STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
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 MIKE HANAGAN

Intervenor Independent Petroleum Association of New Mexico submits the following rebuttal fact testimony of Mike Hanagan:

Q: Please introduce yourself to the Commission.

A: My name is Mike Hanagan. I am the Owner of Manzano LLC.

Q: Do you understand that this testimony is sworn testimony as if you were live at the Commission and under oath?

A: I do.

Q: Have you reviewed the rule making proposals before the Commission?

A: Yes, I have reviewed both the Amended Proposals from the Western Environmental Law Center and other Applicants (WELC), the Oil Conservation Division's Proposals, and certain testimony submitted on behalf of WELC and OCD.

Q: Briefly introduce the Commission to Manzano LLC.

A: Manzano LLC is a New Mexico company based in Southeast New Mexico in Roswell, formed in 2001. Manzano is a private company specializing in drilling and producing horizontal wells in the northern end of the prolific Permian Basin. Along with my partner, we have drilled, produced from, and successfully exited several plays, including the Raton Basin, the Texas Panhandle and the northern end of the Delaware Basin. For the last several years we have been focused on the northern end of the Permian Basin with our main focus being the Bone Spring, Canyon Shale and San Andres formations. Recently, we developed and permitted the conversion of a vertical producing well into an injection well for a permanent pressure maintenance project in northern Lea County, New Mexico, approved as a pilot project in March 2022.

Q: How long have you been working in the industry?

A: I started in the oil business in 1983 after getting my degree in Geology from Fort Lewis College in Durango, Colorado and have been active in the exploration and production segment of the oil and gas industry for over 40 years with the last 20 years as an owner of Manzano and its associated entities. Manzano operates wells and is a non-operating working interest owner in wells operated by others.

Q: How is Manzano's Jenkins San Andres Pressure Maintenance Project relevant to this rulemaking?

A: I have reviewed and heard a lot of testimony about marginal wells at the end of their life being high-risk, uneconomic properties that should all need to be plugged right now. The position of WELC and its experts strikes me as incredibly closed-minded, short-sighted, and directly opposed to the duty of the Commission to protect correlative rights and prevent waste. Manzano's San Andres project started with the Vince BGH #001 Well, a circa-2005 vertical oil well drilled to 12,655 feet to the Devonian formation. The Vince BGH well produced over 37,000 barrels of oil and 328,000 mcf of gas over 17 years, but would have been considered a marginal under WELC's definition for five of those years. Manzano drilled and operated two nearby horizontal wells, the Rag Mama 30-19 Fee #1 and Sodbuster 21 Fee #4 in the Jenkins; San Andres pool at about 4,100 feet. In December 2021, Manzano applied to plugback and convert the Vince Well for pressure maintenance, which would stabilize the San Andres formation pressure reduction, flatten the oil decline, and recover more of the oil in place. Since approval of the project in March 2022, rather than leaving more oil behind in the reservoir as pressure drops, the gas-oil ratio and monthly gas production for the Rag Mama and Sodbuster wells has decreased and oil production has improved, and the continued injection of gas into the Vince Well will allow for the recovery of more oil over time. I point to this project as an example of alternative uses for older vertical, marginal wells that promote the Commission's duty to prevent waste. Had Manzano been forced to evaluate the economics of single-well bonding all three wells in this project or plugging the Rag Mama and Sodbuster, in the three years since the pressure maintenance project was started over 50,000 barrels of oil have been produced and I would anticipate the recovery an additional 50,000 barrels over the next five years that would have been wasted as unrecoverable from the reservoir.

Q: What are your concerns with WELC's proposal and the testimony submitted in support?

A: I am not a member of the Society of Petroleum Evaluation Engineers, but I do have over 40 years of operational industry experience. There are several blanket and conclusory statements made by Mr. Purvis in his direct testimony that do not reflect my experience in oil and gas development and operations in the Permian Basin.

Q: Please walk the Commission through the statements by Mr. Purvis that you find misleading.

