November 18, 2026

Via electronic mail to rulescoordinator@rrc.texas.gov

Rules Coordinator
Office of General Counsel
Railroad Commission of Texas
P.O. Box 12967
Austin, Texas 78711-2967

Re: Comments of Pantera Energy Company on Proposed Amendments to 16 Texas Administrative Code §3.15 (Surface Equipment Removal Requirements and Inactive Wells) and §3.58 (Certificate of Compliance and Transportation Authority), Implementing Senate Bill 1150, 89th Legislature (Regular Session, 2025), as Published in the October 23, 2026 Issue of the Texas Register

Dear Rules Coordinator:

Pantera Energy Company ("Pantera") respectfully submits these comments on the Railroad Commission's proposed amendments to §§3.15 and 3.58 implementing Senate Bill 1150, approved for publication at the Commission's October 6, 2026 conference. Pantera is a small operator of shallow, gas-weighted wells in the Texas Panhandle.

Pantera appreciates the work Commission staff has done since the August 2026 draft rule. The proposal resolves several concerns raised in Pantera's August comments. In particular:

- The fixed 3-year / 5-year / 25% / 30% compliance-plan schedules have been replaced with a pace of the operator's "total number of 15/25 wells divided by the remaining number of years until September 1, 2042."
- The three-extension cap on financial-hardship extensions has been removed.
- Nonoperator identification now includes a good-faith, reasonable-effort safe harbor (Commission filings, county tax rolls and other readily available sources).
- Applicants receive a 90-day cure period for incomplete applications.

The issues that remain are mostly ambiguities that a small operator cannot plan around. Pantera's comments are summarized below and explained in detail in the sections that follow.

Summary of Comments

Priority requests:

1. **Transfers (§3.58).** Give buyers time to evaluate acquired wells, and do not require a buyer to vouch for the seller's compliance. As drafted, §3.58 could effectively shut down acquisitions and divestitures of Texas properties that carry inactive wells.
2. **Net assets.** Use net assets, not total assets, in the financial-hardship test.

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3. **All plugging obligations.** Measure financial hardship against all of the operator's plugging obligations, including its other inactive wells, wells that will go inactive, mechanical failures that must be addressed immediately, and the eventual plugging of its active wells, not only the cost of its 15/25 wells.
4. **Inactive inventories are not static.** Every year, inactive wells cross into 15/25 status and active wells go inactive. The pace formula, the 10% option and the financial tests all treat the inventory as a snapshot, so an operator cannot plan beyond the current year. The rule should state how the pace is recalculated and let operators plan against projected inventories, and the Commission should support a statutory fix for wells that become 15/25 after 2042.

Additional requests:

- Complete the financial-hardship tests: define EBITDA, and apply the one-fifteenth annualization consistently.
- Define the CPA financial-statement requirement. The statute does not require audited or reviewed statements. Accept CPA compilations with a sworn management attestation where legally permissible, permit tax-basis reporting, and recognize the cost of three years of historical statements for small operators.
- Narrow the mandatory denial grounds. "Potential hazards" and "prior violation" with no lookback period could disqualify nearly every operator.
- Allow a well's plug-or-restore designation to change once the well has been tested.
- Make the full cost calculation predictable: publish a district table, and keep RRC staff and indirect costs out of operator-performed plugging.

I. Pantera's Inventory as a Worked Example

The examples in these comments use Pantera's full inactive-well inventory of 208 wells, mostly shallow Panhandle gas wells. Forty-eight already meet the 15/25 definition, and all but one will meet it by September 1, 2042 if they remain inactive.

Inactive wells	15/25 today	15/25 by 9/1/2042	Avg. depth	Counties
208	48	207	~3,850 ft	Moore, Gray, Carson, Roberts, Sherman, Hutchinson, Hansford

15/25 status was computed from each well's shut-in date and original completion date in Pantera's well records.

