Environmental Defense Fund

October 6, 2025

Ms. Lauren Sanchez
Chair, California Air Resources Board
1001 I Street Sacramento, CA 95814

Submitted Electronically

Re: Information Solicitation to Advise Implementation of the Carbon Capture, Removal, Utilization, and Storage Program: Senate Bill 905

Dear Chair Sanchez,

Thank you for the opportunity to provide feedback to inform the implementation of Senate Bill 905 (Caballero, 2022) and the development of California's framework for carbon capture, removal, utilization, and storage (CCUS). Environmental Defense Fund (EDF) appreciates the California Air Resources Board's (CARB) focus on developing a durable, science-based regulatory structure for CCUS.

EDF is one of the world's leading international non-governmental organizations and creates transformational solutions to the most serious environmental problems. To do so, EDF links science, economics, law, and innovative private-sector partnerships. With over 3 million members and activists, including half a million in California, and offices in the United States, China, Mexico, and the European Union, EDF's scientists, economists, attorneys, and policy advocates are working in 23 countries to turn our solutions into action.

CCUS can be an important part of California's climate solution set, but it must be deployed with rigorous guardrails to ensure it delivers verifiable emissions reductions in a safe and effective manner. While CCUS is not a substitute for other critical efforts to reduce emissions and transition toward a clean energy economy, EDF recognizes — along with experts like the Internation Panel on Climate Change and the International Energy Agency — that these technologies have a role to play in meeting California's climate goals, including reducing emissions 85% below 1990 levels and achieving carbon neutrality by 2045, as established by Assembly Bill 1279 (Muratsuchi, 2022).

EDF hopes to see CARB's framework establish strong, enforceable standards that minimize health and safety risks, address co-pollutants, and prioritize protections for communities most burdened by pollution. To that end, we offer the following responses to selected questions and additional recommendations to inform the SB 905 rulemaking.

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10. What specific criteria pollutants or toxics emissions should be prioritized for monitoring and where along the CCUS/CDR project components (i.e. capture, transport, injection/utilization) should monitoring be prioritized?

California can lead in establishing control measures and emission monitoring for secondary non-CO2 emissions associated with amine carbon capture.

Amine solvents are one of the most widely used post-combustion carbon capture materials globally. There is incomplete understanding and public knowledge of the potential of limited emissions of amines and their degradation products to contribute to ambient levels of criteria and hazardous pollutants. If not properly managed and avoided, the creation and potential release of toxic breakdown products like nitrosamines may pose serious hazards to the public near capture facilities. In part due to limitations in publicly available data on amine composition and emission and complexities in emission monitoring, this risk and its associated solutions are not well characterized in the literature. While there are available control measures that can significantly reduce the potential for harmful amine-related emissions, the risk of amine emissions and the associated solution sets are not represented in existing regulatory and permitting programs. As such, while options to select appropriate solvents and to implement engineered controls exist, they may not be widely utilized – which could lead to emissions and formation of probable human carcinogens. California can step in here and prevent this outcome.

In February of 2024, EDF held a scientific workshop on the topic of post-combustion carbon capture amine solvent degradation monitoring and control. The workshop gathered experts from academia and industry together to discuss solution-sets for this complex challenge – a report summarizing the discussion, findings and recommendations of this workshop is **attached** to these comments.[1]

EDF recommends that CARB take into consideration the recommendations of this workshop in prioritizing amine, nitrosamine, and nitramine emissions – including via limiting the creation and release of aerosols – at capture facilities utilizing amine-based solvents. California has an opportunity to lead as the first state to establish explicit requirements with respect to non-CO2 air pollution risks tied to the use of amine-based solvents for carbon capture.

This recommendation is in line with Department of Energy's Carbon Management Roadmap (October 2024),[2] which states:

> "Secondary non-CO2 emissions: For both point-source and direct air capture projects, secondary air pollutants could result from amine-based capture technologies (e.g., solvents and sorbents) being deployed. Monitoring and reporting requirements, mitigation strategies, engineering process operation controls and the development of regulations or standards around these pollutants will be essential as these technologies scale. Direct nitrosamine emissions measured in pilot campaigns have been reported to be at acceptable levels and can be mitigated by engineering process operation controls.

[1] EDF - Workshop on post combustion carbon capture amine solvent

[2] https://www.energy.gov/sites/default/files/2024/Carbon%20Management%20Strategy_10.10.24_0.pdf

Atmospheric reactions of amines present an additional pathway for nitrosamine formation which requires monitoring. Similarly, other degradation products, such as ammonia, can participate in atmospheric reactions to form hazardous compounds. Therefore, atmospheric photochemistry and dispersion modeling is required to determine the fate of direct emissions and quantify potential air quality impacts that arise during atmospheric reactions.

At DOE, the following efforts are underway to effectively measure, mitigate and evaluate the impacts of secondary emissions of carbon capture solvents and sorbents:

- A workshop was convened in June 2023 to discuss the air quality impacts associated with carbon capture and to identify research needs. The workshop also resulted in clarifying how engineering process controls can be applied to large scale and demonstration projects to prevent nitrosamine emissions.
- Monitoring and reporting data on non-CO2 pollutants has been made a requirement for many project funding opportunities.
- Research and development priorities include: lab-scale testing of the degradation of capture materials to inform requirements and monitoring; enhancement of existing photochemical air quality models to include new emissions species and degradation pathways; development of a mobile test unit at the NETL's Research and Innovation Center that will measure secondary emissions during pilot campaigns; development of technologies that can be used to mitigate secondary emissions, including tools to predict these emissions with machine learning."

15. What types of strategies are in use in other regulatory or voluntary programs that could be adapted to meet the statutory requirements?

In September of 2025, the Interstate Oil and Gas Compact Commission adopted a set of model statutes on geologic sequestration of carbon dioxide. The model statutes address many issues that may be of interest and relevance to the SB 905 rulemaking process including some topics of high priority to EDF, such as the prevention, monitoring, and response to induced seismicity – a topic on which EDF, jointly with Oxy Low Carbon Ventures, has previously indicated falls short as currently addressed in the LCFS. The final statutes are not yet published online, but the final draft is available here.[3]

This is the proposed language EDF and Oxy LCV submitted to CARB in 2022 as recommended language regarding Seismicity Monitoring – EDF continues to support this language, as well as the language represented in the IOGCC's recently adopted model statutes, Section 1.18.

4.3.2.3. Seismicity Monitoring
(a) The CCS Project Operator must deploy and maintain a microseismic monitoring system in order to determine the presence or absence, magnitude and the hypocenter location to the best of the operator's ability, of micro-seismic activity of Richter magnitude -0.3 or greater within the vicinity of all wells and near any discontinuities, faults, or fractures in the storage

[3] https://oklahoma.gov/content/dam/ok/en/iogcc/documents/committees-councils/legal/Model%20Statutes.pdf

complex. If, based on site-specific risk analysis, CARB determines that microseismic monitoring does not need to be permanent for a particular project, CARB may permit microseismic monitoring to be discontinued.

(4) The design of the array should consider if the seismic risk of triggering an earthquake of Richter magnitude 2.7, or greater, is significantly increased by injection;
(4) The array should be designed with surface arrays and/or downhole arrays as required to meet minimum magnitude of completeness of -0.3, and to appropriately calibrate event magnitudes and hypocentral locations;
(4) Calibrated with check-shots, sonic logs, or other velocity information, preferably at depth; and
(4) *If analysis of microseismic and other relevant data determines that an increase in risk is determined, mitigation is required.*

In addition, in light of EPA's proposed repeal of the Greenhouse Gas Reporting Program (GHGRP), CARB should consider whether any aspects of applicable GHGRP Subparts, including Subpart RR and Subpart VV, are not adequately covered in current regulations, including in the LCFS CCS Protocol. Where gaps are identified, CARB should adopt regulations to ensure an equivalent or superior level of oversight, public input, public transparency, and third-party verification are in place for the approval of monitoring, reporting, and verification plans and an eventual demonstration of secure storage.

16. Are there other guardrails that should be considered beyond existing local, state, and federal regulations to minimize impacts?

EDF recently filed comments with the Environmental Protection Agency (EPA) on the topic of actions that Texas can and should do to enhance protections related to carbon sequestration that go beyond existing regulatory programs, including the Class VI baseline, after receiving primacy over the Class VI program. Receiving primacy, however, is not a prerequisite for state action on these topics. EDF strongly encourages CARB to closely review these **attached** comments for consideration in the forthcoming rulemaking.[4] Topics include:

- Taking caution with respect to modifications of long-term liability and responsibility for carbon storage operators;
- Establishing robust, well-funded, and well-trained regulatory programs – including utilization of modern software for data management like GWPC's Risk Based Data Management System, and attending up-to-date training such as GWPC's Class VI Regulatory Training program;
- Incorporating learnings from ADM monitoring well events – including material selection, placement, and enhanced requirements for siting, construction, integrity and operation of monitoring wells;
- Adopting advanced seismicity protections based on site characterization and modeling – including site-specific seismic monitoring plans and seismic event response;
- Ensuring that initial permitting as a Class II or Class V injection well is not allowed to function as a loophole to the rigor of the full suite of Class VI requirements;

[4] EDF Comments EPA TX Class VI Primacy 7-31-25

- Implementing best practices for identifying undocumented potential fluid conduits in areas of review – including instrumented undocumented orphan well surveys and a requirement for desktop research on historical maps;
- Reducing conflict between sequestration activities and other subsurface operations, including protections to avoid risks to safety and storage security;
- Assessing the need for a modernized, precautionary approach to pressure – including guidance on accounting for pressure interference within and among projects, dynamic capacity assessments, and the collecting and sharing of data;
- Adopt advanced, more specific emergency and remedial response planning requirements; and
- Requiring appropriate levels of meaningful engagement with potentially impacted communities.

In addition, EDF has **also attached** a paper, *Strategies for Attaining CO2 Sequestration with Environmental Integrity*, that we wrote and presented in 2022 at ADIPEC in Abu Dhabi, UAE.[5] The paper more comprehensively addresses a range of topics relevant to environmental integrity that California should consider during this SB905 rulemaking process.

#22. What role could projects developed under SB 905 play in these programs, and are there other programs or policies in which carbon capture removal, storage, and utilization could play a role for compliance?

Carbon capture and storage is a key component in the production of fossil-based (or 'blue' hydrogen). For the reasons outlined below, we urge CARB, as they develop rules for CCUS, to develop protective safeguards that limit climate and air pollution impacts from both existing and new fossil-based hydrogen production facilities.

Strong CCUS regulations are critical, as California's fossil-based hydrogen market is expected to grow.

California is currently projected to be one of the largest producers of blue hydrogen in the country; that is, fossil-based hydrogen production with carbon capture. This is due in part to federal policy incentives for low-carbon hydrogen, including the 45V Clean Hydrogen Production Tax Credit and 45Q Tax Credit for Carbon Sequestration.

In addition, California has several state policies that either directly or indirectly incentivize low-carbon hydrogen production, including blue hydrogen. These include the Clean Transportation Program for hydrogen refueling infrastructure; several programs focused on fuel cell vehicle adoption; the Low Carbon Fuel Standard, which determines fuel eligibility based on a life cycle assessment; and the Buy Clean program, all of which are expected to result in market demand for blue hydrogen.[6]

[5] ADIPEC Paper CO2 Storage Integrity- EDF
[6] National Petroleum Council, *Harnessing Hydrogen*, Ch. 6 Policy and Regulation, pgs. 17-19 (2024), https://harnessinghydrogen.npc.org/files/H2-Ch_6-Policy_And_Regulation-FINAL.pdf

California is the second highest producing state in terms of existing grey hydrogen capacity, at 1.6 million tons/year.[7] Several notable blue hydrogen and ammonia projects are in development. Two well-publicized projects – the Lone Cypress Elk Hills Hydrogen Project and the Grannus Blue Ammonia and Hydrogen Project – are projected to produce a total of 33,725 metric tons a year of blue hydrogen and 150,000 metric tons a year of blue ammonia combined.[8]

Hydrogen carries a range of climate and environmental risks that rigorous carbon capture standards must address.

Zero- and low-carbon hydrogen has the potential to be a promising decarbonization solution, but whether it delivers climate benefits depends on how it is produced, transported, stored, and used. Today, nearly all hydrogen in the U.S. is produced from fossil fuels through a high-pollution process, with less than 1% produced using renewable energy.[9] The methods of production greatly influence hydrogen's lifecycle emissions and to what extent using it in place of fossil fuels produces any net climate benefit. Carbon capture can mitigate some risks, but only if deployed with the highest environmental and safety standards.

Existing hydrogen production facilities in California collectively emit more than 4 million tons of greenhouse gases annually.[10] Fossil-based hydrogen production causes significant health-harming pollution too. Some hydrogen production facilities individually emit hundreds of tons of NOx that contribute to health-damaging NO2, ozone, and particulate pollution, along with VOCs, SO2 and PM2.5 that contribute to harmful health effects.[11] Existing facilities also report emissions of hazardous air pollutants (HAPs), underscoring the need to investigate and address these emissions.[12]

On top of the production emissions, there are significant emissions further upstream, as well as the potential for pollution across the supply chain. Fossil-based hydrogen production methods often use methane as a feedstock—methane is a potent greenhouse gas with over 80 times greater near-term warming power than CO2, and it commonly leaks at high rates across the oil and gas supply chain.

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[7] Hensley Energy Consulting LLC, Report on CO2 Abatement Opportunities at Existing Industrial Hydrogen and Ammonia Production Plants, 2023. This includes merchant and captive facilities.
[8] https://www.crc.com/news-releases/news-release-details/california-resources-corporation-announces-carbon-dioxide
[9] Saadat & Gersen, *Reclaiming Hydrogen for a Renewable Future: Distinguishing Fossil Fuel Industry Spin from Zero-Emission Solutions*, Earthjustice (2021), https://earthjustice.org/features/green-hydrogen-renewable-zero-emission. In the U.S. today, nearly all hydrogen (95%) is produced from fossil fuels through an energy intensive industrial process called steam methane reformation (SMR), and 55-60% of domestic hydrogen demand comes from crude oil refineries, where it is used to lower the sulfur content of diesel.
[10] Sun et al., Criteria air pollutants and greenhouse gas emissions from hydrogen production in U.S. steam methane reforming facilities, 53 Env. Sci. Tech. 7103-7113 (2019), ☐HYPERLINK "https://pubs.acs.org/doi/10.1021/acs.est.8b06197"https://pubs.acs.org/doi/10.1021/acs.est.8b06197, Table 2
[11] Lewis et al., Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies, National Energy Technology Laboratory, Report No. DOE/NETL-2022/3241 (2022), https://www.osti.gov/biblio/1862910
[12] Davenport Engineering, Inc., Health Risk Assessment RY 2016, prepared for Air Liquide El Segundo Hydrogen Plant, July 30, 2020.

In addition, leakage of hydrogen itself can be significant and may undermine the potential climate benefits from use of hydrogen because hydrogen is a potent indirect greenhouse gas.[13] Recent studies have found hydrogen's warming power is over 35 times larger than CO2 pound for pound over the 20-year period after it is emitted, and about 12 times larger over 100 years—values that are 2-6 times higher than previously thought.[14] When hydrogen is released directly into the atmosphere, it contributes to climate change by "affecting chemical reactions that increase the amount of greenhouse gases including methane, tropospheric ozone, and stratospheric water vapor."[15]

Together, these impacts are substantial. For fossil-based hydrogen that utilizes carbon capture, high levels of methane leakage (5.4%) and hydrogen leakage (10%) can increase near-term warming by up to 50% compared to the fossil fuel applications they are replacing.[16] Moreover, one of the most substantial determinants of climate impact is the rate of carbon capture. A 60% carbon capture rate can reduce the climate benefits of blue hydrogen pathways by 15-50% in the near term and 20-60% in the long term, relative to a 98% capture rate.[17]

Hydrogen and subsequent CCUS buildout also carry important environmental justice implications.

Hydrogen production, infrastructure buildout, transportation, storage, and end use come with serious environmental justice implications. This is especially true of fossil hydrogen facilities using carbon capture, where numerous types of equipment, pipelines, and processes are involved. Hydrogen production facilities are typically co-located with or located alongside petroleum refineries and other chemical manufacturing plants and are often sited in or near communities with high proportions of low-income residents and people of color. New facilities should not be allowed to move forward if they will contribute to or worsen pollution in heavily overburdened communities.

Increased hydrogen production and demand for hydrogen in new end uses is likely to drive pipeline buildout as well, posing serious safety concerns because hydrogen is flammable. Leaks of hydrogen can pose a fire hazard when mixed with air at certain concentrations and an asphyxiation hazard when it displaces oxygen in the air. Because its molecules are very small, hydrogen is more prone than methane to leaking through joints, cracks, and seals in infrastructure. It can also permeate directly through materials used for natural gas distribution faster than methane, leading to deterioration and embrittlement of pipelines and other infrastructure. This means that existing gas infrastructure is generally not suitable to transport

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[13] Ocko & Hamburg, Climate consequences of hydrogen leakage, 22 Atmos. Chem. & Phys. 9349 (Feb. 2022), https://acp.copernicus.org/articles/22/9349/2022/ [hereinafter "Ocko & Hamburg 2022"]; Mejia et al, Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure, 45 Intl. J. of Hydrogen Energy 8810 (2020), https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275.

[14] Ocko & Hamburg 2022, supra note 6; see also Warwick et al., Atmospheric Implications of Increased Hydrogen Use, Dep't for Bus., Energy & Indus. Strategy (July 20, 2022) https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use.

[15] Ocko & Hamburg 2022

[16] Sun, et al, *Climate Impacts of Hydrogen and Methane Emissions Can Considerably Reduce the Climate Benefits across Key Hydrogen Use Cases and Time Scales,* 58 Env. Sci. & Tech. (Feb 2024), https://pubs.acs.org/doi/10.1021/acs.est.3c09030

[17] *Ibid.*

hydrogen. Likewise, hydrogen production facilities utilizing carbon capture technologies would require additional CO2 pipeline infrastructure that can pose serious safety risks and environmental justice implications.

While this discussion only concerns GHG and air pollution from fossil-based hydrogen production facilities, we urge CARB to continue to update and enforce other environmental requirements that apply to hydrogen production facilities to reduce the cumulative pollution burden on communities from these plants, beyond the air emissions. Likewise, to address the broad range of concerns outlined above, and to further improve safeguards to protect frontline communities, we encourage CARB to work with other departments and agencies with jurisdiction over these facilities and other portions of the hydrogen supply chain.

In developing hydrogen policies and the rules for CCUS in the SB 905 rulemaking, California policymakers should elevate the needs of communities facing environmental justice burdens, including communities in the vicinity of petrochemical infrastructure which have historically borne disproportionate pollution burdens and had little voice in decisions affecting their health and well-being. In developing regulations to limit pollution from hydrogen production, we encourage CARB to engage robustly with the communities that have experienced the most harm from refining and petrochemical development and use, as well as from climate change impacts.

