COMMISSION SHIFT

November 20, 2026

Submitted via: rulescoordinator@rrc.texas.gov

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

Re: Commission Shift comments re: Amend §§3.15 and 3.58 re: Senate Bill 1150 (89th Legislative Session, 2025)

Dear Rules Coordinator:

Commission Shift has assembled a working group that has evaluated the proposed amendments to Rules 15 & 58 in light of SB1150, considered in detail the language provided, and offers input on the rulemaking for the Railroad Commission's consideration.

Commission Shift is a nonpartisan non-profit focused on reforming oil and gas oversight in Texas. We have met with community members and groups affected by oil and gas waste, inactive unplugged wells, and orphaned wells and have collected feedback relevant to the anticipated rulemaking.

In line with these goals and concerns, Commission Shift respectfully submits the enclosed comments. While preparing the rule, the working group emphasizes that the Railroad Commission ("RRC" or "Commission") must keep the Legislature's charge central to the rulemaking. That is, in adopting these rules, the RRC "shall consider: the risk to public safety or the environment; wellbore and wellhead integrity, including the ability to monitor casing pressure; and regional risk considerations, including penetration of corrosive or over-pressured formations and completion in zones containing hydrogen sulfide." Tex. Nat. Res. Code § 89.051(b).

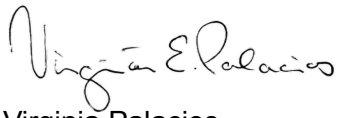
We also highlight that plugging extensions are a privilege, not a right. The statute uses the permissive word "may" to indicate that the RRC is not required to grant <u>any</u> plugging extensions. Tex. Nat. Res. Code § 89.023(c). The RRC must exercise its authority to deny extensions that put health, safety, or the environment at risk. Tex. Nat. Res. Code § 89.051(b); 89.023(f)(7). A strong rulemaking will incorporate rules to limit plugging extensions to better protect the public and environment from the risks posed by unplugged wells, including to taxpayer's pocketbooks and landowners' ability to enjoy their land.

Many of these comments mirror those that Commission Shift and the working group submitted on April 24, 2026 in advance of the rulemaking for the Commission's consideration as it prepared a formal rule. While we appreciate the meeting that was granted to discuss our concerns, Commission Shift was excluded from stakeholder meetings with trade association and operator representatives that the Commission held in the months before the draft rules were made public. As part of those meetings, at least one draft of Rule 58 and three drafts of Rule 15 were shared with trades and operators, which do not appear to have been otherwise made public. In fact, those drafts were withheld for weeks from Commission Shift, and were not disclosed until a week before the comment period ended, despite multiple information requests. Texas's Public Information Act required that they be disclosed much more promptly. This—coupled with an unusually short comment period and no automatic public hearings scheduled during the comment period—does not engender public confidence in the Commission, especially when public records show how much influence industry has had to weaken the drafts thus far.

As for the substantive comments that follow, in Part 1 we have shared more global comments and rulemaking considerations to frame the rulemaking, then in Part 2 specific comments are offered in order of Rule 15 and 58 sections.

Commission Shift welcomes a dialogue with the Commission as any questions or concerns arise during the Commission's review of these recommendations. The Commission must listen to the voices of concerned Texans. Please implement common-sense rules that safeguard human health and the environment, as required by statute.

Sincerely,



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Enclosures

Enclosures have been sent in multiple parts due to file size limitations.

Enclosure 1 contains Appendix B and Exhibits 1-15.
Enclosure 2 contains Exhibits 16-30.

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Executive Summary

Commission Shift consulted with a group of groundwater experts, representatives from Groundwater Conservation Districts, industry experts, legal experts, regulatory experts, energy advisors, landowners, and other interested stakeholders to review SB 1150 and make suggestions as to its implementing regulations. Commission Shift also offered organizations who did not participate in the working group an opportunity to sign on to these comments. A list of working group participants and other organizations who have reviewed these recommendations and are generally supportive is provided in Appendix A. The term "Commenters" as used in this document refer to all of these individuals and groups that have signed on, including Commission Shift.

While preparing the rule, the working group emphasizes that the Commission must keep the Legislature's charge central to the rulemaking, namely that in adopting these rules, the RRC **"shall consider: the risk to public safety or the environment; wellbore and wellhead integrity, including the ability to monitor casing pressure; and regional risk considerations, including penetration of corrosive or over-pressured formations and completion in zones containing hydrogen sulfide."** Tex. Nat. Res. Code § 89.051(b)(1)-(3).

We also highlight that **plugging extensions are a privilege, not a right**. The statute uses the permissive word "may" to indicate that the RRC is not required to grant <u>any</u> plugging extensions. Tex. Nat. Res. Code § 89.023(c). The RRC should exercise its authority to deny extensions that put health and safety, or the environment, at risk, and unnecessarily impose on taxpayers and surface owners' property rights.

We are disappointed that the Commission has not made this rulemaking transparent and accessible, as we requested in our April 2026 letter and have called for repeatedly for all rulemakings. The Commission should have offered in-person opportunities for public input around the state, especially near communities with oil and gas activity, and should extend the comment period or alter their rulemaking timeline to allow for those opportunities.

The following is a summary of our top recommendations, with detailed explanations provided in the corresponding sections of the rule:

- Direct public feedback is essential to the RRC's mission of stewarding natural resources and the environment and protecting personal and community safety.
- The final rules should reduce Texas's inventory of inactive wells, prevent new orphans, and prevent inactive wells from remaining unplugged indefinitely. To adequately address Texas' inactive well problem, please make these changes to the rules:
    - As statute requires, before granting any extension, specify how the RRC is fully considering "risk to public safety, health, and the environment; wellbore and wellhead integrity, including the ability to monitor casing pressure; and regional risk considerations, including penetration of corrosive or over-pressured formations and completion in zones containing hydrogen sulfide."

- Set stricter well integrity standards and monitoring of casing pressure; ban extensions in high-risk zones. Require annual mechanical integrity testing of these wells.
- Set clear metrics based on statutory criteria to ensure operators applying for "financial hardship" still plug wells and that they have a path out of hardship. As is, the proposal allows business-as-usual practices of indefinite plugging extensions that lead to well orphaning.
- Update the definition of "active operation" to require meaningful, economic production.
- Require well-specific reports for each 15/25 well, certified by professionals, confirming the well still has economic value and future beneficial use.
- Regardless of the extension option requested, require a well-specific plugging-or-restoration plan and schedule for all 15/25 wells, and deny extensions if the operator deviates without good cause so wells with no benefit do not remain unplugged indefinitely.
- Only older inactive wells, not younger wells, should count toward qualifying for a plugging extension based on a history of "returning inactive wells to operation." RRC's rules must prevent operators from gaming the system by temporarily shutting wells on and off to gain extensions.
- Say the Commission "shall," not "may," deny applications that remain incomplete and do not meet the criteria set by the Commission.
- Ensure that an operator's compliance history is fully considered before granting extensions, and more clearly specify what types of violations will result in denial of extensions.
- Establish administrative penalties for rule violations and false affirmations for transfers as required by SB 1150, with bigger penalties for falsification and repeat offenses.
- Set clear metrics for a good-faith transfer and make operators submit evidence to substantiate their claim, with an opportunity for interested parties to rebut the evidence.
- Give more notice and standing to interested parties like surface and mineral owners for observing well tests and participating in transfer and extension proceedings. Afford landowners and other interested parties the opportunity to protest and operators the opportunity to prove their good-faith claim to operate and maintain 15/25 wells, or require them to plug the wells.
- Landowners and the public should have public, searchable information on applications, compliance plans, which wells are granted extensions and why, and whether the operator is complying with its declared plans.

In addition, Commenters adopt many of the recommendations made by Environmental Defense Fund ("EDF") in its November 13, 2026 Comment Letter (attached as **Appendix B**). The sections of EDF's letter that Commenters join are further described below, and includes the recommendation that the Commission require evidentiary hearings before the Commission approves extensions based on an operator's history of restoring inactive wells or financial hardship under Texas Natural Resources Code § 89.023(c)(1).

Part 1: General Comments

Factual Background on Why This Matters

The Commission has long recognized that "inactive unplugged land wells pose a continuing threat of pollution of subsurface and surface usable quality water because the open wellbore is a potential conduit for flow from oil and gas zones or salt-water zones to fresh water zones or to the surface."[1] These inactive wells are liabilities that become more expensive to address over time. Unmonitored inactive wells today become neglected and abandoned zombie wells tomorrow, which must be plugged at significant cost to the taxpayer and have the potential to cause serious pollution and harm safety. Commission Shift has recommended for years that Texas improve how it handles inactive and orphan wells.[2] Recent public opinion research in Texas and other oil-producing states shows a broad-based support approaching 90% for requiring clean-up, and a strong super-majority of 72% support for requiring the oil industry to pay the costs.[3]

SB1150 was passed into law in 2025 and is the state's latest attempt to address the proliferation of inactive land wells. It both updates the rules for all inactive wells and sets additional rules for a subset of older wells that were completed over 25 years ago and have been inactive for at least 15 years ("15/25" wells). In particular, SB 1150 takes a modest step toward limiting how long a well can stand idle: Wells may stay inactive for only 15 years unless they are less than 25 years old or the Commission grants an extension. All other factors being equal, these older wells are most at risk of becoming orphaned and are also more likely to

[1] Proposed Rule 16 TAC 3.15, 35 Tex. Reg. 5407, 5414 (June 25, 2010). This fear is not without basis; a review of groundwater contamination from oil and gas development by the Ground Water Protection Council (2011) found that abandoned wells accounted for 14% of groundwater contamination events in Texas. Meanwhile, "across the country something like 95% of all production is from wells that produce more than 15 BOE a day, and 5% is from wells that produce less." Adam Peltz, Testimony to Committee on Energy Resources (2026). https://house.texas.gov/videos/22867 at 4:27:45-4:27:58.

[2] *See* Ex. 1 Unplugged and Abandoned: The growing orphan well crisis facing the Railroad Commission of Texas. (Feb. 2021) https://commissionshift.org/wp-content/uploads/2025/02/Unplugged-and-Abandoned-Mar-2021.pdf; Ex. 2 Eliminating Orphan Wells and Sites in Texas: A Toolkit for Redesigning the Railroad Commission's Oil and Gas Well Plugging and Cleanup Programs. (Jan. 2022) https://commissionshift.org/wp-content/uploads/2023/02/Eliminating-Orphan-Wells-and-Sites-in-Texas_CommissionShift.pdf.

[3] Frequently Asked Questions, https://www.texasorphanedwells.org/faqs (citing Resilient Energy Economics. *Public Opinion on Economic Transitions in Oil- and Gas-Producing Communities.* (June 2026) https://cdn.prod.website-files.com/65f9f863036e7bbd0fc012f9/6a3ea3c31843d7c911394442_REE%20Policy%20Brief%20-%20Mahdavi%20Public%20Opinion%203.pdf ("Nearly three out of four respondents (72%) want oil companies to pay for the costs of plugging old oil and gas wells. This holds across conservatives (74%), moderates (65%), and liberals (85%); and oil industry workers (70%) as well as non-oil workers (74%).")).

threaten public health, safety, and the environment.[4] Younger inactive wells still affect land use and value, but they are less likely to be actively causing other problems.

As the Commission considers which amendments to adopt, it may also be helpful to consider how the composition of these wells will change over time. In practical terms, the wells that qualify when the rule goes into effect will have been completed in 2002 or before, and became inactive in 2012 or before. These will likely be vertical wells. But every year, more and more wells have the potential to graduate into this class. For example, by 2036, 15/25 wells will include those completed on or before 2012, and that became inactive in 2022 or before. These may be a mixture of vertical and horizontal wells, with different risk profiles.

By year...	… a 15/25 well was completed…	…and became inactive…	… with the following characteristics:
2027	On or before 2002	On or before 2012	Likely a vertical well
2032	On or before 2007	On or before 2017	Likely a vertical well
2037	On or before 2012	On or before 2022	A mix of vertical and horizontals
2042	On or before 2017	On or before 2027	A mix of vertical and horizontals; last year the compliance plan extension is available.
2047	On or before 2022	On or before 2032	A mix of vertical and horizontals, no compliance plan extension available.

To help the public track and learn more about inactive and orphaned wells in the state over time, Commission Shift and its partners have launched a website and mapping function for these wells based on Commission data: https://www.texasorphanedwells.org/. Currently it's estimated that there are over 105,000 inactive wells in Texas, at least 14,000 of which are current 15/25 wells, with an additional 91,000 aging into the category by the time compliance plans expire in 2042.[5] Estimated plugging costs for all current 15/25 wells exceeds $1.76 billion dollars; and the plugging cost for the additional inactive wells are estimated to exceed $15 billions dollars, a cost that will fall on the taxpayer if these wells become orphaned.[6] But it also

[4] Adopted Rules 16 TAC §3.15, 36 Tex. Reg. 5096, 5097 (Aug. 12, 2011) ("All other factors being equal, the older a well is and the longer a well has been inactive, the more likely the well is to suffer a mechanical failure or otherwise become a potential threat to ground or surface water.").

[5] Data from https://www.texasorphanedwells.org/methodology (explaining that "Our figure for inactive wells runs similarly lower than other sources because we exclude orphaned wells and exclude wells inactive for less than 12 months. Still-unplugged orphaned wells are sometimes counted as a subset of inactive wells, as in the RRC's Inactive Well Aging Report which shows a higher number. The RRC's Well Distribution Tables shows a significantly higher number of inactive wells because it also includes wells inactive for less than 12 months. This report by the RRC often shows 150,000 to 160,000 inactive wells in each month.").

[6] Per a conservative methodology used to estimate costs. *See* https://www.texasorphanedwells.org/methodology Other sources estimate this cost to be higher. *See e.g.,* Ex. 3 Intraigo, Luis Fernandez. *Texas can create 150,000 jobs by plugging non-producing wells.* (April 4, 2025).

brings the opportunity for job growth: EDF estimates that for plugging inactive wells, 79,500 direct plus indirect jobs would be created, while long-term idle wells (15 years or longer) would account for the creation of nearly 14,800 direct and indirect jobs.[7]

With this rulemaking, the Commission has an excellent opportunity to guide industry toward reducing the number of wells that remain inactive indefinitely and while ultimately reducing the number of orphaned wells that become financial burdens for the citizens of the state and creating jobs.[8]

Legal Background

The SB1150 Rulemaking Must Comply with the Texas APA.

The Texas Administrative Procedures Act prioritizes public participation in the rulemaking process and sets the minimum standards of uniform practice and procedure for state agencies engaged in rulemaking.[9] The Commission must fully consider all written and oral submissions about the rule, and give all interested persons a reasonable opportunity to submit data, views, or arguments, orally or in writing.[10] Here, the Commission has failed to provide a reasonable opportunity for stakeholders to participate because it has not held public hearings throughout the state and at times convenient for the public to attend nor has it granted a minimum of 30 days for comment as measured from the date of notice.[11]

The Texas APA further requires the Commission to adhere to the following requirements, many of which the Commission has declared irrelevant. Critically, the Commission appears to have omitted a government growth impact statement under Tex. Gov't Code § 2001.0221[12] even though one is required if "implementation of the proposed rule requires ***the creation of new employee positions***"[13] and the preamble states that the Commission "expects additional costs to the Commission" because of the rule, in part "based on ***the Commission's need to . . . hire and retain 86 full-time employees***."[14] These two statements stand in contradiction to each other, which leaves the Commission open to litigation on this rule. Nor is litigation out of the

https://blogs.edf.org/markets/2025/04/04/texas-can-create-150000-jobs-by-plugging-non-producing-wells/ ("Inactive wells account for 21% of all wells in the state and represent a potentially enormous $15.5 billion plugging cost for taxpayers.")

[7] *Id.*

[8] Proposed Rule at 8:16-19 ("the public benefit anticipated as a result of enforcing or administering the amendments will be a reduction in the amount of wells that remain inactive indefinitely, and ultimately placed on the orphaned well list, becoming the responsibility of the Commission to plug, and financial burden of Texas.")

[9] Tex. Gov't. Code § 2001.001(1) & (2).

[10] Tex. Gov't Code § 2001.029(a)&(c).

[11] Tex. Gov't Code § 2001.025 (notice is effective on date of filing in the Texas Register); Tex. Gov't Code § 2001.023 (30 days notice required prior to adoption); Tex. Gov't Code § 2001.029(a) (agency must give all interested persons a reasonable opportunity to provide input).

[12] *See* Proposed Rule at 9:11-15 (finding no impact on elements that correspond to those listed in Tex. Gov't Code § 2001.0221).

[13] Tex. Gov't Code § 2001.0221(b)(2) (emphasis added).

[14] Proposed Rule at 8:4-15 (emphasis added).

realm of possibility—indeed, the Commission's experience with the Waste Rules that went into effect in 2025 are even now being litigated by small operators claiming that the Commission failed to conduct a similar required analysis.[15] To protect its rule and avoid costly litigation (whose cost is ultimately borne by the Texas taxpayer), the Commission should remedy its error and include the required government growth impact statement under Tex. Gov't Code § 2001.0221.

