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**

REBUTTAL TESTIMONY OF HAROLD MCGOWEN

ON BEHALF OF

NEW MEXICO OIL AND GAS ASSOCIATION

September 19, 2025

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I. INTRODUCTION

My name is Harold McGowen, and I am the plugging and abandonment expert witness for the New Mexico Oil and Gas Association ("NMOGA") in this Oil Conservation Commission ("OCC" or "Commission") rulemaking proceeding, Case No. 24683, specializing in regulatory affairs and compliance within the oil and gas industry. My education, background, qualifications, and prior expert experience are set forth in my direct testimony submitted to the Commission on August 8, 2025, offering my opinion as to the proposed rules on behalf of NMOGA, with my curriculum vitae attached as Appendix A thereto.

II. PURPOSE OF REBUTTAL TESTIMONY

I have reviewed the prehearing statements and direct testimony submitted by the Applicants—led by the Western Environmental Law Center ("WELC" or collectively the "Applicants")—as well as the Oil Conservation Division ("OCD" or "Division"), the New Mexico State Land Office ("SLO"), the Independent Petroleum Association of New Mexico ("IPANM"), and OXY USA Inc. ("Oxy"). Based on their filings, OCD and SLO generally support the Applicants' amendments, offering only limited technical changes, if any.

All direct testimony filings concerned the proposed amendments to **Sections 19.15.2.7, 19.15.5.9, 19.15.8, 19.15.9, and 19.15.25 of the New Mexico Administrative Code ("NMAC"),** which are the subject of this rulemaking proceeding. I address the relevant testimony by regulation in that order.

III. REBUTTAL TESTIMONY

A. Overarching Concerns with Applicants' and the Agency's Experts

In reviewing the direct testimony submitted by Applicants' witnesses, I observed a number of disconnects and inconsistencies that merit the Commission's attention. These issues extend across the witnesses' backgrounds, methodologies, and use of data and exhibits. They are particularly evident in the treatment of well repurposing, the characterization of industry practices and innovation, and the lessons that may be drawn from the development of legacy wellbores during the shale revolution.

1. Varying Definitions of Orphan Wells Create Skewed Data Across Direct Testimony and Exhibits

The rulemaking process is framed as a response to the "orphan well problem" as identified by Applicants' witnesses. Yet neither Applicants nor OCD provides a clear or consistent definition of what constitutes an "orphan well." This raises several critical questions that remain unanswered: At what point does a well become an orphan? Under what circumstances is a well likely to be orphaned? And what legal threshold must be met before the state acquires the right or obligation to assume plugging responsibility?

New Mexico statutes and regulations do not currently define "orphan well." As a result, estimates of both the number of existing orphan wells and the projected future inventory vary widely depending on context, source, and the perspective of the party providing the data. This definitional gap leads to subjective interpretations of the scope of the problem and raises concerns about the reliability of the data and statistical methods relied upon by Applicants.

In my professional opinion, based on the information reviewed, the Applicants' characterization of the number of orphan wells significantly overstates the actual risk to the state. This concern is not only academic. As NMOGA's surety expert Douglas Emerick explains in his rebuttal testimony, the definitional expansions proposed by Applicants will directly drive financial assurance obligations.[1] Inflated orphan well counts become the basis for inflated bonding requirements, magnifying collateral demands, shrinking surety capacity, and destabilizing operators. In short, without a clear and uniform definition, the Commission cannot have confidence in the data underlying Applicants' proposals, nor in the costly financial consequences those proposals would trigger.

i. LFC Reports Only 700 Orphan Wells, But Applicants Use MOSS to Define

I have reviewed NMOGA technical expert Dan Arthur's analysis of the Legislative Finance Committee's ("LFC") 2025 Spotlight on Orphan Wells ("LFC Report"). I found his reasoning persuasive and consistent with my own industry experience regarding what qualifies as an orphan well—namely, a well where the operator has defaulted and the state has actually exercised plugging authority. The LFC Report reflects this definition and places the number of orphan wells in New Mexico at approximately 700.

Applicants, however, rely instead on the OCD's Master Orphan Well Spreadsheet ("MOSS"), attached as Exhibit 55 to their prehearing statement, which lists more than 1,800 wells. Applicants' experts, including Mr. Purvis, adopt the MOSS figures as the operative baseline for their analysis, and other supporting experts rely on that data in turn. In my view, this approach introduces significant distortion. By expanding the category to include wells that do not meet the criteria for orphan status, Applicants inflate the apparent scale of the problem.

Accordingly, I concur with Mr. Arthur's recommendation that all analyses relying on the MOSS as a measure of the orphan well population should be recalculated using the LFC's figure.

[1] Rebuttal Testimony of Douglas Emerick, NMOGA Surety Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Sept. 19, 2025 (hereinafter, "NMOGA's Emerick Rebuttal Testimony"), at 2: 24-29; 26: 530-537.

Only then can the Commission fairly assess the actual magnitude of the issue. Moreover, as NMOGA surety expert Douglas Emerick explains, overstated orphan well counts are not a harmless data choice—they directly translate into higher projected financial assurance obligations, increased collateral demands, and systemic market disruption.[2]

ii. Statistical Flaws in Estimating P&A Costs Using MOSS Data

Applicants' expert Mr. Purvis relies on OCD's MOSS to generate an "average" plugging and abandonment (P&A) cost for orphan wells in New Mexico. That figure is not drawn from the full population of wells in the state but from a highly selective and incomplete dataset. Indeed, approximately 83% of the wells in MOSS contain no cost data at all. The resulting "average" is therefore based on a small subset of wells with available records, introducing serious risks of sampling error, sample bias, and population bias.

In standard statistical practice, the first safeguard is to ensure the defined population is analogous to the universe of interest. The second safeguard is to ensure that the sample drawn from that population is unbiased and representative. Neither safeguard is present here. Purvis relies on a subset of wells that were not chosen randomly but instead identified by OCD because they presented the most obvious and immediate environmental or public health risks. OCD has stated that it prioritized wells for plugging based on inspections, historical records, and methane-emission monitoring to identify those "warranting swift remediation actions."[3] The very first well selected under the program, for example, was chosen because it was actively releasing methane and hydrogen sulfide within 1,000 feet of residences.

By design, then, MOSS cost entries exist only for wells plugged by the State in cases of

[2] NMOGA's Emerick Rebuttal Testimony at 4:69-73.

[3] State of New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, *Orphan Well Clean-Up Work Begins* (Press Release, Nov. 3, 2022), available at https://www.emnrd.nm.gov.

compromised wellbore integrity or other severe failures. Plugging these types of wells is inherently more expensive than plugging mechanically sound wells. From a statistical perspective, the dataset is not representative of the broader population of wells potentially subject to P&A obligations; rather, it reflects a disproportionate concentration of the most complex and costly cases. Using that biased subset to calculate an "average" and then applying it to all wells in the state inevitably produces an inflated figure.

The consequence is clear: Applicants' reliance on MOSS-based averages overstates the cost of plugging and abandonment across the board. This not only distorts the magnitude of the orphan well problem but also risks driving financial assurance obligations far above what is necessary to protect the State. A uniform statewide average further obscures the reality that P&A costs vary dramatically with well depth, age, completion type, and surface conditions. Shallow stripper wells may cost a fraction of deep, older gas wells, yet the inflated mean drawn from MOSS penalizes the low-risk wells equally.

A more reliable and equitable approach would be to build a dataset that includes both state-plugged and operator-plugged wells across a range of depths, ages, and geologic conditions. From that more complete dataset, the Commission could derive a variable-based model that accounts for the true drivers of cost. Such a framework would both safeguard the State from underfunding difficult wells and avoid excessive collateral demands on low-risk wells.[4]

2. *Applicants' and the Agency's Experts Characterize Held-By-Production Wells as "Speculative"*

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[4] Rebuttal Testimony of Dan Arthur, NMOGA Surety Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Sept. 19, 2025 (hereinafter, "NMOGA's Arthur Rebuttal Testimony"), at 73:1687-99 (explaining that MOSS-based averages are skewed toward high-cost wells and that removing outliers drops costs well below Applicants' cited figure); see also NMOGA's Emerick Rebuttal Testimony, Part II.2–3 (22:438-441; 26:536-541) (explaining that inflated orphan well cost assumptions directly translate into higher collateral demands, reduced surety capacity, and premature plugging of viable wells).

Applicants' and OCD's experts have characterized the practice of maintaining low-production legacy vertical wells in held-by-production ("HBP") status as "speculative." This framing is both inaccurate and revisionist. It disregards the central role that HBP acreage, anchored by stripper wells, has played in enabling New Mexico's modern unconventional development.

The oil and gas industry is capital-intensive and globally competitive. In the last decade alone, U.S. producers have faced market shocks—including OPEC's effort to undercut shale through oversupply—that required operators to maximize efficiency and secure lease positions. Legacy vertical wells producing only a few barrels of oil or a few Mcf of gas per day were not speculative placeholders. They were deliberate strategic assets that preserved lease rights until horizontal multi-stage fractured ("HMSF") technology matured.

This practice provided the stable lease base and runway necessary to plan and finance large-scale unconventional development. Without it, New Mexico would not have experienced the extraordinary horizontal drilling boom of the last 15 years, nor the billions in state tax revenues that now fund public services. Far from speculation, HBP acreage was a cornerstone of the "shale revolution."

My analysis confirms this point. Using Enverus data, I identified 83 operators that held nearly 49,000 vertical wells producing below 2.5 BOPD or 15 MCFD, and later drilled 1,804 horizontal wells on the same or adjacent leases. The top 21 horizontal drillers accounted for about 34,000 of those vertical wells and 1,624 horizontals. These data show that so-called marginal wells, maintained in HBP status, directly enabled the rapid, efficient horizontal development that now defines New Mexico's production profile.

Appendix B to this rebuttal testimony illustrates this history, showing vertical and horizontal drilling activity in New Mexico by year since 1960. The surge in oil and gas production—and corresponding state revenues—was built on the legal and physical foundation created by stripper wells holding acreage. In Appendix B, *Examples of Stripper Redevelopment in New Mexico*, I have provided the results of a literature search regarding the vertical well packages that were acquired and subsequently converted into unconventional Horizontal-Multi-Stage-Hydraulic-Fracturing (HMSF) projects, yielding entire portfolios of highly productive horizontal wells. Dismissing these wells as "speculative" ignores both their proven past value and their continuing role as anchors for future recompletions, refracs, and redevelopment.

