TEXAS GENERAL LAND OFFICE
GEORGE P. BUSH, COMMISSIONER

May 16, 2022

Railroad Commission of Texas
Attn: Leslie Savage, Chief Geologist
1701 N. Congress
Austin, Texas 78701

RE: Texas General Land Office Comments on Amend re: HB 1284 (2021), RRC's sole jurisdiction over carbon sequestration wells

Dear Ms. Savage,

The Texas General Land Office (GLO) is pleased to submit these comments regarding the Railroad Commission of Texas' (RRC) application for primacy to assume sole jurisdiction over carbon sequestration wells from the U.S. Environmental Protection Agency (EPA).

The GLO has jurisdiction over the leasing of most State-owned uplands and submerged lands for the purpose of energy resource development—including, but not limited to, offshore carbon sequestration activities under authority of the Texas Clean Air Act (Health and Safety Code, Sec. 382.501 et seq.). Revenue from GLO energy leases accrues to the Texas Permanent School Fund (PSF), a public endowment that is currently used to collateralize approximately $97 billion in K-12 school district bonds across the state[1], many in rural counties which would otherwise struggle to obtain a strong credit rating from capital markets. The maximum bond guarantee amount allowed under current federal law is $117 billion, which makes aggressive growth of the PSF vital to the long-term financing of Texas public education. The GLO therefore has a fiduciary duty to protect the physical and financial integrity of its assets—including Texas offshore carbon storage reservoirs. For this reason, we oppose several aspects of this proposed rulemaking as being insufficiently protective of the ability of candidate geological formations to contain high pressures and quantities of injected carbon dioxide over the 1000-year period commonly considered "long-term sequestration."

[1] Texas Education Agency, Texas Permanent School Fund Disclosure Statement - Bond Guarantee Program | Texas Education Agency , Accessed on May 16, 2022

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Historically, the vast majority of PSF income has been derived from oil and gas production leases, and hydrocarbon leasing will continue to be an important revenue stream for years to come. Nevertheless, as we look forward 20–30 years into the future, we see inevitable increases in the volatility of oil and gas production. The global oil and gas industry clearly shares this perspective. The 2021 BDO anonymous survey of energy company chief financial officers found that 89% of respondents planned to invest in renewable energy projects in that year[2]. Carbon sequestration is an important part of that investment strategy, with ExxonMobil alone committing $3 billon between 2021 - 2026 to advance carbon capture technologies[3]. Texas has perhaps one of the world's best candidate locations for large-scale carbon sequestration in Miocene age sediments in the near-offshore region of the Gulf of Mexico[4], and the GLO expects to earn billions of dollars in PSF revenue from leasing offshore carbon storage space by 2050. We must therefore work with industry to maximize the efficient use of that resource and to ensure that it is not physically damaged by poor operational practices.

Many of us maintain a conceptual framework of reservoir management that is the product of decades of familiarity with the oil and gas extraction industry. Carbon sequestration reservoir management requires a different mindset. Rather than gradually draining an accumulation of trapped fluids from high to low pressure, we must now envision raising a low-pressure volume to very high pressures which can approach the ultimate failure stress of the rocks. Not only are we pressurizing the reservoir, but we are displacing tons of native reservoir fluid—high salinity brine—toward faults which could be reactivated to induce seismicity or invade aquifers miles away from the carbon injection site. And well integrity is one of the largest sources of risk involved in carbon sequestration. Poorly executed production from oil wells can limit recovery from a petroleum reservoir. Likewise, mistakes in the construction or operation of carbon sequestration wells can destroy large portions of the reservoir's ability to hold pressure if workovers are ineffective. To use an everyday analogy, sequestering carbon is like inflating a tire. If the tire develops a slow leak, you may be able to patch it and continue driving. But if the leak is catastrophic, you will have to buy a new tire. Texas does not have a second Miocene carbon storage reservoir, which makes caution and best operational practices essential.

