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 ROBERT ARSCOTT, PH.D.

Q: Please identify yourself and the reason for your testimony.

A: My name is Robert Arscott. I am offering technical testimony on behalf of the Independent Petroleum Association of New Mexico ("IPANM") regarding the potential economic effects of the proposed amendments to 19.15.2, 19.15.5, 19.15.8, 19.15.9, and 19.15.25 of the New Mexico Administrative Code.

Q: Please tell the Commission about your current role and experience in the oil and gas industry and your qualifications for offering technical testimony.

A: I am a consultant at Applied Economics Consulting Group, located in Austin, Texas. My firm and I conduct economic and financial analysis for a wide variety of clients, including those in the oil and gas industry. Since joining Applied Economics Consulting Group, most of my work has been focused on economic analyses of various aspects of the oil and gas industry, including the evaluation of the costs of midstream services, the appropriate calculation of royalty payments and taxes in upstream operations, evaluation of operating and post-production costs for producers, and the valuation of various oil and gas assets ranging from mineral interests to options embedded in drilling and development agreements.

Prior to joining Applied Economics in 2023, I was an Assistant Professor of Finance at Syracuse University, where I taught courses in corporate finance and real estate, and conducted research on market efficiency, risk management, and other topics in corporate finance. I hold a Ph.D. in Finance from the University of Rochester, a Master of Science in Business Administration from the University of

Rochester, a Master of Business Administration from the University of Oxford, and a Bachelor of Business Administration from Concordia University Texas.

Q: Is it unusual to expect the amount of financial assurance to fall short of anticipated costs of plugging and abandonment ("P&A") for oil and gas wells?

A: No.

Recently, there has been considerable attention given to the fact that bond values are often small fractions of the anticipated costs of plugging a well and site remediation, prompting policy proposals to increase bonding requirements. However, as illustrated by Gerard (2000), the optimal bond amount is often less than the expected costs of remediation. This is because the forfeiture of a bond, even one in an amount equal to the expected remediation cost, is in most cases small in comparison to other costs borne by the operator should it not perform its plugging obligations.

From a social standpoint, Dachis et al. (2017) argue there is a tradeoff between the gain in economic growth accompanied by low bonding requirements and costs borne by the state when operators default. Financial assurance requirements impose costs on operators which reduce the economic incentives to produce oil and gas. Specifically, bonding and similar forms of insurance introduce transaction costs related to the underwriting of the risk associated with a particular well and operator. In some cases, transaction costs can result in total costs of financial assurance that exceed the value of anticipated P&A costs. On this point, Boomhower (2019) writes, "[a] bond requirement can inefficiently exclude some firms. Underwriting or other transaction costs increase bond prices above the insurer's expected losses, potentially excluding some firms that would otherwise operate profitably."

For some operators the only realistic financial assurance instrument is a cash bond, for which the transaction costs can be extreme. In addition to the liquidity requirement of immediately depositing the full bond amount in cash up front, the ongoing service of that cash bond is equal to the operator's cost of capital, which can be 10 percent or more per year. In addition, the operator must still pay the cash expenses associated with actual plugging and reclamation activities, effectively doubling the liquidity demands of responsible plugging and abandonment. The operator can expect to receive its cash from the bond released only after plugging has been verified by the state, which takes time – all the while the operator must continue to pay the opportunity cost associated with that capital. Those opportunity costs and liquidity demands contribute to the transaction costs associated with financial assurance. Low bonding requirements minimize those transaction costs and their associated distortions on the continued production of oil and gas.

To summarize, a bonding requirement set below the expected costs of reclamation can be socially beneficial.

Q: Besides the forfeiture of reclamation bonds, what are some other costs operators face if they fail to properly plug and abandon their wells?

A: In practice, operators face significant costs outside of financial assurance associated with failure to responsibly plug and abandon their wells. These include the loss of reputational capital, penalties resulting from non-performance, and the potential loss in future profitable operations due to regulatory enforcement. For many operators, the potential forfeiture of a bond, even one equal to the full P&A cost of a well, is likely tiny in comparison to the cost of enforcement actions such as revocation of authorizations to transport and permit denials, to say nothing of civil penalties that may be levied by the New Mexico Oil Conservation Division ("OCD"). An inability to operate would mean a complete loss of potential profit from future participation in the state's oil and gas industry, which would be significant for most operators. Additionally, operators could face litigation related to damages caused by improper abandonment. These significant costs are demonstrated by New Mexico's recent experience, as reported by the New Mexico Legislative Finance Committee (2025), that about 95 percent of plugging and reclamation activity has been performed by the operator and the remainder by the State.

In short, the potential loss of bond principal is just a part – and often a minor part – of the overall costs operators would face if they failed to plug their wells.

Q: Do the costs of reclamation vary across oil and gas wells?

A: Reports on P&A costs vary widely. According to Vertex Resources estimates, reproduced by the Center for Applied Research (2021), P&A costs scale according to the depth of the well, the number of zones accessed by the well, and various other well-specific circumstances. For example, differences may arise due to the integrity of the well, the degree of decay, and various other aspects that correlate with well age. In a recent study of the factors that affect P&A costs, Raimi et al. (2021) found that vertical depth, age, location, elevation, whether surface reclamation was performed, and whether the well produced predominantly oil or gas were all significantly correlated with the cost of reclamation. Numerous other well-specific factors are likely important in determining the liabilities associated with asset retirement, some of which offset P&A costs, such as the salvage value of equipment and the availability of carbon credits related to anticipated reduction in methane emissions.

The costs of plugging and remediation among New Mexico observations examined by Raimi et al. (2021) range from approximately $8,000 to over $1.1 million. The Interstate Oil & Gas Compact Commission (2024) reports the average costs of plugging orphan wells with Federal Funds in 2023 ranged from approximately $10,500 (in Kansas) to $586,000 (in New York). In Texas, the Railroad Commission (2024) reports plugging cost estimates according to district, ranging from an average of $5.96 per vertical foot to $46.48 per vertical foot for fiscal year 2024 (although, the New Mexico Legislative Finance Committee (2025) attributes that high end plugging cost to specific emergency incidents in District 8). Indeed, the Interstate Oil & Gas Commission (2024) reports Texas plugged 663 orphan wells with Federal funds during 2023 at an average per-well cost, without site restoration, of approximately $33,000.

Here in New Mexico, the New Mexico Legislative Finance Committee (2025) estimates state-contracted rates for plugging orphan wells to average $43.85 per vertical foot in Fiscal Year 2024. Those plugging costs were found to be highly correlated with well depth and varied considerably on a well-by-well basis, ranging from $31,000 to $778,000. Those recent estimates are also high, historically, and may not represent the typical costs of site remediation throughout the state. According to Ben Shelton (2025) of the OCD, the state's costs are approximately 10 to 15 percent higher than private industry's.

Further, the average P&A cost of orphan wells plugged by OCD, according to the New Mexico Legislative Finance Committee (2025), increased from $30,000 in FY 2019 to $163,000 in FY 2024. While some of that increase may be the result of cost inflation, two other factors are likely influencing the short-term rise in costs. First, operators have reported that the required regulatory approvals of plugging and site remediation have increasingly made the process more expensive. According to one midsize operator I have spoken with, the time spent waiting on concrete has increased substantially since 2020 and has resulted in substantially higher costs. Second, it may also be a function of the types of wells the state prioritizes for plugging, which may not be indicative of the typical well. Wells with active leaks, for example, are given the highest priority in the state's plugging program and likely have more substantial costs necessitated by the specific problems leading to their prioritization. In presentation materials regarding an OCD Orphan Well Spotlight, Ben Shelton (2025) referenced one such example, the Buckskin Federal #2 well, which was "one of the riskiest, most degraded wells OCD have ever seen."

Simply put, there is significant variation in the costs of plugging and reclamation activities across oil and gas wells.

Q: Do the proposed financial assurance requirements reflect the expected P&A costs for all wells in New Mexico?

A: In short, no. Because there is significant variation in the P&A costs across wells, the proposed amendments to financial assurance requirements would likely exceed the anticipated costs of remediation in many cases, thereby imposing an economically unjustified burden on those wells.

Q: Would it be fair to say the historical average P&A cost is a reasonable estimate of the anticipated costs of P&A for most wells?

A: Not necessarily. Aside from the fact that the average cost is, by definition, higher than the anticipated costs for a large number of wells, the distribution of historical P&A costs may be skewed by high-cost wells. That skewness could lead the average to exceed the actual anticipated costs for *the majority* of wells. Whether this issue applies to the distribution of P&A costs is an empirical question that can be answered using data on the historical costs of reclamation.