Four facts about Pantera make the ambiguities in the proposal concrete:

- **Operator of record only.** Pantera Energy Company earns administrative and overhead fees. The oil and gas revenue and the oil and gas assets are held by other entities.
- **A large active base that keeps feeding the inactive inventory.** Pantera also operates about 1,000 active wells. On average, about 3% of them go inactive or develop a mechanical failure each year, and a mechanical failure must be dealt with immediately.
- **Small, shallow, gas-weighted wells.** Most are 2,500–4,200 ft Panhandle Field and Hugoton gas wells. Plugging cost per well is low, but many of these wellbores still have value.
- **Real restoration options.** Pantera's operations team's field notes on these wells include "Tested 34 MCFD in 2015?", "Need to pump test. SIP 150#", "still a good backup if 1R fails", "Save

wellbore for replacement. Only 80 acres" and "in process of RTP." These wells cannot honestly be designated "plug" or "restore" until they are tested.

II. A Real-World Example: The North Quinduno Waterflood

The cost of these rules is easiest to see in a field Pantera is developing today. In 2025, Pantera began a secondary-recovery waterflood in the North Quinduno field using six existing wellbores: two producers, two injectors and two water-supply wells. Injection began in 2026, and Pantera estimates the project's potential at up to 200,000 barrels of oil.

- **Four of the six wells would have been plugged.** Pantera has held this field and these wellbores since 2010. Had SB 1150 and the proposed rules been in effect, four of the six would have been 15/25 wells, and Pantera would have been required to plug them years ago, long before Pantera had any plan to waterflood the field.
- **The project depends on those wellbores.** The waterflood is economic only because these wellbores were still available. If Pantera had been required to drill replacements, it would not have undertaken the project, and those barrels would have stayed in the ground.
- **Why it took fifteen years.** Pantera bought the field for its shallow gas zone, which accounted for most of the field's production. At the time, Pantera did not have the skill set or experience to design and operate a waterflood. It built that expertise by completing five waterfloods in Kansas between 2019 and 2025, and then chose to apply it to its Texas fields. North Quinduno is the result.
- **The lesson.** A wellbore is often idle not because it has no value, but because its best use has not yet been found. New expertise, new technology and new prices can change a wellbore's value on a timeline much longer than the fifteen years in the 15/25 definition.

Pantera's view is direct: as drafted, SB 1150 and the proposed rules will stop exactly this kind of development and innovation in Texas oil and gas fields. Forcing operators to plug wellbores before they can be put to their best use does not reduce the State's long-term liability; it destroys the reserves that would otherwise pay to plug those wells.

Recommendation: the proposal's EOR provisions help only after a project exists. Pantera had no plan to waterflood North Quinduno until 2025, fifteen years after it acquired the field, and under SB 1150 these wellbores would have been plugged long before then. A rule that protects a wellbore only once the operator has a project in hand will not preserve the wellbores that future projects need. Pantera asks the Commission to: (1) allow a mechanically sound 15/25 well that passes the required fluid-level or hydraulic pressure testing to remain in a compliance plan as "restore" without an identified project, along the lines of the "regulatory standby" status proposed in Section IV.2; (2) confirm that a 15/25 well counts as restored once it is producing, injecting or supplying water for a commission-approved EOR or secondary-recovery project, including a waterflood, and that water-supply service is an "other type of operation" under §3.15(h)(4)(C); and (3) to the extent the statute does not allow item (1), include it in the statutory change Pantera requests in Section IV.1.

III. Transfers — §3.58(a)(5)–(6)

This is Pantera's highest-priority issue. As drafted, the transfer provisions could effectively shut down acquisitions and divestitures of Texas properties that carry inactive wells.

A. No time to evaluate acquired wells

Under §3.58(a)(6), a prior-history or financial-hardship extension does not transfer, and nothing in §3.15 gives the buyer time to obtain its own. Read together, a 15/25 well appears to fall out of compliance the day the Form P-4 is approved. Any package with 15/25 wells then carries an immediate plug-or-restore obligation on wells the buyer has had no opportunity to test. Buyers will either price those wells at full plugging cost or walk away. The likely result is fewer sales of mature properties to operators who would restore them, and more wells left with sellers that want to exit, or orphaned.

Example: a package like Pantera's own inventory has 208 inactive wells, 48 already 15/25, with field notes such as "need to check hole & test." No buyer can responsibly designate each well "plug" or "restore" at closing.