The Class II UIC program is inadequate for managing carbon sequestration wells

It is apparent from the proposed rulemaking that several pathways are intended to allow use of the Class II UIC program to regulate carbon sequestration wells under various conditions. Anthropogenic carbon dioxide that is sourced from high acid gas hydrocarbon production operations is proposed to be classified as "oil and gas waste," and thereby be eligible for

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[2] BDO, 2021 Energy Sector CFO Outlook Survey | BDO Insights , Accessed on May 16, 2022.
[3] Forbes, The Oil Industry Jumps On The Low Carbon Bandwagon (forbes.com) , Accessed on May 16, 2022.
[4] Meckel, T. and Trevino, R. (2014), "Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect", The University of Texas at Austin Bureau of Economic Geology, p. 15

injection into Class II wells. Wells "not originally completed" for carbon sequestration service are proposed to be "converted to the geologic storage of anthropogenic carbon dioxide", without a clear indication of whether such converted wells would be required to meet the far more rigorous Class VI standards of construction, maintenance, and monitoring. Finally, the Commission proposes to create a new exemption for the conversion of Class II enhanced recovery wells "for the exclusive purpose of Class VI injection for geologic storage".

The Class II regulatory program is not an acceptable substitute for the Class VI program. To begin with, existing federal Class VI guidelines are most similar to Class I industrial waste injection well guidelines. To put this into visual perspective, a typical Class I permit application requires submission of several 3-inch D-ring binders of data and routinely involves between 12 – 24 months of review by professional engineers and geologists. On the other hand, a Texas Class II permit application could be structured several different ways. If the carbon dioxide is considered to be "oil and gas waste," is it processed as a simple disposal well permit within 30 days? If it is an "enhanced recovery" well, can it be treated analogously to a waterflooding injection well, or must it always go through a (potentially) more rigorous application procedure used for carbon dioxide EOR wells—even if the storage operator declines to apply for a federal carbon tax credit and instead only sells offset credits against the stored carbon?

Use of the Class II program as a substitute for geologic carbon sequestration also begs the question, why does the existing federal Class VI regulatory program not contemplate such "upgrades"? A new fit-for-purpose class of UIC regulation was designed because it is needed to ensure the safe and consistent operation of geologic carbon storage facilities. It is the anticipated delegation of that program to Texas that has initiated this rulemaking, and the delegation should implement the Class VI practices required under federal law, rather than attempting to circumvent them. It is conceivable how the existing Class II program could possibly give inadequate attention to the detail necessary to review carbon sequestration wells. This is even more evident when considering that the Commission states that no additional budget or staff augmentations are being requested to administer the newly delegated carbon sequestration well program. An understaffed office could lead to minimal oversight of insufficiently detailed applications which will have to be processed under unrealistically rapid timeframes. Indeed, the addition of more qualified resources at the federal level could improve UIC review efficiency at the EPA.

It is also worth mentioning that carbon sequestration activities conducted using sources of high-acid hydrocarbon gas will not necessarily be small operations. Indeed, two of the world's largest carbon sequestration projects—Sleipner in Norway[5] and In Salah in Algeria[6]—used acid gas as their feedstock for sourcing anthropogenic carbon dioxide. The In Salah project is also notable for being shut down prematurely due to the evolution of increasing carbon containment loss risks. Well integrity was a particular problem at In Salah[7], which highlights the need for high quality construction standards. Mechanical failures which limit maximum injection reservoir pressure will reduce its practical storage capacity, and less capacity means less revenue for the storage facility owner. This means that the PSF could lose significant revenue-generating opportunities even if actual containment of the injected fluid is not jeopardized, because permitted injection quantities will have to be curtailed. Class VI well construction practices are designed to prevent this.

CO_2 is a compressible fluid and must be measured and monitored accordingly

Many documents in both the federal and state regulatory injection well programs and the associated literature refer to the "volume" of carbon dioxide emitted, injected, or stored. Although use of this terminology is also common practice in the natural gas industry, the highly compressible behavior of carbon dioxide in the vicinity of the critical point makes it even more important to measure mass, rather than volume. Moreover, all custody transfer measurements of carbon dioxide for tax credit or offset credit computation purposes are made in terms of mass—specifically metric tons (1 metric ton = 1000 kg). Every reference to "volume" in the proposed rules should be changed to "mass", and all continuous monitoring and measurement plans and requirements should include either both volume and density or else a direct mass measurement. Temperature should also be measured and monitored in all instances where pressure is.

