The Texas Alliance of Energy Producers (Alliance) represents over 2,600 individuals and member companies in the upstream oil and gas industry; our members are oil and gas operators/producers, service and drilling companies, royalty owners, and a host of affiliated companies and industries in Texas and beyond.

Thank you for the opportunity to provide comments on the published draft amendments to SWRs 15 and 58. We appreciate the Commission's diligent work on this issue to find a rule that is workable for all stakeholders, given the mandate from the legislature with the passage of SB1150 in the 2025 legislative session.

While our members had many other concerns with the published rule, our comments today will focus on the concerns which we heard from the most members, that we believe are very workable within the existing draft rule framework, and that would be the most meaningful from an operational perspective to our members.

We want to help by sharing those issues which pose the largest operational challenges for our members if implemented as drafted, while providing practical and easy ways to tweak the draft to accomplish the same goals in the same timeframe. These issues include clear published information related to the full cost calculation of plugging found in the rule draft, a few changes to some of the financial hardship extension criteria and other extension related criteria, flexibility for operators who need to make changes to their compliance plan while still meeting their goals, a transition period after acquisitions of qualified inactive wells, and several provisions where the draft rule requires more than SB 1150 does. We feel these are very reasonable requests, which will make the rule eminently more workable for our members, while still meeting the obligations of SB 1150 and the Commission's objectives in the rule.

A. Full cost calculation for plugging an inactive well

So much of the draft rule revolves around, and is driven by, the defined term of "full cost calculation for plugging an inactive well," which is found in SWR 15(a)(6). Getting this definition right is imperative for the rule to function properly. As currently drafted, this calculation will require quite a bit of staff time to track the federal Negotiated Indirect Cost Rate Agreement (NICRA) and calculating different indirect costs. This is going to be confusing for both Railroad Commission staff and the operator community.

Alliance Recommendation *The Alliance proposes that it would be much simpler for the administration of the rule and for operator compliance if the Railroad Commission published a district-by-depth full cost calculation table each year, defined "indirect costs associated with third-party goods and services" so that this isn't a moving target, and only used the Railroad Commission staff and NICRA components for calculating the bond amount when the state is going to do the plugging. This way the full cost calculation for the financial hardship and compliance plan portions are much simpler to apply and understand for all parties involved. Operators should also be able to rely on the published figure in their compliance plans and performance bonds. Proposed §3.15(h)(4)(C)(i) requires the operator to include the full cost calculation in its compliance plan, but an operator has no way to calculate RRC staff time or NICRA-based indirect costs on its own.*

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B. Restoring wells to active status

1. SB 1150 states that by order, the Railroad Commission may grant an extension to plugging based on the operator's demonstrated history of returning inactive wells to operation. The draft rule provides two criteria that operators of different size may meet to request this extension. Both of these criteria are focused on returning inactive wells of any age, not just 15/25 wells, yet the extension itself is only for 15/25 wells. This outcome creates an inequitable tension in the rule that several Alliance members would like to see addressed. The practical effect of this inequity in the rule will be to require operators to plug a larger pool of wells (that are not the well population SB 1150 was focused on) to be able to meet the criteria of this extension.

Alliance Recommendation *The Alliance suggests that the Railroad Commission could easily address this tension by adding a third criterion as SWR 15(i)(1)(A)(iii), focused on the percentage of inactive wells to active wells, rather than the total number of inactive wells plugged. That language could read something like: "(iii) the operator's inactive wells constitute no more than twenty-five percent of the operator's total well count, and the operator has restored at least one inactive well to active operation in the preceding three years."*

2. In addition, SB 1150 bases this extension on the operator's "demonstrated history" of returning inactive wells to operation (Tex. Nat. Res. Code §89.023(c)(1)(A)). A history is more than a single year, yet both criteria in proposed SWR 15(i)(1)(A) look only at the "preceding year," a term the rule does not define. Workovers and reactivations at smaller operators are uneven from year to year, so an operator with a strong multi-year record could fail a one-year test. The preamble and the rule text also differ on the threshold: the preamble refers to operators with "less than 10" inactive wells, while the rule text says "no more than 10."

