due to weather or rig availability, a delayed report filing due to a clerical oversight, or inadvertent expiration of a chart recorder calibration certificate, all of which can be remedied quickly and without impact on the actual well integrity. These issues may arise when service vendors are overbooked, during supply chain delays, or when a well is inaccessible due to leaseholder activity or surface use conflicts.

The operational realities of temporarily abandoned wells include periodic site visits, pressure monitoring, fluid level checks, maintenance of fencing or signage, and surface inspections, activities that are meaningful and demonstrative of continued stewardship. WELC's proposal would classify wells as "expired" even when operators are actively maintaining the well and preparing it for future reactivation, simply because of a missed document or non-substantive technical issue. That is not sound regulatory practice.

C. Proposed Changes to Permanent Plugging and Abandonment (P&A) Requirements and Timelines

The full permanent P&A process is far more intrusive and permanent than obtaining Approved TA Status. Operators must file forms OCD C 103 and OCD C 105, Well Completion or Recompletion Report,[9] deploy rigs to set multiple cement plugs (each at least 100 ft plus depth-based buffers), perform annular squeezes if necessary, remove equipment, restore the surface site within one year, install permanent markers, and pass final OCD inspections before bond release. This multi-step procedure, spanning months to over a year, permanently seals the well but involves

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[9] *Well Completion or Recompletion Report and Log*, New Mexico Oil Conservation Division, New Mexico Energy, Minerals and Natural Resources Department, available at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Form-C-105-2.pdf

heavy operations, higher costs, and greater environmental disruption during execution.

1. Current P&A Timeline and Requirements

It is my understanding that under current OCD rules, an operator must move promptly once a well becomes inactive. The existing version of 19.15.25.8 NMAC requires that within 90 days after certain triggering events, the operator either plugs and abandons the well or secures Approved TA status. The triggers include: (1) 60 days after drilling operations cease (for a drilled well that is not completed), (2) a determination that the well is no longer useful for a "Beneficial Purpose" (e.g. a depleted or uneconomic well with no other viable completion or re-purpose options), or (3) one year of continuous inactivity. 19.15.25.8(B)(1)-(3) NMAC (2025). **In practical terms, after roughly 15 months with no production (12 months idle + 90-day grace period), the well must either be permanently abandoned or formally put in TA status to remain idle legally.**

i. Timeline from P&A Application to Completion

To fully grasp whether the proposed timing is reasonable, and to illustrate that the process of plugging a well is both thorough and difficult to reverse, consider the following summary of the basic process for plugging a well in New Mexico at present which is described below:

a. Application and approval

To plug a well, the operator files a Notice of Intention to Plug (Form C-103) with OCD before beginning work, detailing the proposed procedures and wellbore diagram. OCD must review and approve the plugging plan (often with conditions of approval) before operations commence. OCD typically requires at least a 24-hour notice prior to the start of plugging so that a field inspector can witness key steps. Once approval is granted, the operator generally has up to one year to initiate the plugging work; if plugging has not started within one year of OCD's approval, the previously granted approval expires, and a new application must be submitted. This allows some flexibility in scheduling rigs and crews, though in practice operators usually act sooner when a regulatory deadline looms.

b. Plugging operations and duration

The actual plugging operations for a single well usually span a few days up to about a week, depending on well depth and complexity (number of plugs, any remedial work, etc.). OCD's standard conditions now stipulate that once a rig or plugging unit is rigged up, the well must be fully plugged before the rig leaves, that is, you cannot partially plug and suspend operations for an extended period without OCD approval. If an unforeseen delay causes a break of >30 days in plugging activity, the operator must file a summary of work done and obtain a revised approval to complete the remaining work. The presumed purpose of this condition is to ensure continuous progress once abandonment starts and prevents wells from being left in a halfway abandoned state.

c. Post-plugging cleanup and reclamation

New Mexico's rules give operators up to one year after completing downhole plugging operations to perform site decommissioning (surface cleanup and reclamation). As soon as practical, but no later than one year, the operator must remove all surface equipment and debris, close any pits, grade and level the site, and take any other measures required to restore the location to a safe, clean condition. All open pits or below-grade tanks must be closed in accordance with the pit rule requirements (19.15.17 NMAC). After cleanup, the well's location is inspected by OCD, and only once the agency approves the restoration will the operator be released from the plugging bond.

d. Final reporting

Within 30 days after finishing all required reclamation work, the operator must file OCD forms C-103 and C-105. The well's exact plugged configuration, cement plug depths, and any casing left in place must also be documented on a final well record (Form C-105). OCD will not release the operator's bond or consider the well fully abandoned until all reports are received and the site passes inspection.

In summary, from the time an operator applies for plugging to the final sign-off, the process can span on the order of months to a year: application and approval (days to weeks), plugging operations (days), and surface restoration (often completed within a few months, but allowed up to one year by rule).

ii. Mechanical P&A Procedures for Vertical Wells (Plugs, Cement, Squeezes)

The P&A process in New Mexico involves placing a series of cement plugs to isolate each zone and casing shoe, verifying each plug's integrity, and performing any necessary cement squeezes behind casing to remedy inadequate annular cement. These requirements reflect standard industry practice (and largely mirror federal BLM Onshore Order 2 plugging rules), with specific numeric standards: 100-foot minimum plug lengths, 50 feet of cement above/below zones of interest, and maximum 3,000-foot gaps between plugs in cased hole, including 10% excess length per 1,000' of depth. The goal is a multilayered barrier system that leaves no pathway for fluids to migrate out of a hydrocarbon (or salt water) productive zone up the hole or between formations after the well is abandoned.

New Mexico's plugging regulations require a well to be sealed in a manner that "permanently confines all oil, gas, and water in the separate strata in which they are originally found". In practice, this means setting a series of cement plugs inside the well and sometimes using a cementing pump to squeeze cement through perforations placed in a section of the casing to place cement in the annulus outside the targeted casing, that is, between either the casing and the open hole, or the targeted casing and another string of casing. This work is done to isolate each fluid-bearing zone and protect groundwater. Key mechanical requirements for a typical vertical well P&A include:

a. Isolation of producing zones

A cement plug must be placed across each producing or injection interval. Often a mechanical bridge plug is set near the top of the perforated zone as a foundation, followed by at least 100 feet of cement on top to seal the interval. Regulations call for cement plugs to extend a minimum of 50 feet below and 50 feet above the top and bottom of any open perforated section. This creates a solid barrier spanning the entire zone. If multiple producing zones exist, each must be isolated in similar fashion (or a single plug can cover multiple closely spaced zones, so long as the plug meets the minimum length and coverage requirements).

b. Casing shoes and freshwater protection

Cement plugs are required at all casing shoes, for example, at the base of surface casing and any intermediate casing, to prevent migration behind pipe. A plug should start at least 50' below the shoe depth and extend at least 50' above it. The surface casing shoe plug is crucial to protecting freshwater aquifers: it seals off the open-hole segment below the surface casing where fresh and brackish water formations might be open. Additionally, New Mexico's practices (aligned with BLM guidelines) require that no open hole interval greater than 2,000 feet and no cased interval greater than 3,000 feet be left without a plug. In other words, long spans of the well cannot be left as "open pipe," cement or mechanical plugs must be spaced such that you never have more than

3,000' of cased hole or 2,000' of uncased hole uncemented in the wellbore. This ensures continuous barriers against vertical flow.

c. Minimum plug lengths and cement quality

Each cement plug in the well must be at least 100 feet in length (or more, depending on depth) to ensure a robust seal. New Mexico's updated plugging conditions specify 100' minimum, plus an extra 10% length for every 1,000' of depth (for example, a plug set at 5,000' would be ~150' long). Incidentally, Texas (Railroad Commission, 16 TAC § 3.14) also requires all cement plugs (except the top-surface plug) to be at least 100 feet long, with an additional 10% for every 1,000 feet of depth.

All cement used must be a "neat" (uncontaminated) cement slurry of appropriate class for the depth, with waiting-on-cement times of 4–6 hours to allow it to set before testing or tagging. The OCD has standardized cement blend requirements to align with API standards (e.g. use of Class C, H, etc. for certain depth ranges).

d. Plug verification by tagging or testing

After placement, cement plugs are typically tagged (i.e. physically touched with a work string) to verify their top is at the expected depth and that they have set up properly. Any critical plug isolating freshwater or a productive zone must hold its position and weight when tagged (if it fails or is found lower than planned, remedial work is required). In cases where a cement plug is the sole barrier for a freshwater aquifer or other sensitive interval, OCD specifically requires that plug to be tested by tagging to ensure it is in place. An alternative to tagging is allowed if a pressure test of the sealed casing annulus is successful and the plug is purely an internal casing plug (this scenario arises if cement is placed inside casing and the casing's annular integrity is confirmed, then a pressure test can indicate the seal without tagging).

e. Top-of-cement and squeeze cementing

Proper cement coverage behind casing (top-of-cement) is essential, especially across groundwater zones. If review of records or a new cement bond log finds that any casing string was not cemented across critical intervals (e.g. if cement never reached surface behind the surface casing, or did not cover the usable water zone), the P&A plan must address this by perforating the casing and squeezing cement into the annulus. OCD's 2024 guidelines explicitly require that if cement does not exist behind casing at the recommended formation isolation depths, the operator must perform a cement squeeze: perforations are shot 50 feet below the formation/top to be isolated and a cement retainer is set no more than 50' above the perf cluster, through which cement is pumped to fill the annular space. This technique, often called a section squeeze, ensures that zones like shallow fresh water or oil/gas zones behind pipe are externally sealed off. Squeeze operations must be designed with safe pump pressures (not exceeding the formation fracture gradient or casing burst limits). After a squeeze, typically a cement plug is also placed inside the casing covering that interval for redundancy.

f. Surface plug and wellhead removal

Near the surface, a final cement plug (commonly 50-100 feet in length) is set inside the casing, usually from a point below the ground water or casing cut depth up to the surface. The wellhead and any remaining casing are then cut off (often below ground level, except for a vented cap if required) and a permanent dry-hole marker is installed. New Mexico requires a steel marker pipe at least 4 inches in diameter, set in cement and extending four feet above ground, with the well's identity (operator name, well name/number, and location coordinates) permanently engraved. This marker is a visible sign of the abandoned well and must not be removed or built over without OCD approval. (On cultivated farmland, OCD may allow a flush buried marker plate 3' below grade instead, to avoid interfering with agriculture.)

g. Unique treatment of horizontal wells and laterals in P&A

Notably, the lateral or drain hole section (the part of the wellbore drilled at approximately 90 degrees from the vertical) of a horizontal well is typically not plugged at the toe or along its length. A plug at the heel or kickoff point is only set when necessary to isolate the productive formation from the vertical portion of the well or to address squeeze perforations. Regulations primarily require isolation of fluid-bearing zones, casing shoes, and protection of freshwater, rather than sealing lateral sections within the productive formation. If the lateral is fully cased and cemented and remains within a single productive interval, it is permissible under both New Mexico and Texas regulations for the lateral to remain uncemented internally, filled with kill fluid, and isolated by up-hole plugs. This method aligns with industry standards and meets requirements to confine fluids to their original strata.

2. Changes to P&A Process and Requirements Under Consideration – Proposed 19.15.25.8 NMAC

Under proposed 19.15.25.8 NMAC, operators would have only thirty (30) days after a triggering event, as amended, to apply for TA or to permanently P&A. The proposed amendments would also tighten the requirements of 19.15.25.8 NMAC regarding how long a well can remain inactive before it must be abandoned. **This would mean that after 13 months with no production (12 months idle + 30-day grace period), a well must either be permanently abandoned or**

formally put in TA status to remain legally idle. This is mirrored in WELC's related amendment to existing 19.15.8.9D(3) NMAC which would create a rebuttable presumption a well is out of compliance with 19.15.25.8 NMAC after 13 months of inactivity, which WELC would reduce from the 15-month period current in place.

Under current law, a well that's been inactive for 1 year can avoid plugging by going into ATA status, and such ATA status can be renewed repeatedly (in five-year increments under current rules). 19.15.25.12 NMAC. As discussed above, the proposed amendments to the existing version of 19.15.25.12 NMAC on ATA would give operators: 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, and after that a mandated decision point (Commission review or plugging). *See supra*, Part III.B.2.

Ostensibly, these proposed changes are presented as a method to prevent wells from languishing indefinitely under minimal production or serial TA extensions and to ensure that abandonment is carried out in a timely manner when a well has no viable future. But the reasoning behind these proposed changes is flawed: there is no demonstrated correlation between accelerating P&A and improved environmental outcomes. On the contrary, the push to prematurely plug wells ignores the substantial potential of properly maintained temporarily abandoned wells, many of which can be reactivated, recompleted, or repurposed for environmental benefit. It also ignores scenarios where premature plugging and abandoning in a piece-meal fashion can result in multiple, potentially broader surface environmental impacts. New Mexico's own 2025 Well Repurposing Act explicitly recognizes 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. Forcing premature P&A undercuts the very infrastructure this bipartisan legislation was designed to leverage such as wasting sunk capital, reducing long-term resource recovery, and eliminating future public benefits from well reuse.

i. Under the Existing Version of the "Wells to Be Properly Abandoned" Regulation, There is a 90-Day Compliance Window and Three (3) Triggering Events

The current version of 19.15.25.8(B) NMAC requires operators to either P&A the well or place it in approved TA status, *see supra,* Part III.B., within ninety (90) days of one of three events:

- Within one year of continuous inactivity;
- An OCD determination that the well is no longer usable for beneficial purposes; or
- Sixty (60) days after drilling operations are suspended.

19.15.25.8(B)(1)-(3) NMAC.

ii. Proposal to Reduce 90-Day Compliance Window to Only 30 Days to P&A or Apply to TA a Well After Triggering Event

The newly proposed revision would reduce the compliance window from 90 days to just 30 days. This change demonstrates a fundamental misunderstanding of the operational, logistical, and contractual realities of the upstream oil and gas business. Thirty days is not a reasonable timeframe in which to plan, schedule, and safely execute a P&A operation or obtain approved TA status. In most producing basins, the availability of qualified workover rigs, competent supervisors, and certified cementing crews is limited, particularly for plugging operations, which are often less prioritized compared to revenue-generating well workovers. Workover rigs suitable for P&A operations are typically truck-mounted units with limited range and speed, not designed for long-distance relocation. Scheduling them involves coordinating multiple vendors, managing weather delays, accessing lease roads, and aligning personnel, tasks that cannot be completed on short notice.

Prudent operators don't do business with just anyone and they codify terms and conditions (including insurance issues) in a Master Service Agreement ("MSA") between the operator and the service company. If MSAs are not already in place with approved vendors with availability and capacity beyond normally scheduled activities, the operator must first negotiate terms, ensure regulatory compliance, and verify adequate insurance coverage, steps that alone can exceed 30 days. Further, critical supplies such as specific cement blends, bridge plugs, downhole tools, and work strings may be backordered or regionally unavailable. These constraints are not hypothetical; they are day-to-day challenges encountered in any mature oilfield.

a. Compressed time frame could result in reduced safety and increased risk of personal, property and environmental injury

As an engineer and manager with decades of experience in field operations, well abandonment planning and personal injury/safety incidents, it is my opinion that the proposed compressed time-frame could result in reduced safety/increase injuries and possibly increased risk to the environment. Although based on my personal experience, industry standards reinforce my position.

API RP 1176,[10] Recommended Practice for Risk-Based Well Integrity Management in Offshore Oil and Gas Operations, emphasizes:

> *"The decision to permanently abandon a well should consider the technical, operational, and economic feasibility of the available options.* ***Scheduling should be prioritized based on risk, not on rigid timeframes****."*

[10] American Petroleum Institute. API Recommended Practice 1176: Risk-Based Well Integrity Management for Offshore Wells. 1st ed. Washington, DC: API; 2016.

API RP 1176, §7.4.3 Planning and Scheduling, 2016

Further guidance states:

> *"Operators should maintain an inventory of wells and* ***prioritize actions based on a structured risk assessment*** *that considers well condition, location, environmental sensitivity, and resource availability."*

API RP 1176, §6.2 Well Prioritization and Monitoring

This reference supports my point that P&A work should be prioritized based on actual well risk and logistical capability, not forced into a fixed 30-day timeframe that disregards scheduling and vendor constraints.

ISO 16530-1:2017,[11] Petroleum and natural gas industries, Well integrity, Part 1: Life cycle governance, sets out internationally recognized practices:

> *"The operator shall implement a risk-based approach to define the frequency and extent of well integrity assessments, including the timing of decommissioning activities."*

ISO 16530-1, §9.3.2

Additionally, this standard emphasizes:

> *"The decommissioning phase shall be planned and executed considering available resources, contractor availability, well condition, and environmental risk. Timeframes should be adaptable to those constraints to ensure safe and effective operations."*

ISO 16530-1, §9.5 Decommissioning Planning

ISO 16530-1 recognizes that resource availability (rigs, people, tools, etc.) is a legitimate planning constraint, and that safety and environmental protection are better served by deliberate, well-

[11] International Organization for Standardization. ISO 16530-1:2017: Petroleum and Natural Gas Industries – Well Integrity – Part 1: Life Cycle Governance. Geneva, Switzerland: ISO; 2017.

executed plugging operations, not reactive, rushed work.

Many companies maintain P&A queues that exceed nine months, even under normal planning cycles. More likely than not, forcing operators to reshuffle these queues to comply with a 30-day deadline could:

- Divert critical resources from higher-risk wells already scheduled for plugging;
- Compromise job planning and execution standards, increasing the risk of well control incidents, cement failures, or surface spills;
- Overwhelm the OCD with a sudden influx of emergency TA applications that exceed the agency's administrative capacity to review and approve, potentially leading to premature plugging of wells that could otherwise be economically repurposed or recompleted in the near future.

Therefore, first, this proposed change undercuts the flexibility operators need to manage their well portfolios safely, economically, and responsibly. Rather than improving environmental outcomes, it may incentivize hurried, under-planned operations and discourage the use of regulated temporary abandonment status as a prudent asset management strategy. A more realistic and effective alternative would be to maintain the current 90-day window and focus regulatory oversight on ensuring that idle wells are being actively monitored and responsibly managed under existing rules.

b. Would mean simply not producing for 13 months puts a well out of compliance unless a TA application is filed or P&A started

As proposed, 19.15.25.8 NMAC would explicitly state that an operator must "either properly plug and abandon a well or apply to the division to place the well in approved temporary abandonment" within 30 days of the trigger. This would mean that simply not producing for 13 months (12 months plus proposed 30-day compliance window) puts a well out of compliance *unless* affirmative action (plug or TA application) is taken.

c. Would create a presumption that any well inactive for more than 13 months is out of compliance

Furthermore, a new provision would create a "rebuttable presumption" that any well inactive for more than 13 months is out of compliance with the rule. That shifts the burden to operators to prove compliance if they exceed the timeframe. In practice, OCD has indicated it will generate an "inactive well list" posted online that flags wells past 15 months idle. Operators with too many such wells could face enforcement under separate compliance rules. In fact, a parallel proposed rule would deem an operator out of compliance and subject to penalties if they have more than a certain number of wells beyond the 15-month limit without TA or plugging, scaled by company size.

This "rebuttable presumption" approach is problematic because it effectively treats wells, and their operators, as out of compliance by default, without requiring the OCD to conduct any meaningful/in-depth technical analysis, or any guarantee that the OCD will have the resources needed to perform such meaningful/in-depth technical analysis. It essentially assumes guilt unless the operator can prove innocence, placing the burden entirely on mostly small operators to justify the continued existence of a well that may, in fact, have significant strategic value. Many wells are temporarily shut in for legitimate reasons: awaiting infrastructure buildout, price recovery, offset drilling, or evolving technologies like recompletion or carbon injection. These are field-level decisions made based on complex technical and economic analysis, not conducive to arbitrary time limits. Yet the proposed rule bypasses that real-world complexity entirely, imposing a rigid calendar-based trigger and requiring operators to rebut the presumption with no assurance that OCD staff will fully grasp the broader reservoir context, statistical trends, or redevelopment strategy. The result is a rule that prioritizes bureaucratic enforcement over sound resource management and risks penalizing responsible operators who are managing their fields with a long-term, technically informed view.

Similarly, WELC's related amendment to existing 19.15.8.9D(3) would create a rebuttable presumption a well is out of compliance with 19.15.25.8 NMAC after 13 months of inactivity, which WELC would reduce from the 15-month period current in place.

iii. WELC Would Strike "Continuously" from the 1-Year Inactivity Triggering Event

WELC proposes striking the word "continuously" from the one-year inactivity triggering event that requires a well must be plugged or placed into TA.

a. Discourages responsible stewardship of marginally producing but still viable and potentially profitable wells

Eliminating the "continuously" qualifier creates compliance obligations that are disproportionate to actual environmental or mechanical risk, introduces legal ambiguity, and imposes timelines for abandonment that do not reflect how field operations work. Rather than facilitating responsible resource management, the proposal would penalize prudent practices aimed at responsible compliance, deter reinvestment in marginally producing wells, and increase the likelihood of unnecessary well destruction, undermining both economic recovery of oil and gas and environmental reuse potential.

This discourages responsible stewardship of marginally producing but still viable and potentially profitable wells. It creates the risk that one or more wells awaiting repairs, awaiting workover equipment, or shut-in due to pipeline constraints or commercial issues would automatically fall under P&A or TA mandates by arbitrary timing rather than engineering judgment. Such a change would fundamentally undermine operator flexibility in managing wells and increase the likelihood of premature P&A, contrary to broader resource conservation goals.

b. Could inadvertently trigger abandonment requirements based on seasonal curtailment, periods of maintenance, or shut-in strategy alone

Without the "continuously" limitation, wells that are shut-in intermittently, for maintenance, seasonal curtailment, or shut-in due to economic conditions or as part of a broader shut-in strategy, could inadvertently trigger P&A or TA obligations once they cross the cumulative threshold, even if they were never intended to be permanently idle.

Based on my experience, this change is not only unnecessary but also impractical and counterproductive. Maintaining and/or repairing oil and gas wells is not a matter of simply turning a few valves at the surface. Equipment fails, often on multiple wells at once, and repairs cannot be executed on demand. Workover rigs, qualified personnel, and necessary equipment are frequently in limited supply and must be scheduled in advance. Diagnosing a problem is akin to diagnosing a patient, except the symptoms lie thousands of feet underground and must be inferred from indirect data. Engineers must test multiple hypotheses to isolate the root cause, then design a technical solution, develop a workover plan, coordinate with vendors, and compile cost estimates. That effort requires cross-functional input, bidding or contracting through service agreements, and may involve insurance and safety verifications.

Additional delays often stem from access issues such as poor road conditions, surface damage, or the need for landowner negotiations. If non-operated partners are involved, the process includes circulating an Authorization for Expenditure (AFE), allowing up to 30 days for partner elections, and possibly an additional round of approvals if any party opts out. Even with the best intentions, reactivating or repairing a well is inherently uncertain, frequently interrupted, and always subject to regulatory, commercial, logistical, and technical constraints.