In other aspects, the Commission appears to have complied with the APA. A small-business impact analysis under Tex. Gov't Code § 2006.002 is not needed because filing for an extension is not obligatory and "[a]n operator's duty to plug inactive wells has not changed because of these amendments, and thus, the amendments do not cause additional economic costs to regulated persons."[16]

Likewise, no regulatory analysis under Tex. Gov't Code § 2001.0225 is necessary because the rule is not a major environmental rule with any of the characteristics described by Tex. Gov't Code § 2001.0225(a)(1)-(4); instead it is a rule expressly required by a state law, namely SB1150.[17]

Moreover, there are many benefits expected from this rule — a decrease in inactive and orphaned wells will increase property values.[18] A working paper from April 2026 that analyzed data from wells decommissioned with federal funds in Texas and five other states highlighted prior studies and also independently agreed that property values should increase as wells are decommissioned.[19] A variety of other analyses have demonstrated that pollution mitigation efforts not only benefit the environment, but also can reduce public health risks and raise local property values (Currie et al. 2011; Zabel and Guignet 2012; Gamper-Rabindran and Timmins 2013; Haninger et al. 2017; Marcus 2021).[20] "Decommissioning well sites can also make locations more attractive for development. Harleman et al. (2022) estimate that construction activity around plugged and abandoned wells in one Pennsylvania county was significantly higher than construction around unplugged wells over several decades. They estimate that increased investment near plugged wells raised property values by 12 percent (compared with

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[15] *CrownQuest Operating, LLC v. Railroad Commission of Texas*, D-1-GN-25-007868 (53rd Dist. Ct., Travis County, Tex. Sep. 9, 2025).
[16] *See* Proposed Rule at 8:20-28. This is another reason that there is no basis for the Commission to add a definition of "small operator," as one commenter proposes.
[17] *See* Tex. Gov't Code § 2001.0225(a)(1)-(4) (describing the conditions in which the regulatory analysis is not required).
[18] *See* Proposed Rule at 8:32-9:1-4 (finding that "[T]hese rules may have a positive economic effect on rural communities, small businesses, or micro-businesses, as SB 1150 and these amendments intent is to decrease the number of inactive wells, and ultimately, the number of orphaned wells, which should increase economic opportunity via growth in the well plugging industry, and potentially increased property values as a result of a decrease in inactive wells and orphaned wells.")
[19] Ex. 4 Daniel Raimi and Christina Cilento, *Costs and Benefits of Decommissioning Orphaned Oil and Gas Wells: Evidence from Six States*, Working Paper 26-07 at 21 (April 2026) https://media.rff.org/documents/WP_26-07_Updated_2026-05-18.pdf (estimating a total of approximately $8 million in property value increases for properties where federal funds were used to decommission wells across the six states).
[20] *Id.* at 14.

properties surrounding unplugged wells)."[21] In addition, low-producing and inactive wells can prohibit landowners' access to tax breaks on the surface. For example, one participant at this rulemaking public hearing noted that unproductive oil and gas infrastructure on his property precluded him from growing timber on part of his land, thereby disqualifying those affected acres from special timberland valuations and costing him thousands of dollars in property tax exemptions. Benefits to the environment and public health and safety are also well documented. Another commenter on this rulemaking reported the problems with submarginal wells on his property, which have been the source of a dozen RRC-documented saltwater spills into his cattle pasture, permanently killing the grass and spreading salty contamination over the property.[22]

Finally, when adopting the SB1150 rules, the Commission must include a reasoned justification for its decision, which includes a summary of comments received, a summary of the factual basis for the rule as adopted which demonstrates a rational connection between the factual basis for the rule and the rule as adopted, and the reasons why the agency disagrees with party submissions and proposals.[23] Failure to do so can be a reason for a court to declare the rules void and remand them to the agency.[24] As such, the Commission should be careful to address each comment received on its proposal and if it disagrees, explain the reasons why. This explanation must go into the adopted rule preamble, or the Commission puts itself at risk of litigation and puts the SB1150 rules in danger of being voided completely.

The Legislature Intended SB1150 Rules to Not Ignore Safety and Risks, to Incentivize Plugging, and to be Objective; as Proposed the Rule is Vulnerable to Litigation.

A rule is at risk of being declared void if it "(1) contravenes specific statutory language; (2) runs counter to the general objectives of the statute; or (3) imposes additional burdens, conditions, or restrictions in excess of or inconsistent with the relevant statutory provisions."[25]

Here, the Legislature has identified three factors that the Commission must consider when adopting SB1150 rules, namely Tex. Nat. Res. Code § 89.051(b)(1)-(3):

> *Sec. 89.051. RULEMAKING. (a) The commission shall adopt rules as necessary to regulate and monitor inactive wells under this chapter.*

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[21] *Id.* at 5 (citing Harleman, Max, Jeremy G Weber, and Daniel Berkowitz. 2022. Environmental Hazards and Local Investment: A Half-Century of Evidence from Abandoned Oil and Gas Wells. Journal of the Association of Environmental and Resource Economists 9 (4): 721–53.). *See also* Ex. 5, Harleman, Max and Harleman, Max and Weber, Jeremy and Berkowitz, Daniel, Environmental Hazards and Local Investment: A Half-Century of Evidence from Abandoned Oil and Gas Wells (September 14, 2020) at 3. USAEE Working Paper No. 20-470, Available at SSRN: https://ssrn.com/abstract=3692098 or http://dx.doi.org/10.2139/ssrn.3692098

[22] Comment of William Lovelace (Nov. 16, 2026) https://www.rrc.texas.gov/media/5pxcsdux/111626-sb-1150-lovelace-william.pdf

[23] Tex. Gov't Code § 2001.033.

[24] Tex. Gov't Code § 2001.040.

[25] *Tex. State Bd. of Exam'rs of Marriage and Fam. Therapists v. Tex. Med. Ass'n*, 511 S.W. 3d 28, 33 (Tex. 2017).

> *(b) In adopting rules under this section, the commission shall consider:*
> *(1) the risk to public safety or the environment;*
> *(2) wellbore and wellhead integrity, including the ability to monitor casing pressure; and*
> *(3) regional risk considerations, including penetration of corrosive or over-pressured formations and completion in zones containing hydrogen sulfide.*

The Commission has not sufficiently considered these factors nor provided any provisions for how these factors will be considered in regulating, monitoring, or in granting plugging extensions. *These statutory considerations apply to **all** inactive wells*, not solely to 15/25 wells: Tex. Nat. Res. Code § 89.051(b) refers to "inactive wells under this chapter"; neither the subsection, section nor chapter is limited to regulating 15/25 wells. When drafting rules, the Commission should keep in mind that there may be formations in which aging, inactive wells cannot be left unplugged safely because the risk is too great. Additionally, conditions in a formation can change. If conditions in an area have deteriorated, the Commission should have criteria for evaluation of such a formation and the duty to deny any plugging extension within that area, for any inactive well.

In addition, Tex. Nat. Res. Code § 89.023(j) requires the Commission to set administrative penalties for violations of SB1150 and its rules, but no such penalties have been proposed. Therefore the rule as proposed both contravenes specific statutory language and runs counter to the general objectives of the statute, and is vulnerable to litigation. Ways to remedy these errors are proposed in Part 2, the Section-by-Section comments.

In addition to the statutory language that demonstrates legislative intent, several lawmakers close to the bill have weighed in as to the intentions behind SB1150. While not as persuasive as the legislative intent that can be gleaned from the language of SB1150 itself, the letters from these drafters—albeit from individuals—can help illuminate intent when it is unclear. Senator Kevin Sparks, Chairman of the Committee on Natural Resources identifies that "[t]he goal of this legislation is long-term compliance and the eventual plugging of wells that pose a genuine risk to the public and the environment."[26] "If the agency gets it wrong, this mandates a legislative fix."[27] Senator Sparks requested that the Commission specifically:[28]

- *Establish objective, specific criteria for financial hardship extensions that operators can evaluate and apply without uncertainty about Commission discretion;*
- *Protect against the transfer of liability to undercapitalized or bad-faith operators while providing reasonable transition provisions for legitimate transferees;*

[26] Ex. 6 Sparks, Sen. Kevin. *Legislative Intent and Expectations for Rulemaking Under Senate Bill 1150 (89th Legislature)* (July 16, 2026) ("The extension process exists to give responsible, legitimate operators a workable ***path to compliance***.") (emphasis added).
[27] *Id.* at 2.
[28] *Id.*

- *Tie economic hardship determinations to objective, published external benchmarks so that the goalposts cannot be moved through administrative discretion.*

Senator Mayes Middleton, author of Senate Bill 1150, also authored a letter to the Commission to further clarify legislative intent of the bill.[29] He describes the two goals of the bill: (1) increasing the number of inactive wells plugged; and (2) shifting the burden onto operators and away from the state, as "complementary, not competing":

> The objective of Senate Bill 1150 was never solely to increase the number of inactive wells plugged in a single year. The broader objective was to, over the next decade, reduce the number of orphaned wells plugged by state funds.

Senator Middleton further stated that "[w]herever possible, the Commission should rely on objective standards that are transparent, measurable, and consistently applied."[30] He also reiterated that transfers should not be allowed for those who cannot comply with Commission rules.[31] And that extensions should go only to responsible operators who demonstrate "measurable progress"---the Commission's rules should actively "reward[] compliance rather than discourage[] it."[32]

A Brief Legislative History: Current Rules 15 & 58 Have Not Been Updated Since 2017 and Are Ripe for Independent Review

This rulemaking proposes changes to Rules 15 and 58, which have not been updated for some time, despite Tex. Gov't Code § 2001.039's requirement that agencies review adopted rules every four years and assess whether the reasons for initially adopting the rule continue to exist.[33]

For example, Rule 15 was last updated in 2016, in which the definition of "active operation" was expanded to encompass lower producing wells. Instead of keeping the threshold for return to active operation at production levels of 10 barrels of oil / 100 Mcf of gas each month for three consecutive months (as it had been since 2000[34]), the Commission decreased the

[29] Ex. 7 Middleton, Sen. Mayes. Letter to Commission Chairman Jim Wright. (July 28, 2026).
[30] *Id.*
[31] *Id.* ("Strong enforcement should remain focused on those seeking to transfer liabilities they cannot satisfy or otherwise avoid their legal responsibilities.")
[32] *Id.* (stating that "responsible operators demonstrating measurable progress should encounter a regulatory framework that rewards compliance rather than discourages it.")
[33] Tex. Gov't Code § 2001.039.
[34] At which point the definition was found in Rule 14. Proposed Rules for 16 TAC 3.14, 25 Tex. Reg. 6888, 6889 (July 21, 2000) (adding the minimum production level). ("Finally, amendments are proposed to the definition of "active operation." Under the newly-proposed definition, once a well has been inactive for one year, the well will remain designated as inactive and subject to the requirements for inactive wells, regardless of any minimal activity, until the well has reported production of 10 barrels of oil or 100 mcf of gas per month for at least three consecutive months. This definition change is proposed to alleviate the problem of operators filing "paper production" or taking de minimis actions, not truly intended to restore

minimum production volume to 5 barrels of oil / 50 Mcf of gas each month for three consecutive months or 1 barrel oil / 10 Mcf of gas each month for 12 consecutive months. In essence, the Commission reset the threshold for active operation to a de minimis standard because 1 barrel oil is the minimum reportable amount.[35]

The Commission originally raised the threshold for active operation to 10 barrels / 100 Mcf because of the problem of operators taking de minimis actions to avoid inactive well rules:[36]

> amendments to the definition of "active operation" alleviate the problem of operators filing "paper production" or taking de minimis actions, not truly intended to restore the well to continuous active operation, and claiming this minimal activity relieves them from the obligation of complying with the rules for maintenance and transfer of inactive wells.

But exactly such a problem has again arisen with the 2016 modification to the definition of "active operation." Indeed, the Commission's annual reports show that the number of inactive wells has risen from 116,067 in 2016 to 156,531 in 2025, despite relatively steady plugging.[37] Over the same time period, the orphaned well population has increased from 6,805 wells to 10,029 wells.[38] Clearly the 2016 revisions and Rule 15 as currently drafted has not helped diminish the orphaned well population; holistic change is needed, in line with Commenters' suggestions.

SB1150 Forms Should be Addressed in This Rulemaking and in Compliance with the Texas APA.

It is Commenters' understanding that after the SB1150 rules are adopted, the Commission will need to update its forms accordingly, including Form W-3X.[39] The Commission must not use the form drafting processes as a way to weaken the adopted rules. Any attempt to

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the well to continuous active operation, and claiming this minimal activity relieves them from the obligation of complying with the rules for maintenance and transfer of inactive wells."))

[35] *See* Monthly Production Report Instructions, Form PR (Jan. 25, 2022) https://www.rrc.texas.gov/media/mxcpw5vn/form-pr-instructions-01-25-2022.pdf ("Indicate volumes for each lease as monthly totals, in whole numbers, computed by accepted standards of measurement. Do not use decimals, fractions, or negative numbers.").

[36] Adopted Rules for 16 TAC 3.14. 25 Tex. Reg. 9924, 9925 (Sep. 29, 2000).

[37] RRC, *Oilfield Cleanup Program Annual Report* (2016) at 3 https://www.rrc.texas.gov/media/portalvhdskzlfb8q9lqr9/37219/ogrc-annual-report-2016.pdf; RRC, *Oilfield Cleanup Program Annual Report* (2025) at 4 https://www.rrc.texas.gov/media/xgtpvwhf/2025-oilfield-cleanup-program-annual-report_final.pdf. And as explained above (supra note 3), it is difficult to ascertain the exact number of inactive wells given inconsistencies in the Commission's database, but conservative estimates from https://www.texasorphanedwells.org indicate that the current population is over 105,000.

[38] RRC, *Oilfield Cleanup Program Annual Report* (2016) at 3 n.1 https://www.rrc.texas.gov/media/portalvhdskzlfb8q9lqr9/37219/ogrc-annual-report-2016.pdf; RRC, Oilfield Cleanup Program Annual Report (2025) at 12 https://www.rrc.texas.gov/media/xgtpvwhf/2025-oilfield-cleanup-program-annual-report_final.pdf;

[39] Ex. 8 Form W-3X. Application for an Extension of the Deadline for Plugging an Inactive Well. https://www.rrc.texas.gov/media/2vymqxgz/w-3x-fill.pdf

do so would run afoul of the Texas Administrative Procedures Act, which sets the procedural requirements for substantive rulemaking.[40] **Commenters request an equal seat at the table with trades and associations when the SB1150 forms are being drafted, including access to all pre-public drafts shared with third parties and equal opportunity to provide feedback.** And any form changes or additional forms should go through a public comment process fully compliant with the APA.

Moreover, as the Commission explained in its 2010 amendments to Rule 15, the APA requires that the rule must identify **"**the specific form to be used to meet the requirements of a rule."**[41]** This suggests that the forms for the SB1150 rules should be developed concurrently with these rules, not after the fact.

Furthermore, the Commission should draft SB1150 rules with sufficient clarity and detail such that the information that must be collected by form is straightforward and comprehensive, and that such information allows the Commission to fulfill its other reporting requirements, including the new annual report required by SB1150 (Tex. Nat. Res. Code § 89.049).

An Overview of What's Still Missing

Robust Avenues for Public Participation in the Rulemaking

This rulemaking is another example of how the Commission has failed to include robust avenues for public participation in its rulemaking, to the expected detriment of public health, safety and the environment.

The Working Group's April 2026 comments[42] highlighted many ways the Commission could better incorporate public feedback into its SB1150 rulemaking, such as:

- Offer multiple in-person opportunities for public input around the state, especially near impacted communities with O&G activity.
- Ensure meetings are held at times that are convenient for the general public, with language interpretation available.
- Give adequate notice of such meetings to ensure potential participants have time to prepare and make arrangements to attend.

[40] *See* Tex. Gov't. Code § 2001.003(6) (defining "rule[s]" subject to the Texas APA). The Commission's recent procedures for form approvals has not treated forms as rules and so has not involved necessary APA procedures like posting notice through the Texas Register.

[41] Adopted Rules, 35 Tex. Reg. 8332, 8333 (Sep. 10, 2010) ("TXOGA recommended that references to specific forms should be replaced with "the appropriate form" to avoid having to amend the rule any time a new form is created. **The Commission disagrees with this comment as well.** The reference in the rule text to the specific form to be used to meet the requirements of a rule **is necessary to meet the mandate of the Administrative Procedure Act that agencies adopt rules of practice stating the nature and requirements of all available formal and informal procedures**.") (emphasis added).

[42] Ex. 9 Working Group Comments (April 2026).

These are all means of increasing public input that the Commission has used in the past, but in recent years shied away from—for example during the 2002 proposed amendments to Statewide Rule 8, six public workshops were held across the state to seek input,[43] yet for the most recent amendments of Rule 8, no such meetings were held. Nor did the Commission hold such meetings or hearings for the SB1150 rulemaking; indeed, the only public hearing set for the SB1150 rulemaking came only after Commission Shift and members of the public repeatedly advocated for it.[44]

Commission Shift has also repeatedly requested that the Commission include it and other public stakeholders in the informal stakeholder meetings that the Commission has held on other recent rulemakings. In the past, input of landowner and public groups has been important in bill drafting—for example, starting in 2007, HB 2259 and its implementing rules (which included Rule 15) were shaped by an Inactive Well Study Group, "which included associations representing both industry and landowners."[45] Indeed, other states also recognize the importance of including a broad coalition in the drafting of rules.[46] Texas should do so as well.

As in prior rulemakings,[47] Commission Shift was again excluded from stakeholder meetings with trade association and operator representatives that the Commission held in the months before the draft rules were made public.[48]

As part of those meetings, three drafts of Rule 15 and one draft of Rule 58 were shared with trades and operators, which do not appear to have been otherwise shared with non-industry stakeholders.[49] In fact, those drafts were withheld for weeks from Commission Shift (well beyond the deadlines set in the Public Information Act), and were not disclosed until a week before the comment period's close, despite multiple information requests and follow-up

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[43] The workshops were held in Midland, Wichita Falls, Houston, Kilgore, Austin, and Amarillo. "A total of 188 people attended, including 152 representing industry, six representing land and royalty owners, seven with groundwater conservation districts, and 23 who identified themselves as representing 'other.'" Comments were received from 120 persons, many who were not in attendance at the workshops. "Proposed Rules: 16 Tex. Admin. Code § 3.8," 27 Tex. Reg. 4264, 4265 (May 17, 2002).

[44] *See* Ex. 10 Commission Shift Request for Hearings (Oct. 16, 2026) https://www.rrc.texas.gov/media/siho5as5/101626-sb-1150-commission-shift.pdf; Ex. 11 Commission Shift Request for Hearings (Nov. 6, 2026) https://www.rrc.texas.gov/media/4bwpyfgp/110626-sb-1150-commission-shift.pdf.