For all these reasons, California should prioritize hydrogen from electrolysis powered by new, hourly-matched, regionally delivered clean electricity over fossil-based methods. At the same time, any fossil-based hydrogen facilities that do move forward — whether existing grey retrofitted with CCS or new blue hydrogen projects — must be held to the strongest emissions, environmental, and safety standards.

Fossil-based production methods are associated with greater levels of GHG emissions, criteria air pollutants, and hazardous air pollutants.

Hydrogen molecules are produced for industrial processes by breaking down compounds that contain elemental hydrogen, such as water, methane, or other hydrocarbons and feedstocks. Several pathways can be used to produce hydrogen, including splitting water by electrolysis; biological production from biomass; and thermochemical production from fossil fuels. Renewable-powered electrolysis produces relatively minimal direct emissions, whereas thermochemical production methods reliant on fossil fuels have much greater potential for direct emissions of NOx, methane, CO2, and other pollutants.

Hydrogen proponents aspire for production through clean pathways with minimal emissions, such as water electrolysis with renewable or other low-carbon electricity. Electrolysis using the current U.S. average grid mix electricity has an estimated carbon intensity of 21 kg of CO2e/kgH2, though electrolytic hydrogen powered by new clean electricity resources that are hourly matched and regionally delivered can achieve the lowest carbon intensity of 0.45 kgCO2e/kgH2 or less.[18]

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[18] Thomas Koch Blank & Patrick Molly, Hydrogen Decarbonization Impact for Industry: Near-term challenges and long-term potential, RMI (2020), https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf.

However, most hydrogen used in the U.S. is currently produced through steam methane reforming of natural gas, which has significant emissions. Autothermal reforming is another high-polluting process that generates hydrogen from fossil fuel feedstocks and is projected to increase in coming years. These methods emit greenhouse gases both as a byproduct of the hydrogen production itself and through upstream methane releases, resulting in a lifecycle emissions intensity of between 8 and 12 kg of CO2e/kg H2.[19] Both methods also produce NOx, methane, VOCs, and other health-harming and hazardous air pollutants. As CARB develops regulations under SB 905, it should account for the full lifecycle of these fossil-based pathways to ensure climate integrity and community protection.

CCS is a commonly cited method for reducing emissions from fossil-based hydrogen production. Overall CO2 capture rates of 90% are commonly assumed in environmental assessment studies of SMR with CCS.[20] Proposed new projects with carbon capture reviewed by Lewis et al. (2022) target 94.2 to 98.7% capture rates,[21] and the IEA finds that with post-combustion capture technology, over 90% capture can be achieved in an integrated SMR system with a relatively low energy penalty.[22] However, the small number of SMR facilities that currently employ carbon capture typically achieve only 50-69% plant-wide capture rates, indicating that regulatory standards would be required for wide scale achievement of higher capture rates.[23] This reinforces the importance of CARB establishing ambitious, enforceable performance standards under SB 905.

Some existing hydrogen production facilities individually emit hundreds of tons of NOx, contributing to health damaging NO2, ozone, and particulate pollution, and tens of tons of VOCs, SO2 and PM2.5 that contribute to harmful health effects of ozone and particulate matter. Studies suggest that future facilities using SMR with CCS could still emit tens of tons of NOx per facility, and future hydrogen production facilities using coal gasification could individually emit hundreds of tons of NOX, SO2, and particulates.[24] Some existing hydrogen production facilities appear to qualify as major sources of HAPs, while other existing facilities would be classified as area sources based on emissions reported to the National Emissions Inventory (NEI). Inventories indicate that methanol and n-hexane are issues at some existing facilities, and better data may show additional quantities and types of HAPs are emitted from these facilities. As

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[19] *Ibid.*
[20] Riemer & Duscha, Carbon Capture in Hydrogen Production – Review of Modelling Assumptions, Frauhofer Institute for Systems and Innovation Research, Energy Proceedings, ISSN 2004-2965 (2022), https://publica-rest.fraunhofer.de/server/api/core/bitstreams/77ec29e5-4af8-4812-9793-8501f92a6f8d/content [hereinafter "Riemer & Duscha"].
[21] Lewis 2022
[22] International Energy Agency (IEA), Global Hydrogen Review 2022 (Sept. 2022), https://www.iea.org/reports/global-hydrogen-review-2022.
[23] Riemer & Duscha 2022; Lewis 2022. A DOE-supported CCS project at the Vallero Port Arthur Refinery is reported to have captured more than 90% of CO2 from the product streams of two SMR units that were retrofit with vapor swing adsorption in 2013. Overall capture rates for the facility were not reported in the DOE notice. DOE, DOE-Supported CO2-Capture Project Hits Major Milestone: 4 Million Metric Tons (Oct. 2017), https://www.energy.gov/fecm/articles/doe-supported-co2-capture-project-hits-major-milestone-4-million-metric-tons.
[24] EDF, Petition for Rulemaking - Hydrogen Production Facilities - CAA 111 and 112, at 33-38, https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf

CARB crafts regulations, standards should not only address CO2 but also ensure controls for criteria and hazardous pollutants from both existing and future facilities.

There are no comprehensive emissions standards for hydrogen production facilities.

At present, there are no national emissions standards that apply specifically to merchant hydrogen production facilities.[25] Depending on circumstances, including the other products generated by the same facility or at the same location, equipment and operations at some hydrogen production facilities may be subject to certain NSPS or NESHAPs for other categories of sources, such as petroleum refining[26] or organic chemical manufacturing or service.[27] Some process heaters at hydrogen production facilities should be subject to the requirements of 40 C.F.R. Part 63, Subpart DDDDD, which addresses a subset of HAPs through work practice standards and emissions limitations for specified fuel/combustion technology combinations but does not limit NOX or greenhouse gas emissions.[28] These existing regulations are thus limited in their applicability and do not comprehensively cover criteria pollutants, HAPs, or greenhouse gases of concern from hydrogen production facilities. Furthermore, outside of severe and extreme ozone nonattainment areas, most hydrogen production facilities would not be classified as major sources for criteria air pollutants, so federal new source review requirements would also be lacking. Given these gaps, CARB has a unique opportunity under SB 905 to design comprehensive performance standards that protect climate and public health.

In a limited search, we identified regulations that are specifically applicable to hydrogen production facilities from two jurisdictions: California's South Coast Air Quality Management District (SCAQMD) and its Bay Area Air Quality Management District (BAAQMD). This includes SCAQMD Rule 1109.1, which sets new NOx and CO emissions limits for combustion equipment at petroleum refineries and facilities with related operations, including hydrogen production plants;[29] SCAQMD Rule 1118, which requires monitoring and record keeping of flaring operations for hydrogen production plants that supply petroleum refining operations;[30] SCAQMD Rule 1189, which limits VOC emissions from hydrogen plant process vents;[31] and BAAQMD Rule 13-5, which limits emissions of methane and other organic compounds from hydrogen production plants and carrying systems in the Bay Area District.[32]

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[25] While the GHGRP imposes reporting requirements, it does not require any actions to reduce or limit emissions.
[26] See, e.g., 40 C.F.R. Part 60 Subpart GGG; 40 C.F.R. Part 60 Subpart GGGa; 40 C.F.R. Part 60 Subpart J; 40 C.F.R. Part 60 Subpart Ja; and 40 C.F.R. Part 63 Subpart CC.
[27] See, e.g., 40 C.F.R. Part 63 Subpart G; 40 C.F.R. Part 63 Subpart H.
[28] 40 C.F.R. Part 63 Subpart DDDDD.
[29] SCAQMD Rule 1109.1 Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations, South Coast Air Quality Management District, adopted November 5, 2021, https://www.aqmd.gov/docs/default-source/rule-book/reg-xi/r1109-1.pdf?sfvrsn=8.
[30] SCAQMD Rule 1118. Control of Emissions from Refinery Flares, South Coast Air Quality Management District, adopted February 13, 1998, most recently amended January 6, 2023), http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1118.pdf?sfvrsn=4.
[31] SCAQMD Rule 1189, Emissions from Hydrogen Plant Process Vents, adopted January 21, 2000, http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1189.pdf.
[32] BAAQMD Rule 13-5, Regulation 13 Climate Pollutants Rule 5 Industrial Hydrogen Plants, May 4, 2022, https://www.baaqmd.gov/~/media/dotgov/files/rules/reg-13-rule-5-petroleum-refinery-hydrogen-systems/rule-version/documents/20220504_rg1305-pdf.pdf?la=en.

Additional analysis is required to identify any other local air quality standards which may apply to certain hydrogen production facilities, and the full suite of regulatory gaps. This further underscores the importance of CARB's SB 905 rulemaking in filling these gaps with strong, science-based standards.

CARB should consider performance standards for fossil-based hydrogen production facilities.

As CARB crafts CCS regulations under SB 905, it will be important to establish clear performance standards that both maximize greenhouse gas reductions and protect public health. In particular, CARB should consider setting standards for fossil-based hydrogen production facilities to ensure that any reliance on CCS delivers real climate benefits while minimizing local pollution burdens.

We urge CARB to develop performance standards for both new and existing fossil-based hydrogen facilities that reduce greenhouse gas, criteria air pollutant, and hazardous air pollutant emissions. If CARB sets a CO2 standard based on the level of emission reductions achievable through application of CCS, it must match the level of reductions achievable with SMR or ATR using the maximum feasible CO2 capture rates. For SMR facilities, this would require addressing both the post-combustion and process CO2 emissions streams, with overall capture rates of 95% or higher. With ATR facilities, natural gas fired burners for process heat are eliminated so combustion-generated CO2 is reduced, but high rates of process-generated CO2 capture must be required. In all cases, CARB should also consider community concerns, co-pollutants, and cumulative pollution impacts when setting standards.

CARB should also set standards to reduce NOx emissions from new fossil-based hydrogen production facilities, including through use of low- or ultra-low-NOx burners with selective catalytic reduction (SCR) for the reformer furnace or low-emissions electricity for process heat. In ATR systems, NOx emissions from the reformer furnace are sharply reduced by eliminating the need for combustion air for process heat. Limits on venting as well as leak detection and repair can reduce methane, VOCs, and hydrogen emissions as well.

We likewise urge CARB to consider developing emission standards for hazardous air pollution to limit toxic air pollution from new and existing hydrogen production facilities. While HAP emissions reported to the NEI differ widely across facilities, some hydrogen production plants report emitting more than 10 tons per year of methanol. Reformer furnaces, process and deaerator vents, catalyst beds and flares are among potential sources of HAPs that should be considered for emissions limits or design or work practice standards, including standards for start-up, shut-down, and maintenance operations, and fence-line monitoring. CARB should also secure additional supporting detail about hydrogen production processes, emissions, and control opportunities, and ensure sufficient safety and risk management programs are in place to cover chemical production, transport, and distribution.

For more information on the climate and air quality risks associated with fossil-based hydrogen production, please refer to EDF comments submitted to the EPA in 2023.[33]

[33] Environmental Defense Fund, Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under Clean Air Act Sections 111 and 112, Sept 2023, https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-

Strong safeguards are essential to ensure CCUS delivers real climate benefits.

CCUS can meaningfully contribute to California's climate strategy only if it is governed by robust safeguards that ensure real, durable, and verifiable emissions reductions, while minimizing co-pollutants and protecting communities. By addressing non-CO_2 emissions such as amines and hazardous air pollutants, adopting strong seismic monitoring requirements, applying safeguards across the full project lifecycle, setting ambitious and enforceable capture rates, and engaging directly with impacted communities, CARB can establish a regulatory framework that provides a strong and durable foundation.

Thank you for your consideration of these comments. EDF looks forward to continuing to work with CARB to ensure the effective implementation of SB 905. If you have questions or would like to discuss any of these recommendations, please contact Katelyn Roedner Sutter at kroedner@edf.org.

Sincerely,

Katelyn Roedner Sutter
California State Director

%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf

Environmental Defense Fund

Climate Innovation Initiative

Workshop on post combustion carbon capture amine solvent degradation monitoring and control

Environmental Defense Fund

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1. Background – climate and policy context

Post-combustion carbon dioxide capture technology has the potential to significantly reduce anthropogenic carbon dioxide emissions. Ultimately the net zero energy systems necessary for climate stabilization involve the minimal use of unabated fossil fuels, and use of carbon capture in the remaining fossil fuel system[1]. While electrification alternatives are readily available for sectors including power generation and heating, carbon capture may need to play a meaningful role in decarbonizing heavier industries such as cement, paper, steel, and chemical production.

However the research, industry, non-profit communities, and the White House have raised questions regarding the air pollution and health risks of carbon capture solvents used in these processes, and how to manage impacts on nearby communities.[2] EDF's view is that the question of how post combustion point source carbon capture can be done in a way that manages the risk of amine solvents and related toxic exposures should be thoroughly addressed to avoid future challenges that may threaten climate progress and put health at risk.

Amine solvents are one of the most widely used post-combustion carbon capture materials globally. There is incomplete understanding and public knowledge of the potential of limited emissions of amines and their degradation products to contribute to ambient levels of criteria and hazardous pollutants. EDF's view is that if not properly managed and avoided, the creation and potential release of toxic breakdown products like nitrosamines may pose serious hazards to the public near capture facilities. In part due to limitations in publicly available data on amine composition and emission and complexities in emission monitoring, this risk and its associated solutions are not well characterized in the literature. EDF's view is that the risk and solutions may not be broadly represented in regulatory and permitting programs, meaning that while options to select appropriate solvents and to implement engineered controls exist, they may not

[1] IPCC WGIII 2022, Summary for Policymakers

[2] *See e.g.,* White House Council on Environmental Quality, *Guidance to Responsibly Develop Carbon Capture, Utilization, and Sequestration,* 87 Fed. Reg. 8808 (Feb 16, 2022); Workshop Summary: Workshop on Measurement, Monitoring and Controlling Potential Environmental Impacts from the Installation of Point Source Capture (June 7-8 2023), https://usea.org/sites/default/files/event-/PSC%20Enviromental%20Impacts%20DOE%20Workshop.pdf.

be widely utilized. It follows that lack of control or regulation of amine emissions, or lack of their enforcement, could lead to emissions and formation of probable human carcinogens.

With fewer than thirty unique commercial point source carbon capture facilities operational worldwide[3], data on the actual degradation of amines in full-scale applications is limited. A preliminary understanding of amines and their degradation compounds led Norwegian authorities to set a permitting limit for amines and their degradation products. No standard or emissions monitoring requirements have been established in the United States. Still, project investments are moving forward. The Bipartisan Infrastructure Law of 2021 (BIL) authorized $2.5 billion for the U.S. Department of Energy's Office of Clean Energy Demonstration (OCED) to accelerate demonstration and deployment of carbon management projects and point source carbon capture demonstration facilities. The law authorized up to $820 million in funding for large-scale pilot projects to de-risk carbon capture technologies across the power and industrial sectors, with four projects announced in February 2024 for award negotiation[4].

The workshop convened by EDF in February 2024 explicitly built upon the information presented and discussions at a White House Council on Environmental Quality roundtable in March 2023, and a workshop hosted by the US Energy Association in cooperation with the U.S. Department of Energy (U.S. DOE) at the National Carbon Capture Center (NCCC) in June 2023.

The White House roundtable participants noted that "emission composition and levels will depend significantly on the flue gas being processed, choice of solvent, plant operation conditions, and environmental factors at the plant site" and drew the following conclusions (reproduced from the NCCC summary report[5]):

- Adding a solvent-based carbon capture to existing facilities could result in improved air quality from a criteria pollutant perspective (e.g., sulfur dioxides). However, there is the potential for solvents to degrade resulting in degradation products such as nitrosamines and aldehydes, and for amine emissions to form aerosols in the atmosphere, which may further degrade into other pollutants via photochemical reactions in the atmosphere.
- Although the potential exists and research needs were identified, it is important to underscore that these emissions can be managed and avoided. The potential will vary depending on the configuration of the solvent-based carbon capture unit and the location. For example, amine aerosols are minimized on a facility that already has a baghouse or wet electrostatic precipitator (wet ESP) to control for particulate matter.
- Emissions of nitrogen containing compounds (e.g., nitrosamines) can be minimized by fitting the solvent-based carbon capture plant with highly efficient engineering control systems (e.g., 2-stage water wash, acid wash).
- Carbon capture technologies based on adsorption (physical sorbents), or cryogenic separation do not create any secondary air emissions.

The USEA-NCCC workshop summary presented the following suggested action items:

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[3] Source: https://co2re.co/FacilityData of unique operational commercial CCS facilities.
[4] Source: https://www.energy.gov/oced/articles/oced-selects-four-projects-ky-ms-tx-and-wy-advance-technologies-reduce-harmful-carbon
[5] https://usea.org/sites/default/files/event-/PSC%20Enviromental%20Impacts%20DOE%20Workshop.pdf

TOPIC	Action Items
R&D	✓ Develop advanced water-wash systems ✓ Develop mitigation processes for aldehydes ✓ Develop continuous solvent reclamation processes ✓ Validate the safety of solvent emissions ✓ Develop engineering control systems tailored for specific industrial applications ✓ Develop air dispersion models tailored for specific carbon capture material chemistry
Project Implementation: Carbon Capture Pilots and CCS Demos	✓ Install online FTIR and other advanced/more sensitive analytical equipment (e.g., Proton Transfer Reaction TOF- MS) ✓ Install mandatory pre-CCS and post-CCS advanced engineering controls ✓ Measure co-benefits ✓ Implement standardized procedures for flue gas compositional monitoring ✓ Implement 3rd party emissions testing
Communications	✓ Disseminate R&D results including emission monitoring from Carbon Capture Pilots and CCS Demonstration projects by developing publicly accessible databases ✓ Distill information for non-scientific communities

Source: https://usea.org/sites/default/files/event-/PSC%20Enviromental%20Impacts%20DOE%20Workshop.pdf

Note that for the USEA-NCCC workshop, "co-benefits" refers to air quality benefits.

Building upon these efforts, the EDF workshop brought global leading experts together to identify next steps on science and technology with a focus on near-term opportunities for control and risk management. EDF is grateful for the participation and contributions of these experts to our workshops, and their participation in the discussion does not equate to full endorsement of this report.

2. Key findings and recommendations – for U.S. DOE, U.S. Environmental Protection Agency, state permitting entities, and operators:

2.1 The use of amine-based carbon capture solvents presents a potential risk to the public if not controlled. Control technologies exist but may not be incorporated into facility design without clear drivers (3.1.2, 3.2, 3.6)

- Considering the uncertainties and especially inherent uncertainties at scale, take a precautionary approach with broad amine removal techniques to address unknowns and yield the most benign emissions possible – such as by sequential control technologies.
- Identify and disclose risks in advance, mitigate them as much as possible, and be transparent with communities about risks and risk controls.
- Before moving to demonstration scale, run a 5-15 ton per day pilot using best practices described in 2.3 on the intended flue gas and solvent to operate at steady state and report data to U.S. DOE, regulators, and the public. The demonstration plant should operate with the same or better controls.
- Behavior and control of some amines are better understood than others, and those with more unknowns and therefore increased risk should be adequately addressed in pilots.