Recommendation: provide a one-year evaluation window after P-4 approval, during which transferred 15/25 wells are treated as in compliance (with all other safety rules still in force). The buyer's own extension application would be due by the end of that window or at its first P-5 renewal, whichever is later, as proposed in Pantera's August comments.

B. A buyer cannot affirm the seller's compliance

Texas Natural Resources Code §89.023(h) requires both operators to jointly affirm that the well "is in compliance," and proposed §3.58(a)(5) repeats that language. A buyer has no way to verify the compliance history of wells it has never operated, and a careful operator will not sign an affirmation it cannot verify. Because the joint affirmation comes from the statute, the fix lies in how the rule allocates it between the parties.

Recommendation: the transferring operator affirms that the well is in compliance as of the transfer date; the receiving operator affirms that the transfer is made in good faith and that it will ensure compliance from that date forward; and neither operator is responsible for the other's affirmation.

C. Transfer of compliance plans and financial assurance

Section 3.58(a)(6) bars the transfer of prior-history and financial-hardship extensions but is silent on compliance plans and bonds. **Request for clarification:** may a buyer assume the seller's compliance plan and bond for the transferred wells?

IV. Compliance Plan — §3.15(h)(4)(C) and (i)(1)(C)

The compliance plan is the path most of Pantera's wells would use, so clarity matters most here.

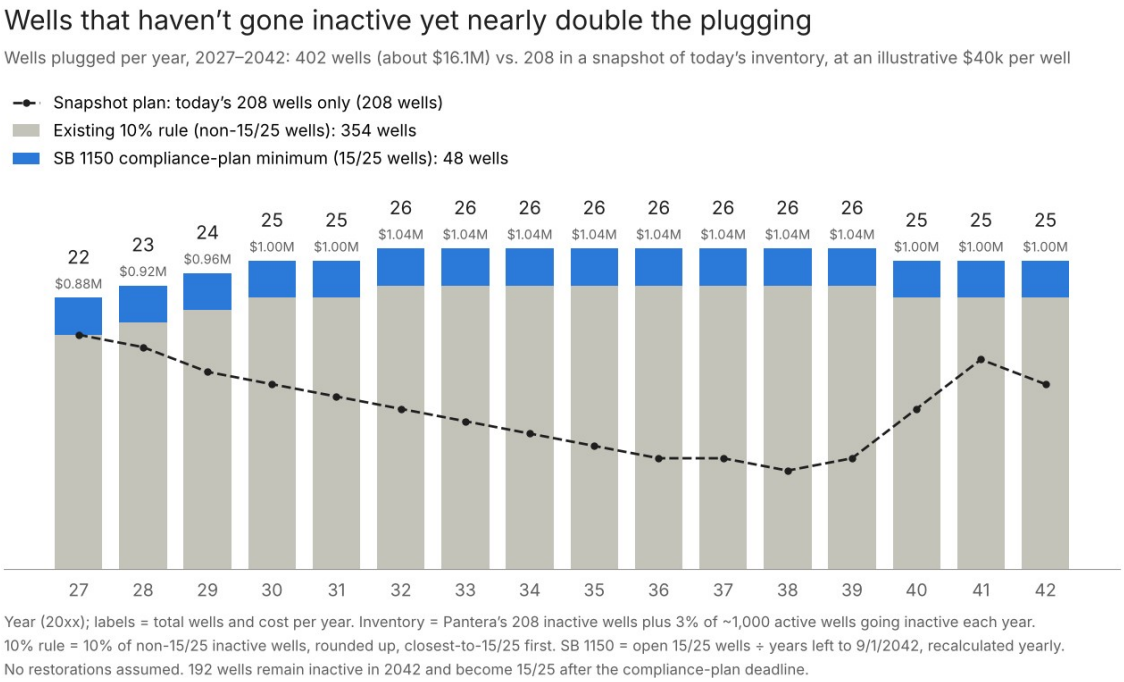


Figure 1. Computed from Pantera's inactive-well records (shut-in and original completion dates), plus 3% of approximately 1,000 active wells going inactive each year. Illustrative; no restorations assumed.

1. The pace formula treats a moving inventory as a snapshot

The minimum is the "total number of 15/25 wells divided by the remaining number of years until September 1, 2042." The rule does not say whether that is a one-time snapshot or recalculated every year, whether wells that will age into 15/25 status are counted, or how a partial year is counted.

