STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

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

TESTIMONY OF DAN ARTHUR

ON BEHALF OF

NEW MEXICO OIL AND GAS ASSOCIATION

August 8, 2025

TESTIMONY OF DAN ARTHUR

I. INTRODUCTION AND BACKGROUND

My name is Dan Arthur. My business address is 1718 S. Cheyenne Avenue #A, Tulsa, OK 74119.

I am a founder, President, and Chief Engineer of ALL Consulting and have served in those capacities throughout the firm's 26-year history. I also serve as the Vice President of Well Plugging Initiatives for CSR Services, as Vice President for Engineering for DynaVert Holdings, and Vice President of Sustainability for Verdant Technologies. My curriculum vitae is attached hereto as **Exhibit A**.

I am a registered professional engineer in 36 states, a Certified Petroleum Geologist (CPG) through the American Association of Petroleum Geologists, a registered professional Petroleum Engineer (SPEC) through the Society of Petroleum Engineers, a Fellow of the Geological Society (FGS), a Qualified Measurement Specialist (QMS), and a Certified Climate Management Leader (CCML). I have completed projects throughout the United States and in 30 other countries.

I earned a Bachelor of Science degree in Petroleum Engineering from the Missouri University of Science and Technology. I started my career at Halliburton Services, worked as a field engineer for a small independent oil and gas company, and then served as a national expert in the Environmental Protection Agency's (EPA) Underground Injection Program (UIC). I then served as Vice President of Upstream Services for a large international consulting company, where I performed a variety of environmental, water, and geoscience projects.

At ALL Consulting, I helped build a multi-disciplinary firm that has completed numerous regulatory analyses, including new regulation development, commenting on new proposed regulations, evaluation of regulatory implementation impacts, effects of historic regulatory and industry practices, as well as negotiating with regulatory agencies concerning their rules for conventional and unconventional oil and gas development and closure (e.g., plugging and abandoning various types of wells). My CV presents numerous examples from across the globe such as coalbed methane development in China, hydraulic fracturing in Canada, unconventional development in Mexico and Saudi Arabia, as well as carbon credit guidelines for African well fields, to name a few.

I have presented and published hundreds of times on environmental geosciences issues, underground injection and water management, environmental issues, best practices, well abandonment and site reclamation, and a variety of other topics. Throughout my career, I have been recognized as an expert on a broad range of topics and have earned multiple appointments from government and industry.

I have been an expert witness on more than 2,500 dockets and more than 100 litigation cases throughout the United States on a variety of issues and topics, including before the New Mexico Oil Conservation Commission. Throughout my career, I have worked on financial assurance issues throughout the United States as well as internationally (e.g., New Zealand). While working for the EPA, I worked with various types of oil and gas operators on financial assurance for all types of injection wells. While working with oil and gas clients, I managed environmental due diligence in evaluating idle and marginally producing wells, assessed potential risks and compliance costs, helped to assess wells that required plugging versus those that had potential to be put back into production, and assisted operators in attaining financial assurance with various states. I advised the Florida Department of Environmental Protection and the Florida Attorney General's Office on various financial assurance options as their Expert Consultant. I have worked with multiple types of marginal and inactive wells in assessing reserves and potential beneficial uses (e.g., conversion to a disposal well, production of source water for enhanced recovery, conversion to a water supply well for farming, etc.). I have also worked with the U.S. Department of the Interior, Bureau of Land Management (BLM) on performing Paying Well Determinations for marginally producing wells and assessing financial assurance requirements for operators. I have also assisted operators in using new technologies to re-complete wells in ways to increase production dramatically (e.g., short radius horizontal wells) and using unique pumping methods (e.g., air lift).

II. PURPOSE OF TESTIMONY

I have reviewed the proposed amendments from the applicant, the Western Environmental Law Center ("WELC"), particularly to **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]

First, I will address issues I have identified regarding the proposed definition of marginal wells, beneficial purpose or use, wells in approved and temporarily abandoned status, as well as the proposed changes to compliance, reporting, and operator requirements. In general, I believe the proposed approach risks premature plugging and abandonment of potentially economic wells and well units.

Second, I will address the proposed financial assurance requirements and provide some context for NMOGA witness Doug Emerick's testimony based on my operational experience. I have examined other states' approaches to financial assurance, and I find that WELC's proposals would

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

be unnecessarily rigid and do not incorporate a risk-based framework to establish appropriate levels of financial assurance. As a result, in my expert opinion, the proposed approach poses a risk of unintended and undesirable outcomes.

Specifically, the proposed framework fails to reflect the operational and cost variability of well plugging and abandonment. In my experience, a one-size-fits-all requirement, such as the proposed $150,000 per well, ignores significant differences in plugging costs that can range from under $20,000 for shallow vertical or coalbed methane wells to higher amounts for deeper or more complex completions. The proposals do not account for the fact that only the vertical section of horizontal wells typically requires abandonment, and that many low-producing wells can be responsibly decommissioned for far less than the proposed financial assurance.

Furthermore, this approach would disproportionately impact smaller operators and those with large portfolios of marginal or inactive wells, potentially accelerating the premature abandonment of wells that remain economically viable. It also poses barriers to routine transactions by requiring transferee operators to post excessive bonding amounts and by triggering blanket bonding requirements based on marginal well percentages that do not correspond to actual risk.

III. TESTIMONY

A. Proposals to Add New Definition of Beneficial and Related Presumptions of No Beneficial Use – Proposed 19.15.2.7(B)(7) and 19.15.25.9 NMAC

WELC proposes introducing a new definition for “Beneficial Purposes” or “Beneficial Use” under 19.15.2.7(B)(7) and a new presumption of no beneficial use provision under 19.15.25.9 NMAC.

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

i. Beneficial Definition Under Consideration

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, and does not include use of a well for speculative purposes. WELC's reference to speculative purposes is subjective and invites inconsistent enforcement or litigation.

Historically, the New Mexico Oil Conservation Division ("OCD") has recognized a variety of "beneficial use" categories, including uses for on-lease fuel, equipment power, vapor recovery, flare reduction, storage, recycling, pressure maintenance, enhanced recovery, and pilot projects.[2] New Mexico has historically extended "beneficial use" beyond volume-based thresholds or narrowly defined production activity. Many of these functions are essential to field development and compliance and are not speculative.

However, WELC's inclusion of the term "speculative purposes" as a disqualifying factor, without definition, introduces subjectivity and regulatory uncertainty. This position is further supported after reviewing NMOGA witness Harold McGowen's testimony on the same issue. I have also reviewed the testimony of Clayton Sporich, NMOGA's operational and legal witness, on this term, and I support his conclusions.

[2] New Mexico Energy, Minerals and Natural Resources Department – Oil Conservation Division. Notice – Additional Beneficial Use Categories for Waste Rule Reporting (C-115B). September 21, 2022. Available at: https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/9-21-22-NOTICE-C115B-Updated-Beneficial-Use-Codes.pdf

ii. My Concerns for Defining Beneficial

In my professional opinion, WELC's definition, as proposed, is ambiguous, vague, overly narrow, and overly prescriptive. I have also reviewed the testimony of NMOGA legal witness Clayton Sporich, and his legal perspective has helped inform my operational perspective on WELC's proposed definition.

Defining an industry term of art, such as 'beneficial,' could have significant impacts on existing interpretations by OCD and regulated operators. "Beneficial purpose" has been treated historically by OCD as meaning that a well is engaged in some form of productive, regulatory, or operational activity such as production, monitoring, lease maintenance, or on-lease fuel use, even when that activity does not meet specific volumetric thresholds. Assigning a brand-new definition, or a variation that deviates from OCD's historical application, could conflict with existing regulatory frameworks that already use the term without a formal definition. For example, the term "beneficial use" or "beneficial purposes" appears in the existing versions of 19.15.25.8(B) NMAC (governing plugging requirements) and 19.15.25.12 NMAC (on approved temporary abandonment), and is inherently embedded in the current definitions of "inactive well" under 19.15.2.7(I) NMAC.

Defining "beneficial use" now risks creating internal inconsistencies across Title 19 of the NMAC. Such a definition could contradict long-standing regulatory flexibility that permits operators to justify non-production status based on field development plans, economic considerations, or compliance activity. Moreover, if "beneficial use" is defined more narrowly in one part of the code, it could have unintended consequences in other areas where the term is referenced without qualification, such as in well status, plugging timelines, or bonding obligations. This risks introducing duplicative standards, inconsistent enforcement, and legal ambiguity that could hinder the regulatory process and increase the risk of dispute or protest.

In my opinion, adopting the proposed definition would likely result in the misclassification of viable wells, increased plugging obligations, and associated loss of production and tax revenue. Accordingly, I recommend rejecting adding a new defined term of "beneficial purposes" or "beneficial use." However, in the event the Commission proceeds with the recommendations, I have reviewed the testimony of Clayton Sporich, NMOGA's legal witness, on this term, and I support his alternative definition of "beneficial purpose" and "beneficial use" which better reflect the reality of oil and gas operations in New Mexico.

2. Proposed "Presumptions of No Beneficial Use" Provision – 19.15.25.9 NMAC

i. WELC's Presumption a Well is Not Capable of Beneficial Use Using 90-Day Criteria

WELC proposes a parallel amendment as a new 19.15.25.9 NMAC to contain a rebuttable presumption of no beneficial use provision. As proposed, production wells would be presumed to have no beneficial use if, during any consecutive twelve (12) month period, there was less than ninety (90) days of production and less than ninety (90) total barrels of oil equivalent (BOE); saltwater disposal and injection wells would be presumed to have no beneficial use during any consecutive twelve (12) months of less than ninety (90) days of injection and less than one hundred (100) barrels total injected (collectively and hereinafter, the "90-Day Criteria"). But wells drilled but not completed for less than eighteen (18) months, and wells that have been completed but not produced for less than eighteen (18) months, would be exempt from WELC's presumption of no beneficial use threshold.

The proposed presumption goes on to set forth the sole process for refuting the presumption, which results in a preliminary determination, with required operational and financial documentation. Operators who receive a preliminary determination from OCD that a well or wells are not being used for beneficial purposes would have only thirty (30) days to file an application for administrative review which must include a forecast demonstrating future production in paying quantities, evidence of financial capacity beyond financial assurance, or other relevant information requested from OCD, including a plugging and abandonment plan.

ii. Recommendation to Reject or Revise 90-Day Criteria

The 90-Day Criteria are too rigid and fail to account for wells in temporary non-productive status due to valid operational factors. At a minimum, the consecutive 12-month periods are too short. In my experience, operators may intentionally shut-in viable wells for extended periods, often exceeding twelve (12) months, due to market downturns, lack of takeaway capacity, or strategic deferrals pending infrastructure upgrades or recompletions. The planning, funding, permitting, and execution of major remedial or redevelopment activities such as recompletions, enhanced recovery pilot tests, or pad-level infrastructure upgrades often span multiple years.

The 12-month timeframe to determine cumulative production days and production volume should be extended to multiple years, at least three (3) years, if not more, to account for maintenance, safety, and downtime scenarios that occur in normal operations. If the 90-Day Criteria are retained, I recommend using consecutive five (5) year periods to determine cumulative production days and production volume, to align with the 5-year maximum for Approved Temporary Abandonment ("ATA") status under the current versions of 19.15.15.12(A) NMAC and 19.15.25.13(E) NMAC, which WELC does not oppose or seek to change in this rulemaking. In fact, WELC actually proposes to strike the language from existing 19.15.25.13(E) NMAC which would require an ATA permit have an expiration no more than 5 years from the date of approval.[3] Five years provides sufficient time for operators to evaluate redevelopment options, align capital resources, and respond to market conditions.

But in my opinion, the 90-Day Criteria should be removed entirely and instead a presumption triggered only if the subject well has not produced or injected for any reason for 5 years, and the operator has not submitted a plan or application demonstrating intent to return the well to productive service.

iii. Recommendation to Reject or Revise How Presumption is Refuted

WELC's proposal requires that applications for administrative review of a preliminary determination must include documentation demonstrating that the subject well is reasonably projected to produce in paying quantities, as well as other documentary requirements.

First, production in paying quantities is a holistic concept that addresses the entire lease. Under industry custom, and as adopted in other states' oil and gas regulatory frameworks, such as Texas, where the state Supreme Court in *Clifton v. Koontz* and subsequent rulings apply a two-part test to determine lease-level "production in paying quantities" or "paying quantities" refers to whether

[3] At least five (5) years is often necessary due to capital allocation cycles, drilling limitations, lease term negotiations, and permitting timelines that extend beyond two years in both federal and state regulatory environments. Capital allocation cycles refer to the multi-year planning and budgeting processes operators use to prioritize projects across their entire asset base. Investment decisions are typically made on an annual or biennial basis, with funds directed toward the highest-return opportunities, often driven by fluctuating commodity prices, rig and service availability, and broader corporate strategy. As a result, lower-tier projects, such as marginal well recompletions, infill drilling, or reactivations, may not receive immediate funding but remain part of a future-phase development plan. Operators often defer activity on temporarily abandoned wells until capital is available, regulatory approvals are secured, and adjacent infrastructure is constructed or upgraded. Compressing this planning horizon into a two-year window disregards the financial discipline required for sustainable operations and undermines the phased nature of oil and gas field development.

the entire lease produces enough revenue over operating costs to justify continuation.[4, 5] Applying this concept on a well-by-well basis is misleading or burdensome, as a well may operate at a loss while the lease as a whole remains economically viable.