2.2 Measuring and monitoring amines and their degradation products is complex, but techniques are improving (3.3)

- Monitoring efforts should focus on limiting amine, nitrosamine, and nitramine emissions, including limiting aerosols
- Investments and U.S. government support for capture technology and deployment should prioritize funds to ensure proper amine and degradation product modeling, measurement, monitoring and verification is established in advance of broad commercialization.
- Monitoring and reporting programs should be articulated and required for specific compounds of concern to prevent exposures, e.g.:
    - Continuous Proton Transfer Reaction-Mass Spectrometer amine measurement at the top of the stack
    - Reactive plume model to predict ground level concentrations and deposition
    - More frequent measurement necessary when starting up
    - Direct sampling of nitrosamine emissions

2.3 A quantitative amine emission limit will enable identification of Best Available Control Technology as a standard for facilities (3.4)

- Adopt an initial limit in line with the Norwegian approach (i.e. 6ppm for total amine emissions, and 0.3 ng/m3 for combined nitramines and nitrosamines in the atmosphere, in line with local atmospheric modeling) unless and until research and assessment provides evidence for a different level. This limit may need to be a funding condition that awardees use advanced controls, potentially via aerosol control, a water wash, and acid wash for flue gas, with online amine monitoring, although in many settings the effectiveness of these controls still requires further validation, and better alternatives could yet be developed.
- With many commercial plants being built, a safety-focused approach would need to be developed that could apply broadly and swiftly.

2.4 While currently regulation of atmospheric levels does not exist anywhere, permit-associated limits in Norway and the United Kingdom have led to advancements in risk reduction controls and limits that can be built upon in the U.S.to expedite the establishment of controls (3.5, 3.6)

- Make as much use as possible of existing institutional and operational knowledge in Norway and the UK to set conservative limits which may be refined as facilities go online and more data become available. Charge a respected entity such as the National Academies of Science (NAS) and/or the International Standards Organization (ISO) with crafting science-based recommendations for exposure limits on nitrosamines and nitramines in air and water, which in turn might involve their recommendations on additional toxicity testing needs.

2.5 Additional targeted research is needed to rapidly address scientific questions in order to ensure proper controls are put in place and standardized across industry (3.2, 3.3, 3.4, 3.5, 3.6 and compiled in Annex I)

3. Discussion summary

3.1 Overview

3.1.1 Process

The basic objective of amine-based capture is to efficiently remove the highest amount of carbon dioxide (CO_2) possible while retaining the original nature of the amine such that reclamation and reuse can be maximized – both increasing efficiency and cost-effectiveness, as CO_2 absorption and solvent regeneration can represent as much as 75% of capture costs [6].

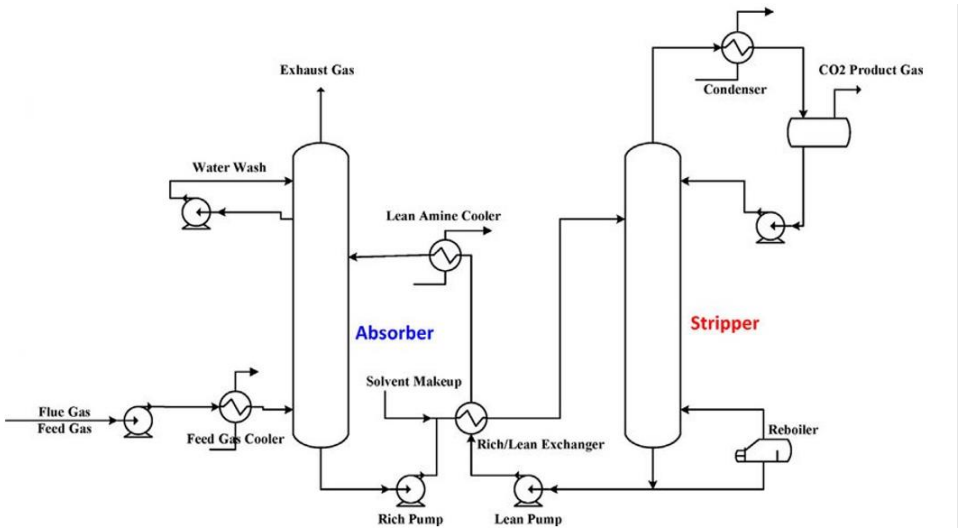

Figure 1: Modified from Liang, Zhiwu et al. (2015). "Recent progress and new developments in post-combustion carbon-capture technology with amine based solvents." *International Journal of Greenhouse Gas Control*. 40. 26-54.

An incomplete (no solvent reclaiming or cleaning is shown) setup for post combustion carbon capture involves an inlet for feed gas either from a combustion power plant (coal, gas, or biomass), or an industrial facility such as one producing steel, paper, or cement and is reproduced above (Figure 1).

The gas stream first passes through any pretreatment steps for fine particulate matter (PM2.5), aerosols, nitrogen oxides (NOx), sulfur oxides (Sox), and/or other air pollutant removal that may be present. Other pollutants can interfere with this objective, reducing capture efficiency and contaminating the amine itself – outcomes that increase the overall cost of capture at design rates. For this reason, properly managing and protecting the amine solvent to ensure expected outcomes often inherently involves pre-treatment to remove other pollutants as an alternative to having them removed in the post combustion carbon capture process itself, which can be associated with degradation or need for additional cleaning. In either case this can present numerous co-benefits for conventional emissions. Enhanced standards and controls for amines and amine degradation products could result in more consistent co-benefits for such pollutants as facilities are further incentivized to design tighter controls on the absorber and reclamation processes.

[6] https://chemrxiv.org/engage/api-gateway/chemrxiv/assets/orp/resource/item/6377bad6207981ee472c3bfc/original/comparison-of-detailed-capital-expense-estimates-for-two-ngcc-retrofits-with-capture-by-amine-scrubbing.pdf

Meeting participants noted that particular pretreatment steps depend upon the type of gas stream, and are usually more necessary when the inlet gas could contain aerosols (e.g. coal and biomass combustion, cement production, and cracker gas. The formation of aerosols in the gas is relevant for solvent management controls because controls tend not to act on aerosolized solvent. There are various options for control of aerosol formation, and equipment for removal of aerosols may be present in the initial gas stream from the power plant or industrial facility for the purposes of criteria pollutant attainment (see section 3.5.1). Continuously monitoring the levels of aerosols and other co-pollutants throughout the process is necessary to protect against formation of degradation products, as peaks can occur that may not be reflected in steady-state conditions modeled in a pilot – such as startup and shut down – and necessitate additional controls or management strategies (e.g. a "peaker" plant).

The pretreated gas then enters an absorber tower where it comes in contact with the selected amine solvent. The solvent binds to and absorbs carbon dioxide, and the remaining flue gas is emitted from the top of the stack. Here an operator would again measure for any permit-limited pollutants such as NOx and SOx, the emissions of which could also affect the formation of degradation products, and would be needed to estimate their concentrations via atmospheric modeling (see section 3.4) , The carbon dioxide-bonded ("rich") solvent then travels to the desorber, or stripper, where it is heated to release the carbon dioxide which is compressed for utilization or storage. The "lean" solvent then returns to the absorber tower for reuse.

This amine carbon capture process is in use at over two dozen commercial facilities and has been examined in detail at the Technology Centre Mongstad (TCM) test facility in Norway and the NCCC facility in Alabama. See section 3.5.2 for a table representing participant overview of these technologies and their roles.

3.2 Risks

The extent to which amines and their degradation products pose a risk to individuals working and living in the affected area of a capture facility depends on stack emissions, on stack height, planned or unplanned solvent releases from the plant and on specific site conditions that determine the effectiveness of dispersion from the stack, including weather, geography, and existing air pollutants. Assessing risk for stack releases necessitates an understanding of the potential exposure pathways as well as the levels at which those exposures create a hazard or potential harm over a specific time period. While amines themselves are not expected to be a direct health concern due to their low concentrations, when, where, and how they react in the atmosphere to form other potentially toxic degradation products is vital to designing proper amine risk controls. There is also a risk of primary emissions of toxic degradation products that form in the solvent.

Furthermore, capture facilities may be clustered in existing industry-heavy areas. Regulation of existing permit-limited pollutants will assist in the management of risks from amines. Cumulative impacts and the net benefits of reduced co-pollutants are relevant considerations.

<u>Questions posed to workshop participants:</u>

- What are toxicological risks at different levels of exposure?

- Which compound(s) are most relevant and meaningful to measure?

Amines are derivatives of ammonia (NH_3) with one or more of the hydrogen atoms replaced, such as with an alkyl or aryl group. They are classified as primary, secondary, or tertiary amines according to the number of hydrogen atoms replaced. The solvents tested and used for carbon capture at TCM, NCCC and elsewhere can be single amines such as monoethanolamine (MEA) or solvents that contain combinations of multiple amines. Although compositions for some solvents composed of multiple amines are in the public domain, others are proprietary. As such their composition is confidential business information, which adds significant complexity to their measurement and monitoring (see section 3.4.2).

3.2.1 Toxicity of amines and their degradation products

The toxicity of amine solvents themselves varies, but the concentrations at which they are released in the flue gas are low enough not to be a direct health concern[7]. However, in the atmosphere amines can react with coemitted NOx to produce nitrosamine and nitramine compounds. Nitrosamines make up a group of compounds whose toxicity ranges widely (Table 1). Table 1 reports oral cancer risk (Cancer Slope Factor – CSF) determined by the US EPA, but a participant noted that the cancer risks from inhalation may differ from oral exposure. In principle, a higher emission of amines can enable more production of nitrosamines and therefore higher health risk.

Table 1: Relative carcinogenic potencies of different nitrosamines, from the Norwegian Institute of Public Health report "Health effects of amines and derivatives associated with CO2 capture: Nitrosamines and nitramines" and based on US EPA Integrated Risk Information System assessments

Substance	**CAS No**	**Oral CSF§** $(mg/kg\ bw/d)^{-1}$
N-Nitrosodiethanolamine	1116-54-7	2.8
N-Nitrosodi-n-butylamine	924-16-3	5.4
N-Nitrosomorpholine	59-89-2	-
N-Nitroso-di-n-propylamine	621-64-7	7
N-Nitrosomethylethylamine	10595-95-6	22
N-Nitrosopiperidine	100-75-4	37.5
N-Nitrosodimethylamine	62-75-9	51
N-Nitrosodiethylamine	55-18-5	150

§Intigrated Risk Information System EPA

Five components on the U.S. EPA list of Hazardous Air Pollutant have also been identified in air emissions from capture plants and thus subject to a facility level limit on annual emissions. These include formaldehyde, acetaldehyde, methanol, acetamide, and acetonitrile. Their precise pathway of production in the amine carbon capture process has not been identified but modeling and measurements have shown aldehyde concentrations to be consistent, and at below a level of concern ($1/10^{th}$ of the standard for cancer risk). While current knowledge does not appear to

[7] Rohr, Annette C., et al. "Potential toxicological effects of amines used for carbon capture and storage and their degradation products." *Energy Procedia* 37 (2013): 759-768.

indicate levels of these Hazardous Air Pollutants that are of public health risk, this underscores the need for monitoring protocols at these facilities.

3.2.2. Potential exposure rates and hazard levels

In the process described in section 3.1, the amine solvent is looped and reused. However, as with all engineered systems, there is a risk of leakage, and amine solvent can escape out the absorber stack and into the atmosphere. Under certain conditions, nitrosamines can form in the circulating solvent during the process and be emitted directly via solvent escape. As shown in Figure 2, reactions of escaped amine or nitrosamine can occur at variable distances from the point of emission creating harmful products. It is important to understand exposure rates and hazard levels under these various circumstances.

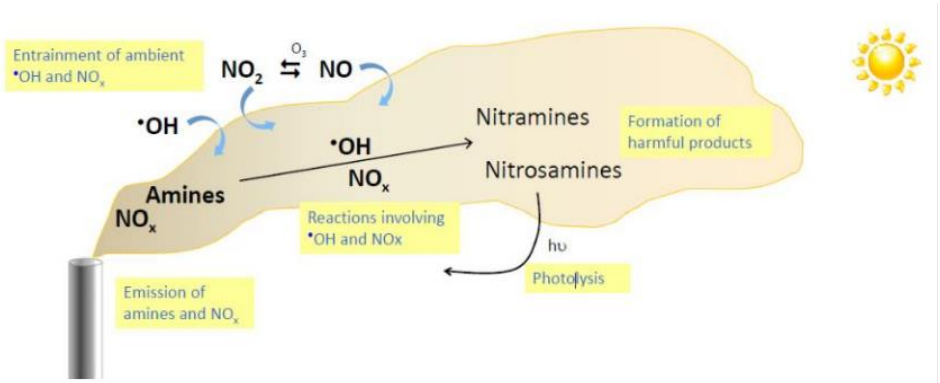

Figure 2: Overview of amine chemistry, reaction pathways. Products form at variable distances depending upon conditions and facility specifications. (From presentation by Catheryn Price, CERC. ADMS User Group meeting 2021, via https://www.oresundskraft.se/globalassets/bilder--material/om-oss/bilaga-1-amine-dispersion-modelling-carbon-capture-filborna-efw-plant.pdf)

The primary degradation pathway of nitrosamines once out of the plant stack and in the atmosphere is photolysis. Weather also affects the concentrations of degradation products: for example, atmospheric inversions will reduce dispersion and increase concentrations at ground level. Agricultural activities can also be a source of amines, which form nitrosamines in the ambient environment. Depending on the nitrosamine these other sources may or may not be distinguishable from nitrosamines formed from amine emissions of a carbon capture plant. Studies of other sources of nitrosamines, such as a degradation product of other manufacturing, agriculture or natural processes and, in particular, their presence in aquatic environments and wastewater effluent are informative as study of these constituents in newer contexts like carbon capture is considered[8,9].

Another group of amine degradation products, nitramines, have been shown to be mutagenic in bacterial cultures but additional toxicology studies have not been performed. Nitramines have no

[8] Minakata D and Coscarelli E. "Mechanistic Insight into the Degradation of Nitrosamines via Aqueous-Phase UV Photolysis or a UV-Based Advanced Oxidation Process: Quantum Mechanical Calculations." *Molecules*. 2018 28;23(3):539.

[9] EPA Six Year Review 3 Technical Support Document for Nitrsosamines (2016) https://www.epa.gov/sites/default/files/2016-12/documents/810r16009.pdf

known sink and can accumulate in water bodies. For these reasons, they have been included along with nitrosamines in the TCM permit (see section 3.4).

Workers could potentially be exposed to solvent leaking around gaskets, although a participant stated that since such leakage would be aqueous, there is no occupational exposure route. Participants had differing perspectives and experiences with occupational nitrosamine concentrations with some saying they were at undetectable levels, while others emphasized that detection levels may be above that of exposure concern. It was noted that the evolution of the solvent makeup over years in service could also pose risks to workers. This points to a clear need for ongoing monitoring of the circulating solvent composition to better constrain potential risks to workers.

Another risk to workers and communities is a large-scale solvent spill. At a full-scale plant a participant estimated that a year's worth of solvent – up to one million pounds, might be present onsite. In a spill of this volume the amine itself as an irritant could be a health concern. As at industrial sites that manage hazardous chemicals, spill prevention and containment systems can be put in place to address such risks. As with other facilities there is also the potential for an event like a hurricane or earthquake that could cause a spill, which should also be accounted for in engineering and containment design.

Key questions to address going forward:

- Would additional understanding of toxicity of nitramines through animal studies support clarity on whether lowering a combined limit below that of Norway (see Table 2) could be warranted?
- How are aldehydes produced and controlled in the amine-based carbon capture process?

3.3 Detection and Measurement

Complexity in monitoring and regulation arises due to the detection of nitrosamine and nitramine concentrations at very sensitive levels currently being challenging or not available on existing instrumentation. While the question of whether an instrument(s) can or should be developed that could detect at such levels remains, there are alternatives available. Advanced atmospheric models can assess site-specific risks and predict nitrosamine and nitramine concentrations such that risks can be overseen and managed at the point of emissions even where direct measurement may not be available. U.S. EPA's approach to ground level ozone air pollution regulation using precursors as a method for control could be relevant[10].

Question posed to workshop participants:

- Where should monitoring take place and how could/should it be informed by site specific atmospheric modeling?

3.3.1 Direct measurement challenges

Amine emissions present a regulatory challenge because the solvent makeup is often proprietary, which limits a regulator's ability to identify specific expected nitrosamine or nitramine products with limits in a permit. Further, ambient monitoring of specific nitrosamines and nitramines at a

[10] https://www.epa.gov/sites/default/files/2020-09/documents/appw_17.pdf

level of granularity necessary to catch emissions that may be of public-health significance is not currently possible. Moreover, due to formation of nitrosamines in the presence of amines and NOx on sampling and instrument surfaces, a time-integrated sampling approach may not be possible. Participants at the workshop agreed, therefore, that measuring amine precursors at the point of emissions and relying on modeling to estimate expected total nitrosamine and nitramine levels is the most practical near-term approach. It requires both a limitation and monitoring requirement for amines in addition to a limitation and modeling requirement for total nitrosamines and nitramines. This is expected to allow for monitoring and control of the constituents of concern without substantive disclosure of trade secret information. This is the approach taken at TCM, where nitrosamine and nitramine concentrations are determined by a site-specific atmospheric dispersion model based on local topography, meteorology, and air quality. A detailed model run for the meteorological conditions at TCM was performed initially, and a simplified calculation tool was developed based on the obtained results. This tool[11] uses a subset of variables to estimate nitrosamine and nitramine concentrations prior to individual tests.

Because of the difficulty in measuring nitrosamines and nitramines, participants agreed that emissions of their amine precursors are the most meaningful indicator, both for measurement and control. A proton transfer reaction-mass spectrometer (PTR-MS) can be installed on the stack and measure amine concentration continuously (1–10-minute resolution) online at ppt level sensitivity. An alternative way to measure the rate of amine emission is to take samples of flue gas periodically at the emission stack and analyze them offline. If there is a reason for concern and/or if the emission profile is highly variable and/or poorly understood, offline samples could be taken in 1-to 7-day intervals. If there is no reason for concern and the emission profile is well understood, stable and well characterized, offline samples could be analyzed every 2-4 weeks. Together, these measurement approaches, along with process data including on other pollutants, and the atmospheric modeling described below would be best practice for monitoring at facilities employing amines.