Q: What other resources besides financial assurance are available to the state to finance the remediation of orphaned wells?

A: A reclamation fund is available to the OCD to plug orphaned wells. That fund is supported not only by the redemption of reclamation bonds but also by a conservation tax of 0.19 percent to 0.24 percent levied on hydrocarbons severed and sold in the state. 19.7 percent of that tax revenue is directed to the reclamation fund when oil prices are higher than $70, and 10.5 percent otherwise. Therefore, there are additional funds, besides those resulting from bond redemptions, raised from private industry to pay for the reclamation of orphaned wells. The New Mexico Legislative Finance Committee (2025) reports the balance of the reclamation fund was over $60 million as of fiscal year-end 2024.

Several federal grants are also available to offset the costs of plugging orphaned wells. According to the New Mexico Legislative Finance Committee (2025), the state has received $55.5 million such grants to date and remains eligible for a further $111.8 million in further federal funding. Testimony by Secretary Shelton before that Committee and documents from the OCD reporting on their activity from fiscal years 2020 through 2023 suggest that bond forfeitures have rarely been pursued and revenue from forfeitures has been negligible in comparison to other sources.

Q: Will the proposed financial assurance requirements adversely impact the incentives to produce oil and gas in New Mexico?

A: Yes, the proposed rules will lower the incentives to produce oil and gas in New Mexico, and the effects will vary by operator.

For many large operators, the financial assurance requirement is likely trivial in comparison to the reputational and operational costs of defaulting on P&A liabilities. In those cases, the bonding requirement is likely to have little effect on the incentives to responsibly plug and abandon wells. Accordingly, the existing blanket coverage at a fraction of anticipated P&A liabilities is justified because it reduces the transaction costs accompanied by financial assurance requirements.

Existing rules permit single well coverage as a function of vertical depth, which has been shown to relate to the anticipated costs of remediation. The existing rules also allow for blanket coverage for larger portfolios of wells, which provides a decreasing per-well bond requirement and offers correspondingly lower distortions to operators' production incentives. While the existing financial assurance requirements do not perfectly account for individual well circumstances, they do account for well depth and inactive status, two factors that are known to correlate with the expense and timing of well retirement.

In contrast, the proposed rule applies a one-size-fits-all approach, imposing a flat $150,000 coverage requirement on all marginal and inactive wells, thus ignoring the differences in default likelihood among operators and the anticipated P&A costs of individual wells. It also ignores the costs that industry is pre-paying into the Reclamation Fund via the portion of the Conservation Tax that the New Mexico Legislature is electing to direct to that fund. This will result in the imposition of costs on some operators that exceed the fully internalized costs of operation, thereby adversely distorting the incentives for continued production. Put another way, it will result in waste of otherwise economically producible oil and gas in those cases.

The adverse effects on the economic incentives to produce oil and gas will be most pronounced in low-producing wells but will also extend to more productive properties as well. The proposed amendment to 19.15.8.9(D) would result in a significant jump in financial assurance expenses associated with even high-producing active wells in the event an operator's marginal and inactive wells account for more than 15 percent of their total portfolio. Under the proposed rule, all wells operated by an operator with more than 15 percent marginal and/or inactive wells would be subject to a bonding requirement of

$150,000 per well. Accordingly, the incremental cost associated with an additional marginal or inactive well will be astronomical if it results in an operator breaching the 15 percent threshold.

Q: Please provide an example to illustrate how the proposed 15 percent threshold might affect the incentives to produce oil and gas.

A: An operator with eight highly productive active wells, one older well with less production, and a single inactive well would require bonding in the amount of $400,000 under the proposed rule ($150,000 for the inactive well and $250,000 blanket coverage for the other nine wells). If, however, just one of the nine active wells were to decline into marginal status, 20 percent of the operator's wells would be classified as marginal and/or inactive, thereby triggering the increased bonding requirement of $150,000 for all ten of the operator's wells. The financial assurance requirement would therefore immediately increase to $1.5 million, an increase of 3.75 times. Consequently, the ongoing costs of financial assurance would also increase by at least 3.75 times and possibly more if bond premiums increase with coverage amounts. As a result, the proposed 15 percent rule would increase the financial assurance requirements for active, highly productive wells, for which the current risk of improper abandonment is low.

Q: Will the proposed rules affect the marketability of marginal and inactive wells?

A: The proposed rules will reduce the marketability of marginal and inactive wells. The steep incremental cost of an additional marginal or inactive well will be such that operators will expend considerable effort to avoid breaching the 15 percent threshold if possible. The demand for wells in or nearing marginal status, as defined by the proposed rule, will likely be substantially reduced. As a result, operators looking to sell such wells may find little interest from potential buyers, which would lead operators to prematurely plug such wells. In the example above, plugging a single well to avoid the significant increase in financial assurance expense is perhaps a feasible option, assuming the operator could arrange for plugging services, which would certainly be in high demand. Although the ability of operators to adjust to the 15 percent threshold will likely vary according to the number of marginal and inactive wells that they operate.

Q: In what circumstances would an operator find it difficult to respond to the proposed 15 percent threshold?

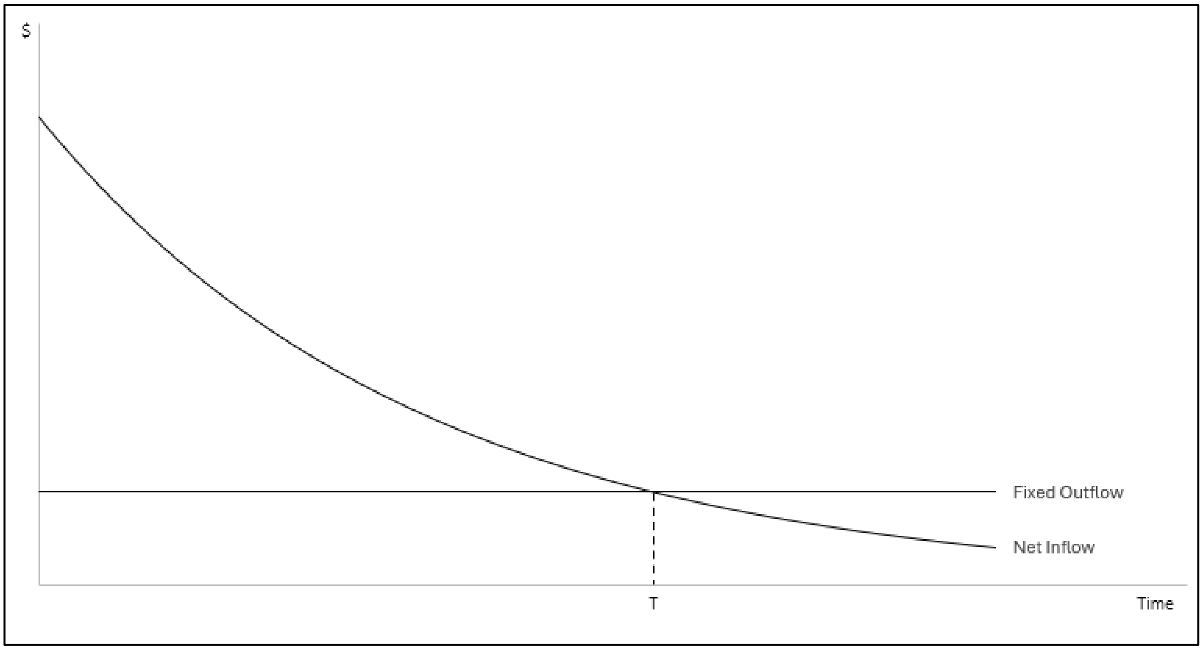
A: For operators who presently operate a significant number of marginal and inactive wells, the likely adverse effects on the market for those wells will be significant. To illustrate, an operator with five marginal wells and five non-marginal wells under existing rules would require financial assurance in the amount of $50,000 for blanket coverage. Under the proposed amendment, that operator's financial assurance would immediately increase to $1.5 million. The operators considered in this and the earlier example would have identical financial assurance amounts under the proposed rule despite the fact that one operator has 80 percent higher-producing, active wells, while the other has only 50 percent.