In addition, the 30-day response window is too short a time period to provide the required application information and any "relevant" information required by OCD in light of recordkeeping requirements. Considering the volume and complexity of recordkeeping required to compile historical production data, financial documentation, lease terms, infrastructure schedules, and field development plans, especially for older wells or recently acquired assets with limited documentation. OCD production data typically lags by two (2) months. In addition, the timing and coordination of internal records between OCD and operators could create an additional layer of confusion in interpretation. It is also unclear from the proposal when the 30-day response window would begin.

iv. Risks and Potential Impacts of Using the 90-Day Criteria to Determine Whether a Well is Capable of Beneficial Use

Introducing these specific time/volume thresholds, which can and will lead to a determination of no beneficial use if not refuted, provides no flexibility. The 90-Day Criteria are not operationally realistic, particularly for marginal wells or wells with variable production, maintenance downtime, unitized acreage, or those with shared or waiting on infrastructure systems. In many instances,

[4] *Clifton v. Koontz*, 325 S.W.2d 684, 690–91 (Tex. 1959). Available at: https://law.justia.com/cases/texas/supreme-court/1959/a-6555-0.html

[5] Burney, John McFarland. "What Constitutes Production in Paying Quantities?" *Oil and Gas Lawyer Blog*, Graves Dougherty Hearon & Moody, September 6, 2016. Available at: https://www.oilandgaslawyerblog.com/what-constitutes-production-in-paying-quantities/

individual well economics may not be profitable in isolation but remain integral to lease maintenance, reservoir management, or infrastructure optimization. This is particularly true for wells located on unitized acreage or multi-well pads where shared facilities, centralized production equipment, or common gathering lines may cause some wells to remain temporarily offline or underutilized while others support active development.

Wells that do not meet the 90-Day Criteria often still serve critical regulatory and strategic functions and should not be presumed nonbeneficial. For example, a well with intermittent output may be maintained specifically to preserve leasehold rights – especially on federal, tribal, or state lands – where continuous production is required to hold leases in force. In unitized areas, even low-rate wells may be used to preserve the integrity of the unit, maintain compliance with communitization agreements, or facilitate ongoing reservoir studies, including pressure monitoring and fluid migration studies. In these contexts, operators may temporarily shut-in one well while actively investing in adjacent locations or planning future recompletions – all within a broader, phased development strategy.

Moreover, wells awaiting recompletion, re-fracs, or reactivation of artificial lift systems may temporarily fall below arbitrary production thresholds but remain fully integrated into an operator's capital and field development plan. Requiring such wells to meet the 90-day criteria risks a premature presumption of no beneficial use, potentially triggering unnecessary plugging obligations or financial assurance burdens. Simply put, not all productive contributions are immediate or measurable by short-term production volumes. If adopted as written, these thresholds would disproportionately impact smaller operators, discourage incremental development, and potentially result in the loss of leasehold rights or disruption of unit agreements.

v. Using the 90-Day Criteria to Determine Whether a Well is Capable of Beneficial Use Ignores Operational Value

Just like its proposed definition of "beneficial" I discuss above in Part III.A.1., WELC's parallel presumption of no beneficial use provision also focuses on production and fails to recognize the benefit of operational value, i.e., non-productive but regulatory or infrastructure-related functions that serve essential roles in leasehold maintenance, reservoir management, environmental compliance, or future field development. Wells can serve beneficial purposes beyond production, like for enhanced oil recovery (EOR) or secondary/tertiary recovery, monitoring, or regulatory compliance. Additionally, production can vary due to market, seasonal, or infrastructure factors like pipeline takeaway capacity, gas plant downtime, weather-related shut-ins, or scheduled maintenance and recompletions. Limiting a well's capability of beneficial use to production volumes is shortsighted. It does not account for the complexities of oil and gas operations, particularly for marginal wells or those with shared infrastructure.

Wells may be cycled and go temporarily offline for a variety of reasons, including infrastructure limits, commodity price downturns, or in anticipation of future use for up-hole potential testing or injection/EOR. Although "Beneficial Purpose" or "Beneficial Use" are seemingly objective thresholds, the failure to consider operational variables could create unjustified burdens such as unnecessary presumption of non-use, forced reporting, or the triggering of bonding or abandonment obligations based solely on a calendar threshold. This could lead to unintended early plugging and abandonment costs, especially for marginal assets that still provide lease maintenance or hold future value for deeper drilling or enhanced recovery. If 'beneficial' is even to be defined, which in my opinion is inadvisable based on the foregoing reasons, other evidence the Commission should consider when making a beneficial determination for a well, and which the definition should encompass, include documented infrastructure plans or delays (e.g., pending pipeline construction); projected use within a defined field development plan; monitoring data or regulatory filings demonstrating compliance-related functions; evidence of shared use or pad-level economic contributions; planned reactivation timelines; and operator-submitted documentation explaining leasehold strategy or reservoir management objectives.

This broader and more practical approach mirrors the framework used by the BLM, which does not define beneficial use based on rigid production or injection thresholds. Instead, the BLM considers whether a well is serving a functional purpose, such as contributing to a unit development plan, maintaining lease rights, or fulfilling a regulatory monitoring or environmental function. BLM's approach thus avoids misclassifying wells that are temporarily shut-in for legitimate reasons and supports continued development flexibility, consistent with longstanding agency practice and industry norms.[6]

vi. If the 90-Day Criteria is Triggered, the Presumption Results in a Preliminary Determination, Which, if Not Refuted, Becomes a Determination that a Well is Not Capable of Beneficial Use

The 90-Day Criteria in WELC's proposed presumption provision will likely lead to premature plugging of viable wells, contrary to the Commission and Division's mandate to prevent waste and protect correlative rights. As proposed, if the 90-Day Criteria are triggered, the presumption results in a preliminary determination a well is not capable of beneficial use. If not refuted, that

[6] Bureau of Land Management, "Instruction Memorandum No. 2020-006: BLM Statewide Inspection and Enforcement Strategy – Appendix 4 (Beneficial Use Determination Guidance)," https://www.blm.gov/sites/blm.gov/files/policies/IM2020-006_att4.pdf.

presumption will become a determination that a well is not capable of beneficial use. Although the proposal indicates any such final determination would be appealable, in other parts of the Commission's rules, a determination that the well is no longer usable for beneficial purposes is sufficient to mandate that the subject well be properly plugged and abandoned or placed in approved temporary abandonment status, as I discuss next in Part III.B.

B. Proposal to Change When Wells are to Be Properly Plugged and Abandoned – Proposed 19.15.25.8(B) NMAC

WELC proposes amending 19.15.25.8(B) NMAC (Wells to be Properly Abandoned), which currently requires operators to either properly plug and abandon a well, or place it in approved temporary abandoned status, as explained in Part III.C. below, within ninety (90) days of the following events:

i. sixty (60) days after drilling operations are suspended;

ii. a determination that the well is no longer usable for beneficial purposes; or

iii. within one (1) year of continuous inactivity.

WELC proposes: shortening the action deadline from ninety (90) days to thirty (30) days; modifying the requirement to place the well in approved temporary abandonment within the compliance window to instead require the operator to apply to do so within the new 30-day timeframe; and striking the word "continuously" from the 1-year inactivity requirement provision, thereby broadening its application.

These revisions are entirely contrary to actual timelines for plugging and abandonment activities. Typically, once a decision is made to plug a well, the process, from internal review and cost estimation to contractor mobilization, permitting, and scheduling, takes 6 to 18 months, depending on well depth, site conditions, and regulatory coordination and authorization. For wells with surface access issues, sensitive environmental settings, or tribal/federal land considerations, timelines may extend even further. These timeframes represent the minimums and often require additional time to account for safety prioritization like weather-related deferrals, wildfire or flood risk mitigation, or proximity to critical wildlife or surface infrastructure and logistical constraints such as limited availability of plugging rigs, high seasonal service demand, permit processing delays, or coordination with other ongoing field activities.

Additionally, the rule, as proposed, has the potential to distort ordinary well management by resulting in premature plugging decisions for otherwise viable wells, disrupting integrated asset planning, and discouraging operators from pursuing recompletion or infrastructure investments during late well life. It would also impose duplicative filings via redundant beneficial use justifications, economic declarations, and resubmitted documentation that overlap with existing C-145 (Well Status and Operational Data) and the C-103 (Sundry Notices and Reports on Wells) processes, thereby increasing administrative burdens for both operators and OCD staff without a corresponding regulatory benefit. This position is further supported in great detail in McGowen's expert report, which offers more insight into the timelines associated with plugging and abandoning wells.

C. Proposals to Amend the Regulations Governing Temporary Abandonment of Wells

1. Approved Temporary Abandonment – Proposed 19.15.25.13 NMAC

WELC proposes amending existing 19.15.25.12 NMAC on "Approved Temporary Abandonment" to: impose extensive documentation requirements, including seismic data, economic projections, Health, Safety, and Environment (HSE) plans, etc.; require a beneficial use demonstration as a condition for approval or extension; enable broader public intervention in temporary abandonment extension requests; create hard cutoffs for temporary abandonment eligibility based on inactivity; and require operators of wells in expired temporary abandonment status to re-apply or plug said well. Due to WELC's other amendments to 19.15.25 NMAC that are also under consideration, the proposed requirements would be recodified at 19.15.25.13 NMAC.

WELC's proposal represents legal and institutional overreach due to the proprietary nature of certain economic and technical data requested (such as seismic and financial models), the disclosure of which may risk compromising confidential business information and competitive positioning. WELC's proposal also unnecessarily expands the categories of persons who might intervene in what are routine proceedings, which will expose operators to unnecessary protests and strain OCD's already limited administrative resources. WELC's proposal also unnecessarily shifts control over operational authority over permitted temporarily abandoned wells away from operators and to OCD.

Based on my review of WELC's proposed amendments, it is my opinion that they are overly restrictive, operationally impractical, and inconsistent with standard industry timelines for infrastructure planning, investment, and redevelopment. Rather than adopting rigid technical submittal requirements, the Commission should allow for a streamlined but non-prescriptive narrative for projected beneficial use. Furthermore, intervention rights should be limited to parties with demonstrable standing to prevent unnecessary procedural delays, and the Division should retain discretion to approve extensions on a case-by-case basis without triggering automatic plugging deadlines. This ensures that regulators can manage inactive wells effectively while recognizing the operational and economic realities faced by operators. Finally, operators should retain control over operational decisions, including the timing and method of well reactivation or decommissioning, subject to OCD oversight and environmental safeguards. The flexibility to manage well portfolios over multi-year horizons is essential to responsible field development and long-term resource conservation.

Clayton Sporich, who is involved in this proceeding as an expert legal witness, has proposed an alternative to WELC's proposal that, in my opinion, addresses the concerns that I have raised in my testimony.

2. Demonstrating Mechanical Integrity – Proposed 19.15.25.15 NMAC

WELC proposes amending existing 19.15.25.14(A) NMAC, which outlines how an operator must demonstrate internal and external mechanical integrity when requesting approved temporary abandonment status for a well, to add an isolation device requirement and a mandatory caliper and casing integrity log requirement under proposed new subsections (4) and (5), respectively. Due to WELC's other regulatory additions in 19.15.25 NMAC that are also under consideration, the proposed requirements would be recodified at 19.15.25.15(A)(4)-(5) NMAC.

i. New Isolation Device Requirement

First, proposed subsection (4) would require mandating the bridge plug or packer to remain in place during the entire temporary abandonment period. This may conflict with operational safety or prevent monitoring by limiting access to the wellbore for pressure diagnostics such as fluid level surveys or other mechanical integrity evaluations. The isolation device requirement could also hinder re-entry or maintenance during temporary abandonment by necessitating costly milling operations, increasing the risk of damage to casing or downhole hardware, and introducing delays to recompletion or workover planning.

Based on my decommissioning experience, major logistical challenges like limited equipment availability, retrieval complications, and excessive costs associated with multi-well programs would result from implementing these proposed requirements in day-to-day plugging and abandonment planning. Under existing 19.15.25.13 NMAC and 19.15.25.14 NMAC, and other related provisions, OCD requires that a well proposed for temporary abandonment must demonstrate mechanical integrity. In my opinion, the added requirement is unworkable due to technical limitations and practical implications when applied across all temporary abandonment cases, and is unnecessary if the initial pressure test is passed and the well is properly sealed in accordance with OCD-approved standards. Mandating that bridge plugs or packers remain in place throughout the entire temporary abandonment period, without flexibility, imposes additional risk and cost without improving integrity assurance, especially when ongoing wellhead monitoring and OCD oversight remain in place.

There are also safety concerns associated with leaving bridge plugs or packers in place for multi-year periods. Over time, mechanical isolation devices are subject to degradation due to corrosion, temperature cycling, chemical exposure, or seal fatigue. If not actively monitored or maintained, these devices can fail silently, potentially compromising zonal isolation or causing pressure migration that may go undetected. From a well-integrity standpoint, the most effective approach is to ensure initial isolation via testing, then preserve flexibility to remove or replace plugs as needed based on field conditions and planned well use, not to mandate permanent, static hardware with no means of verification until re-entry. I have reviewed and agree with Mr. McGowen's analysis of these proposed revisions as set forth in his testimony.

ii. New Caliper and Casing Integrity Logs Requirements

Second, the proposed amendment to subsection (5) would require caliper and casing integrity logs but lacks defined acceptance criteria for what constitutes "passing" for said logs. Requiring mandatory caliper and casing integrity logs would be costly, potentially redundant with pressure tests since a properly conducted casing pressure test already demonstrates mechanical integrity and zonal isolation without the need for visual or downhole geometric confirmation. Caliper logs are designed to detect casing deformation or corrosion, but do not directly measure hydraulic seal integrity, which is the primary concern for temporarily abandoned wells. Similarly, casing integrity logs, such as multi-finger imaging or electromagnetic inspection, are highly sensitive, expensive, and require rig-up and wellbore re-entry, making them impractical as routine requirements for every ATA application. A multi-finger imaging tool uses a radial array of mechanical "fingers" (usually 24 to 60) that contact the internal surface of the casing. As the tool is pulled up the wellbore, each finger measures variations in casing radius, capturing high-resolution images of wall thickness changes, pitting, corrosion, or deformation. These logs generate detailed cross-sectional images but require a clean, fluid-filled wellbore, centralization, and often a rig-assisted intervention, especially in deviated wells.