3. Applicants' Experts Equate Speculative Uses and Marginal Production with End-of-Life and Ignore Repurposing Potential

i. Focus on Plugging as Primary Outcome

Applicants' experts' consistently frame plugging and abandonment (P&A) as the proper or default end state for marginal, inactive, or "speculative" wells. Their testimony gives little or no substantive consideration to repurposing strategies such as pressure monitoring for offset horizontal stimulations, microseismic data acquisition for offset horizontal development, recompletions, refractures, deepening, acidizing, horizontal sidetracks, or conversion to other uses such as brine disposal, water supply, carbon capture and sequestration (CCS), geothermal, or enhanced oil recovery (EOR). This "plug-first" orientation treats end-of-life as the only path and ignores the technical and economic upside demonstrated by decades of industry practice. NMOGA witness Dan Arthur correctly notes that the proposed presumption of no beneficial use hardwires an assumption that low production is tantamount to no benefit.[5]

ii. "Speculative" Use Dismissed

Mr. Alexander characterizes keeping wells for speculative future use as unjustified, equating it with the absence of information and supporting plugging unless a specific beneficial

[5] NMOGA's Arthur Rebuttal Testimony at 111:2524-29.

use can immediately be demonstrated. He cites examples (Denver International Airport and a Kentucky case) as cautionary tales, rather than success stories of innovative use, and frames holding for future re-purposing as wasteful or risky. His analysis is overly narrow and fails to account for the broader context, effectively overlooking the larger opportunities and risks that are apparent when the full picture is considered.

While Mr. Alexander presents his analysis within a conventional framework, it is not adequately informed by the approach that has long defined the work of oil and gas entrepreneurs. For more than 40 years, across a wide variety of basins, entrepreneurs such as myself have re-imagined and re-purposed mineral acreage and legacy wells, uncovering reserves that conventional analysis overlooked by combining proven practices with innovative technologies and interpretive techniques. NMOGA legal witness, Clayton Sporich, correctly notes that Applicants' proposed definition of "speculative purpose" is not rooted in the Act and would penalize common industry practices for holding wells and leases, recompletions, refracs, and infrastructure dependent redevelopment.[6]

The historic role of the entrepreneur in this industry has been to recognize and develop potential not immediately visible in surface-level reviews. That enduring mindset, that is, seeing beyond the current use of an asset to what it could be, is what has consistently turned overlooked acreage into productive opportunities.

iii. Testimony Lacks Entrepreneurial Framing

Moreover, across all the technical and legal testimony presented by the petitioners, there is little to no acknowledgement of the potential value to be unlocked by entrepreneurial operators or

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[6] Direct Testimony of Clayton Sporich, NMOGA Legal Expert, *In the Matter of Proposed Amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 NMAC*, No. 24683, OCC, Sept. 19, 2025 (hereinafter, "NMOGA's Clayton Sporich Testimony"), at ¶ 12.

through emerging technologies, and the potential opportunity loss the proposed rules changes are likely to produce. Instead, entrepreneurship and the holding of "inactive" wellbores for future upside (e.g., Application of Multi-Stage-Horizontal wells, Recompletions, EOR, SWD, conversion to other wells, or pending new tech) are implicitly or directly described in negative terms, especially as mechanisms of possible delay or regulatory evasion.

Holding acreage for future horizontal development is dismissed out of hand as speculative, when keeping acreage in "Held By Production" status until the timing and technology are right has allowed the "Shale Revolution" to occur with rapidity and efficiency. Re-leasing mineral acreage for future development is a very lengthy and expensive process.

iv. No Substantive Discussion of Repurposing Potential

None of the witnesses thoroughly and substantively explores or cites experience with reactivating idle wells, pursuing recompletions, or adopting new uses for wellbores as viable risk/reward strategies. The only mention of such activities is framed as problematic, manipulative, or grounds for higher bonding or plugging, rather than as a means to preserve or create value.

In my opinion, the continued maintenance of qualifying legacy vertical well bores in New Mexico provides substantial economic and resource recovery benefits because these assets serve as proven conduits to established reservoirs. Even when legacy wells exhibit marginal production, they retain significant latent potential that can be unlocked through re-stimulation techniques such as hydraulic fracturing and recompletions, as well as through lower-cost workover operations including acid treatments, artificial lift installation, and gas-lift optimization. By preserving wellbore integrity, operators avoid the high capital costs of drilling new wells while maintaining access to known hydrocarbon zones. Moreover, incremental technologies continue to advance, creating opportunities for step-change improvements in production from previously uneconomic vertical wells. This means that maintaining such bores not only preserves valuable infrastructure and reservoir knowledge but also positions operators and the State of New Mexico to realize outsized production increases and economic returns as enhancement methods evolve.

In addition to their value as conduits for modern re-stimulation, legacy vertical wells remain strategically important when new drilling is not economically viable, since they can be maintained at relatively low cost and offer immediate pathways to upside production. Industry case studies demonstrate that recompletions and workovers in legacy vertical wells can transform uneconomic producers into commercial assets, often yielding substantial rate increases without the expense of new wellbores (Permex Petroleum, 2019; EON Resources, 2024)[7,8]. Even informal enhancement methods, such as acid treatments and artificial lift optimization, have been shown to revive wells from marginal output to meaningful production levels in mature New Mexico fields (American Oil & Gas Reporter, 2021)[9]. This makes the preservation of vertical wellbores not only a hedge against commodity price volatility but also a practical strategy for extending field life and maximizing recovery when capital for horizontal development is constrained. Maintaining these bores therefore secures both optionality and operational resilience for operators and mineral owners alike.

In addition to routine workover and recompletion uses, vertical wells provide significant value in the context of modern horizontal development because they can be repurposed as cost-

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[7] Permex Petroleum. (2019). *Permex Petroleum reports successful recompletion of wells on its New Mexico and Texas properties.* [Press release]. Retrieved from https://seekingalpha.com/pr/18921870-permex-petroleum-reports-successful-recompletion-of-wells-on-its-new-mexico-and-texas.

[8] EON Resources. (2024). *EON secures funding to launch horizontal San Andres program in Grayburg-Jackson and South Justis fields, Lea & Eddy Counties.* [Press release]. Retrieved from https://drillingcontractor.org/eon-enters-into-farm-out-of-san-andres-horizontal-drilling-program-74826.

[9] American Oil & Gas Reporter (AOGR). (2021). *Unconventional technologies drive San Andres resurgence. AOGR.* Retrieved from https://www.aogr.com.

effective monitoring and pressure-management tools during hydraulic fracturing operations, including microseismic data acquisition for optimizing offset horizontal development. Studies demonstrate that offset well pressure responses are a key indicator of fracture driven interactions (FDIs), with vertical wellbores often serving as the most practical observation points for detecting hydraulic communication and pressure perturbations between wells[10]. Analyses of offset pressure behavior during stimulation confirm that different types of interference, including poroelastic responses, hydraulic connections, and direct fracture hits, can be distinguished through careful monitoring, enhancing both operational safety and completion design[11]. Industry guidance also emphasizes that wellbore pressure pulses are critical for understanding fluid communication during fracturing, underscoring the role of vertical well infrastructure in broader reservoir surveillance and management strategies[12]. Trade coverage reinforces this view, noting that offset well pressure anomalies provide valuable insights into interwell communication and reservoir depletion effects, which can be leveraged to optimize horizontal development programs[13]. Together, these findings illustrate how legacy vertical wellbores can extend their utility beyond direct hydrocarbon production to play an integral role in pressure management and reservoir optimization during horizontal field redevelopment.

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[10] ScienceDirect. (2022). Using pressure changes in offset wells for interpreting fracture driven events. Journal of Petroleum Science and Engineering. Retrieved from https://www.sciencedirect.com/science/article/pii/S0920410522009639.

[11] Unconventional Resources Technology Conference (URTeC). (2020). Rapid analysis of offset well pressure response during fracturing. URTeC Conference Proceedings. OnePetro. Retrieved from https://onepetro.org/URTECONF/proceedings/20URTC/20URTC/D023S033R003/448142.

[12] American Petroleum Institute (API). (2014). Wellbore pressure and fluid communication. API Hydraulic Fracturing Guidance. Retrieved from https://www.api.org/oil-and-natural-gas/wells-to-consumer/exploration-and-production/hydraulic-fracturing/wellbore-pressure-and-fluid-comm.

[13] American Oil & Gas Reporter (AOGR). (2019). Approach reveals insights into well communication, pressure interference issues. Frac Facts. Retrieved from https://www.aogr.com/magazine/frac-facts/approach-reveals-insights-into-well-communication-pressure-interference-iss.

v. Absence of Entrepreneurial Mindset and Recognition of Value-Unlocking

Applicants' experts' direct testimony contrasts with operator and industry expert testimony elsewhere in the record (including mine), who highlight the importance of flexibility for recompletions, repurposing, or holding wells for new opportunities. Industry witnesses argue that rigid frameworks and gatekeeping definitions like those proposed by Applicants stifle innovation, cause premature plugging, eliminate value that entrepreneurial operators might otherwise realize, and probably generate more orphaned wells, not less.

vi. No Recognition of Repurposing as Legitimate Value Stream

Applicants' experts do not articulate a framework in which innovative (or even routine) repurposing of wells is recognized as a legitimate part of oil and gas asset management. This incentivizes operators to prematurely plug their wells since repurposing is not even considered as an objective.

4. Acceptance of Bankrupting or Driving Small Operators Out of Business is Inconsistent with Applicants' Stated Objectives

It is readily apparent that several of the experts for Applicants and OCD have a bias against small operators and that they would prefer to bankrupt these companies and/or drive them out of business:

- Thomas Alexander, a technical witness for Applicants, suggests that adopting regulations now, even if it results in a small percentage of operators and wells being eliminated, is preferable to leaving future issues for the state to address.[14]

- Peter Morgan, another Applicant witness, indicates that smaller operators are the target of the rulemaking, implying that the financial assurance requirements are designed to address the risk posed by these operators.[15]

[14] Alexander Direct Testimony 27: 12-18.

[15] Morgan Direct Testimony 76: 2-7

- Dwayne Purvis, an Applicant technical witness, argues that companies at risk of bankruptcy due to increased financial assurance requirements are likely unable to meet their decommissioning obligations, suggesting that the financial burden is an acceptable consequence.[16]

- Adam Peltz, an Applicant legal witness, contends that the wells targeted in the rulemaking produce only a negligible amount of New Mexico's oil and gas, implying that the environmental and safety benefits justify the economic impact on small operators.[17]

Applicants' experts' direct testimony collectively frames bankruptcies among smaller operators as acceptable collateral consequences of the proposed regulations, emphasizing environmental and public safety risks as justification for the reforms.

A central contradiction in Applicants' position must be addressed in this rulemaking: bankrupting small operators—or pushing them to abandon obligations—is no solution to the orphan well problem. Forcing financially constrained operators over the edge while simultaneously deterring qualified buyers will predictably create more orphan wells, not fewer. The sequence is obvious:

i. The proposed rule takes effect.
ii. Many small operators cannot meet the new bonding requirements.
iii. At the same time, OCD layers on burdensome and ambiguous conditions for transfer approvals.
iv. Potential buyers walk away, deterred by high bonding costs, mandatory plugging of marginal wells (extinguishing HBP acreage and future redevelopment options), and increased regulatory hurdles.
v. As a result, wells that could have been sold, repurposed, or redeveloped instead become orphaned—leaving the State with the plugging liability and depriving it of future tax revenue.

5. Specific Recommendations

Throughout this rebuttal testimony, I provide responsive recommendations tailored to each proposed amendment. In the sections that follow, I address the direct testimony concerning the

[16] Purvis Direct Testimony 44: 4-11;

[17] Peltz Direct Testimony 44: 15-24; 45: 1-17.

proposed changes to 19.15.2.7 NMAC and 19.15.8 NMAC, and I conclude each with specific recommendations for the Commission's consideration.