A: First, Mr. Purvis claims that "there is practically no drilling going on in the country except for horizontal drilling to shales and other very low permeability reservoirs." *See Direct Testimony of Dwayne Purvis, WELC Ex. 30,* 11:4-5. While it might be correct to say broadly that the majority of wells being drilled nationwide are horizontal wells, Mr. Purvis ignores the wells drilled by small operators like Manzano and Armstrong Energy. In fact, the Permian Basin remains the nationwide leader in vertical well rig counts, with 80% of vertical rigs nationwide in 2024, and 50% of vertical rigs in 2025 so far.[1] While the vertical rig count nationwide has remained essentially unchanged over the past year, horizontal rigs fluctuated by over 50. Discounting the development potential by smaller operators drilling vertical wells ignores a large percentage of the population of operators in New Mexico. In fact, Mr. Purvis's first allegation taken together with his second claim that: "There is practically no such thing as a small company that drills shale wells," *see* Purvis, WELC Ex. 30, 21:13-15, reads independent operators out of New Mexico entirely. And yet, IPANM has over 300 members. Mr. Purvis' analysis of large and small companies appears to be based on wellcount and the fractional percent of horizontal wells in an operator's inventory—nothing in Mr. Purvis's Exhibit 35 reflects drilling, nor does wellcount or horizontal well percentage correspond to company size. Using OCD's databases for filed C-101 permits to drill from 2023 to current, 66 different operators filed permits to drill over 1900 wells, with 3,600 wells spud during that same time frame. *See*

[1] Available at https://rigcount.bakerhughes.com/na-rig-count, last accessed September 11, 2025 (for United States, 8 of 10 active vertical rigs in Permian Basin in 2024, 6 of 12 in 2025 as of September 5, 2025); *see also Guess Where They're Drilling the Bulk of the USA's Vertical Wells?*, Oil & Gas 360 (June 5, 2018), available at https://www.oilandgas360.com/guess-where-theyre-drilling-the-bulk-of-the-usas-vertical-wells/, last accessed September 11, 2025 (explaining how vertical activity remains strong presence in Permian Basin).

OCD Geospatial Hub Well, *Wells Spudded by Year*, attached here as Exhibit 42.[2] Mr. Purvis may claim to have "even operated a few wells,"[3] but his disregard for smaller operators in New Mexico shows just how out of touch he is with the landscape here. The Commission really need not look past his company's opening website to understand his motivating bias, in which he proclaims, "I believe that the world needs *less* oil and gas, not more."[4] One would think this is fundamentally at odds with the purpose of the Commission under the Oil and Gas Act to prevent waste.

Q: What other disconnects do you see between the conclusions offered by Mr. Purvis and the current state of the industry?

A: I find Mr. Purvis's thinly veiled contempt for independent operators to be borderline disrespectful. WELC's experts make much of the "boom and bust" cycle of our industry, but during down times, it is the independent, local operators who stick around, keep the economic lights on, and keep putting paychecks in the pockets of our employees. Mr. Purvis believes that those same operators—who will be disproportionately affected by WELC's single-well bonding proposal—are "…the companies at risk…who will be missed the least." *Purvis*, 44:19–20. His Exhibit 37, however, looks only at well count and production levels, ignoring the indirect impact, jobs, and contributions at the local economy level supported by independent operators and those in the purported other "90%." *See WELC Ex. 37.*

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[2] Available at https://ocd-hub-nm-emnrd.hub.arcgis.com/, last accessed September 14, 2025.
[3] Purvis Energy Advisors, availablea at https://www.purvisenergyadvisors.com/about, last accessed September 14, 2025.
[4] *See id.* at https://www.purvisenergyadvisors.com/about