Errors in measurement due to volume discrepancies at different temperatures and pressures measured at different locations can result in large differences in mass balance calculations, particularly as the density of carbon dioxide can change as much as 70% over a temperature change of less than 5 °C near the critical pressure[89]. Thermodynamic equations of state do exist for conversion of volume, temperature, and pressure measurements to mass. However, the need to control and measure each of those quantities independently creates additional uncertainty in the derived mass quantity. Fiscal carbon measurements will be more accurate if all the allowable

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[5] Energy Factor Europe, Sleipner: Pioneering Carbon Storage Under the Sea - Energy Factor (exxonmobil.eu) , Accessed on May 16, 2022.

[6] Massachusetts Institute of Technology, Carbon Capture and Sequestration Technologies @ MIT , Accessed on May 16, 2022.

[7] Ringrose, P., Mathieson, A., Wright, I., Selama, F., Hansen, O., Bissell, R., Saoula, N., and Midgley, J. (2013), "The In Salah CO_2 Storage Project: Lessons Learned", Geomechanics, Status November 2010 (ieaghg.org) , Accessed on May 17, 2022.

[8] Sadr, R., CO2 Utilization (tamu.edu), Texas A&M University at Qatar Micro Scale Thermal Fluids Laboratory, Accessed on May 17, 2022.

[99] Xing, K., Ji, Y., Wang, Z., Wang, M., Liu, Y., Xu, H., and Xiao, G. (2021), A potentially non-contact monitor method for CO2 at the pseudo-critical region using infrared spectrometer - ScienceDirect , Accessed on May 17, 2022.

uncertainty is either applied to a single mass measurement or aggregated from combined measurements of density and volume; otherwise, density changes could result in payment errors.

A review of flowmeters for use in carbon capture and sequestration (CCS) projects was conducted by researchers at Heriot Watt University. The review emphasizes the need for accurate mass measurement in carbon custody transfer or other fiscal applications as follows[10]:

> "Examples exist for large scale CCS projects. For example, the Sleipner project [25] uses ultrasonic meters [26], while both the In Salah [25] and Vattenfall projects employ orifice plates [26]. The Yates project uses orifice plates supplemented by Coriolis meters and Sheep Mountain project operates both turbine meters and densitometers [26]. It may appear then that the task of choosing mass flowmeters suitable for CCS has already been accomplished; however, *there is one major difference between the projects listed above and those of the future: the matter of accuracy. In these earlier projects the operators were not compelled to record the mass flowrate of* CO_2 within the bounds determined by EU ETS." (emphasis added)

Another important aspect of carbon dioxide density variation is in its relationship to storage depth. These proposed rules contemplate waivers of the federal depth limitations for carbon sequestration wells. Not only could such waivers place usable groundwater at risk, but they could result in carbon dioxide being stored at, or migrating to, depths shallower than required to maintain the fluid in its dense supercritical state. Storage of carbon dioxide in the less dense vapor phase makes inefficient use of available pore space[11]. Moreover, flashing of dense supercritical carbon dioxide into the vapor phase is a safety concern: the lower density of the vapor phase increases buoyancy forces and, consequently, the risk of vertical migration[12]. There is also evidence that vapor phase carbon dioxide can flow more easily through caprock seal pores than supercritical phase fluid, even at otherwise constant pressure differentials[13].

Finally, injection of carbon dioxide should be required to be under supercritical conditions. While it is also possible to inject cold liquid carbon dioxide and allow it to warm inside the reservoir to a supercritical state, such practices could create undesirable thermal stresses and either initiate or propagate fractures in the injection zone.

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[10] Collie, G.J., Nazeri Ghojogh, M., Jahanbakhsh, A., Lin, C-W., and Maroto-Valer, M.M. (2017), 'Review of flowmeters for carbon dioxide transport in CCS applications', Greenhouse Gases: Science and Technology, vol. 7, no. 1, pp. 10-28, https://doi.org/10.1002/ghg.1649

[11] National Energy Technology Laboratory, Carbon Storage FAQs | netl.doe.gov , Accessed on May 18, 2022.

[12] Solomon, S. (2006), Criteria for Intermediate Storage of Carbon Dioxide in Geological Formations - Bellona.org , Accessed on May 18, 2022.

