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Railroad Commission of Texas
1701 N. Congress
Austin, Texas 78701

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

Re: **Comments on Railroad Commission of Texas ("RRC") proposed 16 TAC § 3.82 ("Proposed Regulation")**

Dear Railroad Commission of Texas:

I am a Board Certified Oil, Gas, and Mineral law attorney located in Longview, Texas. I graduated law school in 1999 and went to work as a law clerk for the Honorable William M. Steger, United States District Judge for the Eastern District of Texas for two years. In 2001 I came to work with Howard Coghlan doing oil, gas, and mineral law work both for the upstream and midstream space and have practiced in that area of law continuously for the past twenty-three (23) years. I am the current Managing Partner for COGHLAN CROWSON, LLP. In our firm, I practice with two other Board Certified Oil, Gas, and Mineral law attorneys, J. Don Westbrook and Joshua Swain.

Our firm is currently representing one company working on Direct Lithium Extraction ("DLE") technology, Energy Exploration Technologies, Inc. (d/b/a EnergyX). We are also actively representing numerous real property owners who have both surface ownership and mineral ownership or one or the other. Our clients are being inundated by requests to enter into brine mineral leases by Standard Lithium, TerraVolta, Exxon, BrightStar, Liger, Black Mountain, GeoFrame, ETNR, and the myriads of land brokers and leasing agents each or these companies has hired. We are actively negotiating lease terms and have come to realize the uncertainty surrounding legal, operational, and geological concepts related to mining for minerals in brine solution.

Our landowner clients have interest in Bowie, Cass, Titus, Hopkins, Van Zandt, Franklin, and Morris Counties, Texas and have collectively more than 100,000 impacted surface and mineral acres across these counties. Our client EnergyX is also attempting to establish a functioning DLE facility in Northeast Texas—Project Lonestar.

I am also a licensed attorney in Arkansas since 2009 and I am actively involved in representing clients in Southwest Arkansas in relation to brine mining for bromine and lithium. Consequently, I am closely monitoring the Arkansas Oil & Gas Commission proceedings and rulings on royalty rates for brine mining to extract lithium. Though the statutory scheme in Arkansas is significantly different from Texas, the data regarding the brine mining extraction and production is relevant to a regulatory mechanism in Texas.

Due to our law firm's extensive exposure to the brine mining rush, leasing, DLE development, and the activity being in our back yard, we contacted and are working with Senator Bryan Hughes' of State Senate District 1 on potential legislation to address continued questions in the law concerning brine minerals and ownership that impacts his constituents and our clients in Northeast Texas.

I. <u>Introductory Comments on the Proposed Regulation</u>

We are concerned about anything in the Proposed Regulation that causes further confusion over ownership of the minerals in solution or that works in the favor of the current large market entrants, limits free market competition, and creates a barrier to entry for smaller players in the emergent brine mining space in Texas. The way the spacing, unit sizes, financial obligations, and project descriptions overlay what we are seeing on the ground appears, whether intentional or not, to be anti-competitive and not something we should want to force on our companies and citizens in Texas.

We have talked directly with almost all of the companies we mentioned above and are aware there are multiple thoughts on the scale and size of DLE necessary to make a commercially viable project. Some DLE companies envision a modular, well-by-well-based approach, while others believe large scale projects with big, centralized facilities are best. More importantly, we are not aware of any DLE technology that has been demonstrated at commercial scale. This is true even in Arkansas and the players still seem to be determining what works best.

The RRC should bear this in mind when crafting the final regulations for the acreage/lease provisions as any barriers to land aggregation for other participants could foreclose market entry of newer, more competitive technologies. When you overlay the fact that the two principal elements of bromine and lithium are essentially both controlled by oligopolies in Arkansas then one would hope the RRC would support competition to help promote and stimulate greater activity to bring supply into the market here in Texas with as little regulatory oversight and market barriers as possible. Because brine mining is not actively occurring in Texas, we do not know what the space will eventually reveal with real world data. It seems far too early in the life of brine mining to overlay this Proposed Regulation with such specificity.

