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

DIRECT TESTIMONY OF KYLE ARMSTRONG

Intervenor Independent Petroleum Association of New Mexico submits the following technical testimony of Kyle Armstrong:

Q: Please introduce yourself to the Commission.

A: My name is Kyle Armstrong. I am the President of Armstrong Energy Corporation located in Roswell, New Mexico.

Q: Mr. Armstrong, you understand that this written testimony is given under oath as if you were testifying live?

A: I do.

Q: Tell us about Armstrong Energy Corporation.

A: We are a small independent operator based in Roswell, New Mexico, founded by my father, Bob Armstrong, in 1976. We currently operate approximately 75 wells. Historically, our operations principally have been in southeastern New Mexico.

Q: Please give the Commission an idea about the origin of the wells you operate.

A: Historically, Armstrong Energy drilled vertical wells. More recently, we have acquired existing vertical wells from larger operators that are relatively low volume producers and later in their productive life. Larger producers typically put together a package of wells and sell the package as one rather than individual wells. We have bought a couple of such packages.

Q: Why do you buy well packages?

A: Larger companies may not devote engineering and technical resources to their mature, declining production unless that production will be part of a secondary or tertiary recovery unit. If those mature wells are not holding acreage or designated to be part of a unit, the larger company will often package them up and sell them. We find that many, but not all, of the wells in these packages can become more productive if subject to engineering and maintenance programs designed to address issues particular to each well, or the package wells can be operated more efficiently. However, some wells included in these packages invariably have no further potential and Armstrong Energy eventually plugs and abandons those wells.

Q: Have you read the rule proposals before the Commission?

A: Yes, I have reviewed the Amended Proposal from the Applicants as well as the Division's proposed rule.

Q: Do you have any concerns that you wish to express to the Commission and explain?

A: I do. Like many independent operators, my primary concerns pertain to the definition of marginal well and bonding requirements that would be imposed on marginal wells.

Q: Explain your concerns.

A: I have a few. First, while certain wells that we purchase in packages that larger operators sell do not produce prolifically, the wells can still be long-lived producers generating income and creating jobs for decades.

Q: Generating income for whom?

A: Extending the life of a productive well, even at lower volumes, generates revenue at the local, state, and federal level. Of course, the operator and any working interest owners in the well, but that check is cut last. First, various local service providers and equipment supply businesses are paid for work performed or related to continued operation of the wells. Then, the royalty owner, which may be the State, federal government or fee owners receives income out of related production, and finally, the State of New Mexico recovers a substantial portion of its general fund through the various forms of severance taxes imposed on all oil and gas produced in the State. The increased bonding requirements proposed by WELC and the Division would substantially increase costs to buyers and sellers of these lower producing wells, discourage these transactions, and result in noticeable revenue loss.

Q: What financial effect do you foresee?

A: Some of the wells in these packages would qualify as marginal wells under the definitions proposed. When buying a package from another operator, the purchaser must assume all operations which includes any bonding obligation associated with each well in the package.

Q: How does Armstrong Energy secure bonding for its wells?

A: We have a long-standing relationship with a surety company and pay a percentage of the face value of our bonding each year in return for our required bonds.

Q: Would you be able to do that with marginal wells if one of the rules are adopted?

A: I doubt it. I do not think that our surety company is likely to offer, on a large scale, individual well bonds which are effectively a prepayment of plugging, abandoning and reclamation costs on an individual basis. The risk of such bonds to the insurer may be too high. If the company does offer individual well bonds, I expect the costs and annual premiums to be much higher under the proposals than our current bonding.

Q: How would that affect your business?

A: We would not be able to take on certain wells that are in packages and would be less likely to take risks buying packages understanding that some of the wells would either need immediate bonding at $150,000 per well or might need increased bonding in the near future.

Q: You mentioned you had multiple concerns. What is another one?

A: I would be very concerned about the Applicant's proposal which requires, as I understand it, that once a well is designated as marginal, the bonding requirement remains in place forever. That would serve to de-incentivize the investment of capital in improving production because the money for a cash bond would be tied up for the remaining life of the well regardless of future production obtained. For example, there may be additional intervals above the existing production that are prospective for hydrocarbons. But if an operator's capital is deployed to cover increased financial assurance requirements, that cash is no longer available to either improve production or develop additional intervals. Thus, Applicant's proposal creates waste caused by the premature abandonment of a producing interval and prospective intervals in order to avoid bonding that one well. Or worse, we could reach a threshold where Armstrong would be required to have single bonds for all wells and the cost of doing so would exceed the economics of operation, forcing Armstrong to move operations outside of New Mexico.

Q: Do you have other concerns?

A: Yes. If the Commission is going to adopt any definition of marginal wells, it needs to provide for greater flexibility than either the Division or the Applicants are proposing. In particular, the definitions of marginal wells do not seem to allow exceptions where a well is capable of production at non-marginal levels but cannot for reasons outside the operator's control.

Q: Can you give an example?

A: Sure. I can think of three separate instances in the past few years where Armstrong Energy has had to shut in wells because of mechanical problems with the gathering system to which our wells were connected.

Q: First, please explain what you mean by "gathering system."