I also see problems in Mr. Purvis's support of WELC's transfer restriction rule changes. Relying on his concept of holdback that IPANM's expert addresses in rebuttal testimony, *see Rebuttal Testimony of Rob Arscott,* Mr. Purvis believes that: "The [WELC 19.15.8.9D(1)] provision would prevent the transfer of wells to operators who would like to take a gamble on their ability to increase production and don't have the funds to cover a failed bet." *Purvis*, WELC Ex. 30, 63: 6-8. Framing the reworking and recompletion of marginal wells on projects taken on by smaller, independent operators as a "gamble" assumes that the same operators who are willing to invest the individual time, expertise, and care to save and repair existing wells and increase production—in other words, the ones who are willing to work and repair wells, not just pass them off or walk away—are at the same time irresponsible and negligent. To this baseless assumption by Mr. Purvis, I would direct the Commission's attention to earlier testimony submitted by Jeff Harvard, Harvard Petroleum and its partner, Buckhorn Production. In 2021, it purchased 220 stripper wells, 180 being "marginal" under WELC's proposal, and has successfully reworked over 200 wells, and plugged the remainder. As the Commission is aware, the industry relies on a diverse, variety of business models: some companies are focused on acquiring and developing acreage, while others run a leaner model focused on the next discovery, new plays, or making older wells profitable. The responsible extraction and development of natural resources in New Mexico needs and relies upon that diversity to maintain balanced and stable markets. These are the companies that are extracting the last hydrocarbons from these wells and producing those wells for years and even decades.

I disagree with another pronouncement made by Mr. Purvis regarding independent, or private, companies that buy later-life assets: "In my experience and observation, these stripper well operators tend to have worse operational track records of compliance." *Purvis*, WELC Ex. 30, 74:20-21. Without any supporting facts, Mr. Purvis assumes that the reduced overhead costs incurred by a smaller operator means cutting corners and noncompliance, because the private company has "less exposure to public opinion." *Id.*, 74:15–18. Finally, if Mr. Purvis wants to analyze environmental compliance among smaller, independent operators, the data is readily available from the Oil Conservation Division. Issuing blanket conclusions without supporting statistical analysis is simply not helpful to the Commission during this Rulemaking.

Q: Are there any points that Mr. Purvis makes which you agree with?

A: Not many, but he is correct in that, "The number of companies that offer the plugging bonds has diminished in recent years, and anecdotally they have been requiring more collateral…" *Purvis*, WELC Ex. 30, 68:16–22. Like IPANM's financial surety expert Trevor Gilstrap and NMOGA's financial expert Doug Emerick also testified, the underwriting on plugging bonds is becoming more and more difficult, with fewer bonding companies in the marketplace. Moreover, it makes little sense to me why the State would want operators paying 10% premiums to a private company for the lifetime of the well when not a penny of those funds will ever come back into the state for plugging or reclamation. All WELC's financial assurance proposal does is increase the costs of operating a well, leaving less to repair, maintain, and plug, abandon, and reclaim the well site when the time comes.

Q: Were you able to review the testimony of OCD Witness Justin Wrinkle concerning lease operating expenses?

A: I did.

Q: What was your overall impression?

A: I found it very believable that Mr. Wrinkle was a lease operator for a large exploration and production company as his testimony reflects certain activities that occur on a well early in its life and are generally representative of certain lease operating expenses that a major company might charge and capital costs with which a large company's lease operator would be familiar. But his experience does not correlate to my own or that of the smaller independent operators who specialize in operating older wells. Also, from my review of his experience as a Production Supervisor and Lease Operator, it does not appear that he would have any practical experience in meaningful oil and gas accounting for billing working interest owners. Lease operators are generally involved in the physical, daily operation of the well, not the more complex oil and gas accounting which occurs after. I do not doubt the truthfulness of his testimony and some Mr. Wrinkle's experiences. However, I do not believe that Mr. Wrinkle's testimony is particularly accurate or helpful when it comes to lower-volume producing wells operated by smaller independent companies. Because it is this category of wells targeted by the WELC Applicants' proposed rule changes, I believe it is critical for the Commission to have balanced information upon which to support any decision which disproportionately affects the operation and economics of stripper and marginal wells.

Q: Is there a logical way to divide your testimony concerning Mr. Wrinkle's costs?