More fundamentally, an operator's inactive inventory is not static. Every year, inactive wells cross the 15/25 threshold, active wells go inactive or suffer mechanical failures, and wells leave the inventory as they are plugged or restored. The compliance-plan formula and the 10% option each look at a single moment, so the count an operator commits to this year says little about what it will owe next year.

- *Pantera example:* a snapshot of today's 208 inactive wells shows 48 wells that are 15/25, a compliance-plan minimum of 48 ÷ 16 = 3 wells per year, and, with the 10% option on the remaining wells, about 208 wells to plug or restore through 2042: roughly 19 per year at first, declining to 8–9 (the dashed line in Figure 1). That is the inventory the rule asks Pantera to plan against.
- *What actually happens:* Pantera operates about 1,000 active wells, and on average about 3% go inactive or develop a mechanical failure each year. At that rate, roughly 386 more wells become inactive between now and 2042. Recalculating each year on the inventory as it actually changes, the 10% count rises from 19 to about 23 wells per year, and total plugging rises from 22 to about 26 wells per year (the bars in Figure 1). Over 2027–2042, that is about 402 wells (roughly $16.1 million at $40,000 per well), compared with 208 wells (about $8.3 million) in the snapshot. Even then, about 192 wells would still be inactive in 2042. Those wells become 15/25 after September 1, 2042, when the compliance-plan option is no longer available.
- *Why it matters:* the problem is not any single year's number. It is that neither the compliance-plan minimum nor the 10% count can be known more than one P-5 cycle ahead, because both depend

on wells that are producing today. An operator cannot budget, contract rigs or commit to a multi-year plan it must attest to when the obligation is reset every year against a different inventory.

- **Recommendations:**
  - State that the compliance-plan minimum is recalculated each year on the then-current inventory, net of wells already plugged or restored.
  - Allow an operator to build its plan on a projected inventory, including wells that will age into 15/25 status and wells it reasonably expects to go inactive, and to commit to a multi-year schedule based on that projection.
  - Allow the target to be met on a rolling three-year average, and provide that a plan that is on schedule is not reopened because the inventory changed mid-cycle.
- **The root problem is in the statute.** SB 1150 tests 15/25 status as of the extension request (Tex. Nat. Res. Code §89.023(b)(1)) and sets a single compliance-plan deadline of September 1, 2042 (§89.023(c)(2)). It does not address wells that become 15/25 later, so each well that ages in receives less time than the one before, a well that crosses the line in 2041 receives about one year, and a well that goes inactive after 2027 does not reach 15/25 status until after the compliance-plan option has expired. The recommendations above soften this, but only the Legislature can fully fix it. Pantera asks the Commission to acknowledge the gap in the adoption preamble and to support a statutory change, for example: a well that becomes 15/25 after the effective date receives a compliance-plan deadline a set number of years after it becomes 15/25, or September 1, 2042, whichever is later.

2. Each well must be designated "plug" or "restore" before it is tested

Section 3.15(h)(4)(C)(i) requires the plan to state "whether the included inactive well will be plugged or restored." Changing that designation later could be treated as a deviation from the plan, which is a mandatory denial ground under (i)(2)(F).

- *Pantera example:* the Sweatt #3 shows 275 psi shut-in casing pressure and will likely need to be pumped; the field estimate is 25–30 MCFD with $75,000 of equipment. Neither it nor similar wells can be honestly designated until tested.
- *Some wells are inactive only because Commission rules do not allow them to produce.* The Simmons B-1 is capable of production, but current proration rules allow only one producing well per 160 acres, and the Simmons 1R holds that allowable. The B-1 serves as a backup if the 1R fails; the Ward A-2 and Taylor -A- #1 are in the same position. These wells are idle because of a Commission rule, not because of anything the operator did or failed to do.
- *Why it matters:* plugging a well that is capable of production and could be restored wastes resources the Commission is charged with conserving. If the producing replacement well fails, the operator would have to drill a new well to recover the same reserves.
- **Recommendations:**
  - Allow an "evaluate" designation through the first annual report.
  - State that changing a well's designation from restore to plug (or the reverse) after testing is not a deviation from the plan, as long as the annual count is met.
  - Recognize a "regulatory standby" status for a well that is mechanically sound and capable of production but cannot produce solely because of proration or density limits. Such a well would remain in the compliance plan as "restore" without counting against the annual pace,

as long as it passes the required testing. When the producing well fails or the field rules change, the operator would restore the well or redesignate it for plugging.