Alliance Recommendation *The Alliance requests that the Commission allow an operator to meet either criterion using the preceding year or the average of the preceding three years; that "preceding year" be defined as the operator's most recent organization report renewal period, since 15/25 extensions renew with the organization report (proposed §3.15(h)(2)); and that the preamble be conformed to the rule text.*

3. Additionally, several of our members have pointed out that plugging an inactive well is giving a more permanent resolution to a well than bringing it back into active status. Similarly, bringing a well back online as an injector in a water flood operation, for disposal, or as a monitoring well, in many circumstances could be creating more value than if it were brought back as a marginal producer. §89.023(c)(1) directs that this extension be determined by final order, and SWR 15(i)(1) says approval of this extension "is warranted if" rather than "only if." Existing SWR 15(p) (subsection (r) under this draft) already treats plugging as the equivalent accomplishment of bringing back to active status for the blanket option, and §89.023(a)(3)(A) frames the parallel test as wells "plugged, or restored to active operation." So, we believe there is statutory and existing rule precedent to credit plugged wells toward this particular extension.

Alliance Recommendation *The Alliance believes it would follow the spirit of SB 1150 for operators to receive credit toward receiving this particular extension if they plug a well or bring it back into some sort of service for the oilfield, just the same as if they bring it back into production.*

C. Financial hardship

Hardship must be measured where the plugging cost falls – The proposed rule asks the operator for objective evidence of financial hardship "specific to the inactive well" (proposed §3.15(h)(4)(B)(iii)). It then decides the application on five tests that use only company-wide figures: total annual revenue, total assets and EBITDA, measured against the cost of plugging all of the operator's 15/25 wells (proposed §3.15(i)(1)(B)(i)–(v)). Company-wide figures say nothing about whether the owners of a particular well can support the cost of plugging it. An operator's financial statements combine properties with different working interest owners, as well as non-operated interests where the operator pays its share of another operator's costs. The owners of one property do not share in the cost of plugging a well on an unrelated property, and the rule should not treat one set of owners' revenue as available to plug another set's wells.

1. A test based on the inactive well alone would not work, because a well that has been inactive for more than 15 years has no revenue of its own. A test based on the RRC lease would not work either, because each gas well carries its own lease number. The economic unit that actually bears the plugging cost is the group of wells with common working interest ownership.

Alliance Recommendation *The Alliance requests an additional, optional financial hardship test measured at the level of the ownership group: the wells the operator operates that share common working interest ownership with the 15/25 well, regardless of RRC lease number. Approval would be warranted if the ownership group's net revenue, after operating costs, cannot reasonably carry the full cost calculation for plugging that group's 15/25 wells over the years remaining to September 1, 2042. Where no well in the group is producing, the operator could instead show that the 15/25 well has a reasonable expectation of being restored, the same standard used for abeyance of plugging reports (proposed §3.15(l)), supported by records the operator already keeps, such as fluid level or pressure tests, offset production and workover history. The operator would support this test with the attestation and CPA-certified financial statement that §89.023(d) already requires. Ownership records and revenue decks would not be filed; they would remain in the operator's files, available to the Commission on request and treated as confidential.*

2. Revenue test – Under the first test for financial hardship found in SWR 15(i)(1)(B)(i), the draft rule compares one year of revenue with the full multi-year plugging cost, while the tests found in (iii)-(v), use one-fifteenth.

Alliance Recommendation *The Alliance requests that the Railroad Commission amend this test to use the same annualized full cost calculation in every financial hardship test, so that one year of resources is measured against one year of obligation.*

3. Net Assets – Under the financial hardship extension option SWR 15(i)(1)(B)(ii) in the draft rule, the test uses "total assets", rather than "net assets", which does not consider an operator's actual financial capabilities. For example, an operator with $5 million in assets and $4.5 million in debt, has only $500,000 of real capacity. Whereas, using "total assets", it looks like it has $5 million.