3. P&A Triggers in Other Jurisdictions and Legislative Idle Wells Efforts

Plugging and abandonment requirements vary by jurisdiction, but there is a common theme: regulators want to prevent wells from sitting idle indefinitely. Different states and countries use different time triggers and criteria to decide when a well must be abandoned:

i. Texas

Texas has a one-year inactivity rule similar to New Mexico's, but with a comprehensive extension program. Under Railroad Commission (RRC) Statewide Rule 14, an operator must initiate plugging of a well within 1 year of it becoming inactive unless they obtain an approved extension. Texas operators can keep wells idle by qualifying for extensions under Statewide Rule 15, which imposes escalating requirements as inactivity lengthens. For instance, after a well has been shut-in for more than 1 year, the operator can avoid immediate plugging by doing things like disconnecting power, maintaining a fluid level or pressure test, and paying additional fees. For wells inactive 5 to <10 years, Texas requires measures such as purging fluids from tanks and lines, and maybe an integrity test. Once a well hits 10 years inactive, Texas effectively requires plugging unless the operator performs a costly fluid level or casing pressure test annually and posts a supplemental bond. Even then, extensions beyond 10 years are harder to get. In short, Texas uses a combination of fees, testing, and partial equipment removal to allow up to a maximum of ~10 years shut-in, after which most wells are plugged by rule. Notably, Texas focuses on continuous inactivity as well; an operator can "reset" the clock by briefly returning a well to production, a loophole often used to keep marginal wells on the books. (The RRC has addressed this somewhat by requiring a minimum production to count as active, but the threshold is low.)

ii. Colorado

Colorado overhauled its rules in 2021–2022 (mandated by SB-181), focusing on financial assurance and risk mitigation rather than a strict time limit for inactivity. Colorado's Oil and Gas Conservation Commission (COGCC) rules now require mechanical integrity tests on shut-in wells every 5 years to ensure they are not leaking. If a well fails a test or is determined to have no future use, the Commission can order it plugged. Colorado doesn't have a blanket "X years and you must plug" rule; instead, they created an Idle Well Plan system and greatly increased bonding per well. However, Colorado's approach indirectly pressures operators to plug low-producing "zombie" wells. For example, operators must pay an annual fee for each inactive well to fund an orphan well fund. Also, Colorado can deny continued inactive status if an operator cannot demonstrate a viable future use (similar to NM's proposed approach). One external reference notes that Nebraska sets a hard limit of 5 years idle before a well must be plugged (with any extensions requiring special approval). Many other oil-producing states have comparable 5-year or 2-year limits, but often with waiver processes.

iii. Other U.S. States

Many states use a framework of "after 1 year idle, do X; after 5 years, do Y." For example:

- Wyoming and North Dakota, generally, allow 1 year idle unless in approved TA status; TA usually limited to 5 years without higher review.

- California has an idle well management plan system; idle wells must be tested or plugged on a schedule, and after 15 years idle, California requires plugging or a rigorous risk analysis.
- Ohio requires operators to apply for Temporary Inactive status for wells idle >12 months (similar to NM). Under Ohio law (ORC 1509.062), an initial Temporary Inactive status can last 2 years, with possible renewals, but the operator must submit a plan for ultimate disposition. Ohio has been debating stricter limits as well.
- Oklahoma and Louisiana require a well to be plugged or temporarily abandoned after 1 year of inactivity, but allow extensions with mechanical integrity tests and additional bonding.
- Nebraska (as noted) has one of the stricter policies: 5 years max idle without plugging.
- Kansas and Illinois have laws where if a well hasn't produced for 2 years, it's deemed abandoned unless the operator files a yearly intent to maintain it.

iv. Alberta, Canada

Alberta's system doesn't set a firm year limit for abandonment, but it mandates that after 12 months of inactivity, a well must be either suspended to a defined safe standard or abandoned. Under Alberta Energy Regulator Directive 013, an "inactive" well must be properly suspended (which often involves setting bridge plugs and pressure testing, effectively a temporary abandonment) according to its risk category (e.g., high-pressure wells have to be suspended sooner). Alberta recently introduced an Inventory Reduction program that forces companies to close a certain percentage of their inactive wells each year. While not a single trigger date, this effectively ensures that very old idle wells (e.g., 10+ years) get addressed. Alberta also uses a

Licensee Management Program (Directive 088), which can compel a company to abandon wells if their overall liability profile is too high.

4. Risks and Potential Impacts of Proposed Changes

i. Assumes Bad Faith and Disregards Legitimate Reasons for Idling and Inactivity

This push to penalize intermittent production by replacing "continuous inactivity" with some form of "total cumulative shut-in time" is deeply flawed in both fairness and practicality. It assumes bad faith where none may exist and risks punishing thoughtful, adaptive field management. In reality, production in marginal fields is often sporadic for legitimate reasons, such as pricing fluctuations, compressor outages, pipeline constraints, workover scheduling, or offset development delays. Producing a well for a few days may not be a trick; it may be a prudent test of viability or infrastructure readiness. Painting all intermittent production as a loophole ignores the technical and economic nuance behind field operations.

ii. Unmanageable Data Burden

More importantly, cumulative shut-in tracking would impose a massive data burden on both operators and regulators. Tracking the on/off status of thousands of wells across years and parsing intent behind each interval would be a bureaucratic nightmare. That's likely why no major oil-producing state has adopted it successfully.

iii. Existing Rules Already Ensure Wells Only Remain Idle If Operator Proves Well Is Sound, Bonded, and Monitored

Instead, most jurisdictions, including New Mexico, have chosen a more effective approach: requiring that idle wells be placed in Approved TA status or plugged, but only after proper mechanical integrity testing and financial assurance are in place.

New Mexico's existing TA program already addresses the underlying concern: wells can only remain idle legally if the operator proves the well is sound, bonded, and monitored. Creating a rebuttable presumption of non-compliance simply because a well hasn't produced continuously ignores this regulatory safeguard. And layering in subjective "beneficial use" reviews risks unfairly targeting wells that are being responsibly preserved for future redevelopment. In short, the obsession with eliminating every possible workaround is leading toward regulatory overreach, one that penalizes responsible operators, stifles innovation, and creates more red tape without delivering better environmental protection.

iv. Real-World Factors That Conflict with or Complicate Proposed Timeline and Requirements

In the oil and gas industry, the beauty of a new project idea is truly in the eye of the beholder. What one operator sees as a liability, another sees as an opportunity, based on a different technical insight, business model, or risk tolerance. This diversity of vision is a defining feature of the industry and a key reason it has been able to continuously reinvent itself over decades. It's why so many small and mid-sized operators have thrived: they see potential where others don't. They take overlooked wells and transform them into productive assets through innovation, unconventional thinking, and hands-on experience. Imposing rigid rules or forcing public justification for holding TA wells risks flattening this creative landscape and replacing entrepreneurial judgment with bureaucratic skepticism. The result would be fewer success stories, fewer innovative recoveries, and more missed opportunities in the name of regulatory simplicity.

One concern when tightening P&A timelines is how they align with practical field logistics and safety considerations. In practice, plugging a well involves more than just regulatory deadlines; operators must also manage equipment, crews, surface access, and safety. Below are some real-world factors that sometimes conflict with or complicate the strict timelines:

a. Regulatory approvals and scheduling delays

Even though rules say "90 days to act" after a well goes idle, obtaining OCD approvals and scheduling a plugging crew can itself consume much of that time. The OCD has a finite staff reviewing Notices of Intent to Plug, and a surge in required P&A filings (as will happen if many wells hit the 15-month limit together) could bottleneck approvals. In recognition of this, OCD has developed a priority review system where operators can request expedited permit reviews for a limited number of critical projects. As of mid-2025, OCD had to limit priority requests to 10 per operator per month because the volume was increasing beyond what staff could handle. This demonstrates that even regulators acknowledge that not every plugging can happen immediately; there must be triage and scheduling. If an operator has dozens of inactive wells all coming due, they will need to stagger plugging jobs, and OCD in practice may work out compliance agreements (giving a schedule to plug over a longer period) rather than enforcing all to be done at once. The new rules explicitly allow OCD to enter into compliance orders with schedules, and they set thresholds so that having a handful of slightly-overdue wells does not instantly trigger penalties.

b. Crew and rig availability

The physical act of plugging requires a workover rig or plugging unit, experienced personnel, and cementing equipment. There is a limited supply of these resources, especially in busy oilfield regions. If many wells require plugging simultaneously (for instance, due to a regulatory push or an operator facing a blanket deadline), contractor availability can be a serious constraint. Mobilizing a rig can take time; operators usually have to book slots with plugging companies weeks or months out. Real-world logistics, such as other higher-priority operations (e.g., emergency well control jobs or high-value well workovers), can also delay when a rig can get to a low-producing well that needs P&A. The regulations do allow some flexibility; OCD can extend deadlines "for good cause" in certain cases (for example, if weather or rig strikes prevent timely action). The draft rule changes do not explicitly account for industry-wide logistics, but in enforcement, OCD is likely to consider whether an operator made good-faith efforts to schedule the work.

c. Safety and well condition

Some inactive wells may pose potential safety hazards that require careful planning before plugging. For instance, if a well has high pressure or H_2S gas, rushing to plug it within a short timeframe might be dangerous without proper equipment and personnel prep. Wellbore integrity issues (collapsed casing, stuck valves) can also extend plugging time significantly. The rules allow operators to request variances or extensions in such cases, but these have to be negotiated. Safety always takes priority in field operations; crews will not proceed with plugging steps (like cutting pipe or pulling tubulars) if conditions are unsafe, even if a regulatory clock is ticking. The new OCD conditions of approval explicitly require the use of appropriate blowout preventers during plugging if any over-pressure zones or H_2S could be present. In practice, if addressing such hazards means the 90-day limit is exceeded, OCD can and does accommodate via compliance agreements, as the alternative (rushed work) would risk spills or injuries.

d. Surface access and landowner coordination

Before plugging, operators must often coordinate with landowners or other agencies (state/federal land managers). Gaining surface access to bring in equipment can be delayed by issues like seasonal road restrictions (county roads becoming impassable mud in spring), agricultural activities (waiting until after crops are harvested to avoid damage), ranching operations (avoiding cattle during calving season, etc.), or environmental and species specific limitations. Road repairs might be needed if a location has been idle for years and roads have eroded. These logistical steps can push a project past the ideal timeline. Regulators generally consider such factors "good cause" for extension if communicated. Additionally, on federal lands or Indian lands in New Mexico, the BLM or tribal authority must approve the plugging program as well, and navigating that additional approval can introduce delay beyond OCD's process.

e. Concurrent workload, resource constraints

New Mexico (like many states) is dealing with hundreds of aging wells requiring plugging (including orphan wells). There's a finite workforce to address them. The new rules will require operators to plug wells more promptly, but if many operators all comply at once, there could be a strain on cement supply, disposal capacity for fluids, and experienced personnel. For example, each well P&A generates waste (old fluids, cut up scrap metal, etc.) that must go to licensed disposal facilities. If dozens of wells are being abandoned in a short span, local disposal sites can get backlogged. The OCD's own orphan well plugging program (funded by federal IIJA money) is ramping up at the same time, which means the state is hiring many of the same contractors to plug orphaned wells. This can inadvertently make it harder for the industry to schedule those contractors. In the real world, meeting a timeline often involves prioritizing which wells to tackle first, typically those posing the greatest environmental risk or those easiest to plug to quickly reduce counts. Under the current rules, OCD's enforcement can be expected to account for these practical realities and prioritize compliance on wells that are longest-idle or pose risks (e.g., on a "priority list").

The new stricter timelines (e.g., plugging after 15 months idle or within 5 years of TA) are much more aggressive and are probably not achievable for single wells or very small groups of wells. However, when scaled to dozens of wells, constraints like rig availability, weather, land access, and regulatory processing speed become significant. The rules themselves don't explicitly list these logistical considerations (beyond allowing extensions for good cause), but these factors will play a role in how the rules are implemented. For example, if an operator shows they scheduled a reputable plugging contractor at the earliest available date, OCD is likely to exercise some discretion if that date is slightly beyond the deadline. Likewise, if a well cannot be plugged in time due to a genuine safety issue (say some required equipment is back-ordered), regulators should prefer a slight delay over a botched job. Safety must always be prioritized over speed in field operations.

D. Proposed Financial Assurance (FA) Requirements for Securing Permanent Plugging and Abandonment (P&A) of Wells and Surface Reclamation

WELC also proposes numerous changes to the financial assurance requirements pursuant to which operators provide financial assurance to secure plugging and abandonment and surface reclamation.

1. Amendments to FA Requirements for Active Wells – Proposed 19.15.8.9(C) NMAC

Under the amendments proposed by WELC to the existing version of 19.15.8.9(C)(1) NMAC, operators would be required to provide individual financial assurance of $150,000 per well, whether through a bond, letter of credit, or insurance policy[12] for each active well (i.e., wells not subject to OCD's inactive well financial assurance requirements under existing 19.15.8.9(D) NMAC) in New Mexico not subject to federal financial assurance requirements. The amendments would remove the existing risk-based approach for securing individual active wells, with assurance requirements starting at a floor of $25,000 and increasing incrementally based on well depth: "a one well financial assurance in the amount of $25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells[.]" 19.15.8.9(C)(1) NMAC.

Alternatively, operators can obtain a blanket bond of $250,000 to cover all active wells under the current version of 19.15.8.9(C)(2) NMAC. WELC also proposes to remove the existing tiered approach for blanket bonds for active wells which currently only requires a blanket bond totaling: (a) $50,000 for one (1) to ten (10) active wells; (b)$75,000 for eleven (11) to twenty five (25) active wells; (c) $125,000 for 51 to 100 wells; and (d) $250,000 for more than 100 wells. 19.15.8.9(C)(2) NMAC. WELC's proposal would require a blanket bond of $250,000 for any number of active wells, the level of bonding currently required for 100 or more wells. WELC originally proposed an additional option of a $200,000 blanket bond for operators with five (5) or fewer active wells in its proposed amendment to 19.15.8.9(C)(2) NMAC.

2. Amendments to FA Requirements for Inactive Wells and Wells in Pending, Approved, and Expired TA Status – Proposed 19.15.8.9(E) NMAC

[12] Bonds, letters of credit, and insurance policies are hereinafter collectively referred to as financial assurance or bonds.

Currently, inactive wells and wells that have been in temporarily abandoned status for more than two years or for which the operator is seeking TA status are subject to financial assurance requirements under existing 19.15.8.9(D) NMAC. WELC proposes to expand this provision to cover all wells in pending, approved, or expired TA status. WELC would move these requirements to 19.15.8.9(E) NMAC and add new marginal well requirements to 19.15.8.9(D) NMAC, as discussed below.

Under WELC's proposed new 19.15.8.9(E)(1) NMAC, operators would also be required to provide individual financial assurance of $150,000 per well, for each inactive well or wells with pending, approved, or expired TA status in New Mexico not subject to federal bonding requirements. Again, removing the existing risk-based approach for securing individual inactive and expired or pending TA wells, also with assurance requirements starting at a floor of $25,000 and increasing incrementally based on well depth: "a one well financial assurance in the amount of $25,000 plus $2 per foot of the projected depth of a proposed well or the depth of an existing well; the depth of a well is the true vertical depth for vertical and horizontal wells and the measured depth for deviated and directional wells[.]" 19.15.8.9(D)(1) NMAC.

In contrast to its proposal for active wells, WELC's proposed blanket financial assurance requirements for inactive and temporarily abandoned wells under new 19.15.8.9(E)(2) NMAC would eliminate a flat-rate blanket bond option. Instead, WELC would require that any blanket bond provide, on average, $150,000 in coverage per well included under the bond.

i. Certain TA'd Wells Can Be Safer Than Many Active Producers

From a risk management standpoint, a properly TA'd well**,** with tubing removed, bridge plug and cement, pressure-tested to 500 psi, inert fluid-filled, bonded, and routinely renewed, can be safer than many active producers. It eliminates hydrocarbon transport, mitigates internal corrosion, establishes verified mechanical isolation, and ensures regulatory oversight. Meanwhile, permanent P&A wells, once completed, carry minimal long-term risk, but the path to reach that state comes with short-term operational uncertainties. Lumping TA wells and unapproved idle or orphaned wells with P&A under a single definition misunderstands the nuanced risk hierarchy and undermines both regulatory precision and environmental protection.

3. New FA Requirements for Marginal Wells – Proposed 19.15.8.9(D) NMAC

The proposals include multiple other instances where single well assurance of $150,000 is required. WELC proposes that additional individual well financial assurance requirements be added to 19.15.8.9 NMAC. Some of the jointly proposed changes are summarized below:

- $150,000 single well bond for each well, regardless of status, if the amount of marginal and inactive wells, or a combination thereof, registered to the operator makes up at least 15% or more of their total New Mexico wells;
- $150,000 single well bond for every marginal well involved in an operator transfer, to be posted by a transferee operator, required immediately upon effectiveness of the proposed regulations; and
- $150,000 single well bond for every marginal well, required effective January 1, 2028.

4. Single Well FA Requirement for Incomplete Blanket FA – Proposed 19.15.8.9(F) NMAC

WELC also proposes adding a requirement under 19.15.8.9(F) NMAC that a $150,000 single well bond be obtained for each well not properly covered by proposed blanket financial assurance requirements.

5. Automatic Annual Inflation Adjustments to FA Requirements – Proposed 19.15.8.9(G) NMAC

Under 19.15.8.9(G) NMAC, WELC proposes that OCD adjust the required financial assurance amounts based on a Consumer Price Index (CPI) inflation factor. In my opinion, an automatic CPI-based inflation adjustment is not advisable, for several reasons:

i. Correlation to P&A Cost Inflation

WELC does not demonstrate that using a broad Consumer Price Index (CPI) derived from the overall economy accurately reflects changes in plugging and abandonment (P&A) costs in the oilfield. In practice, P&A expenses may diverge from general consumer inflation due to various factors, including fluctuations in oil and gas prices. During periods of low product prices, operators often reduce overall spending, which can lead to decreased service company costs. Oilfield service costs for items such as rig rates, cement, and labor can fluctuate independently of the CPI. As a result, using a generic CPI escalator may not correspond to actual changes in plugging costs. There is currently no conclusive evidence that economy-wide consumer inflation has a direct relationship with well P&A cost trends. Hence, linking bond amounts to CPI appears to be arbitrary without further substantiation.

ii. Risk of Outpacing Bonding Capacity in a Hardening Surety Market

Imposing mandatory annual CPI-based escalations, combined with across-the-board financial assurance increases on all New Mexico operators, risks overwhelming the capacity of what can be expected to be an already tightening surety market. This approach could extend the duration and severity of bond market strain, particularly as sureties reassess risk exposure in a regulatory environment that is rapidly becoming more burdensome and unpredictable.

As discussed above, the new rules themselves (with high base amounts) are likely to harden the surety market, many surety providers may reassess their exposure and require more collateral or higher premiums. Layering on automatic annual increases compounds this risk. In my experience, the surety industry does not typically issue oil and gas operators “ever-increasing” bond instruments; each uptick would likely require riders or new bonds, subject to fresh underwriting. There is a genuine concern that the private surety market might not even offer CPI-indexed bonds, particularly as an operator’s cumulative bonded liability grows over time. Although from a much higher risk market (offshore), we have evidence that sharply rising bond demands can strain the market. For example, the federal offshore regulator (BOEM) estimated that under its new decommissioning rules, the cost of obtaining surety bonds could increase by roughly $258 per $1,000 of coverage for smaller operators, effectively a ~25% premium, “assuming the surety bond market can bear the increased demands.”[13] This provides evidence that there are limits to surety capacity. Annual inflation-based hikes could quickly push some operators beyond what sureties are willing to underwrite, leaving operators unable to secure the needed bonds. In short, taken together with the other changes proposed by the OCD, an automatic CPI escalator could price marginal operators out of the market or force them into costly alternatives (like cash bonds or letters of credit), all for marginal inflationary increases.

iii. Administrative Burden with Little Practical Gain

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[13] JDSupra. *BOEM Releases Tougher Financial Assurance Requirements for Offshore Oil and Gas Operations*. JDSupra; 2024, available at: https://www.jdsupra.com/legalnews/boem-releases-tougher-financial-6845002/

Annual recalculation of bond amounts would add significant complexity and cost for both operators and OCD yet yield little tangible benefit in most years. Each year, OCD staff would have to calculate the new CPI-adjusted bond levels, update guidance, and ensure that hundreds of operators adjust their financial assurance accordingly. Operators would face yearly paperwork to increase bond amounts (through riders, new sureties, or additional collateral), incurring transaction costs and fees each time. This continual churn offers minimal practical gain in terms of well security. That is, a 2% or 3% annual inflation tweak on a bond (e.g., raising a $150,000 bond to $154,500) does not markedly change the protection against orphaned well costs, yet it creates new compliance steps every single year.

The process could also complicate corporate budgeting and capital planning, as companies must account for incremental bonding costs on an ongoing basis. By comparison, other regulators favor periodic adjustments on a longer cycle to balance adequacy with practicality. For example, even the notoriously tough U.S. Bureau of Land Management's updated rules will adjust federal onshore bond minimums for inflation only once every ten years.[14] Within ten years it is reasonable to expect that the majority of the currently unapproved temporarily abandoned wells will already be plugged. Moreover, this decade-scale interval reflects a desire to keep bonding aligned with cost trends without imposing annual administrative burdens. In my view, New Mexico similarly would see diminishing returns from yearly CPI recalculations, while incurring higher administrative overhead for both industry and the Division.

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[14] U.S. Bureau of Land Management. Oil and Gas Bonding Requirements. Washington, DC: U.S. Department of the Interior, Bureau of Land Management; 2024, available at: https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/leasing/bonding

iv. Conflict with Multi-Year Capital Planning Cycles

Annual CPI-based updates also conflict with the multi-year budgeting and planning cycles of many mid-sized and larger operators. Oil and gas companies typically plan their capital expenditures, asset retirement obligations, and financial assurance strategies on a multi-year horizon. They value predictability in regulatory costs. A bond requirement that can change every year introduces volatility that is difficult to manage. CPI itself has been highly volatile in recent years, ranging from historic lows to 40-year highs within a short span (for example, U.S. consumer inflation spiked to 9.1% in 2022, after being around 1–2% just a couple years prior.)[15] Indexing bonds to such a volatile metric could result in unplanned jumps in required coverage, right when an operator might be in the middle of a 5-year development or P&A program. This unpredictability impairs long-term budgeting. A mid-sized operator, for instance, could carefully allocate funds for compliance over a five-year plan, only to find that a surge in CPI next year mandates significantly more bonding than anticipated. The result may be last-minute scrambles to free up capital or delay other projects. In essence, tying bond amounts to an unstable annual index like CPI injects uncertainty into business planning. This is especially problematic given that plugging liabilities are typically managed over the long term (wells are plugged on schedules or as part of asset retirement plans, not on a year-to-year whim). A static or infrequently adjusted bond framework is

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[15] *See* Bureau of Labor Statistics, *Consumer Prices Up 9.1 Percent Over the Year Ended June 2022, Largest Increase in 40 Years*, *The Economics Daily* (July 18, 2022) (noting that "over the 12 months ended June 2022, the Consumer Price Index … increased 9.1 percent"), and Investopedia, *Historical U.S. Inflation Rate by Year* (noting CPI rose from the typical 1–2 percent range just years ago to 9.1 percent in 2022)

far more conducive to orderly, multi-year capital planning, whereas annual CPI adjustments would be disruptive.

For all of these reasons, I believe an automatic annual inflation adjustment to financial assurance is not advisable and not worth the trouble it would create. The core goal, ensuring bond amounts keep pace with actual plugging costs, can be achieved in more targeted, less onerous ways. If inflation adjustments must be included, they should be on a much less frequent cycle (e.g. reviewed every 5 to 10 years as needed, rather than every year) or structured in fixed tiers that get revisited periodically. This would allow calibration of bond levels to real cost changes without constant micromanagement. Another preferable approach would be to use New Mexico-specific cost data or indices rather than a one-size-fits-all nationwide CPI. New Mexico could, for example, periodically adjust bond amounts based on its observed average well plugging costs or a regional oilfield cost index metrics that directly reflect the actual expenses in this jurisdiction calculated over a longer period, such as 5-10 years, in order to smooth out the volatility caused by oil and gas price fluctuations.

In summary, an inflexible CPI indexing mandate adds complexity and uncertainty with little benefit. A more measured approach (or simply leaving bond amounts fixed until a substantive review is warranted) would better balance financial assurance with practical feasibility for operators. Therefore, I respectfully recommend against adopting the proposed CPI-based inflation factor. If the Commission nonetheless feels an adjustment mechanism is needed, it should be implemented in a gradual and New Mexico-tailored manner, not as an automatic annual escalator tied to the consumer price index.