3.3.2 Utility of atmospheric models

Using the measured amine concentration in the emitted flue gas and other site-specific input parameters, regulators and operators can estimate the production and concentration of nitrosamines and nitramines in the ambient environment. However there are many uncertainties associated with the current state of atmospheric modeling of nitrosamines and nitramines. Currently applied models simulating the secondary formation of nitrosamines and nitramines are highly simplified, and more complex reactive plume models are not yet available for this kind of application. Importantly, none of the available models has been validated by in-plume measurements of amines and their more abundant atmospheric degradation products. More laboratory studies are also needed to determine the gas-to-particle partitioning and heterogeneous chemistry of amines in aerosol particles. Further peer reviewed studies of chemical mechanisms to be included in atmospheric models are needed.

Participants also noted that existing but unpublished chamber results would be helpful for model validation. There is also the potential for field validation via in-plume helicopter measurements

[11] https://nilu.no/publikasjon/25966/; https://nilu.com/publication/26340/

in the near future. Incorporating improvements in models and model validation are necessary for their operability in the commercial control context – underscoring the importance of this research and data gathering in piloting and demonstration phases.

The Norwegian authorities used the modeled total nitrosamines and nitramines for determining maximum permissible amine emissions at TCM. A participant stated that there have been occasions when the TCM facility was shut down due to amine emissions exceeding this limit. This has tended to happen due to changes in the input flue gas that could for example increase aerosol formation and affect the amine management measures. These conditions can be detected by online monitoring, but are unlikely to be caught by offline sampling alone, underscoring the need for online measurements. At these times the operator has taken measures to control amine emissions from the stack as discussed in section 3.5, and successfully brought the emissions down to within permissible limits.

Participants noted that the case of amines and their degradation products are different than typical air pollutants because both the compound and level at the emission point are different than at the exposure point. However in water quality regulation, there is a precedent for being concerned about a concentrated source but basing exposure limits on dispersion modeling with conservative assumptions.

Participants noted that it would be important to measure baseline levels of any relevant compound before facility operation so that other sources of contamination could be ruled out.

Key questions to address going forward:

- Does a standardized flue gas amine and nitrosamine measurement protocol exist, and could it be recognized?
- Does a standardized ambient baseline measurement protocol exist and could it be recognized?
- Can research and data measurement efforts improve and validate current and future atmospheric models to support their use in assessing risk management at facilities?
    - Can models be validated with plume observations?
    - How would improvements in atmospheric chemistry affect estimates of ground level concentrations and deposition?
- Can we advance information on where down-wind monitoring might be most appropriate based on expected exposures coupled with assessment of whether instrument(s) need to be and/or can be developed to detect ambient nitramines and nitrosamines at concentrations relevant for exposure concern (0.3 ng/m3)?

3.4 Limits

While normal operating procedures may be designed to avoid the loss or degradation of amines, absent established limits or other control requirements, uniform and consistent application of the best practices and monitoring of outcomes is unlikely. The establishment of conservative permit limits in Norway presents an opportunity for the U.S. to build on the case study and applications there to identify a best path forward for emerging projects here.

<u>Questions posed to workshop participants:</u>

- Should nitrosamine concentrations (at facility sites) be compared to the U.S. EPA's recommended limit in drinking water, or something else like Norway's?
- What about air concentrations?

3.4.1 Regulatory status of amines and nitrosamines

A preliminary review of the U.S. approach indicates that while some nitrosamines may be addressed in water quality criteria guidelines[12] and included in U.S. EPA's Toxics Release Inventory, amines, nitrosamines, and nitramines are not currently controlled via federal limitations with respect to air quality and emissions from carbon capture facilities. Limits for total amine and total nitrosamines have, however, been adopted or recommended in Norway and the United Kingdom. At least one U.S. air emission permit for a carbon capture facility has addressed amines, discussed below, but a substantive review of all permits has not been conducted to identify whether this application of best professional judgement by permit writers is widespread.

Table 2: Summary of permit limits (bold) and recommendations for amine and nitrosamine emissions in the UK, Norway, and the United States.

	UK	Norway	US
Air	Amine (MEA): 0.1 mg/m3 (24hr mean)	**Total amine emissions: 6ppm**	-
	Nitrosamine (NDMA): 0.2 ng/m3 (24hr mean)	**Emissions should not result in sum concentrations of nitrosamines and nitramines in the atmosphere to exceed: 0.3 ng/m3**	
Water		**Emissions should not result in sum concentrations of nitrosamines and nitramines in drinking water to exceed: 4 ng/L**	Total nitrosamine: 0.8 ng/L

Norway does not have a national regulatory limit, but the permit under which its TCM facility operates contains a limit on total amine emissions – which has broad implications as any entity proposing to use an amine in Norway must first run a test at TCM. Emission permits also exist for two additional full-scale units that are currently under construction. This limit is based on the toxicity of N-nitrosodimethylamine (NDMA), one of the most toxic nitrosamines, though not the most toxic.

The limit for amines was set by calculating the acceptable exposure for total nitrosamines and nitramines, and calculating backwards how low the amine emission would have to be to prevent the emission of amines that would lead to exceedances of that acceptable exposure. In practice this would involve measuring amine emissions at the stack and using an atmospheric model or

[12] https://www.epa.gov/sites/default/files/2018-12/documents/ambient-wqc-nitrosamines.pdf

simplified tool to estimate the resulting level of total nitrosamines and nitramines at ground level.

The U.K. has set recommended environmental assessment levels (EALs) for monoethanolamine (MEA) and NDMA in air: all emissions must be reported, and if concentrations at the stack are at levels that are predicted to breach the EALs at sensitive locations in the area affected by the plant then it may be issued with an improvement order, after which if there is no improvement the plant could be shut down.

For the U.S., the drinking water level is a recommendation.

3.4.2 Challenges to setting a limit in the U.S. in the near-term

Workshop participants agreed that the U.S. approach for adding new federal limitations for complex constituents or expanding lists such as the Hazardous Air Pollutant (HAP) list or other lists of regulatory consequence can take significant data, resources, and time – as the ongoing experience with per- and polyfluorinated substances (PFAS) has made clear. While knowledge and guidelines on nitrosamines exist (predominantly in the water context) in the U.S., more work is needed to develop the data and methodologies necessary to establish federally applicable limitations.

A regulatory approach would need to contend with some challenges with respect to measurement as well as trade secret protections on the precise composition of some amines. To combat this issue, for example, the Norway approach settled on a limit on total nitrosamines and nitramines – a number that could be reported publicly without identifying each specific nitrosamine such that the permit releases confidential business information on the amine being used. For example a nitrosamine such as nitrosopiperazine is unique to its amine precursor, piperazine, and identifying it could reveal protected information about the composition of the amine solvent in use. Nitramines are included in the total nitrosamine and nitramine limit at TCM due to their potential for toxicity. While total limits can address public health and environmental risk exposures, they may not result in preferred levels of data transparency – participants were not able to identify a solution for this challenge, but did note that similar circumstances had led to acceptable disclosures in other contexts such as hydraulic fracturing fluid disclosures[13].

Depending upon the regulatory approach deemed a best fit in the U.S., advancements may be necessary in analytical methods and other sampling and measurement protocols. For example, while there is a protocol to measure total nitrosamines without knowing exactly which nitrosamines are present, this is not possible for amines. In order to monitor amine emissions, the TCM facility measures individual amine concentrations and combines them for a total value. As the solvent makeup is confidential in many cases, information on which amines were measured cannot always be shared publicly. The information is shared with the facility doing the chemical analysis and is protected as confidential business information – TCM satisfies its permit requirements by simply reporting the total amine and confirming the estimated nitrosamine and nitramine formation using a calculation tool. While the TCM facility has tested many proprietary solvents in this way, the public reception in the U.S. may be different and should be considered

[13] fracfocus.org

as approaches to move forward are identified. Under U.K. environmental permitting regulations[14] it is presumed that any novel, secondary, tertiary or other amine would need to be disclosed; better understanding the role of the Toxic Substances Control Act in the U.S. may provide further insights into near term controls and assessment. Other contexts involving proprietary chemicals (e.g. fracking) could be instructive as well.

3.4.3 Opportunities to reduce risk in the near term

Without a current air-emission regulatory limit in the U.S., participants discussed how a recommended or best-practice limit could be set quickly, using a conservative approach based on the precautionary principle. Ideas were not mutually exclusive and participants were not necessarily in agreement upon them. They included:

- Using the Norwegian or UK limit;
- Establishing a conservative limit based on the well-studied and second-most toxic nitrosamine, NDMA;
- Commissioning a National Academy of Science study to make a science-based recommendation;
- Relying on best professional judgment of state permit writers;
- Requirements in contracts for U.S. DOE funded projects;

Participants also discussed the prospect of a gated approach by which if an NDMA-based limit is exceeded, operator provides more detailed data about the specific nitrosamine emitted and its toxicity. Participants noted that there is a bounded list of about two dozen nitrosamines that could conceivably be produced by the amines used in carbon capture, and limits could be set for individual nitrosamines if the gated approach identified it necessary. Some participants viewed the approach as impossibly complicated while one pointed out that without such a staged method, there is no incentive for an operator to use an amine with a nitrosamine degradation product any less toxic than the one the total limit is based upon.

In the U.S. there is a precedent of an amine emission limit in the permit application for a natural gas combined cycle with carbon capture facility in the Permian Basin, called Quail Run. The Texas Commission on Environmental Quality (TCEQ) issued a permit specifying the acceptable absorber vent stream composition, including “amine solvent” which in this case is the KS 21 solvent. The applicant provided information to TCEQ to develop a provisional Effect Screening Level (ESL) for that proprietary amine solvent, and the modeled annual amine output was 1.37 mg/m3 - less than 1/10th of the ESL. However TCEQ did not model the levels of potential nitrosamine products. Still, participants agreed that going forward, even while federal approaches may take time, states could set their own risk-based limits in permits in the U.S. and help move protections forward, as was seen with PFAS. It is worth noting that with exceptions, states hosting initially identified projects may not be the most likely to enact such guardrails. With the development of a science-based recommendation, such as from the National Academies, more data would also be available to support using “best professional judgement” to establish permit-specific limits even while a technology-wide standard may not be available. Participants noted, for example, that this is how ammonia is regulated in air emissions, as there is no limit at the federal level.

[14] https://www.legislation.gov.uk/uksi/2016/1154/made

Key questions to address going forward:

- What is a reasonable limit on nitrosamines and nitramines in the absence of a regulatory limit?
- In the context of a limit, what is the best approach to measure and report total amines? Are total amines an acceptable indicator for degradation product risks?
- How are or might amines, nitrosamines, and nitramines be addressed by existing federal and state regulatory programs, such as TSCA?

3.5 Controls:

Despite the challenges with respect to monitoring and measuring amines in a commercial or regulatory context, participants shared enthusiasm that numerous, well-studied and effective control mechanisms exist today to avoid impacts from nitrosamines and nitramines by avoiding the release of amines all together. As noted elsewhere, these control measures will vary depending upon the industrial process, facility design, and amine selection. Immediate risk reductions are available by stacking these control technologies though drivers for adding the capital and operational cost of additional controls are needed to ensure uniform adoption. Selecting amine packages that are less likely degrade to the higher toxicity nitrosamine and nitramines is also a significant form of risk management and control.

<u>Question posed to workshop participants:</u>

- What control measures exist, how much do they cost, and what evidence exists for their effectiveness?

3.5.1 Solvents

Control measures for amines and their degradation products can include a wide range of options. Participants agreed that they are not all essential at every facility, and that the effective combinations would vary with facility and solvent. Some measures that control for amine content in the flue gas may be installed for the primary purpose of meeting criteria pollutant limits, but others could be added specifically to reduce amine emissions as they were at TCM with the proper driver – such as the TCM limits.

At the highest level, participants noted that the choice of solvent is one of the largest if not the largest determinant of risk for nitrosamine and nitramine exposure. Primary and secondary amines have higher rates of reaction with carbon dioxide while tertiary amines have a higher carbon dioxide carrying capacity but slower reaction kinetics. Primary amines will not of themselves form stable nitrosamines (only their degradation products) but tend to have somewhat higher regeneration energy requirements. Secondary amines require less energy to regenerate, but may be more expensive, and produce stable nitrosamines directly and so at a faster rate. These varying strengths are why a vendor may not use certain amines, and also may devise a proprietary solvent blending two or more types of amines. Many newer solvents are designed in order to both reduce the cost of the amine and improve energy performance, though one participant stated that in tests of multiple solvents, the range of energy performance is only about 15%.

The USEA-NCCC workshop also noted the following on solvent selection: “To this end, discussion focused on solvent/amine selection and how appropriate selection and pre-screening are important. Specifically, selecting amines that (i) do not form nitrosamines, (ii) have lower volatility, and (iii) are highly resistant toward oxidation, and/or other types of degradation processes, is recommended.”

Some nitrosamines appear to be far more carcinogenic than others, and participants noted that perhaps solvents containing their precursor amines should simply be avoided. A participant suggested that all secondary amines should be avoided due to the nitrosamine risk, given that alternative primary amine solvents are commercially available. Participants familiar with projects in Europe noted that all or nearly all use primary amines. The primary amine MEA is the most studied solvent, and appears to have low toxicity of degradation products and is available at low cost. At the time of the meeting, permits in the United Kingdom had exclusively involved MEA as a solvent. However other participants pointed out the potential risk of nitramine production from primary amines including MEA. Choice of solvent, therefore, has significant implications for the necessary control designs as well as monitoring approaches. The UK Environment Agency and the Carbon Capture and Storage Association published a report evaluating the relative risks of a list of amine chemicals that could be used for carbon capture, and their degradation products. This could be valuable for risk assessment in the United States.

The solvent amines often degrade to smaller amines within the circulating solvent. Being smaller, they are also more volatile and more likely to be emitted. These smaller amines will also form nitrosamines and/or nitramines in the atmosphere. The potential to form smaller, more volatile amines is thus also an aspect that needs to be considered.

One participant held the view that any facility should have the ability to switch solvents in the event that the first solvent has unacceptable emission rates or other issues arise. In practice, to switch solvents, necessary controls such as temperature and column sizes could be changed, but the solvent reclamation process might also need to be significantly changed, which depending on the facility could be difficult and costly. Furthermore some solvents such as piperazine require tailored systems that would be more challenging to modify than others. Others stated that the solvent vendor’s revenue comes from a long-term contract to supply a facility with a specific solvent rather than the license itself, and that the solvent switching approach would not work with the solvent vendors’ business model. Others questioned whether protecting business models was acceptable as a sole reason to remove amine switching as a control possibility.

3.5.2 Other controls

In the course of the workshop, subgroups collaborated to walk through the different control processes and components and discuss their varying roles, uncertainties, costs, and other notes. Costs could not be confirmed at enough specificity to include here, but the remainder of those conversations are summarized in the table below.

Process/Component	Role	Uncertainties	Other Notes
Existing Facility			

Selective Catalytic Reduction (SCR)	Reduces NOx and PM2.5 NO2 is hard on amine solvents NOX removal minimizes nitrosamines	Can create ammonia slip Space availability if not already present Is SCR needed – consider attainment; solvent susceptibility to NO2, etc. Does SCR work in all conditions?	Relevant on both Coal/Gas power and potentially other industry
Bag Filter	Reduce aerosol sources SO3, NO2	Likely won't add if not present because expensive to retrofit although such an economic driver is uncertain, exceptions to attainment can be made.	Applications: lime, paper, cement, bioenergy, waste incineration. Some but not all power plants have this feature to treat for particulate matter and NOx, depends on whether region is in or out of attainment for these criteria air pollutants
Flue Gas Desulfurization	Removes 95%+ SO2		
Stack height			Tall stack aids in dispersion of emissions and reduces ground level concentrations. Consider whether can add to existing stack or need to build a new one
Capture – Prescrubbing			
Electrostatic Precipitation (ESP)	aerosols	Effectiveness is not well understood	
Direct Contact Cooler	SO2 polishing; water balance		
Sodium Sulfite	Scrub NO2 – reduces solvent oxidation and nitrosamine in solvent	Only works if not diluted Don't completely understand chemistry yet	
Brownian Demister	Reduce aerosols; Reduce SO3 (primary aerosol source)	Creates pressure drop Need fans	Doesn't scale to full scale plant
Absorber			
Solvent Packing			

Water Wash	Removes amines Single stage (default) – 99+% removal Single stage + drybed/trickle bed Two stage – 99.9+% removal		Closed loop – goes back into solvent UV Light addition – removes nitrosamine, and aldehydes but unknown efficacy and byproducts Plasma addition Carbon Treatment Only works for some compounds in vapor phase - not be effective with aerosolized solvent, hence potential need for aerosol prevention measures above
Acid Wash	Removes amines, ammonia, and some nitrosamines		Only works for compounds in vapor phase - not be effective with aerosolized solvent, hence potential need for aerosol prevention measures above
Treat Reflux (condensed vapors)	Aldehydes, ammonia, nitrosamines, volatile impurities		
Other Potential Oxidation Controls (not in order of application)		Unknown: load following Not completely sure yet how any of these work – reclaiming has most clear impact	Oxidation can create env impact (nitrosamines) and also solvent loss ($$) + more unknowns from oxidative products. Applies to all below
Scrub NOx ahead of absorber			
Strip dissolved oxygen off absorber/sparge with nitrogen			
Reclaiming	Degraded products accumulate in	Not well tested & very hard to pilot due to size constraints for equipment. Eg TCM and	Should be performed periodically (every 4 wks), ideally

	solvent and dissolved iron increases, so oxidation increases	NCCC do not routinely employ Have seen 5-30% solvent loss, reclamation rate can vary Over time multiple amines in a solvent may be reclaimed at different rates thereby changing their proportion in the solvent. Means toxicity of the solvent and its degradation products, can change over time. Hazardous liquid waste management (incinerator)	continuously; have seen good results in study
Carbon treating	Reduces foaming and keeps solvent clean	Disposal?	
Anion exchange	Metals removal		

Particulate and NOx countermeasures including SCR, bag filter, ESP, and BDU would reduce the aerosols in the gas entering the absorber which would in turn improve the effectiveness of a water and/or acid wash. The effectiveness of any of these measures could be confirmed via existing sampling protocols that would measure amine emissions in gas and aerosol form. This would also depend on operators measuring concentrations of all remaining components of the stream to ensure that criteria pollutants are removed and aerosols are reduced, and fully characterizing the gas entering the absorber tower in order to ensure absorber efficiency.

Participants noted that in the normal functioning of a plant, an operator would need to be monitoring process variables such as temperature at various points that would also provide key information about the efficacy of functions such as absorption, desorption and reclamation. The operator would also want to monitor the performance of the capture process by measuring the rate of CO_2 absorption. A drop in this value could indicate the same issues associated with amine emissions, and therefore also be a check on such emissions.