[13] Niemi, A., Bear, J., and Bensabat, J. (Eds.) (2017), "Geological Storage of CO_2 in Deep Saline Formations", Theory and Applications of Transport in Porous Media Volume 29, Springer, p. 294.

Fracturing of the injection zone is highly undesirable

These proposed rules explicitly authorize "controlled" fracturing of the injection zone. This is highly undesirable as it could negatively impact both the "seal" of the storage area and revenues that depend on a reliably sealed storage area. Fractures, once created, require relatively less stress to propagate—all other things equal. To say this another way, the fracture initiation pressure in a wellbore is, in theory, greater than the fracture propagation pressure[14]. As such, fracturing the injection zone could lead to a reduction of the maximum allowable storage pressure, and, consequently, reduce storage capacity and the associated revenue available to the PSF as the facility owner. Several other sections of the proposed rules refer to preventing the initiation or propagation of fractures in the confining zone. These should therefore be revised to also prohibit initiation or propagation of fractures in the injection zone. Notably, prohibitions on fracturing of the injection zone are also consistent with Texas Class I regulations, because injection zone fractures which propagate to the boundary of the confining zone can increase containment loss risk.

Fracturing of the Miocene age sediments comprising the best offshore Texas carbon storage reservoir candidates is particularly undesirable because of the region's highly faulted and compartmentalized geology. The Texas Bureau of Economic Geology anticipates that reservoir compartmentalization—or the number, capacity, and sealing (or lack thereof) of smaller, adjacent, and possibly interconnected blocks of the subsurface created by faulting—will be "critical" to assessing practical storage capacity limitations[15]. Furthermore, consolidation of injection-induced fractures near lateral fault boundaries may—under the right combination of initial fracture trajectory and geomechanical stress state—create conditions that may result in lower fault surface cohesion[16]. Lower fault surface cohesion could then lead to fault slippage, higher fault transmissivity and new carbon leakage pathways, or perhaps more favorable conditions for induced seismicity. Numerical modeling studies of geologic carbon injection have also shown that there is the potential for injection zone fractures to intersect the caprock (confining zone) and create localized higher permeability channels through which carbon dioxide would preferentially invade the caprock[17]—a preventable step toward loss of containment.

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[14] Feng, Y., Jones, J. F., and Gray, K. E. (2016), "A Review on Fracture-Initiation and -Propagation Pressures for Lost Circulation and Wellbore Strengthening", SPE Drilling & Completion, v. 31 no. 2, pp. 134 – 144.

[15] Meckel, T. and Trevino, R. (2014), "Gulf of Mexico Miocene CO_2 Site Characterization Mega Transect", The University of Texas at Austin Bureau of Economic Geology, p. 256.

[16] Koshelev, V. and Ghassemi, A. (2003), "Hydraulic Fracture Propagation Near a Natural Discontinuity", Proceedings, Twenty-Eight Workshop on Geothermal Reservoir Engineering Stanford University, Stanford, California, January 27-29, 2003 SGP-TR-173.

[17] Pan, P. Z., Rutqvist, J., Feng, X-T., and Yan, F. (2014), "An Approach for Modeling Rock Discontinuous Mechanical Behavior Under Multiphase Fluid Flow Conditions", Rock Mechanics and Rock Engineering (2014) 47:589–603.

When considering maximum allowable surface injection pressure, fracture stress should be calculated using rock data from cores that comprise all of the relevant lithologies in the injection and confining zones. Just as a chain is only as strong as its weakest link, fracture stress will be the minimum strength among these lithologies—not an average value. There is no such thing as an "average rock" in the reservoir, and it will fail (fracture) at its weakest point first. Safety factors should then be applied to the minimum value of fracture stress.

Conversion of existing wells to carbon sequestration service requires extra care

The proposed rules would facilitate conversion of existing wells to geologic carbon sequestration service. The construction standards, and typical materials of construction, for wells not designed to withstand long-term exposure to highly corrosive CO_2-rich brines will be unlikely to meet Class VI requirements without extensive modifications. It is important to reiterate that "long-term" in this context is at least 1000 years. Simulations of 1000 years of carbon dioxide injection into wells specifically designed for sequestration service at the Ketzin pilot site in Germany showed that, if reservoir pressures were to remain elevated over the entire sequestration period, saturation of well cements with carbon dioxide and possible containment loss through the wellbores to the surface could occur[18]. An important assumption made in that study was that pressure would not quickly dissipate post-injection, a situation most relevant to large-scale carbon sequestration in confined reservoir compartments having closed boundaries. Also important, however, is that CO_2 saturation of the well cement caused its permeability to increase to a level enabling carbon dioxide migration. That is to say, it may not be necessary for the whole cement layer to entirely degrade before its ability to contain carbon dioxide becomes compromised. Significant corrosion of casing materials was also observed in the simulations.