6. Comparison to Typical P&A and Reclamation Costs Being Secured

i. New Mexico

In my opinion, the $150,000 per-well bond (plus inflation) proposed by WELC is far above what it actually costs, or should cost, on average, to plug and abandon a typical New Mexico oil or gas well.

Plugging and abandonment (P&A) costs vary widely from well to well. A small minority of extreme cases, such as very deep or damaged wells, can cost an order of magnitude more than typical wells, skewing the average cost upward. In contrast, the median (50% of the cases being below and 50% of the cases being above) cost better represents a "typical" well. Key technical factors driving *above-normal* P&A costs include:

a. Well depth

As noted in previous discussions above, deeper wells are much more expensive to plug with the data indicating an additional 1,000 feet of well depth increases plugging cost by about 20% on average.[16] A 10,000-ft well can cost roughly double what a 5,000-ft well costs to plug. For example, shallow onshore wells often cost only tens of thousands to plug, whereas ultra-deep wells (~15,000 ft) can run into the six figures (North Dakota regulators report costs around $150,000 for very deep 20,000-ft wells).[17]

b. Well age and condition

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[16] Daniel Raimi, *et al.*, "Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers," *Environmental Science & Technology*, vol. 55, no. 15, 2021, pp. 10224–10230, available at https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c02234.

[17] *"Why It's So Hard and Expensive to Plug an Abandoned Well,"* WESA/Public Radio Pittsburgh (August 1, 2021), available at https://www.wesa.fm/environment-energy/2021-08-01/why-its-so-hard-and-expensive-to-plug-an-abandoned-well.

Older wells (drilled decades ago) tend to be costlier to abandon due to deteriorated equipment and unknown conditions. Wells over 60 years old cost ~20% more to plug than wells under 40 years old.[18] Aging wells often lack modern cement and casing standards, leading to integrity problems (corroded or collapsed casing) that require extra work. For instance, in one Oklahoma case a well with a hole in its casing was initially estimated to cost ~$48k to plug, but actual cost increased to over $70k after dealing with the damaged casing.[19]

c. Fluid type and composition

Gas wells and "sour" (high H_2S) wells can cost more to safely plug than simple oil wells. Research shows natural gas wells are ~9% more expensive to plug than oil wells on average[20], probably due to factors like high concentrations and partial pressures of CO2 and H_2S and also gas molecules are smaller increasing migration risks through small pathways. Wells producing corrosive or toxic fluids may need specialty cement, venting, or safety measures that potentially add cost.

d. Surface and environmental factors

Remote location, difficult access, or contaminated sites drive costs up. While the OCD

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[18] Daniel Raimi, *et al.*, "Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers," *Environmental Science & Technology*, vol. 55, no. 15, 2021, pp. 10224–10230, available at https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c02234.

[19] Niles Stuck, "Overcoming Oklahoma's Orphaned and Abandoned Well Problem," *Oklahoma Bar Journal* (May 2024), available at https://www.okbar.org/barjournal/may-2024/overcoming-oklahomas-orphaned-and-abandoned-well-problem.

[20] Daniel Raimi, *et al.*, "Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimates and Cost Drivers," *Environmental Science & Technology*, vol. 55, no. 15, 2021, pp. 10224–10230, available at https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c02234.

estimates that basic surface reclamation (removing equipment and regrading the site) adds about ~$35,000 on average per well,[21] any major contamination cleanup can escalate into "millions" in extreme cases[22]. Such outliers are rare but dramatically increase average cost figures.

Because of these factors, most wells have moderate P&A costs, with only a few outliers costing extreme amounts. Studies of thousands of wells confirm a skewed cost distribution with some wells can cost over $1 million to plug, but these super expensive jobs are outliers (probably higher-risk situations and wells that were not monitored and maintained properly) and the median plugging cost is in the tens of thousands[23]. In short, using the median (which filters out the few high-cost anomalies) gives a more accurate indicator for a typical well's P&A cost, whereas the mean can be misleadingly inflated by a handful of expensive cases.

ii. National and State Statistics

Multiple credible studies and government data sets show that typical P&A costs are far below $150,000 for most wells. See Table 1 below for a summary of P&A cost metrics nationally and for several oil-producing states for context:

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[21] Dylan Fuge, *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory and Public Affairs Committee, December 1, 2023, available at https://www.nmlegis.gov/handouts/RHMC%20120123%20Item%202%20EMNRD%20OCD%20-%20Orphan%20Well%20&%20Financial%20Assurance.pdf.

[22] Dylan Fuge, *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory and Public Affairs Committee, December 1, 2023

[23] *Plugging Orphaned Oil and Gas Wells: What We Know and Need to Know*, Resources for the Future (February 25, 2021), available at https://www.resources.org/archives/plugging-orphaned-oil-and-gas-wells-what-we-know-and-need-to-know/.

Table 1- Median vs Average P&A Cost per Well (Onshore)

Region/State	**Median P&A Cost** (per well)	**Average P&A Cost** (per well)
United States (overall)	~$20,000 (plugging only); ~$76,000 including site[24][25]	*~$75,000–$100,000 (mean)* (skewed by outliers)[26]
New Mexico	*Not reported*	**$125,000** (plugging only average)[27] ~$35k surface rehab (typical)[28] Apparently, when OCD is managing the plugging average total is ~**$150k**.
Texas	~$20,000–$40,000 (typical median range)[29]	**$30,000–$35,000** (recent average per well)[30]
Oklahoma	~$10,000–$20,000 (shallow well median)	**$17,861** (FY2023 state program average)[31]
Colorado	~$50,000 (median depth ~8,000 ft)	**$92,710** (state-estimated average w/ reclamation)[32]
California	~$50,000 (many shallow old wells)	**$111,000** (CalGEM analysis average per well)[33]

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[24] *"New Study Reveals Key Factors for Estimating Costs to Plug Abandoned Oil and Gas Wells,"* Resources for the Future (July 21, 2021), available at https://www.rff.org/news/press-releases/new-study-reveals-key-factors-for-estimating-costs-to-plug-abandoned-oil-and-gas-wells/.

[25] *"New Study Reveals Key Factors for Estimating Costs to Plug Abandoned Oil and Gas Wells,"* Resources for the Future (July 21, 2021), available at https://www.rff.org/news/press-releases/new-study-reveals-key-factors-for-estimating-costs-to-plug-abandoned-oil-and-gas-wells/.

[26] *Plugging Orphaned Oil and Gas Wells: What We Know and Need to Know*, Resources for the Future (February 25, 2021), available at https://www.resources.org/archives/plugging-orphaned-oil-and-gas-wells-what-we-know-and-need-to-know/.

[27] Dylan Fuge, *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory & Public Affairs Committee (RHMC), December 1, 2023, available at https://www.nmlegis.gov/handouts/RHMC%20120123%20Item%202%20EMNRD%20OCD%20-%20Orphan%20Well%20&%20Financial%20Assurance.pdf.

[28] Dylan Fuge, *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory & Public Affairs Committee, December 1, 2023

[29] Erin Douglas, "Texas will plug 800 abandoned oil and gas wells, funded by $25 million federal infrastructure grant," *The Texas Tribune* (August 26, 2022), available at https://www.texastribune.org/2022/08/26/oil-gas-wells-

RFF/DOE analysis[34] *of ~19,500 wells found a* ***median*** *of $76k (as noted elsewhere above) vs. a long tail of high-cost wells (90th percentile ~$160k, with a few extreme cases >$1M), implying a higher mean in the ~$100k range. Median values for CO and CA are rough estimates (not officially reported) to indicate typical scale; actual averages are shown in the next column.*

Table 1 shows that a median U.S. well costs on the order of $20k (plug only) or around $50k–$80k including surface closure – only a fraction of $150k. Even the *average* cost (skewed by outliers) across most states tends to fall well below $150k per well. For example:

a. Texas

The Railroad Commission reports recent average costs of ~$30–35k per well to plug and

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infrastructure-money-texas-railroad-commission/.

[30] Jim Wright, *"Response of the Railroad Commission of Texas to Congressional Testimony on H.R. 7053,"* Railroad Commission of Texas (February 24, 2023): "Estimates vary, but the specific costs of monitoring can result in anywhere from $2,000 to $5,500 dollars in additional expenses… plugging an onshore well … has averaged anywhere between $30,000 to $35,000 over the last several years."

[31] Niles Stuck, "Overcoming Oklahoma's Orphaned and Abandoned Well Problem," *Oklahoma Bar Journal* (May 2024), available at https://www.okbar.org/barjournal/may-2024/overcoming-oklahomas-orphaned-and-abandoned-well-problem/

[32] *Revisions to Orphaned Well Program Costs for Financial Assurance Rulemaking*, Colorado Energy and Carbon Management Commission (July 23, 2021), available at https://ecmc.state.co.us/documents/sb19181/Rulemaking/Financial%20Assurance/2021-07-23%20Revisions%20to%20%20Orphaned%20Well%20Program%20Costs%20for%20Financial%20Assurance%20Rulemaking.pdf.

[33] *California Proposed Budget: Natural Resource Agency (2023–24)*, Legislative Analyst's Office (May 2023), provides "$200 Million Over Two Years… enough to plug 1,800 wells with the proposed funding," available at https://lao.ca.gov/Publications/Report/4508.

[34] Raimi, D., Krupnick, A. J., Shih, J.-S., & Thompson, A. (2021). Decommissioning orphaned and abandoned oil and gas wells: New estimates and cost drivers. Environmental Science & Technology, 55(15), 10224–10230. https://doi.org/10.1021/acs.est.1c02234

restore sites.[35] Past analyses found typical Texas P&A jobs range $20k–$40k total.[36] This is in line with Texas's many shallow to moderate-depth wells.

b. Oklahoma

With its abundance of shallow wells, Oklahoma's state-managed plugging program plugged 376 wells in FY2023 at an average cost of only ~$18k per well.[37] Many simple legacy wells in OK can be plugged for just five figures.

c. Colorado

Colorado's orphan well program tends to involve deeper wells and comprehensive reclamation – even so, the state estimates ~$93k on average to plug and fully reclaim a well site.[38] Median costs would be lower.

d. California

California faces some challenging sites (urban wells, etc.), yet even CalGEM's analysis found

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[35] Jim Wright, *Testimony before the House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources*, Railroad Commission of Texas, July 23, 2024, available at https://www.rrc.texas.gov/media/sxmlnxg5/testimony-of-texas-railroad-commissioner-jim-wright-hr-7053.pdf: "Estimates vary, but …the specific costs of monitoring can result in anywhere from $2,000 to $5,500 in additional expenses. … plugging an onshore well … has averaged anywhere between $30,000 $35,000 over the last several years."

[36] Erin Douglas, "Texas will plug 800 abandoned oil and gas wells, funded by $25 million federal infrastructure grant," *The Texas Tribune* (August 26, 2022), available at https://www.texastribune.org/2022/08/26/oil-gas-wells-infrastructure-money-texas-railroad-commission/.

[37] Niles Stuck, "Overcoming Oklahoma's Orphaned and Abandoned Well Problem," *Oklahoma Bar Journal* (May 2024), available at https://www.okbar.org/barjournal/may-2024/overcoming-oklahomas-orphaned-and-abandoned-well-problem/.

[38] Nick Bowlin, "Colorado works on an oil and gas well cleanup guarantee, but doubts loom," *High Country News* (January 13, 2023), noting that "the state estimates that plugging and fully reclaiming a Colorado well costs $92,710 on average, although the number can vary for a variety of reasons, including the depth of a well," available at https://www.hcn.org/articles/energy-industry-colorado-works-on-an-oil-and-gas-well-cleanup-guarantee-but-doubts-loom/.

~$111k on average per well for plugging and cleanup.[39] This average is heavily influenced by a few high-cost wells in sensitive areas; many routine onshore CA wells still plug for well under six figures.

iii. Compared to New Mexico

New Mexico's recent figures initially appear high, OCD reported spending about $125k on average per orphan well for plugging alone.[40] Based on my experience, and comparison to data from other states, this NM average P&A cost appears to be an extreme outlier. This could be due to the unusual way in which the OCD was plugging the wells (more on this below). Moreover, this average may be skewed upward by lumping all the categories of wells together regardless of risk factors (like including SWD wells with Producers), such that a few very expensive problem wells drive up the average cost. In fact, the range was $50k on the low end to ~$320k on the high end.[41] In other words, *some difficult wells* cost over $300k, inflating the mean. New Mexico's current average OCD plugging cost may also be higher than is typical because the state has been tackling a backlog that includes many orphan wells, which unsurprisingly would be more expensive to plug

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[39] *California Proposed Budget: Natural Resource Agency (2023–24)*, Legislative Analyst's Office (May 2023), providing "$200 Million Over Two Years… enough to plug 1,800 wells with the proposed funding," available at https://lao.ca.gov/Publications/Report/4508.

[40] *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, Dylan Fuge, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory & Public Affairs Committee, December 1, 2023, available at https://www.nmlegis.gov/handouts/RHMC%20120123%20Item%202%20EMNRD%20OCD%20-%20Orphan%20Well%20&%20Financial%20Assurance.pdf.

[41] *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, Dylan Fuge, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory & Public Affairs Committee, December 1, 2023, available at https://www.nmlegis.gov/handouts/RHMC%20120123%20Item%202%20EMNRD%20OCD%20-%20Orphan%20Well%20&%20Financial%20Assurance.pdf.

than wells being monitored by responsible/solvent operators.

In summary, comparable states show median P&A costs in the tens of thousands, broadly similar to New Mexico's typical well costs, and only a few special cases approach or exceed the $150k mark. The median cost is far lower than $150k, once the outliers are accounted for.

a. Well depth is the most significant predictor of costs

Of all the various factors influencing plugging and abandonment (P&A) costs, **well depth** consistently emerges as the most significant predictor of cost. New Mexico has thousands of shallow wells, for instance in the Yeso formation of southeast NM (oil wells often ~5,000–7,000 ft deep) and the Pictured Cliffs gas wells of the San Juan Basin (often only ~1,000–4,000 ft deep), which are low-risk, low-cost candidates for plugging. In contrast, the state also has some very deep wells (e.g. in the Delaware Basin) exceeding 10,000–12,000 ft, which unsurprisingly are far more expensive to abandon. It is technically inconsistent with the data to require the *same* $150k bond for a 3,000-ft shallow stripper oil well as for a 13,000-ft high-pressure gas well. The cost scales with depth, repeated here for convenience, are shown Table below.

Table 1 - Typical P&A Median Cost by Well Depth (onshore wells)

Well Depth	**Typical Median P&A Cost**
Shallow Wells < 5,000 ft	**~$20,000 – $30,000**
Mid-Depth Wells 5,000–10,000 ft	**~$50,000** (tens of thousands)
Deep Wells > 10,000 ft	**~$100,000+** (up to low six figures)

Note: Median cost including plugging and site reclamation, rounded to illustrate scale. Actual costs vary; deeper wells also have more variability (some >$1M outliers). The location remediation cost would of course not vary appreciable with depth, and gas wells can be expected to have less surface remediation costs than oil wells.

Bottom Line: Depth correlates so strongly with cost that any logical bonding regime should take it into account, rather than impose a flat figure.

b. Bonding policy: one-size-fits-all vs. risk-based approach

Given the evidence, a flat $150,000 per-well bond is not aligned with the actual risk/cost profile observed in the field. It far exceeds the P&A cost for the vast majority of low-risk, properly maintained wells. Requiring every well to carry $150k in financial assurance would be technically unjustified overkill. For example, an operator of shallow, well maintained, relatively new, oil wells would be forced to post the same bond as an operator with deep, poorly maintained, old, gas wells. Moreover, this level of bond could needlessly tie up capital for the operators of the shallow, well maintained, or otherwise low-risk wells. This concern is echoed by experts and regulators nationwide:

- Resources for the Future (RFF) researchers conclude that bonding requirements should be tailored to well characteristics. Instead of a one-size-fits-all bond, regulators can adjust financial assurance to match the risk factors like depth, age, and well type.[42] The data show "considerable cost variation," so a nuanced, risk-based bonding approach is more efficient.[43]
- Many states already use tiered bonding schedules. For example, Texas employs per-well bond amounts that increase with well depth or total well count (recognizing that deeper wells cost more). Even after recent increases, New Mexico's own bonding rules

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[42] *"New Study Reveals Key Factors for Estimating Costs to Plug Abandoned Oil and Gas Wells,"* Resources for the Future (July 21, 2021 available at https://www.rff.org/news/press-releases/new-study-reveals-key-factors-for-estimating-costs-to-plug-abandoned-oil-and-gas-wells/.

[43] *"New Study Reveals Key Factors for Estimating Costs to Plug Abandoned Oil and Gas Wells,"* Resources for the Future (July 21, 2021 available at https://www.rff.org/news/press-releases/new-study-reveals-key-factors-for-estimating-costs-to-plug-abandoned-oil-and-gas-wells/.

acknowledge depth by requiring extra per-foot amounts for deep wells.[44] A blanket $150k per well would ignore these gradations and overshoot on the vast majority of wells.

- Engineering consensus holds that financial assurance should cover the *expected* plugging liability of a well, not an arbitrary high-end figure. If a well typically costs $30k to plug, a $150k bond (5 times the expected cost) is excessively conservative and could discourage legitimate well transfers or continued use. As the Colorado Oil & Gas Conservation Commission noted, the goal is to ensure operators can cover *their* wells' plugging costs without forcing them into bankruptcy.[45] Overly high blanket bonds risk stranding viable assets and creating more orphaned wells, the opposite of the policy intent.

There is some evidence that New Mexico's inflated OCD P&A cost data was driven by OCD's plugging and project management practices, for example: OCD's 24-Hour cement waiting policy.

c. Impact of OCD's 24-hour cement waiting policy

It is my understanding that OCD had been requiring operators to wait roughly a day for cement to set between plugs, even though this was not codified in the formal rules. This unusual "wait on cement" requirement, introduced around 2020, effectively stretched what could be a 1–2 day plugging job into a week or more of crew time. It is my understanding that the OCD only recently moved to standardize a shorter wait. To wit, effective 2024, OCD's new guidelines set cement

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[44] *State of New Mexico Class II UIC Program Peer Review*, Ground Water Protection Council (January 8, 2020), available at www.gwpc.org/uploads/documents/publications/New_Mexico_Peer_Review_1_8_2020.pdf.

[45] Nick Bowlin, "Colorado works on an oil and gas well cleanup guarantee, but doubts loom," *High Country News* (January 13, 2023) https://www.hcn.org/articles/energy-industry-colorado-works-on-an-oil-and-gas-well-cleanup-guarantee-but-doubts-loom/

curing times at 4 hours (with accelerator) or 6 hours (regular cement).[46] The agency explicitly noted that these published conditions "formalize [an] existing practice" previously enforced in the field without a written rule.[47] Based on this information, it appears that the OCD had been making plugging contractors wait far longer than was necessary for cement to cure, driving up labor and rig standby costs, but now is correcting course to a reasonable 4–6 hour wait. This should significantly lower P&A costs.

Another inefficiency related issue inflating costs is OCD's limited pool of plugging contractors. It is my understanding that as of late 2022, OCD had entered agreements with only two contractors to handle nearly 200 orphan wells statewide.[48] Legislative analysts flagged this lack of competition and recommended that OCD reopen its statewide plugging contract to solicit more bidders by 2025.[49] Notably, the approved contractors have been based in the San Juan Basin (northwestern New Mexico), yet most orphan wells are in the Permian Basin in the far southeast.

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[46] *Notice of Plugging Authority and Associated Procedures*, New Mexico Oil Conservation Division, New Mexico Energy, Minerals and Natural Resources Department, available at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/NM-OCD-PA-Notice-Combined.pdf.

[47] *Notice of Plugging Authority and Associated Procedures*, New Mexico Oil Conservation Division, New Mexico Energy, Minerals and Natural Resources Department, available at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/NM-OCD-PA-Notice-Combined.pdf.

[48] "The OCD has obligated funds with two plugging contractors to plug 196 orphan wells situated on state and private surface lands." *Orphan Wells Progress Report – February 2023*, New Mexico Energy, Minerals and Natural Resources Department, Office of the Secretary, available at www.emnrd.nm.gov/officeofsecretary/wp-content/uploads/sites/2/orphan_wells_progress_report_02_2023.pdf.

[49] "Re-open its statewide purchase agreement for plugging and remediation work to solicit additional bids from plugging contractors by September of 2025; This effort was initiated in March 2025 and is ongoing." *Presentation to the Legislative Finance Committee*, New Mexico Energy, Minerals and Natural Resources Department, June 24, 2025, available at https://www.nmlegis.gov/handouts/ALFC%20062425%20Item%204%20NMEMNRD%20Presentation.pdf.

This requires crews and equipment to travel 6–8 hours each way to job sites, incurring substantial mileage, hotel, and per diem expenses. This unproductive time and travel expense gets billed to the state's plugging program, unnecessarily inflating the per-well cost. If local Permian-based service rigs could be utilized instead, many of these costs (and delays waiting for crews) could be avoided. Some of that increase is due to deeper or more complex wells (as discussed) and some could be from general inflation. Nevertheless, analysts have indicated that OCD's procurement practices were a major driver of the cost jump.[50] In short, more likely than not, OCD's procedures have made state-led well plugging more expensive than it could have been. This is further evidenced by the fact that the average cost for the state to plug a well has surged by about 450% since 2019.[51]

I am not faulting the OCD, as the OCD has been faced with a difficult task. Launching any new large-scale plugging program can be expected to require an expensive learning curve. However, now that OCD's more cautious cement cure times and evolving contracting processes have been evaluated, it is reasonable to assume that OCD will streamline operations and ultimately bring costs down over time.

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[50] "Analysts also recommended the Oil Conservation Division adopt new rules to address wells at the end of their lifespan; change its bidding procedures; and adopt controls to ensure that the state is not overpaying contractors for plugging. The report found the state's costs for plugging wells have dramatically risen in recent years, in part due to plugging deeper, more complex wells, and some inflation, but also due to procurement practices at the Oil Conservation Division." *New Report: New Mexico on the Hook for Millions, If Not Billions, to Plug Oil and Gas Wells*, Source New Mexico (June 26, 2025), https://sourcenm.com/2025/06/26/new-report-new-mexico-on-the-hook-for-millions-if-not-billions-to-plug-oil-and-gas-wells/.

[51] "The average per-well cost of state-contracted plugging has risen nearly 450 percent since FY19, and the average per-foot cost has risen 270 percent, more than eight times the rate of overall oilfield inflation." Policy Spotlight: Orphaned Wells, New Mexico Legislative Finance Committee, presented June 24, 2025, available *at* *www.nmlegis.gov/handouts/ALFC%20062425%20Item%204%20Policy%20Spotlight%20Orphaned%20Wells.pdf*

This context is crucial when evaluating proposals like a $150,000-per-well bonding requirement: that figure is inflated by OCD's operational inefficiencies. Addressing these internal issues should be considered as part of the process of determining the bond per well that will be required, rather than simply saddling operators with prohibitively high bonds based on an out-of-date "outlier" cost structure.

In conclusion, most New Mexico wells should not require anywhere near $150,000 to plug and abandon. A few atypical, higher-risk wells will probably approach or exceed that cost, but those are exceptions that should be handled with targeted financial assurance (e.g., special bonding for deep or high-risk wells). A tiered or risk-based bonding system, where bond amounts scale with factors like well depth, age, or known integrity issues, well type (e.g. producers vs injectors) would be far more technically justified. Such an approach protects the state from true high-liability wells without over-penalizing the thousands of low-risk shallow wells that are inexpensive to plug. The evidence from P&A cost data across the U.S. strongly supports a more nuanced bonding requirement, rather than a flat $150,000 per well that far exceeds typical plugging costs for the median well in New Mexico.[52,53]

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[52] Dylan Fuge, *Orphan Well Plugging & Site Remediation Update – Overview of Financial Assurance Requirements*, New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division, presented to the House Regulatory & Public Affairs Committee, December 1, 2023, available at https://www.nmlegis.gov/handouts/RHMC%20120123%20Item%202%20EMNRD%20OCD%20-%20Orphan%20Well%20&%20Financial%20Assurance.pdf.