3. Prioritization is a bare cross-reference

Section 3.15(i)(1)(C)(iv) refers to Texas Natural Resources Code §89.023(f)(1) and (7) without stating how those factors apply to an operator's plan. **Recommendation:** list the factors in the rule; confirm that they govern *which* wells are addressed first, not how many; and allow operators to group wells by lease to reduce mobilization costs. For example, the eight inactive Bennett wells on Lease No. 05817 in Moore County can be plugged with a single rig move.

4. Exceeding the annual target earns only discretionary credit

Section 3.15(i)(1)(C)(v) provides that the Commission "may consider" wells addressed above the minimum. **Recommendation:** make the credit a carry-forward. If an operator plugs 8 wells against a target of 3, the additional 5 should count toward later years, and 8 should not become the operator's new baseline.

5. Mid-term amendments and annual renewal

Plans are valid for one year and renewed with the Form P-5, but the rule does not say whether a plan may be amended mid-term or what renewal involves. **Recommendation:** state that renewal is a status update and that, if the operator met the prior year's target, the plan continues. Also allow a good-cause amendment for contractor shortages, cost spikes, nonoperator defaults, weather or access problems, and acquisitions or divestitures.

6. Two pace tests could conflict

Section 3.15(i)(1)(C)(ii) requires the annual number to be "not less than" what compliance requires, while (iii) sets the formula. **Recommendation:** confirm that the formula in (iii) is the sole measure of the minimum.

V. Financial Hardship — §3.15(h)(4)(B) and (i)(1)(B)

The five tests are more objective than in the August draft. As proposed, however, they mix one-year and fifteen-year figures, and in one case the arithmetic does not work. The figures below use Pantera's estimate of roughly $40,000 per well for the full cost calculation ("FCC"). Applied to the 48 wells that are 15/25 today, that is about $1.9 million in total, or about $128,000 per year over fifteen years.

1. The text of test (iii) does not match the preamble

The preamble describes test (iii) as comparing EBITDA with "one-fifteenth of the full cost calculation." The rule text in §3.15(i)(1)(B)(iii) instead asks whether (three-year EBITDA minus FCC), "divided by fifteen (15), is negative." Dividing a difference by 15 never changes its sign, so as written the test asks only whether three years of EBITDA is less than the entire FCC. The preamble also omits "three-year," while the rule text retains it, so even if the division is moved, the test would compare three years of earnings with one year of plugging cost.

- *Example at Pantera's scale:* with an FCC of $1.9 million, the rule text as written qualifies any operator with three-year EBITDA under $1.9 million. Under the preamble's version, the threshold is FCC ÷ 15, about $128,000. If "three-year" EBITDA is kept against that one-year figure, the threshold drops to roughly $43,000 of EBITDA per year. One clause produces three very different thresholds.

- **Recommendation:** conform the rule text to the preamble and use average annual EBITDA, for example: "(iii) the difference between the operator's average annual earnings before interest, taxes, depreciation and amortization for the three fiscal years shown in the financial statements required under subsection (h)(4)(B)(i), and one-fifteenth of the full cost calculation for plugging and abandoning all of the operator's 15/25 wells, is negative." (Dividing the FCC by the years remaining until September 1, 2042 would also work.) Define EBITDA, and exclude interest income and one-time gains such as asset sales.

2. The revenue test (i) is not annualized

Test (i) compares one year of revenue with the full multi-year plugging cost, while tests (iii)–(v) use one-fifteenth. **Recommendation:** use the same annualized FCC in every test, so that one year of resources is measured against one year of obligation.

3. Test (ii) uses "total assets," which ignores debt

An operator with $5 million in assets and $4.5 million in debt has only $500,000 of real capacity, yet under a "total assets" test it appears to have $5 million. **Recommendation:** use "net assets (total assets less total liabilities)."