Further studies have shown that the ability of well cement to withstand carbonic acid attack is sensitive to the temperature and pressure of initial cement curing, the composition of the cement and any additives, and the pressure, temperature and pH of the carbon-rich brine environment to which the cement is exposed. Cement degradation rates have been seen to be especially sensitive to brine (reservoir) temperature[19]. These results imply that the history and condition of existing well materials can have a strong impact on the expected ability of the well to seal against carbon dioxide release for protracted periods of time. Older wells not originally designed for carbon sequestration service will not generally have been constructed from materials optimized for carbonic acid resistance. Workovers can perhaps be effective in some cases, but it is important to emphasize that any conversion should be to a level fully compliant with Class VI standards:

[18] Le Guen, Y., Huot, M., Loizzo, M., and Poupard, O. (2011), "Well Integrity Risk Assessment of Ketzin Injection Well (ktzi-201) over a Prolonged Sequestration Period", Energy Procedia, vol. 4, pp. 4076–4083.
[19] Kutchko, B. G., Strazisar, B. R., Dzombak, D. A., Lowry, G. V., and Thaulow, N. (2007), "Degradation of Well Cement by CO_2 under Geologic Sequestration Conditions", Environ. Sci. Technol. 2007, 41, pp. 4787-4792.

this includes material and chemical compatibility, and may necessitate additional monitoring over and above the level mandated for a purpose-built Class VI well to adjust for unknown risk.

Data and draft permit disclosures to affected or interested parties should be electronic

We support the Commission's decision to rely on the existing Geologic Sequestration Data Tool for submission and retention of all permitting data and documentation. There is great value in standardization of the applicable data formats and retrieval systems. However, it is important that all interested parties have access to this electronic archive, and that all notices, draft permits, monitoring reports, and permit correspondence be included in the archive. The amount of information related to a Class VI permit will be substantial, and it is not practical for the GLO, or any other entity, to receive and store paper copies. Not only is it impractical for the GLO to store and digitize large documents, but many data items will require digital interactivity.

In particular, the Texas Clean Air Act requires the GLO to publish annual reports on "the total volume of carbon dioxide stored", "the total volume of carbon dioxide received for storage during the year", and "the volume of carbon dioxide received from each producer of carbon dioxide"[20]. The determination of "stored" demands an analysis of the various physical carbon dioxide trapping mechanisms (structural, capillary, dissolution, and mineralization) that is conducted through the interrogation of models and data submitted by Class VI permittees. Reconciliation of the mass balances among the received, injected, and stored carbon dioxide quantities affects the periodic auditing of rental payments made to the State of Texas and the verification of tax credits. Inconsistencies among these quantities will have to be resolved both in the aforementioned GLO annual reports and in the accounts of GLO carbon storage lessees.

Annual data collection is essential to robust storage model calibration

The Commission proposes to require five-year pressure falloff testing as a default for carbon sequestration wells. This should be an annual requirement, as it is for Texas Class I wells[21]. The computational reservoir models used to monitor, verify, and quantify carbon storage are extremely sensitive to input data, including permeability, pressure, and the locations of reservoir boundaries, that are all routinely obtained or calibrated ("history matched") against falloff test interpretations[22]. Moreover, falloff test results can signal increases in reservoir pressure that could lead to fracturing of the injection or confining zone, and to loss of containment – important information that should be gathered more often than once every five years.

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[20] Texas Clean Air Act, Subchapter K, Section 382.510, HEALTH AND SAFETY CODE CHAPTER 382. CLEAN AIR ACT (texas.gov), Accessed on May 18, 2022.
[21] US Environmental Protection Agency (2002), "UIC Pressure Falloff Testing Guideline, Third Revision", UIC Pressure Falloff Testing Guideline - Third Revision (epa.gov), Accessed on May 19, 2022.
[22] Jones, N. (2014), "The Quantification of Uncertainty in Reservoir Management", GEOExPro, v. 11, no. 5, pp. 42 – 45, GEO ExPro - The Quantification of Uncertainty in Reservoir Management, Accessed on May 19, 2022.