[53] Texas Railroad Commission, *"RRC Commissioner Wright Highlights Issues with Federal Orphan Well Plugging Program in Testimony to Congress,"* news release (July 25, 2024): "The methane monitoring requirements under the DOI's current Formula Grant increase the cost to plug these wells." available at https://www.rrc.texas.gov/news/072524-rrc-commissioner-wright-highlights-issues-federal-orphan-well-plugging-program-testimony-congress/

iv. Bottom Line Recommendation

Given 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. Regulators should establish bond levels according to the assessed risk and clearly documented characteristics of specific well categories within an operator's portfolio, thereby ensuring that required securities correspond to actual potential plugging and abandonment liabilities.

This approach is supported by research. Experts have noted that bonding requirements should "match the characteristics of different wells, rather than using a one-size-fits-all approach." A high blanket bond might overshoot the needed coverage for the vast majority of wells (tying up capital unproductively), while still possibly undershooting in rare worst-case scenarios (for instance, a $150k bond wouldn't fully cover a $778k complex plugging job either). A risk-tiered system encourages right-sizing: low-risk, shallow wells could have lower bonds, whereas higher-risk wells (deeper, H_2S, etc.) carry higher individual assurances. New Mexico's current framework actually recognizes some differentiation, e.g., current rules set base bonding of $25,000 + $2/ft per well (so a 5,000 ft well needs $35k bond) and allow blanket bonds (capping out at $250k to cover 100+ wells). 19.15.8.9 NMAC(C)-(D). The problem is that those amounts are outdated and too low overall (hence the push to increase them). But the solution should not be to swing to the opposite extreme with a flat $150k bond for each well, ignoring well differences. Instead, a graduated bonding schedule or risk assessment model would ensure adequate coverage without over-securing low-cost wells to a punitive degree.

7. Comparison to Other Jurisdictions FA Requirements

Other oil-and-gas states have been moving toward more nuanced financial assurance requirements rather than rigid per-well mandates. For example, Texas historically allowed a blanket bond of $250,000 to cover an unlimited number of wells (100+ wells), which works out to only a few thousand dollars per well in many cases, well under actual plugging costs. While that Texas system is now under scrutiny for being too low, it illustrates that a flat $150k per well bond would be an outlier. Colorado recently overhauled its bonding rules to tailor amounts to well depth and production status. Under Colorado's new rules, an individual well generally must have $10,000 in bond if shallow (<4,000 ft), $30,000 if medium depth (4,000–8,000 ft), and $40,000 if deeper than 8,000 ft, plus an additional $100,000 per well site for surface reclamation.[54] However, Colorado also created alternative compliance options: large operators with strong production can still use blanket bonds that scale with the number of wells (for instance, as low as ~$12,000 per well for companies with <50 wells, or even ~$1,500 per well if you have 4,000+ wells, under certain high-production options[55]). Mid-size and low-producing operators likewise have sliding scales or can contribute to plugging funds over time. The key point is, Colorado did not simply impose a $150k-per-well bond, it recognized different well classes and operator circumstances. Even the federal government (BLM), which just updated its bonding rules for wells on federal land for the first time in decades, did not go so far as to require $150k for each well. The new BLM rule sets a $150,000 minimum bond per lease (covering all wells on that lease) and a $500,000 blanket

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[54] *See* Colo. Energy & Carbon Mgmt. Comm'n, *700 Series – Financial Assurance*, Rule 704.b.(2) (eff. Jan. 15, 2023), available at ecmc.state.co.us.

[55] *See* Colo. Energy & Carbon Mgmt. Comm'n, *700 Series – Financial Assurance*, Rule 700-05.b.(1) (eff. Jan. 15, 2023), available at ecmc.state.co.us.

bond for all a company's wells in a state. These federal bonds will also adjust for inflation every ten years. BLM arrived at those figures by estimating a typical orphan well plugging cost of ~$71,000 (and acknowledging future expenses could be $112k–$180k for some wells[56]). In practice, BLM's $150k-per-lease bond often covers multiple wells, so the effective per-well coverage is well below $150k in most cases, again, reflecting that not every well will need the maximum. Other major oil-producing states likewise set bonding requirements that scale with the number of wells or well depth. For instance, North Dakota requires a base bond (e.g. $50k) plus additional amounts per well over certain counts,[57] and Wyoming uses a $10 per foot bonding formula (so a 5,000 ft well needs $50k bond) with a $100k blanket option.[58] Oklahoma and California have been considering higher bonds for idle wells, but still generally in the tens of thousands, not hundreds, per well.

In summary, the trend in other jurisdictions is to improve bonding adequacy by targeting higher-risk wells with higher bonds, not simply imposing an across-the-board figure like $150k regardless of well size or risk. In practice, most jurisdictions are moving away from flat, across-the-board bond amounts and are increasingly adopting risk-informed, tiered bonding systems that:

- Charge higher bonds for higher-risk or costly wells, and
- Avoid blanket coverage for dozens of low-risk wells, unlike a one-size-fits-all $150K

[56] *See* Bureau of Land Mgmt., *Final Rule: Fluid Mineral Leases and Leasing Process* (Apr. 2024) (setting minimum bond amounts at $150,000 per lease and $500,000 statewide, subject to inflation adjustment every ten years, and citing average well plugging costs of $71,000, with potential future costs ranging from $112,000 to $180,000), available at blm.gov.

[57] *See* N.D. Dep't of Mineral Resources, *Financial Assurance & Bonding* (Rules & Regulations – NDAC 43-02-03-15) (requiring a bond of $50,000 for a single well, and a $100,000 blanket bond option for multiple wells)

[58] S*ee* Wyo. Code R. § 055-3-3-4(A) (2024)

bond.

Adopting a flexible, risk-based bonding scheme in New Mexico would be far more "advisable," in my view, than the rigid per-well requirement proposed by WELC/OCD. It would protect the state from true problem wells while not over-burdening operators of low-risk wells, aligning financial assurance with actual plugging cost expectations. This balanced approach would encourage responsible operations and timely plugging (since risky, idle wells would carry higher financial costs), without disproportionately penalizing the many typical New Mexico wells that can be decommissioned for a fraction of $150,000. Such a regime has the potential to strike a better balance, ensuring adequate funds for well closure when needed, but calibrated to well-specific liabilities, much like the models being deployed in Colorado, Texas, and soon Utah, as well as at the federal level.

The Colorado Oil and Gas Conservation Commission implemented tiered bonding focused on orphaned or idle wells, with significantly higher bonds for wells above a certain risk threshold or count. Their system includes "orphans backstop, tiers, financial assurance plans, out-of-service programs," clearly diverging from uniform bonds.[59]

Utah is engaged in a 2025 state rulemaking proceeding actively developing a tiered bonding system that incorporates production levels and well risk ratios, carefully matching bond amounts to well characteristics and risk profiles.[60]

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[59] *See* Chas Woodruff, *Oil and Gas Regulators Float Tiered Financial-Assurance System, 'Amnesty' for Risky Wells*, *Colo. Newsline* (Jan. 28, 2022)

[60] *See* Utah Div. of Oil, Gas & Mining, *Rulemaking – Oil and Gas Bond* (draft R649-13, Mar. 2025)

8. Risks and Implications of Adopting Proposed FA Changes

Below, please find a summary of my opinion regarding the risks and implications of the proposed amendments to Rule 19.15.8.9 NMAC regarding financial assurance requirements, taking into account the realities of the oil and gas ecosystem described above. It touches on inventory dynamics, reserve replacement, operator interdependence, transactional friction, and administrative challenges tied to bonding updates.

i. Amendments and Additions Fail to Address Real Risks and Manufacture New Risks

The proposed amendments[61] to New Mexico's financial assurance rules demand a level of rigidity and economic burden that is simply misaligned with efficient upstream oil and gas industry value creation. Operators must constantly manage and evolve their portfolios to remain viable. As previously discussed, upstream companies, large and small, are in a daily race to replace and grow reserves. Production is the act of selling from inventory, and without continual reinvestment, whether through recompletions, new drills, or strategic acquisitions, the company's value declines. The need for a positive Reserve Replacement Ratio (RRR) is not theoretical; it is a central operating truth.[62] The proposed rules appear blind to this imperative, erecting arbitrary thresholds and inflexible bonding demands that distort or actively block the rational movement of assets necessary to maintain this dynamic.

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[61] New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Division. *Revised Proposed Amendments to 19.15.8 NMAC.* Santa Fe, NM: EMNRD, 2024. [Online], available at: https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/19.15.8-Revised-Proposed-Amendment.pdf

[62] Salacz, D., Allam, F., Al Araimi, W. M., & Al Mansoori, Y. *Forecasting Reserves Replacement Ratio (RRR): A Method for Benchmarking the Ability of the Company to Mature Projects and Reduce Uncertainty.* Paper SPE-206284-MS, presented at the SPE Annual Technical Conference and Exhibition, Dubai, UAE, September 2021.

What the rules fail to appreciate is that the U.S. upstream oil and gas industry is an interdependent hierarchy that functions like an ecosystem. Large companies divest non-core or lower-rate assets, which smaller companies then acquire, innovate upon, and often transform into profitable ventures. This "food chain" from large to small and back again is not just economically efficient; it is vital for the industry to sustain and/or grow production levels.[63] Smaller operators thrive by being lean,[64] agile, taking calculated risks and applying novel techniques on marginal wells that would be uneconomic or operationally inefficient for large firms. Many of these wells, especially those classified as TA or marginal, are precisely the platforms upon which a combination of tried-and-true techniques and new technologies are applied, and value is created. Burdening their transfer or retention with excessive bonding requirements disrupts this exchange and penalizes the very innovation that reduces future liability.

Additionally, these rules fail to account for the routine transactional churn that defines the upstream sector. Acquisitions, divestitures, and farmouts are core to how operators manage capital and risk. The idea that bonding must be recalculated instantly and posted in full the moment a portfolio shifts by a single marginal well, due to sale, plugging, or even a rod failure, is both operationally unworkable and economically punishing. This challenge is further compounded in the context of farmout agreements, where asset interests are often earned incrementally through performance milestones, making real-time bonding recalculation not only impractical but

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[63] Energy Council. *The Next Wave of Consolidation: Navigating M&A and Strategic Divestitures in U.S. Oil and Gas.* Energy Council, 2024. [Online], available at: https://energycouncil.com/articles/the-next-wave-of-consolidation-navigating-ma-and-strategic-divestitures-in-u-s-oil-and-gas/

[64] Lower overhead/flatter management/lower OPEX.

misaligned with the very structure of how risk and ownership are transferred in these nuanced, multi-stage transactions.[65] Updating bonding levels each time a well's status changes, without grace periods, proportionality, or acknowledgment of timing lags in data reporting and well file updates, creates a compliance and administrative nightmare. It turns what should be a transparent and manageable financial assurance system into a volatile liability that deters capital flow, chokes off transactions, and incentivizes premature plugging over responsible reuse.

If small, moderately capitalized operators cannot obtain the required bonds due to a lack of capital, credit rating, or perceived risk in the bonding market, then they will not be able to acquire the marginal or inactive wells that they would normally bring into inventory to fuel their efforts to increase or replace reserves. This disrupts 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. Without this essential middle layer of the food chain, irreplaceable wellbore assets that would otherwise be rejuvenated may be prematurely plugged. The upward flow of proven opportunities, from small operators back to larger firms seeking scalable, de-risked inventory, will dry up, reducing reserve replacement options at the top end of the chain as well. In effect, the entire system is compromised: large operators lose a key source of future inventory, entrepreneurial operators are locked out of the ecosystem, and the state risks an increase in truly orphaned wells as small operators go out of business and the transfer pathways collapse under the weight of unattainable financial assurance requirements.

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[65] Lowe, J. S. *Analyzing Oil and Gas Farmout Agreements.* Southwestern Law Journal, vol. 33, no. 4, 1980, pp. 695–749. Reprinted in *Oil and Gas Contracts* (Rocky Mountain Mineral Law Foundation, 2017), available at: https://scholar.smu.edu/law_faculty/606/

There is an important backdrop to this discussion that needs to be considered. The likelihood that Permian shale production has already peaked is more than just speculation, it is becoming the prevailing leitmotif for the industry's evolving dynamics.[66] For example, Diamondback Energy, a bellwether in the basin, recently acknowledged that U.S. shale production "has likely peaked" amid falling oil prices and declining rig counts, signaling a shift away from relentless growth[67]. Meanwhile, analysts from Reuters and Permian-focused firms caution that the region has entered a geological plateau, with core Midland and Delaware acreage extensively drilled and marginal wells now dominating new completions.[68] Beyond geology, falling productivity, rising water and gas volumes per well, and diminishing high-grade inventory are eroding returns, and both OPEC+ decisions and shifting capital discipline are reinforcing this trend. Rather than an ever-expanding frontier, the Permian is now considered to be a mature basin where strategic flexibility, innovation on legacy assets, and cost discipline will determine success. Ignoring this "peak shale" reality in crafting New Mexico P&A bonding rules risks further destabilizing the delicate balance of innovation, investment, and responsible stewardship that the operators in New Mexico require to maintain and/or production in the future. Revising rules to impose more stringent abandonment requirements risks prematurely eliminating access to existing wellbores, assets that, in the context

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[66] Tang, H.-Y., He, G., Ni, Y.-Y., Huo, D., Zhao, Y.-L., Xue, L., & Zhang, L.-H. *Production Decline Curve Analysis of Shale Oil Wells: A Case Study of Bakken, Eagle Ford, and Permian.* Petroleum Science, vol. 21, no. 6, pp. 4262–4277, Dec. 2024.

[67] Bloomberg, *US Shale Output Has Peaked as Prices Fall, Diamondback Says* (May 6, 2025), available at: https://www.energyconnects.com/news/gas-lng/2025/may/us-shale-output-has-peaked-as-prices-fall-diamondback-says

[68] Pipeline & Gas Journal, *Permian Oil Growth Slows as U.S. Shale Hits Geological Limits* (Apr. 3, 2025), available at: https://pgjonline.com/news/2025/april/permian-oil-growth-slows-as-us-shale-hits-geological-limits

of a maturing Permian Basin, are increasingly valuable targets for reentry and revitalization through emerging refracturing technologies and enhanced reservoir management. These wellbores represent a critical means of sustaining production and extending field life in an era defined not by expansion, but by optimization.[69]

In short, these amendments not only fail to address real risk, but they also manufacture new ones, not the least of which is the risk of reduced tax revenue to the State of New Mexico soon. They introduce inefficiencies through deal friction and distorted decision-making, and they potentially penalize the very practices (like moving wells into Approved TA Status) that enable responsible stewardship of marginal wells. If adopted as written, they will slow transactions, undermine the TA program, discourage small operator innovation, and potentially break, or at least damage, the natural supply chain that enables resource optimization across the industry in New Mexico. That's not sound regulation; that's self-inflicted harm of the State of New Mexico under the guise of environmental prudence. A risk-based, administratively feasible approach would better align with both the environmental goals of the state and the operational realities of the upstream sector.

ii. Major Concerns for Marginal and Inactive Wells

I appreciate OCD's commitment to responsible well stewardship and the long-term goal of minimizing orphaned wells. However, I have serious concerns about the structure of WELC's proposed financial assurance requirements, such as the abrupt and disproportionate consequences

[69] PBOG (Permian Basin Oil and Gas Magazine). *Ongoing Research Boosts Refrac Results in the Permian and Elsewhere.* Nov. 28, 2023. [Online]. Available: https://pboilandgasmagazine.com/ongoing-research-boosts-refrac-results-in-the-permian-and-elsewhere/

imposed by the 15% marginal/inactive well threshold. To understand the potential consequences of these proposed changes to the regulations, consider the following discussion of where marginal/inactive wells fit into the upstream oil and gas industry ecosystem.

In some important ways, oil and gas companies function like a grocery store: they sell from inventory daily and must continuously replenish it, without new inventory, the store (or company) is effectively having a going out of business sale every day. In the upstream energy industry, this principle is known as the Reserve-Replacement Ratio (RRR),[70] that is, the rate at which a company replaces the reserves of oil and gas that it holds in the ground that it then produces up its wells and sells. Industry analysts agree that an RRR below 100% is a warning sign, indicating the company is producing and selling its inventory faster than it can restock, threatening its long-term viability and precluding the possibility of significant growth in enterprise value. Executives and investors watch the RRR closely: consistent replacement, either through drilling, recompletions, workover, and/or acquisitions, is necessary for sustainability. Unless value is being created by proving up future mineral acreage/potential, an RRR greater than 100% is generally required to achieve growth. Large companies, burdened with high overhead, must deliver high-return projects that meaningfully grow their reserve base; smaller operators, by comparison, can exploit niche or marginal assets to add reserve additions more affordably. Regardless of scale, the logic is universal: without active efforts to replace and build reserves, companies are effectively conducting a "going-out-of-business sale" every day, bleeding value until there's nothing left.

[70] *See* Maitali Ramkumar, *Why Is Reserve Replacement Ratio Important to the Upstream Sector?*, *Market Realist* (Dec. 8, 2015).

Grasping this dynamic, that oil and gas companies must continually replace and grow their reserves to remain viable, is essential to understanding why portfolio rationalization plays such a central role in modern upstream strategy. Nearly every oil and gas company engages in continuous portfolio rationalization at one time or another, which means they constantly evaluate and adjust their inventory of wells and mineral acreage holdings to optimize financial performance (RRR, profitability, growth in enterprise value, etc.), minimize risk, and align with their strategic focus on providing returns to shareholders/owners. At its core, rationalization involves analyzing each assets' 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.

It is important to understand that the perception of value for an oil and gas asset is a moving target as the development potential for undrilled acreage and legacy wellbores may be proven-up or condemned based on the success or failure of drilling, workovers, or recompletions in an area, or the success of failure of a new technology or process in an area. Moreover, oil and/or natural gas prices (which are beyond the control and prediction capability of the operator) can change radically, which then can radically change the development potential of a particular asset. These rapid fluctuations in potential mean that determining "beneficial future use" for a given oil and gas asset (including the inactive/marginal wells within that asset) is like catching a falling knife.

This is because, in the oil and gas industry, one operator's overlooked legacy well or parcel of acreage can be another's golden opportunity. Innovative oil and gas companies thrive by seeing opportunities where others see none, snapping up legacy wells (including marginal/temporarily abandoned wells) and the associated acreage that others (often larger) operators have deemed not to fit their portfolios, and applying their own creativity, experience, and technology to transform these assets into profitable projects.

From my perspective, this approach isn't just a hypothetical concept; it's been the core focus of my career over these last 40 years. By repurposing marginal or idle wellbores that I have acquired for various companies, I have repeatedly leveraged these wells as low-cost testing opportunities for new recompletion techniques or production strategies. The reason this is important is that refurbishing and re-purposing existing wells and infrastructure drastically reduces development costs and reduces the risk involved in experimentation. For just one example, see my paper from 1992 about a project I successfully executed in the Giddings Austin Chalk field of Texas, where I combined proprietary expert system/database/GIS information technology with what was then a cutting-edge hydraulic fracturing technique to unlock the hidden potential in numerous marginal/inactive wells.[71] The eventual fieldwide application of this approach to vertical wells by numerous operators across the field not only provided a test bed for this new frac technique and technology but eventually led to combining the then proven frac technology with horizontal drilling technology to unlock the full potential of the field. The dynamic demonstrated in the Giddings Austin Chalk field underscores a vital truth: determining "beneficial future use" in oil and gas is a constantly moving target, shaped by an individual Operator's insights, proprietary data/knowledge, ability to leverage technology, and/or willingness to innovate where others cannot

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[71] McGowen III, H.E. and Krauhs, J., 1992, *Development and Application of an Integrated Petroleum Engineering and Geologic Information System in the Giddings Austin Chalk Field*, SPE Paper 24441, presented at the Seventh SPE Petroleum Computer Conference, Houston, Texas, July 19–22.

or will not.

The idea that every operator can foresee the hidden potential in every marginal or inactive well, predict future market conditions with precision, and rigidly plan for "beneficial future use" is fundamentally flawed. Building asset value in oil and gas is dynamic and often unlocked through creative application of unique expertise, proprietary data, or novel technologies. My experience has been that *"Information never arrives in the right order or at the right time to make the perfect decision.[72]"* Many operators, me included, have built profitable companies by acquiring legacy wells and/or acreage written off by others and repurposing them into successful projects. By retaining these marginal assets long enough to analyze the wellbores, research available options, and then test new recompletion strategies or apply new technologies, operators can uncover value that wasn't apparent before. For example, leveraging legacy wellbores as part of a staged development strategy, where operators obtain critical information before committing to new well drilling, can significantly reduce risk, particularly under oil price and reservoir quality uncertainty. In short, retaining flexibility, keeping options open, and having sufficient time for analysis and information to become available are not luxuries, they are critical tools that enable transformation of what once seemed like junk into high-performing assets.

It is worth noting here that in the United States, oil and gas wells are often co-owned by an Operator and various non-operating working interest partners, typically under a Joint Operating Agreement (JOA)[73]. Standard JOA templates (such as the AAPL Form 610, including the 2015

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[72] Rita Gunther McGrath, *The End of Competitive Advantage: How to Keep Your Strategy Moving as Fast as Your Business*, Harvard Business Review Press, 2013.

[73] In New Mexico, in the limited case of parties that gained their non-operating working interest (WI) through

version) include strict consent requirements for operations on wells that are "producing in paying quantities." In fact, Article VI.B.9 of the AAPL 610-2015 model JOA[74] explicitly prohibits any major operations (reworking, deepening, recompletion, etc.) on an existing well that is capable of producing in paying quantities "except with the consent of all parties" to the agreement. This means that if a well is still producing profitably, even a very small non-operating interest holder can veto proposed major work on that well. The intent is to protect minority partners from unilateral expenditures or risks on a well that is already yielding a return. These type of JOA provisions often make low-producing or inactive wells attractive candidates for testing new techniques or conducting major remedial operations. If a well is marginal (barely economic or shut-in), the Operator can declare it not producing in paying quantities and propose a bold operation (such as a refracture, deepening, or new completion) without being vetoed by cautious minority partners. Any non-operating partner that doesn't believe in the project can opt out and face the non-consent penalty, while the Operator (and any others who elect to participate) can proceed at their own risk. In essence, the Operator cannot be blocked by non-consenters when it comes to a non-paying well. The worst that can happen is those partners go non-consent and temporarily relinquish their interest. As a result, marginal wells become ideal test beds for new ideas and technologies: the Operator has the contractual freedom to try to increase production, and if successful, the rewards (for a time) flow exclusively to the risk-takers, with potentially 2× to 4×

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forced pooling, and the parties have not agreed to operate under a JOA, said non-operated WI may not include JOA voting rights or mechanisms for blocking operations.

[74] *See* A.A.P.L. Form 610-2015, Model Form Joint Operating Agreement, art. VI.B.9.

payout before the others rejoin the revenue stream. This dynamic preferentially incentivizes innovation on marginal/inactive wells, since an Operator can typically move forward without unanimous approval and reap an enhanced reward if the experiment works.

As 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. The proceeds from these sales or the cost savings from plugging and abandonment are then redirected into wells or acreage with higher growth potential, stronger margins, or technological or geographic importance.