4. Every test counts only the cost of the operator's 15/25 wells

Tests (i)–(v) all measure the operator's resources against the FCC for "all of the operator's 15/25 wells." The operator's actual plugging obligations are much larger, and most of them are not optional: its other inactive wells under the 10% option, wells that will go inactive each year, mechanical failures that must be repaired or plugged immediately, wells that will age into 15/25 status before 2042, and the eventual plugging of its active wells. All of those obligations draw on the same revenue, assets and EBITDA. A test that ignores them overstates what the operator can devote to its 15/25 wells and will rarely find hardship even where it exists.

- *Pantera example:* the 48 wells that are 15/25 today carry about $1.9 million of FCC, or about $128,000 per year over fifteen years. Over the same period, Pantera expects to plug roughly 402 wells under the 10% option and the compliance plan combined (about $16.1 million, or about $1.0 million per year; see Figure 1), while also responding to mechanical failures as they occur and carrying the eventual plugging liability of about 1,000 active wells. The hardship tests would measure Pantera's resources against about one-eighth of its required annual plugging spend.
- **Recommendation:** in every test, compare the operator's resources with its total plugging obligation, meaning the full cost to plug all of its wells, inactive and active (for example, the asset retirement obligation in its financial statements), annualized the same way. Alternatively, keep the 15/25 FCC as the obligation but reduce revenue, net assets and EBITDA by the operator's other plugging obligations, including the plugging required each year under the 10% option. Paired with net assets in test (ii), this measures what the operator actually has available for its 15/25 wells.

5. Tests (iv)–(v) do not specify the required proof

Recommendation: list acceptable evidence for the bankruptcy and default tests, such as a covenant calculation attested by the operator (or a CPA's agreed-upon-procedures report on it) or a lender's written notice, so the determination is not left to staff discretion.

6. Company-wide tests sit beside a well-specific evidence requirement

Section 3.15(h)(4)(B)(iii) requires "objective evidence ... specific to the inactive well," but every test in (i)(1)(B) is company-wide. **Recommendation:** state whether a hardship application is per well or operator-wide, and add a separate well-specific path for plugging bids far above district averages, contractor shortages, nonoperator defaults, or unusual mechanical or access problems, as Pantera also recommended in its August comments.

7. "Sworn financial statements certified by a CPA" should be defined

The phrase comes from SB 1150 itself (Tex. Nat. Res. Code §89.023(d)(2)), so the rule cannot drop the CPA requirement, but it should define what satisfies it. The statute does not require audited or reviewed financial statements, and the rule should not add that requirement. Under professional standards, a CPA reports on financial statements through an audit (reasonable assurance), a review (limited assurance) or a compilation (no assurance). None of these is a "certification," and a sworn representation that financial information is accurate and complete is management's responsibility, not the CPA's.

Many small, privately held operators keep their books internally or through a bookkeeper for management and tax purposes, and have never been required to obtain audited, reviewed or even compiled statements. Requiring three years of audited or reviewed statements would add substantial cost for exactly the operators the hardship provision is meant to help, and could keep them from qualifying at all. The test should measure an operator's actual capacity to plug its wells, not its ability to pay for assurance services the statute does not require.

Recommendations:

- Define "certified by a certified public accountant" to accept CPA-compiled financial statements accompanied by a sworn management attestation, rather than requiring an audit or review, to the extent consistent with the statute.
- Allow the CPA to compile three years of comparative statements from the operator's internal records in a single engagement, rather than requiring separate annual engagements.
- Accept statements prepared on an income-tax basis or another special-purpose framework rather than requiring GAAP.
- Where legally permissible, accept a CPA's agreed-upon-procedures report on the hardship calculation in place of a full financial-statement engagement.
- Treat filed financial statements and supporting financial information as confidential to the extent permitted by law.

VI. Prior History, Bond Option and Full Cost Calculation

A. Prior history — §3.15(i)(1)(A)

An operator with more than 10 inactive wells qualifies if it restored "the equivalent of at least 10 percent of its total inactive well population" in the "preceding year." The concept is reasonable, but each key term is undefined. At 208 inactive wells, Pantera would need about 21 restorations in one year. At 20 restorations (9.6%), Pantera would receive nothing, even though that is far more than the compliance-plan pace would require.