Electromagnetic inspection tools, by contrast, use variations in magnetic fields induced around the casing to detect changes in wall thickness or metal loss. These tools do not require physical contact with the casing, making them suitable for certain cased-hole environments, but they still demand clean well conditions and calibrated interpretation. Both methods generate large datasets that require expert analysis and are typically interpreted in conjunction with other logs or historical well integrity data.

Requiring these logs to be conducted for all proposed temporary abandonment wells could also lead to inconsistent application across wells due to variations in wellbore configurations, age, accessibility, and historical data availability. For example, older wells with restricted access or uncertain downhole conditions may not be suitable for log tool deployment without substantial preparatory work, adding cost and risk with limited technical benefit. Inconsistent enforcement or interpretation could result in uncertainty, delay, or unnecessary reclassification of wells in good condition simply because a caliper log could not be acquired or was difficult to interpret. Such logs should only be used as supplemental reporting, not required unless problems are suspected, as is the case in the majority of jurisdictions, such as Texas (Railroad Commission),[7] Wyoming (WOGCC),[8] and North Dakota (NDIC),[9] where casing logs are only required under specific conditions (e.g., before final abandonment, or following a failed MIT). These jurisdictions identify "suspected problems" based on failed or inconclusive pressure tests, sustained annular pressure, surface leakage, known casing damage, or historical performance issues. This evidence-based approach ensures that casing logs are used as diagnostic tools where appropriate – not imposed universally where they may provide little added value.

Based on my field experience, the standard industry practices for demonstrating mechanical

[7] Texas Railroad Commission. *Injection/Disposal MIT Testing Exclusions – Mechanical Integrity Tests.* Available at: https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/mechanical-integrity-tests/injection-disposal-mit/testing-exclusions/

[8] Wyoming Oil and Gas Conservation Commission. *Temporary Abandonment – Wyo. Admin. R. Chapter 3, Section 16* Available at: https://regulations.justia.com/states/wyoming/agency-055/sub-agency-0001/chapter-3/section-3-16/

[9] North Dakota Industrial Commission, Department of Mineral Resources. *Well Plugging Requirements – N.D. Admin. Code § 43-02-03-55.* Available at: https://www.law.cornell.edu/regulations/north-dakota/N-D-A-C-43-02-03-55

integrity are to perform a pressure test on the casing, tubing, or annulus (typically for a specified duration and at a defined pressure above formation pressure), combined with a visual inspection of wellhead equipment and casing valves to ensure no observable leaks. These practices are widely accepted and are consistent with the EPA's UIC program under 40 CFR § 146.8, which allows for mechanical integrity to be demonstrated through either a pressure test or monitoring of annulus pressure, as well as the absence of significant fluid movement behind casing. WELC's proposed heightened requirements, such as mandating caliper logs or requiring bridge plugs to remain in place during the entire temporary abandonment period, are excessive and do not provide value sufficient to justify the added obligations.

Moreover, the current OCD rules align with EPA standards by requiring periodic mechanical integrity testing and maintaining well construction and plugging requirements that protect underground sources of drinking water.[10,11,12,13] Under the current application of EPA regulation 40 C.F.R. § 146.8(c), operators are allowed first to demonstrate external mechanical integrity using pressure monitoring, pressure testing, and cementing records. It is my understanding that, as 40 C.F.R. § 146.8(c) is currently applied to TA wells, more advanced diagnostic tools, such as temperature logs, noise logs, or radioactive tracer surveys, are only required when those primary

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[10] U.S. Environmental Protection Agency. Mechanical Integrity – 40 C.F.R. § 146.8(a). Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/section-146.8

[11] U.S. Environmental Protection Agency. Mechanical Integrity Testing Methods – 40 C.F.R. § 146.8. Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/section-146.8

[12] U.S. Environmental Protection Agency. Operating Requirements for Class II Wells – 40 C.F.R. § 144.28(f)(2). Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-144/section-144.28

[13] U.S. Environmental Protection Agency. Permit Conditions – 40 C.F.R. § 144.52(a)(5). Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-144/section-144.52

methods indicate a possible issue or when cementing records suggest inadequate annular isolation. To be consistent, a well that passes pressure testing, has adequate cementing records, and shows no signs of leakage or external communication should be considered compliant under both state and federal rules and should not require the aggressive proposed caliper and casing integrity logging requirements. Amending existing 19.15.25.14 NMAC, as proposed, could deviate from those standards by imposing universal logging and isolation device mandates that are not required under EPA's UIC Class II program, introducing inconsistency with federal regulatory benchmarks, and potentially discouraging practical well management and re-entry flexibility.

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

WELC proposes amending 19.15.2.7(A)(13) NMAC to expand the existing definition of "Approved Temporary Abandonment"—which currently refers to the status of an inactive well approved under 19.15.25.13 NMAC and compliant with 19.15.25.12 through 19.15.25.14 NMAC—to incorporate two newly defined terms: "Temporary Abandonment" and "Temporary Abandonment Status." In my experience and opinion, combining these three terms into a single definition is unworkable and creates unnecessary confusion. Operationally, wells may be inactive without being officially placed into approved temporary abandonment status. Many operators rely on this distinction to manage capital efficiently, especially during infrastructure delays, market-driven curtailments, or planning phases for recompletion or secondary recovery. From an economic perspective, requiring all inactive wells to obtain formal "approved" status would impose redundant regulatory burdens and eliminate needed flexibility to cycle wells in and out of production. The proposed definition also risks reclassifying wells that are functionally inactive but still integral to a lease's long-term development strategy, such as those used intermittently or for planned future use, as improperly noncompliant.

In my opinion, WELC's proposal to add "Temporary Abandonment" and "Temporary Abandonment Status" to the existing definition of "Approved Temporary Abandonment" under 19.15.2.7(A)(13) NMAC is unnecessary and will likely lead to confusion. As a general matter, a well is temporarily abandoned when operations have ceased, but the well is expected to be returned to service and remains mechanically sound, with no immediate intent or need to plug and abandon. Operators utilize temporarily abandoned status for wells because they wish to preserve leasehold interests, maintain future development options, and avoid premature abandonment while awaiting improved market conditions, infrastructure access, or completion of reservoir studies or project approvals.

Under New Mexico's current oil and gas regulatory framework, "Approved Temporary Abandonment" is already defined under 19.15.2.7(A)(13) NMAC. Introducing separate definitions for "Temporary Abandonment" and "Temporarily Abandoned Status" risks creating confusion and conflict, as there is no meaningful distinction between the terms. Furthermore, requiring formal approval for all "temporary abandonment" statuses would unnecessarily eliminate the regulatory category of wells that are merely inactive but not yet approved by OCD for temporary abandonment. From an operational perspective, WELC's proposals add distinctions without meaningful differences from the existing definition of approved temporary abandonment, which will result in duplicative filings, delays in routine shut-in and reactivation decisions, and increased administrative burdens for both operators and OCD. For example, a well awaiting a workover rig during seasonal access constraints, a well offline due to downstream processing or takeaway limitations, or a well held inactive under drilling or seismic timing stipulations would all require unnecessary applications for approval, even if the downtime is short-term and already being monitored.

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

WELC proposes adding a new definition for "Expired Temporary Abandonment" or "Expired Temporary Abandonment Status" under its proposed amendments to 19.15.2.7(E)(8) NMAC to mean the status of a well that is inactive and has been approved for temporary abandoned status in accordance with existing 19.15.25.13 NMAC, but that no longer complies with existing 19.15.25.12 NMAC through 19.15.25.14 NMAC. Under current practice, existing 19.15.25.12-.14 NMAC are administered and enforced by OCD primarily through annual reporting requirements, status updates via Form C-145, and case-by-case discretionary review, not as automatic, self-executing triggers. The current rules focus on ensuring that temporarily abandoned wells are structurally sound, monitored, and not neglected, rather than establishing hard expiration deadlines or punitive compliance standards. For example, existing 19.15.25.12 NMAC governs requests for Approved Temporary Abandonment status, while existing 19.15.25.13 and 25.14 NMAC primarily set out conditions for mechanical integrity and reporting obligations. In practice, OCD allows operators reasonable time to correct deficiencies and demonstrate beneficial use or integrity compliance through supplemental filings or field inspections.

By redefining "expiration" to encompass any non-compliance with any part of these rules, WELC's proposal could transform reporting oversights into grounds for status termination and forced plugging. This broad interpretation introduces legal ambiguity and elevates administrative findings to a regulatory presumption of non-compliance, effectively bypassing OCD's discretion and operator due process. In contrast, the existing time-based expiration threshold (e.g., 5 years from ATA approval) provides clarity and predictability.

This new definition does not account for excusable short-term non-compliance caused by, for example, weather-related access limitations, third-party service delays, or regulatory backlogs, all of which are common in remote or legacy fields. These delays can occur, for example, when routine inspections, pressure tests, or surface maintenance must be postponed due to road conditions, contractor availability, or overlapping work on shared infrastructure.

In operational practice, temporarily abandoned wells are often monitored periodically (e.g., quarterly or annually), with inspections confirming wellhead integrity, surface conditions, and pressure status. Maintenance may include inspection of the onsite equipment, including the wellhead and valves, replacing signage, and confirming that the well remains mechanically sound. Reclassifying a well as "expired" due to minor or temporary lapses in these tasks would be an inappropriate and overly punitive shift that undermines both regulatory flexibility and responsible field management.

D. Proposals to Increase Financial Assurance Requirements – Proposed 19.15.8.9 NMAC

1. Active Wells – Proposed 19.15.8.9(C) NMAC

WELC proposes amending 19.15.8.9(C)(1)-(2) NMAC (Active Wells) to require companies with "active" wells provide financial assurance of $150,000 per well or a blanket bond of $250,000. However, even where the blanket option is utilized, the operator remains subject to additional single-well financial assurance requirements for marginal wells, as I explain below in Part III.D.3.

Under WELC's proposal, WELC would define "active wells" subject to the requirements of 19.15.8.9(C) as wells subject to financial assurance requirements pursuant to 19.15.8.9(A) NMAC, but not subject to either (i) inactive well financial assurance requirements (which WELC also proposes to amend and broaden the financial assurance requirements to encompass more types of temporarily abandoned wells) that I discuss next in Part III.D.2. of my testimony, or (ii) the new marginal well financial assurance requirements WELC proposes that I discuss in Part III.D.3.[14]

WELC's proposal abandons the existing risk-based financial assurance requirements for individual bonding for such active wells, which currently starts at $25,000 plus $2 per foot of well depth, calculated based on the true vertical depth for vertical and horizontal wells or measured depth for deviated and directional wells. WELC also abandons the tiered blanket financial assurance alternatives for active wells, depending on the number of active wells secured: $50,000 for one (1) to 10 wells; $75,000 for 11 to 50 wells; $125,000 for 51 to 100 wells; and $250,000 for more than 100 wells. WELC's proposal is unworkable, will exponentially increase the bonding required for active wells – which pose the least risk of all well types considered under WELC's proposed financial assurance requirements and are the most prevalent type of well in New Mexico, see my note on marginal well production in the state in Part III.D.3. below – and will likely drive business and tax revenue out of state.

2. Inactive Wells and Temporarily Abandoned Wells – Proposed 19.15.8.9(E) NMAC

Under proposed 19.15.8.9(E) NMAC (Inactive Wells and Wells in Approved or Expired

[14] Under the current version of 19.15.8.9(C) NMAC, "active wells" include wells subject to financial assurance requirements but are not subject to the existing version of 19.15.8.9(D) NMAC which currently only applies to wells in temporarily abandoned status for more than two years or for which the operator is seeking approved temporary abandonment.

Temporarily Abandoned Status), WELC would also require single-well financial assurance of $150,000 per inactive well, temporarily abandoned well in approved or expired status, or for which temporary abandonment approval is sought, but proposes that those inactive and temporarily abandoned wells' blanket financial assurance total amount be an average of $150,000 per well secured

This average blanket financial assurance provision (i.e., averaging $150,000 per well) creates a "moving target" bonding framework, which in turn creates internal compliance risks like frequent recalculation of bond amounts as well counts fluctuate, difficulty forecasting financial assurance needs during asset transfers or divestitures, and increased risk of inadvertent noncompliance due to shifting well classifications or status changes.