Alliance Recommendation *The Alliance proposes changing this test to use "net assets" in lieu of "total assets" to reflect the company's actual financial capability.*

4. Reconciling Test (iii) preamble with rule language – In the draft rule, the preamble describes the financial hardship test found in SWR 15(i)(1)(B)(iii) as EBITDA compared with "one-fifteenth of the full cost calculation." The actual rule text for this test, can instead be read to mean that to meet the test

one must take the operator's three-year EBITDA minus the full cost calculation, divided by fifteen, and if the figure is negative, then the test has been met. Dividing a difference by 15 never changes its sign, so under that reading, the test asks only whether three years of EBITDA is less than the whole full cost calculation. The preamble also drops "three-year," and the rule text keeps it, so even once the ÷15 is moved, the test would compare three years of earnings with one year of plugging cost.

Alliance Recommendation *To reconcile these differences, the Alliance suggests conforming the rule text to the preamble and using the average annual EBITDA, for example: "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." Alternatively, using the full cost calculation divided by the years remaining to September 1, 2042 would also work. We also suggest for the EBITDA calculation, the rule should exclude interest income and one-time gains such as asset sales, since these are not reliable, consistent flows of income for the operator.*

5. Total plugging costs vs. 15/25 only – All of the financial hardship tests in the draft rule measure the operator's resources against the full cost calculation for "all of the operator's 15/25 wells." The operator's real plugging liability is much larger: its other non 15/25 inactive wells (including those under the legacy HB 2259/existing SWR 15), wells that will age into 15/25 before 2042, and the eventual plugging of its active well population. All of those draw on the same revenue, assets and EBITDA, so a test that ignores these other wells overstates what the operator can put toward its 15/25 wells.

Alliance Recommendation *The Alliance would like to propose that the rule be changed so that in every financial hardship test, one would compare the operator's resources with its total plugging obligation: i.e., 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, we would suggest keeping the 15/25 full cost calculation as the obligation, but reducing revenue, net assets and EBITDA by the operator's other plugging obligations. Paired with net assets in test (ii) mentioned above, this measures what the operator actually has left to put toward its 15/25 wells.*

6. Statutory factors – SB 1150 lists factors the Commission may consider on a hardship request: the operator's prior investment in plugging or maintenance of wells, its compliance history, current economic conditions, and its percentage of inactive wells (§89.023(e)). The proposed rule collects this information in (h)(4)(B)(iv), but the approval criteria in (i)(1)(B) are limited to the five numeric tests.

Alliance Recommendation *The Alliance requests that the rule state that an operator that does not meet one of the numeric tests may still show that an extension is warranted based on the §89.023(e) factors, and that meeting any one test is sufficient.*

7. CPA-certified financial statements - Proposed SWR 15(h)(4)(B)(i) requires "sworn financial statements, certified by a certified public accountant," for the three fiscal years before the organization report renewal date. Neither the rule nor SB 1150 says what "certified" means. CPA services on financial statements range from a preparation or compilation, to a review, to a full audit. The difference in cost is large. For one small operator, a compiled statement runs about $500, while an audit runs about $10,000, and the rule asks for three years of statements. Most small operators have no lender or investor that requires audited statements, so they don't have them. If "certified" is read to mean audited, the hardship extension becomes too expensive for the operators most likely to need it.

Financial statements filed with the Commission may also be subject to requests under the Public Information Act. An operator's revenue, debt and margins are sensitive commercial information that competitors, buyers and counterparties should not be able to obtain by asking the Commission for them.