The tests can also help to detect the changing transmissivity or sealing potential of faults over time[23]. To reiterate, the Miocene reservoirs identified for carbon storage in offshore Texas are heavily faulted, and knowledge of the dynamic sealing potential of isolated reservoir compartments must inform decisions about the number, location, and size of carbon storage repositories offered for lease by the GLO. Annual pressure falloff testing is key data needed to make these decisions, and—again—to help validate carbon storage estimates in the annual reports the GLO is required by law to publish and to audit storage lease rental payments. A five-year test cycle could lead to substantial model inaccuracies, particularly where injectivity is changing due to reservoir heterogeneity or alterations to operational practices.

Regular monitoring data is also essential for reducing the uncertainty of reservoir models used to provide early warnings of containment loss or plume migration post-injection. When combined with the knowledge that well cement degradation may occur over a period of several decades at rates that are sensitive to the well's construction and material history, the federal default of 50 years of post-injection monitoring should be retained. Reduction of the monitoring or post-injection care period could create financial incentives for operators to design wells and ancillary equipment to have a shorter service life. Long-term monitoring will also help to mitigate against the possibility that latent errors will cause future damage to the facility that is not easily traceable to specific operational actions taken by a storage lessee.

For this reason, the Commission's proposal to require Class VI permittees to retain "records, including modeling inputs and data to support area of review calculations and integrity test results, for at least 10 years" should be modified to mandate permanent archival in the EPA Geological Data Storage Tool with access granted to the public for purposes of independent computational modeling and validation in support of safety and royalty payment auditing.

Carbon storage property protection must be equal to mineral property protection

The Commission proposes to require carbon sequestration well permittees to coordinate with oil and gas or geothermal exploration projects. The proposed rules also would require geologic carbon storage wells to be "drilled and operated in a manner that will prevent injury to adjoining property". It is unclear what precisely "coordination" entails, and it should be emphasized that all operations which intersect the carbon storage confining or injection zone must exercise a duty of care to protect the mechanical integrity of the storage reservoir.

Consider the analogy to downhole commingling of oil and gas production or the requirement to drill offset wells where production is closely adjacent to a lease boundary. The Commission

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[23] Kamal, M. M., Braden, J. C., and Park, H. (1992), "Use of Pressure Transient Testing To Identify Reservoir Damage Problems", SPE Paper 24666, Society of Petroleum Engineers.

requires that the rights of all mineral owners under these circumstances be equally protected. Industry has developed relatively straightforward procedures and remedies to achieve this. Wells can be preferentially completed in one or more producing zones, and isolation devices can direct flow from one zone or another as required. Offset wells in conventional reservoirs can balance pressure depletion among neighboring wells, or drainage from neighboring property can be financially compensated after the fact.

The equivalent remedies for loss of carbon storage capacity due to competition for pore space are less clear. Recall that a storage reservoir is a pressure vessel: loss of mechanical integrity due to poor well construction or degradation of materials will—in the event that workovers or other remedial actions fail—likely lead to a reduction in the maximum reservoir pressure under which carbon can be safely stored. Reductions in maximum storage pressure equate to a loss of storage capacity for any and all operators in the reservoir volume that is hydraulically connected to the source of the damage. In cases where neighboring carbon sequestration well operators inject at rates sufficient to cause their respective pressure fronts to overlap across a lease boundary, the effect will be to accelerate pressure rise in both storage leases. Accelerated pressure rise then reduces ultimate storage capacity and the economic life of both leases. Therefore, the concept of an "offsetting" injection well is not applicable in the same sense as it is in a production context.

One potential solution to the injection offset dilemma is to drill water production wells to relieve the pressure of displaced native reservoir brine. It does not appear that these proposed rules contemplate that possibility or the conditions under which it would be allowable—or required. The brine displaced by carbon dioxide will, in general, be of high salinity, perhaps even more saline than the surrounding water column. It may also contain heavy metals or other dissolved minerals which should not be disposed of directly into the water column or ground surface. Therefore, coordination must occur not only among different users of the pore space (e.g. oil and gas exploration and carbon sequestration), but also among adjacent carbon injection operators. Pooling or unitization of injection acreage alone will not solve the capacity reduction problem.