Currently, only wells that have been in temporarily abandoned status for more than two years or for which the operator is seeking approved temporary abandonment are subject to the heightened inactive well financial assurance provision under the existing version of 19.15.8.9(D) (Inactive Wells). WELC would broaden the types of wells subject to heightened inactive well financial assurance requirements and abandon the existing risk-based approach, which currently allows for individual well bonding starting at $25,000 plus $2 per foot of well depth, calculated based on the true vertical depth for vertical and horizontal wells or measured depth for deviated and directional wells. WELC would also abandon the current tiered blanket bonding alternatives available for such wells, depending on the number of active wells secured: $150,000 for one (1) to five (5) wells; $300,000 for six (6) to 10 wells; $500,000 for 11 to 25 wells; and $1,000,000 for more than 25 wells. Yet again, these changes by WELC are unworkable, will exponentially increase the bonding required temporarily abandoned wells – which Mr. McGowen explains can in some cases be even safer than actively producing wells – and for even more types of temporarily abandoned wells, as well as inactive wells, which will in turn likely drive business and tax revenue out of state.

3. Marginal Wells and Tie to Inactive Well Inventory – Proposed 19.15.8.9(D)

Additionally, WELC's proposed new marginal well assurance provision 19.15.8.9(D)(1)-(2) NMAC would compound the required financial assurance by requiring operators to provide single-well financing of $150,000 for **each** marginal well (subject to the proposed amended definition described above) beginning in January 2028, and as of the effective date of the proposed rule, for every marginal well that is the subject of a transaction.

Under its proposed 19.15.8.9(D)(3) NMAC, WELC would also require individual well financial assurance of $150,000 for **each** well – not just marginal wells – registered to any operator with fifteen percent or more ($\geq$15%) of an operator's total well inventory made up of inactive or marginal wells, or a combination thereof, until the percentage falls below fifteen percent (<15%).

These per well financial assurance requirements for marginal wells will exponentially increase the bonding amounts required under the rule because stripper wells (a subset of marginal) wells represent 54% of oil wells and 81% of gas wells in New Mexico, and in 2023 alone, these wells produced approximately 18% of the state's total oil output and 10% of its total gas production, according to the U.S. Energy Information Administration's 2024 Well Distribution Report.[15]

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[16] New Mexico Legislative Finance Committee, *Policy Spotlight on Orphaned Wells*, p. 14 (June 24, 2025). Available at: https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf

4. New Individual Well Requirements for Incomplete Blanket Financial Assurance – Proposed 19.15.8.9(F) NMAC

WELC's proposal further requires operators with incomplete financial assurance under the blanket assurance requirements to provide additional single-well financial assurance for uncovered wells under its proposed amendment to 19.15.8.9(F) NMAC. WELC would also remove the alternative to rectify incomplete coverage using a blanket bond. From a real-world perspective, it is unworkable to mandate matching new wells with bonding coverage without accounting for the frequent acquisitions and dispositions in the oil and gas industry and related challenges of updating bonds as wells are plugged, sold, or transferred.

5. New Requirement for OCD Approval of Financial Assurance before Both Drilling New Wells and Acquiring Existing Wells

Relatedly, WELC further proposes amending 19.15.8.9(A) NMAC by adding an express requirement that the OCD approve the required financial assurance before any proposed drilling or acquisition. I have reviewed the testimony of NMOGA legal witness Clayton Sporich and found his testimony that neither the Commission nor the Division have authority over the acquisition of oil and gas assets.

6. Comparison to Plugging and Abandonment Costs Being Secured, Which Can Vary Greatly

One of the problems with the single well financial assurance approach under consideration, and described above by well type affected, is that it bears no relationship to risk or lived experience. It is true that some wells can be expensive to plug and abandon. It is equally true that some wells – in my view, many wells – can be fully plugged and abandoned for far less than $150,000. The applicant's proposal (and the OCD proposal) does not reflect this fact.

In my experience, the cost of plugging and abandoning an oil and gas well can vary enormously. That is why I think a bonding regime should take experience, risk, well characteristics, and other factors into account.

I've witnessed many wells that were plugged and abandoned for $20,000 or even less. A shallow vertical well might be plugged and abandoned for even less than $20,000. A coalbed methane well would fall into a similar range.

Of course, a long horizontal well might demand greater costs to abandon, but it is important to remember that even there, only the vertical wellbore will be cemented; there is no need to cement a long horizontal well segment buried deep underground with no connection to the surface or shallower formations.

The amounts demanded must also be examined with respect to the actual risk that the government will be forced to call on those bonds to complete decommissioning. In practice, this risk appears to be consistently low. OCD has only pursued forfeiture on one (1) bond in the last five years,[16] indicating that the vast majority of decommissioning continues to be handled by the well operators themselves. Consequently, currently proposed bonding levels may significantly overstate the financial risk to the state, and in reality, the risk that the State of New Mexico will be forced to resort to secured amounts to cover plugging and abandonment is improbable. In short, a rigid single well financial assurance of $150,000 is simply unnecessary and even excessive in many situations. There will always be exceptions, but in my expert opinion, there are better, more tailored ways to decide on appropriate levels of financial assurance.

7. Comparison of Other Jurisdictions' Financial Assurance Requirements and

[16] New Mexico Legislative Finance Committee, *Policy Spotlight on Orphaned Wells*, p. 14 (June 24, 2025). Available at: https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf

Alternatives Based on Their Experiences

Other states provide examples of different approaches. Utah, for instance, sets bonding levels for wells of different depths, presumably under the rationale that deeper wells cost more to plug and abandon. A shallow well of less than 1,000 feet can be bonded for $1,500 per well, while a well that is more than 10,000 feet in depth can be bonded for $60,000. Shut-in and temporarily abandoned wells must demonstrate wellbore integrity, and the regulatory agency can require necessary remedial action.

North Dakota takes an alternative approach. It sets single well bonds at $50,000 and blanket bonds at $100,000, but strictly limits the number of un-reclaimed and abandoned wells an operator may hold. Above that baseline, the regulatory agency can set a higher bond based on a well's economic value and the costs of plugging, abandoning, and reclaiming wells.

Then there is the neighboring state to the north, Colorado, which allows operators to demonstrate that their plugging, abandonment, and reclamation costs are far less than the default value of $150,000.

Of course, there are other states and other examples of how regulatory agencies seek to factor in risk and experience into financial assurance levels that are less rigid than those proposed here, including:

i. Texas, where the Railroad Commission maintains a tiered blanket-bond schedule ($25,000 for ≤10 wells; $50,000 for 11–100 wells; $250,000 for >100 wells) and specifically excludes low-risk wells from blanket bonding obligations.[17]

[17] Texas Railroad Commission. *Financial Assurance Requirements for Oil & Gas Operators.* Available at: https://statutes.capitol.texas.gov/Docs/NR/htm/NR.91.htm

ii. North Dakota, which allows field-specific or unit-based bonding arrangements under NDAC 43-02-03-15; operators and regulators can tailor financial assurance to reflect local well risk profiles and reclamation timelines through administrative approvals.[18]

8. Risks and Potential Impacts of Adopting Proposed Changes

One approach to this problem would be to take a step back and engage parties in a technical discussion about the relative risks associated with plugging and abandoning a variety of wells. That would be my recommendation.

Managing financial assurances on a per-well basis is risky for operational efficiency and acquisitions because it introduces volatility and administrative burden into budgeting, impedes flexible field development planning, and complicates or delays asset transfers when each well must be individually bonded. From an operator's perspective, numerous and widespread internal capital, compliance, and transaction costs could result, including repeated revisions to bonding instruments, legal review of acquisition documents for bonding contingencies, delays in closing deals, and higher overhead to track and update well-level bonding status. In my experience, the private surety market typically requires substantial capital to secure oil and gas activities—especially for smaller or less creditworthy operators, where the demands can be even more burdensome. Additional compliance and transactional costs will include posting collateral or cash to obtain surety bonds, potential increases in bonding premiums due to perceived regulatory risk, expanded internal compliance staffing, and third-party legal and financial advisory expenses associated with ensuring bonding sufficiency on a dynamic, per-well basis.

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[18] North Dakota Industrial Commission, Department of Mineral Resources. *Well Plugging Requirements – N.D. Admin. Code § 43-02-03-15.* Available at: https://www.law.cornell.edu/regulations/north-dakota/N-D-A-C-43-02-03-

Beyond those direct operational impacts of the heightened financial assurance requirements on a per-well or blanket basis, other unintended consequences for operators may result from the implementation of WELC's amendments to 19.15.8.9 NMAC, as proposed, including reduced access to capital for smaller or mid-sized operators, discouraged participation in asset acquisitions or farm-in agreements due to bonding burdens, premature plugging of otherwise viable wells, increased risk of orphaned wells due to operator insolvency, and consolidation of assets into fewer hands, undermining competition and local economic participation.

All these direct and indirect adverse effects have been experienced firsthand by operators in other states where similar heightened binding requirements have been unreasonably imposed on oil and gas operations. For example:

i. California implemented bonding reforms in 2021–2022, which led to significantly higher bonding obligations per well, triggering delays in permit approvals and asset transactions, and contributing to the early abandonment of marginal wells.[19, 20]

ii. Alaska attempted a per-well bonding increase in 2019 that was ultimately scaled back after strong industry opposition and concerns about operator insolvency and stranded assets.[21]

[19] California Department of Conservation, Geologic Energy Management Division (CalGEM). Idle Well Program Report for 2021 (April 2023). Available at: https://www.conservation.ca.gov/calgem/Documents/Idle%20Well%20Program%20Report%20for%202021.pdf

[20] FracTracker Alliance. "California Must Improve Management of Idle Wells" (May 2024). Available at: https://www.fractracker.org/2024/05/california-must-improve-management-of-idle-wells/

[21] Center for International Environmental Law (CIEL). *Toxic Assets: How the Energy Transition is Exposing Systemic Risks in Oil and Gas* (April 2021). Available at: https://www.ciel.org/wp-content/uploads/2021/04/Toxic-Assets-Report.pdf

iii. Colorado, following its 2022 financial assurance overhaul (COGCC Rule 434),[22] created a tiered bonding system with high default per-well bonding assumptions (e.g., $150,000), which has led to operator consolidation, divestment from marginal assets, and increased bonding disputes.[23]

It is the State of New Mexico's responsibility to protect and effectively use its resources. Prematurely plugging a well could mean resources are lost forever. In my opinion, these heightened financial assurance requirements proposed by WELC and OCD will lead to premature plugging of viable wells and will make operating in the state riskier for operators, effectively driving away operators from New Mexico and to a different state to do business. Each state is essentially in competition with other states to attract development. This means that these increased financial assurance requirements also have the potential to, and will likely, decrease tax revenue in the state, as well as jobs in the state. These far-reaching and expansive negative effects greatly outweigh any incremental benefit the new requirements would provide, and in my opinion, are completely unnecessary considering the level of financial assurance already provided under New Mexico's current financial assurance requirements, as explained in Mrs. Felix, Mr. Emerick, and Mr. McGowen's testimony, and the Reclamation Fund is in place as a financial backstop, in addition to the protections provided under the state's existing temporary abandonment program I discussed above in Part III.C.

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[22] The Colorado Oil & Gas Conservation Commission (COGCC) became the Colorado Energy & Carbon Management Commission (ECMC) effective July 1, 2023.

[23] Carbon Tracker Initiative. *False Start: How Colorado's New Bonding Rules Failed to Increase Coverage* (February 2024). Available at: https://carbontracker.org/new-bonding-rules-expected-to-drop-colorados-2024-oil-and-gas-bonds-below-2021-levels

E. Proposals to Reclassify Marginal Wells – Proposed 19.15.2.7(M)(2)

1. New Definition of Marginal Wells Under Consideration

WELC proposes adding a definition of "Marginal Well" as an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent (BOE) within a consecutive twelve (12) month period.

2. Marginal Well Financial Assurance Implications

As noted above in Part III.D.3., WELC's marginal well assurance proposal, if adopted and once effective, would immediately require individual financial assurance of $150,000 for every marginal well that is the subject of a transfer, and effective January 1, 2028, would require financial assurance of $150,000 for every marginal regardless of transfer status. It is unclear whether classification as a marginal well under WELC's proposed new definition would trigger these heightened assurance requirements, but conceivably could. Regardless, these additive requirements would have substantial and immediate implications for asset transfers and operator changes, as I discuss in Part III.G., the regulatory requirements for which also reference and require compliance with financial assurance requirements.

In addition, if marginal or inactive wells, or a combination thereof, comprise 15% or more of an operator's total well inventory, WELC would require financial assurance of $150,000 for every well the operator holds, not just the marginal ones, until the ratio falls below 15%. By reclassifying otherwise active wells as marginal under its proposed new definition, WELC could potentially apply its proposed heightened marginal well assurance requirements to many otherwise active wells that will now be deemed just marginally producing.

3. Overarching Concern for Adding a Definition of "Marginal Well"

It is my professional opinion that marginal well classification must be grounded in operational and economic context, not abstract thresholds. In practice, the viability of such wells hinges on leasehold strategy, reservoir management needs, and cash flow projections – not a rigid 180-day/1,000 BOE test. For this reason, the marginal well definition should incorporate flexibility and allow for a case-by-case economic assessment, like the EPA's production-based criteria. Adopting more nuanced definitions, such as those used in Texas or North Dakota, would better align with regulatory and operational realities while avoiding unintended premature plugging and abandonment of economically viable assets. In my experience, these wells often fulfill lease retention obligations and infrastructure utilization roles.

WELC's proposed definition would deem otherwise active and productive wells as marginal producers by setting thresholds that do not align with the reality of how marginal wells operate or their prevalence in the New Mexico and U.S. oil and gas industries. Marginal wells, also known as "stripper wells," are characterized by low but ongoing production. These wells can continue producing small volumes for extended periods, often years or even decades, at low but steady rates.