Participants noted that currently there is no quantitative estimate of exactly what a given combination of control measures would cost. However, participants estimated that amine packages are about 75% of the cost of capture and adding additional preventative/precautionary controls could be estimated at as little as 1% of project cost.

Although any loss of solvent would represent a cost to the operator, they would not necessarily know the rate without measuring it and the cost would depend on the cost of the solvent. Moreover, at the Boundary Dam facility in Saskatchewan, solvent losses were far higher than

initially expected, at a cost of approximately $20/tCO2 captured vs $5/tCO2 predicted[15]. This demonstrates that the effectiveness of the process data and the economic incentive to retain solvent are not themselves always effective as a check on amine emissions. There is also some data collection that would not otherwise take place were the operator not controlling amine and nitrosamine emission: measuring amines on and offline at the stack, and measuring the nitrosamine content of the solvent.

Amine content of the final carbon dioxide stream could also be indicative of issues with control. Participants did not have any experience with exploring the potential for amines or other impurities such as acetaldehydes in the final carbon dioxide stream.

The takeaway from this discussion was that with careful monitoring and control measures it is possible to limit amine emissions to low enough levels that would satisfy a conservative limit on their toxic degradation products. For example, the TCM facility is able to limit stack amine emissions to <1ppm, compliant with its operating permit, using a BDU and acid and water washes.

Key questions to address going forward:

- Does a standardized lab-based method of accelerated life testing of solvents to understand what they might form as breakdown products exist? Could one be recognized?
- Can a best-practice treatment train be identified that results in adequate controls of nitrosamine and nitramines that can be applied across all facility and amine types (e.g., 2-stage water wash + acid wash) and what incremental cost does that add to normal capture process design and operation?
    - e.g. How can operators ensure that a solvent management system/advanced controls is consistently effective?
- What can DOE require as a requisite of government funding for capture projects to reduce amine-related risks?
- How can solvent oxidation be further reduced to prevent degradation?
- Can solvent be reclaimed continuously, reducing risk of amine loss, degradation, and contamination?
- Are there amines, acetaldehydes, nitrosamines, or nitramines in the concentrated CO2 stream?
- What are the waste implications and potential management streams for the waste from solvent control measures?

3.6 Pilots

As investments and incentives, such as those from the U.S. DOE from deployment of BIL, funds from the Inflation Reduction Act of 2022, and the U.S. 45Q tax credit, continue to subsidize the advancement of carbon capture technologies in a variety of industries to reach broad commercialization, immediate attention is needed to ensure that amines are being properly

[15] https://docs.legassembly.sk.ca/legdocs/Legislative%20Committees/CCA/Tableddocs/CCA%2061-28%20SaskPower%20Responses%20to%20questions%20raised%20at%20the%20June%2027,%202018%20meeting.pdf

monitored and controlled. One mechanism for gathering data while limiting exposure risk is pilots.

Question posed to workshop participants:

- What amine and nitrosamine data (if any) could carbon capture pilot facilities collect and report to demonstrate that their operations do not result in harmful exposure of workers or communities to nitrosamines?

Participants engaged in a lengthy discussion on the cost, value, and necessity of pilot plants. In theory, an operator cannot know the exact behavior of the specific flue gas and the specific solvent without running a pilot plant in the configuration that they would for a full-scale plant, and for a time reaching steady state. Several participants noted that the solvent degradation can dramatically accelerate over time, and that typical testing times of several weeks would not capture this behavior. One participant suggested that 18 months would be needed at a pilot plant with a given solvent to demonstrate a good understanding of the solvent behavior but that it could continue to change up to five years in service. This underscores the need for substantive and thorough pilot testing to ensure adequate understanding of what pollutants may build up to levels of concern and design appropriate risk controls for demonstration and commercialization.

Pilots are expensive both in cost and personnel time. Participants were not in agreement on whether it would be practical to fund a pilot for each full-scale plant. In Norway operators are required to test at TCM and pilot at their specific site. Another option could be to operate a test site/pilot plant for each type of industrial process and combustion power so that at least an approximation of the flue gas composition could be tested for an amine being proposed for use. Of course, pilots are a highly valuable mechanism for identifying and designing against risks, but even then, there may be non-linearities or other unexpected behavior when a process is brought to full scale, underscoring the importance of ongoing monitoring and controls.

Data on amine emissions and modeled nitrosamine concentrations should be made available to the public on a timely basis, as well as information regarding the installation of specific amine emission and nitrosamine formation controls. Participants pointed to the value of communicating data about reduced copollutants such as NOx, SOx, and ammonia without overselling the cobenefits.

Key questions to address going forward:

- What can and what cannot be confirmed by pilot plants?
- What processes scale non linearly with size of plant?
- What is the best approach to incorporating pilots in decision-making to ensure amines are piloted properly before full-scale use?
- Can a best practice standard be developed for piloting?
- What can be done in piloting phases to take into consideration the potential for cumulative impacts, such as in a future hub setting?

4. Next Steps

There was broad agreement among workshop participants that now is the time to more definitively address and manage the risk of amines in carbon capture. Multiple next-step opportunities and research needs were identified.

In the U.S. context, the chief opportunity identified was to consider to what extent research needs and best practices could be incorporated in government-funded (DOE) projects even where regulatory limits are not in place. Current contract negotiations between the DOE and potential awardees are confidential and it is unknown to what degree they incorporate the elements and recommendations above and whether they would make such data and information available to the public. A participant noted that DOE is taking a gated approach whereby projects would need to demonstrate efficacy and safety as determined by the DOE, and any project could be terminated if it does not reach specific but unspecified benchmarks after a period of time allowed for improvement. Furthermore, the contracts for each stage are general, and only finalized for the immediate next step.

With only three projects yet confirmed past the Front End Engineering Design (FEED) study stage, and several years until work commences on any physical plant, there is potential for physical plant contracts to include specific testing and piloting procedures and monitoring, equipment, and reporting requirements. There is also time to address a number of the outstanding research needs and considerations enumerated above via an intentional research and development program built into the FEED and piloting system.

A participant noted that all three of the DOE-funded projects that have progressed past the FEED study have already done solvent testing at TCM (although only for limited periods and possibly not with full reclaiming or other solvent management; full details are not available in the public domain), and others plan to do testing with FTIR monitoring in the U.S. at a 10MW pilot scale. However, TCM has a permit limit on amines, and nitrosamines and nitramines whereas no such limits exist in the U.S.. Therefor monitoring in the U.S. could reveal emissions but without a limit would not force additional controls unless under contractual or other obligation. This underscores the importance of parallel next-step efforts to establish higher level, science-based recommendations or standards – such as through NAS and the International Standards Organizaion – to identify limits, controls, operating procedures, and monitoring approaches necessary to protect public and environmental health. The combination of these approaches is more likely to result in concrete outcomes and changes in industry and permitting practices on a timeline that ensures implementation prior to broad commercialization of carbon capture globally and in the U.S..

Participants:

EDF is grateful for the participation and contributions of the following experts to our workshops. Their participation in the discussion does not equate to full endorsement, by them as individuals or as representatives of their institutions or organizations, of this summary of the workshop.

Sarah Forbes (DOE)
Dan Hancu (DOE)
Sarah Leung (White House/CEQ)
Robert Bivens (EPA)
Armin Wisthaler (U Oslo)
Jon Gibbins (U Sheffield)
Gary Rochelle (U Texas and Honeywell)
Heather Nikolic (U Kentucky)
Bill Mitch (Stanford)
Bill Elliot (Bechtel)
Neil Barone (Exxon)
Eladio Knipping (EPRI)
Donna Voorhees (Heath Effects Institute)
Alice Alpert (EDF)
Brian Buma (EDF)
Blake Walkowiak (EDF)
Nichole Saunders (EDF)
Scott Anderson (independent)

Annex I: Compiled key questions to address going forward

Risks (3.2)

- Would additional understanding of toxicity of nitramines through animal studies support clarity on whether lowering a combined limit could be warranted?
- How are aldehydes produced in the amine-based carbon capture process?

Detection and measurement (3.3)

- Does a standardized flue gas amine and nitrosamine sampling protocol exist that captures aerosolized compounds, and could it be recognized?
- Does a standardized baseline measurement requirement to establish other potential sources of contamination exist? Could one be recognized?
- Can research and data measurement efforts improve and validate current atmospheric models to support their use in assessing risk management at facilities?
    - Can models be validated with plume observations?
    - How would improvements in atmospheric chemistry and kinetics in transport models affect estimates of ground level concentrations and deposition?
- Can we advance information on where down-wind monitoring might be most appropriate based on expected exposures coupled with assessment of whether or not an instrument needs to be and/or can be developed to detect ambient nitramines and nitrosamines at concentrations relevant for exposure concern (0.3 ng/m3)?

Limits (3.4)

- What is a reasonable limit on nitrosamines and nitramines in the absence of a regulatory limit?
- In the context of a limit, what is the best approach to measure and report total amines? Are total amines an acceptable indicator for degradation product risks?
- How are or might amines, nitrosamines, and nitramines be addressed by existing federal and state regulatory programs, such as TSCA?

Controls (3.5)

- What can DOE require as a requisite of government funding for capture projects to reduce amine-related risks?
- Does a standardized lab-based method of accelerated life testing of solvents to understand what they might form as breakdown products exist? Could one be recognized?
- Can a best-practice treatment train be identified that results in adequate controls of nitrosamine and nitramines that can be applied across all facility and amine types (e.g., 2-stage water wash + acid wash) and what incremental cost does that add to normal capture process design and operation?
    - e.g. How can operators ensure that a solvent management system/advanced controls is consistently effective?
- How can solvent oxidation be further reduced to prevent solvent degradation?
- Can solvent be reclaimed continuously, reducing risk of amine loss, degradation, and contamination?

- Are there amines, acetaldehydes, nitrosamines, or nitramines in the concentrated CO2 stream?
- What are the waste implications and potential management streams for the waste from solvent control measures?

Pilots (3.6)

- What can and what cannot be confirmed by pilot plants?
- What processes scale non-linearly with size of plant?
- What is the best approach to incorporating pilots in decision-making to ensure amines are piloted properly before full-scale use?
- Can a best practice standard be developed for piloting?
- What can be done in piloting phases to take into consideration the potential for cumulative impacts, such as in a future hub setting?

Environmental Defense Fund

U.S. Environmental Protection Agency Region 6
Lisa Pham, Groundwater/UIC Section Mail code:
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July 31st, 2025

RE: Texas Underground Injection Control Program Class VI Primacy Proposed Rule Docket ID No. EPA-HQ-OW-2025-0157.

To Whom It May Concern:

Environmental Defense Fund (EDF) appreciates this opportunity to provide comments on the Environmental Protection Agency (EPA)'s proposed approval of Texas's application for Class VI Primacy. EDF is a science- and economics-based advocacy organization devoted to finding practical, powerful, nonpartisan solutions for people and the climate. We have 120,000 Texas-based members and a growing cohort of staff based in the state.

Carbon management technologies, including geologic carbon sequestration, are likely to play an important and meaningful role in meeting both public and private clean energy and clean fuel objectives for Texans and Texas businesses—but they must be deployed with safeguards that ensure operations are held accountable for technical, environmental and community outcomes. The Intergovernmental Panel on Climate Change (IPCC) has concluded with high confidence that "[i]f the geological storage site is appropriately selected and managed, it is estimated that the [carbon dioxide] can be permanently isolated from the atmosphere."[1] Implementing and enforcing a robust Class VI permitting program is one safeguard that supports agencies and operators in ensuring sites are "appropriately selected and managed" in order to meet permanence expectations.

EPA has determined that the Railroad Commission (RRC or Commission) "has adopted and will implement a Class VI [Underground Injection Control (UIC)] program that meets the requirements of 40 CFR parts 144, 145, and 146"—the legal requirement necessary for the transfer of primacy. EDF recognizes that the RRC has met this standard.

[1] Core Writing Team, Hoesung Lee & Jose Romero, Intergovernmental Panel on Climate Change, *Summary for Policymakers, in* Climate Change 2023: Synthesis Report 21 n.47 (2023), https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf.

However, merely meeting the baseline requirements to implement the Class VI program does not immediately equate to a program definitively designed to ensure the environmental integrity of storage—nor does it conclusively ensure successful ongoing implementation and oversight of a program. How Texas moves forward will determine if the state can establish a globally relevant and reliable oversight program for carbon storage. A strong, stable Class VI permitting program is particularly important to support Texas industries and their ability to verify the production of low-carbon energy, fuels, and products that are competitive in domestic and global markets. With primacy, Texas will have the opportunity to use its unique experience and knowledge base to create a globally leading carbon storage program—but EDF believes it is necessary to implement several targeted program enhancements to get there.

If Texas is given primacy, it will be charged with building an advanced, technically sound regulatory program. Additionally, Texas will also assume a key portion of the responsibility for building the credibility and public support of carbon sequestration as a safe, valuable technology that can support Texas industries without harming its people and places. A strong program on paper does little to garner support without public faith in regulatory oversight and enforcement. History has shown, for example, that with rapid increases in volume and activity in Class II injection and permitting, RRC oversight and enforcement has been largely reactive[2] rather than proactive—resulting in meaningful pressure, seismicity, and other surface and subsurface challenges.[3] The RRC has demonstrated willingness to evolve and improve approaches,[4] but not always at the speed necessary to avoid negative outcomes in the interim. EDF encourages the Commission to work proactively get it right from the start with Class VI, learning from the Class II experience[5] and minimizing the need for reactive adjustments after the damage is done.

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[2] *See, e.g.*, Hart Energy Staff, *Texas RRC Implement Operator-led Plan to Reduce Seismicity in the Permian* Basin, HartEnergy (Mar. 8, 2022), https://www.hartenergy.com/exclusives/texas-rrc-implement-operator-led-plan-reduce-seismicity-permian-basin-199113.

[3] *See, e.g.*, Kevin Crowley & David Wethe, *Permian Basin at Risk of Poisonous Water Leaks, Warns Texas Regulators*, WorldOil (May 22, 2025), https://www.worldoil.com/news/2025/5/22/permian-basin-at-risk-of-poisonous-water-leaks-warns-texas-regulator/#:~:text=Water%20management-,Permian%20basin%20at%20risk%20of%20poisonous%20water%20leaks%2C%20warns%20Texas,for%20new%20wastewater%20disposal%20wells; Dylan Baddor & Carlos Nogueras Ramos, *Ranchers Reported Abandoned Oil Wells Spewing Wastewater. A New Study Blames Fracking*, Tex. Trib. (Aug. 7, 2025), https://www.texastribune.org/2024/08/07/texas-oil-fracking-wastewater-injection-blowouts-permian-basin/; *New Research Provides an Improved Understanding of Earthquake Hazards in the Permian Basin*, U. of Tex.: Tex. Geosciences (Dec. 2, 2024), https://www.jsg.utexas.edu/news/2024/12/new-research-provides-an-improved-understanding-of-earthquake-hazards-in-the-permian-basin/. *See also EPA to Review Texas' Oil and Gas Injection Well Program*, Comm'n Shift (Jun. 21, 2024), https://commissionshift.org/news/epa-to-review-texas-oil-and-gas-injection-well-program/ (outlining Commission Shift's petition regarding Class II primacy); Troy C. Hill, Env't Prot. Agency, Water Div., Letter Granting Commission Shift's Petition to Withdraw Texas Class II Underground Injection Control Program (May 23, 2024), https://commissionshift.org/wp-content/uploads/2024/06/2024.05.23_EPA-R6-Response-to-Class-II-Petition.pdf (noting the petition raises "substantial concerns regarding the sufficiency of Texas' implementation" of the UIC Class II program").

[4] *RRC Issues Enhanced Guidelines for Permian Basin Disposal Wells*, Railroad Comm'n (May 16, 2025), https://www.rrc.texas.gov/news/05162025-permian-disposal-wells-guidance-release/.

[5] EDF understands that the Ground Water Protection Council's independent peer-review of RRC's Class II UIC program is nearing completion and urges the Commission to proactively consider the recommendations of its peers with respect to opportunities to improve not only the Class II program, but also learnings that may be applicable to Class VI. *RRC Works With National Experts on Underground Injection*, Railroad Comm'n (July 11, 2024), https://www.rrc.texas.gov/news/071124-rrc-works-with-national-experts-on-underground-injection/.

In particular, EDF is concerned that the primary industry reason for supporting Texas primacy has been due to the promise of faster permit processing under the RRC. However, it is imperative that the RRC balance this perceived need for speed from industry with its overriding duty to provide protective oversight that ensures stewardship and protection of natural resources, the environment, and community safety.[6] Demonstrating the success of commercial carbon dioxide (CO_2) storage demands it—and the world is watching Texas to see if it can be done right.

It is EDF's position that with industry commitment to best practices *and* a strong regulatory and oversight program, carbon sequestration can be achieved with environmental integrity—avoiding leaks, felt earthquakes, groundwater pollution, and other negative impacts. EDF believes that primacy offers Texas the opportunity to build on the baseline requirements of Class VI to better foster this outcome. EDF also emphasizes that nothing in the Memorandum of Agreement or Safe Drinking Water Act precludes Texas from adopting or enforcing requirements that are more stringent or more extensive than those required in Class VI or operating a program with a greater scope of coverage than required by Class VI.[7]

To this end, EDF offers the following recommendations to ensure that RRC continues to meet the standards necessary for attaining and maintaining primacy, while also demonstrating global leadership in adopting more modernized and holistic regulatory approaches where new information and best practices indicate new methods are appropriate.

1. **Texas must retain an approach to long-term responsibility and operator liability that does not call into question its ability to fully enforce the requirements of the Class VI program as required by the Safe Drinking Water Act.**

As of the most recent regular Texas legislative session, Texas thankfully has not made meaningful changes to long-term liability for carbon storage operators. As EPA indicated clearly in response to comments during the recent approval of the State of Louisiana's Class VI primacy application, state liability release programs that go too far can run afoul of EPA's expectations for UIC enforcement: "…even after the former permittee has fulfilled all of its UIC regulatory obligations, it may still be held liable for previous regulatory noncompliance. Thus, there may be stringency issues if a state law authorizes the permitting agency to release a former permittee from liability for earlier UIC violations…[A] former permittee may always be subject to an order the Administrator deems necessary to protect public health if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. The EPA's UIC regulations require that state UIC programs possess similar emergency authority (40 CFR 144.12(e))."[8]

[6] RRC's Mission Statement is "to serve Texas by our stewardship of natural resources and the environment, our concern for personal and community safety, and our support of enhanced development and economic vitality for the benefit of Texans." *About Us*, Railroad Comm'n, https://www.rrc.texas.gov/about-us/ (last visited July 30, 2025).
[7] State Underground Injection Control Program Requirements, 40 C.F.R. § 145.1(g) (2024).
[8] Env't Prot. Agency, EPA-HQ-OW-2023-0073, EPA Response to Public Comments on the Louisiana Department of Natural Resources' Class VI primacy Application 17 (2023).