This ongoing rationalization enables firms to maintain and/or improve financial performance, manage risk, and preserve operational flexibility for future opportunities. Rather than a one-time action, this strategy is a dynamic asset management practice, one that seeks to ensure capital is always aligned with assets expected to yield the highest risk-adjusted returns. This strategy is important for large operators with deep pockets and high enterprise value because for these companies any investment must be large enough, and must provide a high enough rate of return, to significantly increase the profitability and value of the company. With their higher overhead and larger starting point in terms of enterprise value, they must have focus their investments on low risk, high return, repeatable projects that provide a large inventory of future development opportunities (also known as “running room”).

Smaller oil and gas operators also buy and sell oil and gas properties, but they don’t merely sell off underperforming wells, they also actively pursue marginal or temporarily abandoned wellbores precisely because larger companies overlooked their potential. Armed with unique geologic insights, proprietary data, or innovative recompletion techniques, these nimble operators can pivot quickly, refurbish these assets at low cost, and test new ideas with much less financial risk. Larger operators often offload low-rate assets to smaller players who have leaner cost structures and a higher tolerance for experimentation. That ability to pivot, holding onto wells long enough to demonstrate their upside or packaging them for resale, is crucial for this process. It allows smaller operators to unlock value others couldn't see, unlock hidden potential, potentially generate outsized returns, and then pass the asset upward to companies needing a proven project concept and production scale. In short, portfolio rationalization for small operators isn't just trimming the fat, it's a strategic, creative endeavor grounded in timing, information asymmetry, and technological leverage.

Smaller operators often act as de facto incubators for innovation in the oil and gas sector, because their incentives aren't capped by corporate bureaucracy or fixed career trajectories. In a large company, an engineer who pilots a successful innovation may receive a raise or promotion, but if the project fails, the response is often to revert to low-risk, status-quo approaches, or even fire that engineer for making a mistake. By contrast, a smaller operator can enjoy the benefit of entrepreneurial upside: if a recompletion technique or new technology succeeds on a marginal or temporarily abandoned well, it can generate significant returns and even be sold to a larger firm seeking to scale up the play. These small operators typically operate with lower overhead, fewer layers of management, and greater agility, enabling rapid experimentation, and they are motivated to innovate because they can fully enjoy the upside of success. As one landmark example, Mitchell Energy's persistence and experimentation in the Barnett Shale, trying unconventional fracs in a formation the majors had overlooked, sparked a major industry revolution that larger firms couldn't have risked exploring initially.[75]

The foregoing demonstrates the critical need to minimize unnecessary barriers to property transfers and to afford all operators entrepreneurial flexibility. Operators require both time and agility to retain potentially valuable marginal, inactive, or temporarily abandoned wells until market conditions, technology improvements, data capture, and analysis converge. These marginal/inactive wells are often indispensable for low-cost hypothesis testing, monitoring, etc., often serving as the launch pad to prove an operator's vision for an asset or region, or to conduct the groundwork necessary to validate a concept, preparing it for acquisition by a larger, better capitalized operator capable of advancing it to full development.

Real-world experience and portfolio optimization theory show that staged development using existing wellbores as a starting point can significantly reduce cost and risk under price and reservoir uncertainty. Based on my personal experience and industry trends, entrepreneurial operators often convert marginal/inactive wells into industry-transforming assets through a creative process that requires considerable analysis, persistent innovation and focused experimentation over a long period of time. Without rules that allow flexible holding and transfer of marginal wells, the ability to incubate new ideas, unlock latent value, and responsibly steward wells through full development will be severely compromised.

In short, rules that rigidly limit time, flexibility, or transferability of marginal and inactive wells will stall this entire ecosystem. They will constrain innovation, discourage risk-taking on lower-

[75] Steward, D., *George P. Mitchell and the Barnett Shale*. Journal of Petroleum Technology (2013, October 31), available at: https://jpt.spe.org/george-p-mitchell-and-barnett-shale

cost platforms, and penalize those Operators best positioned to convert what appears to be liabilities to the uninformed or unimaginative into high-performing assets. The ability to hold, analyze, test, repurpose, or transfer wells based on evolving information and market conditions isn't a luxury, it is a vital tool for enabling beneficial future use and aligning regulatory goals with prudent well stewardship.

Scenario 1: Small Well-Count Operator:

As I understand proposed rules, the OCD will require a $150,000 per-well financial assurance amount for each active well, unless the operator qualifies for and opts into the blanket bond of $250,000. This means that an operator with just two active wells, even wells that have been demonstrated to have adequate casing/wellbore integrity and that do not pose any heightened P&A risk, must post $250,000-$300,000 to secure those two active wells. That is, 2 wells × $150,000/well = $300,000, or the Operator can choose instead to post a $250,000 blanket bond that covers all active wells, whether it's 2 or 200. So, the floor for a two well Operator is $250,000 if the Operator uses the blanket option and the ceiling is $300,000 if the Operator chooses to post the per well bond of $150,000. In this case, the per well option only makes financial sense if one of the two wells is inactive such that this two well Operator would have more than 15% marginal/inactive/un-approved TA/Approved TA wells, and therefore must post $150,000 per well, because in this case, the blanket option is not available.

This example powerfully illustrates why the proposed financial assurance rules are fundamentally flawed, both in logic and economic impact, and why they disproportionately harm responsible, small operators without providing meaningful environmental or regulatory benefit.

In the case of a two-well operator, the proposed rules require a $150,000 bond per well unless the operator qualifies for and elects the $250,000 blanket bond covering all active wells. On the surface, this appears to offer flexibility. But upon closer inspection, the rule structure collapses into absurdity.

Under the per-well bonding scheme, the operator would owe $300,000 to secure two active wells, even if those wells are in excellent condition, have been recently tested, and pose no material risk of becoming orphaned. Meanwhile, the blanket bond offers a cheaper alternative, $250,000 for all active wells, whether you have two or 200. In other words, an operator with just two wells pays the same blanket amount as a large operator managing hundreds of wells with a much higher aggregate risk. This is plainly regressive: the small operator pays vastly more per well than the large operator, even though the total P&A exposure is significantly smaller.

It gets worse. The moment one of those two wells is temporarily shut in, deemed marginal, or placed into temporary abandonment (even if compliant with OCD requirements), the operator crosses the 15% threshold of marginal/inactive wells and is disqualified from the blanket option entirely. They are now forced to post $150,000 per well, raising their bond requirement to $300,000, despite having done nothing wrong, and despite those wells potentially being key candidates for recompletion or low-cost redevelopment. The rule thus punishes not risk, but math, creating an arbitrary and punitive outcome for small operators based solely on well count and portfolio status, not actual environmental exposure.

It's also important to recognize that the cost to plug and abandon a well is generally proportional to the depth of that well. According to a major 2021 study on decommissioning costs, each additional 1,000 feet of well depth increases plugging costs by approximately 20%, with the median cost to plug and restore a shallow well under 5,000 feet being significantly lower than

$150,000.[76] In fact, median plugging and surface reclamation costs across the U.S. average around $76,000.[77] [78] New Mexico has thousands of shallow wells, for instance in the Yeso formation of southeast NM (oil wells often ~5,000–7,000 ft deep) and the Pictured Cliffs gas wells of the San Juan Basin (often only ~1,000–4,000 ft deep), which can be expected to be lower-risk, low-cost candidates for plugging. In contrast, the state also has some very deep wells (e.g. in the Delaware Basin) exceeding 10,000–12,000 ft, which can be expected to be far more expensive to abandon. Given the difference between these boundary values, it is technically unwarranted to require the same $150k bond for a 3,000-ft shallow stripper well as for a 13,000-ft high-pressure gas well. For validation from the literature that P&A cost scales with depth, see Table 2. [Note: Median cost including plugging and site reclamation, rounded to illustrate scale.]

Table 2 – Typical P&A Median Cost by Well Depth (onshore wells)

Well Depth	Typical Median P&A Cost	Example Context
Shallow Wells < 5,000 ft	**~$20,000 – $30,000**	*Small legacy wells, e.g. shallow oil producers in KS/OK or Pictured Cliffs gas.* Oklahoma's average ~$18k[79] reflects this category.

[76] Raimi, D., Krupnick, A. J., Shah, J.-S., & Thompson, A. (2021, July 14). *Decommissioning orphaned and abandoned oil and gas wells: New estimates and cost drivers*. Environmental Science & Technology, pg.10228, 55(15), available at: https://doi.org/10.1021/acs.est.1c02234

[77] Raimi, D., Krupnick, A. J., Shah, J.-S., & Thompson, A. (2021, July 14). *Decommissioning orphaned and abandoned oil and gas wells: New estimates and cost drivers*. Environmental Science & Technology, pg. 10224, 55(15), available at: https://doi.org/10.1021/acs.est.1c02234

[78] *See* MineralAnswers, *Colfax County, NM Oil & Gas Activity Stats* (May 2025) (reporting an average well depth of 2,379 feet in Colfax County), and MineralAnswers, *New Mexico Oil & Gas Activity Stats* (May 2025).

[79] Niles Stuck, "Overcoming Oklahoma's Orphaned and Abandoned Well Problem," *Oklahoma Bar Journal* (May 2024).

Well Depth	Typical Median P&A Cost	Example Context
Mid-Depth Wells 5,000–10,000 ft	**~$50,000** (tens of thousands)	*Typical onshore well in many basins (Yeso, Permian strata). Moderate depth wells generally plug for five figures.* Texas P&A costs ~$20–40k for many mid-depth wells[80].
Deep Wells > 10,000 ft	**~$100,000+** (up to low six figures)	*High-depth, high-pressure wells.* Costs rise substantially, e.g. ND ~15,000-ft wells can cost ~$150k each with site restoration.[81] Only a minority of onshore wells fall in this extreme category.

Therefore, applying a flat $150,000 bond per well regardless of depth or actual risk results in a dramatically overstated financial assurance requirement, especially for small operators managing low-depth, low-risk wells. This one-size-fits-all approach is not only economically inefficient, it also ignores basic cost structure realities.[82]

This is a textbook example of how one-size-fits-all regulation fails. It shows no understanding of how operators, especially smaller, entrepreneurial ones, strategically manage their portfolios. These operators often acquire relatively shallow, underutilized wells, invest in recompletion strategies, and act as incubators for innovation. From the perspective of the small operator, marginal wells are not signs of irresponsibility; they are potential fuel for the creative process that

[80] Erin Douglas, *The Texas Tribune* (August 26, 2022), available at https://www.texastribune.org/2022/08/26/oil-gas-wells-infrastructure-money-texas-railroad-commission/.

[81] *Why It's So Hard and Expensive to Plug an Abandoned Well,"* WESA / Public Radio Pittsburgh (August 1, 2021), available at https://www.wesa.fm/environment-energy/2021-08-01/why-its-so-hard-and-expensive-to-plug-an-abandoned-well.

[82]*See* Resources for the Future, *New Study Reveals Key Factors for Estimating Costs to Plug Abandoned Oil and Gas Wells* (July 21, 2021) (reporting median plugging-and-reclamation costs of $76,000 per well and carriage-only median of $20,000), based on data from over 19,500 orphaned U.S. wells.

generates value while minimizing new surface disturbance and capital exposure.

Clearly, plugging costs vary significantly based on key factors like well depth, well age, and well type (oil vs. gas).[83] Therefore, there is no engineering-based rationale for imposing a flat $150,000 bond per well without regard to well depth, age, mechanical integrity status, or proximity to sensitive areas. The proposal ignores all principles of risk-based bonding in favor of a crude numeric threshold that fails both technically and economically. Clearly, financial assurance rules should reflect these variables, rather than applying a flat, one-size-fits-all bond, and smart design could reduce future orphan wells without overburdening responsible operators. Unfortunately, the proposed New Mexico rules do the opposite: they ignore well depth, age, and type entirely, applying a blunt $150,000 per-well requirement that overstates risk in some cases, understates risk in others, and fails to reward low-risk operations.

In summary, this two-well operator example highlights how the proposed rules create arbitrary thresholds, regressive economics, and misaligned incentives, penalizing low-risk, small but compliant operators while doing little to reduce orphan well risk. It's not just unjust and punitive; it is irrational.

Scenario 2: Larger Well-Count Operator

For another example, suppose that, under the proposed rule, an operator with 100 total wells whose portfolio includes exactly 15% marginal or inactive wells (15) is required to post $150,000 in financial assurance for every well they operate, or they can elect to post the $250,000 flat

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[83] Raimi, D., Krupnick, A. J., Shah, J.-S., & Thompson, A. (2021, July 14). *Decommissioning orphaned and abandoned oil and gas wells: New estimates and cost drivers*. Environmental Science & Technology, pg. 10226, 55(15), available at: https://doi.org/10.1021/acs.est.1c02234

amount. Obviously, this operator would choose to post the $250,000 flat amount.

Now, suppose that this operator with 100 wells increases its inactive well count[84] by just one (1) marginal/inactive well from fifteen (15) to sixteen (16) marginal wells. This Operator would suddenly see their financial assurance obligation increase from $250,000 (via a blanket bond) to a staggering $15,000,000.

This "all-or-nothing" trigger introduces an irrational financial cliff that is not risk-based, not proportional, and not economically viable for most independent operators. This rule would penalize routine operational issues and variations in production, such as natural production declines, equipment failures (like a rod part or a hole in the production tubing) or temporary shut-ins, with a catastrophic increase in bonding requirements. Moreover, it is impracticable in terms of the time required because no grace period is provided for the operator to either plug some wells or obtain the enormous bond.

Considering the scenario of an Operator going from 15% to 16% marginal and inactive wells reveal that lumping marginal wells, ATA wells, and unapproved inactive wells together under a single regulatory threshold ignores both the vastly different environmental risk profiles and the distinct intentions of the operators managing them. An ATA well, backed by pressure tests or mechanical integrity documentation and subject to ongoing oversight, which may be an irreplaceable and potentially valuable asset in the future, presents a fundamentally different risk

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[84] If the Operator fails the 15% rule, under the proposed regulations, active, fully compliant, producing wells and wells Approved for Temporary Abandonment and marginal/unapproved temporarily abandoned wells, and even wells that are simply waiting on parts, equipment, laborers, financial partners, rig availability, or engineering plans to execute workover operations required to put the well back on production, would all require the $150,000/well bond.

than a well left idle without compliance. Similarly, a marginal producing well that continues to yield hydrocarbons and is actively monitored does not carry the same abandonment risk as an unreported, unmaintained well. Treating these categories as one and the same is not only analytically illogical, but it also unfairly penalizes responsible operators who follow the rules, invest in well integrity, and practice sound stewardship. The proposed rules reflect a troubling bias that paints all operators with the same brush, reinforcing a narrative that any well not producing robustly must be a liability and that every operator is a potential bad actor. It creates a form of regulatory prejudice that substitutes blanket suspicion for measured risk-based oversight.

The punitive and abrupt shift created by making the trigger a step-function imposes a massively disproportionate financial penalty for what may be a minor operational change (an increase of just one marginal well) without any scientific basis for how this proportionately punitive penalty meaningfully reduces risk to the environment. The result is a sudden $14.75 million increase in bonding requirements. This is not risk-based, it is a looming regulatory cliff that introduces severe financial strain and risk, especially for small and mid-sized operators who lack immediate access to multi-million-dollar surety instruments. Further, this structure distorts prudent management, by:

- <u>Discouraging moving wells to a planned Approved TA status (where a well could be appropriately prepared for Temporary Abandonment and inventoried for beneficial use in the future):</u> Under current more reasonable rules, Approved TA is a formal, supervised status, where operators must apply using Form C-103, demonstrate mechanical integrity via testing, provide financial assurance, and receive OCD approval for up to five years of TA status.
- <u>Penalizing wells in Approved TA status:</u> Although these wells meet integrity and

regulatory standards and are not an environmental liability, under this rule in this situation they would count toward the operator's marginal/inactive total.

- Undermining OCD's established TA Program - The TA framework under 19.15.25.12–.14 NMAC was designed to facilitate responsible management of idle wells, not to impose potentially punitive statewide bonding on wells where none is needed.

iii. Impact of Concentrated Idle-Well Bonding Requirements in New Mexico

Requiring all operators with numerous marginal or inactive wells in New Mexico to obtain new financial assurance bonds simultaneously would create a highly concentrated risk in one industry and geographic area. In my experience, surety bond providers typically try to avoid correlated exposures, that is, if every bond is tied to the same sector and location, a single adverse event (like a regulatory crackdown or oil market downturn) could trigger many simultaneous bond claims. In this scenario, risk diversification is minimal, so insurers and surety companies perceive a higher chance of widespread defaults. Indeed, industry analysts note that capacity challenges[85] in surety markets tend to be "deal or geography specific and are driven by risk, regulatory restriction or concentration risk." In other words, more likely than not, a *convergence of many high-risk bonds in one state* will make underwriters cautious and could strain the available bonding capacity.

iv. Unanticipated Effects on Obtaining New and Maintaining Existing Assurance Instruments

In my professional opinion, based on my experience as the CEO of multiple oil and gas

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[85] Aon. *2025 Global Construction Insurance and Surety Market Report.* Aon plc, 2025.

operating companies and overseeing acquisitions and divestitures worth millions of dollars, the private surety and insurance markets are more likely than not ill-prepared to meet the surge in demand for financial assurance that this rulemaking will create for New Mexico operators. I anticipate that surety and insurance providers will require significant collateral from operators to issue the newly mandated bonds, given the increased risk exposure. However, many smaller and mid-sized independent operators likely will not have the necessary collateral available to acquire these bonds. I would also expect repercussions for existing bonds: surety companies may reassess their risk and demand additional collateral or stricter terms even for bonds already in place, further straining operators' finances. As a result, I foresee that numerous operators, who are currently in compliance with today's financial assurance requirements, will be unable to satisfy the new mandates, potentially forcing them out of business (even into bankruptcy) thus preventing them from continuing operations. If these small operators go into bankruptcy they will probably not be able to plug any more wells, regardless of their condition.

It is my opinion, as someone who has done numerous oil and gas deals, that these heightened financial assurance requirements will also have adverse effects on the flow of capital and the feasibility of transactions in the upstream oil and gas sector in New Mexico. Capital that must be tied up as bond collateral or allocated to meet financial assurance obligations is capital taken away from productive uses such as field development, well maintenance, or new acquisitions. In effect, this reduces the funds available for both acquisition and subsequent investment in the properties and increases the effective liability and cost associated with every deal. In my experience, any added regulatory complexity or uncertainty, often referred to in the industry as "hair on a deal," translates directly into heightened risk for investors and lenders. This dynamic discourages capital providers like banks and private equity firms from financing projects or acquisitions in New Mexico, as the potential returns may not justify the elevated risk and compliance costs. Consequently, operators in New Mexico will find it more difficult to raise funds and attract partners, and many potential buyers may shift their focus to opportunities in other states with more manageable regulatory burdens. In short, more likely than not, the onerous bonding requirements proposed (along with proposed regulatory interference in the A&D process) and associated compliance costs will make transactions less competitive and far more challenging to execute, jeopardizing deals that might otherwise benefit both the industry and the state.

Moreover, these 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 that small, medium-sized, and larger companies divest. These companies typically have limited capital resources and rely on reasonable bonding terms to repurpose wells,[86] or keep low-producing fields running. They may have plans to re-purpose wells,[87] 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.

Moreover, as someone who has re-purposed many wells, I can say that there is a practical component of this discussion that has been entirely missing. Acquisitions typically are closed in a compressed period, which limits due diligence and analysis time. An operator may often acquire a

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[86] Interesting Engineering. *Repurposing Oil and Gas Wells for Compressed Air Energy Storage,* (July 17, 2024), available at: https://interestingengineering.com/energy/compressed-air-energy-storage-oil-gas-wells

[87] Santos, L., Taleghani, A. D., & Elsworth, D. *Repurposing Abandoned Wells for Geothermal Energy: Current Status and Future Prospects.* Department of Energy and Mineral Engineering, Pennsylvania State University, University Park, PA, USA (2022), available at: https://personal.ems.psu.edu/~fkd/publications/journals/2022_j_renengy_wells_for_geotherm_arash.pdf

property with a particular development and asset utilization plan in mind based on the information available to the operator before and during the acquisition process. Once the buyer gains ownership of the property, they will have access to and time to review more detailed records and then be able to observe the performance and characteristics of the wells first-hand. Often, field hands who come with the acquisition hold critical information that is not written down anywhere and cannot be known by the buyer until after the transaction is complete. The buyer will at some point begin testing their business plan for the property by re-entering wellbores and executing operations, inevitably discovering even more information about the condition of the wellbores in the package they just bought and information about the practicality/performance of the "Beneficial Purpose" plan that they had no way of knowing before the transaction was closed. An experienced oil and gas buyer will understand that they will probably gain information after the acquisition is closed, which will cause them to change/adjust their plans. All of this increases the risk to the buyer.

Because of the risk inherent in making an acquisition, combined with high collateral requirements that make obtaining bonds prohibitively expensive (or impossible), more likely than not, many would-be buyers will be effectively removed from the market. That means a critical exit path is lost for wells whose current owners are seeking to sell, often precisely because those owners lack the capital to plug the wells themselves. I have observed that many small operators are willing to purchase wells in need of remediation, for this reason, stepping in where the original operator cannot afford the eventual plugging costs. However, under the new rules, those buyers will struggle to secure the necessary bonding, and such transactions will likely collapse. The net effect is that the pool of qualified buyers shrinks at the very time they are most needed, leaving more wells stranded without a responsible new operator. This outcome could lead to otherwise productive wells being prematurely shut-in or even orphaned. Owners who cannot meet the new assurance demands may be forced to walk away from their assets, with no outside capital available to step in and assume those obligations.

Furthermore, the added regulatory complexity, from more extensive financial filings to additional legal and engineering reviews required by the new rules, will slow down deal-making and increase transaction costs. In some cases, it may even prevent deals that would have enabled proper well management or continued production. For example, the proposed rules would even impose heavy burdens on wells in "approved temporary abandonment" status,[88] wells that have been safely idled with state approval and oversight, by requiring large bonds and imposing rigid time limits on them. In my view, this approach essentially penalizes operators for complying with existing regulations and will further dissuade potential buyers from taking on such wells. Transactions involving such temporarily abandoned wells could easily be killed by the extra costs and uncertainties. Faced with these obstacles, operators might choose to plug those wells unnecessarily or abandon potential acquisitions rather than navigate the onerous new requirements, even if the wells might have been viable for future use. In sum, the cumulative effect of these financial assurance changes will be to drive away much-needed capital and capable operators from New Mexico. It will increase costs and risks across the board, discourage the transfer of wells to responsible parties, and ultimately may lead to more wells being hastily plugged or left unmanaged, outcomes that ironically undermine the very goals of the new rule by threatening both

[88] New Mexico Administrative Code. *Title 19, Chapter 15, Part 25 – Temporary Abandonment and Decommissioning.* 19.15.25 NMAC, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Santa Fe, NM, available at: https://www.srca.nm.gov/parts/title19/19.015.0025.html

economic viability and proper well management.

a. Surge in bond demand and market capacity constraints

If the proposed rule changes force dozens of operators to seek large surety bonds all at once, the supply of bonding might not meet this sudden spike in demand. The surety industry has finite capacity and must allocate capital carefully. A dramatic increase in required bond amounts (potentially hundreds of millions of dollars in aggregate) could exceed what surety providers are willing or able to underwrite at that time. We have a recent analogue in the offshore sector: when regulators proposed ~$9.2 billion in new decommissioning bonds, surety companies warned they *"will not provide $9 billion of new capacity"* given recent losses and limited capital, and that operators would struggle to afford the massive premiums and collateral required for such bonds. This illustrates that a sudden, large bonding mandate can overshoot market capacity.