4. Importance of Marginally Producing Wells

According to the Interstate Oil and Gas Compact Commission (IOGCC), a stripper well is defined as one producing **10 barrels per day (b/d) or less of oil** or 60,000 cubic feet per day (cf/d) or less of natural gas over a 12-month period. The Internal Revenue Service (IRS) uses a slightly broader definition for tax purposes: 15 b/d or less of oil, which equates to 90,000 cf/d or less of gas on an energy-equivalent basis over a calendar year.[24] To put this in practical terms, a single oil

[24]U.S. Energy Information Administration (EIA). Well Distribution Report 2024. U.S. Department of Energy, Office of Petroleum and Natural Gas. Published March 2024. Available at:

well producing 15 barrels per day at a $70 per barrel price would generate approximately $1,050 per day – or about **$31,500 per month** in gross revenue. For small operators and family-run businesses across New Mexico, that level of production can mean the difference between sustaining a livelihood and shutting down entirely. These are not speculative ventures; they are often operated by multigenerational New Mexico families, small LLCs, and tribal leaseholders who rely on modest, steady cash flow to cover their mortgages, local wages, and community taxes.

Imposing excessive financial assurance or regulatory hurdles on these wells could force many such operators out of business. The result would be not only fewer barrels produced but also fewer paychecks sent to local roustabouts, pumpers, and truck drivers, many of whom live and work in rural counties where oil and gas are the economic backbone. WELC's proposed definitions risks penalizing precisely the wells that, while small in volume, provide consistent income to working New Mexicans and preserve leasehold value for future development.

Despite their low individual output, these wells collectively contribute a meaningful share of national production. As reported in the U.S. Energy Information Administration's 2024 Well Distribution Report, stripper wells represented the vast majority of producing wells in the U.S., with over 78% of oil wells and 77% of gas wells falling into this category in 2021. Collectively, these marginal wells produced approximately 6% of total U.S. oil and natural gas in 2023.[25]

A significant portion of New Mexico's oil and gas portfolio consists of marginal wells. According to the U.S. Energy Information Administration's 2024 Well Distribution Report, 10,579

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https://www.eia.gov/petroleum/wells/pdf/WDR2024_Full%20Report.pdf

[25] Ibid.

oil wells (54%) produced less than 15 barrels of oil equivalent per day (BOE/d) in 2023, which meets the IRS and IOGCC definitions of marginal or stripper wells. When it comes to gas wells, 33,443 wells (81%) produced less than 90,000 cubic feet of gas per day. Altogether, these low-production wells, represented approximately 11 million barrels of oil (18% of New Mexico's oil output) and 310 billion cubic feet (Bcf) of gas (10% of the state's gas production) in 2023.[26]

By setting unrealistic parameters for determining when a well is properly classified as a marginal well, more wells would be subject to the heightened bonding requirements WELC and OCD propose apply to marginal wells. And because marginal wells play a vital and crucial role in the State of New Mexico's oil and gas sector, WELC's proposal would have a chilling effect on their operation, which could decrease aggregate production substantially.

According to the U.S. Energy Information Administration's 2024 Well Distribution Report, marginal oil wells (producing ≤15 barrels per day) accounted for approximately 18% of New Mexico's oil production in 2023, while marginal gas wells (producing ≤90 Mcf/day) contributed 10% of the state's total gas output.[27] If roughly 50% of marginal wells are prematurely plugged or shut-in due to these financial assurance burdens, New Mexico could face annual production losses of ~5.5 million barrels of oil and ~155 billion cubic feet (Bcf) of natural gas. Based on an estimate of $70 per barrel of oil and $3.00 per Mcf of gas and New Mexico's severance tax rates (3.75% for oil and gas),[28] this would result in a direct annual loss of approximately $14.4 million in oil

[26] U.S. Energy Information Administration (EIA). Well Distribution Report 2024. U.S. Department of Energy, Office of Petroleum and Natural Gas. Appendix B. Selected Summary Sheets. Published March 2024. Available at: https://www.eia.gov/petroleum/wells/xls/WDR2024_Appendix_B.xlsx

[27] Ibid.

[28] New Mexico Statutes Annotated (NMSA) 1978, § 7-29-4(A)(1)–(2). Available at:

severance tax revenue and $17.4 million in gas severance tax revenue, totaling almost $32 million in foregone tax revenue each year. (Oil severance taxes: $70/bbl × 5.5 million bbl × 3.75% = $14.4 million) (Gas severance taxes: $3.00/Mcf × 155 Bcf × 3.75% = $17.4 million) Total direct tax revenue loss: ~$39.75 million/year.

Moreover, my understanding is that the four forms of taxes on the value of severed oil and gas (Severance, Conservation, Emergency School, & Ad Valorem Production) total ~8.15% on oil and ~9% on gas (with the local taxing authority at the site of well having the ability to affect both figures slightly). Once considered, this more than doubles the total direct tax revenue loss I anticipate would flow from implementing WELC's changes as proposed.

These estimates do not include further fiscal impacts such as lost royalties from federal and state trust lands, reduced ad valorem property taxes collected by counties, diminished gross receipts tax collections from service activity, or the broader economic ripple effects on employment and local businesses. In short, the proposed marginal well definition and related financial assurance thresholds risk removing tens of millions of dollars annually from the NM's general fund and communities, while offering little meaningful gain in environmental or operational accountability.

In my experience, a marginal well might produce intermittently due to a combination of technical, economic, and operational factors, including operational prioritization, where limited resources are directed toward higher-producing wells, temporary shut-ins while awaiting recompletion, workover, or infrastructure upgrades (especially common in older fields), and low

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https://law.justia.com/codes/new-mexico/2021/chapter-7/article-29/section-7-29-4 reservoir pressure that requires periodic buildup or limits artificial lift efficiency, all of which are not uncommon occurrences in practice. Variability in marginal well production can also be due to maintenance, infrastructure limitations, or market conditions. None of these factors is considered or accounted for under the proposed definition's thresholds. Marginal wells also contribute to leasehold operations and reservoir pressure management by maintaining production sufficient to hold acreage and preventing premature lease or unit expiration. The impact of applying a rigid threshold to shut-in or curtailed wells could result in unnecessary reclassification of viable wells, premature abandonment of economic assets, and the loss of long-term recovery potential from established reservoirs.

Contrary to the proposed definition, operators assess the economic viability of marginal wells based on based on a combination of leasehold economics, operating costs, projected recovery, tax treatment, and the strategic value of holding acreage or infrastructure, not simply on short-term production volumes or number of days producing. These criteria do not necessarily align and could conflict with the proposed definition by misclassifying viable wells as non-productive based solely on arbitrary volume and time thresholds. For example, a well producing just under the proposed 90-day/1,000 BOE cutoff might still be generating positive cash flow after operating costs, or may serve a critical role in maintaining lease obligations, preserving infrastructure, or avoiding more costly re-entry later. Imposing rigid thresholds ignores these economic realities and could lead to unnecessary abandonment, impairing the long-term asset value of the lease and undermining full reservoir development.

5. Comparison to Other Jurisdictions

Other jurisdictions, such as Texas, North Dakota, and Colorado, use the following definitions, which better reflect the operational realities of marginal well valuation:

i. Texas defines marginal oil wells based on depth, with production thresholds ranging from ≤10 barrels per day (bbl/day) for wells ≤2,000 feet to ≤35 bbl/day for wells deeper than 8,000 feet, and classifies gas wells as marginal if they produce ≤250 Mcf/day. Additionally, the Texas Commission on Environmental Quality (TCEQ) applies operational plugging criteria of ≤15 bbl/day for oil and ≤90 Mcf/day for gas when prioritizing marginal wells for closure.[29]

ii. North Dakota uses stratified thresholds ranging from ≤10 bbl/day in wells under 6,000 feet to ≤35 bbl/day for deep wells in the Bakken or Three Forks formations.[30]

iii. Colorado defines stripper wells as those producing ≤15 bbl/day for oil or ≤90 Mcf/day for gas.[31]

iv. BLM does not have a standalone regulatory definition of a stripper or marginal well. However, it has adopted the IRS definition of a stripper well for fiscal and regulatory analyses. Under Internal Revenue Code § 613A(c)(6), a "stripper well property" is defined as a property producing not more than 15 barrel-equivalents per day, averaged across all producing wells on the lease.[32]

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[29] Texas Natural Resources Code, Title 3, Subtitle B, Chapter 85, Subchapter D, §85.121. Available at: https://statutes.capitol.texas.gov/Docs/NR/pdf/NR.85.pdf

[30] North Dakota Administrative Code, §43-02-08-03. Available at: https://ndlegis.gov/prod/acdata/pdf/43-02-08.pdf

[31] Colorado Office of the State Auditor, *Oil & Gas Severance Tax: Stripper Well Exemption*, July 2020. Available at: https://leg.colorado.gov/sites/default/files/2020-te22_stripper_well_exemption.pdf

[32] IRS Notice 2017-51, "Reference Price for § 45I Credit for Production of Natural Gas from Marginal Wells," July 2, 2017, §2(c); https://www.irs.gov/pub/irs-drop/n-17-51.pdf

In addition to that broader classification, BLM performs “paying well determinations” as part of its lease administration responsibilities. These determinations are used to assess whether a producing well on federal leases meets the minimum standard to hold the lease in force beyond the primary term. A paying well must generate sufficient production to cover operating costs, not necessarily to produce a profit. In practice, these determinations are conducted on a lease-wide basis, not well-by-well, and involve field-specific factors such as transportation costs, gathering and processing fees, infrastructure constraints, and actual revenue from production sales.[33]

In my experience working with operators on BLM-administered leases, BLM’s Petroleum Engineers and Reservoir Management teams will review monthly production reports (OGOR-B), cost spreadsheets, and marketing data, and often accept qualitative evidence like shut-in strategy explanations or development plans. For marginal wells near the threshold, BLM field offices may also accept anticipated reactivation plans or unit development schedules as part of a paying well analysis. These cases are inherently case-specific and tend to prioritize lease preservation and future resource potential over short-term production metrics.

For example, I was directly involved with multiple projects (about 100 wells) in the Williston Basin of Montana and North Dakota where BLM accepted a showing of consistent albeit low output, supported by field-level operating cost analysis and leasehold strategy documents, as sufficient to establish that the well remained a “paying well.” That case involved marginally producing wells and the lease was maintained without plugging or abandonment obligations

[33] U.S. Bureau of Land Management. *Title 43 Code of Federal Regulations (CFR) Part 3160 – Onshore Oil and Gas Operations*. U.S. Government Publishing Office. See Subparts 3162.3 and 3163.1, which reference lease continuation and enforcement related to production in paying quantities. Available at: https://www.ecfr.gov/current/title-43/subtitle-B/chapter-II/subchapter-C/part-3160

despite falling below typical commercial volumes.

These BLM practices reinforce the argument that no rigid time or production thresholds should be used to define "beneficial use" or "economic production." Instead, determinations should allow for flexibility based on full-field economics, lease maintenance value, and broader operational strategy – particularly for wells in marginal, transitioning, or shut-in status.

6. Risks and Potential Impacts of Proposed Changes

Any of the alternatives utilized in other jurisdictions and analyzed above would be superior to the definition of marginal wells proposed by WELC because they reflect real-world production variability, recognize that marginal wells operate economically at different volumes depending on depth and formation, and provide administrative clarity without triggering premature or unnecessary plugging of viable wells.

Moreover, WELC's proposal presents serious potential cost implications for the State of New Mexico and operators alike. Marginal wells play a significant role in royalty, revenue, and fee contributions to New Mexico oil and gas production and tax revenue. According to the U.S. Energy Information Administration's 2024 Well Distribution Report, wells producing 15 BOE per day or less (the common threshold for marginal classification) accounted for 10,579 oil wells and 33,443 natural gas wells, representing over 54% of oil wells and 81% of natural gas wells in New Mexico. These marginal wells produced approximately 10 million barrels of oil (or 18% of the state's total oil production) and 310 billion cubic feet (Bcf) of natural gas (or 10% of the state's total gas output) in 2023.[34] The premature abandonment of marginal wells could significantly reduce annual

[34] U.S. Energy Information Administration (EIA). Well Distribution Report 2024. U.S. Department of Energy, Office of Petroleum and Natural Gas. Appendix B. Selected Summary Sheets. Published March 2024. Available at:

production and directly erode state revenue. In fiscal year 2024, industry contributed 49% ($7.4 billion) of all State of New Mexico General Fund revenue,[35] funds that would likely decrease if it were no longer worth the risk and cost to operate marginal wells in the state under the proposed requirements.

For operators, adopting a definition that misclassifies productive marginal wells as inactive could trigger disproportionately high financial assurance requirements from the OCD—costly demands that far exceed the actual risk of those wells needing to be plugged. As discussed further in my analysis of WELC's proposed financial assurance provisions below, the proposal would significantly increase financial obligations for marginal wells. Specifically, beginning in January 2028, operators would be required to post single-well financial assurance for each marginal well, even if a blanket bond is otherwise in place. In the context of asset transfers, the proposal would also require transferee operators to post $150,000 in financial assurance per marginal well acquired.