Requests for clarification:

- Does "total inactive well population" mean all inactive wells or only 15/25 wells?

- Does “the equivalent of” allow plugged wells, or wells converted to injection, to count toward the 10%?
- Is the “preceding year” the calendar year or the P-5 renewal cycle?
- Is “restored” the same as “active operation” under (a)(2)? If so, how does a well count when its required months of production straddle the renewal date?
- How is 10% rounded? For example, is 10% of 104 wells 10 restorations or 11?
- Does the extension cover all of the operator’s 15/25 wells, or only some of them?

Recommendation: where an operator falls short of 10%, give proportional credit toward its compliance-plan count rather than an all-or-nothing result.

B. Bond option — §3.15(h)(4)(D) and (i)(1)(D)

Pantera does not believe this option is workable as drafted. Pantera knows of no market for a bond that covers a single inactive well at its full plugging cost and remains with the well through a change of operator.

- **It mixes two instruments.** The Commission’s own P-5 financial-assurance rules accept performance bonds from surety companies registered with the Texas Department of Insurance and letters of credit from financial institutions. This rule calls for a “performance bond ... issued by and drawn on by a third-party bank.” Banks issue letters of credit, not performance bonds. And because §3.15(i)(2)(G) makes a bond not issued by a bank a mandatory denial ground, an operator cannot cure the mismatch by posting a conventional surety bond.
- **Sureties underwrite the operator, not the well.** A bond that “runs with ... the inactive well, regardless of a change in the operator” would expose the surety to a new principal it never underwrote. For a well inactive 15 or more years, a surety would likely demand full collateral, making the “bond” a cash escrow in practice.
- **The amount is inconsistent.** Section 3.15(h)(4)(D) requires “not less than” the FCC, while (i)(1)(D)(i) requires an amount “equal to” it.

Recommendations: SB 1150 provides a financial-assurance path, so the rule should make it usable rather than delete it:

- Accept any form already allowed for P-5 financial assurance: a surety bond, a letter of credit or cash.
- Allow it to be posted at the operator level for a named list of wells, and released well by well as each is plugged or restored.
- Count the operator’s existing P-5 financial assurance toward it.
- Do not require it to follow the well after a transfer; the buyer posts its own.

Unless these changes are made, Pantera does not expect to use this option, which makes the compliance-plan and financial-hardship fixes more important.

C. Full cost calculation — §3.15(a)(6)

The FCC now adds RRC staff time for monitoring and RRC indirect administration at the federal NICRA rate, on top of third-party direct and indirect costs. An operator cannot calculate either RRC component, yet the FCC drives the hardship tests, the compliance-plan cost figures and the bond amount. Pantera’s wells range from a 1,566 ft Red Cave gas well in Hutchinson County to the 9,960 ft

Locke -A- #1 in Roberts County. Without a published method, Pantera cannot provide a defensible FCC for either well in a plan it must attest to.

Recommendations:

- Publish a district-by-depth FCC table annually.
- Define the "indirect costs associated with third party goods and services."
- Use the RRC staff and NICRA components only for the bond amount, where the State would perform the plugging. Keep them out of the hardship tests and compliance-plan figures, where the operator performs the plugging.

VII. Mandatory Denial Grounds and Testing

A. Mandatory denial — §3.15(i)(2)

These grounds are "shall deny," leaving staff no discretion once one applies. Several are worded broadly enough that a good operator cannot tell in advance whether it qualifies.

Ground	Concern	Recommendation
(A) A barred nonoperator	A single nonoperator could block the operator's entire application.	Apply the ground only to the well in which that nonoperator holds an interest.
(C) Well "poses potential hazards"	Every inactive well poses *potential* hazards. It is unclear whether one such well defeats the entire application.	"Poses an imminent threat to public health, safety, or the environment that the operator has not abated after notice." Apply it to that well only; the remainder of the plan stays eligible.
(D) Hardship "due to the operator's fault or negligence"	Undefined. It is unclear whether a commodity-price collapse or a plugging-cost spike is "fault."	Define the term, and exclude commodity prices, market plugging costs and regulatory changes.
(E) "Previously penalized" for a safety or pollution violation with "significant impact," or "deliberate disregard"	No lookback period. "Penalized" versus a notice of violation, and "significant," are undefined.	Count only final orders assessing an administrative penalty, within a lookback period (for example, three years). Define "significant impact."
(F) "Deviated ... in bad faith" from the prior year's plan	No safe harbor.	An operator that met its annual count, or had an approved good-cause amendment, is not acting in bad faith.