A: Yes. Mr. Wrinkle identifies a number of costs I would consider capital equipment or capital expenses, which are different from normal lease operating expenses. Although he acknowledges that certain "one-time costs" costs "*could be considered CAPEX," Direct Testimony of Justin Wrinkle, OCD Ex. 7, 2:12-16 & 4-5, and that "one-time costs can be categorized as Capital Expenditures," Mr. Wrinkle still treats these one-time costs as operating expenses with respect to marginal wells. *Id.* However, it is my experience over the past four decades that capital expenditures are treated differently from recurring lease operating expenditures in evaluating the economics of a producing well. Because of that distinction, it makes the most sense to address these expenses separately.

Q: What are those capital expenses and what are your comments?

A: Mr. Wrinkle identifies a number of capital items in his testimony. Those are generally infrastructure items, like meter installation or marketing, flare stack installation, tank installation, production vessel installation, vapor recovery units, remote monitoring, vapor recovery towers, new vessels, piping and emergency shutdown valves. All of those capital expenditures (which are depreciable expenses as opposed to normal lease operating expenses) incur at the beginning of the life of a productive well. These one-time cost items are generally recovered over the first five years of production from the well, not in the last 10 to 20 years of operation. In the industry, this is referred to as CAPEX, whereas lease operating expenses are known as OPEX. As to all of those capital items, it is possible that some maintenance or repair expense is occasionally incurred later in the well's life when it is a low volume producer. For example, an operator may elect to successfully repair a tank at a cost of $2,000 to $3,000 first, rather than replace wholesale. *Cf.* Wrinkle, Ex. 7, 4:1–9. However, as to each of those items, years can go by without a repair expenditure on those items. To the extent that there are items in that list such as the vapor recovery unit that Mr. Wrinkle testifies about, one simply does not rent that sort of equipment in the sort of wells that are primary concern and subject matter of this rulemaking, namely those that make less than 1,000 barrels of equivalent per year.

Q: What is the next category of expenses in Mr. Wrinkle's testimony in which you wish to comment?

A: There are some expenses for which he testifies that are not capital expenses, but either incurred rarely or not at all in low volume producing wells as lease operating expenses (LOE or OPEX). For example, Mr. Wrinkle estimates that a marginal well would need tanks "hot oiled" (a procedure to remove paraffins and other waste) a monthly. Given the lower production of marginals wells, I would be surprised to see a related tank hot oiled more than once a year, if that..

Q: What is the next category of costs in Mr. Wrinkle's testimony in which you wish to comment?

A: There are some costs that are applicable to gas wells and not to oil wells and vice versa. First, although one cannot make absolute statements regarding hydrogen sulfides (H2S) gas, it generally does not occur at gas wells and only occurs at some oil wells. It is not accurate to assume its presence at an "average" marginal well for the purposes of this discussion relating to marginal well profitability and lease operating expenses. Accordingly, any costs associated with monitoring equipment is often non-existent and for older wells without preexisting monitoring, workers visiting the well need to wear individual monitors which are issued by their employer and, in the event of sustained work activities, a "sniffer" or mounted monitor may be rented.

Second, compression is only a cost on some gas wells. For wells that produce low volumes of gas, the compression is usually system-wide compression on the gathering system for which there is a deduction related to the price paid by the midstream company for the gas. When the midstream company does not want to take large volumes of gas, it simply reduces the amount of compression thereby increasing line pressure and causing wells not to produce gas into the system. Thus, compression *might* be a cost for some wells, but much less likely for later-life wells and stripper oil wells.

Third, water and waste removal by truck, pipeline or otherwise is typically not an issue at gas wells, such that collective waste removal costs would be zero. For oil wells, the volume per barrel is quite variable depending upon the "oil cut" (the percentage of liquids produced that is oil rather than produced water). Additionally, water removal charges depend on the tank capacity available for the well and costs is dependent upon the proximity of the well to a salt water disposal well. Even limiting Mr. Wrinkle's "low" costs to the average marginal oil well, the resulting expense is much higher than a well producing less than 1,000 barrels of oil equivalent per year (83.3 BOE per month) would be expected to incur.

Fourth, hot oiling is a means of enhancing production from oil wells and is not applicable to gas wells. The suggestion from Mr. Wrinkle's testimony that hot oiling occurs monthly bears no relationship to any low producing oil wells of which I am aware. If a low producing oil well is subject to a hot oiling job once per year, that is frequent in my experience.