Alliance Recommendation *The Alliance requests that the rule state that a compiled or reviewed financial statement prepared by a certified public accountant satisfies the requirement, and that an audit is not required. The Alliance also requests that financial statements and supporting documents filed under subsection (h)(4)(B) be treated as confidential commercial and financial information to the extent allowed by Government Code §552.110.*

D. Compliance plans

1. Annual minimum and small operators – SB 1150 requires a compliance plan in which the operator commits to plugging or restoring the included wells by September 1, 2042, and directs the Commission to consider, among other things, current economic conditions, the operator's percentage of inactive wells, any financial assurance on file, and "any good faith demonstrated by the well operator" (§89.023(c)(2), (f)). The statute does not set a fixed annual minimum. The proposed rule sets one in three places: the plan's schedule must specify a number of wells each year (proposed §3.15(h)(4)(C)(i)(III)); each year's number must keep pace with 2042 (§3.15(i)(1)(C)(ii)); and the annual minimum is the operator's total 15/25 wells divided by the years remaining (§3.15(i)(1)(C)(iii)). The plan must also be renewed every year.

The rule does not say how a fraction is treated, and the answer falls hardest on small operators. Say an operator has three 15/25 wells and 15 years remain to September 1, 2042. The formula gives 3 ÷ 15 = 0.2 wells per year. If that rounds up to one well per year, the operator must plug or restore all three wells in the first three years, giving up twelve of the fifteen years the Legislature provided. An operator with 150 15/25 wells needs 10 per year, exactly its proportional share, so rounding affects only the smallest operators. Under cumulative milestones, for example one well within five years, two within ten and all three by September 1, 2042, the small operator keeps the full statutory period. It can schedule work when a rig is already nearby, when prices and cash flow allow, and can group wells under one rig mobilization. The milestones still prevent any operator from deferring all of its work to the final year.

Alliance Recommendation *The Alliance requests that the Commission (1) allow the schedule in (h)(4)(C)(i)(III), (i)(1)(C)(ii) and (i)(1)(C)(iii) to be met through cumulative milestones, such as at five-year intervals, rather than a strict annual minimum, so long as the plan reaches full compliance by September 1, 2042; (2) keep an approved plan in effect through 2042, subject to the annual status report required by proposed (h)(4)(C)(iii), and revoke it only for failure to perform; (3) change "may consider" in (i)(1)(C)(v) to "shall credit," so that wells plugged or restored above the minimum count toward later years, consistent with the existing credit for plugging more than 10% of inactive inventory (proposed §3.15(r)); and (4) clarify how wells that become 15/25 wells after a plan is approved are added to it.*

2. Under the current draft, SWR 15(h)(4)(C)(i) requires the plan to state "whether the included inactive well will be plugged or restored." Changing that later could look like a deviation from the plan, which is a mandatory denial ground under (i)(2)(F) of the rule. This is an impractical outcome given that what the operator chooses to do with that well could change once they have an opportunity to run a test on that well.

Alliance Recommendation *The Alliance suggests the Railroad Commission should create an "evaluate" designation for wells until they get through the first annual report, so that operators have a chance to*

understand what is best for each well and aren't penalized if they need to change the designation. We also believe it would be reasonable to change the rule language so that changing a well from restore to plug (or vice-versa) after testing is not a deviation, as long as the annual count or cumulative milestone is met.

3. Additionally, the draft rule does not contemplate wells that may only be inactive due to Railroad Commission proration/density rules, not through any proactive decision on the operator's part. If a field rule only allows one producing well per 160 acres, and the operator has one producer on 160 acres, but is keeping an inactive well in case they have a failure of some sort on the producing well, the operator should not be penalized in this instance. Plugging a well that is capable of production and could be restored is a waste of resources, which the Commission exists to prevent. If the producing well fails, the operator will have to drill a new well to recover the same reserves, rather than just re-working the inactive well it had to plug.