[45] "Proposed Rules: 16 Tex. Admin. Code §§ 3.1, 3.14, 3.15, 3.21, 3.78," 35 Tex. Reg. 5407, 5407-08 (June 25, 2010).

[46] For example, the New Mexico rulemaking on idle well management, financial assurance, and well transfer involved industry, nonprofits and regulators.

[47] Commission Shift and other landowner and public interest groups were excluded during the pre-public "stakeholder" meetings on the Rule 8 and Chapter 4 rulemaking in 2021-2023.

[48] While Commission Shift was granted a meeting in mid-2026 to discuss the Working Group Recommendations, such a meeting is not the same as being able to review pre-public rule drafts and work side-by-side with industry stakeholders and regulators at the same time. Moreover, the Commission regularly takes one-on-one meetings with trade associations and operator representatives; a single meeting with a public interest group does not equate to an equal seat at the table for groups that represent community or landowner interests.

[49] Ex. 12 (Aug. 12, 2026 Rule 15 Draft); Ex. 13 (Sep. 2, 2026 Rule 15 Draft); Ex. 14 (Sep. 16, 2026 Rule 15 Draft) (marksups in original); Ex. 15 (Apr. 5, 2026 Rule 58 Draft).

reminders.[50] Texas's Public Information Act required that they be disclosed much more promptly. This—coupled with an unusually short comment period and no automatic public hearings scheduled during the comment period—does not engender public confidence in the Commission, especially when public records show how much influence industry has had to weaken the drafts thus far.[51] Select instances of how industry has weakened the draft rules are highlighted in the relevant sections in Part 2.

Robust Avenues for Participation by Affected Persons in the Extension Review Process are Still Missing.

The proposed rules lack avenues for affected persons to participate in the review process for extensions even though the statutory language supports their inclusion.

Commenters agree with EDF's comments as to the necessity of hearings,[52] but go one step further to argue that hearings should be required for all proposed extensions to determine whether the wells warrant Commissioner approval for extensions described in subsection (c) for inactive wells. Operators should be required to give written notice to land and mineral owners and other affected persons of any request for an extension and affected persons should be afforded standing to participate in the hearing before the extension is granted.

For Texas landowners, farmers, and ranchers, inactive and orphaned wells can adversely impact their legal interests and property rights. These wells can interfere with agricultural operations, limit productive land use, threaten groundwater and surface water resources, and impose significant costs on landowners. Protecting private property, water resources, and agricultural productivity requires ensuring that operators remain responsible for the wells they own. Likewise, mineral and royalty owners may have interests impacted by the decision to grant a plugging extension for a nearby well. In addition, groundwater districts, counties, and municipalities all likely have at least public health, safety, and environmental protection interests that are implicated by the decision to grant a plugging extension. Therefore notice should go at least to:

- Each surface owner of the tract on which the inactive well is located;
- Impacted mineral and royalty owners;
- The county in which the well is located, with notice provided to the county clerk;
- Any municipality within whose boundaries the well is located, with notice provided to the city clerk or other appropriate official; and
- Any groundwater conservation district with jurisdiction over the location of the well.

[50] Ex. 16 (Commission Shift Emails to the Commission). Ex. 17 Public Information Act Requests filed by Commission Shift regarding SB1150 (Aug. 21, 2026) (Sep. 5, 2026) (Oct. 5, 2026).
[51] Ex. 18 (Excerpts of PIA Responses). *See also* Ex. 19 Comments of Dwyane Purvis. https://www.rrc.texas.gov/media/4ywfwtlw/110226-sb-1150-purvis-dwayne.pdf ("Industry has told me that they have extensive input to the rules before they were published, and short-sheeting the public comment only compounds the appearance of impropriety.").
[52] App. B (EDF Comments) at 8-12.

The Commission should require operators to send notice of the application to these persons and provide at least 30 days to file a protest before the hearing. An affected person who timely protests should be entitled to participate in the hearing and present evidence relevant to whether the requested extension is warranted and whether the operator has established a good-faith claim to continue operating the well.

These requirements would provide the Commission with a more complete evidentiary record and an opportunity to consider information from affected persons before determining whether an extension is warranted. They would also allow landowners and local governmental entities to raise concerns before 15/25 wells are allowed to remain unplugged.

Indeed, the statutory language supports the conclusion that evidentiary hearings are required before a "demonstrated history" exception or a "financial hardship" extension is granted. Specifically, Texas Natural Resources Code § 89.023(c)(1)(A) and (B) authorizes a 15/25 plugging extension only when ***the Commission*** determines, ***by order***, that an operator's demonstrated history of returning inactive wells to operation or financial hardship warrants an extension. The statute (section 89.023(g)) does not expressly provide a post-denial hearing right for these applications. In contrast, compliance plans may be approved by the Commission ***or its delegate***, and a post-denial hearing right is expressly specified by statute. In past revisions of Rule 15, the Commission explained that "the term 'delegate' allows for administrative approval by any designated Commission staff rather than only the executive director.[53] The Legislature's careful omission of the term "delegate" and insistence that an "order" be required for extensions under under (c)(1)(A) & (B) supports the understanding that SB1150 requires that the full safeguards of a hearing plus opportunity for affected persons be provided.

Although proposed §§ 3.15(h)(4)(A) and (B) require operators to submit written requests for Commission orders, the proposed rules do not require these applications to be referred to the Commission's Hearings Division or provide for an evidentiary hearing before the Commission determines whether an extension is warranted. **As such, the Commenters propose changes to those sections as described in Part 2 of these comments, adopting the blackline proposals found in EDF's comment letter regarding the right to a hearing with only minor changes.[54]**

Finally, simply because SB1150 allows the Commission's delegate to approve an extension based on a compliance plan, the Commission has the authority to adopt the

[53] Adopted Rules 16 TAC 3.15, 35 Tex. Reg. 8332, 8332-33 (Sep. 10, 2010) (The Commission was responding to a trade association's critique of its proposed rule: "TXOGA suggested that throughout the amendments and new rule, the term "its delegate" should be replaced with "executive director." The Commission disagrees with this comment; the term "delegate" allows for administrative approval by any designated Commission staff rather than only the executive director.).

[54] App. B (EDF Comment Letter) at 30 (Proposing amendments to 3.15(h)(4)(A) and 3.15(h)(4)(B)). Commenters adopt and advocate for this amendment language. As for the changes to 3.15(i), Commenters propose adding two sections (i)(1)(E) and (i)(1)(F) to clarify the hearing process; these two sections mirror the ones EDF proposes as (i)(1)(A) and (i)(1)(B). *See* Part 2 of these Comments; *see also* App. B (EDF Comments) at 31.

necessary rules to honor the intent of SB1150, which would include a right for affected persons to participate in an evidentiary hearing before the extension is granted.[55] The Legislature has identified several criteria that the Commission must assess before granting an extension based on a compliance plan for which input from affected persons is essential. Specifically, SB1150 requires that prior to approving a compliance plan extension, the Commission "shall consider" factors such as "(5) the well operator's record of compliance;" . . . "(7) any potential hazards to the health and safety of the public or the environment posed by the inactive well;" and "(8) any good faith demonstrated by the well operator." Affected persons would be uniquely situated to provide evidence as to these factors that the Commission must consider, but will only be able to if notice and an opportunity to participate is provided to them. Therefore Commenters recommend that notice and the opportunity to protest be provided to the same group as described above whenever an operator seeks a compliance-plan extension as well.

The Public Must Have Access to the Data and Reports Related to Inactive Wells

SB1150 requires the Commission to produce a new annual report about inactive wells (Tex. Nat. Res. Code § 89.049) and it requires operators to submit annual reports to the Commission about the testing results for each inactive well that was completed 15 years ago or more (i.e., more than just its 15/25 well population). All of these reports should be made publicly available on the Commission's website, without the need for the filing of a Public Information Act request.

Commenters also request that the annual report should include (perhaps as an appendix), a list of the extensions granted, especially those granted for financial hardship. Wells that receive financial hardship extensions are at most risk for becoming orphaned and whose plugging costs will fall on the taxpayer, so both the Legislature and the public should be informed of the extent of liabilities that will be likely in the future.

In addition, all documentation related to each extension (including applications that are denied) should be made publicly available online without a Public Information Act Request. This would necessarily include the well-specific plans identifying whether each 15/25 well will be plugged or restored to active operation, together with schedules for completing that work. Again, these wells are most likely to end up as orphaned wells to be plugged with public money; therefore the public has the right to know this information. In addition, operators should be required to send copies of their annual reports and all documentation related to each extension / extension request to the same entities that should be entitled to notice of an application:

- Each surface owner of the tract on which the inactive well is located;
- Impacted mineral and royalty owners;
- The county in which the well is located, with notice provided to the county clerk;
- Any municipality within whose boundaries the well is located, with notice provided to the city clerk or other appropriate official; and
- Any groundwater conservation district with jurisdiction over the location of the well.

[55] Tex. Nat. Res. Code § 89.051(a).

Providing direct notice of extensions, the well-specific plans, and compliance plans to these groups is essential to ensure that operators are complying with their commitments. It is widely acknowledged that the Commission does not have sufficient field staff to monitor all of the wells in the state, much less witness the monitoring of these wells (notice of monitoring should also be sent to these groups, who should be allowed access to witness well tests if they so choose). By making public this information and having it sent directly to the parties most invested in ensuring compliance, the Commission increases its ability to identify bad actors and prevent pollution,[56] a legislative purpose of SB1150 and of the Commission's enabling statutes in general.[57]

The SB1150 Program Must be Fully Funded

The fiscal reports on SB1150 make clear that substantial resources are needed to fully fund this program, including 7 new positions by 2027, 86 new positions by 2028, and $4 - $14 million dollars a year starting in 2027.[58] However, the Commission has not requested additional funding or FTEs for the 2027 Legislative Session.[59] The Commission must fully fund this program for the Legislature's intent to be fulfilled.

Commenters specifically request that the Commission explain in the preamble to the adopted rules how it plans on meeting the requirements of SB1150 without requesting additional funding from the Legislature, and what other services it will cut if the Legislature fails to allocate it sufficient funds.

Many Other Suggestions from the Prior Working Group Recommendations Were Not Implemented Yet Remain Valid.

SB1150 states that the Commission is to adopt rules related to monitoring inactive wells, yet the proposed rules include little on this topic. Monitoring inactive wells requires monitoring

[56] For example, if a surface owner knows that an operator has reported wells as active—but the wells do not have a pipeline or tank battery connection—then the surface owner will know to file a complaint with the Commission.

[57] *See e.g.*, Tex. Nat. Res. Code § 91.101(a)(3) ("To prevent pollution of surface water or subsurface water in the state, the commission shall adopt and enforce rules and orders and may issue permits relating to: . . . the operation, abandonment, and proper plugging of wells subject to the jurisdiction of the commission").

[58] Specifically the Legislative Budget Board estimated that "7.0 new positions would be required in fiscal year 2026 and fiscal year 2027, and 86.0 new positions would be required in each fiscal year after. Salary costs would include $767,746 in fiscal year 2026 and fiscal year 2027, and $6,353,031 in each fiscal year after." In addition, "technology costs related to updating multiple systems and developing additional data integrations and workflows for inactive well analysis and reporting would include $4,934,400 in fiscal year 2026, $3,832,800 in fiscal year 2027, $2,519,859 in fiscal year 2028, $2,081,499 in fiscal year 2029, and $1,643,139 in fiscal year 2030." Ex. 20 Fiscal Note on Enrolled SB1150. https://capitol.texas.gov/tlodocs/89R/fiscalnotes/html/SB01150F.htm

[59] *See generally*, Ex. 21 RRC Legislative Appropriations Request (2028-2029) https://www.rrc.texas.gov/media/vhro3aw2/lar-28-29.pdf (requesting no additional funding related to implementing SB1150).

the wells themselves, and also the formation in which they exist. Commenters suggest the following:

Better Monitoring of Wells is Needed

Current Commission rules do not require sufficient testing of inactive wells to evaluate risks to public safety and the environment.

This rulemaking is a great opportunity to modernize mechanical integrity testing standards. The Commission should reconsider when pressure tests or fluid-level tests are most appropriate. Age, well condition, and subsurface conditions may warrant more frequent pressure testing. Commenters recommend that the Commission:

- Implement Bradenhead monitoring and testing protocols similar to Colorado Rule 419 - Bradenhead Monitoring, Testing, and Reporting.[60] These require operators to equip wells with Bradenhead access (a port and valve that allows access for measurement) and periodically report these conditions to the RRC.[61]
- Require that a third-party, independent, licensed, and certified well tester conduct the well tests. The license requirement could apply to already licensed professionals, such as professional engineers, geologists, or licensed safety inspectors who attest on their license that the inspection was accurately reported. This ensures tests are performed to high standards and reduces the risk of cheating.
- Update equipment and reporting requirements. Testers should be required to use calibrated, high-accuracy gauges and, if possible, digital data loggers for continuous recording. If possible, all test results, including failures, should be reported in real time or within 24 hours of testing.[62]
- If not already in use, the RRC should use automated data software to validate results and flag failed tests for follow-up. Adopt blockchain-based data verification from the test, including date, time, and location stamp, test results, and information about the individual tester. Adopt stronger verification tools for fluid level test results.
- Require prior written notification to landowners of well tests so they can witness the testing and serve as an additional set of eyes.
- Depending on the current well configuration, require testers to use treated water with corrosion inhibitors when fluid is to be left in the casing and tubing annulus to minimize casing damage.
- Investigate pressure in the casing; anomalous readings could indicate underground leaks. Require additional follow-ups to check for leaks underground or at the surface. Consider the value of requiring additional follow-up testing to evaluate cement integrity, to identify fluid flows behind casing, or to identify zones for which fluids are leaving by using Cement Evaluation Tool (CET) testing, Casing Inspection Logs,

[60] This would augment Rule 3.17, which requires that wells be equipped with a Bradenhead and that annular pressure be monitored, and any observed pressure be reported.
[61] *2 CCR 404-1-419—BRADENHEAD MONITORING, TESTING, AND REPORTING*. (n.d.). LII / Legal Information Institute. Retrieved March 13, 2026, from https://www.law.cornell.edu/regulations/colorado/2-CCR-404-1-419
[62] Retesting, of course, should be allowed/required for user error and faulty equipment failures.

Temperature/Noise Logs, Radioactive Tracer Surveys, Fluid Level Measurement ("Ada" Test), and others.

- Require steady monitoring and major trend changes on a monthly or temporal timeline for reported pressures. Ensure spikes are investigated, as they often indicate something has gone wrong. Set up automatic flags for variances (greater than 10%) within the RRC reporting systems, or for max pressures that could indicate problems, to trigger a detailed review.

It may also be prudent to require additional action or more frequent testing (beyond fluid level or hydraulic pressure tests) to ensure public safety for unplugged wells. Depending on the conditions, the following actions may help illuminate risks posed by unplugged, inactive wells, and the Commission's rules should expressly contemplate the collection of this data. The Commission could:

- Require measurement of leaking gases that pose health risks and may indicate a failure of mechanical integrity. Measurements outside wellbores of gases such as VOCs (benzene, toluene), methane, and H2S may indicate wellbore failure. The RRC should require the use of IR cameras to detect gases emanating from wells.
- Require that all leaks in reportable quantities (30 TAC §327.4) be reported and tested to establish contamination and to fingerprint fluids to inform remediation needs. Guidance tools, such as the RRC's Field Guide for the Assessment of Cleanup and Soil and Groundwater Contaminated with Condensate from a Spill Incident,[63] offer a good roadmap for testing and remediation, but stronger verification of reporting, testing, and cleanup is needed. The Commission should consider requiring sampling for the same suite of parameters it uses to assess groundwater contamination from waste management sites.[64]
- Although there are many ways to strengthen water quality testing, one could be to require water quality testing of any water sources within 0.5 miles of a failed well for all failed mechanical integrity tests, within 30 days of the detected failure, with annual follow-up testing for 3 years. Ideally, the RRC would adopt requirements to collect baseline water source testing prior to drilling to establish a baseline for comparison, since if contamination is found, it is unknown whether a mechanical integrity failure caused the measured degraded water quality or if that was the baseline water quality.
- Even though currently many inactive wells (especially 15/25 wells) are vertical wells, more and more horizontal wells will be at risk of becoming inactive as time goes on. The Commission's rules should be proactive and not ignore the risk posed by leaks from horizontal sections of a wellbore. These can be difficult to prove, but these leaks can still cause damage.

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[63] RRC. *Field Guide for the Assessment and Cleanup of Soil and Groundwater Contaminated with Condensate From a Spill Incident* https://www.rrc.texas.gov/oil-and-gas/environmental-cleanup-programs/guidance-documents-and-helpful-links/condensate-spill-guidance/

[64] *See* 16 Tex. Admin. Code § 4.131 (b)(4)(c).

The Commission should also consider rules for when complaints are filed about inactive wells. For example, when there are suspicious livestock illnesses or deaths,[65] the Commission should investigate the cause and test water sources for contamination. In addition:

- The RRC should ensure that oil and gas operators report leaks and comply with cleanup responsibilities, and if any gaps exist in reporting or investigations of oil and gas spill or leak exposures, the RRC should consider establishing reporting and investigation requirements similar in principle and practice to other state programs. For example, many spills and leaks are already subject to the Texas Commission on Environmental Quality (TCEQ) Texas Risk Reduction Program (TRRP)[66]. Similarly, Texas Parks & Wildlife has a Kills and Spills Team to investigate wildlife and fish deaths.[67]

Better Monitoring of the Well's Environment is Needed

The Commission should establish more robust rules that require monitoring of the downhole conditions around inactive wells, to help determine whether changes to the well's available extensions are needed.

This should not be a static, one-time analysis: downhole conditions can change over time. For example, as Class II injection wells inject fluids and the subsurface pressurizes, they have been known to interact negatively with aging, plugged, and unplugged wells. Class VI wells pose a similar risk. It would be prudent to require plugging inactive wells in the path of these injection plumes and in areas where the background reservoir pressure has increased substantially from the baseline pressures that existed when the wells were initially constructed. The rules can be written to deny well-plugging extensions to wells when downhole conditions become conducive to failure, or when within a certain distance of injection wells.