In practical terms, a bond market crunch could occur. Premium rates would likely skyrocket as many companies compete for bonding from a small pool of providers. (Surety bond premiums for oil & gas are often around 1–5% of the bond's value in normal times, but higher risk and limited supply could push rates up further.) Additionally, underwriters may demand substantial cash collateral before issuing bonds, effectively requiring operators to tie up capital equal to a big portion of the bond. One industry comment likened this dynamic to a financial "run on the banks," where if one surety tightens terms and demands cash, others quickly follow, exacerbating the credit squeeze. Thus, *many operators seeking large bonds simultaneously* can expect higher costs and difficulty obtaining bonds, especially for those with weaker balance sheets.

b. Surety providers' view of a hostile regulatory environment

A regulatory regime perceived as hostile or unpredictable further amplifies the bond market's reaction. Surety underwriters thrive on stable, well-defined risk; that is, they normally issue bonds expecting no losses, because they carefully vet each operator's ability to fulfill obligations. If New Mexico suddenly increases bond requirements and hints at future tightening (or mandates immediate plugging of many wells), it signals that the probability of bond forfeiture is rising. From the surety's perspective, the bonds start to resemble "forfeiture instruments," one of the riskiest forms of obligation where a bond can be called in full if the operator fails any task. More likely than not, under such conditions, many sureties will either exit the market or drastically raise their underwriting standards. As a joint letter from the surety industry cautioned, when obligations carry excessive uncertainty or perpetual liability, there is a *"strong likelihood that sureties would not be willing to write such an obligation or would only issue such bonds for the financially strongest businesses."* In short, a tough regulatory environment with aggressive rules makes bond providers fear that they'll end up paying out claims en masse, so they respond by insuring only the most credit-worthy operators, requiring extra security, or not offering bonds in that arena at all.

Regulatory uncertainty also plays a role. Just like any other prudent business, firms invest and insurers underwrite more freely when rules are steady. Frequent or severe rule changes create a climate of unpredictability, which "may be impacting … investment decisions" in oil and gas, as noted in a federal analysis.[89] Sureties prefer clear, consistent bonding rules; if New Mexico regulators have demonstrated a bias against the industry (for instance, abruptly raising requirements or showing willingness to impose costly obligations with little regard for the financial

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[89] Ma, X., & Xie, Z. *The Economic Impact of Uncertainty About U.S. Regulations of the Energy Sector,* (Sept. 2024), available: https://regulatorystudies.columbian.gwu.edu/sites/g/files/zaxdzs4751/files/2024-11/Econ_Impact_Uncertainty_Energy_Sector_Ma_and_Xie_Sep2024_RSC.pdf

health of the regulated companies), insurers interpret that as a sign that future rules could become even more onerous. More likely than not, they will factor this into pricing and availability, often by adding a risk premium or capping their exposure in the state. Essentially, New Mexico's policy risk becomes part of the underwriting assessment, more likely than not, resulting in *higher bond costs or outright refusals for higher-risk operators*.

c. Consequences and costs of risk concentration will mean less providers will issue FA and for fewer clients

The combined effect of these factors is a much harsher bond market for New Mexico operators that operate many low-producing or inactive wells. A concentrated, correlated risk profile means less competition among bond providers, possibly only a few insurers willing to write the bonds, and only for select clients. Those operators that do secure bonding will more likely than not face steep premiums and strict terms, reflecting the heightened risk. Industry observers note that in some cases, traditional bonding is becoming so difficult that states are exploring alternatives, such as escrowed trust accounts, sinking funds, or cash bonds, to ensure well closure obligations are covered. This is essentially a workaround because surety bonds have become harder to obtain for marginal-well operators under current market conditions.

There is also a broader economic and operational impact. Smaller independent operators, who often hold a large number of marginal wells, could be unable to afford or obtain the new bonds. If they cannot comply with the financial assurance rules, they may be forced to shut in wells or declare bankruptcy. The Independent Petroleum Association of New Mexico (IPANM) has warned that haphazardly raising bonding requirements would likely *"lead to an immediate spike in* *abandoned wells and [drive] many highly reputable small oil & gas companies out of business.'*"[90] In other words, an aggressive bonding mandate could backfire: instead of providing security, it might result in more orphaned wells if operators collapse under the new financial burden. Those orphan wells would ultimately fall to the state to plug, which is exactly the outcome the bonding was meant to prevent.

In summary, forcing a large bloc of New Mexico operators to seek hefty assurance bonds simultaneously would significantly disrupt the bond market. We would expect a scarcity of surety capacity, higher costs of bonding, and selective underwriting favoring only the strongest firms. Bond providers, wary of the concentrated risk and a tough regulatory backdrop, are likely to retreat or charge a premium for doing business in this environment. The costs to operators would more likely than not rise accordingly; not just in premiums, but also in tied-up collateral and compliance overhead. This concentrated-risk scenario illustrates the classic market response to correlated threats: prices go up and capacity goes down, leaving the most vulnerable participants at risk of being unable to secure the financial guarantees they need. Such outcomes underscore why regulators must balance financial assurance needs with market realities; otherwise, well-intended rules could create a bonding bottleneck with costly side effects for industry and regulators alike.

d. Operators with lower working capital and large numbers of legacy wells may be unable to obtain the new FA required

More likely than not, the current surety market cannot support the scale of financial assurance

[90] Independent Petroleum Association of New Mexico (IPANM). *IPANM Pushes Back on Problematic Abandoned Well Report* (June 26, 2025), available at: https://ipanm.org/2025/06/26/ipanm-pushes-back-on-problematic-abandoned-well-report/

proposed. It is my understanding that surety underwriting for what are perceived to be risky ventures often requires collateral equal to 50–100% of the bond amount, with high selectivity based on operator financials. Operators with lower working capital and large numbers of legacy wells (i.e., older/low-production/marginal/inactive) may be unable to secure any surety, making the proposed per-well bond requirements unworkable for many.

E. Proposed Reclassification of Marginal Wells

1. The Importance of Marginally Producing Wells

Marginally producing wells, referred to as "Marginal Wells" or sometimes stripper wells, are oil or gas wells that produce at low but still economically viable rates, often contributing significantly to cumulative field production over long periods. Many marginal wells are maintained for reasons that go beyond short-term volume, including strategic lease retention, pressure support, or as future candidates for EOR projects. In EOR contexts, these wells may become injection wells, pilot wells for reservoir evaluation, or part of a broader field-wide development plan. Additionally, maintaining marginal production can preserve access to the subsurface estate and keep valuable leases active, avoiding costly re-leasing or unit restructuring. For many operators, particularly small and mid-sized independents, marginal wells are the backbone of sustained cash flow and long-term asset value.

Marginal wells and stripper wells account for a significant share of U.S. oil and gas production. According to the U.S. Energy Information Administration (EIA), stripper wells produced approximately 7.4% of total U.S. oil output and about 8.2% of total U.S. natural gas in

2022.[91] National Stripper Well Association (NSWA) estimates suggest that over 400,000 active stripper wells are in operation in the U.S., producing nearly 600 million barrels of oil and 2.9 trillion cubic feet of gas annually. The OCD publishes Stripper and Marginal Wells data (e.g., Stripper and Marginal Wells (Oil), updated October 12, 2021) that shows 3.63 million barrels produced by 11,635 wells, averaging ~2 BPD. If we assume a conservative GOR of 1,000 standard cubic feet per barrel (scf/bbl), a reasonable mid-range estimate for stripper wells, then a well producing 2 bbl oil/day would generate 2,000 scf gas/day, and since 1 BOE ≈ 6,000 scf of gas, the gas adds 0.33 BOE/day. Therefore, total output would be 2 (oil) + 0.33 (gas) ≈ 2.33 BOE/day. This is below the 1,000 BOE over 12 months proposed as the defining limit for marginal well status. These figures underscore the importance of marginal production in meeting domestic energy needs, particularly in mature basins like the Permian, San Juan, and Anadarko.

2. *New "Marginal Well" Definition – Proposed 19.15.2.7(M)(2) NMAC*

WELC proposes to add a new definition of "Marginal Well" under 19.15.2.7(M)(2) NMAC as meaning any "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."

3. *Risk of Misclassification*

Misclassifying productive or strategically maintained wells as marginal could force operators to prematurely plug viable wells or face unnecessary bonding burdens. This creates economic disincentives to maintain low-rate production and undermines the business case for revitalizing older assets through recompletions, artificial lift upgrades, or EOR. Operators often

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[91] National Stripper Well Association, *Stripper Wells.* Available at: https://nswa.us/stripper-wells/

plan such work on multi-year investment cycles and cannot respond efficiently to reactive or overly narrow regulatory metrics.

i. 12-Month Assessment Window is Too Short

The consecutive or prior twelve-month assessment window contemplated under both definitions is too short. The language at a minimum needs to be clarified to "within a prior twelve-month period." But I also have concerns about the administrative burden of continuously evaluating well status under a rolling 12-month window. Based on my experience, given the volatility often seen in these types of wells, extending the timeframe to a two-year or rolling multi-year period would better accommodate real-world factors like maintenance downtime, market constraints (such as gas takeaway bottlenecks), shutting in wells offsetting modern well fracs, or planned inactivity due to offset operator actions.

Contrary to the proposed definitions, operators assess the economic viability of marginal wells based on full-cycle economics, net cash flow after lifting costs, the presence of associated production (gas, NGLs), and strategic lease considerations. These do not necessarily align and could conflict with the proposed definitions by disregarding the broader economic rationale for keeping a well online at low rates. For example, shallow vertical wells with minimal overhead and direct-to-market sales may be profitable at 0.5 BOEPD. If regulators impose a blanket standard that such wells must be classified as marginal and subject to enhanced bonding, it penalizes efficiency and discourages investment in these cost-effective, low-risk assets.

Many wells producing under 2 BOEPD remain economic due to extremely low lifting costs (less than $5/BOE), no water disposal requirements, and paid-off infrastructure. These wells often generate steady, predictable cash flow and serve as "anchor wells" to preserve operational presence in a field. They can also become staging points for pilot testing or secondary recovery. Forcing their classification as marginal would reduce the incentive to maintain this inventory and could erode field-wide reserve value by eliminating options for incremental development.

ii. Valid Reasons for Intermittent Production

In my experience, a marginal well might produce intermittently because of curtailment, scheduled maintenance, infrastructure limitations, market conditions, offset fracs, and other operational realities that may temporarily reduce production below thresholds. These occurrences are not uncommon in practice. Marginal wells also contribute to leasehold operations and reservoir pressure management by holding leases in effect, stabilizing producing formations through drainage balancing, and preventing premature abandonment of reservoir-connected acreage. Once a producing unit is broken up, it can require years and enormous expenditures to put the acreage back together again for future development. None of these factors for variability in marginal well production are considered or accounted for under the proposed definition thresholds. The impact of applying a rigid threshold to shut-in or curtailed wells could result in mass misclassification of viable wells, unnecessary P&A costs, and the elimination of low-volume but high-value producing zones.

4. Bottom Line Recommendation

Ultimately, New Mexico's oil and gas landscape is diverse and full of marginal wells that serve long-term strategic functions. Also noted in Dan Arthur's testimony, the proposed definition, while intended to flag truly uneconomic wells, risks sweeping in far too many productive or strategically maintained wells, with negative economic and environmental consequences. I recommend that the definition as proposed not be adopted. But if a definition is to be adopted, then a more flexible definition that reflects the operational realities and economic diversity of marginal production should be considered instead.

F. Proposed Operator Registration and Change of Operator Restrictions

WELC proposes to amend the operator registration and change of operator requirements. WELC's amendments to expand the discretion of the agency to deny requests to change a designated operator. There are numerous legal and commercial risks embedded in WELC's proposal. These new operator registration requirements are also unreasonable and not feasible.

Specifically, current regulations fail to address the so-called "liability tail," that is, the period following a change of operator during which the outgoing or incoming operator remains responsible for plugging and environmental compliance. In Texas, for example, if an inactive well is transferred, the new operator must bring it into compliance within six months or face enforcement under Rule 15, including potential denial of organizational report renewals.[92] Under WELC's proposal, New Mexico operators could face similarly rigid timelines without any grace period, which is unworkable given the volume of wells and the complexity of turnover logistics. Furthermore, WELC's proposal introduces an unbounded threshold on inactive wells per operator, meaning that acquiring or divesting a portfolio of wells could trigger automatic regulatory scrutiny or even denial of operator status. From my experience overseeing field transfers, administratively transferring large numbers of wells often triggers unexpected data review, regulatory issues, and site inspection requirements that strain both operator and regulator (in this case, OCD) capacity.

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[92] Jennifer Gilmore, Texas Railroad Commission, P-5 Statewide Rule 15 Inactive Wells (July 2020), available at: https://www.rrc.state.tx.us/media/z5ngbaek/p-5-statewide-rule-15-inactive-wells-powerpoint-slides.pdf

Imagine a scenario where a mid-sized operator acquiring ~150 wells is forced to post additional bonds and submit pressure test records for all wells, delaying the transfer by six months and limiting their planned development operations.

Adding rigid, subjective denial criteria for operator changes injects operational uncertainty into every transfer or acquisition. It would penalize routine business transitions, raise transaction costs, and deter investment, particularly from smaller operators who rely on flexibility to manage portfolios. Conversely, clear, objective standards, modeled after Texas's six-month compliance window, combined with performance-based thresholds, would preserve regulatory oversight while enabling efficient, business-driven, well stewardship.

1. Amendments to Operator Registration Requirements – Proposed 19.15.9.8(B)-(E) NMAC

The current requirements to register with OCD and obtain an Oil and Gas Reporting Identification Number (OGRID) from OCD are codified at 19.15.9.8(B)-(E) NMAC. WELC alone proposes additional disclosure and certification requirements, including:

- **Affirmative certification of compliance** with all federal and state oil and gas laws in each state where the operator does business;
- **Mandatory disclosure** of whether any current/past officers or owners with more than 25% interest were affiliated with non-compliant operators in the past five years; and
- **Annual certifications** for existing operators regarding compliance with all current/past leadership and ownership.

i. Risks and Potential Impacts of Proposed Changes

a. Legally infeasible and operationally burdensome

Based on my experience, verifying compliance across operators and jurisdictions would be legally infeasible and operationally burdensome. Records of non-compliance may not be publicly available, vary significantly between states, or be under appeal or sealed. Requiring certification of unviolated status effectively penalizes personnel for past associations, even if they exited the company before non-compliance occurred. This creates a chilling effect on executive and investor mobility, discouraging talent from joining or leading operators due to fears that legacy issues could block registration or trigger liability. For some companies, the personnel operating in Texas (for example) could be completely different than the personnel operating in New Mexico, so this requirement would not change the competence or prudence of the personnel working on the New Mexico properties.

b. Policy will drive capital investment and operators out of state

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. Tracking and certifying multi-state compliance and officer histories would turn registration into a forensic audit. In real-world mergers and acquisitions, mapping out liabilities across dozens of fields and jurisdictions can take months, requiring detailed financial models, consultant assessments, and legal opinions. Requiring this for every registration, even annual certifications, would more likely than not overwhelm many operator compliance teams (especially for small operators) and delay new registrations.

ii. Burdensome and Excessive Compared to Other Jurisdictions

By contrast, Texas allows operators to register or change control by submitting a Form P-5 and provides a six-month window post-transfer to bring inactive wells into compliance under Rule 15, with plug or restore requirements, without demanding upfront cross-state compliance affidavits. Louisiana requires registration and bond confirmation but does not require detailed public officer histories; operators simply file an annual Organization Report (Form OR-1) with basic contact and bonding info. At the federal level, EPA relies on Class II injection well mechanical integrity testing and bonding rather than owner certification, streamlining oversight while avoiding subjective disclosures.

WELC's proposal lacks these practical guardrails, replacing them with broad, unexplained certifications. Instead, OCD should adopt a standardized, objective, and administratively feasible model, similar to Texas's structured compliance timeline, where operators file a registration, acknowledge known liabilities, and use a limited remediation window tied to physical compliance, not speculative historical associations.

2. *Amendments to Change of Operator Requirements – Proposed 19.15.9.9(B) NMAC*

The current version of 19.15.9.9(B) NMAC defines when a change of operator occurs, how it's reflected in OGRID numbers, the information required in Form C-145s, and states when the Division may deny a change of operator request.

i. *New Certification of Compliance with Other State and Federal Laws for Change of Operator Approval – Proposed 19.15.9.9(B) NMAC*

WELC proposes to add to 19.15.9.9(B) NMAC the requirement of certification of a P&A plan and give the Division the ability to request additional records pertaining to operator solvency and ability to perform P&A, provided such requests are narrowly tailored and reasonably necessary. The Division supports WELC's proposal without any changes.

a. Why the proposed changes are problematic

In my opinion, the proposed amendments to 19.15.9.9(B) NMAC are problematic for the following reasons:

- Delays operator transfers by making approval contingent on pre-approved P&A plans and financial scrutiny—unlike Texas, where compliance is post-transfer under Rule 15.
- Creates vague discretion—OCD would have undefined authority to demand solvency documents with no clarity on standards or thresholds.
- Increases administrative burden—especially in multi-state transactions, requiring detailed project-level P&A and financial plans up front instead of structured deadlines after transfer.

b. Comparison to other jurisdictions

The proposed amendments are excessive and burdensome compared to other jurisdictions:

- In Texas, Operator changes are processed via Form P-4, which requires:
  - Certification of responsibility for plugged or inactive wells under Rule 14 at time of filing—meaning paperwork is rejected if plugging isn't planned or completed; and
  - Evidence of bonding adequate to cover current operations and transferred wells, as specified in the instructions.
  - There's no requirement to submit detailed P&A plans or financial documents beyond bond proof. Any deferred plugging must follow Rule 15, giving operators six months after change-in-operator approval to execute P&A or obtain extensions
- In Louisiana, new operators must post financial security for wells being transferred before approval of the operator change, but compliance standards are objective and narrow,

centered on bonding and technical capability, not subjective solvency or P&A planning. Transfers aren't stalled by vague agency discretion.

ii. New Grounds for Change of Operator Denial – Proposed 19.15.9.9(C) NMAC

Under the current version 19.15.9.9(C) NMAC, the Division may currently deny a change of operator if they are 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.

Under proposed 19.15.9.9(C) NMAC, WELC proposes to expand the Division's discretion to deny a change of operator request under the following circumstances:

- Any officer, director, or twenty-five percent or more interest holder who is or was in the past five (5) years involved with an entity not currently in compliance with 19.15.5.9(A) NMAC (under proposed 19.15.9.9(C)(3)-(4) NMAC);
- Applicant is not properly registered or in good standing with the New Mexico Secretary of State (under proposed 19.15.9.9(C)(5) NMAC); and
- Certifications or disclosures show a "substantial risk" that the new operator can't meet P&A requirements (under proposed 19.15.9.9(C)(6) NMAC).

a. Why the proposed changes are problematic

In my professional opinion, requiring upfront certification of a P&A plan and subjective proof of operator solvency injects transactional uncertainty, inhibits investment, and renders due diligence burdensome or even impossible. Consider a scenario where a private-equity-backed operator seeks to acquire a portfolio of 200 wells across multiple states, including New Mexico.

Under WELC's proposal, the buyer would need to gather and certify P&A plans for every inactive well across all the states involved before operator status is approved in New Mexico, despite many of those wells being planned for continued operation or structured for sale, and demonstrate financial resources sufficient to carry out those plans. For private firms or smaller operators with rolling capital strategies, this effectively ends the deal unless financial contingencies are met long in advance, elevating risk and discouraging participation.

b. Seller cannot realistically certify buyer's compliance across other jurisdictions

Further, the seller cannot realistically certify the buyer's compliance across other jurisdictions. Oil and gas rules differ widely among states. For example, Texas requires Rule 14 plugging certification with P-4 filings. In contrast, Louisiana requires only notification and financial assurance within six months, yet WELC's rule would impose a rigid, one-size-fits-all standard. This conflicts with interstate commerce norms and data privacy: operators would be forced to expose competitive information such as planned investments, proprietary P&A cost models, and internal bonding strategies, information typically kept confidential and unless required by law. That would not only violate trade secret norms but also potentially trigger renegotiation of deals or breach confidentiality clauses in purchase agreements.

IV. RECOMMENDATIONS

To better achieve the shared goals of environmental protection, responsible well stewardship, maintaining tax revenue for the State of New Mexico, continued job creation and economic growth in the state, and contributing to the long-term energy security of the United States of America, I respectfully offer the following recommendations:

A. **Avoid rigid production-based thresholds or presumptions** that could misclassify viable wells as not capable of beneficial use, marginally producing, or required to be permanently P&A, and which discourage responsible operational practices like lease-level cycling.

B. **Preserve and strengthen the existing TA program**, recognizing its value in preventing unnecessary plugging and enabling future beneficial use.

C. **Allow pressure testing to serve as the primary means of demonstrating mechanical integrity**, with additional logging required only when warranted by test results or well history.

D. **Adopt a risk-based bonding framework** that differentiates between well types, ages, and conditions, rather than imposing a uniform per-well amount.

E. **Collaborate with industry to define realistic cost benchmarks** for financial assurance, drawing from actual plugging data and national best practices.

F. **Facilitate responsible operator transitions** by streamlining registration and bonding processes during asset transfers, particularly for low-risk or fully compliant wells.

These recommendations are presented in the spirit of constructive engagement and reflect lessons learned from decades of practical experience. They are intended to support the New Mexico Oil Conservation Division's mission while safeguarding the long-term viability of responsible oil and gas development in New Mexico.

That concludes my testimony on behalf of the New Mexico Oil and Gas Association.

SIGNATURE PAGE

I hereby affirm that the statements, analyses, and opinions contained in this report are true and accurate to the best of my knowledge and belief. This report has been prepared in a manner consistent with generally accepted professional and engineering standards.

Prepared by:

Signature: ________________________ **Date:** August 8th, 2025

Name: Harold E. McGowen III, PE No. 66419-Texas

Title: President and CEO

Company: Navidad Forensics

Dated this day of August 8th, 2025.