While the first operator may find it feasible to simply plug the single marginal well to remedy the spike in its bonding requirement, the second operator must sell or plug all five of its marginal wells to accomplish the same. If that operator is unable to sell those wells, which again may be difficult considering the likely effect the proposed rule would have on the demand for such wells, the alternatives would be to either plug the wells immediately, pay the increased financial assurance, the costs of which make that option unlikely, or to cease operating in New Mexico.

Q: Why would the proposed rule change lead to premature abandonment of oil and gas wells?

A: The proposed increase to the costs of financial assurance will reduce the expected economic life of oil and gas wells. The effect will be most pronounced in low producing wells, for which fixed costs are large relative to expected revenues from continued oil and gas production. Revenue from sales of oil and gas produced from a well declines over time as reserves are depleted. Net cash inflows, defined as gross sales revenue less variable costs, represent the economic benefit associated with operating a well. However, while variable costs fluctuate with production volume, fixed costs, or outflows, remain more or less constant. IPANM Exhibit 1 provides a graphical illustration of net inflows and fixed outflows of a hypothetical well over time.

1 IPANM Exhibit 1

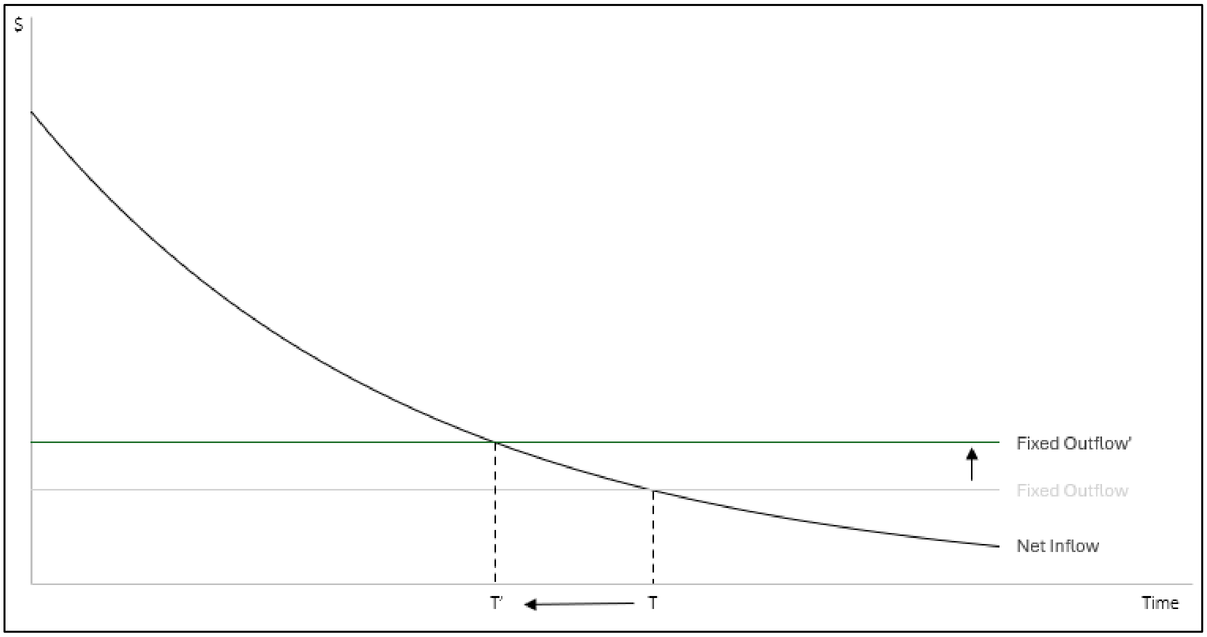


For most of a well's economic life, net inflows exceed the fixed outflows necessary to maintain the well's operation. However, at some point (T), net inflows will drop below the level of fixed cost, at which point the well becomes unprofitable and the operator has a strong economic incentive to plug and abandon the well. Accordingly, the well's economic life typically ends shortly after that point.

Barring unforeseen events, such as mechanical failure, that prematurely end a well's life, the timing of plugging and abandoning a well is the decision of the operator, who plugs a well when the value of anticipated benefits, including any option value, are exceeded by the well's anticipated costs.

Financial assurance requirements are fixed costs; they must be paid each period regardless of production volume. The proposed amendment to financial assurance requirements will increase the fixed costs necessary to operate oil and gas wells in the state. As a result, wells will be plugged earlier as operators revise their decision-making regarding the timing of plugging and abandonment. IPANM Exhibit 2 presents a graphical illustration of this point.

2 IPANM Exhibit 2



As a result of increased financial assurance costs, the depicted well will reach its economic limit at time T', not T. In practice, the magnitude of this reduction in economic life will be determined by market factors including interest rates and commodity prices, and the individual circumstances of a well, such as the rate of production decline, variable costs, fixed costs, and the required risk premium. However, the increase in financial assurance-related costs will certainly result in some decrease for all wells. For an analysis of how those factors affect the optimal timing of plugging a well, see the model submitted as Appendix A to this testimony.

As part of my research on this issue, I interviewed several independent operators here in New Mexico. Circumstances reportedly vary from well-to-well, leading to a wide range in operating costs. Monthly operating expenses for gas wells were reported to range from $1,200 - $2,000 per month for conventional flowing wells, $2,500- $4,000 if compression is required, and $3,500- $5,000 for coalbed methane wells. Oil wells were reported to carry higher operating expenses of up to $14,800 per month. Many of those costs, such as electricity, labor, equipment rentals, insurance, and bond expense, are relatively fixed in nature.

The proposed rule would result in a steep increase in the costs of financial assurance, and therefore the fixed costs of operation, which would be economically unjustified and excessive for many wells. In those cases, the effect of the proposed rule would lead those wells to be prematurely plugged, resulting in the loss of reserves that would otherwise be extracted.

As previously noted, the 15 percent threshold of marginal and/or inactive wells resulting in the requirement to bond all wells at $150,000 would lead to significant increases in the fixed costs of operating in some cases, further incentivizing operators to prematurely plug wells.

Q: Why shouldn't all inactive and marginal wells be plugged immediately?

A: It would be incorrect to assume the only reason for delaying the plugging of inactive and low-producing wells is due to avoidance or delay in the costs of remediation. The industry has seen multiple technological improvements that have resulted in the operational and economic rejuvenation of once-idle properties. Secondary (and tertiary) extraction methods have improved production efficiency from legacy wells in ways that were unforeseen decades ago. It is difficult to predict if or when the next technological advancement will occur; but, that uncertainty does not mean that there is no expectation that future innovation can revitalize an old field. While that possibility exists, inactive and marginal wells have an option-like value associated with future production possibilities. And, that value would be permanently extinguished if the well is plugged.

One should not ignore the real option value associated with some inactive and low-producing wells and the possibility that those wells can and do create significant value. In some cases, that could be the result of technological innovation. In others, that value might arise through additional capital investment to rework the well, recomplete the well into an alternative formation, or more active management through wireline or other activities aimed to stimulate production.

In researching the value of such wells, I downloaded monthly production data from Enverus for every vertical oil and gas well in New Mexico. I did not restrict the analysis to wells on state and private fee lands because my intent was to determine the value of wells categorized as marginal, regardless of where in the state they are located. I focused on vertical wells as they are more likely older on average than directional or horizontal wells, and therefore more likely to be nearing the end of their productive lives. I then filtered those wells to the subset that were active at some point in the 12 months preceding the end of June 2017. From that set, I identified wells that would have been classified as marginal according to the proposed amendment to 19.15.2.7(M)(2)- *i.e.* "*an oil or gas well that produced less than 180 days and less than 1,000 barrels of oil equivalent within a consecutive 12 month period*." I removed wells which had fewer than 24 months of production history to avoid counting recently completed wells. I then recorded the subsequent production of those wells in the years since.

The results of this analysis are presented in IPANM Exhibit 3. I have summarized the current status of those wells and their production measured in barrels of oil equivalent ("BOE") between July 2017 through November 2024.

3 IPANM Exhibit 3

BOE Production per Well	Total BOE Jul-17 to Nov-24	Number of Wells	Plugged and Abandoned	Temp. Abandoned	Inactive	Active
0 to 999	418,584	6,260	2,561	146	1,264	2,287
1,000 to 4,999	2,296,674	892	147	5	133	607
5,000 to 9,999	2,564,045	356	30	1	22	303
10,000 to 49,999	5,818,957	309	7	-	15	287
50,000 to 99,999	1,418,270	21	1	-	-	20
>100,000	1,098,463	6	-	-	1	5
Total	13,614,993	7,844	2,746	152	1,435	3,509

There were 6,260 wells that produced less than 1,000 BOE over the time period or did not have monthly production data in the years after June 2017- implying that few, if any, of those wells returned to meaningful production. 2,561 (41 percent) of those wells are listed as having been already plugged and abandoned.