As made clear by the sheer volume of approved and pending Class VI permit activity in Texas,[9] liability changes are not legally or commercially necessary for the success of a carbon storage program. If in the future Texas does change its approach to operator liability or responsibility, EPA should immediately assess whether RRC's ability to enforce the Class VI program remains equivalent to the federal approach and, if not, revoke this primacy decision.

2. Texas must invest in building a robust, well-funded, and well-trained Class VI oversight program, and should carefully consider whether it can safely and realistically deliver on estimated permit review timelines at current staffing levels with available funding.

Running a sizeable Class VI program is expensive, laborious, data intensive, and requires personnel with technical skills outside those normally found in an oil and gas agency. To this end, the RRC must have a sufficient and consistent budget to support expected activity levels in Texas. For transparency and efficiency, the RRC should use modern software able to accommodate the various data types needed for Class VI project approval and oversight. Ideally, the RRC should look to the Groundwater Protection Council (GWPC)'s Risk Based Data Management System, a multistate project already used by the majority of states with Class VI primacy.[10]

In order to ensure personnel are up-to-date and equipped with the knowledge they need for program oversight, RRC staff working on Class VI should undertake the GWPC Class VI regulatory training program, whose curriculum was developed in partnership with the Texas Bureau of Economic Geology.[11] Where RRC relies on contractors for regulatory work, efforts must be undertaken to reduce conflicts of interest.[12] Finally, the Texas Commission on Environmental Quality (TCEQ), that has a role to play in Class VI permitting, especially in Class I no-harm determinations, needs to be properly funded to do this work without delay or shortcuts.[13]

In additional to these high-level thoughts on regulatory capacity, EDF offers the following observations and suggestions:

A. Funding levels, permitting timelines and oversight quality

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[9] The RRC's Class VI Program Description indicates that applications for 10 projects with a total of 26 wells have been submitted to date in Texas. The Commission "anticipates that, during the first two years after approval of the state Class VI program, permit applications for approximately 37 Class VI wells may be submitted." Railroad Comm'n of Tex., Class VI Underground Injection Control 1422 Program Description at 20 (2025) [hereinafter Texas UIC Program Description], https://www.regulations.gov/document/EPA-HQ-OW-2025-0157-0002.

[10] *About RBDMS*, Groundwater Prot. Council, https://www.gwpc.org/rbdms/ (last visited July 31, 2025).

[11] The curriculum is available at https://www.gwpc.org/wp-content/uploads/2022/06/Class_VI_Curriculum_for_Regulators_update92222.pdf.

[12] For more information on conflicts of interest that should be accounted for, see EDF's comment submission during Wyoming Class VI primacy rulemaking. EDF, Comment Submitted by Adam Peltz, Senior Attorney, Energy (June 4, 2020), https://www.regulations.gov/comment/EPA-HQ-OW-2020-0123-0021.

[13] See https://www.tceq.texas.gov/permitting/radmat/uic_permits/class-vi-injection-wells-requesting-a-letter-of-determination.

The documents related to the Class VI program are light on details as to staffing and funding levels. Texas indicates clearly in the program description that during the first year of RRC's Class VI implementation, "additional funding in excess of the projected fee collections will be required" and indicated that this excess would come in part from federal funds, namely "the UIC grant."[14] But the fate of EPA funding to states to cover UIC activities under block grants is far from certain. Also, the $1,900,000 per state to support Class VI primacy and implementation as part of the Infrastructure Investment and Jobs Act is, as far as EDF can tell, not yet delivered.

EDF recommends that the EPA meet its commitments and provide support to states with UIC primacy, as it has historically. But given the uncertainty around federal funding, Texas must prepare to either fill federal funding gaps with additional permitting and activity fees, from general tax revenue, or reduce its planned throughput of project approvals.

The RRC's Program Description notes:

> Applications for ten [] projects with a total of 26 wells have been submitted to date. The RRC anticipates that, during the first two years after approval of the state Class VI program, permit applications for approximately thirty-seven Class VI wells may be submitted, including applications for twenty-five Class VI wells in the first year and applications for twelve Class VI wells in the second year.[15]

It additionally anticipates that it will take the RRC six months to issue a permit to drill/convert and an additional six months to issue an authorization to inject, assuming proposed staffing levels and full applicant cooperation.[16]

Using a standard of 1500 person hours to completely process a permit, one would expect the RRC to need at least a dozen people working on only Class VI to meet these deadlines with additional staff at TCEQ to undertake Class I non-interference determinations. Also, Class VI permitting does not always work out as expected. Louisiana, for example, has yet to issue a Class VI permit despite the fact that there were 22 projects with applications already deemed complete by EPA at the time the state obtained primacy in December of 2023.[17]

The regulatory goals of efficiency and quality need not be in conflict but achieving both requires adequate staffing and funding. To achieve the RRC's ambitious goal of 12-month permitting, Texas must invest in its regulatory staff and not cut corners. At the outset of this key industry, mistakes will have lasting consequences—if projects do not have integrity and are not meeting their CO2 storage performance goals, Congress may well reduce or eliminate the 45Q tax credit, stranding billions of dollars in assets and leaving a mess of the Texas subsurface.

B. Learnings from earlier Class VI primacy states (North Dakota, Wyoming, Louisiana)

[14] Texas UIC Program Description, *supra* note 9, at 4.
[15] Texas UIC Program Description, *supra* note 9, at 20.
[16] Texas UIC Program Description, *supra* note 9, at 4.
[17] *See Class VI Carbon Sequestration Program: Permits and Applications*, State of La. Dept' of Energy & Nat. Res. (June 26, 2025), https://www.dnr.louisiana.gov/page/permits-and-applications.

In 2024, EDF undertook unpublished research on the programmatic aspects of EPA's Class VI permitting versus that of the three states that have received Class VI primacy to date. EDF highlights three key learnings from this research.

First, all three state programs facilitate coordination with other relevant agencies. This includes offices related to public bonds, game and wildlife, historic preservation, pipeline siting, and water management, among other functions. EDF recommends that the RRC cast a wide net and coordinate with its sister state agencies and relevant local authorities on all aspects of the Class VI project's lifecycle. This includes capture and transport in addition to storage. Carbon sequestration is a complex, multi-stage endeavor that works best with a whole-of-government approach. Piecemeal oversight leads to inefficiencies, unintended consequences, an overwhelmed operator community and a frustrated public.

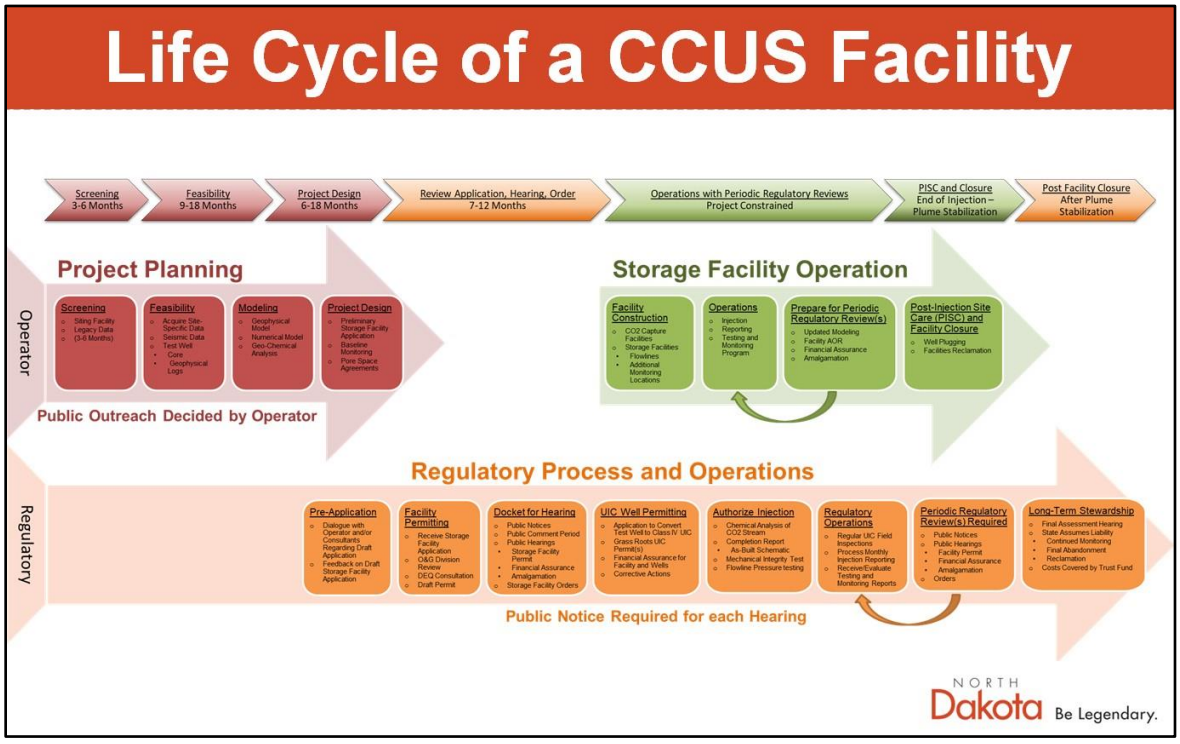
The second learning has to do with outreach to potential project proponents on regulations, guidelines, permit conditions and other need-to-know aspects of the Class VI regulatory program. Class VI permit applications are notoriously complex not just for the regulatory agency to review, but even more so for the applicant to prepare. Part of this is due to a limited understanding of the Class VI program at large, including its differences from other UIC programs, as well as limited knowledge of detailed agency expectations with respect to implementation and interpretation of policies and procedures. EDF recognizes that RRC has a robust history of sharing information via workshops, conferences, and webinars explaining rules, rule changes, and other guidance and policies related to compliance.[18] In the case of Class VI, EDF strongly recommends comprehensive outreach and compliance guidance materials to support operators in understanding how to develop robust applications and comply with the program.

Third, RRC can promote efficiency and reduce back-and-forth between the agency and applicants by way of formalizing the pre-application process. One key learning from EDF analysis of state program implementation after the granting of primacy is that North Dakota and Wyoming have benefited from extensive, formalized pre-application project planning. In both cases, the state regulatory process requires or ensures that an applicant shares project information with the regulator in the early stages of project screening and application development—which appears to lead to more compressed permit review periods. The chart immediately below outlines permitting phases by time estimate for the EPA and three primacy states; additional figures below provide a process flow chart for Class VI permitting in North Dakota and Wyoming.

[18] *See RRC Workshops and Conferences*, Railroad Comm'n, https://www.rrc.texas.gov/about-us/organization-and-activities/activities/workshops-and-conferences/ (last visited July 30, 2025).

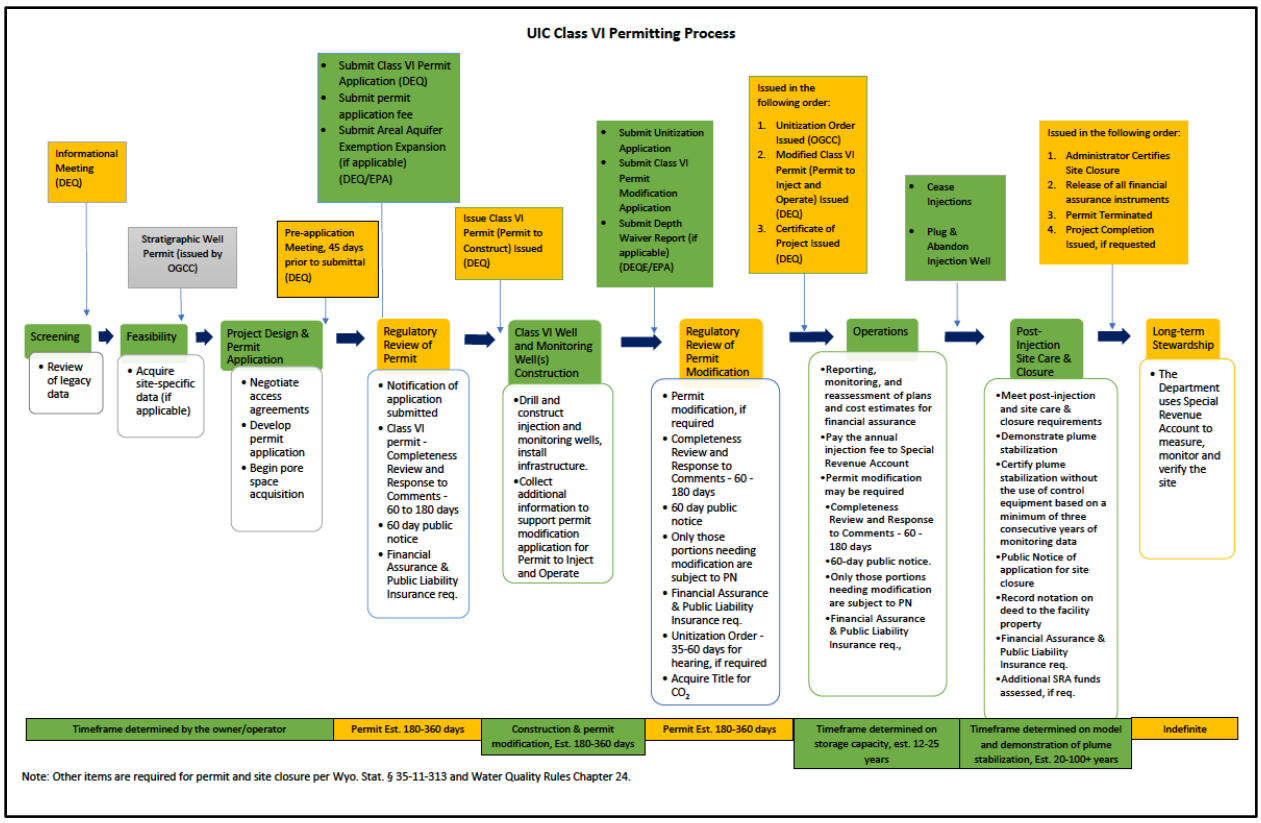
Agency	Preparation		Permitting			Total Time (Months)	Total Injection Permits Issued*
	Characterization & project design	Meeting with Agency	Completeness	Permission to Construct	Permission to Inject		
US EPA	-	-	1	23	-	24	8
LA	-	-	18			18	0
ND	12-24	6-18	7-12			25-54	8
WY	-	1.5	6-12	6-12	6-12	19.5-37.5	4 projects

**As of January 2025*



[19] North Dakota CCUS Facility Life Cycle

[19] *Class VI - Geologic Sequestration Wells*, N.D. Min. Res., https://www.dmr.nd.gov/dmr/oilgas/ClassVI (last visited July 30, 2025).



[20] Wyoming Class VI Permitting Process

3. Texas and EPA should thoughtfully and cautiously consider updated approaches to monitoring wells in light of knowledge and learnings gained from the recent ADM event in Decatur, Illinois.

Effective and protective regulatory programs should incorporate knowledge learned from both positive and negative project outcomes to continuously improve standards. In the case of the ADM incident, while EPA determined no threats to drinking water occurred,[21] injected fluid did migrate into a deep, unauthorized zone due to a loss of integrity in one of the required monitoring wells[22] from corrosion.[23] Notably, this experience underscores the importance of advanced monitoring systems that can detect and allow remediation of leaks and unexpected leak pathways before they result in contamination events—which is a positive in terms of the monitoring

[20] *Class VI*, Wyo. Dep't of Env't Quality, https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/ (last visited July 30, 2025).
[21] *Public Notice: ADM Geologic Sequestration Well – Proposed Order SDWA-05-2025-0001*, Env't Prot. Agency (Sept. 19, 2024), https://www.epa.gov/il/adm-geologic-sequestration-well-proposed-order-sdwa-05-2025-0001
[22] *EPA Announces Proposed Order Requiring Archer Daniels Midland Co. To Take Actions to Ensure Safe Operation of its Carbon Sequestration Well in Decatur, Illinois*, Env't Prot. Agency (Sept. 19, 2024), https://www.epa.gov/newsreleases/epa-announces-proposed-order-requiring-archer-daniels-midland-co-take-actions-ensure.
[23] Archer Daniels Midland Co., ADM Monitoring Well Development: Factual Overview and Timeline (2024), https://www.adm.com/globalassets/standalone-pages/carbon-capture-and-storage/in-depth--monitoring-well-developments.pdf.

program working. However, it also presents an opportunity for regulators and operators to consider program improvements to avoid similar outcomes in the future.

Based on a review of available information and consultation with leading experts, EDF understands that there are two key learnings that may demand program or permitting modifications moving forward: (1) the placement of monitoring wells in the injection zone where it will come into contact with the CO2 plume can provide valuable information, but also add an additional leakage pathway if not appropriately designed, and (2) selected materials for injection and monitoring wells must be compatible with both the operational design and the fluids with which they will come in contact to avoid corrosion or other integrity losses. For example, monitoring wells that will be in constant contact with CO2-saturated brine may require different construction materials compared to injection wells that will be receiving and emplacing dry CO2 streams that force formation fluid away from the well. With these learnings in mind, EDF offers the following recommendations for the RRC's consideration in designing a robust permitting system that hopes to avoid such incidences:

I. Class VI[24] and TAC[25] requires a testing and monitoring plan for monitoring wells but offers no clear guidance or information on siting, construction, integrity, and operation of those wells—including the selection and use of appropriately compatible materials. RRC should issue its own guidance on these topics and update it as appropriate based on any additional future learnings. The guidance should be made public.
II. While Class VI requires direct methods for tracking the CO2 plume in the injection zone, 40 CFR §146.90(g)(1), the RRC should use its authority in section 5.203(j)(2)(e) to make permit-specific, risk-based decisions on whether the use of indirect techniques and testing through injection wells as a substitute for injection zone monitoring wells can meet this objective. If direct placement of a monitoring well in the pathway of the CO2 plume is deemed necessary, the RRC should require that such monitoring wells be immediately plugged and closed as soon as data indicates the plume has arrived at that well. This is likely to prevent the unnecessary presence of a potential leakage pathway, given the monitoring well will no longer serve a useful function in tracking the CO2 plume.

4. The RRC should formalize its approach to advanced seismicity protections via publicly available guidance, even if it continues to implement those requirements via individual permit conditions.

While the Class VI program is focused on preventing endangerment to underground sources of drinking water (USDWs), avoiding problematic seismicity is crucially important to protect project investments, to avoid damage to the integrity of any surrounding wells or surface property, and to support public safety and confidence in carbon storage. The RRC has already made clear its willingness to go beyond baseline Class VI requirements on seismicity, and EDF appreciates changes the RRC adopted with respect to our initial comments on this topic. In particular, EDF appreciates the added clarity that additional measures and actions may be required if site

[24] *See e.g.*, 40 C.F.R. § 146.90.
[25] *See e.g.*, Tex. Water Code Ann. § 27.002(17), 27.046(b); 16 Tex. Admin. Code § 5.102 (37), 5.202(a)(2)(A), 5.203(b)(1).

characterization and modeling suggest it appropriate with respect to submitted emergency and remedial response plans, section 5.203(l), and permit conditions for monitoring, sampling and testing, section 5.206(e).