We are also concerned that the Proposed Regulation seems focused on only one element in solution in the brine—lithium. This focus only on lithium extraction from brine will hinder extraction of other minerals in solute, such as magnesium, potassium, boron, chlorine, iodine, calcium, strontium, sodium, bromine, and others. For example, bromine is and has been produced for decades in commercial quantities from the Smackover in Arkansas. We have seen a recent uptick in bromine interest and leasing in Northeast Texas and this regulation, though well intended, could inadvertently hinder the production of these other minerals. Bromine occurs in much higher concentrations in the brine from the Smackover than does lithium. Thus, fewer barrels of brine are required, and fewer acres are required to make a viable project.

II. Specific Concerns with Definitions in the Proposed Regulation

3.82(b)(5)[1]: Our paramount concern is with the definition of "brine" and the ownership of the minerals in the brine as well as related concepts involving produced water as we approach the upcoming 2025 legislative session and the term of the Texas Supreme Court. As the RRC is aware, there is legal uncertainty surrounding the concept of ownership of the minerals in the brine and the produced water from traditional oil and gas production. We do not yet have statutory clarity from the legislature or the courts on ownership of minerals solute in the brine. There is also an active case before the Texas Supreme Court working through produced water issues—*Cactus Water Services, LLC v. COG Operating, LLC.* As a result, our office has been working on potential new legislative changes for 2025 to provide additional clarity by modification and expansion of the Texas Water Code provisions. The RRC should be aware of the potential for legislation in the 2025 session which could modify definitions from what currently appears in the Proposed Regulation. Promulgating the Proposed Regulation with the current definitions before these issues are settled seems perilous due to the likely need to rework the Proposed Regulation shortly after its adoption.

The proposed changes versus what is in the Proposed Regulation for example will potentially modify the definitions of brine, and brine minerals, and brine mining via statute to delineate and provide clarity on the ownership of solute minerals in brine including bromine, magnesium, potassium, lithium, boron, chlorine, iodine, calcium, strontium, sulfur, barium, and sodium. We believe the definitions proposed in the Proposed Regulation for "brine", "brine resources", and "brine production project" will require change.

[1] All section references within this letter are to the specific sections of the Proposed Regulation, 16 TAC § 3.82.

If the RRC chooses to go forward with the Proposed Regulation it should consider including only enough language to obtain primacy jurisdiction over Class V injection wells from the EPA, but not further. We already know from 40 C.F.R. § 144.80-81(13) a Class V injection well includes "[w]ells used to inject spent brine into the same formation from which it was withdrawn after extraction of halogens or their salts". Halogens are fluorine, chlorine, bromine, iodine, and astatine on the periodic table of elements and occur in solution in Texas brine. The EPA's Underground Injection Control Glossary supplies a definition of "brine" as "water that has a quantity of salt, especially sodium chloride, dissolved in it. Large quantities of brine are often produced along with oil and gas."[2]

It seems the definition of "brine" for the purpose of a Class V injection well is already known. What we do not know yet is who owns the minerals in solution and who owns the produced water and the minerals in it. The RRC has never stepped into the arena of determining ownership or title and should not do so now or cause further confusion by supplying definitions for "brine" that may no longer be valid in the near term. It seems without further definition of "brine" and only utilizing how the EPA describes the reinjection of spent brine would be sufficient to apply to obtain primacy jurisdiction over Class V injection wells.

III. <u>Spacing and Unit Size Concerns in the Proposed Regulation</u>

3.82(d)(1) – (d)(4)(D): We feel the numbers suggested in the Proposed Regulation based on limited modeling are not proven and may be incorrect. The "minimum" unit size of 1280 acres or two square miles seems overly large and prohibitive. Further, lessors need to remain free to contract to protect their interests against dilution as they are able to reach agreement with lessees of brine minerals within the contractual brine leases. Many of the leases we are negotiating have anti-dilution provisions and maximum allowed unit sizes which may conflict with the language in the Proposed Regulation. What if a distinct area reveals a higher concentration of minerals in solution and can support a tract brine production well or, for example, a smaller 1000-acre unit?

It would seem prudent that the RRC's technical team would evaluate the well spacing for supply and reinjection that has occurred in Arkansas to serve as a standard method of assessing those conditions best suited for brine supply and spent brine reinjection with an emphasis on the regulatory review that transpired in Arkansas so Texas can avoid those timing barriers to unlock commercial activity in the brine mining space.