Injection rate increases should be allowed only after an approved permit amendment

The proposed rules make clear that "[a]n operator must file an application to amend an existing geologic storage facility permit with the director… prior to increasing the permitted injection pressure". This should be revised to also require injection rate increases (as measured on a mass flow basis) be preceded by an approved permit amendment. The rate of carbon injection can control reservoir sweep efficiency and, consequently, the degree to which residual phase trapping can act to sequester the carbon. Poor sweep efficiency can also result in a "pancake" of carbon rising to the top of the injection zone where it will migrate farther in the lateral direction than it otherwise would under more uniform reservoir contact conditions[24]. Injection strategy—including rate management—can also affect ultimate storage efficiency[25].

Reservoir data requirements should include both the injection zone and the confining zone

Several sections of these proposed rules mandate data requirements in the confining zone, and they should be revised to also include the injection zone. This is consistent with Texas Class I regulations, and it is necessary to properly manage and protect the integrity of the storage reservoir for reasons which have already been noted above. Rule sections in question include:

> "(C) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR [area of review] and a determination that such faults or fractures would not compromise containment;"

> "(E) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;"

> "(B) with a reasonable degree of certainty will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive;"

> "(B) a confining zone [zone(s)] that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs [underground sources of drinking water];"

> "director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive"

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[24] Niemi, A., Bear, J., and Bensabat, J. (Eds.) (2017), "Geological Storage of CO_2 in Deep Saline Formations", Theory and Applications of Transport in Porous Media Volume 29, Springer, p. 348.

[25] Eiken, O., Ringrose, P., Hermanrud, C., Nazarian, B., Torp, T. A., and Høier, L. (2011), "Lessons Learned from 14 years of CCS Operations: Sleipner, In Salah and Snøhvit", Energy Procedia 4, pp. 5541–5548, doi:10.1016/j.egypro.2011.02.541, Accessed on May 19, 2022.

Compliance with applicable international standards should be mandatory

The proposed rules state that "the director must apply methods and standards generally accepted in the industry". This should be revised to also mandate compliance with international standards applicable to geologic carbon sequestration, particularly ISO Standard 27914 "Carbon dioxide capture, transportation and geological storage — Geological storage". This standard was authored in part by researchers at the Texas Bureau of Economic Geology and will serve as a consistent and uniform set of requirements for monitoring, reporting and verification (MRV). Not only will adoption of this standard ease the Commission's regulatory burden by streamlining the requirements for MRV, but it will eliminate discordance among MRV plans among operators which could complicate leasing, measurement, or auditing of carbon storage.

Cementing should be verified by surface circulation

The proposed rules would allow operators to calculate or otherwise estimate the quantity of cement being used to protect USDW and the storage reservoir through "alternative methods". Such methods ostensibly include purely volumetric calculations and the use of indirect log evidence. None of these alternative methods is consistent with Texas Class I regulation, and they create unnecessary risk: lost circulation while drilling or other anomalies can result in insufficient cement coverage or bonding. The cement layer is one of the most important protections against loss of carbon dioxide from the injection and confining zones, and it should be unambiguously verified through visual observation of cement circulation at the surface. It is also important to realize that remedial cementing operations can be challenging even under optimal conditions, and they are by no means guaranteed to correct primary cementing failures. Finally, cement plugging for abandonment should be from bottomhole to surface consistent with Texas Class I practice. Cement degradation by carbonation is a known risk as mentioned above.

Safe and efficient geologic carbon sequestration is of benefit to Texas

In closing, we emphasize that safe and effective geologic carbon sequestration is of great benefit to the State of Texas, not only as an atmospheric carbon mitigation strategy, but also as an important new source of revenue for the Texas Permanent School Fund. We appreciate the efforts of the Commission to develop robust regulations which will help grow this new industry.

Sincerely

Thomas M. Ortiz

Thomas Manuel Ortiz, Ph.D., P.E.
Petroleum Engineer

TMO/tmo