Next, I observed that 892 wells produced between 1,000 and 5,000 BOE (averaging about a single BOE per day). Despite being relatively low producing, those wells collectively produced approximately 2.3 million BOE after the point at which they would have been classified as marginal under the proposed rule. Only 138 of those wells are currently listed as either inactive or in temporary abandonment status; the rest are either classified as active or have already been plugged.

There were 356 wells that produced between 5,000 and 10,000 BOE each, averaging a little over 2.5 BOE per day. Collectively, those wells produced more than 2.5 million BOE between July 2017 and November 2024. Of those 356 wells, 30 have been plugged, while 303 of the remaining 326 wells (or 93 percent) are currently classified as active.

The remaining three groups of wells could be classified as high-producing relative to the sample as a whole. There were 309 wells that produced between 10,000 and 50,000 BOE, averaging nearly 7 BOE per day. There were 21 wells that produced between 50,000 and 100,000 BOE, averaging nearly 25 BOE per day. Lastly, six wells accounted for nearly 1.1 million BOE, averaging over 67 BOE per day.

Collectively, these wells produced over 13.6 million BOE after the point at which they would have been classified as marginal. Had these wells been subject to the proposed rules, they would have experienced a significant increase in their required financial assurance. Certainly, many of those wells may indeed require closer examination to determine whether the ongoing costs of operation and/or delayed plugging are being fully internalized by their operators. However, the existing rules already allow for enforcement actions specific to idle wells. And it is undeniable that many of those wells are genuinely productive, generating substantial economic output, benefits to landowners, and tax revenue to the state. The proposed rules would likely result in many of those wells being plugged and abandoned prematurely.

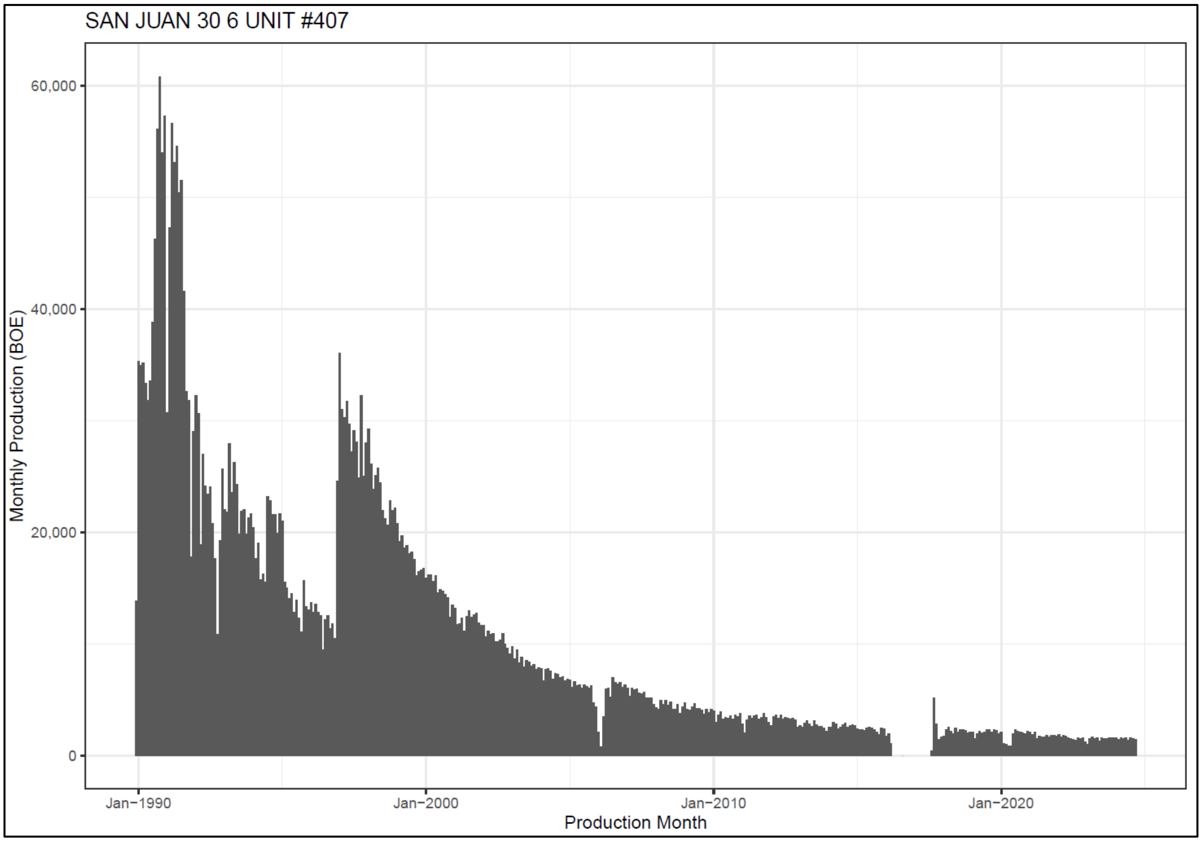
In short, the proposed rules will likely result in the premature plugging of oil and gas wells, resulting in the waste of hydrocarbons that would otherwise be extracted by an economically rational operator.

Q: Can you provide specific examples of wells that might have been plugged prematurely under the proposed amendments?

A: Several wells in my analysis offer interesting case studies in the lifecycle of wells that could be classified as marginal, or even inactive, far before the end of their economic lives. Some would have been classified as marginal during a temporary interruption to an otherwise consistent production profile. Others would have been classified as marginal due to cessation of production related to recompletions or other investments to increase production. Available information on the exact circumstances of each well is incomplete, but records clearly indicate significant production from each of these wells past the point at which they would have been classified as marginal under the proposed rules.

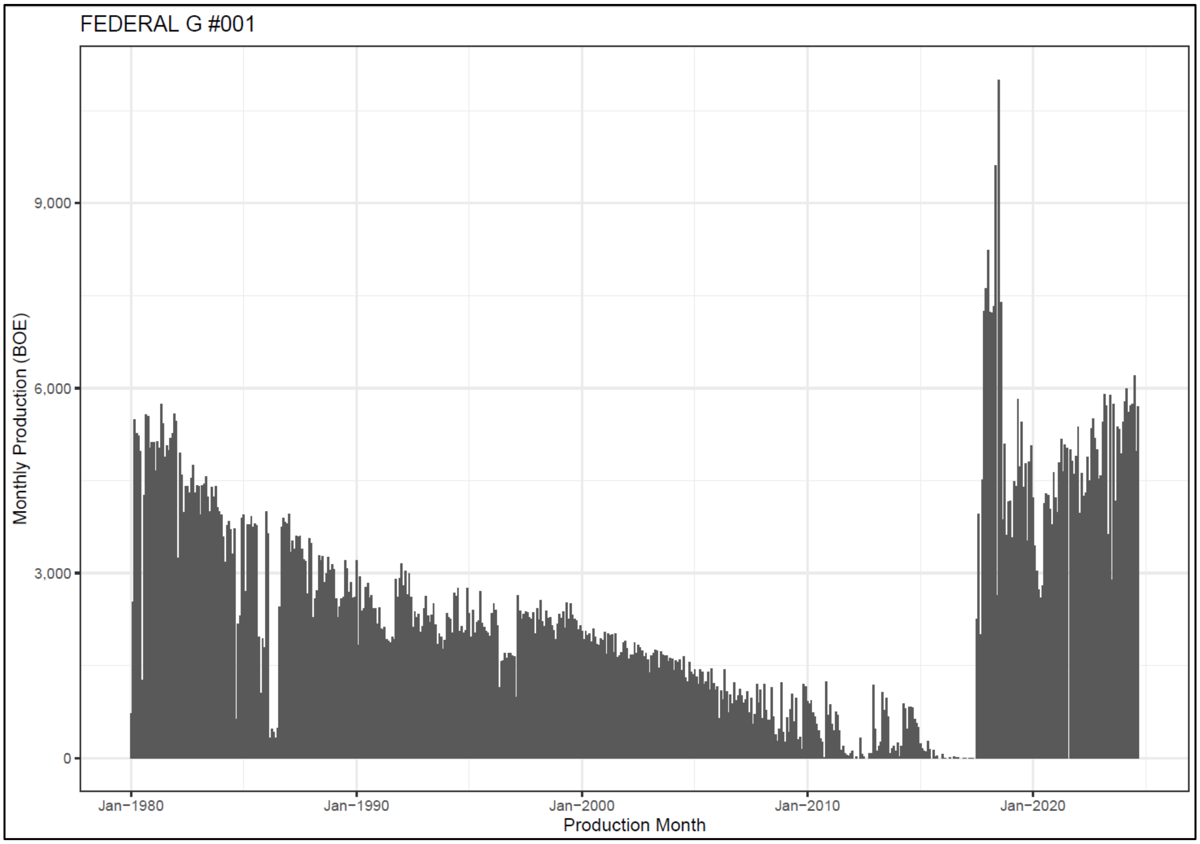
IPANM Exhibit 4 depicts the production history of the San Juan 30 6 Unit #407 well. The brief cessation of production during 2016 would have reclassified this well as marginal, thereby raising the required costs of financial assurance under the proposed rule. This period of inactivity predated a recompletion in 2017. However, had the reclassification into marginal status resulted in a breach of the 15 percent threshold, this well might not have received additional capital investment and may have subsequently been plugged to avoid the resulting spike in financial assurance costs across every applicable well in the operator’s portfolio.