B. How the Proposed Additions and Changes to the Definitions under 19.15.2.7 NMAC Affect Financial Assurance Requirements

Applicants' proposed new and amended definitions in 19.15.2.7 NMAC appear designed to expand the reach of their financial assurance scheme under 19.15.8.9 NMAC—though they never say so outright. The linkage is clear from their own analysis, which applies the definitional changes directly to financial assurance determinations.

As NMOGA's lead technical expert Dan Arthur noted in his direct testimony, the scope of these definitions—including "marginal well" and "beneficial purposes/use"—is unclear. Their intended effect may extend not only to the proposed marginal well bonding requirement and presumptions of no beneficial use, but also to other parts of the regulatory framework.[18]

Applicants' failure to expressly acknowledge that these new terms—"temporarily abandoned," "expired temporarily abandoned," "marginal well," "beneficial purposes/use," and now OCD's proposed addition of "inactive well"—dictate financial assurance determinations is deeply problematic. Without clear boundaries on applicability, these definitional changes risk:

- Expanding financial assurance obligations far beyond what the Act authorizes;
- Creating uncertainty about how different offices within the Division will apply the same standards; and
- Producing subjective and inconsistent enforcement in practice.

The Commission should not adopt definitional changes without fully analyzing their downstream effects on financial assurance. To do otherwise invites confusion, overreach, and uneven regulatory

[18] Arthur Direct Testimony 35:705-713.

treatment once the rules are implemented.

C. Proposed Changes to Financial Assurance Requirements under 19.15.8. NMAC

Applicants propose numerous changes to New Mexico's oil and gas financial assurance framework.[19] First, I summarize the proposed changes by regulation.

Next, I analyze the statutory requirement that OCD financial assurance must cover the plugging and abandonment ("P&A") costs of the well being secured, as explained by NMOGA legal expert Clayton Sporich. I will summarize the consistent and categorical errors, inconsistencies, and issues I noted with Applicants' P&A cost data that they based their estimated average well P&A costs and financial assurance changes on. I show how Applicants' proposed increase to require $150,000 single well financial assurance across the board far exceeds the average well P&A cost that it previously reported, based on OCD's estimate the average well costs $70,000 to P&A, as well as more the average I calculated based on OCD plugging invoices provided pursuant to public records requests.

Finally, I recommended changes to the amendments proposed by the Applicants, which would make these changes more realistic and workable, and drive fewer small to mid-size operators out of business in the process of implementing the increases.

1. Summary of Financial Assurance Changes Proposed by Applicant

Applicants claim that the existing financial assurance requirements in New Mexico are inadequate. They propose the following changes to the existing financial assurance requirements for operators in New Mexico:

i. Ultra vires acquisition authority under proposed 19.15.8.9(A) NMAC;
ii. Changes to active well assurance requirements under proposed

[19] WELC Prehearing Statement Exhibit 1-C.

19.15.8.9(C) NMAC;

iii. Changes to marginal and inactive well assurance requirements under proposed 19.15.8.9(D) NMAC;

iv. Changes to assurance requirements for inactive wells and wells in pending, approved, or expired temporarily abandoned status under proposed 19.15.8.9(E) NMAC;

v. Changes to incomplete blanket assurance requirements under proposed 19.15.8.9(F) NMAC;

vi. Ultra vires annual inflation adjustment under proposed 19.15.8.9(G) NMAC;

vii. Additional requirements for cash and surety bonds under proposed 19.15.8.10(A) NMAC; and

viii. Additional requirements for release of financial assurance under proposed 19.15.8.12(B) NMAC.

2. Statutory Requirement that OCD FA Reasonably Cover P&A of Well Secured

I have reviewed the legal testimony of Clayton Sporich and want to focus on his explanation of the statutory authority for OCD's ability to demand financial assurance from operators to secure the reasonable cost of plugging and abandoning ("P&A") of the well being secured. I will start with a critique of the Applicants' P&A cost data before discussing the estimates the Applicants and the agency have previously reported.

3. Consistent and Categorical Errors, Inconsistencies, and Issues I Noted With Applicants' P&A Cost Data That They Based Their Estimated Average Well P&A Costs And Financial Assurance Changes On

i. The Actual Average P&A Cost Per Well Using Only MOSS Wells with Financial Information Available is $128,645.84

One of the lynchpin sources of data in Mr. Purvis' materials is based on the OCD's Master Orphan Spreadsheet ("MOSS"). *See* Applicants Ex. 55; *see* OCD Ex. 17. In relying on the MOSS, Purvis states that plugging costs estimated by Vertex (full discussion on questionable third-party sources below) result in actual plugging costs per well being paid out of pocket by the OCD as already exceeding $150,000, with actual recent costs for downhole plugging running over $160,000 on average. *See* Apps' Ex. 30 0727 Lines 15-18.

A cursory, basic review of the data presented in the MOSS contradicts Purvis' claims. The MOSS includes "Estimated Plugging Costs" and "Actual Plugging Costs" under columns BI and BK, respectively. There are 308 records with actual cost data. There are 303 records with estimated cost data. There are 298 well records with both actual and estimated cost data. There are 1,507 records with no actual cost data in the MOSS (83%) and thus these records can provide no information for statistical analysis of actual cost data.

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The table below shows a more complete statistical analysis of the actual plugging cost found in the MOSS table:

Actual Plugging Cost		
Mean	$	145,101.10
Standard Error	$	17,405.01
Median	$	97,782.22
Mode	$	139,665.44
Standard Deviation	$	305,456.64
Sample Variance	$	93,303,761,399.67
Kurtosis	$	245.70
Skewness	$	14.94
Range	$	5,162,257.11
Minimum	$	34,609.59
Maximum	$	5,196,866.70
Sum	$	44,691,138.55
Count		308
Largest(1)	$	5,196,866.70
Smallest(1)	$	34,609.59
Confidence Level(95.0%)	$	34,248.20

These statistics show this dataset is highly skewed with extreme outliers, which has big implications for estimating representative plugging costs:

- Mean vs. Median
  - Mean (average) = $145,101
  - Median = $97,782
  - The mean is ~48% higher than the median. This gap signals a right-skewed distribution, where a few very high-cost wells pull the average up. In order to account for the skewed distribution, the median is a better indicator of a "typical" well cost.

- Standard Deviation and Range
  - Std. Dev. = $305,457 (over 2× the mean).
  - Range = $34,610 to $5.2 million.
  - This huge spread confirms costs are highly variable and not clustered tightly around the mean. Relying on a single-point average hides the bias in the data.

- Skewness and Kurtosis
    - Skewness = 14.94 → very strong right skew.
    - Kurtosis = 245.70 → extremely heavy tails.
    - This means the dataset has rare but massive outliers that dominate the distribution (e.g., multimillion-dollar wells). These aren't noise, they reflect real but exceptional costs.

- Mode
    - Mode = $139,665 (most common cost). This reinforces that a large cluster of wells falls in the ~$100k–$140k range, close to the median, not the mean.

- Implications for Cost Estimation
    - The mean ($145k) is inflated by extreme outliers, so using it as a "typical" P&A cost will overstate expected costs.
    - The median (~$98k) better represents the central tendency of the data.
    - The mode ($140k) shows a frequent benchmark, but it is less stable than the median.
    - Extreme tail >$5M must be acknowledged but treated as a rare risk event indicative of the biased/non-representative nature of the chosen data set.

Given that this data set is known to be biased towards worst case scenarios because of the way the OCD prioritized their orphan well plugging program, a more appropriate best practice for reporting these plugging costs would be to use a trimmed mean (exclude top 5–10% outliers). This avoids distortion by rare multimillion-dollar wells while still disclosing the risk. Below, I have generated a trimmed means table for the actual plugging costs. You can now see how excluding the top/bottom 5%, 10%, and 20% of wells affects the "average" and brings it much closer to the typical well cost.

Statistic	Value
Mean (All Data)	$ 145,101
Trimmed Mean (5%)	$ 115,639
Trimmed Mean (10%)	$ 111,346
Trimmed Mean (20%)	$ 106,006

A comparison of this analysis to the Purvis analysis of the MOSS data reveals that through treating a skewed and biased data set as representative of the target population, Purvis effectively cherry-picked select data in a way that exaggerates plugging costs. Moreover, Purvis fails to disclose that his sample size is small relative to the total population of potential P&A candidates in the target population (all the wells in New Mexico) because most wells in the MOSS database lack any financial cost data. Even the mean plugging cost of the $145,101 from the actual data, which is driven up by a few select multi-million dollar outliers, is less than the "exceeds $160,000" estimate provided by Purvis because the mean (or average) was calculated with all the actual values, not just the ones favoring a narrative. I say "even" the mean because the actual cost in MOSS is skewed heavily by large outlier scenarios that are highly unlikely to be representative of the majority of the P&A scenarios encountered in the target population of future potential P&A candidates.

Moreover, Purvis' figure relies on a P&A cost of more than $160,000 but ignores the fact that the MOSS median cost is under $100,000 and an appropriately outliner trimmed mean from the MOSS data set is very close to $100,000 (see table above). Purvis represents that his average is reflective of the entire population of P&A scenarios likely to be encountered in the future, when in fact about 83% of wells in the MOSS database have no actual cost data to factor into estimates and models. By failing to provide an unadjusted mean value, Purvis ignores standard statistical practices of trimming outliers in skewed datasets when dealing with an obviously worst case scenario biased data set.

Purvis claims that costs are consistently above $150,000. Still, even in the upside biased data set being analyzed, the mode[20] of actual cost is $139,665 (most likely cost to be encountered) and the median[21] is ~$98,000, and nearly half of the analyzed wells (with complete financial cost data) consistently came in under their estimated budget. This is opposite to the narrative

[20] In probability terms, the mode is the value of a random variable at which the probability function reaches its maximum, i.e. it is the most likely outcome within the data set being analyzed.

[21] The median is the middle value in an ordered dataset, meaning half the observations are below it and half are above it.

perpetuated by Purvis, where $160,000 plugging costs are the floor and not a biased ceiling.

ii. Self-Reported Operator Data with Admittedly Manual "Corrections" and Double-Counting

Purvis bases various classifications of wells on operator-reported days and volumes, and then proceeds to apply his own fixes (e.g., "Using objective and available data self-reported by the operators to the Commission plus *some correction* for wells that reportedly produced, for example, 36 days in a single month"), thereby introducing substantial subjectivity into the data sets provided. *See* Apps' Ex. 30 0735 Lines 19-20. The subjective nature of the Purvis' "manual" corrections provides ample opportunity for error and prejudice in the analysis in the absence of a stated validation protocol that is disclosed with the findings. Further, Purvis acknowledges that the models provided include double-counting of wells when stating, "it should be noted that some wells appear in more than one not-active category shown on Exhibit 33." *See* Apps' Ex. 30 0701 Lines 7-8.

iii. Artificial Reliance on Third-party Vendor Datasets Lacking Validation or Disclosure

Additionally, Purvis provides sweeping generalizations relating to documents and data reviewed in preparing his testimony, "I have reviewed data from a commercial (pay-for-play) data vendor called WellDataBase, and other agency databases" but provides no other insight into the qualitative nature of the data and purposely obscures the source data by citing to a homepage of a website with no other detail on how the data was gathered or obtained or used. *See* Apps' Ex. 30 0775 Line 8 "Home." n.d. Accessed August 1, 2025. https://welldatabase.com/. The data, paid for and obtained by Purvis from the WellDataBase provider, and associated databases should be provided in order to validate or disclose the baseline data leading to Purvis' conclusions and recommendations, rather than a generic hyperlink to a website.