Respectfully submitted,

By:_________________________

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Testimony of Harold McGowen
NMOGA Exhibit D

APPENDIX A

Curriculum Vitae

Harold McGowen, PE

Curriculum Vitae of Harold E. McGowen III, PE

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Appendix A - Exhibit "A" – Condensed CV

Employment History

• President and CEO, Navidad Operating Company, LLC	2017 - Present
• Principal, Navidad Energy Advisors	2013 - Present
• President and CEO, Navidad Resources, LLC and NRI, Inc.	2003 - 2015
• President, .052 Petroleum Engineers, Tyler, Texas	2001 - 2003
• Senior VP of Engineering Services, Signa Engineering Corp., Houston, TX	1997 - 2001
• President, NaviData Systems, Inc., Kingwood, TX	1992 - 1997
• Engineering Manager, Trinity Resources, Inc., Houston, TX	1988 - 1992
• Petroleum Engineer, Union Pacific Resources Company, Houston, TX	1984 - 1988
• Engineering Technician, GEO-Vann, Inc., Katy, TX	1982 – 1983

Education

Texas A&M University

- Bachelor of Science (BS), Mechanical Engineering 1978 - 1982
  - Focused on Metallurgy, Machine Design, and Manufacturing
- Texas A&M Corps of Cadets
  - Cadet Captain, Scholastics Officer, Squadron 10,
  - Distinguished Student
  - Outstanding Freshman, Squadron 10
- ASME (Student Member)

Southern Methodist University: Executive Education Short Course, 2014

- Dev. a New Gen. of Energy Leaders: Strategic Leadership - ~40 hours
- Strategic Financial Skills - ~32 hours
- Oil and Gas Investing for Institutional Investors
- Formulating and Implementing Exceptional Business Strategy

Longview High School: 1974 - 1978

Activities and societies:

- Future Farmers of America
  - Awarded Star Greenhand for commercial hay growing and sales operation, managed 10 heifer breeding herd, purchased, raised, and flipped 20 stocker steers for a profit.
- East Texas Mud Hogs - Offroad 4WD Club
- Junior Engineering and Technological Society (JETS)

Memberships

Society of Petroleum Engineers (SPE), Since 1984

Accreditations

Registered Professional Engineer (PE) in the State of Texas, since 1989

Awards

Texas Ind. Producers and Royalty Owners - Top 15 Best CEOs - Med. Size Producer, 2013
Aggie100 - Fastest Growing Aggie Run Company - #1 2012, #4 2013, #3 2014, **#9 2023**

Publications:

- "Development of an Integrated Petroleum Engineering and Geologic Information System", SPE 2441, Presented at SPE Annual Meeting, January 1994
- Contributing author of "Underbalanced Drilling Manual", Signa Engineering Corp., 1998
- "UBO Technology Expands Horizontal's Success", The American Oil & Gas Reporter, July 1999 (with co-authors)
- "Fulfilling Technical, Educational Needs Key to UBO's Expansion", The American Oil & Gas Reporter, August 1999 (with co-authors)
- "Applicability of Underbalanced Drilling to Multilateral Junctions", Presented at IADC UBO Technology Conference, Houston, Texas, August 2000 (with George Medley)
- "Effective Methods of Engineering Outsourcing", SPE 84436, presented at SPE Technical Conference and Exhibition in Denver, Co., October 2003
- "OBM MPD Solves Drilling Challenges", American Oil and Gas Reporter, Volume 58 No. 10, 10/15/2013
- "Case Study: Using Managed Pressure Drilling and Oil Based Mud to Efficiently Drill an Extremely Thick and Highly Fractured Carbonate Sequence Under an Extremely Thick and Highly Sensitive Laminated Shale", presented at SPE/IADC Drilling Conference in London, UK, Mar 2015, SPE/IADC-173021, 2015
- "Unified Pressure and Rate Transient Analysis of Production and Shut-in Data from Fractured Horizontal Wells", HanYi Wang, Mukul Sharma, Harold McGowen, SPE-204136-MS, SPE Hydraulic Fracturing Conference, May 4-6, 2021

Speaking Engagements

- Speaker at Well Completions for Unconventional Resource Development Optimization and Parent-Child Interaction — Apr 2024
  - Case Study: Impact of Natural Fractures on Parent-Child Interactions and Mitigation Techniques in a Low Permeability Fractured Carbonate
- Speaker at UPTECh Upstream Oil and Gas Conference — Nov 2015
  - Drilling Optimization and Cost Control
  - Organizational Learning and Continuous Improvement
- Speaker at Low Oil Price CAPEX Reassessment, — May 2015
  - Cost Cutting & Financial Risk Management Congress
  - Impact of Learning Curve and Organizational Learning
  - Implementing Continuous Improvement
  - Strategies for maximizing production while minimizing CAPEX/OPEX
- Speaker at Well Spacing & Completion Optimization Eagle Ford Congress — Jul 2014
  - Spoke on exploration and development of fractured carbonates below the Eagle Ford (Buda, Georgetown, Edwards, and Glen Rose) including a comparison between techniques used in the Eagle Ford and techniques that were successful in these fractured carbonates.
- Speaker at SPE Workshop: Well Completions for Unconventional Resource Development Optimization and Parent-Child Interaction — Apr 2024
  - Spoke on recent experience with Parent-Child interactions and mitigation efforts in the Brookeland Austin Chalk Field of East Texas.
  - Santa Ana Pueblo, New Mexico,15-17 April 2024

Curriculum Vitae of Harold E. McGowen III, PE

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Email: hmcgowen@navidadenergy.com
Website: www.navidadenergy.com

Appendix A - Exhibit "B" – Expanded Curriculum Vitae Detailed Employment History and Training

President and CEO, Navidad Operating Company, LLC, 2017 to Present

Currently, serve as the CEO of Navidad Operating Company, LLC, managing exploration, development, and production operations for Navidad Resource Partners, LLC. Navidad Resource Partners, LLC is a Private Equity-backed oil and gas exploration and production company, actively developing horizontal drilling prospects in the Brookeland Austin Chalk Field. In addition, since 2013, I have provided consulting services through Navidad Energy Advisors, a registered professional engineering firm.

- Successfully identified and leased an approximately 24,000-acre green-field prospect, applying Horizontal-Multi-Stage-Hydraulic Fracturing in a field where all previous attempts had failed to yield economic results.
- Skillfully negotiated Joint Development Agreements with offset operators to accelerate the validation of an innovative exploitation technique and to secure future drilling prospects.
- Drilled and operated ten (10) 20,000'+MD Multi-Stage-Horizontal-Frac Brookeland Austin Chalk wells with capex of ~18MM/well and participated in four (4) similar wells as a non-operating partner.
- Strategically selected drilling locations, determined optimal completion methods, and oversaw both drilling and completion operations.
- Master-minded the construction of a frac water storage system, natural gas processing facilities, gathering system, and saltwater disposal system, inclusive of 2 SWD wells. This efficient SWD system is projected to save millions in operating costs over the life of the asset.
- Spearheaded a multi-disciplinary team, driving production from zero in 2017 to over 5,000 BOEPD (gas to oil at 15:1) in 2023 from eight wells.
- Rapidly expanded revenue from $10MM/year in 2020 to over $50MM/year in 2022, reflecting a compounded annual growth rate of nearly 100% per year.
- In 2023, Navidad Resource Partners, LLC achieved a remarkable 123.74% revenue growth rate over a three-year period, earning recognition as the 9th fastest-growing Texas A&M graduate-run company by the prestigious Aggie 100, which celebrates the world's fastest-growing Aggie-led businesses.

President and CEO, Navidad Resources, LLC and NRI, Inc., 2003-2015

- As President and CEO of Navidad Resources, LLC (an EnCap Investments portfolio company) and NRI, Inc., successfully led the discovery and development of the most prolific portion of the Buda-Rose fractured carbonate oil play in Houston and Madison Counties of East Texas.
- The successful execution of the following technical accomplishments and management functions was vital to building and running this Private Equity Backed oil and gas company, from raising seed

capital from individual investors, to securing a private equity investment, to developing the Buda-Rose play, to achieving the profitable sale of the property to Sequitur Energy Resources, LLC, in 2013 for approximately $220 million.

- Technical Accomplishments:
  - Developed a comprehensive understanding of the geology and reservoir characteristics of the Buda-Rose play, which encompasses multiple formations, including the statistical nature of oil and gas recovery in the Buda Limestone, Georgetown Formation, Edwards Formation, and four benches of the Glen Rose Formation.
  - Applied innovative drilling, commingling, and hydraulic fracturing techniques to unlock the potential of the Buda-Rose play.
    - Successfully drilled and developed approximately 1,400 feet of vertical fractured carbonate pay across the combined interval of these formations.
    - Introduced slick water hydraulic fracturing to formations that had not been previously stimulated, expanding the reach of the fracturing process.
    - Applied horizontal drilling or a vertical commingle technique where appropriate.
  - Guided the development of techniques to drill and complete in the targeted fractured carbonate formations while controlling 600 ft. of highly water-sensitive and unstable shale.
    - Implemented Managed Pressure Drilling (MPD) techniques to optimize wellbore pressure control and enhance drilling efficiency.
    - Utilized Oil-Based-Mud (OBM) drilling fluids to mitigate issues associated with drilling through highly water-sensitive shale, ensuring wellbore stability.
    - Developed customized lost-circulation protocols to minimize fluid loss and maintain efficient drilling operations.
  - Directed the leasing of approximately 100,000 gross acres, drilling around 50 wells, and constructing a state-of-the-art 30 MMCFD gas plant.
  - Installed over 100 miles of pipeline to support production operations.
  - Achieved a remarkable production rate of 5,700 gross barrels of oil equivalent per day (BOEPD).
- Management Accomplishments:
  - Initially raised seed capital of ~$250,000 in Navidad Resources, Inc. from Angel Investors which was augmented by subsequent funding rounds and creative equity financing, investing proceeds in projects that produced ~$10MM in value, which provided the foundation for future growth.
  - Led strategic planning initiatives, developing a comprehensive business plan outlining the company's vision, objectives, and strategies for the Private Equity Backed oil and gas company.
  - Conducted extensive research to identify target areas and potential investment opportunities, informing decision-making in the development of the Buda-Rose fractured carbonate oil play.
  - Created detailed financial models to assess the feasibility and profitability of the venture, supporting strategic decision-making and fundraising efforts.
  - Prepared investor presentations and pitch materials, effectively showcasing the investment potential of the Buda-Rose play to attract venture capitalists, angel investors, and private equity firms.

- Established strong relationships with investors and secured additional funding, including a significant initial equity commitment of $50 million from Encap Investments.
- Negotiated agreement for Navidad Resources, Inc. to contribute its assets, to be combined with an equity infusion from Encap, to form Navidad Resources, LLC. Navidad Resources, Inc. then became NRI, Inc. and the contract operator of the assets of Navidad Resources, LLC, the private equity backed oil and gas exploration and development company.
- Assembled a skilled and experienced management team, recruiting key personnel such as geologists, engineers, finance professionals, and operational staff to execute the company's objectives.
- Fostered a collaborative work environment and established a strong company culture, enabling effective teamwork and driving operational success.
- Identified and acquired leasehold rights and mineral interests in target areas with high potential for oil and gas reserves in the Buda-Rose play.
- Designed and implemented exploration and drilling programs based on thorough geological studies and data analysis, ensuring optimal resource extraction.
- Oversaw drilling operations, well completion, and production processes to ensure efficient and safe operations, adhering to environmental and safety protocols.
- Continuously sought potential acquisitions, joint ventures, and partnerships to expand the company's asset base and production capacity.
- Engaged with independent reservoir engineering firms to generate SEC standard reserves reports, overseeing the evaluation of reserves, production volume estimation, and economic analyses.
- Ensured compliance with regulatory requirements and reporting standards to maintain transparency and accountability.
- Maintained regular communication with investors, providing updates on operational and financial performance, fostering strong relationships and building trust.
- Developed growth strategies, identifying opportunities to expand operations, while evaluating potential exit options to provide liquidity and maximize returns to investors.

President, Navidad Resources, Inc. DBA .052 Petroleum Engineers, Tyler, Texas, 2001 – 2003

- Regional screening study of 14,000+ wells in North Louisiana for infill drilling and stimulation potential as a precursor to property acquisitions.
- Research project to evaluate profit and growth potential of CO_2 EOR combined with CO_2 Sequestration in the U.S. with case studies for international company.
- Multi-year fracturing fluid performance study on 1,000 Codell-Niobrara refracs. Identified key parameters required for stimulation success. Wrote software that automates analysis and mapping. Performed FracPro PT simulations, decline curve projections, and advanced statistical analysis. Made extensive statistical analysis of fracturing fluids including HPG, CMG, CMHPG and foamed fluids.
- Detailed analysis of formation integrity, cementing, completion design, bridge plug failure and coiled tubing versus snubbing unit fishing in a 22,000’ geo-pressured well.
- Expert on composite bridge plug patent case. Activities included research on competing products, comparison of similarities and analysis of relative benefits of designs.

- Performed nodal analysis for various gas wells in order to support reserves projections and improve completion designs.
- Assisted Boswell Minerals in evaluation of investment opportunity by generating reserves projections and economic evaluation of 250+ Bossier/Cotton Valley wells in the Bossier trend.
- Supervised and assisted reservoir engineer in preparation of reserves projections and annual budget reports for JAPEX.
- Prepared reservoir analysis, reserves projections, economics, workover procedure and re-stimulation design for horizontal well, resulted in 1700% increase in production.
- Developed and taught Advanced Completion Technology School for SINOPEC which covered multilaterals, underbalanced completions, and tubing conveyed perforating.

Senior VP of Engineering Services, Signa Engineering Corp., Houston, Texas, 2000 – 2001

- Lead engineer on numerous projects and provided management of engineering group including project proposals, resource allocation, training, customer relationship management, status reports, and implementation of “best practices” project management. Wide variety of projects expanded knowledge. Major projects included:
- Various Completion designs in South Texas and Northeast Texas, including pipeline and facilities specifications and management of implementation.
- Stimulation technology research to defend major service companies’ hydraulic fracturing patents. Managed research assistants and provided opinion. Refined knowledge and expertise in controlling fines migration and hydraulic stimulation of coal bed methane and tight sands in the San Juan Basin of New Mexico.
- Completed 3-year research project related to complex junction multilateral technology. Became intimately familiar with the design/application of the major multilateral completion systems and the methodology for screening multilateral candidates. Identified formations and fields suitable for multilateral. Developed probabilistic damages model.
- Testified on damages model and prior art challenge of patents. Team consisted of geologists, reservoir engineers, drilling engineers, and support staff.
- Developed and taught schools on petroleum economics, risk analysis, project management and multilateral completions.

VP of Project Management, Signa Engineering Corp., Houston, Texas, 1998- 1999

- Provided engineering and team leadership on numerous projects
- Six well completion program in South Texas. Planned, executed, and managed project team. Challenges included H_2S, CO_2, hydraulic stimulation, dual completions, chrome tubulars, underbalanced perforating, facilities, etc.
- Research for major service company. Established specifications for next generation underbalanced surface separation system. Activities included competitive benchmarking, needs analysis, requirements definition, research, and report preparation.
- Evaluated Coastal's Austin Chalk acreage for multilateral recompletion.

Manager of Reservoir, Production & Software Engineering, Signa Engineering Corp., Houston, Texas, 1997 – 1998

- Provided a wide variety of reservoir, production and training services to Signa's clients and completed Signa's IPC database. Significant projects included:
- Lead team that designed horizontal completion for unconsolidated channel sand offshore Thailand. Evaluated numerous sand control designs. Activities included reservoir analysis, equipment evaluation, laboratory testing, nodal analysis, and casing design. This 25-well, $100 million (+/-) drilling project was successfully implemented in January of 1999.
- Environmental audit of brine contaminated aquifer on 15,000-acre ranch in W. TX.
- Performed a field development study and operational review for horizontal potential on three large Algerian oilfields. Made recommendations to client on methods to improve production and lower operating expenses. Team included production engineer, drilling engineer, petroleum engineer and a geologist.
- Created and defended to SEC field development plan for Colombian new field discovery, including reserves, water coning, pipe-line capacity, and horizontal well analysis. Team included geologist, petroleum engineer and Ph.D. reservoir engineer.

President and Principal, NaviData Systems, Inc. Houston, Texas, 1992 – 1997

- Created a production increase of 600% through restimulation. Located, evaluated, planned, capitalized, and executed project to re-enter and stimulate abandoned Austin Chalk well. Increased production from 5 to 300 BOPD, ultimate recovery 125 MBOE, payout < 1 year. and ROR > 100%.
- Managed joint interest services and production operations for small operator.
- Evaluated properties and prepared SEC reserves for publicly traded oil & gas company.
- Supervised four (4) full time employees and five (5) subcontractors.
- Performed environmental site assessments on over five hundred (500) properties. Prepared Spill Prevention Control and Countermeasure plans on over two thousand (2,000) properties for both independents and Fortune 500 companies.
- Through training and experience developed general background in environmental regulations and expertise in Phase I and Phase II environmental site assessments.
- Wrote inspection/auditing software in FoxBase. Increased inspection efficiency 400%.
- Diversified into development of engineering software applications. Through staff and personal effort developed several engineering database applications for Fortune 500 oil and gas operators.
- Through personal study and working with experienced programmers, developed proficiency in object oriented programming language (SAL), graphical user interface design, relational client/server databases, Structured Query Language (SQL), entity relationship diagrams, referential integrity, data synchronization and expert systems.
- Negotiated sale to Signa Engineering Corp. that was finalized in April 1997.

Engineering Manager, Trinity Resources, Inc. Houston, Texas, 1988 – 1992

- Handled all engineering and operations for independent producer. Coordinated and managed activities of two (2) staff members and three (3) consultants.

- Chief architect of several profitable oil field deals. Became experienced in structuring deals and negotiating contracts with sophisticated terms such as due diligence, carries, back-ins and arbitration.
- Developed strategies to meet the company's long-term goals.
- Monitored the companies non-operated interest in over 200 properties; evaluated AFE
- Proposals for workover, re-entry, recompletion and horizontal drilling.
- Performed reserves projections on approximately 150 horizontal Austin Chalk wells and created a probability distribution to predict Horizontal performance.
- Evaluated over 1200 vertical Austin Chalk wells to determine post-stimulation performance increase. Develop model to predict stimulation performance.
- Constructed database and expert system to analyze 4,300-well Giddings Austin Chalk field for re-stimulation, recompletion and horizontal potential. Processed well data, performed statistics, computer mapped performance data and derived expert rules to automate candidate selection.
- Based on expert system, developed, presented to Board, and implemented business plans to invest multi-million-dollar budget. Averaged 40% rate of return.
- Evaluated numerous acquisitions and packaged over $10 million in divestitures. Advised management to reject low offers on major asset; ultimately received 200% of original offer.

Significant Industry Training/Continuing Ed. Courses Attended (through listed organization)

- Navidad Operating Company, LLC
  - Crue Club: Best child well performance yet-Haynesville case study, 21 May — 2024
  - SPE Workshop: Well Completions for Unconventional Resource Development Optimization and Parent-Child Interaction, 15-17 Apr — 2024
  - SPE Workshop: Refracturing: A Proven Strategy to Maximize Economic Recovery: Using existing wellbores to enhance hydrocarbon recovery, 14-15 Aug — 2023
  - SPE Workshop: Well Completions for Unconventional Resources Development Optimization and Parent-Child Interaction, 11 - 13 Apr — 2023
- Navidad Energy Advisors:
  - Determining Negligence in Engineering Failures — 2023
  - Louisiana Laws and Rules for Professional Engineers — 2022
  - BOPE: Blow out Prevention — 2022
  - Deepwater Horizon Oil Spill – OSHA's Role & Response — 2019
  - Opportunities For Petroleum Brownfields — 2019
  - Environmental Benefits of Advanced Oil & Gas Exploration & Production Tech. — 2019
  - BOPE: Blow out Prevention — 2019
  - Exploitation of Tight Carbonates - SPE, June — 2014
  - Dev. a New Gen. of Energy Leaders: Strategic Leadership - ~40 hours, SMU Cox — 2014
  - Strategic Financial Skills - ~32 hours, SMU Cox — 2014
  - Oil and Gas Investing for Institutional Investors — 2014
  - Formulating and Implementing Exceptional Business Strategy - SMU Cox, Nov. — 2014
  - Engineering Economic Analysis Software (PHDWin v2.9) - TRC Consultants, — 2015
  - How to Be an Effective Expert Witness- SEAK Sept — 2016
  - How to Start, Build, and Run a Successful Expert Witness Practice - Sept — 2016

- Navidad Resources, LLC:
  - A&D Strategies and Opportunities - Hart's Conf., 2004
  - Directional Drilling - NRL, 2008
  - Horizontal Drilling in Unconventional Shale Plays - K&M Technology, 2008
- Signa Engineering Corp.:
  - Profit Driven Project Management - Westney Cons. Int., 1998
  - Preparing for the PMP Exam - Westney, 2000
  - Masters Level Statistics Class - University of Phoenix
- Navidata Systems, Inc.:
  - Phase I Environmental Site Assessment - TEEX
  - Phase II Environmental Site Assessment – TEEX
- Trinity Resources, Inc.:
  - Overview of Horizontal Drilling - SPE Short Course, 1989
  - 2nd Conf on Horizontal Well Technology - World Oil, 1990
  - Applied Reservoir Engineering
  - Reservoir Aspects of Horizontal & Multilateral Wells - Joshi Tech
- Union Pacific Resources Company:
  - Hydraulic Fracturing (1) - Halliburton, 1984
  - Hydraulic Fracturing (2) - Western Co., 1984
  - Nodal Analysis - UPRC, 1985
  - Production Operations I - O&G Consultants Int., 1985
  - Production Operations II - O&G Consultants Int., 1985
  - Engineering Economic Analysis - UPRC, 1986
  - E-Log Analysis - UPRC, 1986
  - Minnesota Outward Bound – 10 Day Canoeing the Rio Grande River, 1987
- Texas A&M University:
  - 15 Hours of Industrial Engineering Classes as part of Co-Op Program 1983
    - Engineering Economic Analysis, Accounting, Human Factors, etc.
  - Southwest Outward Bound - 14 Day Mountains, 1982
  - Voyageur Outward Bound School - 28 Day Wilderness, 1978

Appendix A:

EXHIBIT C: EXPERT WITNESS EXPERIENCE

Harold E. McGowen III Cases:

Year Initiated	*Case/Project Name*	*Technical Domain*	*Legal/Industry Category*	*Role/ Responsibility*	*Representation*	*Case Type*	*Reports Filed*	*Depos*	*Trial/ Hearing*	*Total Testimony*	*Case Status*	*Case Description*	*Overview, Key Findings, and Contributions*
1998	Halliburton/Sperry/NRG v. Baker Oil Tools	Completion Equipment	Patent	Expert Witness	Plaintiff	Litigation	2	1	1	2	Complete	**Multi-lateral Completion Patent Dispute**	Assisted Halliburton/NRG (patent owner) by providing expert technical analysis and assisting in preparing logical arguments to defend the validity of Patent. My contributions included analyzing claim construction, identifying key distinctions between patented technologies and prior art, and developing technical positions for court proceedings. Also developed a damages model.
2000	Environmental Damage of Freshwater Aquifer	Environmental	Environmental	Litigation Support	Plaintiff	Litigation	1	0	0	0	Complete	**Brine Water Damage of Fresh Water Acquifer**	Assited attorney's for Plaintiff in evaluating the source and timing of damage to the sole source acquifer for Wink County, Texas.
2001	Underbalanced Drilling Nitrogen Membrane Patent	Drilling Operations	Patent	Expert Witness	Defendant	Litigation	1	0	0	0	Complete	**Underbalanced Drilling Nitrogen Membrane Patent**	Assisted patent holder by providing expert technical analysis and assisting in preparing logical arguments to defend the validity of Patent. My contributions included analyzing claim construction, identifying key distinctions between patented technologies and prior art, and developing technical positions.
2002	Halliburton v. BJ Hughes	Hydraulic Fracturing	Patent	Litigation Support	Defendant	Litigation	2	0	0	0	Complete	**Hydraulic Fracturing Fluid Patent**	Assisted Defendant as consultant in evaluating the patentability of the subject fracturing fluid by the Plaintiff and also assisted in evaluating the relative advantage/benefit of the patented technology for re-fracturing of legacy gas wells by comparing the results obtained from older technology hydraulic fracturing fluids to the subject fluid system. Performed "Big Data" statistical analysis of ~2,000 restimulations which included fracs from both parties.
2002	Halliburton v. Weatherford, Baker, et al.	Completion Equipment	Patent	Expert Witness	Plaintiff	Litigation	1	2	0	2	Complete	**Composite Bridge Plug Patent Case**	Assisted patent holder by providing expert technical analysis and assisting in preparing logical arguments to defend the validity of Patent. My contributions included analyzing claim construction, identifying key distinctions between patented technologies and prior art, and developing technical positions.
2012	Changing Ft. Trinidad/Eastham Field Rules	Reservoir Engineering	Regulatory	Expert Witness	Petitioner	Hearing	1	0	1	1	Complete	**Statistical Reservoir Analysis of Multi-Bench Vertical Play**	Successfully advocated before the Texas Railroad Commission (RRC) for the revision of field rules to optimize production from commingled gas and oil reservoirs in Houston and Madison Counties, Texas, delivering a significant regulatory win for the employer.
2014	Navidad Resources, LLC v. Signa Engineering	Workover Operations	Operations Failure	Witness	Plaintiff	Arbitration	1	1	1	2	Complete	**Remedial Cementing Operations**	Fact and expert witness for employer in Arbitration related to operational failure and damage to critical oil and gas well. Employer prevailed.
2015	VICEROY PETROLEUM, L.P., Plaintiff, v. TADLOCK PIPE & RENTALS, INC., Defendant	Hydraulic Fracturing	Equipment Failure	Expert Witness	Defendant	Litigation	1	1	0	1	Complete	**Examined damages model claims in tubular failure case**	Viceroy Petroleum, L.P. v. Tadlock Pipe & Rentals, Inc. (Case No. 5:14-cv-00006), filed in the Western District of Texas in 2014, involved claims by the Plaintiff that the failure of tubulars provided by the Defendant negatively impacted the hydraulic fracturing treatment of a well, allegedly resulting in a significant loss of potential hydrocarbon recovery. I evaluated the Plaintiff's claims, examined the evidence supporting those claims, and analyzed the methodology and simulations used to estimate the alleged damages. My analysis concluded that the basis for the Plaintiff's claims was unsupported. The case was ultimately dismissed on June 8, 2015.
2015	Oracle Oil LLC v. EPI	Drilling Operations	Operations Failure	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Potential substandard materials and procedures causing operational failure**	Case centered on allegations by Oracle Oil that EPI Consultants provided substandard consulting and engineering services during the reworking of a well. Oracle claimed that EPI's use of corroded, scaly drill pipes and improperly set casing retainers led to well contamination, casing rupture, and operational failures. I conducted an in-depth analysis of the technical aspects of EPI's procedures, including the materials and equipment integrity, as well as the engineering practices employed during the well's reworking. My evaluation focused on determining whether EPI adhered to industry standards and whether their actions likely directly caused the alleged well damage. The findings identified material disputes over the quality of materials and procedures, contributing to unresolved issues of causation. My focus was to take an unbiased approach to evaluating the technical merits of the claims.
2015	Origin v. EOG	Hydraulic Fracturing	Operations Failure	Expert Witness	Plaintiff	Litigation	1	0	0	0	Complete	**Frac hit caused well damage and failure**	This case involved damage to a vertical well caused by a nearby massive multi-stage hydraulic fracturing (MSHF) treatment on a horizontal well. The analysis demonstrated that high-pressure fluids and proppant from the MSHF likely communicated with the vertical wellbore, causing mechanical failure and production loss. Using directional data, temporal correlations, and evidence of fracturing materials in the damaged well, it was concluded that the fracturing activity was the most probable cause. Key systemic issues included inadequate risk assessments, poor operator coordination, and insufficient monitoring of well interference. Recommendations included collaborative planning, proactive monitoring, and enhanced risk mitigation to prevent similar incidents in tight-spacing scenarios.
2016	Bagley v. Brammer	Management/Minerals	Land/ Commercial	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Production cessation and lack of paying quantities**	Analysis addressed allegations of improper oil and gas lease management, focusing on cessation of production, operational practices, surface use, and pipeline maintenance for a gas well. The investigation revealed periods of production cessation exceeding the lease's allowable duration, failure to meet prudent operator standards, and unreasonable use of surface resources, including poorly maintained equipment and inadequate spill prevention measures. The methodology included reviewing production data, lease terms, regulatory requirements, and site inspections. Leveraging my decades of experience as a CEO in the oil and gas industry, I provided expert insights into operational diligence, lease compliance, and environmental stewardship.