4 IPANM Exhibit 4



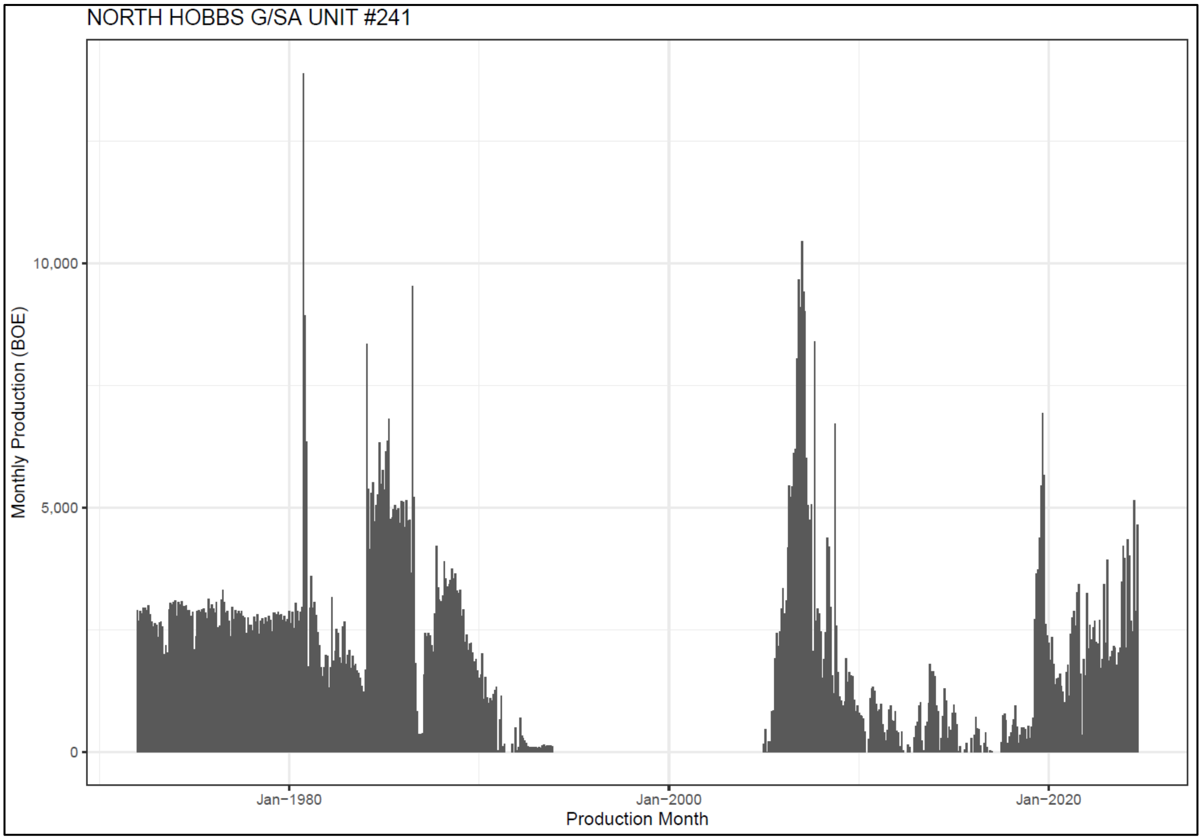
IPANM Exhibit 5 depicts the production of another exemplar well- the Federal G #001 well. It provides an example of a well that could have been prematurely plugged had it been located on state lands and therefore subject to the proposed rule. If one examines only the production history of this well in the five years prior to 2017, it could have been argued that its continued productive value was outweighed by the supposed costs of delayed plugging. Indeed, the reasons for leaving such a well unplugged might have been considered "speculative purposes," which the proposed amendment to 19.15.2.7(B)(5) would explicitly exclude as a "beneficial purpose" or "permitted use." Instead, it is a prime example of a low producing or even inactive well having valuable productive potential for years despite its classification.

5 IPANM Exhibit 5



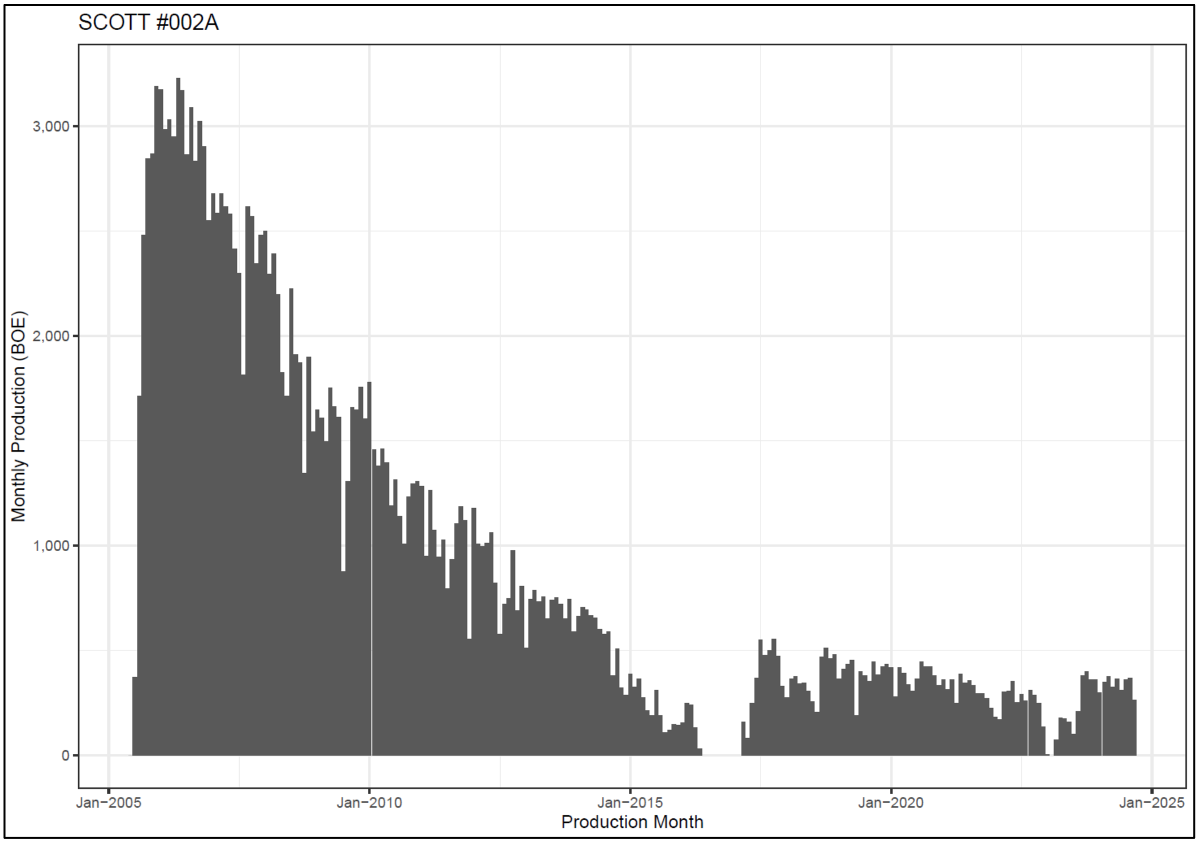
Even wells that have been inactive for years can be returned to productivity. IPANM Exhibit 6 depicts the production history for the North Hobbs G/SA Unit #241 well, which experienced multiple periods of relative inactivity. Prior to 2003, the well had been idle for nearly five years, after which it was returned to significant productivity. The well subsequently experienced waning production in the 2010s, when it once again would have been classified as marginal. However, the well has been producing between 2,500 and 5,000 BOE per month for the last several years. Had this well been subject to the proposed rule, it might have been plugged long ago. While the available information is incomplete, this well appears to have become a restimulated producer in a CO_2 flood, also known as tertiary recovery.