Alliance Recommendation *To address this unintended consequence, the Alliance would like to propose a "regulatory standby" status for a well that is mechanically sound and capable of production but cannot produce only because of proration or density limits. Such a well would stay 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 restores it or moves it to "plug".*

4. Mandatory denial - In the grounds for mandatory denial of a compliance plan found in SWR15(i)(2)(A), the compliance plan is rejected if a bad operator is involved in the ownership of the inactive well. **Alliance Recommendation** *We would like to recommend that the entire compliance plan not be rejected, but just the well where that bad operator has the ownership interest. Additionally, we would request that this criterion only apply if the operator in question knew or should have known about the bad operator's involvement, and that they have the ability to cure prior to denial.* (i)(2)(C) requires rejection if a well poses "potential hazards." Every well poses potential hazards, so this criterion seems particularly harsh. **Alliance Recommendation** *We recommend this denial ground be amended to read: "Poses an imminent threat to public health, safety, or the environment that the operator has not abated after notice." And the rejection should only apply to that problem well, not the entire compliance plan.* Under the criterion found in (i)(2)(E), it requires denial for "previously penalized" for a safety/pollution violation with "significant impact," or "deliberate disregard". None of these terms are defined. **Alliance Recommendation** *We believe this criterion should be amended so that only final orders with an administrative penalty within the last three years would disqualify the plan.* Under (i)(2)(F), a plan shall be denied if the operator deviated in bad faith from last year's compliance plan. **Alliance Recommendation** *The rule should be clarified so that an operator that met its annual count or cumulative milestones, or had an approved good-cause amendment, is not considered "bad faith."* In the proposed rule, there are several instances that mandate automatic denial, while the statute says to weigh the seriousness of violations. A mandatory bar in the rule takes that weighing that the statute requires away. **Alliance Recommendation** *The Alliance requests changing "shall deny" to "may deny" and use a three-year lookback to check on operator's history of violations before making that decision to deny.*

5.Other denial grounds – Proposed (i)(2)(B) (any penalty under §91.143) and (D) (hardship due to the operator's "fault or negligence") raise the same concerns as (E). Neither has a lookback period, and "fault or negligence" is not defined. SB 1150 treats compliance history as a factor to weigh, referring to "any history of previous violations and the seriousness of those violations" (§89.023(e)(3), (f)(5)); it does not list mandatory denial grounds. As drafted, a single past penalty anywhere in an operator's business would require denial of extensions for every one of its 15/25 wells, including wells that had nothing to

do with the violation. The mandatory denials also apply to the performance bond pathway, where the full cost of plugging the well is already secured.

Alliance Recommendation *The Alliance requests that (i)(2)(B) and (E) be limited to final penalties assessed within the preceding three years and apply only to the wells involved in the violation; that (i)(2)(D) apply only on a final Commission finding of fault or negligence, and that commodity prices, market conditions, loss of a purchaser or other circumstances outside the operator's control not be treated as fault or negligence; and that no mandatory denial ground other than (C), applied to the specific well, apply to a well covered by a qualifying performance bond.*

E. Acquisition transition

1. Our members are gravely concerned that, as drafted, the transfer rules could effectively shut down acquisitions and divestitures of Texas properties that carry inactive wells. Under the proposed SWR 58(a)(6), prior-history or hardship extensions do not transfer, and nothing in the proposed SWR 15 gives the buyer time to obtain its own extension. Read together, a 15/25 well appears to fall out of compliance the day the P-4 transfer is approved. Any package with 15/25 wells then carries an immediate plug-or-restore obligation on wells the buyer hasn't been able 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 out, or orphaned.

Alliance Recommendation *The Alliance would like to propose a one-year evaluation window after P-4 approval, during which transferred 15/25 wells are treated as in compliance (all other safety rules still in force), with the buyer's own extension application due by the end of that window or its first P-5 renewal, whichever is later. This is consistent with the six-month period the proposed rule already gives a new operator to file its own abeyance of plugging report, EOR statement, or supplemental financial assurance (proposed §3.15(l)(2), (m)(2) and (p)(2)).*

2. Additionally, SB 1150 requires both operators to jointly affirm that the well "is in compliance," the proposed SWR 58(a)(5) repeats this word for word. In reality, a buyer has no real way to verify the actual compliance (i.e., to know whether the seller is actually in compliance, not just technically in compliance because the paperwork claims it is) of wells it has never operated, and a careful operator won't sign an affirmation it cannot verify. Because the joint affirmation comes from the statute, the fix is in how the rule divides it between the parties.