F. Waste Prevention Requirements and Criteria Under Which an Operator is Considered in Regulatory Compliance – Proposed 19.15.5.9(A)(4)-(5) NMAC

WELC's proposed amendment to Waste Prevention Requirements under 19.15.5.9(A)(4)-(5) NMAC outline criteria under which an operator is considered "in compliance" based on financial assurance, absence of violations or unpaid penalties, and the number of noncompliant wells. However, this framework does not adequately reflect the technical limitations and real-world

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https://www.eia.gov/petroleum/wells/xls/WDR2024_Appendix_B.xlsx

[35] New Mexico Oil and Gas Association, *Drilling Down on Dollars: The Role of Oil and Gas in New Mexico's Budget, State and Local Revenue from the Oil and Gas Industry in New Mexico: Fiscal Year 2024 Update*. Available at: https://assets.nationbuilder.com/nmoga/pages/2283/attachments/original/1745341868/NMOGA_TRI_Study_-_FINAL.pdf?1745341868

compliance practices that affect venting and flaring in daily operations. In practice, operators face a range of unplanned, intermittent, and operationally necessary events that can result in temporary venting or flaring, even in otherwise well-managed and compliant facilities. These include, for example:

1. Compressor or midstream pipeline outages, which may require temporary flaring to maintain safe pressure levels;
2. Well unloading or artificial lift workover operations, where venting may briefly occur during typical operations or during swabbing;
3. Separator upsets or liquid slugging, which can cause momentary gas handling issues.

These scenarios are frequently unavoidable and short in duration, and are often addressed under federal regulations, New Mexico Environment Department (NMED) air permits, and OCD Form C-129 exception reporting. These rules recognize that certain sources, such as pneumatic controllers, storage vessels, and well completions, may temporarily emit gas as part of normal operations and provide specific provisions for initial startup, equipment malfunctions, and repair timelines under existing Leak Detection and Repair programs. Operators routinely report and resolve such events with transparency, but WELC and OCD's current structure risks treating even good-faith technical issues as categorical non-compliance.

WELC's proposed 19.15.5.9(A)(4)-(5) are duplicative of existing requirements in that they cite regulations that operators are already required to comply with, specifically, 19.15.27.8 NMAC,[36] which is already mandatory irrespective of the WELC and OCD's proposed changes to

[36] The applicant cited 19.15.27.A.8 NMAC; for purposes of my analysis only, I assume WELC meant 19.15.27.8(A).

19.15.5.9(A)(4)-(5) NMAC.

In the event the revisions are not rejected entirely, the cross-references should be eliminated and the specific requirements noted. The Waste Prevention Requirements serve as a threshold test for permitting, transfers, and other regulatory functions. Accordingly, references to other regulatory provisions could enable OCD to leverage those separate and distinct requirements for financial assurance obligations or other uses not intended when the referenced rules were promulgated. The proposals also unfairly penalize compliant operators if they acquire noncompliant entities. Considering the number of acquisitions occurring in the industry, if amended, the regulation should include a grace period afforded at the very least to recently acquired entities. Notably, the proposed amendment removes the 2-10 well compliance buffer for smaller operators or minor deviations, which adds impracticality to the rule.

G. Proposals to Restrict Change of Operator and Operator Registration – Proposed 19.15.9.8(B)-(E) and 19.15.9.9(C), (E) NMAC

1. Proposed Amendments to Operator Registration Requirements Under Consideration

i. Proposed 19.15.9.8(B)-(E) NMAC

WELC also proposes to amend (i) the operator registration requirements in 19.15.9.8(B)-(E) NMAC and (ii) the change of operator requirements codified at 19.15.9.9(C) NMAC. OCD joins WELC in its proposal to expand the agency's discretion to deny change of operator requests.

First, 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 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 twenty-five percent (25%+) interest were affiliated with currently non-compliant operators in the past five (5) years; and annual certifications for existing operators regarding compliance of all current/past leadership and ownership.

ii. Risks and Potential Impacts of Adopting Proposed Changes

These requirements are unworkable, if not impossible to meet, due to the difficulty of verifying compliance across unrelated companies, especially post-affiliation, a common occurrence due to the many mergers and acquisitions in the oil and gas industry. Moreover, these provisions would chill executive and investor mobility by deterring otherwise qualified professionals from serving as officers, directors, or equity stakeholders in new ventures due to fear of being penalized for the unrelated compliance history of companies with which they were previously affiliated. That chilling effect could disproportionately impact small and mid-sized firms that rely on experienced professionals moving between operators. It could also dissuade capital formation by imposing opaque due diligence burdens on investors and board members, especially those without operational responsibilities.

2. Proposed Amendments to Change of Operator Requirements

i. Proposed 19.15.9.9(C) and (E) NMAC

Section 19.15.9.9(C) NMAC currently allows OCD to 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. As proposed, OCD's discretion to deny a change of operator would be expanded if: (i) any officer, director, or twenty-five percent or more (25%+) 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 subsections (3) and (4)); (ii) the applicant is not properly registered or in good standing with the New Mexico Secretary of State (under proposed subsection (5)); and (iii) certifications or disclosures show a "substantial risk" the new operator can't meet plugging and abandonment requirements (under proposed subsections (6)). Additionally, a new paragraph (E) is proposed, prohibiting the transfer of non-compliant wells or facilities to operators unless they are brought into compliance or a compliance schedule is approved.

ii. Risks and Potential Impacts of Adopting Proposed Changes

Again, many, if not all, of these requirements are unrealistic and unworkable. Practically speaking, tracking the historical and ongoing compliance status of entities, particularly those with which an individual is no longer affiliated, is cumbersome and often impossible. Officers, directors, and equity holders typically relinquish all operational control and access to internal compliance records once their tenure or ownership interest ends. Without ongoing access to compliance filings, enforcement records, or audit results, such individuals cannot reasonably be expected to certify the status of those entities, especially given the fluid nature of regulatory interpretations and reporting practices across jurisdictions.

Further, requiring affirmative certification of compliance in all states where the operator does business introduces substantial legal and logistical risks. Each state has its own oil and gas regulatory regime, with differing definitions, reporting schedules, and enforcement procedures. A technical violation in one jurisdiction, such as a delayed report or non-material administrative infraction, could inadvertently trigger consequences in New Mexico under this rule. This creates a patchwork compliance burden that is disproportionate and impractical, particularly for operators with a multi-state footprint or legacy assets acquired through mergers and acquisitions.

In addition, the proposal lacks a clear materiality threshold, which means even minor or resolved issues could result in disqualification. These vague standards risk deterring qualified individuals and investors from engaging with New Mexico's oil and gas sector due to uncertainty, compliance exposure, or fear of being penalized for issues beyond their control.

Clayton Sporich, NMOGA's legal expert witness, addresses why OCD does not have the authority to implement these proposals, and while I am not a lawyer, I have reviewed his testimony, and I agree with this assessment based on my experience in the field and with NM OCD rules.

IV. CONCLUSION

In my professional opinion, the proposed rule changes, particularly those related to definitions of marginal wells, beneficial use, temporary abandonment, and financial assurance, are overly rigid, operationally impractical, and economically disruptive. They risk unintended consequences that include the premature plugging of viable wells, reduced production from marginal assets, and substantial revenue losses to the State of New Mexico.

The evidence demonstrates that marginal wells, although lower in output, comprise more than half of all oil wells and over 80% of gas wells in the state. These wells alone contributed approximately 18% of oil and 10% of gas production in 2023. The proposed $150,000 per-well financial assurance framework disproportionately impacts these wells and ignores the wide variability in actual plugging costs, which in many cases are far lower.

Other states have adopted flexible, risk-based bonding regimes that reflect factors such as well depth, compliance history, and plugging cost variability. These approaches provide a far better balance between environmental protection and economic sustainability than the one-size-fits-all model WELC and OCD have proposed.

New Mexico should follow that lead by preserving regulatory discretion, maintaining the 5-year term for Approved Temporary Abandonment, and avoiding definitions or bonding thresholds that conflict with the realities of field development, infrastructure investment, and operator capacity. In doing so, the Commission can ensure that its rules remain both enforceable and aligned with the technical and economic realities of modern oil and gas operations in the state.

V. RECOMMENDATIONS

A. Reject the Definition of Beneficial and Related Presumption of No Beneficial Purposes or Beneficial Use: The Commission should decline to add a new definition of beneficial due to the unintended consequences it could have with respect to other Commission and state regulations that utilize the terms. In the event the Commission moves forward with adding a definition of beneficial purpose or beneficial use, the word speculative should be removed at a minimum, and preferably other non-production related uses identified within the definition. The Commission should also decline to add WELC's proposed presumption of no beneficial use. But in the event the Commission moves forward with the presumption proposal, then the 90-Day Criteria should utilize a 5-year timeframe to align with the current 5-year maximum for approved temporary abandonment, which WELC does not oppose in this rulemaking and which is more consistent with typical infrastructure, reinvestment, and development timelines.

B. Decline to Add Rigid Definition of Marginal Wells and New Marginal Well Financial Assurance Requirements: Similarly, I recommend rejecting WELC's proposal to add a new definition of marginal wells. If a definition must be adopted, which in my opinion is not necessary, then any new marginal well definition and resulting classification must be grounded in an operational and economic context, not abstract thresholds. WELC's proposed definition of "marginal well" would deem otherwise active and productive wells as marginal producers by setting thresholds that do not align with the reality of how marginal wells operate or their prevalence in New Mexico. It is also unclear if this reclassification of marginal wells would trigger the heightened marginal well financial assurance requirements which WELC also proposes, and I also recommend be rejected.

C. **Maintain Regulatory Flexibility:** The Commission should preserve discretion in financial assurance determinations by allowing for risk-based bonding approaches that consider operator compliance history, well condition, asset maturity, and demonstrated plugging costs. Flat per-well bonding requirements, such as the proposed $150,000 per well, fail to reflect actual risk or plugging cost variability and will unnecessarily burden operators with viable, low-producing wells.

D. **Preserve the Use of Blanket Bonds and Avoid Stacking Requirements:** The Commission should affirm that blanket financial assurance satisfies applicable obligations for covered wells and avoid rules that require simultaneous single-well and blanket bonding unless there is a demonstrated, case-specific basis to require both.

E. **Reject the Use of "Average per Well" Blanket Bonding Requirements:** The proposal to require blanket bonding based on an average of $150,000 per well introduces a target compliance standard that is difficult to administer, audit, and enforce. It will create confusion and generate unintended consequences for acquisitions, mergers, and internal compliance systems. The Commission should instead retain fixed blanket bonding tiers that align with industry norms and simplify enforcement.

F. Encourage Adoption of Tiered and Incentive-Based Structures: Similar to other states, New Mexico could adopt a tiered bonding structure that provides reduced financial assurance obligations for operators who maintain strong compliance records, reduce inactive well counts, or actively participate in orphan well reduction efforts.

G. Limit Additional Reporting and Certification Burdens: New registration and ownership certification requirements, such as affirming compliance in all jurisdictions or disclosing historical affiliations with noncompliant operators, are overly broad, likely unworkable in practice, and risk discouraging executive mobility and capital investment. Any ownership-based disclosure should be limited to current control parties with material decision-making authority and based on known, verifiable records.

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 8, 2025

Name: J. Daniel Arthur, PE No. 21858

Title: President/Chief Engineer

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PROFESSIONAL ENGINEER

8/8/2025

Dated this 8th day of August, 2025.

Respectfully submitted,

By:________________________

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APPENDIX A

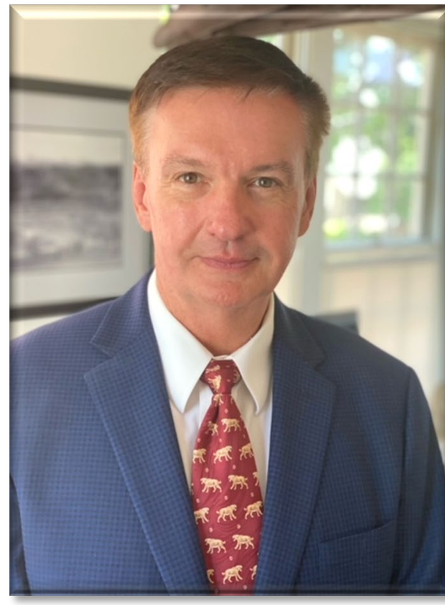
Curriculum Vitae

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS, CCML

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS, CCML

Business Affiliations

President & Chief Engineer (ALL Consulting)
Chief of Sustainability (DynaVert Holdings)
President (One Tonne Capital)



Education

B.S., Petroleum Engineering, University of Missouri-Rolla

Professional Registrations

- *Professional Engineer (36 States)*: Alabama, Arkansas, Arizona, California, Colorado, Florida, Idaho, Indiana, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Jersey, Nebraska, New York, New Mexico, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Tennessee, Texas, Utah, Virginia, West Virginia, and Wyoming.
- *Society of Petroleum Engineers (International Professional Petroleum Engineering Registration)*: SPE Petroleum Engineer Certification (SPEC)
- *American Association of Petroleum Geologists*: Certified Petroleum Geologist (CPG)
- *Geological Society*: Fellow of the Geological Society
- *Certified Climate Management Leader (CCML)*
- *National Association of Forensic Engineers: Senior Member*
- *Petroleum Historical Institute*
- *International Association of Well Control Instructors: Expert*
- *Certified Senior Project Manager*
- *Registered Water Well Driller via ALL Consulting, LLC (Pennsylvania, USA)*
- *Qualified Measurement Specialist (QMS)*
- *Consulting Expert: BCarbon Carbon Registry*
- *Third Party Verification/Validation Expert*
- *Testifying and/or Consulting Expert in multiple areas, including, but not limited to:*

  - **Engineering & Engineering Design (various); Design-Build construction projects (various – including planning/cost estimating/project bidding, Standard Contracts (e.g., NSPE, etc.), Engineering/Construction Standard of Care);**
  - **Oil & Gas Field Operations (including standard of care, production operations, production forecasting, well plugging/decommissioning (onshore & offshore), & site restoration, etc.), economics, financial assurance, etc.;**