The publicly available data in Arkansas through the US Geological Survey reveals the concentration of lithium and bromine in solution varies significantly across the Smackover. The acres required for a unit or well should be a function of all the variables that go into the calculation including pore space, moveable volumes, and sweep efficiency. Is the area a strong water drive,

[2] "brine" definition from EPA Underground Injection Control Glossary
https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=UIC%20Glossary

weak water drive, or largely depletion zone? Is there connectivity for migration to occur, but subsequently closed off through geological activity such as faulting?

It also does not seem intuitive that depth as set out in the Proposed Regulation should be a factor in spacing for wells to prevent interference. It seems geological considerations such as well mapped faults that compartmentalize areas, etc. should be a factor, but even then, there is an argument until proven otherwise that there are always unknowns on the geological side of the equation, including how sands thin, thicken, and pinch out. Porosity and permeability variances should also be considered. These initial limits out of the gate in the Proposed Regulation will limit innovation and best practices based on what is determined when actual brine extraction and injection wells begin to operate at a commercial scale.

This is basic attorney math, but the maximum distance of some 23,760 feet within the assigned acreage plat process as described in the Proposed Regulation could lead to as much as 12,960 acres assigned if the acreage plat is roughly a square (23,760 x 23,760 = 546,537,600 square feet). This is approximately 20.25 square miles at 640 acres per square mile. This creates a large, assigned area to a project that creates prohibitions for other parties. We must ensure that if there is acreage that is assigned per well versus a brine unit overall with associated wells that the assignments to the wells can change. This would naturally reflect the learnings from the subsurface via ongoing production and injection where heterogeneities can be discovered over the life cycle and thus producing wells may become injecting wells and vice versa. It may also be revealed infill wells are required, just as with waterfloods and steam floods today across the world.

The acreage for brine minerals is being competitively leased now in Northeast Texas and this large project size could strand acreage and effectively "box out" other smaller acreage blocks from being developed without partnering or entering into a development agreement with a larger competitor at less favorable terms. We do not see the utility of forcing this large overlay on top of the emerging market and field until more data is gleaned from actual production of brine.

It seems logical a zone of influence provision within the Proposed Regulation would work far better than these seemingly arbitrary limits as proposed now. Over time, ongoing well and reservoir surveillance will further inform the subsurface model and allow brine producers to update their models on how the zone of influence ("ZOI") is interpreted.

ZOI language as follows could replace the current mechanism in the Proposed Regulation and be a more workable system for the initial regulation of brine mining:

> Zone of Influence—The trace (perimeter) on the land surface of the brine production project area plus a circumscribing area the width of which is the lateral distance from the perimeter of the project area and the calculated subsurface extent of the pressure changes resulting from the brine production and Class V spent brine return injection associated with the brine production project. The boundary of the zone of influence is the farthest distance away from the brine production project

> that the pressure effect of production and injection activity is anticipated to reach over the life of the brine production project.
>
> The application must include a discussion of how the zone of influence for the brine production project was determined, including modeling results that support the determination, including calculations showing the anticipated dispersion, diffusion, and displacement of fluids and behavior of transient pressure gradients in the target stratum or strata during the anticipated life of the brine production project.

Language similar to the above would at least allow modeling and data taken from real information to be presented to the RRC before establishing acreages for wells, units and projects. It is our belief the current Proposed Regulation is arbitrary and not based on data from Texas brine production. It is just too early and too soon to overlay such stringent and specific numbers for brine mining in Texas.

IV. Further Comments on Specific Sections of the Proposed Regulation

3.82 (c)(3): Does the proposed language allow for reinjection into the same formation, i.e. the Smackover, or does it have to be within the same formation within the boundaries of the "production project" within the Proposed Regulation? We foresee a climate where, as with current saltwater disposal wells, there may be opportunity for companies to centralize reinjection with a different operator of a Class V injection well to reintroduce the brine in the formation from which it came, but not necessarily within the boundary of a project as defined within the current Proposed Regulation.

3.82 (c)(8): What is the timing and extent of the plugging and abandonment ("P&A") requirements as written under the Proposed Regulation? If the P&A requirements are speaking to and inclusive of a full field removal/restoration within one year of production ceasing, this would be seen by any operator as onerous. As the RRC is aware, it can take several years to properly plan for a full field removal including lining up third-party service firms to execute this work, the associated project planning, any associated permits required, ensuring cooperation from landowners where surface rights-of-way exist and must be worked within the actual safe execution of the full field removal. The optional value of having equipment preserved in good working order is significant – being forced to P&A the full field within one year forgoes future reutilization. Sometimes new mineral plays come to fruition which in this instance could be for other minerals in brine solution or traditional oil and gas. The wellbore can be repurposed via a sidetrack, deepening, etc. in these instances. Similarly, the pipelines can be mothballed with nitrogen and the plants put into preservation mode until such time as a repurposing within the same industry or a new industry all together comes to pass. The costs of having to rebuild pipelines, drill new wells and establish new facility footprints can be detrimental to economic development for new opportunities where repurposing is economically viable and prudent.