Alliance Recommendation *The Alliance proposes that the rule be changed to require the transferring operator affirm the well is in compliance as of the transfer date; then the receiving operator would affirm the transfer is in good faith and that it will ensure compliance from then on, but neither should be responsible for the other party's affirmation.*

3. The draft rule is silent on whether compliance plans can transfer to the new owner of qualifying wells.

Alliance Recommendation *The Alliance proposes that the rule be clarified that compliance plans are transferable to new owners, which will cut down on Railroad Commission staff time processing new paperwork and still ensure compliance with the statute and the rule*.

4. Finally, the proposed rule bars transfer of an extension based on the transferring operator's restoration history (proposed §3.58(a)(6)), but does not say when the receiving operator may rely on its own history.

Alliance Recommendation *The Alliance requests that the rule confirm a receiving operator may apply for a restoration-history extension for acquired 15/25 wells immediately, based on its own record of restoring inactive wells, without first building a record on the acquired wells.*

F. Testing Requirements

Natural Resources Code §89.050 lowers the age at which an inactive well must be tested from 25 years to 15 years and the rule removes the requirement that a well first be inactive for more than 10 years. This would require all inactive wells over 15 years old to be tested, with results submitted annually. The Alliance supports the Commission's goal of confirming that aging inactive wells remain mechanically sound. However, the rule as proposed would bring a large number of wells into the testing program all at once. Many of these wells have no history of integrity problems, and the rule does not consider the condition, construction, or location of any individual well.

The Alliance's members are concerned about practical capacity. Testing contractors are limited, especially in rural districts, and a sudden increase in required tests will raise costs and could make timely compliance impossible for reasons outside an operator's control. District office staff will also have to review and process many more test results. A phased approach would serve both operators and the Commission better.

Alliance Recommendation *The Alliance proposes a phase-in under the new threshold. The first required tests for newly covered wells should be added over several years, starting with wells that present greater risk based on factors such as age, construction, or proximity to groundwater, rather than all at once in 2027. Additionally, we'd recommend keeping newly covered wells on the existing five-year hydraulic test cycle. Wells between 15 and 25 years old should follow the same five-year schedule that operators and districts already use, so that testing obligations stay predictable.*
The Alliance requests that, for a well with an approved hydraulic pressure test that remains valid, the annual submission required by proposed (n)(6) and §89.050 may consist of a filing that references the approved test already on file, rather than refiling the full test documentation each year.

The Alliance also proposes that the rule allow alternative demonstrations of integrity. It should confirm that a district director may approve other engineering methods that adequately show a well's mechanical integrity, as §3.15(n)(2) contemplates.

Additionally, to the extent possible, consistent with §89.050, the Alliance recommends restoring the condition that a well be inactive more than 10 years before testing applies. This will help ensure the number of wells requiring tests remain manageable both from an operator and a contractor perspective.

G. Performance bonds

1. SB 1150 requires an individual performance bond "in an amount that is not less than the full cost calculation for plugging an inactive well … that runs with and covers the lifetime of the well, regardless of a change in the operator" (§89.023(c)(3)). The statute does not say who must issue the bond. Proposed §3.15(i)(1)(D)(iii) requires the bond to be "issued by and drawn on by a third-party bank," and (i)(2)(G) makes any other issuer a mandatory ground for denial. Performance bonds are customarily written by surety companies, while banks typically provide letters of credit. As drafted, this requirement may make the statutory bond pathway unavailable in practice.

Alliance Recommendation *The Alliance requests that the rule accept performance bonds issued by a surety company authorized to do business in Texas, in addition to bank-issued instruments; that (i)(2)(G)*

be deleted; and that "equal to" in (i)(1)(D)(i) be changed to "not less than" to match the statute. The Alliance also suggests that the Railroad Commission consider accepting letters of credit and cash, as it does for P-5 financial assurance already. This would provide more flexibility for operators and still meet the spirit of the statute and rule.