In Rule 3.13, a "potential flow zone" can be designated that requires isolation to prevent sustained casing pressure. Strict limits should be placed on what may be left unplugged in these zones. Well records could be required to reflect that they are built to withstand the anticipated casing pressure.

Updates to the Commission's rules on offshore and bay wells are still needed.

Not addressed by SB1150 are offshore and bay wells. These wells can pose significant risks to public safety and the environment and the Commission and Legislature should update the rules for these wells. The Commission should pay special attention to monitoring and inspecting offshore wells, given the difficulties of detecting and repairing leaks and spills at

[65] The Commission could consider consulting with the Texas Animal Health Commission and state veterinary schools to ensure best practices are followed for blood testing and autopsy requirements, so our food sources are not contaminated by exposure to pollution from spills or breakouts. Certified laboratories and veterinarians can be utilized for these investigations.
[66] *Texas Risk Reduction Program*. (n.d.). Texas Commission on Environmental Quality. Retrieved April 1, 2026, from https://www.tceq.texas.gov/remediation/trrp
[67] *Kills and Spills Investigations*. (n.d.). Retrieved April 1, 2026, from https://tpwd.texas.gov/landwater/water/environconcerns/kills_and_spills/invest.phtml

these sites. Due to the integrity, corrosion, risk considerations, the dangerous conditions, and complications that often occur as these wells and platforms decay, and the catastrophic costs associated with offshore well failure, the Commission should scrutinize well conditions before granting any additional extensions for offshore and bay wells.

Additionally, decommissioning costs are ten times higher offshore, and even higher when platforms and equipment degrade to the point of failure or no longer function. The bar for extensions should be especially high. The Commission should grant them only when it is certain the operator will be able to cover decommissioning costs, there is clear and convincing evidence of future value, and investments are adequate to maintain the integrity and safety of the well, platform, and associated pipeline infrastructure needed to service the well.

Other states both regulate inactive wells more robustly and still allow for a robust oil and gas industry.

Several other states are modifying their rules on inactive wells or have already adopted more robust rules than the Commission proposes. Many of their regulations could serve as models for the RRC to adopt in this rulemaking. These states show that robust regulations and robust oil and gas industries can coexist.

- **Utah**: On June 24, 2026, after almost four years of stakeholder engagement and iterative preliminary drafts, the Utah Board of Oil, Gas and Mining adopted amendments to its Performance Bond Rule, R649-13.[68] The state now treats access to blanket bonds as a privilege rather than a right. The Performance Bond Rule establishes the amount of financial assurance an operator must provide to the Utah Division of Oil, Gas and Mining to ensure the operator timely and properly plugs and abandons its wells and reclaims its well sites at the end of their useful life. The new Blanket Well Performance Bond Rules require operators to provide significantly more financial assurance than the previous rules, which were last modified in 2003.
    - The new rules restrict usage of blanket bonding (which allows a single amount of financial assurance to cover many wells) to operators who meet average daily production volumes and a ceiling on the percentage of “At Risk Wells” in an operator’s well portfolio. An At Risk Well is defined as a State Well that produces an average of less than one barrel of oil equivalent per day over twelve months. A shut-in or temporarily abandoned well that has obtained an extension to remain inactive under R649-3-36 is still considered to be an At Risk Well.
    - An operator that does not meet the requirements for any of the Blanket Well Performance Bond tiers must provide Individual Well Depth Performance Bonds for each of its wells, pursuant to R649-13-2. The financial assurance amount for individual well depth bonds ranges from $5,000 per well for depths of 500 feet or less to $110,000 per well for wells deeper than 12,000 feet.

[68] Rulemaking – Oil and Gas Bond | Oil, Gas, and Mining. https://ogm.utah.gov/rulemaking-og-bond/. Accessed 18 Feb. 2026.

    - When a change of operator occurs, the Division provides the current and proposed new operator the amount of financial assurance required for the new operator. R649-13-6(4). If the new operator's existing financial assurance is insufficient, it must provide a plan to remedy the shortfall. Until the new operator meets the bonding requirements, the current operator's bonds will not be released.
- **Oklahoma:** In 2025, the state mandated that operators plug all current shut-in and idle natural gas wells within 10 years, so that moving forward, wells must be plugged within 10 years of inactivity.[69]
- **New Mexico:** New Mexico just finalized a major rulemaking concerning financial assurance, idle well management, and well transfer. The core of the proposal, which took the form of an eNGO petition that was redlined by Oil Conservation Division staff, requires $150k single-well bonds for inactive wells, wells producing less than 1000 BOE/yr and less than 180 days/yr, such wells on transfer, and for all wells for operators with more than 15% of their portfolios in one of these statuses. The proposal also limits how long wells can stay inactive to 8 years. Finally, it creates a presumption of no beneficial use for wells producing less than 90 BOE/yr and fewer than 90 days a year – operators who do not overcome this presumption by demonstrating future utility above these levels must plug those wells. The rulemaking hearing took place from mid-October to mid- November 2025. Negotiations between NGOs, industry, and the regulator continued through March, and deliberations on the consensus language took place after that. [70] The updated rules:
    - Update bonding requirements to $150,000 per well for oil and gas wells at highest risk of abandonment – including low-producing and inactive wells – more closely aligning with the Oil Conservation Division's actual plugging costs.
    - Require operators with high-risk portfolios – more than 20% inactive wells – to post single-well bonding of $150,000 for all their wells, reducing the risk that large portfolios of aging wells are left without adequate cleanup funds.
    - Strengthen well transfer rules to prevent poorly funded or noncompliant operators from acquiring aging wells – a common pathway to well abandonment.
    - Require the most marginal wells (producing fewer than 90 barrels of oil equivalent in 12 months) to demonstrate they still serve a useful purpose or properly plug them.

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[69] Burns, Green, Boles, & Waldron. (2025, May 22). *SB132 ENR.PDF*. Oklahoma State Legislature. An Act Relating to the Corporation Commission; Amending 17 O.S. 2021, Section 53, Which Relates to Plugging of Oil and Gas Wells; Clarifying Jurisdiction of Corporation Commission; Directing Operators of Idle Gas Wells to Plug or Produce from Certain Wells by Certain Date; Establishing Maximum Time Period for Plugging Certain Idle Gas Wells; Defining Terms; Directing Rule Promulgation; and Declaring an Emergency. https://www.oklegislature.gov/BillInfo.aspx?Bill=sb132&Session=2500

[70] *New Mexico regulators near final rules strengthening oil & gas bonding & cleanup* (Apr. 6, 2026) https://westernlaw.org/new-mexico-regulators-near-final-rules-strengthening-oil-and-gas-bonding-and-cleanup/

    - Tighten rules for inactive wells by requiring operators to show wells will return to production in the future, preventing non-producing wells from lingering indefinitely without cleanup.
- The rulemaking was influenced by a legislative audit that found likely near-term orphaned well burden for the state in the $600 million to $1.7 billion range.[71]
- **Louisiana:** Louisiana adopted reforms to its inactive well program in 2023, reducing the discretion of the secretary to hand out unlimited extensions of temporary abandonment status, strengthening the required showing of future beneficial use, and raising inactive well fees after five years of inactivity.[72]
- **Arkansas:** Arkansas adopted a $35k bond for marginal gas wells on transfer in 2018, and since then has seen less well orphaning, higher bond amounts, and fewer transfers to micro operators.[73]
- **North Dakota:** North Dakota limits the number of inactive wells an operator may have on a blanket bond to no more than 7, after which permits to drill new wells will be suspended. Transferred wells also require a single well bond equal to the cost of plugging the well and reclaiming the site.[74]
- **Wyoming:** While Wyoming allows operational wells to be covered by blanket bonds, bond amounts may be increased up to $10 per foot (adjusted every 3 years) for idle wells. As part of an annual plan of operation, operators shall commit to plugging or returning to service at least 10% of their idle wells each year. Transfer of wells is subject to Supervisor review and may be subject to additional bonding. The Supervisor may hold prior owner/operator bonding until they have reviewed the new operator's status, number of wells, need for additional bonding up to securing actual plugging costs, and fulfillment of bonding obligations.[75]

[71] Fischer, M. (2025). *Policy Spotlight: Orphaned Wells*. https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf

[72] Louisiana Office of Conservation. (2025, November 9). *Title 43 Natural Resources §137. Plugging and Abandonment*. https://denr.louisiana.gov/assets/OC/Rules/43v19Nov25.pdf. Pg 14.

[73] https://www.law.cornell.edu/regulations/arkansas/178-00-18-Ark-Code-R-004

[74] North Dakota Legislative Council. (n.d.). *North Dakota Admin. Code 04-02-03-15 (Bond and transfer of Wells)*. Retrieved April 6, 2026, from https://ndleoperator'sisgis.gov/information/acdata/pdf/43-02-03.pdf. Pg 14.

[75] Cornell Law School. (n.d.). *055-3 Wyo. Code R. §§ 3-4—Bonding Requirements (Forms 8, 8A, 8E and 8F)*. LII / Legal Information Institute. Retrieved April 6, 2026, from https://www.law.cornell.edu/regulations/wyoming/055-3-Wyo-Code-R-SS-3-4

Part 2: Section-by-Section Comments

Commenters provide the following section-by-section comments on the draft revisions to Rule 15 and Rule 58. These line-item edits should be read in context with its comments above. Commenters welcome a dialogue with the Commission as any questions or concerns arise during the Commission's review of these comments, just as industry has been allowed to dialogue with the Commission in closed-door meetings about the drafting of these rules. Commenters reserve the right to alter, refine, and expand its position from those stated herein as it obtains more information about the proposed changes and their impact on communities, safety, and environmental health.

Rule 15

3.15(a) Definitions

The Commission has proposed several changes to the definitions section; more are warranted. We recommend the following changes:

"15/25 well"

SB1150 applies a new set of regulations to a new category of well: the 15/25 well. Commenters have only one small suggested change to the 15/25 well definition[76] to address the circumstance in which a well's completion date is unknown.

As time goes on, it is more and more likely that robust information will exist for how these wells were completed and whether they are indeed 15/25 wells. But currently there are over a thousand old wells in which critical information about construction and completion is missing. Yet the Commission's definition does not explain how it will classify wells without a known completion date. Because the lack of this sort of information suggests that other information about well construction will be unknown (increasing risks under Tex. Nat. Res. Code 89.051(b)), Commenters suggest that the Commission presume that wells that have been inactive over 15 years are 15/25 wells if no completion date information is available. Moreover, Commenters suggest that the Commission not grant extensions for any such wells—they should be required to be plugged as too risky to continue operation under Tex. Nat. Res. Code 89.051(b), with no access to extensions.[77] (At a minimum these wells should also be top priority for plugging.) As such, the definition would become:

> 15/25 well — An inactive land well that has been inactive for more than 15 years and was completed more than 25 years ago. In the event that a well's completion date is unknown, it is presumed that the well is a 15/25 well if it has been inactive more than 15 years.

[76] The Commission's proposed definition: 15/25 well — An inactive land well that has been inactive for more than 15 years and was completed more than 25 years ago

[77] The Commission also has authority under Tex. Nat. Res. Code § 89.023(b)(2) to make a rule requiring the plugging of these wells with no access to extensions.

Such a definition would incentivize good recordkeeping and reduce risks from these wells. No matter what the Commission decides to do about these wells that lack a completion date, it should clarify its intent in the preamble so that operators and affected persons are aware of how these wells will be treated.

"Active operation"

For years, the definition of "active operation" was set at 10 barrels of oil or 100 Mcf of gas a month for at least three consecutive months.[78] But in 2016, without prompting from the Legislature at all, the Commission lowered the threshold for active operation to its current definition,[79] ignoring vigorous protests from many groups, including land owners, who warned that this would leave barely active wells permanently impeding their surface use and frustrate mineral and royalty owners from being able to audit production and otherwise exercise their rights.[80]

The relaxation of this standard has coincided with an increase in the inactive and orphaned well populations.[81] It goes against the Commission's original concerns with setting the threshold for active operation too low; that it would incentivize "paper production" or taking de minimis actions, not truly intended to restore the well to continuous active operation.[82]

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[78] Adopted Rule, 41 Tex. Reg. 9465, 9466 (Dec. 2, 2016) ("By rulemaking effective November 1, 2000, the Commission established minimum production levels for producing wells that must be met before an inactive well could achieve active operation. To return to active operation, an oil well must produce at least 10 barrels of oil per month for three consecutive months, and a gas well must produce at least 100 Mcf of gas per month for three consecutive months.").

[79] Adopted Rule, 41 Tex. Reg. 9465, 9465-9466 (2016). This definition is further flawed because it equates 1 barrel of oil with 1 Mcf of gas, which is not equivalent.

[80] *Id.*; *see also* Ex. 22 McFarland, John. The Problem of Abandoned Wells (Dec. 19, 2016) https://www.oilandgaslawyerblog.com/problem-abandoned-wells/ "(TLMA noted the serious impact to surface owners who do not own the minerals beneath their land and have no say-so in the oil-and-gas operations on their land. Relaxing production requirements means a landowner could find themselves stuck just-barely-active wells that affect the health and use of their land, and that never trigger site-clean-up obligations for the operator. TLMA also took the opportunity in our filed comments to highlight a related concern for mineral owners—the inability to audit production reporting to ensure accuracy. It is practically impossible for a royalty owner to audit reports to make sure that production from an active well has not been attributed to a marginal well in order to keep that well in the active designation.").

[81] *See supra* Part 1 (Factual Background).

[82] At which point the definition was found in Rule 14. *See* Proposed Rule, 16 TAC 3.14, 25 Tex. Reg. 6888, 6889 (July 21, 2000) (adding the minimum production level, stating: "Finally, amendments are proposed to the definition of "active operation." Under the newly-proposed definition, once a well has been inactive for one year, the well will remain designated as inactive and subject to the requirements for inactive wells, regardless of any minimal activity, until the well has reported production of 10 barrels of oil or 100 mcf of gas per month for at least three consecutive months. This definition change is proposed to alleviate the problem of operators filing "paper production" or taking *de minimis actions*, not truly intended to restore the well to continuous active operation, and claiming this minimal activity relieves them from the obligation of complying with the rules for maintenance and transfer of inactive wells.") (emphasis in original)).

While the 2016 change was inappropriate, it also shows that the Commission need not wait for explicit Legislative direction to revise the definitions in Rule 15. The definition of "active operation" no longer makes sense in the context of the amended rule, because it allows too many wells to be classified as active when in fact they are wells that should be plugged. This threshold also makes little sense when compared to the definitions used for the reactivation of orphaned wells: Tex. Nat. Res. Code § 89.047(i)(1) sets the threshold for continuous active operation at 10 barrels of oil equivalent / 100 Mcf of gas for three consecutive months, just as the prior definition in Rule 15 did.[83] Commenters thus recommend that the Commission restore the threshold for reactivation to the previous definition in Rule 15, with the caveat that the production threshold be spread across a twelve month period, to provide flexibility to operators whose wells may produce inconsistently across that period.[84]

Furthermore, any definition of active operation must be informed by how oil and gas production is measured in the field. While gas production is metered by pipeline (and is therefore more accurate), oil production estimates are usually less accurate. Production from multiple oil wells is typically collected into a common tank battery before it is measured (especially for older wells),[85] making it difficult to determine how much one individual well has produced. In addition, on the Commission's current forms, production is reported by lease, not by well.[86] In other words, one higher producing well might mask the presence of wells that have fallen below the threshold for active operation. This is another danger of setting the threshold of active operation too low — it makes it too easy for low producing wells to go unnoticed. **In the preamble to this rule, the Commission should explain how it plans on compensating for the difficulties in measuring production from individual wells.**

Moreover, the interaction of the definition "active operation" and "inactive well" (which is set by statute) leaves a population of underproducing wells that might never become 15/25 wells and never trigger the requirement for plugging. **While this may require legislative action to address, the Commission should articulate in the preamble of these rules how this population of wells is impacted by its SB1150 rulemaking.** This population exists as follows:

An "inactive well" is one that has **zero** production or other permitted activity for more than 12 months.[87] In other words, as long as a well registers some production — which could be

[83] This definition was introduced in 2005 as part of "an incentive program administered by RRC for orphaned oil and gas or service wells adopted by an operator in good-standing to adopt orphaned wells." Ex. 23 Fiscal Analysis for HB 2161 Conference Committee Report (79th Legislative Session) (May 29, 2005) https://capitol.texas.gov/tlodocs/79R/fiscalnotes/html/HB02161F.htm Adoptive operators would receive a payout when they reactivated an orphaned well.

[84] Commenters recognize that others have recommended lower thresholds for active operation, specifically mirroring the standard New Mexico recently adopted (90 barrels of oil equivalent or 540 Mcf gas across 12 months, *see* App. B (EDF Comments) at 2) and are open to that becoming threshold for active operation as an alternative.

[85] It is Commenters' understanding that newer wells may have more accurate measures for tracking production, but SB1150's focus on older inactive wells requires that the Commission make rules that make sense across the entire spectrum of wells, not just more modern ones.

[86] *See* Monthly Production Report, Form PR (Feb. 2021) https://www.rrc.texas.gov/media/pwpegji3/form-pr-02-23-2021.pdf

[87] 16 Tex. Admin. Code 3.15(6); Tex. Nat. Res. Code § 89.002(12).

little as 1 barrel / year, it will not fall into the definition of an inactive well. Meanwhile, the definition for "active operation," simply states that "regular and continuing activities" are needed, with no specific minimum production level required if the well has never become an inactive well. The only numeric production threshold in the definition does not kick in until ***after*** the well has become inactive; i.e., the threshold for reactivation of a set number of barrels or Mcf does not kick in until a well has reported zero production for 12 months. Thus a well producing 1 barrel a year would fly below the radar of SB1150, despite it being a well that likely has no productive use and poses risks to public safety and the environment and should in fact be plugged.