A. Developing publicly available expectations for seismic monitoring and seismic event response.

While the above-mentioned changes were important improvements to clarify the RRC's authority to add additional conditions related to seismic risk management, EDF believes that Texas can and should further formalize and make clear, both to operators and to the public, its expected approach to seismic monitoring and seismic event response. These potentially proactive solutions should not be buried in the individual permit conditions alone. This will give operators advanced understanding of the RRC's expectations on the topic while also providing the public better insight into the steps the RCC is taking to avoid Class VI-related earthquakes.

For example, the approach taken in Part M. of the recently issued Brown Pelican CO2 Sequestration Project permit[26] (Appendix A) serves as a good initial model for all Class VI permits where induced seismicity poses material risks. The RRC could utilize guidance to further consider to what extent it is necessary to adopt different local magnitude thresholds for different regions or permits based on relevant factors such as known geologic considerations, potential hazards to infrastructure or other property, public safety, and other factors. This approach aligns with the model carbon capture and sequestration (CCS) statute forthcoming from the Interstate Oil and Gas Compact Commission (IOGCC).[27]

B. Integrating Class VI Seismic Monitoring Networks into TexNET

The state of Texas developed TexNET around ten years ago in response to a spike in induced seismicity from produced water injection[28]. The RRC has used TexNET to help manage this problem ever since, and TexNET has a role to play in mitigating induced seismicity from CO2 injection as well. Pressure and seismic impacts from injection can travel a long distance, and as Texas's use of the subsurface continues to intensify, projects will consequentially impact each other. Because TexNET has a statewide presence, the system can pick up basin-wide changes in pressure and seismic activity.

In order to best understand seismic implications of individual Class VI projects, as well as multiple Class VI projects and other forms of injection (particularly Class II wastewater disposal), it would be optimal for projects to integrate their seismic monitoring networks into TexNET – the

[26] Railroad Comm'n of Tex., Underground Injection Control Permit Class VI for the Permanent Sequestration of Carbon Dioxide: Brown Pelican CO2 Sequestration Project Permit No. 55294 at 21 (2024), https://www.rrc.texas.gov/media/5m3mkwh1/03-20241014-oxy_brown_pelican_ector-county_draft_class-vi_uic_permit_primary.pdf

[27] Model Statute on Geologic Sequestration of Carbon Dioxide § 1.18 (IOGCC, Proposed Final Draft 2025) [hereinafter IOGCC Model Statute], https://oklahoma.gov/content/dam/ok/en/iogcc/documents/committees-councils/legal/Model%20Statutes.pdf.

[28] *Home*, TexNet, https://texnet.beg.utexas.edu/ (last visited July 30, 2025).

RRC should include this requirement in the guidance EDF is recommending here and further require this as a permit condition for any Class VI permits subject to seismicity-related provisions.

C. Fostering and Facilitating Data Sharing to Improve Understanding of the Subsurface System

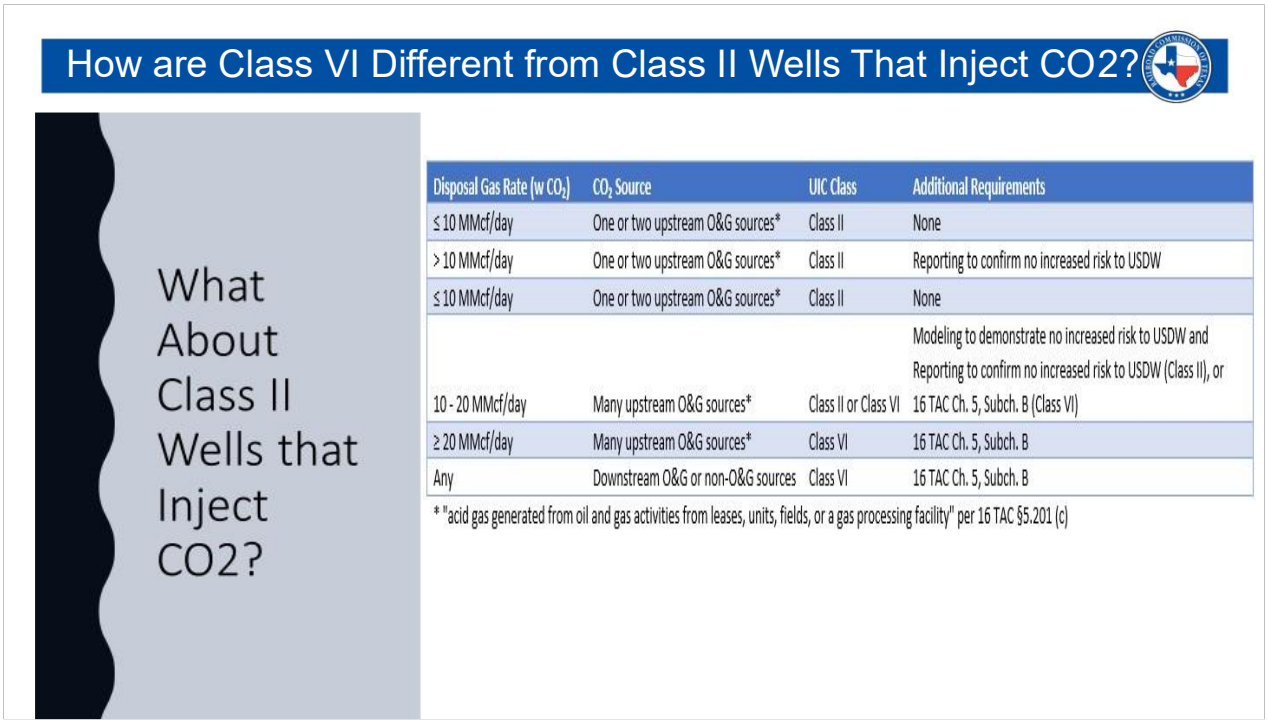
Along these lines, Texas should also endeavor to facilitate data sharing on seismicity, not only from TexNET, but also from private seismic monitoring systems wherever possible. As the RRC learned from produced water earthquakes, no one injection well operates in isolation. Thus, while Texas prepares to permit millions of tons of CO2 for indefinite storage in the geology across dozens of wells operating in and around other injection and production facilities, it will be critical to understand system-wide pressure and seismic impacts. The more monitoring stations surveying this system and sharing data, the better the RRC will be able to proactively recognize areas of growing seismic risk and respond accordingly.

Uncontrolled induced seismicity can dramatically impact social license to operate, and if Texas does not get out ahead of this potential problem with the tools it already has available, it will jeopardize the entire enterprise of economic subsurface use in Texas.

5. The RRC should make clear via more formalized guidance or additional rulemaking its approach to UIC well class conversions, ensuring equivalency in protections and processes, including public notice and public comment where appropriate.

There are numerous Class II well permit applications or active Class II projects either for enhanced oil recovery (EOR) or acid gas disposal (AGD) that currently receive, or intend in the future to obtain, federal 45Q tax credits by injecting or co-injecting carbon oxides into these same wells. Obtaining Class II permits is a much faster process, requiring significantly less modeling and analysis and less stringent specifications for a range of issues including well construction, modeling and monitoring, closure, and financial responsibility. <u>It is imperative that initial permitting as Class II injection well (or a Class V experimental well) not be allowed to function as a loophole to avoid the rigor of Class VI requirements</u>.

EDF recognizes that RRC has already taken steps to enhance clarity around the Class II to Class VI conversion issue, namely via the regulations adopted in 16 TAC section 5.201 and—more informally—via screening guidelines such as the below PowerPoint slide, which further identifies volume and CO2 source differentiations:



A. Closing the potential Class II to Class VI loophole.

The above-mentioned steps are a strong move in the direction of limiting abuse of well reclassifications. There are additional steps EDF recommends RRC consider as it manages these determinations:

I. Formalize, via public notice and comment rulemaking, the screening guidelines identified in the above PowerPoint slide.

II. While the RRC's current approach of adding permit-by-permit conditions on certain Class II wells is a positive interim step, this ad hoc approach can lead to inconsistency in program administration and create discrepancies in the quality of wells allowed to be used for CO2 storage. To avoid this outcome, RRC should adopt a requirement similar to 16 TAC section 5.201(h) that would require EOR or AGD Class II wells reasonably likely to, or planned to, convert to Class VI wells meet the well construction requirements of Class VI.

III. Where the Commission determines that an existing well injecting CO2 and claiming sequestration credits under the 45Q program can remain a Class II well, either based on a finding of no increased risk to USDWs or that regulatory tools of the Class II program can manage an existing risk:

   a. There should be a mechanism for public notice of that finding and its technical support documents to ensure adjacent property owners, operators, and potentially impacted stakeholders have an accurate update regarding the operating purpose and status of the Class II well; and

   b. The Class II well should be required to adhere to other aspects of the Class VI program not covered in the risk-based factors of section 5.201, including stakeholder engagement, emergency response, financial responsibility,

> plume monitoring and modeling, post-injection site care and closure requirements, among other important aspects necessary to ensure safe operation and an eventual demonstration of permanent CO2 sequestration.

B. *Class V Wells Utilized to Expedite Class VI*

EDF also recognizes that another potential pathway to a Class VI well is via the conversion of a Class V exploratory or stratigraphic test well used to gather geologic data necessary to pursue Class VI permitting. This avenue would potentially allow a transition of the original Class V well to Class VI at a later date and theoretically expediting the Class VI process.[29] While EPA originally considered the use of Class V as relevant for early, pre-Class VI pilots of geologic sequestration projects,[30] the agency subsequently made it clear in the adoption of the 2010 Class VI regulatory program that continued use of the Class V program in this manner would no longer be necessary and may, in some instances, be inappropriate (see below excerpts).

The transfer of Class V to Class VI is **not addressed in the program description**, though EDF does recognize that 16 TAC section 5.201(h) makes clear that operators drilling a stratigraphic test well with "plans to convert" to a Class VI well should meet all the well construction requirements of Class VI.[31] EDF applauds the RRC for this initial step in ensuring equivalent protections. However, EDF recommends that RRC formalize, and make public, clear and substantive guidance on the approach it expects to take with respect to the potential transition of Class V wells to Class VI. The EPA should also ensure that this process aligns with the requirements of the Class VI program.

Particularly, the RRC and EPA should consider how to ensure non-experimental and stratigraphic test wells built as Class V projects and later converting to Class VI projects do not conflict with EPA's expectations for the Class VI program. As such, consider these passages from the 2010 Class VI rule preamble addressing Class V wells:

> EPA does not consider it appropriate to permit CO2 injection wells that are testing the injectivity or appropriateness of an individual formation (e.g., as a prelude to a

[29] *See* CCUS Map (@CCUSMap), LinkedIn (July 1, 2025 13:17 MDT), https://www.linkedin.com/posts/ccus-map_gulfcoastccs-carbonsequestration-activity-7345893364581453827-cq9C/. CCUS Map database indicates "ExxonMobil Low Carbon Solutions applied to convert 3 wells from Class V (Strat Test) to Class VI. This *playbook is replicated in many other projects in our database*." *Id.* (emphasis added). .

[30] Cynthia C. Doughtery & Brian McLean, Env't Prot. Agency, UICPG # 83, Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects: UIC Program Guidance 1-4 (2007), https://www.epa.gov/sites/default/files/2015-07/documents/guide_uic_carbonsequestration_final-03-07.pdf.

[31] "An operator shall apply for a permit to drill (Form W-1) prior to drilling a stratigraphic test well, notify the UIC Section of the application, and submit a completion report (Form W-2/G-1) once the well is completed. If the operator plans to convert the stratigraphic test well to a Class VI injection well, the well construction shall meet all of the requirements of this subchapter for a Class VI injection well. Any stratigraphic test well drilled for exploratory purposes only shall be governed by the provisions of Commission rules in Chapter 3 of this title (relating to Oil and Gas Division) applicable to the drilling, safety, casing, abandoning, and plugging of wells. As an alternative to drilling a stratigraphic test well, an operator may obtain data for site characterization from offset wells." 16 Tex. Admin. Code §5.201(h) (2023).

commercial-scale operation) as Class V experimental technology wells. Such wells should be permitted as Class VI wells.

EPA expects that, following today's rule, a limited number of experimental injection projects testing [geologic sequestration] technology will continue. EPA anticipates that these projects will be small-scale and involve limited CO2 volumes. However, if these projects become larger scale and are no longer experimental, they will need to be permitted as Class VI wells. The construction, operation or maintenance of any non-experimental Class V [geologic sequestration] wells is prohibited (§144.15).[32]

Section 144.15 Prohibition of non-experimental Class V wells for geologic sequestration. The construction, operation or maintenance of any non-experimental Class V geologic sequestration well is prohibited.[33]

Finally, while EDF recognizes that there may occasionally be valid reasons for slight deviations from well construction specifics based on technical and geologic characteristics of a project, exemptions from the equivalent rigor of Class VI should not be allowed. Despite this, RRC regulations in section 5.203(e) appears to provide operators that begin the life of their CO2 storage project as a Class II or Class V project an opening for exemption before they even begin their operation—an option Class VI project developers do not have:

(vii) The director may exempt existing Class II wells that have been associated with injection of CO2 for the purpose of enhanced recovery, Class V experimental technology wells, and stratigraphic test wells from provisions of these casing and cementing requirements if the applicant demonstrates that the well construction meets the general performance criteria in subparagraph (A) of this paragraph. A converted well must meet all other requirements under this section. The demonstration must include the following:

(I) as-built schematics and construction procedures to demonstrate that repermitting is appropriate;

(II) recent or newly conducted well-log information and mechanical integrity test results;

(III) a demonstration that any needed remedial actions have been performed;

(IV) a demonstration that the well was engineered and constructed to meet the requirements of subparagraph (A) of this paragraph and ensure protection of USDWs;

(V) a demonstration that cement placement and materials are appropriate for CO2 injection for geologic storage;

(VI) a demonstration that the well has, and is able to maintain, internal and external mechanical integrity over the life of the project; and

[32] Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells, 75 Fed. Reg. 77230, 77245 (Dec. 10, 2010).
[33] 75 Fed. Reg. at 77289 (codified in 40 C.F.R. § 144.15).

(VII) the results of any additional testing of the well to support a demonstration of suitability for geologic storage.[34]

Thus, where the director allows for these exemptions, technical materials submitted by the applicant for conversion to Class VI and the technical reasoning for the exemption from the RRC should be made part of the full record for the Class VI permit. This ensures transparency in the Class VI public notice and comment period regarding the construction of the well that will be utilized for permanent CO2 storage moving forward. In addition, both the RRC and EPA should ensure that RRC's implementation of this discretionary prevision does not conflict with the passages quoted above with respect to experimental Class V wells.

As stated earlier in these comments, beginning a carbon storage project as a Class II or Class V project **cannot, under any circumstance, be allowed to function as a loophole to the comprehensive rigor of Class VI.** This is not only with respect to well construction standards, but also with respect to the entirety of the program from public engagement, notice, and comment to post-injection site care, closure, and long-term responsibility. Anything less than this weakens the entire carbon management program both in safety and credibility.

6. **Given the sheer size of Texas' UIC program and challenges posed by legacy, orphan, and inactive infrastructure, the RRC should adopt more protective and proactive approaches to identifying undocumented potential fluid conduits in areas of review.**

Texas has by far the most wells drilled since the start of oil and gas production of any state, likely numbering well over one million. In the IOGCC's 2024 Idle and Orphan Oil and Gas Wells Supplemental Report, Texas reports approximately 435,000 documented drilled and not plugged wells[35] but does not provide an estimate for undocumented orphan wells.[36] That number is potentially vast—a study in the Science of the Total Environment from February 2025 found that Pennsylvania and Oklahoma, states with comparably early oil and gas industries, each likely have over 300,000 undocumented orphan wells.[37]

As such, large-scale carbon sequestration is likely to occur in Texas in and around areas of historical drilling, which cover much of the state. While operators must conduct a paper exercise to explore potential fluid conduits within their Area of Review (AoR), it is likely that not all relevant penetrations will be in the official record.

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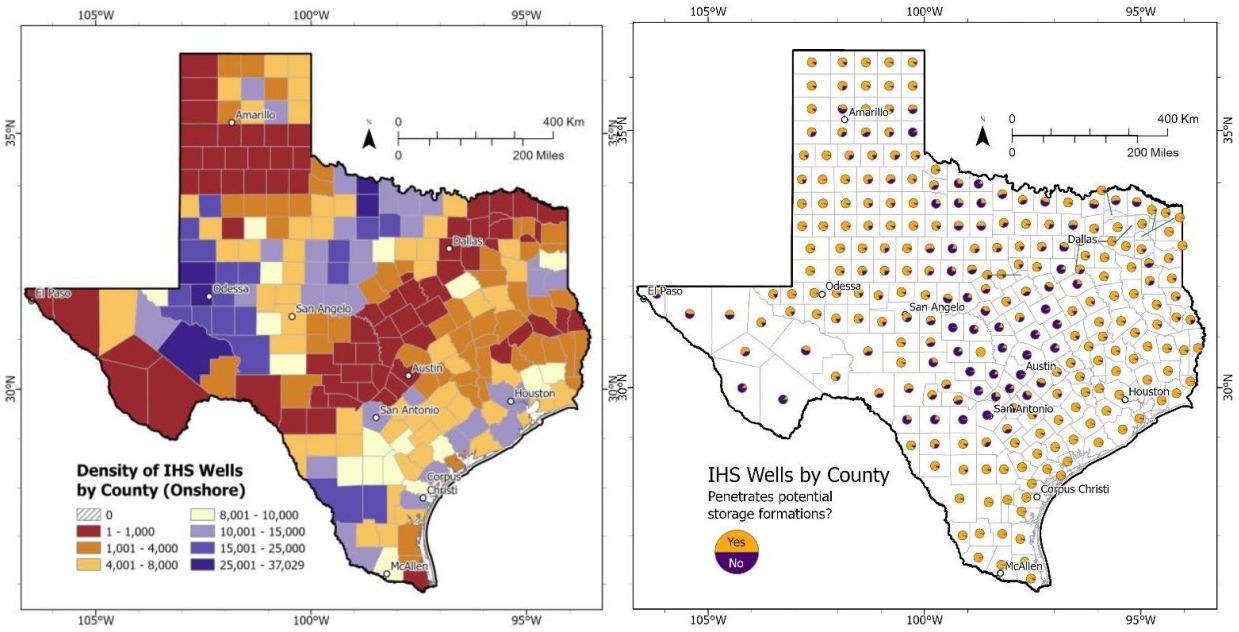
[34] 16 Tex. Admin. Code §5.203(e)(1)(B)(vii).
[35] Interstate Oil and Gas Comm'n, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies at 14 (2024), https://oklahoma.gov/content/dam/ok/en/iogcc/documents/publications/Orphan%20Wells%20Revised.pdf.
[36] Interstate Oil and Gas Comm'n, *supra* note 35.
[37] Ismot Jahan et al., *Data-driven Estimates of Undocumented Orphan Oil and Gas Wells With Implications to the Environment*, 97 Sci. Of the Total Env't 178746 (2025), https://doi.org/10.1016/j.scitotenv.2025.178746.