6 IPANM Exhibit 6



Other examples illustrate moderate production improvements following a change in operator management. IPANM Exhibit 7 depicts the production profile of the Scott #2A well. This well was purchased in 2016 by San Juan Resources. After the well was transferred, production increased to a moderate, but sustained level of around 250-500 BOE per month. This well may not be as prolific a producer as some of the preceding exemplars, but as is evident in my analysis, the collective production of many such wells can be significant and operators with the proper financial incentives can devote money to recovering additional valuable oil and gas.

7 IPANM Exhibit 7



Q: How will the proposed rules affect the typical bonding requirement for various operators?

A: To examine the effects of the proposed financial assurance requirements on operators, I reviewed production records of vertical wells from Enverus. I assigned a marginal classification to wells according to the proposed rules using the 12-month period prior to November 2024. I determined the amount of financial assurance for each operator's wells located on state and private fee lands according to the existing and proposed rules. Details on the number of marginal wells, as defined under the proposed rules, and well depth were considered in those calculations. It should be noted that this analysis only considers vertical wells, which underestimates the total number of wells per operator, especially for larger operators. Nevertheless, the analysis provides an indication of the anticipated effects on bonding amounts per well for various categories of operators.

IPANM Exhibit 8 presents a summary of that analysis. A total of 376 operators were found operating at least one vertical well on state or private fee lands during November 2024. Of those, 61 operated only a single well. For those operators, the required bond amount under the existing rules equals an average of approximately $39,000 per well. Under the proposed rules, the average bond amount would increase to $150,000, more than 3.8 times the existing requirement.

8 IPANM Exhibit 8

Number of Wells per Operator	Number of Operators	Average Number of Wells per Operator	Average Bond per Well (Existing Rules)	Average Bond per Well (Proposed Rules)
1	61	1	$39,117	$150,000
2 to 10	130	5	$27,836	$101,163
11 to 50	94	26	$10,653	$63,899
51 to 100	32	70	$5,120	$51,145
101 to 500	43	228	$3,092	$51,965
>500	16	1,730	$900	$38,402

A total of 130 operators were found to operate between 2 and 10 wells each. Those operators would see a similar percentage increase in the average bond amount per well, increasing from nearly $28,000 under the existing rules to over $101,000 per well under the proposed rules. These two groups contain the smallest operators, who operate many marginal and/or inactive wells. As a result, much of the increase in bond amounts for these operators can be attributed to the proposed rule specifically affecting those types of wells.

Next, operators with between 11 and 50 wells would see average bond amounts per well increase almost six times, from $11,000 under the existing rules to approximately $64,000 under the proposed rules. Again, the number of marginal and idle wells drives most of that increase. That average increase in bonding requirement understates the increase for operators who have greater than 15 percent marginal and/or inactive wells. For example, if an operator in this category breaches the 15 percent threshold, its per-well bonding requirement under the proposed rules would increase to $150,000 for all wells, an increase of 14 times the average requirement of nearly $11,000 under the existing rules. For an operator with the group-average of 26 wells, breaching the 15 percent threshold would result in a total bonding requirement of $3.9 million.

Operators of fewer than 51 wells each represent three-quarters of the number of operators in the sample. As they are the smallest operators on a per-well basis, they are also likely to face the highest bonding costs and therefore least able to afford the proposed financial assurance requirements.

Larger operators are projected to see significant increases as well; however, those operators are more likely to be well-capitalized and better able to adapt to the proposed rules by plugging marginal and inactive wells to avoid the steep increases associated with the 15 percent threshold. Although, there are additional concerns regarding the practicality of plugging so many wells in as short a time as possible.

To summarize, the proposed rules will significantly increase the bonding requirement for most operators. For those operating fewer than 51 wells each, the average bonding requirement will increase by approximately four to six times. However, increases will be more severe in many cases as those smaller operators often operate portfolios that include a significant percentage of marginal and /or idle wells, which would increase bonding requirements even further.

Q: How much will the costs of financial assurance increase because of the proposed rule?

A: If financial assurance is obtained through the issuance of a letter of credit or surety bond, the ongoing costs of that financial assurance take the form of fees or bond premiums. According to one provider in the state, premiums on surety bonds may range from 1 percent to 10 percent per year, depending on the operator's creditworthiness and operational risk.[1] At those rates, the cost of a surety bond with $150,000 of coverage would range between $1,500 and $15,000 per year. Although, Boomhower (2019) cites instances of higher surety bond premiums exceeding 10 to 15 percent for operators deemed to be high-risk.

Alternatively, financial assurance requirements may also be satisfied using a cash bond. Unlike a surety bond, a cash bond requires the amount of coverage to be paid in cash up front. In that case, the associated ongoing cost is the opportunity cost of capital tied up to secure a cash bond. The opportunity cost of capital in the business of oil and gas extraction is likely to exceed expenses on a surety bond. In a survey conducted by the Society of Petroleum Evaluation Engineers (2025), respondents' median discount rate for proved developed producing oil and gas reserves was 10 percent. At that rate, the opportunity cost of securing $150,000 of coverage via a cash bond would be $15,000 per year.

Among the six operators I interviewed, only two had reserve-based loan facilities, which indicate good access to credit markets. Those operators also had the lowest financing expenses related to their

[1] Oil and Gas Surety Bonds in New Mexico, suretynow.com, Accessed 17-Jun-2025.

financial assurance, reporting rates of two and three percent on surety bonds. In contrast, other operators reported higher financial assurance costs ranging from 4 to 10 percent per year.

The smallest of the operators I spoke with reported limited access to surety bonds or similar products and instead satisfied the financial assurance requirements on their wells through cash bonds. The reasons that limit access to the surety bond market also apply to the ability to secure debt financing generally. Operators with few assets suitable for collateral are often financially constrained, with limited access to debt financing such as the revolving credit facilities through which performance letters of credit could be issued. Larger, more diversified operators may face fewer financial constraints, and are therefore better positioned to finance the bonding requirement for marginal and inactive wells. However, those operators may lack the specialized cost structures or incentives to acquire low-producing wells for which the bonding requirements are prominent costs. Regardless, the proposed rules would significantly reduce demand for such wells, making a reallocation of marginal wells from smaller operators to larger operators unlikely. Many marginal wells would instead be plugged prematurely.

The proposed $150,000 financial assurance requirement at a 10 percent required rate of return would add $15,000 annually to the fixed costs for an operator satisfying financial assurance with a cash bond. To put that cost in perspective, consider an operator with a 5,000 vertical foot marginal oil well. Under the existing rules, that operator could satisfy the financial assurance requirement with a single bond in the amount of $35,000. Under the proposed rule, that same well would require a $150,000 bond, regardless of the well's depth and anticipated costs of remediation. At a 10 percent cost of capital, the economic cost associated with a cash bond for that well would increase from $292 per month under the existing rule to $1,250 per month under the proposed rule. Assuming lease operating expenses of $1,500, $2,500, and $5,000 per month, the increase in financial assurance expense corresponds to increases to monthly operating costs of 64 percent, 38 percent, and 19 percent, respectively. Even considering financial assurance costs at a rate of only 2 percent for a surety bond, which is likely too low for many operators if one considers insurance providers may adjust rates upward to account for larger coverage amounts, the monthly cost of financial assurance would increase by $192. Again, assuming lease operating expenses of $1,500, $2,500, and $5,000 per month, that change in financial assurance corresponds to increases of 13 percent, 8 percent, and 4 percent in the monthly cost of operating the well.

Considering operators of marginal wells likely specialize in low-margin assets, that increase could immediately wipe out the economic incentive to continue operations for many wells. Indeed, one of the operators I interviewed stated his business had gross margins of 10 to 15 percent. Even an increase of 10 percent to the operator's cost structure may be sufficient to completely eliminate the economic incentive to continue operation in some cases.