Moreover, this data should be compared to more widely accepted data sources like Enverus and IHS to ensure its reliability and accuracy. Based on my research, WellDatabase is generally seen as a less reliable and less widely adopted source for oil & gas well information when compared to IHS Markit and Enverus DrillingInfo. IHS and Enverus enjoy broad industry adoption, expansive and complete datasets, and a strong reputation built over years of proven service. WellDatabase, while improving and cost-effective, remains a secondary resource, often used by smaller operators or for supplementary needs, and is not yet trusted at the same level for comprehensive, critical data. The trade-off often comes down to cost vs. confidence: It is my understanding that WellDatabase provides inexpensive access to public data, but IHS Markit and Enverus offer deeper coverage, data scrubbing, and trusted accuracy that in my experience most professionals prefer.

Without independent validation from a party other than Purvis, the fundamental data supporting Purvis' testimony obtained from WellDataBase should be presumed invalid and questionable at best, especially absent validation from the agencies from whom the data was collected. Purvis's records should be reconciled with parallel agency records to authenticate their contents or risk prejudicing other parties to the rulemaking.

iv. Selective, Non-Random (AKA "Cherry Picked") Historical Cost Samples

"It is true that the historical portfolio of costs is not a random sample across the state and may be biased toward more expensive wells," full stop. See Apps' Ex. 30 0728 Lines 15-16. Here, Purvis openly admits that the orphan-well cost history selected and opined on by Purvis is not representative of the wells across the entirety of the state, but actually an inflated cost value derived from a biased population and sample set that is not representative of the overall population of P&A candidates likely to be encountered in the future, which predictably overstates the extreme ends of the cost spectrum for orphan wells (see my Actual Cost analysis above). Stated another way, Purvis admits the dataset systematically over-represents high-cost wells. Using these atypical costs for plugging and abandonment exaggerates future liabilities while providing no consideration of the key cost drivers baked into the chosen data set. Such a biased analysis represents worst case scenarios as typical scenarios, effectively ignoring the simpler P&A scenarios likely to be encountered across the state, thus emphasizing inflated averages. “Apps’

v. Heavy, Questionable Reliance on Environmental Contractor’s 2021 Estimate (Vertex) for Costs

Purvis relies heavily on a single environmental contractor’s 2021 estimate of plugging and abandonment costs in his speculative modeling. Specifically, Purvis adopts Vertex Resources Services (“Vertex”) “Class V” (actionable but uncertain) category that places a confidence range of minus thirty percent (-30%) to plus fifty percent (+50%) and produces a sweeping estimate of $22 billion for upstream infrastructure decommissioning.. *See* Apps’ Ex. 30 0705 Lines 12-14.

Notably, the cost estimates provided by Vertex in lay mans terms means that the $22 billion price tag, which is overinclusive of costs such as infrastructure and pipeline removal instead of simply plugging and abandonment costs, could be anywhere from 30% lower than estimated costs to more than 50% higher than estimated costs, meaning the range could be between $15-33 billion. Clearly, Vertex is skilled in environmental remediation, but it is not capable of precise budgeting in this situation, or its estimates would be more tightly scoped, and its plug-and-play of broad cost assumptions is reflected in the sweeping cost range. Similarly, Vertex’s cost estimates for pipeline removal, not a true plugging cost, range from $3.4 to $20.3 billion. *Id.* at Lines 17-20. That is a sixfold spread, further evidence that, more likely than not, these estimates are highly speculative in nature and unreliable for regulatory purposes.

The estimates are also stale. Anchoring costs to 2021 figures is misleading in a commodity-based industry where service pricing is volatile and sensitive to market cycles. Purvis compounds the problem by offering no transparency as to how Vertex's data were compiled, validated, or applied. He provides no step-by-step breakdown of assumptions—such as well counts, depth categories, or per-well costs—leaving only high-level generalities followed by broad conclusions. This "black box" approach prevents stakeholders from verifying assumptions, auditing calculations, or even confirming that Vertex's inputs were appropriate to begin with.

Labeling such work "Class V—actionable but uncertain" is generous. A more accurate label would be "provisional estimate" or "preliminary assessment," reflecting its speculative and non-reproducible character.

In addition, Applicants' expert Peltz also relies on Vertex data for the remediation component of a total decommissioning cost estimate of $249,000, noting that the LFC Report also relied on Vertex. *See* Apps' Ex. 57 0875 Lines 17-18 ("Based on $163,000/well plugging and abandonment estimate from OCD, and $86,000/site remediation cost estimate from Vertex, cited and used by LFC in the previously cited report.). The LFC Report confirms the LFC and SLO relied on Vertex for remediation costs, and for tank batteries which exceed the scope of the inquiry of a well's plugging and abandonment costs:

- "In a 2021 report for the New Mexico State Land Office, Vertex Resources estimated the decommissioning and reclamation costs of a storage tank site at $9.5 million, based principally on an assumption of a large site surface area and the need to remove substantial volumes of contaminated soil. Invoices from the tank battery sites show that removal of contaminated soil is by far the largest line-item expense." Apps' Ex. 04 0118.

- "The 2021 Vertex Resources study for the State Land Office estimated well site remediation and reclamation at $83 thousand per-site, on average, which would put the total at $100 million, not including cleanup of infrastructure associated with the well sites, like tank batteries." Apps' Ex. 04 0121.

  "OCD is also responsible for decommissioning, remediation, and reclamation of 18 infrastructure sites; the estimated cost is $30 million to $140 million. The infrastructure sites include both tank batteries and a waterflood facility, which are facilities that treat, store, and pump (usually produced) water for injection into oil and gas wells to increase reservoir pressure and boost oil recovery. As noted above, the cost for remediation and reclamation of tank batteries has varied widely in the past. . . . Given that the only completed tank battery project cost OCD $5.2 million and a nearing-completion project has already cost $7.6 million, a very conservative estimate for the remaining 15 tank batteries would be $30 million, at $2 million per site. On the high end, using the $9.5 million estimate from the Vertex Resources report, the costs could be more than $140 million." Apps' Ex. 04 0122.

- "The infrastructure sites include both tank batteries and a waterflood facility, which are facilities that treat, store, and pump (usually produced) water for injection into oil and gas wells to increase reservoir pressure and boost oil recovery. As noted above, the cost for remediation and reclamation of tank batteries has varied widely in the past." Apps' Ex. 04 0123.

vi. The Purvis "Holdback" Concept – Not an Accepted Industry Practice, Not Replicable, Not Reliable

Purvis supplements the discussion of the concept of "Holdback" by citing a paper presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition in October 2022. The paper—Economic Yardsticks for the End of Economic Life: Holdback and Its Adjuncts—lists only Dwayne Purvis as the author. *See* Apps' Ex. 30 0776 Line 15. Purvis provides no evidence that the paper was subject to peer review or recognized as a valid industry valuation method. The paper itself admits that no major industry publication has standardized ARO treatment, and Holdback is proposed as a novel approach, not an accepted industry standard. The concept seems to exist solely in Purvis's reports and testimony, suggesting it may be an untested and biased approach rather than a recognized industry standard analytical tool.

The "Holdback" concept is a proposed, experimental yardstick rather than a generally recognized or standardized method in petroleum economics. Its use in the context of this matter appears to replace time-tested and widely accepted financial metrics with a best-guess approach. Holdback is an untested concept because it lacks widespread validation or adoption. Even Purvis notes it is a proposal and has not been formally adopted by SPE, SPEE, or regulators. Replication depends on model inputs and assumptions about future cash flows and AROs; as with many novel yardsticks, this creates challenges for consistency across evaluators.

Standard petroleum economic approaches such as Net Present Value ("NPV"), Internal Rate of Return ("IRR"), and Discounted Cash Flow ("DCF") are universally used because they incorporate the time value of money and risk. Purvis chooses to forego and dismiss these concepts, particularly NPV, in decommissioning contexts but offers no legitimate replacement, only a "rule of thumb" concept of "Holdback," stating "[B]y the time that net revenues at normal prices are only twice as much as monthly costs, a well is within striking distance of its economic limit. This is not a formal or industry-recognized threshold but my 'rule of thumb' based on decades of evaluations." *See* Apps' Ex. 30 0711 Lines 21-23. In effect, Purvis asks the Commission and OCD to discard established economic evaluation tools in favor of his own intuition. That is not a defensible or reproducible basis for regulatory decision-making. Purvis does not present a clear formula for calculating "Holdback," leaving the concept framework vague, unreproducible, and difficult to apply practically. As plugging obligations are future liabilities, discounting their values is generally very critical to understanding their value in today's terms. By failing to utilize the time value of money via NPV, Purvis' "Holdback" concept overstates current liabilities and distorts the economic balance between present revenues and future obligations. *See* Apps' Ex. 30 0714 Lines 15-21 ("the so-called 'time value of money' does not create a preference for decommissioning sooner than later.") In effect, the "Holdback" approach treats a dollar today as the same as a dollar 20 years from now and provides no external benchmark, standard, or empirical validation. In fact, the "Holdback" concept is likely a creature of Purvis's invention to confirm a policy position versus a viable economic analysis tool.

Lastly, the "Holdback" concept creates misleading comparisons. By discarding NPV and ignoring the quality of analytical input and their variability (e.g., price swings, service costs, operator strategy), "Holdback" creates dramatic and exaggerated shortfalls between what companies allegedly set aside currently and what Purvis claims they *should* set aside. These much-inflated gaps between set-aside estimates become justification for stricter rules, even though they are based on a non-industry standard metric and theory.

vii. Purvis Analysis Overlooks Opportunity Loss

Unlike the Holdback concept proposed by Mr. Purvis, "Opportunity Loss" is a well-established principle in engineering economic analysis. In oil and gas, opportunity loss (or opportunity cost) refers to the economic value forgone when projects are delayed, assets are prematurely abandoned, or development windows are missed. Because the time value of net revenues is critical, even short delays or premature curtailment can significantly reduce a project's net present value (NPV) and overall returns. It is important to realize that Purvis (2022) introduces Holdback and related yardsticks as *new* economic tools, specifically developed to provide a "rule-of-thumb" for assessing the risk of residual plugging and abandonment (P&A) liabilities at the end of a well's life (SPE-210226-MS). His framework assumes that the dominant risk in late-life asset economics is the accumulation of asset retirement obligations (AROs), and he recasts cash flow analysis entirely in terms of these liabilities. While such yardsticks may be useful for highlighting downside exposure, they present an incomplete and misleading picture of oil and gas asset economics.