EXHIBIT C: EXPERT WITNESS EXPERIENCE

Harold E. McGowen III Cases:

Year Initiated	Case/Project Name	Technical Domain	Legal/Industry Category	Role/ Responsibility	Representation	Case Type	Reports Filed	Depos	Trial/ Hearing	Total Testimony	Case Status	Case Description	Overview, Key Findings, and Contributions
2016	Jay & Melissa Gribble v. Aruba Petroleum, Inc.	Management/ Minerals	Land/ Commercial	Expert Witness	Plaintiff	Litigation	1	0	0	0	Complete	**Lease Termination and Reasonably Prudent Operator Standards**	Retained by the plaintiffs in 2016 to provide expert analysis in a dispute regarding the interpretation of "operations for drilling or reworking" under a mineral lease agreement. Assessed whether the lessee's activities during periods of production lapse met the standards of a reasonably prudent operator and whether such activities constituted valid operations to maintain the lease. Concluded that the lessee's actions lacked diligence, significance, and alignment with industry standards for sustaining production. Analysis highlighted lapses in continuous operations, inadequate rework efforts, and administrative oversight. These findings were rooted in a comprehensive review of operational records, lease terms, and production data, demonstrating expertise in evaluating complex lease and operational disputes in oil and gas litigation.
2016	Rapid Completions v. Baker Hughes	Hydraulic Fracturing	Patent	Expert Witness	Plaintiff	Inter Partes Review (IPR)	2	2	0	2	Complete	**Sliding Sleeve Technology Patent IPR**	Assisted Rapid Completions by providing expert technical analysis and assisting in preparing logical arguments to defend the validity of U.S. Patent Nos. 7,134,505, 6,907,936, and 7,861,774. My contributions included analyzing claim construction, identifying key distinctions between Rapid's patented technologies and prior art, and developing technical positions for both district court proceedings and Inter Partes Review (IPR) hearings before the Patent Trial and Appeal Board (PTAB). Case underscored the challenging intersection of technical and legal arguments in high-stakes patent disputes within the oil and gas sector. Also, performed "big data" analysis of job data to provide inputs to identify invoiced charges for the sale of infringing products for damages model.
2017	Halliburton v. Schlumberger (Inter Partes Review (IPR) for U.S. Patent No. 7,775,278)	Hydraulic Fracturing	Patent	Expert Witness	Defendant	Inter Partes Review (IPR)	1	0	0	0	Complete	**Degradable plugs patent defended against prior art**	The case involving U.S. Patent No. 7,775,278 primarily revolved around the patentability of a method for using degradable materials to form temporary plugs in wellbores, fractures, or perforations to facilitate staged hydraulic fracturing treatments. As the retained expert for Schlumberger Technology Corporation, I analyzed the technical details of the patent claims, the prior art references presented by Halliburton, and the interpretations of a person of ordinary skill in the art (POSA). My analysis focused on differentiating the patented invention from prior art, specifically distinguishing the claimed use of degradable plugs from fluid loss control agents and mechanical diversion systems like Plug-and-Perf or Open-Hole Multi-Stage (OHMS) fracturing systems. I concluded that the prior art did not anticipate or render obvious the claims of the '278 patent, emphasizing that the use of degradable plugs provided unique advantages such as operational efficiency and reduced risk compared to conventional methods. This analysis contributed to demonstrating the innovation and non-obviousness of the '278 patent claims.
2017	Sanchez Energy Corporation v. Terra	Value of Trade Secrets	Trade Secret	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Theft of Trade Secrets**	Assisted attorneys representing Sanchez by providing technical analysis and supporting the preparation of arguments aimed at demonstrating the potential value of confidential information and trade secrets that Sanchez alleged had been misappropriated by a former employee. My contributions included offering insights based on utility and importance of the data to help frame the significant value add of the tranmittal of the information in question to a competitor.
2018	Schlumberger Technology Corp. vs BICO Drilling Tools, Inc.	Drilling Equipment	Patent	Expert Witness	Plaintiff	Inter Partes Review (IPR)	2	0	0	0	Complete	**Patent Infringement on Optimized Mud Motor Design**	Retained by the plaintiffs in 2018 to provide expert analysis in a patent infringement dispute involving Schlumberger's U.S. Patent No. 6,604,921 ("Optimized Liner Thickness for Positive Displacement Drilling Motors"). Evaluated whether the defendant's mud motor products infringed claims of the patent, focusing on design elements such as liner thickness and rotor-to-stator fit. Concluded that defendant's mud motor designs incorporated features covered by the patent claims, including the optimized elastomer liner thickness and enhanced stator geometry. Analysis included technical comparisons of patent claims against engineering drawings, product samples, and marketing materials, demonstrating clear infringement. Highlights expertise in downhole tool design, mud motor optimization, and intellectual property disputes in the oil and gas sector.
2019	Specialized Desanders	Completion Equipment	Patent	Expert Witness	Defendant	Inter Partes Review (IPR)	1	1	0	1	Complete	**Inter Partes Review on Desander System**	Represented Specialized in defending the validity of U.S. Patent No. 8,945,256 B2 in an Inter Partes Review. The patent covers an innovative desanding system designed for oil and gas production, featuring a uniquely inclined vessel to enhance separation efficiency. Demonstrated that the prior art, including Hemstock and Davis, failed to disclose or render obvious the patented design, particularly the placement of a gas/liquid interface at the fluid outlet and the elimination of internal flow barriers. Provided expert analysis showing that the cited references were non-analogous, lacked applicability to turbulent multiphase flows, and could not achieve the patented system's performance. Supported the case with robust claim construction, technical rebuttals, and evidence that the invention was non-obvious, leading to the PTAB's decision to uphold the patent's validity.

EXHIBIT C: EXPERT WITNESS EXPERIENCE

Harold E. McGowen III Cases:

Year Initiated	*Case/Project Name*	*Technical Domain*	*Legal/Industry Category*	*Role/ Responsibility*	*Representation*	*Case Type*	*Reports Filed*	*Depos*	*Trial/ Hearing*	*Total Testimony*	*Case Status*	*Case Description*	*Overview, Key Findings, and Contributions*
2019	Intrepid v. Fluid Technology	Drilling Operations	Operations Failure	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Wellbore collapse caused by improper mud dilution**	This analysis focused on the collapse of a wellbore during drilling operations caused by the unintended dilution of drilling mud with water, leading to reduced mud weight and bottom-hole hydrostatic pressure. The investigation evaluated the sequence of events, including the introduction of caustic into the mud system, prolonged shale exposure to water-based mud, and subsequent borehole instability and collapse. Methodology included reviewing operational records, technical literature, and applying principles of wellbore stability and drilling fluid dynamics. Leveraging decades of experience as a CEO and petroleum engineer overseeing complex drilling operations, provided expert insights into the root causes and preventative measures.
2019	Swivel Rental & Supply, LLC v. Petro Pull, LLC et al.	Rigless P&A	Patent	Expert Witness	Defendant	Litigation	1	1	0	1	Complete	**Analyzed rig-less P&A system patent infringement damages**	Evaluated allegations of patent infringement related to a specialized rig-less plugging and abandonment system for offshore wells. The investigation focused on assessing the design, utility, and market alternatives for the technology in question, comparing it to prior art and competing solutions. The methodology included a detailed review of technical specifications, Georgia-Pacific factors for determining royalty damages, and hypothetical licensing scenarios to establish a fair royalty base and rate. Leveraging decades of experience as an engineer and CEO in oil and gas operations, I provided a unique perspective that integrated technical expertise with a strategic understanding of technology application and market dynamics.
2020	Leroy Kana vs. E2 Operating, LLC	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Workplace injury during failed mud stuck rig recovery**	Case involves a workplace injury that occurred during recovery of a workover rig stuck in the mud at substandard wellsite. Plaintiff alleges that operator failed to maintain a safe working environment by neglecting to prepare the site adequately for heavy equipment, ignoring a "Stop Work" request, and requiring the recovery of the rig using improper methods and equipment. The injury resulted from the catastrophic failure of a steel tube during the recovery attempt, which caused a piece of the tube to strike the Plaintiff. Assessed operator's liability by evaluating the site conditions, operational practices, hazard identification, and the role of leadership in maintaining safety standards.
2020	Rodriguez vs. Halliburton	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	0	0	0	Complete	**Worker injured recycling decommissioned drilling tool**	Served as a consultant for the Plaintiff's attorney to analyze and determine the root cause of an accident in which a worker was injured while recycling and scrapping a decommissioned logging-while-drilling tool previously manufactured by Halliburton.
2020	Cause No. 21047 Elizabeth Rangel v. Ring Energy	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Fatal Injury due to valve failure from inadequate safety measures**	Analysis addressed a fatal incident involving the catastrophic failure of a wellhead ball valve during the startup of an Electrical Submersible Pump (ESP) at an oilfield site. The investigation determined that the root causes included inadequate wellhead design, lack of active safety measures such as pressure relief devices or automatic shut-down sensors, and insufficient procedural safeguards. The methodology involved a detailed review of engineering designs, operational records, and industry standards to identify safety deficiencies and recommend risk mitigation strategies. Leveraging decades of experience as a CEO managing oil and gas operations, provided expert insights into systemic safety failures and practical recommendations for improving workplace safety, demonstrating capability to address complex personal injury cases in the oil and gas sector.
2020	Robert Long vs. Quality Well Services and Cooper Oil and Gas, LLC	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Ongoing	**Fatal hose detachment from inadequate restraints**	Analysis focused on a catastrophic incident during well pressure bleed-off operations, where an improperly restrained hose and sub violently detached, resulting in severe injuries and a fatality. The investigation evaluated systemic failures, including inadequate hazard identification, deficient safety planning, and non-compliance with industry standards for hose restraint systems and pressure control methods. The methodology involved a review of operational practices, equipment configurations, and adherence to safety protocols. Provided expert insight into best practices, safety leadership, and preventive measures.
2021	Wood vs. NewBridge	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	0	0	0	0	Complete	**Employment Dispute**	Case involved consulting services provided to evaluate allegations of mismanagement, misrepresentation, and trade secret misappropriation within an oil and gas operating company. The analysis focused on reviewing operational practices, corporate governance, and compliance with industry standards to assess the validity of claims.
2021	National Oil Well DHT, L.P. vs. Amega West Services, LLC	Oilfield Operations	Patent	Expert Witness	Plaintiff	Litigation	1	1	1	2	Complete	**Downhole Tool design evaluated for patent infringement**	This analysis focused on evaluating the design and functionality of a downhole vibration tool in the context of patent infringement claims. The investigation assessed whether the tool's design and operation were consistent with prior art and if modifications would have been obvious to a skilled practitioner in the field. Using industry expertise, the analysis considered factors such as the tool's purpose, the functionality of components, and their application in modern drilling operations. Drawing on decades of managing oil and gas operations applying technology. I brought a practical and technical understanding to complex cases involving engineering design and application of technology.
2021	Halliburton - Baker Botts - Electric Fracturing Fleet Patent	Hydraulic Fracturing	Patent	Expert Witness	Inventor	Inter Partes Review (IPR)	1	0	0	0	Ongoing	**Electrified Hydraulic Fracturing Fleet Patent**	Collaborated with attorney to draft precise and industry-appropriate responses to the patent office's critique of claims. Provided expertise in oil and gas terminology to accurately describe technical processes, highlight advantages, and address perceived disadvantages, ensuring alignment with industry standards and strengthening the case for claim approval.

EXHIBIT C: EXPERT WITNESS EXPERIENCE

Harold E. McGowen III Cases:

Year Initiated	Case/Project Name	Technical Domain	Legal/Industry Category	Role/ Responsibility	Representation	Case Type	Reports Filed	Depos	Trial/ Hearing	Total Testimony	Case Status	Case Description	Overview, Key Findings, and Contributions
2021	Whiting vs BTA CAUSE NO. CV57763	Oil Field Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Unknown	**Worksite Injury from Dropped Object**	Evaluated a workplace injury in which a worker on a wellsite was severely injured by a dropped object due to inadequate safety practices and hazard mitigation. The analysis identifies systemic issues, including the lack of fall restraint systems, inadequate lighting, and the absence of an effective dropped object prevention policy. By examining the chain of command, workover procedures, and safety leadership responsibilities, concluded that the incident could have been prevented with prudent operating practices and proper hazard identification. Drew on decades of experience as a CEO and engineer in the oil and gas industry, to bring a comprehensive understanding of safety protocols, risk management, and operational leadership/
2021	CHRIS KILBOURNE vs. OVINTIV PRODUCTION INC.	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	0	0	0	Ongoing	**Rig floor collapse due to safety failures**	The analysis focused on a workplace incident where a rig floor, supported only by a single winch and wire cable, fell during operations, causing severe injuries to a worker. The investigation evaluated the root causes, including the absence of redundant drop prevention measures and the failure to conduct proactive hazard assessments. It examined the role of the operator's representative in enforcing safety protocols and ensuring hazard mitigation. The analysis concluded that implementing prudent safety practices and redundant protections could have prevented the incident, emphasizing the importance of proactive safety leadership and robust operational oversight.
2021	Antwine vs. Aethon	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Ongoing	**Truck rollover caused by unsafe lease road**	Analysis examined an incident where a semi-truck transporting frac sand overturned on a poorly maintained and inadequately designed lease road, resulting in severe injury to the driver. The investigation identified critical safety failures, including narrow road width, lack of proper barriers or signage, and insufficient hazard mitigation measures. The methodology included a site inspection, drone mapping, and application of industry-standard Maintenance of Traffic principles to assess the adequacy of the road and traffic control measures. The conclusions highlighted the operator's responsibility to design and maintain safe infrastructure to accommodate heavy equipment during hydraulic fracturing operations. Leveraged extensive experience as an engineer and CEO overseeing oil and gas operations, including road and site construction, I offered a comprehensive understanding of industry practices.
2022	Alta Mesa Resources, Inc. Securities Litigation, Case No. 4:19-cv-00957	Reserves Projections	SECURITIES LITIGATION	Expert Witness	Plaintiff	Litigation	1	1	1	2	Complete	**Evaluation of Claims Regarding Regarding Potential Reserves**	Evaluated whether defendant's adhered to industry-standard practices in their drilling and development plans within a major unconventional oil and gas play during the relevant period, which led to financial losses and alleged securities and potential misrepresentations. I analyzed the company's well-spacing assumptions, pattern testing, estimation of recoverable reserves, and use of analogs from other geological formations and internal reactions to data relative to facts presented to the public. My expertise in oil and gas reserves estimation, field development, and regulatory compliance from the point of view of a CEO and oil man that has built oil and gas companies supported my role as a believable and knowledgeable expert in this complex securities litigation.
2022	Clayton Jones vs- Energy Transfer GC NGLS LLC et al	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Settled	**Drilling rig injury caused by safety and management failures**	Evaluated a workplace injury involving a drilling rig worker who sustained severe injuries due to unsafe operational practices, including the use of outdated manual tongs instead of safer, industry-standard automated equipment. Plaintiff experienced severe injuries from entanglement with improperly rigged manual tongs and steel cables on a drilling rig. Analysis identified systemic failures, such as inadequate supervision, a lack of adherence to safety protocols, and management's failure to enforce Stop Work Authority. As an expert engineer with extensive experience as a CEO of oil and gas operating companies, I conducted a thorough review of the incident, applying principles of engineering safety, human factors analysis, and operational management to determine root causes and recommend safer practices.
2022	Clifford Louis vs. EOG Resources, Inc. et al CAUSE NO. 2020-49604	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	1	0	1	Complete	**Wireline worker injured by uncovered mousehole**	Evaluated a workplace injury where a wireline worker fell into an uncovered mousehole on a drilling rig floor during operations, resulting in significant harm. Analysis highlighted systemic safety failures, including the absence of a properly secured slotted mousehole cover and a lack of inherently safer design practices by the drilling contractor. It concludes that these deficiencies, combined with insufficient oversight by both the operator and the contractor, directly contributed to the incident. Leveraged extensive experience as an engineer and CEO managing oil and gas operations, including drilling and safety-critical activities, to provide a comprehensive evaluation of the root causes and practical recommendations for hazard mitigation.
2022	Joseph Maynes v. Black Diamond Welding	Oilfield Operations	Personal Injury	Expert Witness	Plaintiff	Litigation	1	0	0	0	Ongoing	**Human Factors Engineering: Addressing Design Flaws to Prevent Workplace Injuries**	Case involves a workplace injury resulting from the lack of fail-safe design in a hot oil truck's steam hose system. The incident underscores critical design flaws, including the absence of a safety-focused control mechanism, such as a dead-man valve, which would have automatically shut off steam flow if the operator released the hose. As a consultant, I conducted a detailed technical analysis of the equipment and identified specific failings in the system's design, proposing industry-accepted safety features that could have prevented the injury. My evaluation highlights a systematic approach grounded in engineering principles, emphasizing the importance of proactive safety measures in hazardous operations.

EXHIBIT C: EXPERT WITNESS EXPERIENCE

Harold E. McGowen III Cases:

Year Initiated	Case/Project Name	Technical Domain	Legal/Industry Category	Role/ Responsibility	Representation	Case Type	Reports Filed	Depos	Trial/ Hearing	Total Testimony	Case Status	Case Description	Overview, Key Findings, and Contributions
2024	Aceco Valves, LLC vs Patricia Wolf	Oil Field Equipment	Trade Secret	Expert Witness	Defendant	Litigation	1	0	0	0	Settled	**Mechanical Design Trade Secret Case**	Providing support as a consultant for the attorney for the Defendant in this trade secret/confidential information case.
2024	Downing Wellhead Equipment, LLC v. Intelligent Wellhead Systems Inc. et al, 1-23-cv-01180	Hydraulic Fracturing Equipment	Patent	Expert Witness	Defendant	Declaration	1	0	0	0	Ongoing	**Declaration fo PATENT TRIAL AND APPEAL BOARD**	This expert declaration supports Downing Wellhead Equipment in a patent dispute by arguing that its October 2020 public webpage disclosed the same continuous pumping (CP) swap method described in the Krupa patent application. The declaration explains that Downing's system allowed for seamless transitions between wells during hydraulic fracturing without stopping the pumps, matching the process claimed in Krupa, thereby invalidating Krupa as prior art.
2025	Concho Resources Inc. Securities Litigation	Petroleum Engineering and Oil and Gas Management	Securities Litigation	Expert Witness	Plaintiff	Litigation	0	0	0	0	Ongoing	**Claimed Securities Fraud**	Scope: Independent technical analysis applying established forensic engineering methodologies to evaluate complex issues and support informed decision-making by finders of fact in specialized domain of unconventional reservoir development.
2025	Cactus v Cameron	Hydraulic Fracturing Equipment	Patent	Expert Witness	Plaintiff	Declaration	1	0	0	0	Ongoing	**Declaration fo PATENT TRIAL AND APPEAL BOARD**	Expert declaration challenging the validity of U.S. Patent No. 11,162,320 on hydraulic fracturing fluid delivery systems. Provided technical analysis and comparisons to prior art (Guidry, Kajaria, etc.) supporting arguments of obviousness for certain claims on behalf of Cactus Wellhead, Inc.
2025	Brian Mayo v. RPM XConstruction, LLC, et al.	Machine Design	Personal Injury	Expert Witness	Plaintiff	Litigation	1	0	0	0	Ongoing	**Claimed defective slaking machine design injury**	Served as a mechanical engineering expert witness for the plaintiff in a personal injury case (Brian Mayo v. RPM XConstruction, et al.) involving catastrophic amputation resulting from an unguarded rotating shaft on an industrial slaking machine. Conducted a forensic engineering analysis identifying critical design failures by the manufacturer, including absence of basic passive and active safety measures (e.g., guarding, interlocks), lack of Prevention through Design (PtD), and unsafe maintenance procedures.
2025	Goes Well Services, LLC (Kirk Veronie) v. M.E.	Plugging and Abaondonment of Well(s)	Operations Failure	Expert Witness	Defendant	Litigation	1	0	0	0	Ongoing	**Claimed negligent plugging operation.**	Dispute over responsibility for cost overruns and operational failures during the plugging of well in Texas. Evaluated chain of command, project planning, and adherence to industry standards. Opined on who retained ultimate control and failed to provide adequate procedures, hazard mitigation, and supervision.
2025	Justina Chappell v. Precision Drilling et al.	Machine Design	Personal Injury	Expert Witness	Plaintiff	Litigation	0	0	0	0	Ongoing	**Claimed defective machine design injury**	Personal injury case involving a rig floor incident, involved applying Prevention through Design (PtD) principles to evaluate how the equipment design may have contributed to the injury. The analysis focused on the integration of inherently safer design elements including safety interlocks/alarms to overcome poor line-of-sight visibility and failure to isolate and control hazardous motion during pipe handling.
40		**Totals**					**41**	**22**	**5**	**27**			

Note: This list represents my most recent update of Expert Witness/Litigation Support projects generated from memory - I may add to or edit the list if I discover any missing cases.

Testimony of Harold McGowen
NMOGA Exhibit D

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served to counsel of record by electronic mail this 8th day of August 2025, as follows:

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