In subsequent rulemaking (and after any required Legislative action), the Commission should consider subjecting these low producing wells to the plugging requirements of SB1150 and treat these wells as 15/25 wells if they have not been able to meet the numeric thresholds for active operation for 15 years (regardless of whether they have ever reported zero production in a 12 month period). One way to do so would be to set a rebuttable presumption that the well is inactive if it produces below the threshold for reactivation.[88] Regardless, in the preamble to the adopted rule the Commission should explain how it will ensure these wells are eventually plugged as well—or clearly indicate if it believes Legislative intervention is required.

Commenters also have concerns about the clause that allows disposal or injection activity to count as active operation and thus be a reason to postpone plugging. As an initial matter, simple repermitting of the well should not suffice; the threshold for active ***operation*** as a disposal or injection well should be tied to its ***operation***. The statutory definition for orphaned well reactivation provides useful guidance, that the well must be used for disposal or injection activities for at least three consecutive months before it qualifies as having returned to active operation.[89]

Therefore we recommend changing the definition of "<u>active operation</u>" to:

> *Active operation – Regular and continuing activities related to the production of oil and gas for which the operator has all necessary permits. In the case of a well that has been inactive for 12 consecutive months or longer ~~and that is not permitted as a disposal or injection well~~, the well remains inactive for purposes of this section, regardless of any minimal activity, until the well has reported production ~~of at least five barrels of oil for oil wells or 50 Mcf of gas for gas wells each month for at least three consecutive months, or until the well has reported production~~ of ~~at least one~~ <u>an average of ten</u> barrel<u>s</u> of oil for oil wells or ~~at least one~~ <u>an average of 100</u> Mcf of gas for gas wells <u>annually</u> ~~each month for 12~~*

[88] This would allow operators that are able to profit at lower thresholds to make that showing (they would still of course need to include the eventual plugging cost in such calculations).

[89] Continuous active operation for a previously orphaned well can be defined as "the well is a service well and the well has been used for the disposal or injection of oil and gas wastes or another purpose related to the production of oil or gas for at least three consecutive months as shown in the records of the commission and as authorized by a permit issued by the commission." Tex. Nat. Res. Code § 89.047(i)(2).

> *~~consecutive month period~~, or if the well is permitted as a disposal or injection well and has been used for the disposal or injection of oil and gas wastes for at least three consecutive months within the past 12 months.*

"Full cost calculation for plugging an inactive well."

An inherent tension appears to exist with respect to how the Commission plans on using the "full cost calculation" for plugging an inactive well. SB1150 only uses the term "full cost calculation" once, with respect to the bonding extension.[90] But the proposed rules use it for the compliance plan and the financial hardship extensions as well.[91] When it comes to assessing the appropriate value for a bond, the cost considered should include all costs that a delinquent operator might leave behind to the state, like poorly maintained site conditions. But when it comes to assessing financial hardship, an operator should not be able to consider its mandatory tasks—like maintaining site access (which is necessary for well testing)---a hardship. The Commission should reconsider the appropriateness of using the "full cost calculation" in the financial hardship extension..

Otherwise, Commenters support the definition for "(6) full cost calculation for plugging an inactive well" as it includes additional all direct and indirect costs, but they should not be limited to those rendered only by third parties or exclude internal costs. Even if the operator will conduct the work itself, that work still comes at a price that must be considered in the cost of bonding. We recommend that the definition be further updated to include costs of plugging in complicated subsurface environments, not just in H2S fields. To the extent that the "full cost" term is used in the financial hardship extension analysis, the costs for general maintenance and access should not be included (but they should be part of the bonding extension option.) Finally, we suggest that RRC broaden subsection (E) to allow for the fact that there may be changes to the federal grant programs in the future. As such we suggest the following changes to the definition:

> *(6) Full cost calculation for plugging an inactive well — The total cost to plug an inactive well in compliance with Commission regulations, including all direct and indirect costs associated with third party goods and services and operator's internal costs that are not overhead~~, but not including any of the operator's overhead or other internal costs~~. Direct and indirect costs include, but are not limited to: .. . (B) additional costs related ~~to road construction, brush clearing, or other~~ necessary actions to access the inactive well site that are not part of general maintenance required by Commission rules (such as road construction or brush clearing); . . (E) for RRC indirect administration using the most recent Negotiated Indirect Cost Rate Agreement used for federal grants or comparable program; and (F) additional costs related to the well's location, e.g., in proximity*

[90] Tex. Nat. Res. Code § 89.023(c)(3).
[91] *See* Proposed § 3.15(h)(4)(C)(i)(V) (compliance plan application information); § 3.15(i)(1)(B) (criteria for financial hardship extension)

to an overpressurized zone, H2S field, enhanced oil recovery or carbon sequestration areas, or other active operations"

New Definitions.

"A good faith transfer"

Commission Shift's April 2026 working group recommendations to the Commission advocated for a clear definition of "good faith transfer," but no such definition has been proposed. This is essential for objective and clear transfer rules, which SB1150 requires a showing that the transfer is "a business practice performed in good faith." Commenters therefore recommend an added definition for "a good faith transfer" that would set objective standards as to whether a transfer has been conducted in good faith, as added via SB1150 into Tex. Nat. Res. Code § 89.023(h)(2) and proposed to be used in Rule 58.

For example, operators should be required to disclose the relationship between transferee and transferor with certain relationships and shared ownership subject to greater scrutiny.[92] The Commission should have authority to request additional information to confirm that the business practice is in fact in good faith. The rule could include rebuttable presumptions as to what qualifies as a business practice performed in good faith. For example, if the transferee posts a full bond equal to the estimated actual cost to plug the transferred wells, the transfer may be assumed to have been performed in good faith. We suggest:

a good faith transfer — an arms-length transfer in which the operator has submitted factual support to the Commission that the transfer was made in good faith, based on evidence such as the relationship between transferee and transferor, that the wells transferred will generate sufficient income to cover operation and plugging costs of all transferred wells over the life of the lease, any plans to drill additional wells on the leases transferred, and any other relevant information requested by the Commission.

(a) A rebuttable presumption arises that a business practice is performed in good faith if the transferee posts a full individual performance bond equal to the full cost to plug each transferred well;

(b) a rebuttable presumption arises that the transfer is not a business practice performed in good faith if:

(i) The transferor and transferee have a parent-subsidiary relationship; or

(ii) An officer, director, general partner, trustee, or owner of more than a 25 percent interest in the operator overlap between the

[92] The Commission could draw on Texas Business and Commerce Code Sec. 24.005, which governs "Transfers Fraudulent as to Present and Future Creditors" and includes many of the defined guidelines. The definition of "Insider" in Sec. 24.002(7) could also be incorporated. Transfers between company insiders can be flags for lack of good faith because they have insider information that makes it easier to self-deal and conceal obligations and assets.

> *transferor and transferee, or if any involved is an "insider," as defined by Tex. Bus. and Commerce Code Sec. 24.002(7); or*
> *(iii) The transfer involves a 15/25 well.*

Other Definitions

The Commission should also define certain terms in Tex. Nat. Res. Code § 89.051(b) that it "shall" consider when drafting rules:

> (1) the risk to public safety or the environment; (2) wellbore and wellhead integrity, including the ability to monitor casing pressure; and (3) regional risk considerations, including penetration of corrosive or over-pressured formations and completion in zones containing hydrogen sulfide."

Tex. Nat. Res. Code § 89.051(b).

Therefore we also recommend, as our April 2026 comments did, several additional terms be defined.

"Over-pressurized formation."

Commenters recommend that Texas Natural Resources Code sec 89.051(b)(3)'s term "over-pressurized formations" be defined following the American Association of Petroleum Geologists (AAPG)'s definition:

> *Over-pressurized formation — a formation whose fluid pressure exceeds the normal hydrostatic pressure in a given depth.*

The definition should further specify quantitative metrics designed to prevent earthquakes and blowouts. Statewide Rule 3.13 and API 65-3 utilize the term "potential flow zone" to define specific geological zones that require isolation to prevent annular pressure buildup; the RRC maintains a list of known zones. The RRC should consider creating a rating system for the severity of pressurization and corrosivity, which may impact whether to allow plugging extensions in problem zones. The RRC should consider designating specific zones where no extension exceptions to well-plugging deadlines are permitted, especially where underground conditions are known to be severe enough to cause failures of previously plugged wells (such as at Antina Ranch[93]). While the RRC may allow exceptions for factors such as higher-standard well construction, a blanket restriction on plugging extensions may be necessary to protect groundwater in areas with known extreme subterranean instability.

[93] Ex. 24, Gold, Russell, "The West Texas Rancher Exposing Big Oil's Buried Secrets" (July 2022) Texas Monthly https://www.texasmonthly.com/news-politics/ashley-watt-rancher-chevron-toxic-water/; Ex. 25 Wethe, David & Crowley, Kevin. "Chevron Buys West Texas Ranch in 'Zombie' Oil Well Settlement" (Feb. 10, 2026) Insurance Journal. https://www.insurancejournal.com/news/southcentral/2026/02/10/857499.htm

"Containing hydrogen sulfide" and "Regional risk considerations"

SB 1150 requires that the Commission's rules consider regional risk considerations and hydrogen sulfide zones. The rules should give clearer guidance about what this means.

For example, Commenters agree with EDF's concerns as to whether extensions will be granted for wells that are located in H2S fields, as defined in Rule 36.[94] Commenters also note that the thresholds that Rule 36 considers safe are still much higher than the standards that are set by OSHA and NIOSH for hydrogen sulfide zones.[95] The Commission should consider using the OSHA and NIOSH thresholds instead, and any wells with hydrogen sulfide levels higher than those thresholds should be prioritized for plugging. Commenters suggest that for all extension requests, the Commission apply a rebuttable presumption that an extension will not be granted for wells located in H2S fields (as defined in Rule 36) unless the operator provides sufficient credible evidence of the well's integrity and minimal risk of H2S exposure.

Commenters also agree with EDF's recommendation that no extensions be granted for wells located within a geologic storage facility or storage facility, as that term is defined in 16 Texas Administrative Code § 5.102(29), unless the operator provides sufficient additional evidence to review the assess safety of the well by providing additional hydraulic pressure testing, monitoring of casing conditions, corrective actions, or any other criteria the Commission sees fit to require to ensure well safety.

"Wellhead and wellbore integrity"

Well records are essential for determining wellhead and wellbore integrity, which SB1150 requires be assessed as part of how it reviews extension requests. The Commission should require that operators submit the well records for every well involved in an extension request. This has the added benefit that if these wells are abandoned or orphaned (as many inactive wells eventually are), the Commission and the taxpayer will be better positioned to plug these wells.

"Violation"

Commenters also agree with EDF's proposed addition of a definition for "violation," as it is used in proposed 3.15(i)(2)'s criteria for mandatory denial.[96] The Commission should adopt EDF's proposal.

Finally, others have proposed the addition of terms like "small operator" or "prudent operator." Commenters ***strongly disagree*** with these two proposals. SB1150 extensions are

[94] App. B (EDF Comments) at 6-7.
[95] This is still high as compared to the OSHA and NIOSH safety limits (15 minute average at 20 ppm and 10 minute ceiling limit of 10 ppm, respectively). *See* Ex. 26 *Hydrogen Sulfide | Public Health Statement | ATSDR*. (n.d.). Retrieved March 22, 2026, from https://wwwn.cdc.gov/TSP/PHS/PHS.aspx?phsid=387&toxid=67.
[96] App. B (EDF Comments) at 28 (Proposed § 3.15(a)(11)); *see also id.* at 7-8 (rationale).

optional, not mandatory; all operators still have the obligation to plug wells, so no carveout for small operators is appropriate, and such a carveout would not be consistent with the Commission's obligations related to the health, safety, and environmental and economic welfare of the state.[97] And SB1150 does not require nor suggest that a "fast-track" option for "prudent operators" is available. SB1150 makes it clear that extensions are ***already*** a privilege, not a right.[98] The only operators who should be granted any extension at all are those with excellent compliance histories.

3.15(g) Commission action on application for plugging extension for an inactive land well that is not a 15/25 well.

Subsection g currently applies to all inactive land wells. The Commission purports to make no change to subsection g other than to now limit its applicability to only those land wells that are **not** 15/25 wells. But the Commission's proposal does result in a substantive change that decreases surface owner rights. Specifically, current subsection g(5) grants surface owners affected persons status and the right to notice when a plugging extension is not granted.[99] These surface owners have the opportunity to participate in the hearing and can move to dismiss the operator's application for want of prosecution, in addition to all other rights afforded to affected persons in Commission hearings.

And concerningly, the Commission's proposal has moved the regulation of 15/25 wells outside of subsection (g) without preserving this right for surface owners to participate in hearings.[100] Thus, the proposed rulemaking unlawfully curtails the rights of surface owners and any other affected persons to participate in these hearings.[101] The Commission must grant surface owners and all other affected persons the right to notice of an application and opportunity to protest any application and participate in all hearings on extension applications and transfers.

3.15(h) Application for an extension of deadline for plugging a 15/25 well

Commenters have multiple concerns about Section 3.15(h):

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[97] *See e.g.*, Tex. Gov't Code § 2006.002(c-1).

[98] And because these extensions are privileges, not rights, the presumption should be that extension requests not acted on by the Commission are denials.

[99] 16 Tex. Admin. Code § 3.15(g)(5): ("At the time an operator files a request for hearing under this subsection, ***the operator shall provide a list of affected persons to be given notice of the hearing***. ***Affected persons shall include the owners of the surface estate of each tract on which a well that is the subject of the hearing request is located***, the director of the Commission's Enforcement Section, and the district director of each Commission district in which the wells are located. The applicant's failure to diligently prosecute a hearing requested under this subsection may result in the application being involuntarily dismissed for want of prosecution on the motion of any affected person or on the Commission's own motion.") (emphasis added)

[100] *Compare* Proposed 16 Tex. Admin. Code § 3.15(g)(5) *with id.* § 3.15(i) (which has no comparable language).

[101] Note that 16 Tex. Admin. Code 3.15(g)(5) does not limit affected persons to surface owners; other persons affected by an extension request should include impacted mineral owners, royalty owners, the area's groundwater district, and the local county or municipality.

Regarding **section (h)(2) annual renewals**, Commenters urge the Commission to require applicants for renewals to include updated information specific to that year. In other words, the applicant should be prohibited from relying on financial information or integrity tests or any other data that is more than one year old. 15/25 wells have been inactive for many years, so required annual testing is paramount to verifying their integrity. Otherwise granting the annual renewal without using the most effective tool to verify safety threatens to become a rubber stamp.

Regarding section **(h)(3) identifying nonoperators**, Commenters agree that it is essential that nonoperators be identified, and that applicants for a plugging extension have a duty to do so.[102] But this should be a black-and-white, objective requirement: there is no reason to implement a more lax "good faith and reasonable efforts" standard. Operators should know the nonoperators because operators already must keep track of working interest owners as part of their good business practices and own internal records.[103] Moreover, information about nonoperators is unlikely to be found in county tax rolls at all, so a review of those records can not constitute "reasonable faith and good efforts" to identify nonoperators.

In addition, if an operator seeks an extension due to financial hardship, financial information about major nonoperators should be collected and considered, not just the nonoperator's name, address, and contact information. Nonoperators' undivided interest should also be reported. Obtaining this information is essential for the Commission to adequately assess the financial resources available for plugging a well. Under Tex. Nat. Res. Code § 89.012, nonoperators are responsible for their proportionate share of plugging costs, and thus their ability to contribute should be a factor.[104]

Section (h)(3) should therefore be modified as follows:

> *(3) An operator applying for a plugging extension under this subsection shall ~~use good faith and reasonable effort to~~ identify nonoperators, as defined in Texas Natural Resources Code §89.002(3), with its application. The operator shall include documentation of the name, address, and contact information of all nonoperators. ~~To the extent the operator is unable to ascertain the name,~~*

[102] Which the Commission proposes to define as it appears in Texas Natural Resource Code § 89.002(a)(3):

> "Nonoperator" means a person who owns a working interest in a well at the time the well is required to be plugged pursuant to commission rules and is not an operator as defined in Subdivision (2) of this subsection.

And § 89.002(b): "The terms operator and nonoperator as defined in this section do not mean a royalty interest owner or an overriding royalty interest owner."

[103] Good business practices for operators include having a written operating agreement assigning nonoperators an interest in the operation and obligating them to pay their share of plugging costs.

[104] Tex. Nat. Res. Code § 89.012 ("If the operator of a well fails to comply with Section 89.011 of this code [duty of operator to plug wells], each nonoperator is responsible for his proportionate share of the cost of the proper plugging of the well within a reasonable time, according to the rules of the commission in effect at the time the responsibility attaches.").

~~*address or contact information for all nonoperators, the operator is considered to have used good faith and reasonable effort to identify nonoperators if the operator has examined Commission filings, current county tax rolls, and other reliable and readily available sources of information.*~~ *If an operator applies for an extension under subsection (h)(4)(B), the operator must also identify the percentage interest that it holds and that is held by each nonoperator in each well in the application;*

3.15(h)(4) Additional documentation must be one of the following:

(A) Demonstrated history of reactivation extension application (h)(4)(A)

Unlike the detail SB1150 provides for the other three extensions, little guidance is provided in the statute as to how an operator shows that it has a "demonstrated history of returning inactive wells to operation" nor what information the Commission should collect.[105] Nevertheless, the Commission has the obligation to collect sufficient information to honor SB1150's intent that only operators with a demonstrated history of returning wells to activity will merit this extension.