A: Every well from which natural gas is produced and sold, either as a natural gas well or an oil well from which natural gas is separated from the production stream, is connected to a single gathering system belonging to a midstream company. The gathering system is a series of pipes and related equipment that is used to transport natural gas to a market point where the producer can sell the natural gas. Those systems move the gas to a cryogenic gas plant where natural gas liquids (propane, butane, etc.) are separated from the methane stream. At the tailgate of that plant are larger pipelines where the combined liquids stream and "dry" methane stream can be sold.

Q: Thank you. Please explain the issues with these systems that affected Armstrong Energy's wells.

A: As is typical in the oilfield, many Armstrong Energy wells produce in areas where there is only one option for selling natural gas. Because these are older wells, the gas gathering systems and infrastructure are typically older too. We have had wells shut-in for many months simply because there were either capacity, mechanical problems or infrastructure problems suffered by the midstream company that, for whatever reason, the midstream company did not fix for a long period of time. In each of those three instances, we had a well perfectly capable of production above "marginal" levels. However, because there was no place to move the natural gas with the midstream facilities shut down, the well had to be shut-in until the midstream system was operational and accepting gas again. In the instances I am thinking about, some of the wells produced over a period of time at a marginal level as those terms are defined in the proposed rulemaking, because they were producing substantially less than 180 days and in lesser volumes. Those lower production levels were not because the wells were incapable of producing more or by any factor in Armstrong Energy's control, but because the problems the midstream company experienced restricted higher production.

Q: Can you provide some specifics as to one of these instances where midstream shut down wells?

A: Yes. AEC has a group of wells in northern Lea County called the Hoovers. This year, those wells were shut-in for 117 out of the first 180 days of the year because of issues with the gathering system. The system was not brought back into operational status for most of the first half of this year. The seven wells on the Hoover lease produce into a common battery, and five of those would be considered marginal as a result, averaging just 1.2 BOPD and 2.5 MCFD each, when looking at the first six months of 2025. The actual average daily production of each of these five wells since brought back online is 4.5 BOPD and 8.7 MCFD, which is above the proposed marginal threshold. Obviously, some of these wells produce more.

Q: If adopted, how would the marginal well bonding rule proposals have affected those wells.

A: In this scenario—had the proposed rules been in effect at the time—Armstrong would be without income from the shut-in wells, but still have expenses in maintaining the lease and may have to pay shut-in royalites (where the lessor is paid a royalty even though there no production). Under the rule proposals, Armstrong Energy would face an increased $150,000 bonding requirement each of those five wells. This would impose substantial financial hardship on smaller operators like Armstrong Energy.

Q: Can you explain to the Commission why an operator may leave wells unplugged for a period of years rather than months?

A: There are a number of reasons. Prior to making a decision to leave a well unplugged, an operator needs to make sure there are no mechanical integrity issues that could potentially endanger the environment or public health. However, assuming no such problems exist, there are many reasons. The foremost reason that an operator may maintain gas wells that produce at so-called "marginal" levels, without attempting to enhance production, is market based. For example, there was an extended period of time recently in the Permian Basin where prices for natural gas were extremely low and often negative—meaning that a producer had to pay to have someone take its gas.

Producers of prolific horizontal oil wells were willing to pay to have their gas taken so that they could continue to produce and sell oil. At the same time, there were also constrained takeaway issues in the Permian—with more gas was being produced than pipelines could take. Under these conditions, a producer may have to wait for better pricing before taking measures to enhance production, because neither gathering capacity nor current pricing supports that step. Most other reasons stem from the fact that New Mexico plugging requirements are quite stringent and, once plugged, there is often no economic way to re-access that wellbore, you have to drill a new well in a new location. Reasons not to plug a well would include the potential for uphole development, where a shallower formation might be productively developed. Second, possible use of the wellbore for water disposal if the need arises and the well has the capacity (and the regulatory permission) to do so. We have two salt disposal wells that came from converted producing wells. A number of operators are also now considering the utility wellbores may have for carbon capture or other energy solutions as that concept expands. Again, accessing and developing carbon capture storage using extant wellbores would be much less expensive, more efficient, with lower environmental impact than drilling new wells.

Q: If a well has uphole potential, why not develop it right away after production from the current formation is played out?

A: If you have other producing wells on the lease, you may wish to deploy capital elsewhere to more urgent projects. Also, if for instance you have three productive wells from a deep formation and one of the wells is still producing productively, you might want to shut-in the other two and wait for the third well to play out so that it is more economic to do all of your workover work all at once and not mobilize all of the workover equipment each time a well goes inactive. From a practical standpoint for smaller operators, completing into a shallower formation requires engineering geological analysis to provide to the working interest owners in the well and that work is most economically and practically done as the production from all the wells on the oil and gas lease is depleting, not just one well in isolation.

Q: Does Armstrong Energy plug any wells or does it leave wells unplugged hoping for some additional potential use?

A: We regularly plug wells. Since 2019 we have plugged and abandoned 16 wells in New Mexico.

Q: At what cost?

A: Regulatory and administrative requirements have become more stringent in recent years. Including reclamation work, we plugged four wells over the past two years at an average cost of roughly $120,000 per well.

KYLE ARMSTRONG

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: August 4, 2025

KYLE ARMSTRONG