- *Pantera example for ground (E):* Pantera has received notices of violation under the Statewide Rule 21(i) "rubbish" interpretation and under the conflict between Statewide Rule 15 and Rule 21(l) regarding de-energized lines. The rule should make clear that notices of violation of this kind, which reflect unresolved interpretive disputes and carry no penalty order, are not disqualifying.
- **Process after denial.** Please clarify whether the extension remains in effect while a hearing is pending, and how long the operator then has to plug or restore before enforcement begins. Pantera suggests 12 months.

B. Testing — §3.15(n)–(o)

- **"More than 15 years old" is undefined,** and the proposal deletes the former "inactive more than 10 years" qualifier. Please clarify whether age is measured from completion, and whether a well inactive only 13 months must be tested if it was completed more than 15 years ago. For Pantera, 188 of the 208 wells were completed more than 25 years ago.
- **Hydraulic tests are valid "for a period of five years" but must be "submitted annually."** Please clarify that annual submission means re-filing the existing valid result, not running a new test.
- **Test results do not transfer for wells more than 15 years old** under (o)(7). **Recommendation:** allow the seller's still-valid fluid-level and hydraulic pressure tests to carry over on transfer.

VIII. Implementation Timing and Fiscal Note

A. When and how to apply

- **No effective date or first-filing deadline. Recommendation:** adopt a transition rule for wells already 15/25 on the effective date (48 wells for Pantera). For example, the first application would be due at the first P-5 renewal at least six months after the effective date.
- **Wells that become 15/25 mid-year.** Extensions are tied to the annual P-5 renewal. Please clarify whether a well that becomes 15/25 between renewals is out of compliance until the next renewal. Pantera suggests that it remain covered until then.
- **Per-well versus operator-wide applications.** The application provisions read as operator-wide, but the bond and "specific to the inactive well" language read as per-well. Please clarify whether an operator may use different paths for different wells, for example a compliance plan for most wells and a hardship extension for one well with an outlier plugging bid.
- **Existing tools for 15/25 wells.** Section 3.15(f) and the 10% blanket option are now limited to wells that are not 15/25. Please clarify whether abeyance under (l), escrow under (q) and supplemental financial assurance under (p) remain available for 15/25 wells.

B. Fiscal note

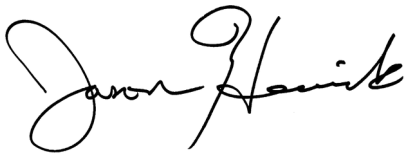
- **Costs to regulated persons.** The fiscal note states that regulated persons bear "no additional economic costs" and finds no small- or micro-business impact. That is difficult to reconcile with the rule: without an extension, a 15/25 well must be plugged, and every extension path carries cost (audited or reviewed financial statements, financial assurance, testing). **Recommendation:** prepare a small-business and micro-business regulatory flexibility analysis under Texas Government Code §2006.002. Pantera, a small Panhandle operator with about 200 shallow inactive wells, is a fair test case.
- **Internal inconsistencies.** The note states that no positions will be created, but its cost estimate includes 86 full-time employees, and the year-two cost is printed as "$4,88,756." **Recommendation:** publish a corrected fiscal note before adoption.

Conclusion

Pantera supports the Commission's goal of reducing the State's long-term inactive-well liability and appreciates the improvements staff has made since the August draft. The changes requested above, especially to the transfer provisions, the financial-hardship tests and the treatment of an inactive inventory that changes every year, would let operators plan for compliance, keep mature properties moving to operators who will restore them, and avoid plugging wellbores that still have value, like the wellbores now at work in the North Quinduno waterflood. Pantera would welcome the opportunity to work with staff on rule language and is willing to share the underlying well data used in these comments.

Thank you for your consideration.

Respectfully submitted,



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