To do so, the Commission must acknowledge that there is a large difference in returning a one-year inactive well to activity as opposed to a well that has been inactive for fifteen years. Environmental Defense Fund analysis shows that in Texas, 68% of wells were orphaned within 10 years of the date of last production.[106] By year 15 of no production, 79% of such wells had been orphaned; only 6% returned to production[107]. And evidence from other states is similar. An analysis of wells in New Mexico conducted by the Environmental Defense Fund found that most well reactivations occur within the first two years of a well being inactive, and that wells inactive for five years or more are highly unlikely to ever be reactivated.[108] Ninety percent of wells in New Mexico that were ever reactivated were reactivated within 3.5 years.[109] Only 0.5% of wells that were reactivated were reactivated after 8 years.[110]

Given that on average, the longer a well has been inactive, the harder it will be to reactivate, the most logical way to interpret the intent of SB1150 is that operators must have a

[105] Tex. Nat. Res. Code § 89.023(c)(1)(A).
[106] Ex. 27 Peltz, Adam. *Orphan and Idle Wells in Texas and Beyond.* (Sep. 15, 2026) at 4. https://capitol.texas.gov/tlodocs/89R/handouts/C2502026091511301/e19b6995-2db8-4ffd-a7d7-54277d895973.PDF.
[107] *Id.* at 3-4; *See also* Peltz, Adam. Oral Testimony at Texas House of Representatives Committee on Energy Resources. (Sep. 15, 2026) https://house.texas.gov/videos/22867 at 4:28:00-4:28:59.(stating that EDF's analysis of Texas wells shows that when a well has been inactive for 15 years, 94% of wells won't be returned to production).
[108] Ex. 28 (Excerpt of Tom Alexander Testimony) at p. 54-55. https://earthworks.org/wp-content/uploads/2025/09/2025-New-Mexico-Bonding-Coalition-Legal-Filings-and-Testimony.pdf
[109] *Id*.
[110] *Id*.

demonstrated history of returning older inactive wells to active operation, not simply any inactive well. Evidence of this fact is that the only reason an operator might need to apply for this extension is if it operates 15/25 wells in the first place.

Otherwise, ***any*** operator can qualify for this extension by gaming the system by turning off marginally active wells and then returning young inactive wells to operation for the qualifying period in order to meet the required 'return to operation' percentage, before shutting them off again. Even if this is not a current practice or involves a risk that a shut-off well may not be able to be reactivated, it may become an economically desirable practice to avoid the cost of plugging if incentivized by SB1150 rules. The Commission must anticipate the actions of bad actors and not inadvertently create loopholes in the rule. The easiest solution is to require operators to show a demonstrated history of returning older wells to activity (which are harder to cycle on and off), not younger wells. Commenters suggest that to obtain an extension based on a history of reactivation of wells, the operator must show that the reactivated wells were inactive for 8 years or longer, in line with the data on reactivation success rates from New Mexico.

In addition, the RRC should not grant extensions to operators who have merely returned wells to active status for a period of three to 12 months with minimal production to show for it. Extensions based on the history of returning inactive wells to operation should be granted only to operators with a history of demonstrating strong performance from aging wells after their return to active status.

Furthermore, Commenters agree with EDF when it recommends requiring applicants to submit a plan identifying whether each well will be plugged or restored to active operation, together with a schedule for completing that work.[111] If the operator deviates from that plan, that could be grounds for denial of the extension. These requirements would help ensure that extensions based on restoration history lead to measurable progress toward plugging or restoration rather than prolonged inactivity.

As such, Commenters recommend the following changes:

(h)(4) In addition to the documentation that identifies nonoperators, and the affirmation required by subsection (f)(2)(A) of this section, the operator shall submit one of the following for Commission approval:

> *(A) a written request that the Commission, by order, determine that the operator's history of restoring inactive wells to active operation warrants the granting of the plugging extension. <u>Upon determining that the application is complete under subsection (i)(1) of this section, the application shall be referred to the Hearings Division for an evidentiary hearing. The operator bears the burden of proving that the requested extension is warranted. The Commission shall determine by order whether to approve the requested extension.</u> The operator shall include documentation identifying:*
>
> > *(i) all of the operator's wells;*

[111] App. B (EDF Comments) at 14 (section entitled "Require a well-specific plugging-or-restoration plan").

(ii) the active or inactive status, according to Commission rules, of each well, including whether it is a 15/25 well or not;
(iii) when each well was acquired, and if it was acquired while in active or inactive status;
(iv)~~(iii)~~ the length of time of inactivity for each inactive well for each period of inactivity across its lifetime;
(v)~~(iv)~~ when each previously ~~an~~ inactive well was restored to active operation, if it was previously inactive; and
(vi)~~(v)~~ all applicable Commission assigned permit numbers, oil and gas lease numbers, API well numbers, and production report filing dates for each active well that was previously inactive;
(vii) a well-specific plan identifying whether each 15/25 well will be plugged or restored to active operation, together with a schedule for completing that work; and
(viii) for each well the operator proposes to restore to active operation, an abeyance-of-plugging report meeting the requirements of subsection (l) of this section.

(B) Financial hardship extension application (h)(4)(B)

Significant changes are needed to the proposed financial hardship rules to fulfill the legislative intent of SB1150. As drafted, the SB1150 rules do not adhere to SB1150, which describes specific criteria that the Commission is to consider before approving a financial hardship extension. Specifically, SB1150 states that in considering whether to grant an extension for financial hardship, the Commission may consider the following:[112]

(1) the attestation, including the statement and financial statement, submitted to the commission under Subsection (d);
(2) the operator's prior investment in the plugging or maintenance of wells;
(3) the operator's history of compliance, including any history of previous violations and the seriousness of those violations;
(4) Current economic conditions;
(5) Operator’s percentage of inactive wells compared to the operator’s total well count;
(6) Any other information as required by commission rules.

To comply with SB1150, the operator’s application must include all of this necessary information. Furthermore, Commenters suggest that the information span the five-year time frame prior to the application, as TCEQ does.[113] This allows the Commission to assess the operator’s history of prior investment, compliance, and screen out bad actors, as is the intent of SB1150.

[112] Tex. Nat. Res. Code § 89.023(e)
[113] TCEQ uses a five-year timeframe to assess compliance as well. *See* 30 Tex. Admin. Code § 60.1(b) (“The compliance history period includes the five years prior to the date the permit application is received.”).

In addition, Commission rules must include the reality that the financial condition of the operator is not the only necessary data point for determining financial hardship. Nonoperators will often have contractual obligations for plugging costs. In recognition of this fact, Commenters propose that the Commission apply a rebuttable presumption that nonoperators are able to cover their share of plugging costs. Operators would be free to rebut this presumption by providing credible evidence to the contrary for the Commission's review, but this would be the default. In addition, for any nonoperator that owns a 25% or more interest in a well, the operator should be required to submit financial information from that nonoperator so that the Commission may better determine if a financial qualification exemption is warranted. Commenters suggest the 25% ownership interest threshold as striking a balance between the burden of collecting this information from all nonoperators and identifying the wells in which nonoperator finances are more relevant.[114] Finally, Commenters agree with EDF that the financial information that the operator submits should reflect its operations throughout the United States, not just Texas.

Also, an extension should only be given if the operator will experience financial hardship for ***its share*** of the plugging costs, not the entirety of plugging costs.

Moreover, as elsewhere in this proposed rulemaking, a simple attestation is insufficient; an operator should be required to certify that its application is true, complete, and correct (under penalties prescribed by the Texas Natural Resources Code 91.143 and the Texas Penal Code), just as the certification on Form W-3X currently requires.[115]

Note that as with <u>any</u> rejection of Commenters' suggestions, the Commission must include a reasoned justification for that decision in its response to comments. Here, Commenters specifically request that the Commission provide such a reasoned justification if it rejects Commenters' proposal that the calculation of an operator's financial hardship should consider only on the operator's portion of plugging costs, without including any portion nonoperaters are liable for.

As such, Commenters recommend the following changes:

(h)(4) In addition to the documentation that identifies nonoperators, and the affirmation required by subsection (f)(2)(A) of this section, the operator shall submit one of the following for Commission approval:

(B) a written request that the Commission, by order, determine that the operator's financial hardship warrants the granting of the extension. <u>Upon determining that the application is complete under subsection (i)(1) of this section, the application</u>

[114] The 25% threshold also aligns with the threshold that the Commission has proposed in 3.15(i)(2) for identifying entities with sufficient interest in a well such that their conduct is relevant to an operator's extension request.

[115] *See* Ex. 8 RRC Form W-3X. https://www.rrc.texas.gov/media/2vymqxgz/w-3x-fill.pdf (requiring an operator to sign its application under the following certification: "I certify under penalties prescribed by the Texas Natural Resources Code 91.143 and the Texas Penal Code that, to the best of my knowledge, the information given in this application is true, complete, and correct.").

shall be referred to the Hearings Division for an evidentiary hearing. The operator bears the burden of proving that the requested extension is warranted. The Commission shall determine by order whether to approve the requested extension. The operator shall include the following documentation:

(i) sworn financial statements, certified by a third-party certified public accountant and prepared in accordance with generally accepted accounting principles, which shall include financial information for the three fiscal years prior to the operator's organization report renewal date for all of its oil and gas operations in the United States. In addition, if any nonoperator owns 25% interest or more in the well, the operator must also submit sworn financial statements, certified by a third-party certified public accountant and prepared in accordance with generally accepted accounting principles documenting the nonoperator's financial information for the same three year period;

(ii) ~~an attestation signed~~ a certification signed by the operator or operator's representative under penalties prescribed by the Texas Natural Resources Code 91.143 and the Texas Penal Code stating that its financial hardship warrants an extension of deadline for plugging an inactive land well;

(iii) a well-specific plan identifying whether each 15/25 well will be plugged or restored to active operation, together with a schedule for completing that work, which may also include objective evidence ~~to demonstrate a reasonable basis and justification in support of granting a plugging extension due to the operator's financial hardship~~, specific to the inactive well. ~~For example:~~ Required evidence includes:

(I) additional costs specific to the wellbore's construction or mechanics;

(II) additional costs related ~~to road construction, brush clearing, or other~~ necessary actions to access the inactive well site that are not part of general maintenance required by Commission rules (such as road construction or brush clearing);

(III) additional costs related to the inactive well's location in a H2S field, in proximity to an overpressurized zone, enhanced oil recovery or carbon sequestration areas, or other active operations;

~~(iv) any other relevant information the Commission may consider to grant or deny the extension application pursuant to the financial hardship considerations listed in Texas Natural Resources Code §89.023(c), including, but not limited to:~~

(I~~V~~) the operator's prior investment in plugging or maintenance of wells for the past five years;

(~~II~~V) the operator's history of compliance, including any history of previous violations and the seriousness of those violations for the past five years;

(~~H~~VI) the current economic conditions as they relate to the operator's financial hardship;
(~~I~~VII) the operator's percentage of inactive wells compared to the operator's total well count for the past five years;
(VIII) for each well the operator proposes to restore to active operation under subsection (iii), an abeyance-of-plugging report meeting the requirements of subsection (l) of this section; and
(IX) the percentage of costs that the operator is responsible for compared to that of all nonoperators.
~~(V) any other information the operator believes is relevant to its financial hardship~~

(v) any other relevant information the Commission may consider to grant or deny the extension application pursuant to the financial hardship considerations listed in Texas Natural Resources Code §89.023(e.

(C) Compliance plan extension application (h)(4)(C)

Commenters agree with and adopt EDF's proposed changes to this section on compliance plans.[116] Proposed § 3.15(h)(4)(C)(ii) should require operators to submit all of the information that SB1150 allows the Commission to consider, including concerning current economic conditions, compliance history, and supplemental financial assurance. The proposed application requirements also do not expressly require operators to identify potential hazards to public health, safety, or the environment posed by each well included in the compliance plan.

Commenters also agree with EDF that the operator's compliance plan should also prioritize plugging or returning to active operation those wells posing a risk to surface water or groundwater, analogous to the risk-based criteria for abandoned wells found in Texas Natural Resources Code § 91.1132 and the Commission's implementing rules.[117]

(D) Individual performance bond extension application (h)(4)(D)

The Commission proposes the following language for the application information required for the bonding extension; Commenters suggest the following minor addition:

(4) In addition to the documentation that identifies nonoperators, and the affirmation required by subsection (f)(2)(A) of this section, the operator shall submit one of the following for Commission approval: . . .

[116] App. B (EDF Comments) at 16-17; 34-26 (proposed language).
[117] Tex. Nat. Res. Code § 91.1132 ("The commission by rule shall develop a system for: (1) identifying abandoned wells that pose a high risk of contaminating surface water or groundwater; (2) periodically testing high-risk wells by conducting a fluid level test or, if necessary, a pressure test; and (3) giving priority to plugging high-risk wells with compromised casings.") *See also* Ex. 29 RRC. *Well Plugging Priority System.* https://www.rrc.texas.gov/media/3hjhjroj/well-plugging-prioritization.pdf

> *(D) an individual performance bond that is in an amount that is not less than the full cost calculation for plugging the inactive well and runs with and covers the lifetime of the inactive well, regardless of a change in the operator. <u>The full cost calculation should be submitted to the Commission along with documentation of the bond.</u>*

This language mirrors the statute (Tex. Nat. Res. Code § 89.023(c)(3)), which creates a new category of individual performance bond that covers the lifetime of the well and requires the operator to pay a third-party bonding company to guarantee, up to a specified amount, the well's plugging costs. Because of this long-term commitment, ensuring bonding companies remain solvent is extremely important, and the Commission may want to evaluate, qualify, and approve companies that can service bonds. Commenters specifically recommend that the Commission require that the bonding companies be listed on U.S. Treasury Circular 570.[118] This would mitigate against the risk that the surety itself defaults and is unable to pay out the full value of the bond provided, a risk that is magnified when a surety issues bonds for multiple operators that are all subject to the same economic forces and geographies.

In addition, the Commission should consider ways to account for the risk that this option may be popular for wells that are significantly more complicated, more compromised, and more expensive to plug than the individual performance bond will cover. The Commission should require the operator to fully evaluate the well's condition before determining the cost of plugging. Requiring that the full cost calculation details be submitted along with the bond documentation should encourage operators to create more accurate estimates. The Commission should consider creating an administrative penalty if this calculation deviates in an unreasonable manner from actual plugging costs (i.e., if it appears that the operator engaged in fraud or negligence in determining the full cost calculation).

With these caveats, operators should be allowed and encouraged to use this class of individual performance bonds for all their wells, especially aging ones and those they transfer to new operators.

<u>3.15(i) Action on application for plugging extension for a 15/25 well.</u>

As the Commission adopts these rules, it must keep in mind that the Legislature has asked it to balance the risk these wells pose with incentivizing operators to plug these wells without abandoning them to the state. In other words the Commission must keep in mind that Tex. Nat. Res. Code § 89.023(c) states that the Commission "**may**" grant one of 4 extensions, not that it must. This suggests strict scrutiny of extension applications, and again encourages

[118] U.S. Department of the Treasury, Department Circular 570: Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reinsuring Companies, July 1, 2024, https://www.fiscal.treasury.gov/surety-bonds/circular-570.html. To be listed on Circular 570, a company must meet minimum criteria for solvency, profitability, and liquidity, and is limited as to the maximum risk it can take on for any individual bond. *See* 31 U.S.C. § 9305 and regulation at 31 C.F.R. Part 223.

the Commission to hold hearings on the applications for "demonstrated history," "financial hardship," and "compliance plan" extensions.

Proposed Language to Require Evidentiary Hearings for All Extension Applications Except The Bonding Extension

As an initial matter, Commenters propose incorporating rules on the evidentiary hearings to section (i) by modifying (i)(1) and adding the two sections to (i)(1)(E) and (i)(1)(F) as follows:[119]

(i) Commission action on application for plugging extension for a 15/25 well.
(1) After receiving the plugging extension application and documentation required by subsection (h), the Commission will notify the operator if the submitted application is complete. If the application is incomplete, the operator will have 90 days from notice from the Commission to cure its application. Approval of a plugging extension under this subsection requires satisfaction of the applicable criteria set forth in subsections (A), (B), (C), or (D) of this section and is subject to the grounds for denial in paragraph (2) of this subsection. Once complete, the Commission shall review the application and supporting documentation as described in subsections (E) and (F) ~~the Commission will review the application and additional documentation, and approve the plugging extension if approval is warranted. Approval is warranted if the operator meets the criteria set forth in one of the following subparagraphs (A), (B), (C) or (D)~~:

. . .

(i)(1)(E) For applications submitted under subsection (h)(4)(A), (B), or (C) of this section, the Commission shall refer the application to the Hearings Division for an evidentiary hearing. In determining whether an extension is warranted, the Commission shall consider evidence relevant to the criteria in subparagraphs (A), (B), and (C) of this paragraph, as well as any other evidence relevant to the operator's request under Texas Natural Resources Code § 89.023(c)(1). Following the hearing, the Commission shall determine by order whether the operator has established that the requested plugging extension is warranted. Notice of the hearing must be provided to the following persons, and the Commission shall provide 30 days from the date notice is mailed to protest:

(i) each surface owner of the tract on which each of the operator's inactive wells are located;
(ii) impacted mineral and royalty owners;
(iii) the county clerk for the counties where the operator's inactive wells are located;
(iv) each city clerk or other appropriate official for inactive wells that are located within the boundaries of a municipality; and

[119] This language largely mirrors the EDF's recommended changes to (i)(1) on page 31 of EDF Comments (see Appendix B), with three changes: (1) Commenters recommend adding the two new subsections about the approval process for an application (E) & (F) to after the Commission's existing sections (i)(1)(A) - (D) about the extensions themselves (instead of renumbering as EDF suggests); (2) Commenters believe hearings are appropriate for compliance plan extensions as well; and (3) Notice should also be given to impacted mineral and royalty owners.

(v) any groundwater conservation district with jurisdiction over the location of the operator's inactive wells.

(vi) Other persons who can establish a justiciable interest are also entitled to protest.

(i)(1)(F) For applications submitted under subsection (h)(4)(D) of this section, the Commission or its delegate may review and approve the application administratively without an evidentiary hearing.