IPANM Exhibit 9 presents the magnitude of the bonding cost increase under the proposed rules for the average single-well operator depicted in IPANM Exhibit 8. Calculations assume bond returns ranging from 1 to 10 percent. Cost increases are expressed as percentages above three assumed monthly lease operating expenses: $1,500, $2,500, and $5,000.

9 IPANM Exhibit 9

Increase in Average Bond Amount per Well	Assumed Bond Req'd Rate of Return	Increase in Bond Cost per Month	% Increase Assuming LOE of $1,500	% Increase Assuming LOE of $2,500	% Increase Assuming LOE of $5,000
$110,000	10%	$917	61%	37%	18%
$110,000	9%	$825	55%	33%	17%
$110,000	8%	$733	49%	29%	15%
$110,000	7%	$642	43%	26%	13%
$110,000	6%	$550	37%	22%	11%
$110,000	5%	$458	31%	18%	9%
$110,000	4%	$367	24%	15%	7%
$110,000	3%	$275	18%	11%	6%
$110,000	2%	$183	12%	7%	4%
$110,000	1%	$92	6%	4%	2%

Under these assumptions, the proposed rules would add between $92 to $917 to monthly operating expense for the well, depending on the cost of the bond. For a well with a baseline operating expense of $1,500 per month, the proposed rule would increase those expenses by 6 to 61 percent. At a baseline of $2,500 monthly operating expense, those same bond-related cost increases would represent between 4 and 37 percent. At a baseline of $5,000 monthly operating expense, cost increases would represent between 2 and 18 percent. However, the rates for these single-well operators are likely higher than 5 percent, and closer to 10 percent if a cash bond is required. At those rates, the proposed rules would add approximately $458 to monthly operating expenses, which would represent a significant increase for single-well operators with baseline operating expenses of $5,000 or less per month.

In summary, the costs of financial assurance will increase significantly under the proposed rule. The magnitude of that increase will depend on the required rate of return on operators' bonds and the increase in bonding amounts required of the operator, which in turn depend on the number and composition of wells in the operator's portfolio. On a percentage basis, the increase to an operator's monthly operating expense resulting from the proposed rules will depend on the level of current lease operating expenses, with low-cost wells reflecting the largest percentage increases.

Q: Which types of wells and operators will be most affected by the proposed rules?

A: The effects of the proposed amendment to the financial assurance requirements in 19.15.8.9 will likely be most pronounced in wells for which the fixed costs of operation are large in relation to the net revenue generated from continued production. In other words, stripper wells. According to OCD records, there are hundreds of operators of wells producing less than 10 barrels of oil equivalent per day.[2]

Those operators include smaller, independent producers that are locally owned and operated businesses that specialize in the production of oil and gas from low-producing wells. For example, Dugan Production, a privately owned, independent oil and gas producer located in Farmington, NM which employs 185 people, operated 695 stripper wells according to OCD data for production year 2020.[3] Per Dugan, it "attributes most of its growth and success to the ability to take marginal wells and restore them to profitable production." A similar ability or specialization in the management of marginal wells is commonly cited as critical for efficient operations of those assets according to the operators I have interviewed.

According to the US Energy Information Administration (2016), stripper wells usually have low ongoing maintenance costs and may be kept active for years provided they are economically feasible. The operators I have spoken with echoed that statement, insisting that stripper well operators survive through attention to detail and a focus on cost. Specifically, stripper well operators do not have the same levels of overhead costs that burden most major oil and gas companies and also have the financial incentive to perform individualized analysis of each well in their portfolio.

A natural concern is that the specialization of stripper well operators is not the result of cost efficiencies, but rather an exploitation of the judgment proof problem-*i.e.*, financially distressed firms operating assets that would not be economically viable but for the failure to fully internalize the costs of their actions. However, it would be unfair to characterize all small, independent operators as such.

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[2] OCD Statistics, https://www.emnrd.nm.gov/ocd/ocd-data/statistics/
[3] OCD Statistics, https://www.emnrd.nm.gov/ocd/ocd-data/statistics/

Indeed, stripper wells contribute a non-trivial proportion of the state's overall production of hydrocarbons. As of production year 2023, the Energy and Information Administration (2024) estimated that stripper wells, defined as those that produce less than 10 BOE per day, represented 71 percent of gas wells and 13 percent of overall gas production in New Mexico.

Q: Does the proposed rule accommodate financially constrained operators?

A: The financial assurance requirements contemplated in the proposed amendment to 19.15.8.9 will most significantly raise the cost of operating stripper wells that are generally operated by smaller producers with financial constraints and are the least likely to survive that burden. Further, unlike severance and ad valorem taxes, which scale with the value of produced hydrocarbons, the proposed increases to financial assurance costs are fixed, therefore providing no relief to struggling operators in low price environments. Operators are unable to pass the costs of financial assurance onto non-operating working interest owners in those wells. And, as a result, some will be driven into insolvency, which could exacerbate the orphan well problem for the State.

For smaller independent operators, the financial assurance requirement is likely more important in addressing the moral hazards of limited liability. However, the one-size-fits-all proposed rule for marginal and inactive wells would not accommodate financially constrained operators in the short run. Responsible operators may be rendered insolvent because of the increased liquidity demands resulting from the proposed rules. That could, in turn, reduce the amount of private funds available for plugging. Said another way, the proposed rules may eliminate responsible operators and ultimately lead to fewer private funds devoted to the plugging of oil and gas wells in New Mexico.

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August 8, 2025

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Date

Appendices

Appendix A: A model relating fixed operating costs and the economic life of an oil and gas well

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Appendix A

A model relating fixed operating costs and the economic life of an oil and gas well

An operator's investment in an oil and gas well can be valued as the net present value ("NPV") of expected cash flow arising from operation of the well. For simplicity, consider a well that has already been drilled, so that the capital investment made in drilling and completing the well is sunk. For further simplicity, hold all prices fixed throughout the life of the well.[1] The expected cash flows are equal to the expected cash inflows (revenues from the sale of produced hydrocarbons) less expected cash outflows (taxes, royalties, capital investment, lease operating expenses, marketing deductions, and various other costs associated with the production and sale of produced hydrocarbons). Cash outflows can be split into three categories: periodic fixed outflows, periodic variable outflows, and plugging & abandonment (P&A) costs.

Variable outflows fluctuate with the volume of hydrocarbons produced. Examples of these include royalties, severance taxes, and certain variable lease operating expenses. Fixed outflows, on the other hand, do not vary with quantities produced. An example of this type of outflow is the cost of financial assurance, which must be paid regardless of the quantity of hydrocarbons produced. Irregular cash flows related to additional capital expenditure (e.g., well workovers or replacement of equipment) could be included in fixed cash outflows if one were to establish a sinking fund into which regular deposits were made to pay for such items. P&A costs must be paid at the end of a well's life, when the well is plugged and abandoned.

Cash inflows and variable outflows both fluctuate with the quantity of hydrocarbons produced from the well. Accordingly, they may be net from one another and expressed as 'net inflow.' Holding prices constant, net inflow varies according to the expected growth in production, which declines over time as oil and gas are extracted. Assuming exponential decline in production (not an uncommon assumption made by petroleum engineers in the projection of future oil and gas production), the rate of growth in net inflow is equal to the constant rate of decline in production.[2]

The present value of expected net inflows is equal to the present value of a growing annuity with an initial level of net inflow per unit of time equal to y, a required rate of return equal to r, a growth (decline) rate equal to g, and a time of expiration (i.e. the expected life of the well) equal to T. With continuous compounding, the present value of expected net inflows may be expressed as follows:

$$Value\ of\ Net\ Inflows = \frac{ye^{-g}}{e^{r-g}-1}\left(1 - e^{(g-r)T}\right)$$

Similarly, the present value of fixed outflows can be valued as a continuously compounded annuity, but without growth. Letting the fixed outflow per period equal x, the present value of fixed outflows may be expressed as:

[1] Stochastic prices conceivably affect the economic life of a well through the value of real options, such as delaying plugging and abandonment of an unprofitable well in the hope that future oil prices may rise. Such options likely extend the economic life of a well beyond that implied by this model. However, stochastic prices are not necessary to illustrate the effect of increasing fixed operating costs on the life of a well.