Purvis' analysis treats retirement liabilities as the central economic determinant while systematically discounting or excluding offsetting opportunities. His cash flow framework assumes revenues near the end of life are inherently too risky to be relied upon, ignoring the enormous amount of new oil that has been found in old fields since the beginning of the unconventional play revolution, yet assuming liabilities are certain and growing. This asymmetry produces a downside-only view of the economics.

What the Holdback framework does not acknowledge is the economic cost of foreclosing future options when wells are prematurely plugged. Once a wellbore is permanently abandoned, all sunk capital in the casing, borehole, and pad is forfeited, and any future development requires drilling anew. This represents a quantifiable opportunity loss that should be weighed alongside liability risks.

In my experience, marginal and/or temporarily abandoned wells often return to production or are repurposed for other beneficial uses. Regulatory frameworks explicitly allow temporary abandonment to preserve these options. By ignoring these pathways, Holdback analysis understates the long-term value of retaining wellbores in compliance with state regulations.

Peer-reviewed studies confirm that delays or deferrals in upstream development carry substantial economic costs. For example, Szklo et al. (2008)[22] demonstrated that deferring a Brazilian field development by five years nearly halved the project's net present value, and a 10–15 year delay rendered the project uneconomic at then-current oil prices. The same principle applies to premature abandonment: hydrocarbons left in the ground due to forced P&A are an irreversible loss of value.

A robust economic framework must account for both sides of the ledger: ARO liabilities and the opportunity costs of foregone production or repurposing. By focusing exclusively on the former, Purvis' Holdback approach exaggerates downside risk and disregards the proven economic benefits of preserving wellbores under temporary abandonment. A balanced yardstick

[22] Szklo, Alexandre Salem & Carneiro, Jason Thomas Guerreiro & Machado, Giovani, 2008. "Break-even price for upstream activities in Brazil: Evaluation of the opportunity cost of oil production delay in a non-mature sedimentary production region," Energy, Elsevier, vol. 33(4), pages 589-600.

incorporating both would provide the Commission with a far more accurate and objective basis for decision-making.

viii. Use of Dissimilar Out-of-State Costs as a Proxy for New Mexico

When estimating agency administrative costs to lump into plugging and abandonment of wells, Purvis blanketly layered a value for the estimated administrative overhead factor of 28% to cover government program management costs based on a dissimilar orphan well program in Ohio. *See* Apps' Ex. 30 0728 Lines 7-14. This approach is problematic because Ohio's program, rules, staffing model, and administrative burdens do not mirror the OCDs. The regulatory workload between Ohio and New Mexico is not apples to apples, as Ohio funds its program through state severance taxes and budget appropriations, while New Mexico uses bonding, the Reclamation Fund, and federal grants. Differing program design dictates overhead, so using a straight transfer of percentages is unjustified and introduces more uncertainty into Purvis' estimates.

4. Applicants and Agency Estimate $70,000 Average Cost to Remediate per Well

Applicants' own "Fact Sheet" for failed Senate Bill 418, The New Mexico Oil and Gas Justice and Reform Act, admits OCD has found the average cost to plug and abandon a well is only approximately $70,000.[23] Therein, WELC also confirms that the controlling New Mexico Oil and Gas Act has a hard cap of $250,000 on the blanket financial assurance the Division can require.[24]

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[23] *See* Western Environmental Law Center, *Facts About the New Mexico Oil and Gas Justice and Reform Act*, W. Envtl. L. Ctr., https://westernlaw.org/facts-about-the-new-mexico-oil-and-gas-justice-and-reform-act/ (last visited Sept. 14, 2025) (citing New Mexico Oil Conservation Division, *Orphan Well Program*, N.M. Legislature, https://www.nmlegis.gov/handouts/WNR%20082522%20Item%2011%20Orphan%20Well%20Program.pdf (last visited Sept. 14, 2025) (setting forth average plugging and abandonment cost by "well" and reclamation cost by "site"))

[24] *Id.* ("The New Mexico Oil and Gas Justice and Reform Act Targets Other Provisions that No Longer Reflect Today's Realities Including: Removing the cap on 'blanket bonds' and ensuring that financial assurance is adequate") ("the 1935 Oil and Gas Act caps financial assurance for "blanket bonds" at $250,000") ("Although the cap amount was revisited by the legislature in 2018, it's already wildly out of step with the real costs of plugging and clean up. The

Additionally, the larger reclamation estimate provided by the Applicants and the agency is per site, as opposed to per well, like the P&A cost.[25] Moreover, as explained by Mr. Sporich, the statute only authorizes coverage to secure P&A costs, not reclamation.

5. Recommended Changes and Alternatives

Alternatively, OCD could only require supplemental financial assurance if the government's decommissioning estimate is greater than the assurance currently on file, and allow the value of reserves and presence of predecessor in the chain of title with an investment-grade credit rating to eliminate the requirement, even where less than the P&A cost on file.

* * *

IV. **CONCLUSION**

I conclude that the amendments to the New Mexico Administrative Code proposed by Applicants pose serious risks of regulatory overreach and unintended consequences. By failing to establish a clear and consistent definition of "orphan well," the proposals rely on skewed data and inflated estimates that misrepresent the true scope of the issue. Their reliance on the MOSS database to estimate plugging and abandonment costs compounds the problem: because the dataset is selective and biased toward high-cost wells, it produces artificially elevated cost projections that do not reflect the broader population of wells in the state.

Equally problematic is the Applicants' characterization of legacy wells as "speculative." This framing ignores both their historic role in enabling New Mexico's unconventional development and their continuing potential for recompletions, repurposing, and redevelopment. Building financial assurance requirements on these flawed definitions and assumptions risks destabilizing

New Mexico Oil and Gas Justice and Reform Act removes the cap on blanket bonds.")

[25] *Id.*

the very operators who manage the bulk of the state's wells. For smaller operators in particular, the likely result would be insolvency or exit from the market—outcomes that increase, rather than reduce, the orphan well burden on the State.

This concludes my rebuttal 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:** September 19, 2025

Name: Harold McGowen, P.E. No. 66419

Title: President and CEO

Company: Navidad Energy Advisors

STATE OF TEXAS
HAROLD E. McGOWEN III
66419
LICENSED
PROFESSIONAL ENGINEER

Dated this 19th day of September, 2025.

Respectfully submitted,

By:_________________________

Miguel A. Suazo
James P. Parrot
James Martin
Jacob L. Everhart
500 Don Gaspar Ave.
Santa Fe, NM 87505
(505) 946-2090
msuazo@bwenergylaw.com
jparrot@bwenergylaw.com
jmartin@bwenergylaw.com
jeverhart@bwenergylaw.com
Attorneys for New Mexico Oil and Gas Association

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served to counsel of record via the EMNRD's CentreStacke Platform this 19th day of September 2025, as follows:

Tannis Fox
Senior Attorney
Morgan O'Grady
Staff Attorney
Western Environmental Law Center
409 East Palace Avenue, #2
Santa Fe, New Mexico 87501
505.629.0732
fox@westernlaw.org
ogrady@westernlaw.org

Kyle Tisdel
Managing Attorney
Western Environmental Law Center
208 Paseo del Pueblo Sur, #602
Taos, New Mexico 87571
575.613.8050
tisdel@westernlaw.org

Matt Nykiel
Staff Attorney
Western Environmental Law Center
224 West Rainbow Boulevard, #247
Salida, Colorado 81201
720.778.1902
nykiel@westenlaw.org
Attorneys for Applicants Western Environmental Law Center, Citizens Caring for the Future, Conservation Voters New Mexico Education Fund, Diné C.A.R.E., Earthworks, Naeva, New Mexico Interfaith Power and Light, San Juan Citizens Alliance, WildEarth Guardians, and Sierra Club.

Santa Fe, New Mexico 87505
Felicia.l.orth@gmail.com
Oil Conservation Commission Hearing Officer

Jesse Tremaine
Chris Moander
Assistant General Counsels
New Mexico Energy, Minerals, and Natural Resources Department
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
jessek.tremaine@emnrd.nm.gov
chris.moander@emnrd.nm.gov
Attorneys for Oil Conservation Division

Michael H. Feldewert
Adam G. Rankin
Paula M. Vance
P.O. Box 2208
Santa Fe, New Mexico 87504
mfeldewert@hollandhart.com
agrankin@hollandhart.com
pmvance@hollandhart.com
Attorneys for OXY USA Inc.

Andrew J. Cloutier
Ann Cox Tripp
Hinkle Shanor LLP
P.O. Box 10
Roswell, New Mexico 88202-0010
acloutier@hinklelawfirm.com
atripp@hinklelawfirm.com
Attorneys for Independent Petroleum Association of New Mexico

Felicia Orth
Hearing Officer
New Mexico Energy, Minerals, and Natural Resources Department
Wendell Chino Building
1220 South St. Francis Drive

Zachary A. Shandler
Assistant Attorney General
New Mexico Department of Justice
P.O. Box 1508
Santa Fe, New Mexico 87504
zshandler@nmdoj.gov
Oil Conservation Commission Counsel

Mariel Nanasi
Lead Attorney and Executive Director
New Energy Economy
422 Old Santa Fe Trail
Santa Fe, NM 87501
mnanasi@newenergyeconomy.org
Attorney for New Energy Economy

Jennifer L. Bradfute
Matthias Sayer
Bradfute Sayer P.C.
P.O. Box 90233
Albuquerque, New Mexico 87199
jennifer@bradfutelaw.com
matthias@bradfutelaw.com

Nicholas R. Maxwell
P.O. Box 1064
Hobbs, New Mexico 888241
inspector@sunshineaudit.com

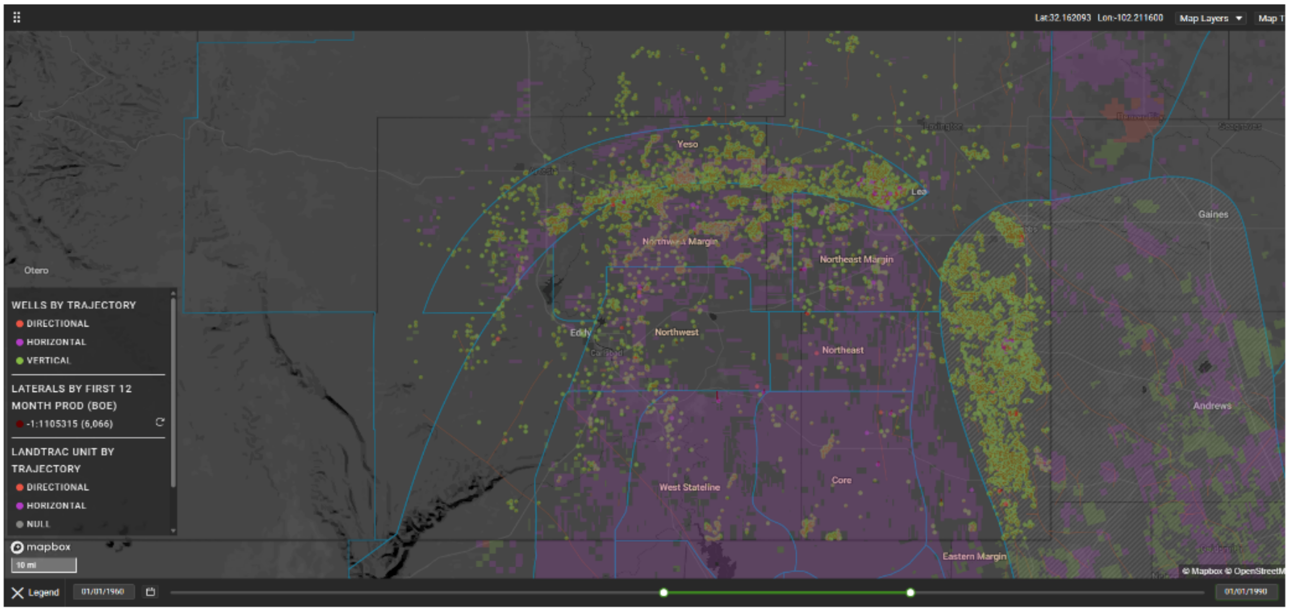
Jordan L. Kessler
EOG Resources, Inc.
125 Lincoln Avenue, Suite 213
Santa Fe, New Mexico 87501
Jordan_kessler@eogresources.com
Attorneys for EOG Resources, Inc.