2. The proposed rule also leaves three practical questions open. It does not say when the bond is released. It does not say whether the bond amount must increase each year as the full cost calculation is updated. And under proposed §3.15(h)(2), every 15/25 extension, including one supported by a bond, is valid for only one year and must be renewed with the organization report, even though the bond itself must cover the lifetime of the well. Clear terms on release and amount will be needed for these instruments to be issued and priced.

Alliance Recommendation *The Alliance requests that the rule provide that (1) the bond is released when the well is plugged or returned to active operation; (2) the bond amount is fixed when the bond is filed, or adjusted only at renewal on a published schedule; and (3) an extension supported by a qualifying bond remains in effect for as long as the bond is in force, rather than requiring a new application each year. The Alliance also recommends that the bond be posted at the operator level for a named list of wells and released per well as the respective wells are addressed.*

H. Identification of nonoperators

Proposed §3.15(h)(3) requires the operator to identify the names, addresses and contact information of all nonoperators of each 15/25 well with each application. Older marginal wells often carry fragmented ownership, and the research must be repeated every year. The only use the proposed rule makes of this information is the denial ground in (i)(2)(A), which concerns nonoperators who were prior operators of record, or their officers, directors, general partners, owners of more than 25%, or trustees, and who are barred under §91.114(2). The Alliance supports that screen.

Alliance Recommendation *The Alliance requests that the requirement be limited to working interest owners of record and the persons described in (i)(2)(A), and that an operator be allowed to carry its list forward from year to year, filing only updates.*

I. Measuring the 15/25 periods; effective date

SB 1150 measures the 25-year period from completion to "the date the operator submitted the request for the extension" (§89.023(b)(1)(B)). Proposed §3.15(a)(1) defines a 15/25 well as one "completed more than 25 years ago." The proposed rule also does not say whether a well that is restored to active operation, as defined in proposed §3.15(a)(2), and later becomes inactive again starts a new period of inactivity. SB 1150 provides that amended §89.023, and the rules implementing it, take effect September 1, 2027 (SB 1150, §§4–5).

Alliance Recommendation *The Alliance requests that the definition in (a)(1) track the statute's measurement date; that (n) and (o) measure well age from the date the completion report was filed, as §89.050 does; that the rule confirm a well's period of inactivity starts over once it is restored to active operation under (a)(2); and that the rule state an operator's first 15/25 extension application is due with its first organization report renewal on or after September 1, 2027.*

J. Economic impact on small and micro-businesses

The proposal concludes that the amendments will have no adverse economic effect on small or micro-businesses, and that no economic impact statement or regulatory flexibility analysis under Texas Government Code §2006.002 is required, because the new plugging extensions are optional. Several costs in the proposal are not optional, however: fluid level or hydraulic pressure testing for every inactive well more than 15 years old, annual submission of test results, and nonoperator research for every 15/25 well. For a small operator that cannot obtain an extension, the alternative is plugging capital on an accelerated schedule.

Alliance Recommendation *The Alliance requests that the Commission revisit its §2006.002 determination, prepare the economic impact statement and regulatory flexibility analysis, and consider the alternatives in these comments as less burdensome ways to meet the statute's objectives.*

Conclusion - The Alliance appreciates the Commission's work to implement SB 1150 and the opportunity to comment on the proposed amendments to SWRs 15 and 58. The changes we have proposed are targeted, fit within the existing framework of the draft rule, and would make the rule more workable for operators and simpler for staff to administer, while still meeting the statute's goal of addressing long-term inactive wells by September 1, 2042.
A summary of our recommendations is provided below for the Commission's convenience. We welcome the opportunity to discuss these comments with staff and would be glad to provide any additional information that would be helpful.