- **Well Plugging & Abandonment (e.g., locating wells, methane quantification, plugging design & oversight, well access & manipulation as required for plugging, use of plugging material & methods, re-plugging methods, incident evaluation, historic practices and regulations, emergency response plans, well control evaluation, etc.;**
- **Carbon and/or Methane Capture, Elimination, Reduction, avoidance, and removal projects related to carbon credit generation (e.g., well plugging, soil treatment, biochar/bio-oil, supercritical CO2, venting/flare elimination/reduction, well repurposing, microgrids, etc.).**
- **Validation & Verification of carbon capture/reduction, methane abatement/mitigation, and emission reduction on nature and industrial based projects.**
- **Various issues related to flow lines, pipelines, related design & material testing, inspection, and failure analysis (various types of pipelines);**
- **Drilling & Completion Planning; Well Workovers, Emergency Response (e.g., New Wells/Re-completions, well control issues, Fishing, Remediation, Sidetracks, etc.);**
- **Hydraulic Fracturing (including well completion design/evaluation, Frac Hits [and drilling hits, trespass, etc.], equipment, chemical usage design, injuries, safety processes, etc.);**
- **Various technical aspects related to Patents;**
- **Water Treatment/Supply Systems (various);**
- **Impoundments/Reservoirs (various);**
- **Underground Injection (Underground Injection Control Program, Underground Sources of Drinking Water, Area of Review Analysis, Aquifer Exemptions, Well Design & Operation, Step Rate Testing, Induced Seismicity, Mechanical Integrity, Injection Fluids, Interference Testing, Assessing Confinement, Fluid Migration, Commercial Disposal Well Infrastructure & Economics, and various other aspects & issues, also including various aspects related to Class I-VI Injection Wells;**
- **Stray Gas/Gas Migration Investigations;**
- **Groundwater and Hydrogeology related issues;**
- **Induced Seismicity;**
- **Alleged Impacts Associated with Hydraulic Fracturing;**
- **Well Interference (Conventional Wells, Unconventional Wells, Injection Wells, Water Wells, etc.);**
- **Spill/Release investigations (e.g., brine, condensate, NGLs, Oil, etc.);**
- **Contamination/Remediation (spills, releases, streams, and other various);**
- **Produced Water Treatment, Produced Water Pits & Impoundments, Pit Design and Closure, etc.;**
- **Salt Solution Mining (e.g., Cavern Stability & Integrity, Well Integrity, Gas Storage, etc.);**
- **Well Spacing, Unitization, Paying Well Determinations, Well Valuation, Well Plugging, Fast Tract Design/Build Projects, BOP Installation/Safety, Various Safety Engineering (e.g., Pipeline Pigging Safety, Flash Fires, Static Electricity as a Source to Flash Fires, Proper Grounding of Equipment, etc.), Standard of Care/Standard Practices (e.g., regarding insurance coverage, contracts, etc.).**

Distinguishing Qualifications

Mr. Arthur is a registered Professional Engineer (PE) in 36 states, a registered professional Petroleum Engineer (SPEC) through the Society of Petroleum Engineers (SPE), a Certified Petroleum Geologist (CPG) through the American Association of Petroleum Geologists (AAPG), a Fellow of the Geological Society (international), a Qualified Methane Measurement Specialist (QMS), and a Certified Climate Management Leader (CCML). Mr. Arthur has served as an expert with the National Academy of Sciences, various state & federal agencies/organizations, and permitted his first injection well in 1981. He has served as an expert in several areas and is a leader in his areas of specialty.

Mr. Arthur has worked for major oilfield service companies, oil and gas producers, environmental non-governmental organizations, state and federal government agencies, and major environmental consulting firms over his 40-year career. He is the Founder, President and Chief Engineer of ALL Consulting and has served as its President & Chief Engineer throughout the firm's 26-year history.

Prior to founding ALL Consulting, Mr. Arthur served as a Vice President of a large international consulting engineering firm and was involved with a broad array of work, including supporting the energy and other industries, various federal agencies, water and wastewater projects (municipal/industrial), environmental projects, various utility related projects, and projects related to the energy & mining industries. Mr. Arthur's experience also includes serving as an enforcement officer and National Expert for the U.S. Environmental Protection Agency (EPA) and a drilling and operations engineer with an independent oil producer, as well as direct work with an oilfield service company in the mid-continent.

In 2016, Mr. Arthur was appointed to serve on a Steering Committee for Natural Gas Storage for the California Council on Science and Technology (CCST). Mr. Arthur's role on the Committee was primarily focused on well construction, integrity and testing based on his expertise, but also included overall analysis on issues such as global climate change and other issues (e.g., induced seismicity, gas markets, etc.). In 2010, as the shale boom was heightening, Mr. Arthur was appointed to serve as a Sub-Group Leader for a National Petroleum Council (NPC) study on North American Resource Development (NARD). His Sub-Group focused on technology that is and will be needed to address development (e.g., hydraulic fracturing, horizontal drilling, production, etc.) and environmental challenges through the year 2050. Mr. Arthur was also appointed to a U.S. Department of Energy Federal Advisory Committee on Unconventional Resources. Over the last 20 years, Mr. Arthur has also served as a Peer Reviewer on several research documents and reports, including studies/investigations performed by the Government Accounting Office, various Universities, and also private research groups. And lastly, Mr. Arthur supported the U.S. Department of Energy through the Annex III Agreement between the United States and China to provide support relative to coal bed methane and shale gas development in China (including produced water recycling & disposal).

Mr. Arthur routinely serves as a testifying and/or consulting expert on a broad variety of issues that range from basic engineering to catastrophic incidents. He has also served to advise management and legal teams on a plethora of issues in an effort to avoid litigation, reach settlements, or develop strategies for future activities. His experience and continued level of activity on such issues has expanded his experience on a variety of issues, while also exposing him to an array of technical and forensic approaches to assess past activities, claims, etc. Mr. Arthur is also a member of the National Association of Forensic Engineers (NAFE) and routinely practices forensics in the project and litigation support work he has been involved in.

Mr. Arthur has managed an assortment of projects/programs, including regulatory analysis (e.g., new regulation development process, commenting/strategizing on new proposed regulations, negotiating with regulatory agencies on proposed regulations, analysis of implementation impacts, etc.); engineering design (including roads, well pads, design of various types of wells; completions/fracturing; water and wastewater systems, and oil & gas facilities (including trucking loading/unloading, fueling stations, pipelines, treatment systems, pigging stations, valves/controls, etc.); life cycle analysis and modeling; resource evaluations; energy development alternatives analysis (e.g., oil, gas, hydrogen, compressed air, coal, electric utility, etc.); feasibility analyses (including power plants, landfills, injection wells, water treatment systems, mines, oil & gas plays, etc.); remediation and construction; site closure and reclamation site decommissioning; reservoir evaluation; regulatory permitting and environmental work; geophysical well logging; development of new mechanical integrity testing methods, standards, and testing criteria; conduction and interpretation of well tests; restorative maintenance on existing wells and well sites; extensive hydrogeological and geochemical analysis of monitoring and operating data; sophisticated 2-dimensional and 3-dimensional modeling; geochemical modeling; drilling and completion operations; natural resource and environmental planning; natural resource evaluation; governmental and regulatory negotiations; restoration and remediation; environmental planning, design, and operations specific to the energy industry in environmentally sensitive areas; water management planning; alternative analysis for managing produced water; beneficial use of produced water; water treatment analysis and selection; produced water disposal alternatives; facilities engineering for wastewater handling (e.g., disposal wells, injection wells, water treatment, water recycling, water blending, etc.); feasibility & cost analysis for design, permitting, drilling/completion, and facility construction of Class I, II, III, V, & VI type injection wells throughout the U.S. and Internationally (although specific classes may not be applicable outside of the U.S.); construction oversight; contract negotiations and management; contract negotiation with wastewater treatment companies accepting produced water; data management related to water and environmental issues; property transfer environmental assessments; and data management of oil and gas producing and related injection well data and information. He maintains experience with the technical and regulatory aspects of oil and gas and underground injection throughout North America. He has given presentations, workshops, and training sessions to groups and organizations on an assortment of related issues and has provided his consulting expertise to hundreds of large and small clients – including several major international energy companies and government agencies.

Specific to unconventional resource development, Mr. Arthur has gained experience in all aspects of planning, development, drilling, well completion, operations, closure, pipelines, facilities, equipment, etc. Mr. Arthur has supported the evolution of various activities through this process that have included technical issues such as water sourcing, well drilling techniques, cement design, well integrity analysis, fracturing design & analysis, well performance assessment, production operations and facilities, well plugging & abandonment, site closures, and regulatory compliance. Mr. Arthur's experience covers ever major unconventional play in North America and on other continents. Moreover, Mr. Arthur's experience also includes work with horizontal drilling and various types of completions in both conventional and unconventional reservoirs and with various types of unconventional reservoirs (e.g., shales, limestones, coal).

As a petroleum/environmental engineer and senior project manager, Mr. Arthur's experience ranges from the drilling and construction of oil- and gas-producing wells to performing site characterization and remediation of soils and groundwater at a variety of sites throughout the United States to develop/protect groundwater supply resources. Mr. Arthur has also gained experience in evaluating large-scale resource plays, responsibility for drilling/completion and operations; conducting implication analysis of new laws and regulations, evaluating options for developing resources (based on economics, environmental impacts, water management challenges, and other factors), and conducting analysis specific to broad program development. Mr. Arthur's experience uniquely qualifies him for dealing with the complex issues associated with projects and concerns of the energy, natural resource, and environmental industries. Mr. Arthur is a recognized expert in the area of environmental law and regulations, as well as fossil energy, produced water, and environmental issues. He has managed large multi-discipline projects, has completed more than 100 publications/presentations, and has been a distinguished lecturer on numerous topics.

Professional Organizations:

Society of Petroleum Engineers
National Association of Forensic Engineers
The Geological Society
Petroleum Historical Institute
Seismological Society of America
International Association of Well Control Instructors
Dark Sky Institute
American Society of Civil Engineers
Society of Professional Well Log Analysts
American Association of Petroleum Geologists
The Geological Society
Ground Water Protection Council
International Association of Hydrogeologists
Southeast Geological Society
Montana Geological Society
Society of American Military Engineers
The Nature Conservancy
Sierra Club
Wildlife Federation
National Ground Water Association
International Association of Well Control Instructors

Various Others

Recent Publications and Presentations:

Note: This is not a comprehensive listing of Mr. Arthur's public speaking events, webinars, presentations, or training events. He has chaired conferences for the American Association of Petroleum Geologists; performed training events to local, state, and federal government agencies; as well as a variety of other speaking engagements. Below is a partial listing.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings). Considerations Significant to Managing and/or Plugging Historic Oil & Gas Wells. Presented at the Petroleum Historical Institute (PHI), May 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). History of Marginal, Idle, & Orphan Wells. Presented May 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). Idle & Orphan Wells: A historic & Ongoing Problem. Presented at the Society of Petroleum Engineers International Conference, April 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). Well Site Plugging & Abandonment Workshop. Presented at the Ground Water Protection Council Annual Meeting, September 2023.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). Well Plugging Significance, Current & Ongoing Risks, New EPA Methane Rule, BCarbon, & Carbon Credit Option Considerations. Presented at the BCarbon Methane Capture Webinar, January 2024

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). History of Idle & Orphan Wells in America. Presented at Oklahoma State University, 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). Methane Monitoring Associated with Well Plugging & Abandonment of Active, Marginal, Idle & Orhan Wells. Full day workshop at the American Association of Petroleum Geologists (AAPG) Workshop (Chaired by Mr. Arthur) on Idle & Orphan Well Plugging, 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies) and Cole Brown (Orr Energy Services). A Closer Look: Conventional, Orphan and Abandoned Wells: P&A Best Practices. AAPG Conference, 2024.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, CSR Services). Ethical Considerations with Idle & Orphan Wells. Presented to the American Association of Petroleum Geologists, August 2023.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting). Orphan Wells: Funds and Tax Credits for Monitoring, Eliminating Emissions, Plugging and Abandonment, and Adhering to Best Practices. Presented at the Tulsa Geological Society & AAPG, March 2023.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting, DynaVert Holdings, True Methane Technologies). Best Practices & Considerations for Plugging Idel & Orphan Wells. Presented to TOPCORP, January 2023.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting). Orphan Wells: A Best Practices Approach. Presented at the International Petroleum Environmental Conference, November 2022.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting). Orphan and Abandoned Wells: Overview, Considerations, and Path Forward. Presented at the American Association of Petroleum Geologists, August 2022.

J. Daniel Arthur, P.E., SPEC, CPG, FGS, QMS (ALL Consulting). Planning, Evaluation, and Plugging of Orphan & Abandoned Wells. Presented at the American Association of Petroleum Geologists (AAPG), 2022.

J. Daniel Arthur, P.E.; Tom Tomastik, CPG; Mark Faucher; and William Green (ALL Consulting). Orphan Wells: A best Practices Approach. Presented to the International Petroleum Environmental Conference, November 2022.

J. Daniel Arthur, P.E.; Tom Tomastik, CPG; Mark Faucher; and William Green (ALL Consulting). Planning, Evaluation, and Plugging of Orphan & Abandoned Wells. Presented to the American Association of Petroleum Geologists, November 2022.