(A) Action on an application for a "demonstrated history of reactivation" extension (i)(1)(A)

Commenters' proposed edits to this section are in line with the concerns raised about (h)(4)(A) that only a history of returning **older inactive wells** to active operation should qualify an operator for this extension. Given the data from New Mexico that only 0.5% of wells that were reactivated were reactivated after 8 years,[120] Commenters propose that this extension be available to operators with a demonstrated history of returning such older wells to operation. In recognition of the fact that it is harder to restore such wells to active operation than younger inactive wells (as the Commission's current proposal allows) Commenters also suggest that a longer period be given to operators to demonstrate this history of reactivation.

Therefore Commenters suggest the following edits to section (i)(1)(A):

(i)(1) . . . Approval is warranted if the operator meets the criteria set forth in one of the following subparagraphs (A), (B), (C) or (D):

(A) ~~the operator has a satisfactory history of restoring inactive wells to active operation~~ if the application and additional documentation required under subsection (h) demonstrates that ~~one of the following criteria~~: ~~(i) for an operator with no more than 10 inactive wells, the operator has restored one well to active operation in the preceding year; or (ii) for all operators with more than 10 inactive wells,~~ the operator has restored the equivalent of at least ~~10~~ 50 percent of its ~~total~~ inactive well population that had been inactive for eight years or more to active operation~~, in~~ during the preceding ten years or since the date the Commission first approved the operator's organization report, whichever is shorter. In addition, an operator requesting renewal under this section shall demonstrate compliance with the plugging-or-restoration plan submitted under subsection (h)(4)(A). The Commission shall deny renewal under this subsection if the operator materially deviates from the approved plan without good cause. The Commission or its delegate may require an applicant to provide any additional information that it finds to be reasonably necessary to determine whether the operator's history of restoring inactive wells to active operation warrants the granting of the extension.

[120] *Id.*

(B) Action on an application for a "financial hardship" extension (i)(1)(B)

Commenters proposed major changes to this section, which does not adhere to the requirements set by SB1150.

As an initial matter, the Commission has not explained why its five proposed tests are appropriate or related to SB1150 at all. It is unclear if an operator must satisfy each test, or just one—the preamble suggests that an operator may meet any one of these tests, but the proposed rule does not specify.[121] The Commission does not explain how it derived these tests. For example, there is no explanation as to why financial information is divided by 15 for several of the five tests.[122] There is also no explanation as to why (i) and (ii) compare annual values to costs that are likely to be spread out over several years. There is also the question of whether the Commission has assessed at all whether these five tests would actually help screen good operators from bad ones, or those that actually are in financial hardship through no fault of their own. The Commission includes no such analysis in the proposed rule.

Meanwhile, EDF ***has*** conducted such an analysis using publicly available data for the first test that the Commission has proposed (3.15(i)(1)(B)(i)), with shockingly high results. It concludes that 42% of operators of 15/25 wells whose P-5s were not classified as inactive would satisfy 3.15(i)(1)(B)(i):[123]

> *Using 2024 data, EDF identified approximately 26,000 15/25 wells associated with 1,916 operators whose Forms P-5 (Organization Reports) were not classified as inactive. EDF estimated plugging costs for these wells using their vertical depths and the Commission's published district-specific plugging costs per foot. Where a well's depth was unavailable, EDF used the median well depth for the applicable district. EDF also estimated each operator's annual gross production revenue nationwide using reported production volumes and average 2024 Henry Hub natural gas and West Texas Intermediate oil prices.*
>
> *Based on these estimates, approximately 42% of the operators evaluated (795 of 1,916) would satisfy the revenue criterion in proposed § 3.15(i)(1)(B)(i). Although EDF's analysis was limited by publicly available data, the results suggest that the proposed revenue criterion may be substantially less restrictive than anticipated.*

Even more fatal to the Commission's proposal is that **none** of the proposed five tests appear in SB1150 at all. Instead, SB1150 states (in Tex. Nat. Res. Code § 89.023(e)) that the

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[121] *Compare* Proposed Rule 5:32 (using the conjunction "or") *with id.* at 16:17 (including no conjunction). If the Commission keeps these five tests, the conjunction used should be "and."

[122] Is it arbitrary? Does it come from the definition of 15/25 well? Why would that be? What about young inactive wells? Is it the length of time between the rule's effective date and the last accepted compliance plan date? Why would that apply here? The Commission's lack of a justification for these categories, which are untethered from the analysis that SB1150 requires, leaves it vulnerable to a post-rulemaking challenge.

[123] App. B (EDF Comments) at 15.

Commission in considering whether to grant an extension for financial hardship, the Commission may consider the following criteria:[124]

> (1) the attestation, including the statement and financial statement, submitted to the commission under Subsection (d);
> (2) the operator's prior investment in the plugging or maintenance of wells;
> (3) the operator's history of compliance, including any history of previous violations and the seriousness of those violations;
> (4) Current economic conditions;
> (5) Operator's percentage of inactive wells compared to the operator's total well count;
> (6) Any other information as required by commission rules.

As proposed, the five tests in (i)(1)(B) do not take into consideration prior investment in plugging or maintaining wells, history of compliance, current economic conditions, or the operator's percentage of inactive wells vs its total well count. The tests also do not incorporate the well-specific evidence that operators are required to submit in proposed 3.15(h)(4)(B)(iii). They also do not reflect the fact that responsibility for plugging costs is shared between the operator and nonoperators. A test that compares only the operator's financials to the entire plugging cost overstates the amount an operator is liable for and does not accurately reflect how costs are allocated. This would also make it easier for operators to obtain a financial hardship extension when in fact, the money to plug is available from nonoperators. For this reason, Commenters suggest the rebuttable presumption described in its comments on (h)(4)(B) that nonoperators will contribute to plugging costs unless an operator provides credible evidence to the contrary.

In addition, as explained above and in EDF's comments,[125] given the language of SB1150 and the criteria identified for analysis, requiring notice and an opportunity for hearing is appropriate before a financial hardship extension can be granted.

Commenters also agree with EDF that applicants seeking hardship extensions should submit a plan identifying whether each 15/25 well will be plugged or restored to active operation, together with a schedule for doing so.[126] When reviewing an application for renewal, the Commission should consider compliance with the plan and deny renewal if the operator materially deviated from the plan without good cause. These requirements would provide accountability while allowing the Commission to consider genuine financial hardship.

Commenters recognize the difficulty in attempting to set objective criteria on such a fact-specific question of assessing whether an operator will experience financial hardship, but the Commission's current proposal improperly prioritizes objectivity over the intent of the statute to limit these extension to true hardship.

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[124] Tex. Nat. Res. Code § 89.023(e)
[125] App. B (EDF Comments) at 9-11.
[126] App. B (EDF Comments) at 16.

As such, Commenters suggest the following edits to (i)(1)(B), which incorporate the above comments and objective criteria that are more in line with the criteria set in Tex. Nat. Res. Code § 89.023(e):

(i)(1) Approval is warranted if the operator meets the criteria set forth in one of the following subparagraphs (A), (B), (C) or (D): . . .

(B) the operator's application and additional documentation required under subsection (h) demonstrates that it will incur financial hardship if the requested extension is not granted, The Commission shall apply a rebuttable presumption that nonoperators are able to cover their share of the plugging costs and thus unless rebutted by credible evidence provided by the operator, the Commission shall consider only the plugging and abandoning costs proportionate to the operator's interest in the well when evaluating financial hardship. The Commission shall consider the following criteria to determine whether a financial hardship extension is warranted:~~in accordance with the following criteria:~~

~~(i) the difference between the operator's total annual revenue, as shown in the most recent annual financial statements, and the full cost calculation for plugging and abandoning all of the operator's 15/25 wells, is negative;~~

~~(ii) the difference between the operator's total assets as shown in the most recent annual financial statements, and the full cost calculation for plugging and abandoning all of the operator's 15/25 wells, is negative;~~

~~(iii) the difference between the operator's three-year earnings before interest, taxes, depreciation and amortization, and the full cost calculation for plugging and abandoning all of the operator's 15/25 wells, divided by fifteen (15), is negative;~~

~~(iv) the payment of the full cost calculation for plugging and abandoning all of the operator's 15/25 wells divided by fifteen (15), will cause the operator to seek relief under 11 U.S.C. §§ 701-784, 1101-1195, 1301-1330;~~

~~(v) the payment of the full cost calculation for plugging and abandoning all of the operator's 15/25 wells divided by fifteen (15), will cause an event of default under one or more of the operator's material debt obligations; or~~

(i) the percentage of an operator's wells that are inactive has decreased over the last five years due to plugging operations and not transfers;

(iii) the operator's prior investment in the plugging or maintenance of wells has increased from year to year;

(iv) the operator's history of compliance is on par or below average for violations with similar size operators, and have no serious violations;

(v) economic conditions, and not the operator's own actions, merit a hardship exemption. The Commission may consider (I) whether Cushing[127] or Henry Hub[128] prices fall below the 10th percentile of monthly prices for the past 10 years for at least 6 months or (II) if the producer price index is above 300 for 6 months.[129]
(vi) objective evidence backed up by sworn financial statements as provided in the certified attestation under penalty that demonstrate a reasonable basis and justification in support of granting a plugging extension due to the operator's financial hardship, specific to the inactive well;
(ii) executive compensation is below average for similarly sized operators and executives forgo bonuses when pursuing a request for financial hardship;
(vii) an operator applying for renewal shall demonstrate compliance with the plugging-or-restoration plan and any abeyance-of-plugging report submitted under subsection (h)(4)(B). The Commission shall deny renewal under this subsection if the operator materially deviates from the approved plan without good cause.

(C) Action on an application for a "compliance plan" extension (i)(1)(C)

Commenters generally agree with and adopt EDF's comments on amendments to this section.[130] However, Commenters add the following suggestions

Prior to industry input, the Commission had proposed three conditions under which a compliance plan extension should be denied, specifically if:[131]

(1) the compliance plan would result in a potential hazard to the health and safety of the public or the environment;
(2) the compliance plan inadequately prioritizes concerns for the health and safety of the public or the environment; or
(3) the compliance plan includes an inactive well that poses an imminent threat to the health and safety of the public or the environment

The Commission's original draft also would have required an annual hydraulic pressure test on all 15/25 wells in the compliance plan until these wells were plugged and abandoned or

[127] Cushing Price Index, EIA https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M.
[128] Henry Hub Price Index, EIA https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.
[129] *Producer Price Index by Industry: Oil and Gas Extraction*. (2026, March 18). https://fred.stlouisfed.org/series/PCU21112111.
[130] App. B (EDF Comments) at 16-17; 35-36 (proposed language).
[131] Compare Ex. 12 (Aug. 12, 2026 Draft) at 12 (Draft 3.15(i)(2)(G)-(I) with Ex. 14 (Sep. 16, 2026 Draft) at 13 (deleting these three items).

restored to active operation in accordance with the compliance plan's schedule.[132] It would have prioritized plugging wells with the longest length of inactivity and those in H2S fields.[133]

Instead of these rules, Rule 15 as proposed for public comment creates a more relaxed timeframe for compliance and omits both the prioritization system for wells and also the annual hydraulic pressure test. Commenters strongly urge the Commission to reinstate those requirements as they are essential in meeting the requirements of Tex. Nat. Res. Code § 89.051(b) that direct the Commission to consider risk to public safety and the environment, wellbore and wellhead integrity and adopt rules that reflect the risks of each well.

For example, an annual hydraulic pressure test is essential to ensure well integrity has not changed from year-to-year and increased the risks the well poses.[134] Hydraulic pressure tests are much more accurate than fluid level tests and the Commission is well within its authority to require such testing, indeed without it the Commission lacks sufficient information to claim that public and environmental safety is protected and there is no potential for pollution.

As for wells that are located in H2S fields, Commenters agree with EDF that there should be a blanket ban on extensions for these wells. But, in the event that the Commission disagrees and decides to allow some extensions for wells that are in H2S fields, then the compliance plan should prioritize plugging in those fields. In addition, an acceptable prioritization scheme for bringing wells into compliance should not be limited to Texas Natural Resources Code § 89.023(f)(1)[135] and (7). The Commission should include these factors, the factors from its original draft, and the considerations of 89.051(b).

A compliance plan should also include a mechanism by which the operator plans for future plugging costs, such as the establishment of a sinking fund. SB1150 also allows the Commission to consider current economic conditions when granting a compliance plan extension (as it does with a financial hardship extension); the Commission should develop metrics that will define the actions the RRC will take in each situation. Arguments can be made for granting plugging extensions in either positive or negative economic conditions, but only extended negative economic conditions should qualify for the more generous granting of financial hardship extensions, such as when Cushing[136] or Henry Hub[137] prices fall below the 10th percentile of monthly prices for the past 10 years for at least 6 months. Or when the producer price index is above 300 for 6 months.[138]

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[132] Ex. 12 (Aug. 12, 2026 Draft) at 11.
[133] *Id.* Draft 3.15(i)(C)(1)(ii)-(iv).
[134] See Ex. 9 (Spring Working Group Comments) at 33 (explaining the importance of more frequent hydraulic pressure tests and more testing in general, especially in high risk zones).
[135] (f)(1): the age and length of activity of the well; (f)(7): any potential hazards to the health and safety or the public or the environment posed by the inactive well.
[136] Cushing Price Index, EIA https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M
[137] Henry Hub Price Index, EIA https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm
[138] *Producer Price Index by Industry: Oil and Gas Extraction*. (2026, March 18). https://fred.stlouisfed.org/series/PCU21112111

(C) the operator's compliance plan satisfies each of the following criteria:

(i) the compliance plan provides that the operator will conduct an annual hydraulic pressure test on all included 15/25 Wells until plugged and abandoned or restored to active operation in accordance with the compliance plan's schedule;

(ii) the compliance plan specifies a number of wells to be plugged or restored to active operation each year, such that the operator will achieve compliance for all 15/25 wells by September 1, 2042;

(iii) the number of wells to be plugged or restored to active operation each year is not less than the amount the operator would need to plug or return to active operation year-over-year to achieve compliance by September 1, 2042;

(iv~~ii~~) the minimum number of 15/25 wells an operator shall plug or restore to active operation each year is not less than the operator's total number of 15/25 wells divided by the remaining number of years until September 1, 2042;

(~~i~~v) the operator reasonably prioritizes the inactive wells to be plugged or restored to active operation each year based on the considerations listed at Texas Natural Resources Code § 89.023(f)(1), (7); 89.051(b) and the Commission's standards adopted pursuant to Texas Natural Resources Code § 91.1132;

(vi) when reviewing a compliance plan, the Commission ~~may~~ shall consider all other information included in the application pursuant to subsection (h)(4)(C)~~the number of 15/25 wells the operator plugged or restored to active operation above the minimum number required in clause (iii) of this subparagraph~~;

(vii) the compliance plan includes mechanisms by which the operator will be able to fund the plugging of its wells, such as a sinking fund; and

(viii) An operator that has received approval of a compliance plan under this subsection (C) may not subsequently obtain a 15/25 plugging extension under subsection (A) or (B) of this paragraph for any 15/25 well, regardless of whether the approved compliance plan included all of the operator's 15/25 wells

(D) Action on an application for an "Individual performance bond" extension (i)(1)(D)

Commenters refer the Commission to its comments on 3.15(h)(4)(D). Modifications to this section would include having the Commission receive and review the full cost calculation and limit the third-party sureties to those that appear on the US Treasury Circular 570. Critically, the Commission must clarify that it is a surety company, not a bank, that issues the individual performance bond. Sureties are entities that issue bonds, not banks, and SB1150 clearly states

that the extension available under Tex. Nat. Res. Code § 89.023(c)(3) is based on "an individual performance bond," not any other type of financial assurance.[139]

> *(D) The operator's performance bond meets the following criteria:*
> *(i) it is in an amount equal to the full cost calculation of plugging the inactive well, documentation of which has been submitted as part of the application;*
> *(ii) it runs with and covers the lifetime of the well, regardless of a change in operator; and*
> *(iii) it is issued by and drawn on by a third-party ~~bank~~ surety authorized under state or federal law to do business in Texas and that appears on the US Treasury Circular 570.*

3.15(i)(2) "Shall deny" criteria and the remaining sections in part (i)

In 3.15(i)(2), the Commission has proposed certain criteria that it will use to deny applications for plugging extensions. While a decent start, more clarity is needed for these to be sufficient. In addition, the Commission should add a denial criteria that limits the number of extensions an operator can receive for an one inactive well. The intent of SB1150 is that all wells will be plugged eventually; but that is not possible unless the Commission caps the number of allowed extensions.

Furthermore, as proposed, §§ 3.15(i)(2)(B) and (E) require the Commission to deny certain plugging-extension applications when an operator has been "penalized" for false-filing, safety, or pollution-related violations. The proposed rule, however, does not define when an operator is considered to have been penalized for purposes of these provisions. Commenters agree with the concerns raised by EDF[140] and recommend adding a definition of "violation" modeled on the definition used in 16 Texas Administrative Code § 3.78, without limiting consideration to violations that remain outstanding.

For purposes of § 3.15(a), a "violation" should include noncompliance with a Commission rule, order, license, permit, certificate, or applicable statute for which either: (1) The Commission has entered an order finding a violation and all appeals have been exhausted; or (2) The Commission and the person or operator have entered into an agreed order relating to the violation.

Defining "violation" with clarity will also avoid any unintended pressure the Commission might come under to resolve violations by agreed order so that operators can avoid triggering (i)(2)(B) & (E)'s mandatory denial of the extension application. The Commission should prosecute violations on their merits, not based on any downstream consequences it might have for an operator.

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[139] While banks may issue letters of credit, the statute does not allow an extension to be granted based on proof of that type of financial assurance.
[140] App. B (EDF Comments) at 7-8 (rationale); 28 (proposed language).