Sheila Apodaca
New Mexico Energy, Minerals, and Natural Resources Department
Wendell Chino Building
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
occ.hearings@emnrd.nm.gov
Oil Conservation Commission Clerk

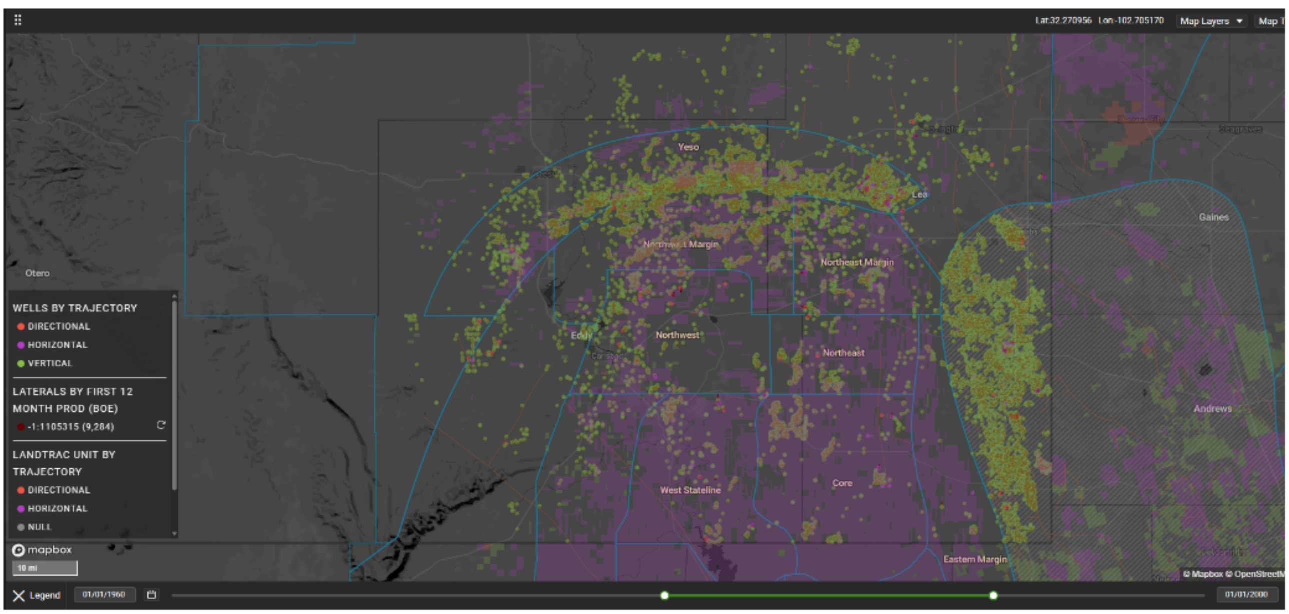
Rachael Ketchledge

APPENDIX A

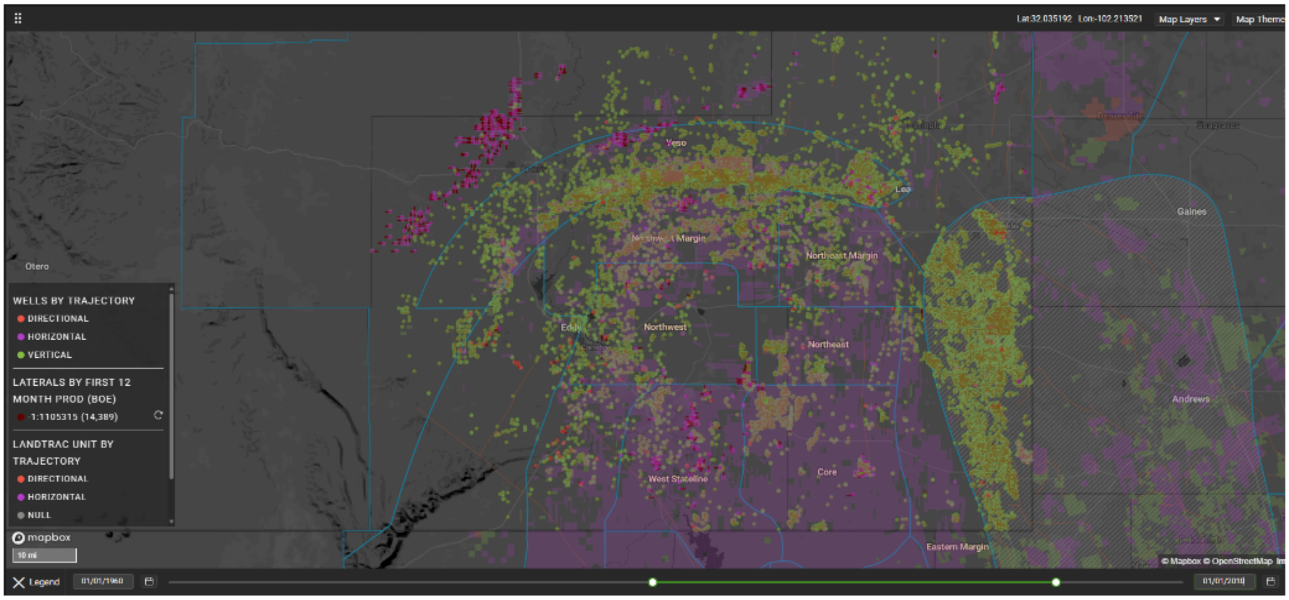
Figure 1 -Transition from Vertical to Horizontal Development



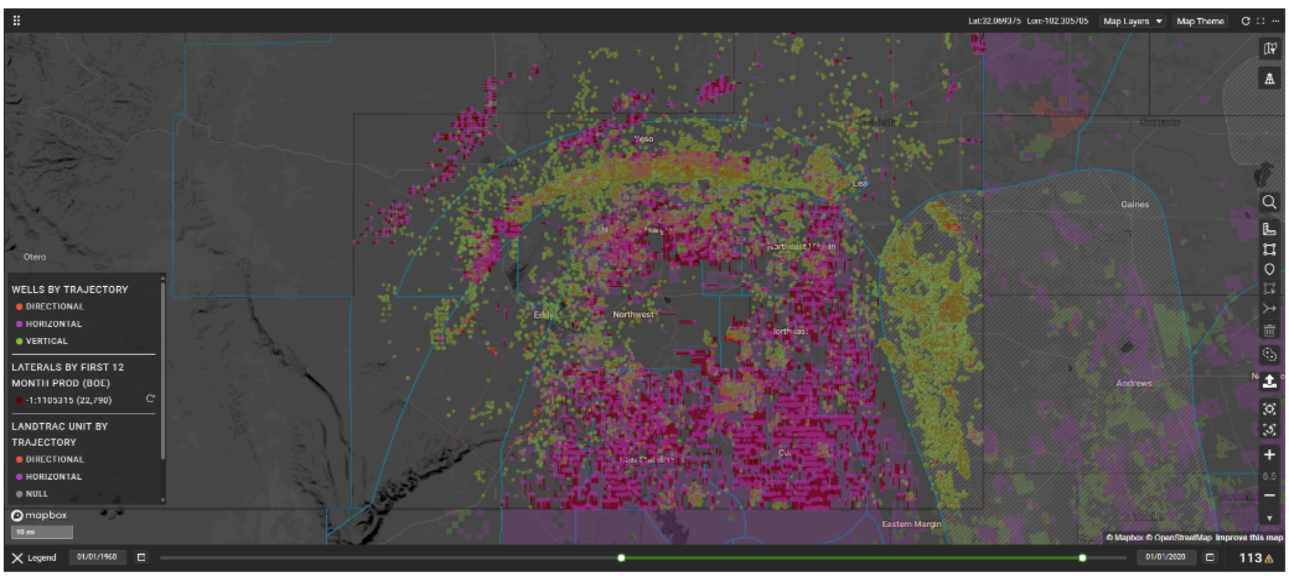
1 New Mexico Permian w/Vertical & Horizontal wells & Land Units - 1960-1990



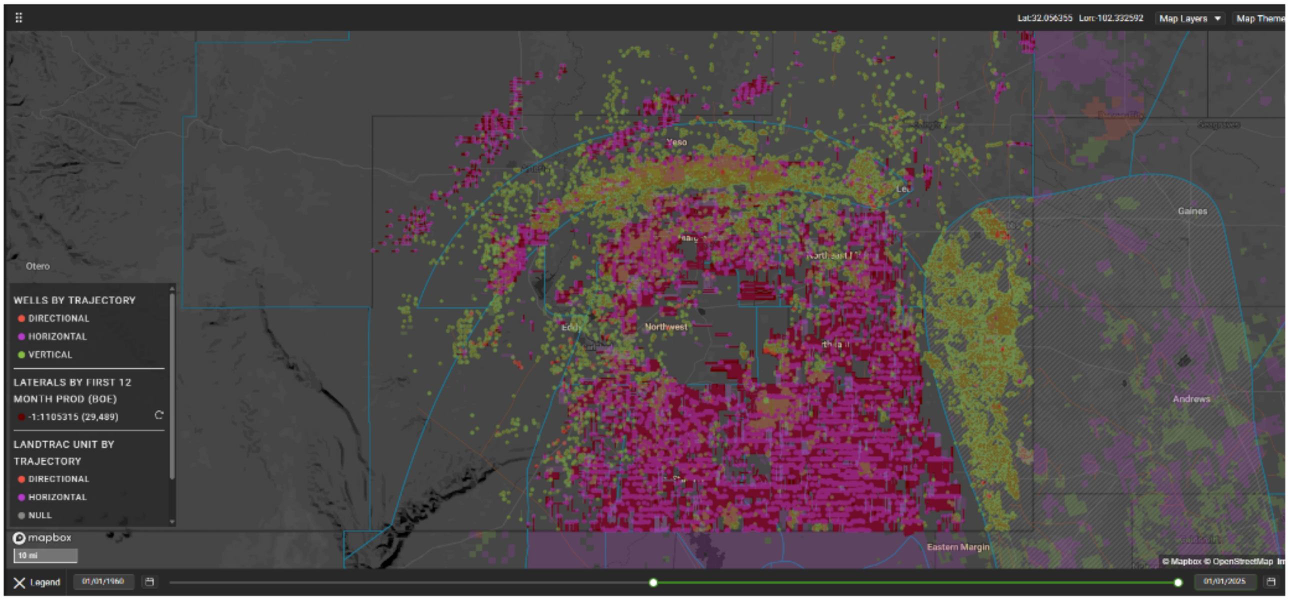
2 New Mexico Permian w/Vertical & Horizontal wells & Land Units - 1960-2000