Finally, as with the presence of H2S, one cannot have hard and fast rule regarding remediation of historic spills, but those are more common on oil wells than on gas wells and are not an issue for a significant number of oil wells. In any event, this is a cost that is incurred on a one time basis and not a recurring expense.

Q: Do you have any other comments regarding the operating expenses related to marginal wells?

A: Yes. Overall, Mr. Wrinkle's estimates—for the regularly occurring OPEX applicable to marginal wells—are still much higher than my experience. For example, Field Operator expenses pegged at $1500 per day at 365 days/year is $550,000. I generally see costs at one-third of that level or less, in the $100,000 range for 50 to 75 wells. To put this in better perspective, that would be around $100-$150 per month, not $900 as estimated.

Separately, I question the value in this exercise of estimating well expenses as helpful to the Commission on the issues raised in the proposed rulemaking. I would actually agree with many of OCD's other witnesses, *see, e.g.*, Direct Testimony of Loren Diede, OCD Ex. 4 at 3-4, that wells are highly individual and independent of each other, even among the same field, formation, and operator. It makes more sense to leave the evaluation of marginal well economics in the hands of the operator and leave those operators with available capital and cash flow to plug wells as needed, applying their decades of experience. At Manzano, we've plugged over 80 wells since we started operating in New Mexico. But the WELC Applicants want the Commission to adopt rules which would arbitrarily deem a well is no longer capable of beneficial use based on some economic or production threshold, and ratchet up financial assurance levels to prematurely plug marginal wells. I want to stress again, that if the Commission were to adopt the Applicant's prorposals, they would be closing the door—forever—on profitable and beneficial opportunities, whether in enhanced recovery form existing reservoirs, new plays, and other innovations yet to be tested or developed.

Q: Do you have any final thoughts or conclusions for the Commission?

A: After reviewing the proposed rule changes and some of the testimony, this whole exercise brings the San Juan Generating Station closure to mind, which prioritized ideological agendas over the economic realities and needs of the state's citizens. That closure, achieved primarily through over-regulation and adoption of the New Mexico Energy Transition Act of 2019, resulted in the loss of hundreds of jobs and tens of millions of dollars in annual tax revenue for Northwest New Mexico schools and community colleges. Following the closure, the Central Consolidated School District in Shiprock reported a 700% increase in homelessness among its students, primarily Navajo Nation and already some of the most vulnerable students in the state, in addition to drastic decreases in enrollment, which in turn has reduced state-provided school funding.[5] In one fell swoop, the Legislature and New Energy Economy eliminated the primary economic driver in the area by closing the generating station and the associated mine, which provided jobs, property taxes, and electrical grid reliability. After the initially planned renewable replacement project defaulted, a substitute solar project is still years away and will not provide the stable, ongoing employment like the San Juan State and the San Juan Mine previously served. Here, WELC and its experts, including Mr. Purvis, unabashedly want to end oil and gas production in the State of New Mexico and have proposed changes to financial assurance and operator restrictions to do so. If the Commission indeed identifies orphan wells as a problem, the answer is not "one-size fits-none" proposed by the WELC Applicants. Instead, we should seek to implement reasonable,

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[5] *See* Hannah Grover, Fight Continues over San Juan Generating Station Replacement Resources, New Mexico Political Report (July 12, 2024), available at https://nmpoliticalreport.com/2024/07/12/fight-continues-over-san-juan-generating-station-replacement-resources/, last accessed September 14, 2025.

evidence-based "bespoke solutions"[6] that facilitate plugging wells, preferably with the millions of dollars already generated over the entire life-span of the well and collected for the purpose of conservation and reclamation.

MIKE HANAGAN

I hereby affirm under penalty of perjury of the laws of the State of New Mexico that the above statements are true and correct to the best of my knowledge, information, and belief.

DATE: 9/17/25

MIKE HANAGAN

[6] Purvis Energy Advisors, see supra note 4.