[2] The society of Petroleum Evaluation Engineers, 42nd Annual Survey of Parameters Used in Property Evaluation, June 2023, pp. 18-19.

$$Value\ of\ Fixed\ Outflows = \frac{x}{e^{r} - 1}(1 - \ e^{-rT})$$

The present value of the lump sum P&A costs, represented by z, which are paid at time T when the well reaches the end of its economic life, may be expressed as follows:

$$Value\ of\ P\&A\ Costs = ze^{-rT}$$

The sum of these three present values is known as the NPV, which equals the expected economic gain or loss associated with the operation of the well. The NPV may be expressed as follows:

$$NPV = \frac{ye^{-g}}{e^{r-g} - 1}\left(1 - \ e^{(g-r)T}\right) - \frac{x}{e^{r} - 1}(1 - \ e^{-rT}) - \ ze^{-rT}$$

The NPV may be periodically calculated by the operator at any time in order to incorporate up-to-date information regarding expected cash flow, production decline, and the required rate of return. Barring some unforeseen event that prematurely ends the well's life, the decision of when to plug and abandon the well lies with the operator. At some point, the NPV of the well will have declined to a point at which the operator will have an economic incentive to plug and abandon the well. Accordingly, the operator chooses time T, such that the NPV of the well is always maximized. Taking the first derivative of the NPV formula with respect to T and solving for T yields the optimal time to plug and abandon the well.[3]

$$T^{*} = \frac{1}{g}\ln\left(\frac{r\left(\frac{x}{e^{r} - 1} - z\right)}{\frac{ye^{-g}}{e^{r-g} - 1}(r - g)}\right)$$

From the above, the time until plugging and abandonment of a well strictly decreases as expected fixed outflows increase.[4] Therefore, an increase to the expected fixed outflows associated with operating a well will decrease the well's economic life. The degree to which a change to fixed outflows will affect a well's economic life varies with the value of P&A costs, the required rate of return, and the current level of fixed outflows. This is illustrated by taking the first derivative of T^{*} with respect to x, shown below:

$$\frac{dT^{*}}{dx} = \frac{1}{g\ (z(1 - \ e^{r}) + x)}$$

As an example, consider a well in which the periodic net inflow is initially equal to \$100, the expected rate of decline is negative 5% per year, the required rate of return is 10% per year, the P&A cost is equal to \$100, and the periodic fixed outflow is equal to \$70. Under these assumptions, the NPV of the well is maximized when the well is plugged and abandoned in 10.9 years. This can be verified graphically when plotting the NPV for various times until P&A, as depicted below.

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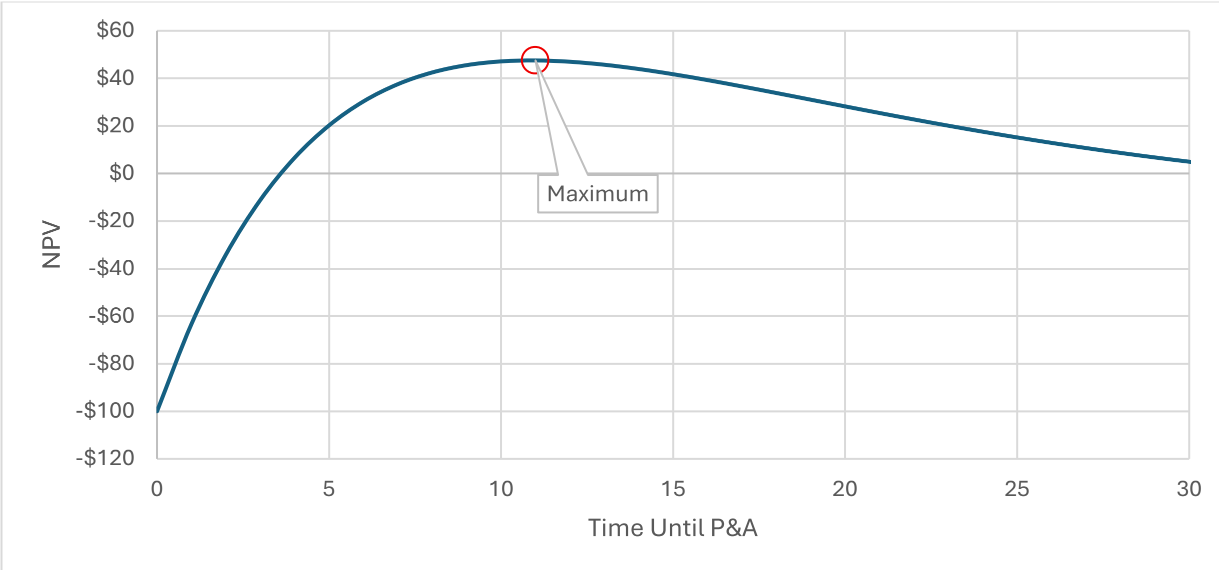
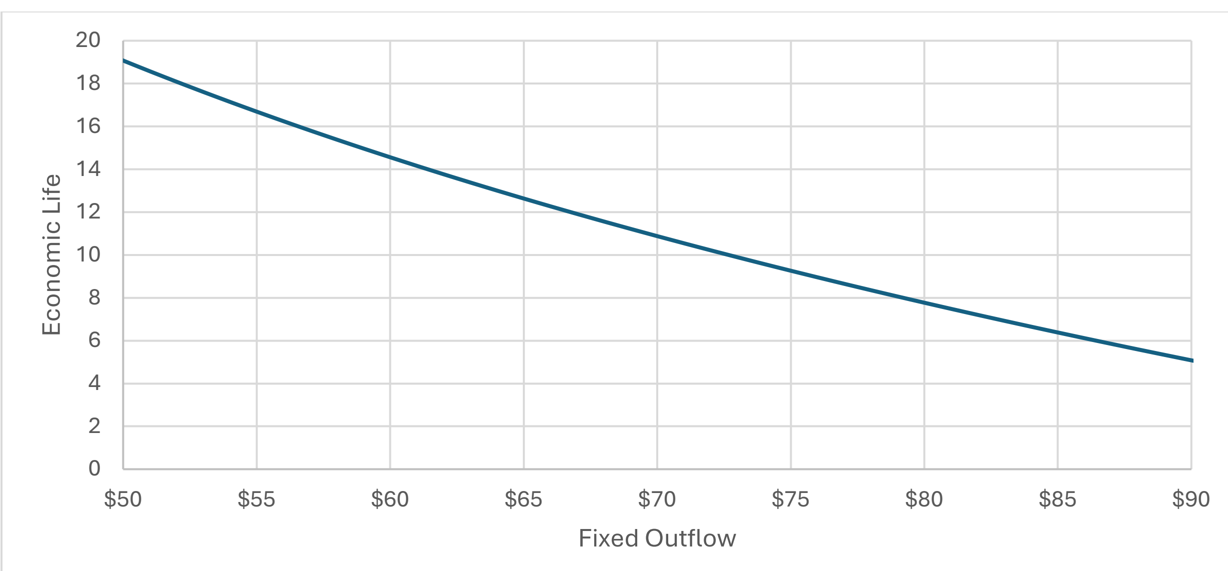
[3] Constraints: $r > 0 > g$; and y > $x > z(e^{r} - 1) > 0$.

[4] The quantity inside the natural logarithm is always less than one, implying the natural log's value is always negative. As fixed costs increase, the value of the logged term approaches zero. Since the rate of growth is negative, the product of 1/g and the logged term is positive and decreasing in x.



If the operator chooses to plug and abandon the well earlier than 10.9 years from now, the opportunity cost of forgone operating cash flow in conjunction with the P&A costs themselves lowers the NPV from its maximum. In the extreme, if the well is plugged and abandoned immediately, the operator receives no cash flow from operating the well and must pay the P&A costs today, leaving the NPV equal to negative $100. Conversely, if the operator delays plugging the well until after 10.9 years, the declining benefits of net inflows are increasingly outweighed by the ongoing fixed outflows associated with continued operation-leading to an overall loss in expected value.

The economic life of the well, dictated by the maximum expected NPV, decreases as the fixed costs of operations increase. This is illustrated by the following figure, which plots the economic life as a function of the level of fixed outflows. From the figure, the 10.9-year economic life of the well when fixed outflows are $70 (or 70% of net inflows) would be expected to decline to only 7.9 years were fixed costs to increase to $80 (or 80% of net inflows).



This model provides a useful distillation of the economic factors influencing the life of an oil and gas well. Unsurprisingly, it implies a negative relation between operating costs and the economic life of a well. Fixed costs, offset by a declining revenue stream, lead to declining profits and eventual abandonment and thus, the higher the fixed costs burdening a well, the shorter the economic life of that well.