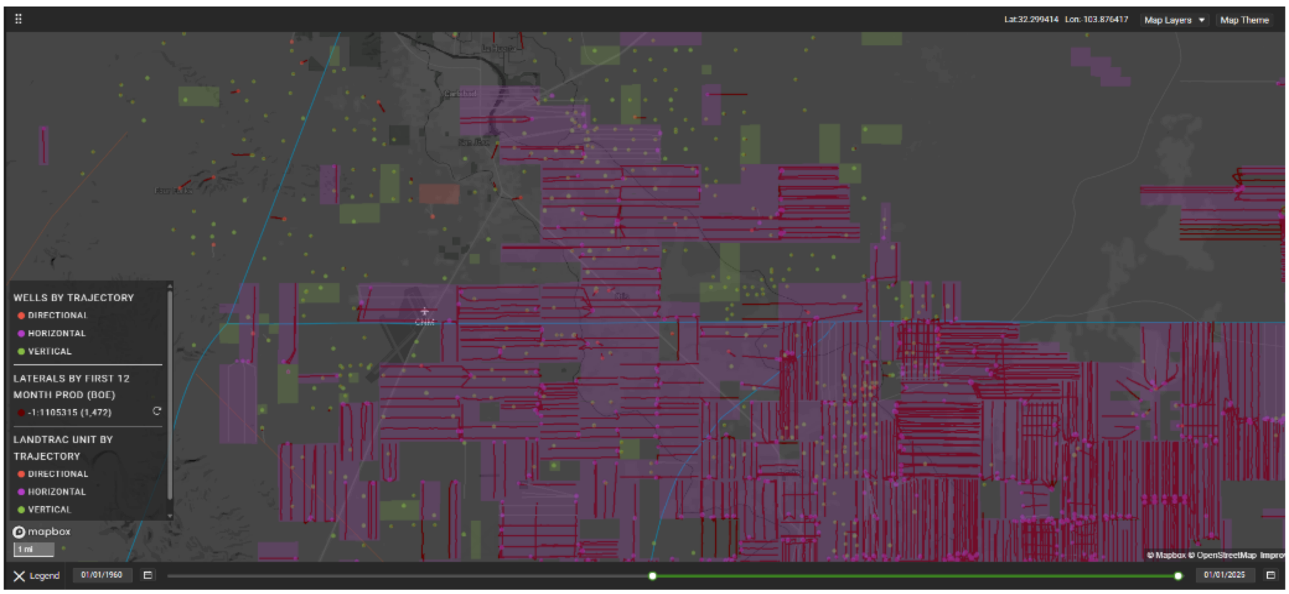
3 New Mexico Permian w/Vertical & Horizontal wells & Land Units - 1960-2010



4 New Mexico Permian w/Vertical & Horizontal wells & Land Units - 1960-2020



5 New Mexico Permian w/Vertical & Horizontal wells & Land Units - 1960-2025



6 New Mexico Permian - Zoomed In - Horizontal Units and Vertical Acreage (units in magenta)

APPENDIX B

Examples of Stripper Redevelopment in New Mexico

A comparative analysis of redevelopment strategies in New Mexico's mature basins reveals a consistent pattern of how operators generated new value from aging assets. Firms targeted portfolios of low-rate vertical producers and applied modern unconventional technologies such as long-lateral horizontal drilling, multi-stage hydraulic fracturing, and pad development.

These methods allowed declining conventional fields to be converted into high-return unconventional developments. This approach has not only extended the productive life of New Mexico's basins but also established a model for unlocking latent hydrocarbon potential in "stripper well" plays once regarded as economically exhausted.

The following case studies illustrate how this redevelopment model has been implemented across different geologic settings in New Mexico.

Hilcorp Energy – San Juan Basin Gas Redevelopment (2017 Acquisition)

Hilcorp, a private E&P, acquired ConocoPhillips/Burlington's legacy San Juan Basin assets in mid-2017, a package of over 12,000 predominantly vertical, gas-producing wells across roughly 2 million gross acres.[1,2,3,4] These mature wells (many dating to the 1980s gas boom) were stripper producers in conventional reservoirs (Fruitland Coal, Mesa Verde, Dakota, etc.).[5,6]

Hilcorp is known for revitalizing old fields, and post-acquisition, it focused initially on operational efficiencies and infill drilling in existing zones.[7,8] By 2024, Hilcorp began horizontal drilling to test the basin's untapped Mancos Shale potential, completing two new horizontal wells in the Mancos formation.[9]

San Juan Basin Trust filings confirm Hilcorp spent approximately $24.6 MM on two Mancos horizontal projects in 2024.[10] SEC reports note these new horizontals started producing in late 2024,[11] which is expected to help recover prior cost carryovers.

Initial results were promising, with the trust's disclosures suggesting the horizontals should boost output enough to restore royalty payouts.[12] While Hilcorp has since scaled back 2025 drilling to focus on cheaper vertical well workovers (possibly due to gas price volatility), its 2024 horizontals mark a clear redevelopment of legacy acreage using modern fracking technology.[13,14]

DJR Energy – Mancos Oil Redevelopment (2017–2018 Acquisitions)

DJR Operating (a private equity-backed startup) entered the San Juan Basin in 2017–2018 by purchasing marginal oil assets from Elm Ridge and Encana.[15] In 2017, DJR acquired approximately 170,000 acres with around 800 old vertical wells from Elm Ridge Resources.[16] In 2018, it bought Encana's entire San Juan position,182,000 net acres, in

New Mexico's oil window producing only approximately 5,400 boed (mostly from decades-old vertical wells).[17]

The acreage is in the southern San Juan Basin's Gallup sandstone/Mancos Shale oil window, where only around 200 horizontal wells had been drilled by prior operators.[18]

DJR explicitly aimed to apply horizontal drilling to the Mancos Shale on this legacy acreage.[19].Shortly after closing the Encana deal (December 2018), DJR deployed modern rigs to drill new horizontal wells in the Gallup/Mancos, leveraging its team's shale experience.[20]

The Encana package "transformed" DJR, according to a Hart Energy Article titled, "Executive Q&A: Transforming DJR Energy," and CEO David Lehman explained that new horizontal wells in the San Juan Basin [were planned] this year (2019).[21] State permit data shows DJR spudded multiple horizontals post-acquisition, and industry reports confirm DJR was among the most active horizontal drillers in the basin by 2023.[22][23]

The horizontal program drove a significant production increase. DJR's oil output reached approximately 13,143 bbld of liquids in 2023, up from barely 3,900 bbld of oil in 2017 under Encana.[24][25] These results underscore how acquiring stripper vertical wells and re-developing with modern horizontals unlocked substantial new oil production.

Enduring Resources – Gallup Oil Horizontal Program (2018 Acquisition)

Enduring Resources (an EnCap-backed private operator) acquired WPX Energy's legacy San Juan Basin oil assets in early 2018 for $700 MM.[26][27] This included roughly 105,000 net acres in the Gallup oil window (Rio Arriba & San Juan Counties) with dozens of existing wells.[28] WPX had drilled over 100 horizontal wells in the Gallup Sandstone (Mancos Shale) since a 2013 discovery,[29] alongside older vertical producers on those leases. The focus is the Gallup sandstone interval of the Mancos Shale, a Cretaceous tight oil formation.[30]

Enduring continued WPX's horizontal drilling program and accelerated it under private ownership. Industry observers noted that Enduring "picked up WPX's San Juan assets" and promptly became a leading operator drilling high-impact Gallup wells.[31] Public filings confirm Enduring "has been actively drilling horizontal Mancos wells" on the acquired acreage.[32] Enduring's team, led by A&D veteran Barth Whitham, had a track record of redeveloping assets (Enduring previously sold a Permian position for $2.5 B in 2014).[33] They applied similar techniques here, such as long laterals (some 2-mile), multi-stage fracs, and pad drilling to improve efficiency.[34][35]

By 2019–2020, Enduring was running multiple rigs in the Gallup. New Mexico OCD data show Enduring averaged approx.11,985 bbld of oil and NGL in 2023,[36] on par with DJR, reflecting the sustained output from horizontals. Trade press also reported that "WPX has since sold their San Juan acreage to Enduring ... and they have been actively drilling horizontal Mancos wells."[37] The linkage between the 2018 acquisition and subsequent production growth is clear: WPX's legacy leases were rejuvenated by Enduring's horizontal redevelopment, stabilizing and even growing oil output in a basin long considered mature.

BP Lower 48 – NEBU Mancos Shale Project (2015–2017 Initiative)

In late 2015, BP's Lower 48 unit acquired Devon Energy's Northeast Blanco Unit (NEBU) assets in the San Juan Basin.[38] This large unit (33,000 gross acres) was historically a coalbed methane (CBM) field with hundreds of vertical Fruitland Coal wells (a "producing powerhouse" of the 1990s).[39][40] Notably, the acreage had no reserves booked in the deeper Mancos Shale at time of purchase,[41] representing latent potential.

BP's new CEO of Lower 48, Dave Lawler, specifically halted the sale of these legacy assets to test modern horizontal technology in the Mancos[42]. In 2017, BP drilled the NEBU 604 (and 602), the first BP-operated horizontal Mancos wells on this acreage.[43][44] They utilized extended 2-mile laterals with multi-stage fracs, collecting extensive data.[45]

The NEBU 602 Com #1H well, drilled summer of 2017, achieved a 30-day IP of 12.9 MMcfd of gas, far outperforming prior San Juan tests, and was drilled and completed with "modern, enhanced fracture stimulation".[46] Lawler reported the well would earn a return above cost of capital and spurred plans for five more 10,000 ft laterals in 2018.[47] BP identified roughly 400 horizontal locations across the NEBU for Wolfcamp-style development.[48]

Production data confirmed the impact: the multi-well NEBU Mancos pilot lifted BP's San Juan gas output and proved up EURs of 11–15 Bcf per well (with 2-mile laterals) according to third-party models.[49] This case illustrates a major operator acquiring an old vertical-well field from a smaller peer (Devon) and immediately unlocking a new shale play (Mancos) via horizontal drilling, evidenced by record well results[50] and BP's subsequent development plans.