3.82 (d)(1): The inability to inject within one-half mile or 2,640 feet of a non-participating area begs the question of holdouts within a brine unit or project as defined in the Proposed Regulation. Arkansas allows forced pooling at 75% and Texas has not traditionally had much functioning forced pooling (MIPA only recently being utilized again in some oil and gas production areas). Texas likely does not want to go further with the expansion of MIPA for this purpose. Based on statutory language of MIPA and its application only to oil and gas we continue with the need for legal certainty from the courts and the legislature about the ownership of the brine and the brine sourced minerals. Regardless, hold outs within a largely aggregated area can severely affect the efficient development of minerals that are beneficial to prevent the waste of natural resources as set out in the Texas Constitution.

3.82 (d)(2)(B): What are the examples of "responsible land management" for 1,280 acres for 2,000 acres versus 640 acres? Yes, some minimal changes on a percentage basis for facility footprint of well site and flow line (minimal in the grand scheme of the overall surface acreage). Likewise, how is the 5,120-acre limit per well derived? Again, it seems we need more of a ZOI analysis than picking a number at this point in time.

3.82 (d)(3)(A)(ii-viii): the 5 mile rule equates to roughly 50,000 acres. Does this mean an operator has to prove that its well taps into a previously unrecognized brine field within 50,000 acres? Implications for brine field sizes are significant and again anti-competitive. As we think about oil and gas fields and how those cross-lease lines, the sizes, unitization, etc., how does this compute and is it incongruent? It seems this requirement could lead to perpetual arguments across operators that everyone is impeding upon everyone.

How long does a company have before it is compelled to file the brine log? The problem we foresee with this requirement is the public filing of proprietary information associated with exploration and delineation programs. At a minimum, it would seem the brine log should not become public record for a reasonable period of time to mitigate actions of surrounding competitors or opportunistic lease aggregators that did not invest in the well, yet take action on adjacent leasing which can significantly impede the operator's prudent and cost-efficient development. It would seem prudent to give the operator who risked the capital the chance to continue its leasing strategy with its proprietary information and its risked capital.

3.82(d)(3)(C): We do not track what the statewide regulations are or will be versus permanent brine field rules. It seems the Proposed Regulation is generally going to put in place a set of statewide regulations, but then also make it clear the regulations will be changed and field rules put in place. Why not wait to see what develops in the field with limited regulation in the beginning and allow operators to come to the RRC for later approvals based on actual data such as under a ZOI mechanism?

3.82(e)(3)(M): how will the operator of a proposed project determine if there are abandoned wells that were improperly completed, plugged or abandoned for third-party wells that preceded them? This seems to put liability on the new operator for determination if "proper" plugging and abandonment was done as the new operator will never have complete information on those third-party wells. It is axiomatic that if the wells are third-party wells, the operator was not the operator or responsible party for the abandonment.

3.82 (g)(1)(A): We read this as positive in that the permit is reviewed for completeness within 30 days. It would be most helpful for operators trying to develop a brine mining play to have a timeline for approval after the permit's completion has been verified, i.e. 180 days after verification of completeness.

V. Conclusion

We thank you for your time and consideration of these comments and are open to further discussion and input should the RRC so desire. Our desire in commenting on the Proposed Regulation is to prevent any inadvertent additional uncertainty on ownership of the minerals in solution within the brine or who owns the produced water and its interstitial minerals until the legislature and the courts complete their work. We also seek to obtain the most open, innovative, free market possible for the development of all the potentially valuable resources in solution in brine located in Texas. What was once a waste product from oil and gas production or that would have been a "wet" dry hole for oil and gas producers, now contains valuable natural resources we hope can be harnessed for the benefit of all Texans. We hope any final regulation promulgated by the RRC will seek to achieve these same goals.

Sincerely,

James T. Carroll, IV