Summary of Recommendations

Issue	Rule provision	Alliance recommendation
A. Full cost calculation	SWR 15(a)(6)	Publish an annual district-by-depth cost table; define indirect costs; use staff/NICRA components only when the state plugs.
B.1. Restoring wells	SWR 15(i)(1)(A)	Add a third criterion based on inactive-to-total well ratio credit plugging and injection/disposal conversions.
B.2. Restoration lookback	SWR 15(i)(1)(A)	Preceding year or three-year average; define "preceding year" as the P-5 renewal period; conform preamble.
B.3. Credit for different dispositions	SWR 15(i)(1)(A)	Credit plugging and injection/disposal/monitoring well conversions.
C.1. Ownership-group test	SWR 15(i)(1)(B)	Optional hardship test on wells with common working interest ownership; attestation and CPA statement; no decks filed.
C.2. Revenue test	SWR 15(i)(1)(B)(i)	Use the same annualized (one-fifteenth) cost in every hardship test.
C.3. Net assets	SWR 15(i)(1)(B)(ii)	Use "net assets" instead of "total assets."
C.4. EBITDA test	SWR 15(i)(1)(B)(iii)	Conform rule text to preamble using average annual EBITDA; exclude interest income and one-time gains.
C.5. 15/25 vs. full plugging obligation	SWR 15(i)(B)	Compare operator's resources with its total plugging obligation, not just 15/25 plugging obligations
C.6. Statutory factors	SWR 15(i)(1)(B)	Allow approval on the §89.023(e) factors; any one test is sufficient.
C.7. CPA Certified Financial Statements	SWR 15(h)(4)(B)	Compiled or reviewed financial statement sufficient; keep information confidential
D.1. Annual minimum	SWR 15(h)(4)(C)(i)(III); (i)(1)(C)(ii)–(v)	Cumulative milestones instead of a rounded annual minimum; plan in effect through 2042; credit wells above the minimum.
D.2. Plug/restore designation	SWR 15(h)(4)(C)(i)	Allow an "evaluate" designation; switching after testing is not a deviation if the annual count is met.
D.3. Regulatory standby	SWR 15(h)(4)(C)	Create a "regulatory standby" status for wells idle only due to proration/density limits.

D.4. Mandatory denial grounds	SWR 15(i)(2)(A), (C), (E), (F)	Deny only the affected well; narrow and define the hazard, penalty and bad-faith grounds.
D.5. Other denial grounds	SWR 15(i)(2)(B), (D), (E)	Three-year lookback; apply only to wells involved; define fault; protect bonded wells.
E.1. Transition window	SWR 58(a)(6)	One-year evaluation window after P-4 approval for transferred 15/25 wells.
E.2 Joint affirmation	SWR 58(a)(5)	Divide the affirmation: seller affirms compliance at transfer; buyer affirms good faith going forward.
E.3 Transferability	SWR 15 / 58	Clarify that compliance plans transfer to new owners.
E.4. Buyer's own history	SWR 58(a)(6)	Buyer may apply immediately on its own restoration record.
F. Testing	SWR 15(n)	Phase in first tests and filings; annual submission may reference an approved test on file.
G. Performance bonds	SWR 15(h)(2); (i)(1)(D); (i)(2)(G)	Accept surety bonds; "not less than" the full cost; release on plugging or restoration; fixed amount; extension lasts while bond is in force. Also accept letters of credit and cash.
H. Nonoperators	SWR 15(h)(3)	Limit to WI owners of record and (i)(2)(A) persons; carry forward with updates.
I. Measurement; effective date	SWR 15(a)(1), (a)(2), (n), (o)	Track statutory measurement dates; inactivity restarts after restoration; first application at first P-5 renewal on or after 9/1/2027.
J. Small business impact	Preamble	Prepare the §2006.002 economic impact statement and regulatory flexibility analysis.

Sincerely,

Karr Ingham

11/19/2026

Karr Ingham
President
Texas Alliance of Energy Producers