Commenters agree with the concerns raised by EDF[141] and also recommend revising §§ 3.15(i)(2)(B) and (E) to require denial when the operator—or an officer, director, general partner, trustee, or owner of more than a 25 percent interest in the operator—has any violation involving Texas Natural Resources Code § 91.143 or a Commission rule related to safety or pollution, where the conduct: (1) Caused or threatened pollution; (2) Created or threatened a safety hazard; or (3) Resulted from reckless or intentional conduct, as those terms are defined in 16 Texas Administrative Code § 3.107. Using existing Commission standards would provide greater consistency in determining which violations warrant denial of a 15/25 plugging extension. In contrast, the proposed language is too narrow and relies on a vague definition of what "significant impact" and "deliberate disregard" would be.

Regarding section 3.15(i)(2)(D), in the preamble to the adopted rules (if not in the rule itself) the Commission should provide examples of what constitutes financial hardship due to the operator's own fault or negligence. These examples should include an operator's failure to set aside funds adequate to cover the costs of plugging and remediating the well, during the well's production. This language is necessary to avoid creating an incentive for operators to avoid setting aside adequate funds in the knowledge that they will eventually be eligible for an extension based on financial hardship. The provided examples should also include an operator's agreement to acquire an inactive well without ensuring that it had adequate cash in hand to cover the cost of plugging that well.

Commenters also support mandatory denials under (i)(C), and recommend adding a citation to the Tex. Nat. Res. Code § 89.051(b) factors for clarity. Finally, Commenters recommend clarifying that if an operator is denied under this section and requests a hearing (e.g., under 3.15(i)(3)), notice and opportunity to protest must be granted to all interested parties.[142] The participation by affected persons in a hearing would aid the Commission in ascertaining whether denial under the listed factors is appropriate.

> *(2) The Commission shall ~~may~~ deny the application if the plugging extension is not warranted, and ~~but~~ shall deny the application ~~for~~ if any one of the following factors is met:*
>
> > *(A) the inactive well is owned, in whole or in part, by a nonoperator who was a previous operator of record, or officer, director, general partner, owner of more than 25% ownership interest, or trustee, of an operator of record, for the inactive well, and currently is barred from being on an organization report under Texas Natural Resources Code § 91.114(2);*

[141] App. B (EDF Comments) at 8.

[142] *I.e.,* Each surface owner of the tract on which the inactive well is located; Impacted mineral and royalty owners; The county in which the well is located, with notice provided to the county clerk; Any municipality within whose boundaries the well is located, with notice provided to the city clerk or other appropriate official; and Any groundwater conservation district with jurisdiction over the location of the well.

(B) the operator—or an officer, director, general partner, trustee, or owner of more than a 25 percent interest in the operator—has been ~~penalized for~~ issued a violation ~~due to false filings~~ under Texas Natural Resources Code § 91.143;

(C) the inactive well poses potential hazards to health and safety of the public or the environment, including under the factors described in Texas Natural Resources Code § 89.051(b);

(D) the operator's financial hardship is due to the operator's fault or negligence;

(E) the operator—or an officer, director, general partner, trustee, or owner of more than a 25 percent interest in the operator—has been previously ~~penalized for~~ issued a violation ~~that was a safety or pollution-related violation that caused a significant impact to public safety or the environment, was accompanied by conditions that indicated a significant impact to public safety or the environment was imminent, or is the result of deliberate disregard of Commission rules and regulations related to public safety or environmental protection~~ of a Commission rule related to safety or pollution, where the conduct: (1) caused or threatened pollution; (2) created or threatened a public safety hazard; or (3) resulted from reckless or intentional conduct, as those terms are defined in 16 Texas Administrative Code § 3.107;

(F) if renewing a compliance plan, the operator deviated from the previous year's approved compliance plan in bad faith or deviated from its compliance plan for three consecutive years; or

(G) the performance bond is not issued by and drawn on by a third-party ~~bank~~ surety that appears on Circular 570 and is authorized under state or federal law to do business in Texas~~:~~.

(3) An operator may not obtain more than three successive annual renewals for the same well under subsection (h)(4)(A) or (B) of this section, regardless of whether the operator relies on the same or a different basis for each renewal. Upon expiration of the final renewal, the operator shall plug the well, restore it to active operation, or qualify for an extension under subsection (h)(4)(C) or (D) of this section;

(4)~~(3)~~ If a plugging extension under this section is denied, the Oil and Gas Division Director will notify the operator, and the operator may request a hearing to challenge the denial by submitting a request for hearing within 30 days from the date of the denial letter. The operator shall provide notice of the denial to the surface owner, royalty and mineral owners, and each groundwater district, county or municipality whose boundaries include where the well is located, as described in (i)(1)(E) of this section, Opportunity to protest must be given, as described in (i)(1)(E) of this section. The party requesting the hearing shall have the burden of proof.

3.15(n) Fluid level or hydraulic pressure test for inactive wells more than 15 years old.

There are significant problems with how inactive wells are tested currently. It is well understood that fluid level tests do not provide the same quality of information as a hydraulic pressure test does as to the well's integrity and risks to safety and the environment. In addition, the results of these tests are easy to manipulate and results from one well can be easily substituted with the results from a different well.[143] Even if the Commission makes no change to the acceptable testing methods or time frames for inactive wells, Commenters urge the Commission to amend 3.15(n) to require operators to give notice to surface owners whenever they conduct a fluid level test or a hydraulic pressure test, so that the surface owner has the opportunity to witness the procedure and confirm it is performed and reported properly. Operators should also be required to give notice to surface owners if pressure develops between casing strings or the operator detects Bradenhead pressure or leakage and immediate notice is required to the Commission.

In addition to this new requirement for surface owner notice under these circumstances, Commenters also suggest that the Commission adopt all of EDF's proposed changes to 3.15(n), which include requiring more frequent hydraulic pressure tests and more frequent casing pressure monitoring and reporting.[144]

Rule 58

3.58 Certificate of Compliance and transportation authority.

SB1150 adds new scrutiny to the transfer of all inactive wells, whether they are 15/25 wells or not. Robust well transfer rules are essential to prevent poorly funded or noncompliant operators from acquiring aging wells that are at high risk of becoming orphaned wells left to taxpayers to clean up. The danger that must be avoided is that operators selling packages of wells often require the buyer to take the marginal or inactive wells in the package in order to get the good wells, in effect offloading the plugging liability to the buyer or the taxpayer. Commenters' suggestions seek to mitigate these dangers.

Commenters suggest that the Commission adopt a two-tiered system of scrutiny for inactive wells. For wells that are not yet 15/25 wells, the Commission could rely on an attestation of the transferor and transferee, much as the Commission currently proposes (with some modifications proposed below). But for a transfer involving a 15/25 well, the Commission should also require the operator to submit an application that includes the information that will allow the Commission to apply more scrutiny and confirm that the transfer will not result in risks

[143] Ex. 30 Drane, Amanda, "Oxy accused of cheating well safety tests amid CO2 storage plans." Houston Chronicle (Sep. 30, 2025) https://www.houstonchronicle.com/news/investigations/article/occidental-petroleum-railroad-commission-well-test-21033243.php

[144] App. B (EDF Comments) at 4-5 (rationale for proposed changes); 24-25 (blackline of proposed changes).

to public safety and the environment. Such a two-tiered system would also have the benefit of focusing the Commission's resources on the transfers that are most likely to be problematic.

Some additional rules should apply to all inactive well transfers. For example, operators that currently rely on ***any*** financial hardship extension or are not in compliance with Commission rules should be prohibited from assuming responsibility for additional inactive wells.[145] This brightline rule will also reduce the work the Commission must do in screening applications—having already assessed an applicant's financial fitness for a financial hardship extension, it can rely on that assessment in determining that a transfer involving inactive wells would not be a "good faith transfer." In addition, the Commission should consider requiring an individual performance bond for each inactive well that is part of the transfer. Requiring well-specific financial assurance before approving a transfer would help ensure that funds remain available to plug the well if the receiving operator subsequently fails to satisfy its regulatory obligations. This would also be evidence of a "good faith transfer."

A transferee must be required to reapply for extensions on any wells it purchases to see whether the transferee's circumstances alter whether the extension is appropriate. This would apply to extensions based on a compliance plan or bond; SB1150 already prohibits transfers of extensions for "demonstrated history of reactivation" and financial hardship. The Commission has discretion to deny the transfer of extensions both as a blanket matter under its rulemaking authority for inactive wells[146] and individually under Tex. Nat. Res. Code § 89.023(h)(3).

Several other modifications to the proposed transfer rule are needed. First, the Commission should add a definition of "good faith transfer" to the definitions section of Rule 15(a) as proposed above to clarify the meaning of the statutory term a "business practice performed in good faith." Second, the affirmation and any application materials should be submitted under penalty of perjury. And the Commission should set explicit penalties for both transferor and transferee if an attestation or application materials are incorrect. In addition, all inactive well transfers should include documentation that the transferred wells have passed well integrity tests.

For the transfer of 15/25 wells, more in-depth information should be collected via application. The Commission should require transfers to disclose information about what life is left in the well, the anticipated plugging costs upon asset retirement, and when those costs are expected to be incurred so the Commission can assess the reasonably equivalent value of the transfer.[147] A statement that each well still has economic value even with full plugging costs included, as attested by a professional engineer or professional geologist, with calculations and evidence submitted will also help ensure that the information submitted is correct. More

[145] SB1150 already expressly prohibits transfers of ***extensions*** granted under Tex. Nat. Res. Code § 89.023(c)(1) (for financial hardship and demonstrated history of reactivation). *See* Tex. Nat. Res. Code § 89.023(i); Tex. Nat. Res. Code § 89.023(c)(1)(A) & (B).

[146] *See* Tex. Nat. Res. Code § 89.051(a) & (b) (allowing the Commission to adopt "necessary" rules and rules to protect public safety and the environment).

[147] This information should be known to the parties already; the purchase contract will usually assign values to each well or lease included in the package.

information as to the business relationship between the parties should be required, and the Commission should require the transferee to make some demonstration that it will have financial resources to eventually plug the transferred wells. Evidence of this could be if a bond accompanies each transferred well or if the transferee has set up a sinking fund to pay for eventual plugging costs.

As such Commenters suggest expanding this section to include an application section for 15/25 wells and a separate section of criteria the Commission uses to decide if the transfer is appropriate, similar to how Proposed 3.15 is divided into an application subsection (h) and a Commission action subsection (i).

> *5) Each operator who seeks to assume operator status of an inactive well, defined in Texas Natural Resources Code §89.002(12) and §3.15(a)(8) of this title (relating to Surface Equipment Removal Requirements and Inactive Wells), shall file with the oil and gas division in Austin a completed form P-4 signed by a designated officer or agent for each operator involved in the transfer. The form P-4 shall be accompanied by a written affirmation* <u>*certified under the penalties prescribed by the Texas Natural Resources Code 91.143 and the Texas Penal Code and*</u> *jointly signed by each operator and submitted to the oil and gas division in Austin stating:*
>
> *(A) the well is in compliance with the requirements of Texas Natural Resources Code §89.023 and §3.15 of this title*~~*.*~~<u>*, including but not limited to:*</u>
>
> <u>*(i) that all transferring wells have been certified to have passed a mechanical integrity H-5 pressure test and site inspection by a third party inspector;*</u>
>
> <u>*(ii) for the transferee, that it does not hold an extension for financial hardship on any of its own wells and is otherwise in compliance with all applicable rules for all wells that it currently operates;*</u>
>
> *(B) the transfer was a business practice performed in good faith; and*
>
> *(C) the operator to whom the inactive well* ~~*was*~~ <u>*will be*</u> *transferred will ensure continued compliance with Texas Natural Resources Code §89.023 and §3.15 of this title*~~*.*~~<u>*;*</u>
>
> <u>*(6) In addition to the affirmation, the following application materials are required when the transfer involves a 15/25 well:*</u>
>
> <u>*(A) A list submitted by transferor and transferee identifying all wells, inactive and active, that are part of the transfer and the age and length of inactivity of each;*</u>
>
> <u>*(B) A statement that each well still has economic value even with full plugging costs included, as attested by a professional engineer, with calculations and evidence submitted;*</u>

(a) This should include information about what life is left in the well, the anticipated plugging costs upon asset retirement, and when those costs are expected to be incurred;

(C) A statement as to the business relationship between the transferor and transferee and an identification of the principals in each organization;

(D) Evidence from the transferee sufficient to show that it will have the financial ability to plug such wells in compliance with applicable Commission rules.

(7) The Commission shall review the affirmation and other application materials, and may request additional information as needed to verify the contents of the affirmation and application.

(A) The Commission may approve the transfer if all applicable elements required by (5) and (6) have been submitted and the transfer appears to be a business practice performed in good faith and that the transferee will be able to ensure compliance with Commission rules and its eventual plugging obligations for the transferred wells.

(B) The Commission may not approve the transfer if:

(a) The transferee has an active financial hardship extension under 3.15(i)(1)(B) or has filed an application for such an extension; or

(b) The transfer does not appear to be a business practice performed in good faith; or

(c) The transferee does not appear likely to be able or financially capable to ensure compliance with Commission rules and its eventual plugging obligations for the transferred wells.

(8)~~(6)~~ An extension granted under Texas Natural Resources Code §89.023(c)(1) and §3.15(h)(4)(A)-(B) of this title is not transferrable to another operator. The Commission may prohibit the transfer of an extension granted under Texas Natural Resources Code §89.023(c)(2).

Rule 107 should be amended as well

Suggestions for the Missing Penalty Section

SB1150 requires that the Commission set administrative penalties for violations of SB1150 and SB1150 rules. Yet the Commission has not done so, nor made any proposed amendments to 16 TAC § 3.107.

Commenters offer the following advice for penalties. The rules should allow the Commission the ability to apply maximum penalties (money, fine, sanctions, corrective actions) to punish bad actors. Administrative penalties for violations should include enhanced penalties for falsification, as TCEQ and other states impose.

As part of establishing the penalty process, the RRC should update Penalty Rules and General Penalty Guidelines.[148] The Commission should increase penalties for failure to notify the RRC of testing and submission of fraudulent tests. Notably, New Mexico recently increased its penalties.[149]

Commenters recommend that the Commission adopt a penalty policy similar to TCEQ's, including enforcement initiation criteria, a compliance history program, and expanded enforcement authority to order corrective actions. It could also inform decisions on whether to grant extensions or transfers. The Commission could develop a similar compliance history scoring system, and when an operator has too low a score, they do not qualify for extensions or to be the transferee of an inactive well.

If an inactive well transferred in good faith is not reactivated by the new operator and then orphaned, that should have implications for the future scrutiny by the Commission that the transferring operator will receive for future transfer applications, inactive well extensions, and other transactions. Using elements similar to those used in TCEQ's compliance history program would help improve operators' understanding of the program and encourage compliance.[150]

Notable elements of TCEQ's new compliance program are as follows:[151]

- TCEQ will now evaluate and classify a site's compliance history twice a year: on March 1 and September 1.
- The initial enforcement screening date—rather than the date of an enforcement settlement offer or petition—marks the start of the five-year compliance review period for an enforcement action.
- TCEQ's new formula includes all moderate and minor violations and repeat similar violations, meaning sites are more likely to accumulate points that hit repeat violator thresholds.
- The more complex the site, the higher the threshold for repeat violation points.
    - Each regulated entity will fall into one of five "complexity point categories."
    - Total "repeat violation points" determine whether a regulated entity is under or over the repeat violator classification thresholds assigned to its complexity point category.
- If the Executive Director grants a mitigation factor, she will adjust a site's compliance rating from unsatisfactory to satisfactory, but the point total will be marginally below the unsatisfactory threshold.

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[148] 16 Tex. Admin. Code § 3.107 (2025). https://texas-sos.appianportalsgov.com/rules-and-meetings?$locale=en_US&interface=VIEW_TAC_SUMMARY&queryAsDate=01%2F08%2F2026&recordId=226944

[149] NM Stat § 70-2-31 (2025). https://law.justia.com/codes/new-mexico/chapter-70/article-2/section-70-2-31/

[150] *See* TCEQ Adopted Amendments to 30 Texas Administrative Code (TAC) §60.1 and §60.2

[151] Lisa Dyar et al., "TCEQ Overhauls Compliance History: Expanded Violation Scoring and Repeat Violator Trigger Levels Pose Risk," Beveridge & Diamond PC, accessed February 17, 2026, https://www.bdlaw.com/publications/tceq-overhauls-compliance-history-expanded-violation-scoring-and-repeat-violator-trigger-levels-pose-risk/.

- Sites that appeal compliance history determinations will use a new form, the Advanced Review of Compliance History.

In addition, Commenters encourage the use of administrative penalties for transfers not made in good faith to fund the plugging of wells when they are found in violation of transfer rules. As part of the attestation, the transferee could be required to agree that should the transfer be found not to have been made in good faith, the penalty could be that prior operators could be held liable for plugging costs should the new operator become insolvent.

Concluding Remarks

In sum, Commenters appreciate the opportunity to comment on the Commission's proposal and respectfully request that the Commission adopt Commenters' requested changes.

Appendix A

SB 1150 Inactive Well Working Group Members and Comment Co-signers

Julie Range, Policy Manager	Commission Shift
John McFarland, Attorney	Graves, Dougherty Hearon & Moody
Annalisa Peace, Executive Director	Greater Edwards Aquifer Alliance
Becky Smith, Texas Director	Clean Water Action
Cecilia Behgam, Executive Director	Texas Climate Jobs Project
Don McCown	Mineral Rights Action Network
Erandi Treviño, Executive Director	Raices Collaborative
Hanna Mitchell, Texas Policy Advocate	Earthworks
Jen Hadayia, Executive Director	Air Alliance Houston
John Beard III, Assistant Executive Director	Port Arthur Community Action Network
Larry Linenschmidt	
Luke Metzger, Executive Director	Environment Texas
Mary Ann Menning	
Melanie Oldham, Executive Director	Better Brazoria
Rebecca Bernhardt, Program Director	Texas Physicians for Social Responsibility
Rob Bartlett, Jr.	Third Act Texas
Sarah Stogner	
Schuyler Wight, Rancher	YT Ranch
Steve Collins	CCT Ranch
Dr. Thelma Scott, Founder & Chairman	S.A.F.E. 4 Communities