ExxonMobil (XTO) – Permian Delaware Revitalization (2017 Bass Acquisition)

In 2017, ExxonMobil's XTO Energy unit acquired the Bass family's BOPCO assets for approximately $6.6 B, adding 275,000 acres in New Mexico's Delaware Basin.[51] The Bass acreage, accumulated over decades, came with numerous legacy vertical wells producing approximately18,000 boed (mostly conventional oil) and extensive unrealized horizontal potential.[52][53] Exxon described this as more than 3.4 Bboe of resource upside in stacked Wolfcamp and Bone Spring shales.[54][55]

Post-acquisition, Exxon launched an aggressive horizontal drilling campaign. Starting in 2017, XTO ramped up rigs on the Bass lands, leveraging Exxon's shale expertise to drill long laterals across multiple benches.[56] The contiguous nature of the Bass acreage enabled "cube development," or simultaneous development of Wolfcamp and Bone Spring zones, and even 4-mile extended laterals on New Mexico state lands.[57]

By 2024, Exxon had drilled 1,000 horizontal wells in the New Mexico Delaware Basin (reaching that milestone in just seven years after the Bass deal).[58] The company credited the Bass acquisition for its "blocky acreage" that unlocked these longer laterals and high-intensity fracs.[59] An Oklahoma Minerals article noted the Bass purchase "significantly bolstered" its Permian holdings and that development wells were achieving attractive returns even at sub-$40 oil.[60][61]

The result has been a dramatic uplift in output. Exxon's Permian production surged five-fold from 2017 to 2023.[62] By 2025, ExxonMobil expects over 600,000 boed from its Permian operations,[63] underpinned by the Bass acreage redevelopment. This case demonstrates a large operator acquiring a smaller family company's stripper wells and rapidly transforming the asset with horizontal drilling, as evidenced by the drilling of 1,000+ new wells and the associated production boom.[64]

EOG Resources – Legacy Yates Acreage Horizontal Program (2016 Combination)

In September 2016, EOG Resources acquired Yates Petroleum – a historic family-run operator in New Mexico – in a $2.5 B stock merger.[65] Yates brought 1.6 million acres across the western US, including 186,000 net acres in the New Mexico Delaware Basin and 138,000 acres on the Northwest Shelf (Yeso play).[66] Yates' production (approx. 29,600 boed) came largely from hundreds of marginal vertical wells developed over decades (Yates drilled New Mexico's first state trust well in 1924).[67] Notably, Yates had done limited horizontal drilling, leaving a vast inventory of undrilled locations.

EOG immediately planned to commence horizontal drilling on Yates acreage. CEO Bill Thomas highlighted 1,740 "premium" drilling locations added in Delaware and Powder River, and announced rigs would start on Yates lands in late 2016 with more in 2017.[68] EOG targeted the stacked pay zones that Yates held: Wolfcamp, Bone Spring, Leonard Shale in the Delaware Basin, plus shallow Yeso/Abo zones on the Northwest Shelf.[69] EOG applied its advanced completion design and precision targeting to these legacy fields, converting them to modern unconventional development.

The combined acreage position (574,000 net acres) allowed EOG to deploy its technology at scale.[70] Leveraging longer laterals and optimized fracs, EOG quickly improved well performance on Yates lands. For example, EOG reported that even the shallow Yeso and Abo formations (traditionally vertical plays) could deliver "premium" returns with horizontal techniques[71]. EOG's SEC filings in 2017–2018 show rapid drilling on the former Yates tracts, and industry reports noted "the horizontal Yeso in New Mexico…breaks even at low oil prices," a testament to successful modernization.[72][73]

This redevelopment boosted EOG's Permian output significantly. By 2018, EOG was the largest oil producer in New Mexico, in part due to the Yates asset horizontals. The Yates acquisition exemplifies acquiring a smaller operator's aging vertical portfolio and unlocking its value via horizontals, documented by EOG's added drilling inventory and swift initiation of new wells.[74]

Spur Energy Partners – Northwest Shelf Yeso Revitalization (2019 Acquisition)

Spur Energy Partners (a KKR-backed startup founded 2019) has built its position by buying legacy conventional wells on the New Mexico Shelf and redeveloping them. In 2019, Spur acquired "New Mexico Shelf" assets from Concho Resources for $925 MM.[75] This package spanned approximately 100,000 gross acres of the Northwest Shelf (Eddy/Lea Counties) with approx. 25,000 boed production from thousands of old vertical wells (primarily in the Permian Yeso formation).[76] Earlier in 2019, Spur also bought Percussion Petroleum's Yeso assets (approx. 22,000 net acres with 380 wells).[77][78]These fields were characterized by low-rate verticals in shallow carbonate formations (Paddock, Blinebry zones of the Yeso).[79][80]

Spur's team (led by former WildHorse Resource developers) explicitly targeted these "conventional oil reservoirs" to drill horizontal wells. Co-CEO Kyle Roane stated, "We like the ability to come into a conventional play and drill horizontal wells," noting Spur acquired producing assets with big upside for horizontal drilling.[81] Spur systematically applied modern horizontal frac techniques to the Yeso, which has relatively low depth (approx. 4,500–6,500 ft) and thickness conducive to lateral drilling.[82]

Within a year, Spur deployed multiple rigs on the New Mexico Shelf. By late 2021, Spur had drilled at least 30 new horizontal wells and was operating approx. 3,000 total wells (of which 400+ were horizontals, up from essentially zero horizontals prior).[83][84] The Concho divestiture press release emphasizes Spur's focus on assets with "substantial low-cost development inventory."[85] Hart Energy reported Spur grew into a "top producer in the Yeso trend" by 2022, targeting the Paddock/Blinebry zones with horizontal drilling.[86]The $925 million Concho deal in 2019 was cited as a key enabler of this strategy.[87]

Spur's output climbed to approx. 34,000 boed by 2023 with the new horizontals.[88] The Yeso wells, while lower IP than deep shale wells, have shallow decline rates and strong economics (Spur's horizontal Yeso wells cost only approx. $400–$500 per lateral foot vs $600–$800 per lateral ft in deeper plays).[89] Spur's case exemplifies how acquiring marginal vertical fields from a larger operator (Concho) and infusing horizontal drilling can rejuvenate a mature play.[90][91]

Marathon Oil – New Mexico Delaware Re-Development (2017 Acquisition)

In early 2017, Marathon Oil re-entered the Permian by acquiring approximately70,000 net acres in the northern Delaware Basin (New Mexico) from BC Operating and partners for $1.1 B.⍰ This acreage in Lea County included 51,500 acres in New Mexico and was producing roughly 5,000 boed.[92] The wells targeted multiple benches (Wolfcamp, Bone

Spring) with limited development by the sellers. According to Marathon Oil President and CEO, Lee Tillman, the deal expanded the quality and depth of Marathon's "already robust inventory while securing a foundational footprint in the Delaware basin with 5,000 feet of oil-rich stacked pay."[93] This acreage in Lea County included 51,500 acres in New Mexico and was producing roughly 5,000 boed.[94] The wells targeted multiple benches (Wolfcamp, Bone Spring) with limited development by the sellers. According to Marathon Oil President and CEO, Lee Tillman, the deal expanded the quality and depth of Marathon's "already robust inventory while securing a foundational footprint in the Delaware basin with 5,000 feet of oil-rich stacked pay."[95]

According to an Oil & Gas Journal article about the acquisition, Marathon received as many as 10 target benches within 5,000 ft of stacked pay and 900 million boe of total resource potential with an inventory of 1,700 total upside locations on the acquired NM acreage.[96] The plan was to increase horizontal drilling. Marathon kept one rig running upon takeover and added a second by mid-2017.[97] Primary targets were the Wolfcamp and 2nd/3rd Bone Spring shales, where multi-mile laterals could be drilled now that Marathon controlled a large contiguous position.[98] Marathon's CEO Lee Tillman lauded the Delaware Basin's "outstanding well economics...unrivaled improvement in well performance."[99]

Marathon's 2018 Capital Program & 2017 Results presentation cited that Northern Delaware was producing outstanding results, with initial Wolfcamp-Bone Spring wells delivering encouraging results, including its first 7,500 ft. long lateral tests.[100]

Marathon's first quarter 2018 results reported Northern Delaware production increased to 1600 net boed; seven wells across Eddy and Lea Counties had average 30-day IP rates of 1,460 boed (69% oil).[101] Marathon's second quarter 2019 results announced that Northern Delaware's production averaged 28,000 net boed in 2Q19.[102] In subsequent years, Marathon chose to divest from its Permian position (around 2021), however, during the 2017–2019 period the acquired NM assets saw new horizontal wells with improved productivity.

The company's 2017 statements and subsequent results underscore the value that was unlocked: "outstanding well economics" were achieved, and the Wolfcamp/Bone Spring potential that was previously untapped became a reality.

Additional Examples of Horizontal Redevelopment of Legacy Vertical Wells in New Mexico

Abstract: Riley Permian announced the acquisition of assets in the shallow Yeso Trend of Eddy County, noting over 100 horizontal drilling locations. The release frames the deal as a horizontal redevelopment of a long-producing vertical play. Importantly, Riley highlights that stable legacy production underpins financing and allows predictable growth with modern frac-enabled horizontals.[1]

Abstract: The JV announcement details Chaveroo Field's original vertical development on 40-acre spacing and its ongoing transformation with ten horizontal infill wells on 20-acre spacing. The bulk of production now comes from these horizontals. The companies emphasize how legacy vertical production demonstrated reservoir quality, enabling new capital investment.[2]

Abstract: LOGOS reported multiple record-setting horizontal wells in legacy San Juan Basin acreage. The company framed historic vertical well performance as 'proof of hydrocarbons in place,' which de-risked horizontal expansion. This legacy evidence was central in attracting outside equity partners.[3]

Abstract: Longfellow describes its position in Loco Hills, with more than 100 producing vertical wells and 43 horizontal wells targeting San Andres/Yeso intervals. The juxtaposition of verticals and horizontals demonstrates how legacy production serves as infrastructure and reservoir proof, while new horizontals deliver uplift.[4]

Abstract: EON raised capital to begin horizontal drilling in mature waterfloods, explicitly citing the hundreds of legacy vertical wells as the basis for securing financing. This illustrates the theme that existing, even low-output production can unlock new capital for redevelopment.[5]

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Abstract: Discusses horizontal drilling and modern completions bringing a resurgence to mature San Andres fields across the Northwest Shelf and Yeso trend. Notes that legacy vertical well performance provided the base for redevelopment strategies.[6]

Abstract: Provides a comprehensive overview of horizontal Yeso development in southeastern New Mexico, detailing how operators use existing infrastructure and legacy wells as stepping stones to implement large-scale redevelopment.[7]

Abstract: Details horizontal infill development in legacy vertical acreage, analyzing parent-child well interference. The study demonstrates both risks and opportunities of redeveloping vertical legacy areas with new horizontals.[8]

Abstract: Reviews the regional shift from vertical to horizontal development in the Yeso Formation, documenting operator strategies, EUR uplift, and capital reallocation. Underscores how legacy wells provided data and justification for redevelopment.[9]

Summary:

Across these operator statements, industry articles, and technical papers, a consistent lesson emerges: legacy vertical wells, even low-output or marginal producers, enable financing, de-risk horizontal investment, and provide infrastructure for redevelopment.

When paired with modern technologies (gas lift, recompletions, multi-stage fracturing), these fields can generate extreme upside and transform mature basins into profitable horizontal plays once again.

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