J. Daniel Arthur, P.E.; Tom Tomastik, CPG; Mark Faucher; and William Green (ALL Consulting). Orphan and Abandoned Wells: Overview, Considerations, and Path Forward. Presented at the American Association of Petroleum Geologists, August 2022.

J. Daniel Arthur, P.E., SPEC (ALL Consulting). Challenges with Induced Seismicity in the Midcontinent. Presented at the U.S. Environmental Protection Agency's Region 8 UIC Director's Meeting, September 2021.

J. Daniel Arthur, P.E., SPEC (ALL Consulting). Limitations of Step Rate Testing when Estimating Formation Parting Pressure. Presented at the Ground Water Protection Council, San Antonio, Texas, February 2020.

J. Daniel Arthur, P.E., SPEC; David Alleman; Mark Faucher; Steve Tipton, P.E. (ALL Consulting). Permian & Anadarko Basin Produced Water Recycling: Keys to Success. Presented at the Ground Water Protection Council UIC Conference, Tulsa, Oklahoma, February 2018.

J. Daniel Arthur, Tom Tomastik, and William Green (ALL Consulting). Application of Infrared Imagery for the Identification of Leaking Historical Production and Idle Oil & Gas Wells in Ohio" presented at Petroleum History Institute Oil History Symposium, Findlay, Ohio. July 2017.

J. Daniel Arthur and Kris Andersen (ALL Consulting). The Changing Oilfield: An Environmental Impact Perspective." Presented at the Petroleum History Symposium, Findlay, Ohio. July 2017.

J. Daniel Arthur and Nathan Alleman (ALL Consulting). Induced Seismic Monitoring: A Regulatory Update. Presented at the Independent Petroleum Association of New York. July 2017.

J. Daniel Arthur, P.E., SPEC. "Oilfield Water Injection: A Summary of Issues". Presented at the 2017 Ground Water Protection Council UIC Conference. Austin, TX. February 21-23, 2017.

Tom Tomastik and J. Daniel Arthur, P.E., SPEC (ALL Consulting). "An Evaluation of Well Construction/Drilling/Conversion Methodologies Associated with Gas Storage Depleted Field Operations in the United States." Presented at the Ground Water Protection Council's Annual Forum. Orlando, FL. September 11-14, 2016.

Steve Tipton, J. Daniel Arthur, P.E., SPEC, and Nate Alleman (ALL Consulting). "Innovation in the Oilfield: How Best Management Practices Have Reduced the Impacts of Shale Development." Presented at the 23nd IPEC Conference. New Orleans, LA. November 8-10, 2016.

J. Daniel Arthur, Tom Tomastik, David Cornue, and Mark Russell (ALL Consulting). Understanding Key Aspects of Well Integrity: A Workshop Ground Water Protection Council, Annual Forum, Orlando, Florida, September 11-14, 2016.

Nate Alleman; J. Daniel Arthur, P.E., SPEC; David Alleman; Tom Tomastik; and Kris Andersen (ALL Consulting). "Underground Natural Gas Storage in the U.S.: State of Play". Presented at the 2016 GWPC Annual Forum. Orlando, FL. September, 2016.

J. Daniel Arthur, P.E. (ALL Consulting) and Will Green, P.G. (ALL Consulting), "Well Integrity Analysis using Infrared Imaging." Presented at the GWPC Annual Forum: State Water Sustainability Planning. Orlando, Florida, September 2016.

Arthur, J.D. "Application of Well Integrity Methods for Gas Storage Wells". Presented at the U.S. DOE National Laboratories Workshop on Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers, Denver, Colorado, July 12-13, 2016.

J. Daniel Arthur, P.E., SPEC; Kris Andersen; Tom Tomastik; and Nathan Alleman (ALL Consulting). "A Historical Look at Underground Natural Gas Storage in America". Presented at the Petroleum History Symposium, Casper, WY. July 28-31, 2016.

David Alleman; J. Daniel Arthur, P.E., SPEC; Nathan Alleman; Tom Tomastik; and Kris Andersen (ALL Consulting). "A Look at Underground Natural Gas Storage Operation and Regulation in the United States". Presented at the 2016 IOGCC Annual business Meeting. Denver, CO. May, 2016.

J. Daniel Arthur, Will Green P.G., Tom Tomastik and Kris Andersen, ALL Consulting, "A Proactive Approach to Addressing Annular Pressure Issues in the Utica-Point Pleasant Shale Play" Presented at the AADE Annular Gas Migration Conference, Ohio, April 28, 2016.

Arthur, J. Daniel, Tom Tomastik, David Overstreet, and Greg Casey, ALL Consulting. "Class II Disposal Well Best Management Practices Workshop." Presented at the GWPC 2016 UIC Annual Conference, Denver, Colorado, February 23-25, 2016.

Nathan Alleman; J. Daniel Arthur, P.E., SPEC; Tom Tomastik; and Kris Andersen (ALL Consulting). "A Look at Underground Natural Gas Storage Operation and Regulation in the United States". Presented at the GWPC 2016 UIC Conference. Denver, CO. February 25, 2016.

J. Daniel Arthur, Tom Tomastik, Kris Anderson, and Will Green, ALL Consulting, "A Proactive Approach to Addressing Annular Pressure Issues and Stray Gas Migration in the Unconventional Shale Plays" Presented at the GWPC 2016 UIC Annual Conference, Denver, Colorado, February 23-25, 2016.

J. Daniel Arthur (ALL Consulting). "Gas Well Integrity and Associated Gas Migration Investigations in the Marcellus Shale." Presented at the National Association of Forensic Engineers, Winter Meeting 2016, Tampa, FL, January 23, 2016.

Nate Alleman, J. Daniel Arthur, P.E., SPEC, and Mark Faucher (ALL Consulting). "Innovation in the Oilfield: How Best Management Practices Have Reduced the Impacts of Shale Development." Presented at the SPE Mid-Continent Section Luncheon. Denver, CO. January 13, 2016.

Mark Faucher, J. Daniel Arthur, P.E., SPEC, and Nathan Alleman (ALL Consulting). "Innovation in the Oilfield: How Best Management Practices Have Reduced the Impacts of Shale Development." Presented at the Environmental Technology & Management Association (ETMA) Technical Dinner Meeting. Saudi Arabia. December 15, 2015.

Nathan Alleman, J. Daniel Arthur, P.E., SPEC, and Mark Faucher (ALL Consulting). "Innovation in the Oilfield: How Best Management Practices Have Reduced the Impacts of Shale Development." Presented at the 22nd IPEC Conference. Denver, CO. November 17-19, 2015.

Tipton, D. Steven, PE (ALL Consulting). "The Oklahoma Water Conundrum." Presented at the Ground Water Protection Council Annual Forum, September 28-30, 2015, Oklahoma City, OK.

J. Daniel Arthur, P.E., SPEC., Kris Andersen. "Spill Response in Ohio: Practical Guidance for Operators of Horizontal Oil and Gas Wells". Presented at GWPC Conference in Oklahoma City, OK. September 2015.

J. Daniel Arthur, P.E., SPEC, Thomas E. Tomastik, Greg Casey, P.E., H. William Hochheiser, David Alleman, Fernando DeLeon, Chuck Lowe (ALL Consulting). "How Things Have Changed: Class II Disposal Wells and Unconventional Oil and Natural Gas Development." Presented at GWPC Conference in Oklahoma City, OK. September 2015.

Arthur, J. Daniel (ALL Consulting). "The Necessary Transition of Best Practices for Conventional Resource Development to Modern Shale Development Worldwide." Presented at Global Shale Oil & Gas Summit – 2015 Europe. London, UK. July 9-10, 2015.

David Overstreet, J. Daniel Arthur, P.E., SPEC, and Nate Alleman (ALL Consulting). "Innovation in the Oilfield: Reducing Environmental Impacts of Shale Development through Best Management Practices." Presented at the Independent Oil and Gas Association of New York. Findley Lake, NY. July 7-9, 2015.

Arthur, J. Daniel (ALL Consulting). "It's Not Easy Being Green: Why Does the Color of the Chemicals Matter?" Presented at the 2015 National Science Foundation Workshop at the University of Arkansas at Little Rock, Little Rock, Arkansas, April 2015.

J. Daniel Arthur, P.E., SPEC and Kris Andersen (ALL Consulting). "Spill Response in Ohio: Practical Guidance for Operators of Horizontal Oil & Gas Wells." Presented at the American Independent Association of Professional Geologists, Columbus, Ohio, April 2015.

J. Daniel Arthur, P.E., SPEC; Kevin Shepard, P.E.; and Blake Arthur, P.E. (ALL Consulting). "Ohio Horizontal Well Sites: Past History and Future Regulations." Presented at the American Independent Association of Professional Geologists, Columbus, Ohio. April 2015.

Tomastik, Tom and Arthur, J. Daniel (ALL Consulting). "Class II Saltwater Disposal Wells in Ohio: Understanding the Avenue to Success." Presented at the American Independent Association of Professional Geologists, Columbus, Ohio. April 2015.

Tomastik, T. and J. Daniel Arthur, ALL Consulting, "A Proactive Approach to Induced Seismicity: Can the Oil and Gas Industry Manage Induced Seismicity and Work in Cooperation with the Regulatory Agencies?" Presented at the GWPC 2015 UIC Conference, Austin, Texas, February 9-11, 2015.

Tomastik, Tom and Arthur, J. Daniel (ALL Consulting). "A Proactive Approach to Induced Seismicity: Can the Oil & Gas Industry Manage Induced Seismicity and Work in Cooperation with the Regulatory Agencies?" Presented at the Ohio Oil & Gas Association Oilfield EXPO and Technical Conference, December 2014.

J. Daniel Arthur, P.E., SPEC., Bill Hochheiser, "Water Use Analysis for Shale Development in the United States". Presented at the 21st Annual IPEC Conference, Houston, TX. October 14-16, 2014.

J. Daniel Arthur, Tom Tomastik, Doug Louis, and Fernando DeLeon, ALL Consulting. "Disposal Wells and Shale Resource Development: A National Perspective." Presented at the GWPC Annual Meeting, Seattle, WA, October, 5-8, 2014.

Arthur, J.D., Casey, Greg, Bruce Jankura, and Tom Tomastik (ALL Consulting). "Summary of Recent Advances in Well Integrity Analysis for Wellbore Gas Intrusion". Presented at the Ground Water Protection Council's Annual Meeting, Seattle, Washington. October 5-8, 2014.

Arthur, J.D. (ALL Consulting), Casey, G. (ALL Consulting), and Zampogna, D. (ALL Consulting). "Engineering Best Practices for Well-Site Environmental Protection". Presented at the American Society of Civil Engineers' Shale Energy Engineering Conference, Pittsburgh, PA. July 20-23, 2014.

J. Daniel Arthur, P.E., SPEC., Bill Hochheiser, Roy Arthur "Analysis of U.S. Hydraulic Fracturing Chemical Disclosure Data from FracFocus." Presented at Hydraulic Fracturing in Western Canada – an Environmental Perspective. May 29, 2014.

Arthur, J.D. (ALL Consulting), Hagemeier, P. (ALL Consulting), and Overstreet, D. (K&L Gates). "Oil & Gas Development and Environmental Protection". Presented at the Ground Water Protection Council's Annual UIC Conference, New Orleans, Louisiana. January 22, 2014.

Arthur, J. Daniel and David Alleman (ALL Consulting). "Innovative Strategies for Management of Water in Unconventional Resource Projects." Presented at the 33rd Annual Governor's Water Conference, 10th Annual OWRRI Water Research Symposium, Tulsa, Oklahoma, November 13-14, 2013.

Short Courses Completed:

***Note**: the list below is NOT a comprehensive listing of courses completed by Mr. Arthur. In addition to those listed, he has regularly taken a variety of courses, both in-person and online and has served as the instructor for a variety of courses as well. The listing below is simply an example of courses he's completed.*

Environmental Protection for Oil & Gas Development Activities
Engineering Ethics
Various State & Other Courses required for Engineering Licensure
Well Pad Design (ALL Consulting)
Well Integrity and Gas Migration Investigations (GWPC/ALL)
ALL Consulting Annual Technical Training Seminar (2021, 2019, 2018, 2017, 2016, 2015, 2014, 2013, 2012, 2011, 2010)
Safe Lands
H2S Safety (various courses)
Temperature, Noise, and Radioactive Tracer Logging, Exxon/Robert S. Kerr Lab
Successful Project Management, CH2M HILL
Successful Project Execution, CH2M HILL
Fundamentals of Cementing, Halliburton Services
Petroleum Engineering as related to Underground Injection Control, Richland College, TX
Ground Water Monitoring, Engineering Enterprises
Well Casings and Tubulars, NL Industries
Expert Witness Short Course, NWWA
Reservoir Pressure Transient Testing, Society of Pet. Engineers
Cased Hole Logging, Schlumberger Well Services
Open Hole Well Logging, Welex
Advanced Open Hole Well Logging, Welex
Class V Injection Wells, Engineering Enterprises
Mechanical Integrity Testing, Engineering Enterprises
Simulation of Hazardous Waste Injection, Scientific Software
UIC Enforcement Training, USEPA - Headquarters
Environmental Risk Analysis, USEPA - Region V
Hazardous Waste Safety Training, HST
Hazardous Waste Safety Training For Managers, HST
Professional Liability, CH2M HILL
Speaking with Others, CH2M HILL
Various Computer Short Courses, Various
First Aid and CPR, Red Cross

Direct Testimony of Dan Arthur
NMOGA Exhibit C

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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Direct Testimony of Dan Arthur
NMOGA Exhibit C

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Rachael Ketchledge