The map on the left shows historical well count by county; the map on the right indicates percentage of historical wells penetrating potential storage formations, where orange indicates a higher percentage and purple indicates a lower percentage.[38]

In order to effectuate meaningful confinement reviews and protect USDWs, the RRC ought to require instrumented undocumented orphan well surveys for project AoRs in areas with historical drilling. EDF understands that other states, like Louisiana, plan to require this in permit conditions. Additionally, the RRC can request that operators undertake desktop research to locate undocumented orphan wells on historical maps. This is a new approach, spearheaded by the Department of Energy, to digitize and geolocate historical maps to identify undocumented orphan wells locations,[39] and some states have successfully begun documenting orphan wells this way.[40]

Failure to take extra care in locating and dealing with undocumented potential fluid conduits in the AoR could lead to loss of the project, and indeed, is a threat to the entire industry. The RRC and project developers must take this risk seriously and employ modern tools to mitigate that risk.

7. **Texas should adopt rules or establish guidance to prevent adverse impacts to Class VI storage facilities from other subsurface activities that may need to drill through or otherwise risk impacting the storage facility.**

Geologic sequestration projects can span vast subsurface areas and, in some cases, will overlap with other economically viable resources, such as oil, gas, or minerals. While the mere presence of a CO2 storage project should not render those resources unavailable or inaccessible, additional

[38] E Rodirguez Calzado et al., Initial Results on Study Evaluating the Impact of Legacy Wells on Carbon Storage and Energy Development in Texas: Risk Assessment, Policy Insights, and Management Strategies 7, Bureau of Econ. Geology (2025) (unpublished white paper) (on file with EDF).
[39] Andrew Govert, Hari Viswanathan & Elizabeth McNamara, Undocumented Orphan Wells Program Annual Report 90 (2024).
[40] Lawrence Berkeley Nat'l. Lab'y, *AI Helps Researchers Dig Through Old Maps to Find Lost Oil and Gas Wells*, J. of Petroleum Tech (Dec. 6, 2024), https://jpt.spe.org/ai-helps-researchers-dig-through-old-maps-to-find-lost-oil-and-gas-wells.

precautions should be taken to ensure that later activities do not impact secure containment of the Class VI project. These issues are not adequately addressed in Class VI regulations.

EDF recommends that the RRC adopt rules or establish guidance in line with the IOGCC's approach to this topic, found in section 1.17 of the draft model statute.[41]

8. Texas should consider emerging research and information on the limitations of 'pressure space' in addition to pore space and adopt measures to get ahead of potential risks that may increase as additional CO2 injection wells are permitted in close proximity to existing projects.

In its program description, the RRC estimates permit applications for at least thirty-seven Class VI wells over the next two years in addition to the twenty-six well permits already submitted at the time of the Program Description.[42] The average Class VI project aims to inject 500KT to 1MT per well per year. While Texas is expected to have ample storage capacity for these volumes,[43] accurately managing the cumulative implications of pressure and additive interactions between project AoRs will be vital to avoid under-managing leakage pathways and overestimating realistic capacities. Researchers have concluded that revised capacity calculations that assume that pressure buildup is the limit on storage (as opposed to pore space alone) reduce the resource capacity from the static by about an order of magnitude.[44] Proactively addressing this challenge is particularly important in the Permian Basin and parts of the Texas Gulf Coast, where pressure issues and multiple-use injection activities already exist.

EPA foreshadowed the need to evolve the Class VI program due to such issues in the preamble to its original 2010 rulemaking, stating:

> The Agency anticipates that a UIC Director will (and encourages the UIC Director to) consider the following types of risks when evaluating additional injection activities into the AoR of a [geologic sequestration] project: The number of artificial penetrations in the AoR, potential adverse geochemical interactions between previously injected CO2 and other injection fluids, and an increase in reservoir pressure as a result of multiple injectors and subsurface plume interaction.[45]

In recent years, globally-leading carbon storage researchers here in Texas have surfaced the concept of "pressure space," "the acceptable pressure increase as a result of injection over a three-dimensional subsurface volume,"[46] and raised important questions about how pressure, rather

[41] IOGCC Model Statute, *supra* note 27, § 1.17.
[42] Texas UIC Program Description, *supra* note 9, at 20.
[43] Reg'l Carbon Capture Deployment Initiative, Texas: Implementing Carbon Capture and Storage Technology (2023), https://carboncaptureready.betterenergy.org/wp-content/uploads/2024/05/TX_2023-Factsheet.pdf.
[44] Alexander P. Bump & Susan D. Hovorka, *Pressure Space: The Key Subsurface Commodity for CCS,* 136 Int'l J. of Greenhouse Gas Control 104174 (2024), https://doi.org/10.1016/j.ijggc.2024.104174.
[45] 75 Fed. Reg. at 77256 (emphasis added).
[46] Susan D. Hovorka & Alexander P. Bump, White Paper: Addressing Multiple Uses of the Subsurface: Allocating Pressure Space 23 (2024), https://www.gwpc.org/wp-content/uploads/2025/05/Pressure-interference-white-paper-updated-12-6-24.pdf.

than pore space and volume, may be a more relevant capacity-limiting factor for safe carbon storage in some geologies. Further, how should permit drafters take into consideration the potentially additive pressure interactions among multiple uses when permitting wells that may now or in the future have overlapping pressure fronts? These concepts are well-summarized by experts Sue Hovorka and Alex Bump from the University of Texas Bureau of Economic Geology (UTBEG) in a 2024 white paper presented to the Ground Water Protection Council.[47]

A key learning from the paper is that "[p]ressure limitations on capacity are small at the start of a project and may increase over time as the impact of boundaries, including adjacent projects *multiply the rate of pressure increase*."[48] This leads to meaningful questions regarding the appropriate approach to defining the AoR for projects or wells proposed in close proximity to each other. The below illustration from Hovorka and Bump indicates that AoRs defined without considering pressure interactions may miss potential leakage pathways, such as legacy wells, that may in fact be in the potential zone of pressure impact. Scenario B below shows that pressure fields of two wells actually interact to create a combined AoR that is even larger than simply adding together the AoRs of the individual wells from Scenario A.

This is a significant advancement in our understanding of subsurface dynamics related to carbon storage that cannot be ignored.

[47] Hovorka & Bump, *supra* note 46.
[48] Hovorka & Bump, *supra* note 46, at 6.

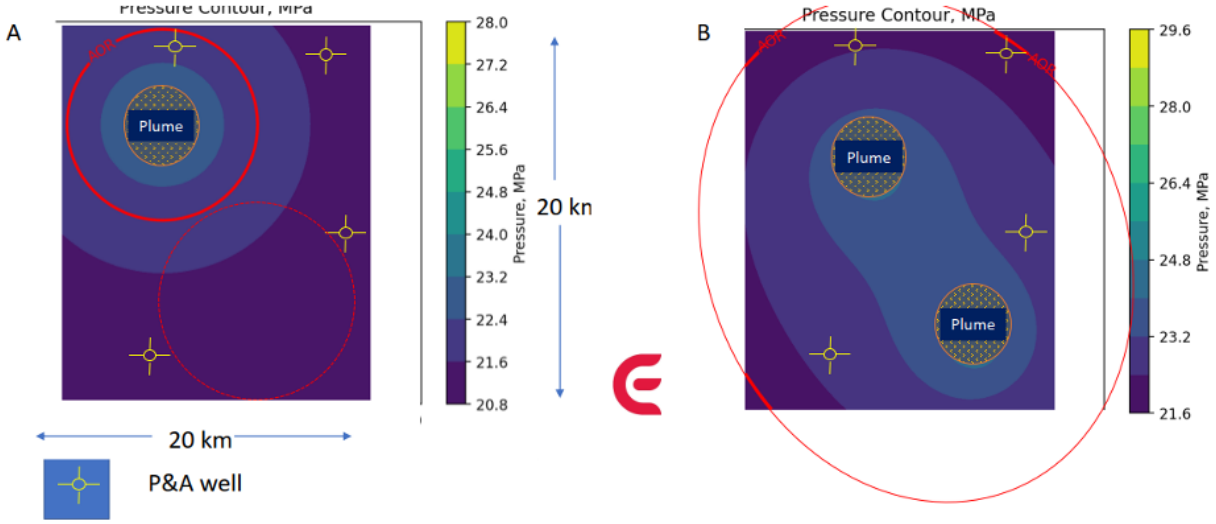


Figure 5A A simple EASiTool illustration comparing the pressure field of one injection well (A) versus two identical injection wells (B). Modeled injection wells are located at the center of the labeled plumes. Four hypothetical legacy wells are shown by the hollow crosses. Background colors show the maximum pressure buildup in the injection zone and the AoR is outlined in red. Note that Scenario A includes a low-pressure area in the lower right corner, apparently with room to locate a second injection project (dashed red circle). Scenario B shows the modeled effect of including that well. Details in text.

Taken from Hovorka & Bump, White paper, Addressing Multiple Uses of the Subsurface: Allocating Pressure Space, fig 5 (2024).

The RRC has an opportunity to present solutions for this complex challenge. Advanced regulatory programs should include opportunities to learn and update models and permitting approaches to incorporate new knowledge. RRC's recent updates to the UIC Class II program[49] to address seismicity and pressure challenges long plaguing that program indicate a willingness to do this. The near blank slate of the Class VI permitting program in Texas presents an opportunity for RRC to be more proactive with this program, avoiding the need to react only after harms have occurred.

Recognizing that there may not be a definitive solution to this emerging issue at this time, adopting clear guidance reflecting a precautionary approach to pressure may be necessary—especially as so many permits are expected to be considered in such a short time period. RRC's Class VI program already recognizes the need to prevent not only fluid movement but also pressure buildup outside of the injection zone(s).[50] EDF recommends adding the following:

I. Establish guidance, in consultation with in-state experts at UTBEG, on how to account for pressure interference within and among projects, including how dynamic capacity assessments that take pressure space into account may impact

[49] Paul Dubois, Ted Wooten & Austin Gaskamp, Permitting Disposal Wells in the Permian Basin (2025), https://www.rrc.texas.gov/media/exolyivw/permitting-disposal-wells-in-the-permian-basin.pdf.
[50] Texas UIC Program Description, *supra* note 9, at 8.

the size of individual permit AoR and how to best monitor for pressure front movement.

II. Experts have made it very clear that "collection of pressure data from multiple wells has the potential to reduce uncertainty about pressure response and future interference at an early time, because the pressure signal travels rapidly over long distances and therefore may be detected early in the injection program long before pressure approaches geomechnical limits"[51]. RRC can contribute to reducing uncertainty by:
    a. Gathering additional data and information on pressure and potential pressure interference during the application process for the permit to construct and use that to inform AoR and other decisions including allowable injection rates. The Gulf Coast Carbon Center's *EASiTool* may be a valuable mechanism for doing this[52] and is available free online. This "tool can be effective in assessing well interference within a project or interference among projects at a sub-basin scale, and to map the AoR for the relevant critical pressure."[53]
    b. Gathering more data and information during the operations phase of projects by taking the approach of Class I wells and strongly considering a requirement for yearly fall-off pressure monitoring tests rather than only every five years, which is the Class VI minimum. Both the Class VI rule[54] and EPA Guidance[55] makes clear that RRC would have the authority to do this with primacy where situations render it appropriate.

III. Consider the reporting and sharing of pressure-related data in the Memorandum of Agreement in development between Texas and Louisiana, and if relevant, other neighboring states (e.g., New Mexico for Permian projects) where transboundary pressure movement is possible due to project locations and expected AoRs.

9. Texas should not allow any exceptions or alterations to permit requirements of the Class VI program in coastal areas or Texas state waters, even if USDWs are not present. Texas should further clarify that the issuance of permits to store carbon are subject to the Texas Coastal Management Program.

A. The RRC should not allow exceptions to the Class VI program for offshore wells.

With primacy, RRC will receive authority for permitting not only onshore wells, but also any wells proposed in the nine nautical miles of Texas state waters. Texas Gulf waters have long been considered a prime location for CO2 storage due to high potential storage capacity,[56] availability of

[51] Hovorka & Bump, *supra* note 46.
[52] *EASiTool,* Gulf Coast Carbon Ctr., https://gccc.beg.utexas.edu/research/easitool (last visited July 28, 2025).
[53] Hovorka & Bump, *supra* note 46.
[54] 40 CFR 146.90(f).
[55] Env't Prot. Agency, Off. of Water, EPA 816-R-13-001, Geologic Sequestration of Carbon Dioxide: Underground Injection Control Program Class VI Well Testing and Monitoring Guidance 50 (2013), https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13001.pdf.
[56] Dylan Baddour, *Texas Opens More Coastal Waters for Carbon Dioxide Injection Wells*, Inside Climate News (Jun 29, 2024), https://insideclimatenews.org/news/29062024/texas-gulf-coast-carbon-dioxide-

3D seismic data, reduced seismicity risks,[57] and the opportunity to reduce some of the proximate-to-community impacts as well as avoid land and pore space ownership complexities that challenge onshore projects.[58] In its most recent request for proposals, the General Land Office opened over a million[59] such acres for offshore carbon sequestration prospects—and months later news of ExxonMobil's lease of over 270,000 offshore acres (the largest such offshore lease in the United States) was made public.[60]

While there has long been a strong inference that EPA considers Class VI fully applicable in all areas where it has jurisdiction regardless of the confirmed presence of a USDW,[61] which would include state territorial waters,[62] this has not been tested by a permit application. EDF is concerned that project proponents will seek exemptions or variances from the RRC for any offshore Class VI wells under the argument that they might not directly endanger communities and USDWs. However, these projects may still endanger sensitive aquatic ecosystems and must be held to an equivalent standard as onshore wells for leak prevention and secure storage of carbon dioxide. EPA has recognized that comprehensive Class VI requirements offshore—including automatic down-hole shutoff devices for offshore wells in submerged lands within the jurisdiction of a state—are necessary precautions to prevent subsurface fluid movement, protect USDWs, and *also* protect human health and the environment.[63]

B. The RRC should note the additional authority of the Texas Coastal Management Plan that would govern offshore Class VI wells.

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injection-wells/#:~:text=One%20worry%20is%20that%20injected,captured%20gases%20to%20injection%20wells; Tip A. Meckel et al., *Carbon Capture, Utilization, and Storage Hub Development on the Gulf Coast*, 11 Greenhouse Gases: Sci. & Tech. 619 (2020), https://doi.org/10.1002%2Fghg.2082; Tip A. Meckel et al., *Mapping Existing Wellbore Locations to Compare Technical Risks Between Onshore and Offshore CCS Activities in Texas*, 13 Greenhouse Gases: Sci. & Tech. 493 (2023), https://doi.org/10.1002/ghg.2220.

[57] *See* Tip A. Meckel & Danny Broberg, Bipartisan Pol'y Ctr., CO2 Sequestration by the Seashore 13-14 (Sept. 2024), https://bipartisanpolicy.org/download/?file=/wp-content/uploads/2024/09/Sequestration-by-the-Seashore-FINAL.pdf.

[58] 2022 Env't Prot. Agency Ann. Rep. to Cong. at 7, https://www.epa.gov/system/files/documents/2024-12/epa-class-vi-ocs-report-to-congress.pdf.

[59] *Lease of Permanent School Fund Land for Storage of Carbon Dioxide: RFP_24-SLB-1-LP*, Tex. SmartBuy (June 10, 2024), https://www.txsmartbuy.com/esbd/RFP_24-SLB-1-LP.

[60] *ExxonMobil Secures Largest CO2 Offshore Storage Site in the U.S.*, ExxonMobil (Oct. 10, 2024), https://corporate.exxonmobil.com/news/news-releases/2024/10102024_exxonmobil-secures-largest-carbon-offshore-storage-site-in-the-us

[61] "[Where] the EPA's SDWA authority applies, CO2 injection wells for [geologic storage] would be considered Class VI wells regulated under the UIC program." 2022 Env't Prot. Agency Ann. Rep. to Cong. at 2, https://www.epa.gov/system/files/documents/2024-12/epa-class-vi-ocs-report-to-congress.pdf.

[62] "Part C of the SDWA requires EPA to establish minimum requirements for State UIC programs that regulate the subsurface injection of fluids onshore and offshore under submerged lands within the territorial jurisdiction of States." 75 Fed. Reg. at 77235. "Under OCSLA, Class VI wells injecting offshore (on the outer continental shelf) but within state territorial waters may be subject to requirements under the OCSLA in addition to the Class VI regulations."
Off. of Water, Env't Prot. Agency, EPA 816-R-18-001, Geologic Sequestration of Carbon Dioxide: Underground Injection Control Program Class VI Implementation Manual for UIC Program Directors 3-10 (2018), https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf

[63] 75 Fed. Reg. at 77251.

Under the Texas Coastal Management Plan (CMP), before the Commission takes any action that may impact any coastal natural resource area[64] it is required to do a consistency review to ensure that action is in alignment with the goals and policies of the CMP. Based on available materials, the RRC actions subject to the CMP do not explicitly list the issuance of carbon sequestration permits.[65] As such, the RRC and, if necessary, the Coastal Coordination Council should review rules, guidance, and notice documents to ensure Class VI well permitting is done in accordance with the CMP, if they have not done so already.

C. Offshore Class VI wells are a developing area of science, technology, and regulation and the RRC should take this opportunity to lead.

Finally, developing a research program to gather additional learnings and identify fit-for-purpose precautions may be necessary due to unique considerations present for storage in submerged settings. In its most recent letter to Congress on Class VI Program Relevance to Outer Continental Shelf Carbon Sequestration Projects Under Department of Interior Authority, the EPA states:

> Examples of areas that are in need of more development and analysis include: assessing methods for long-term monitoring of the CO2 plume and pressure front within offshore formations and the surrounding environment, including the seafloor; optimizing lease spacing and multiple uses of the sub-seabed and water column above the injection formation (the formation into which CO2 is injected); developing appropriate emergency response and contingency plans; and understanding the potential impacts of spilled or leaked CO2 on the marine environment. Finally, while there are notable long-term projects in Norway, and while considerable prior research has been competed on sub-seabed GS, no sub-seabed GS projects are yet operational in the United States. For a successful offshore GS project, safeguards need to be developed to protect against accidental releases of the captured CO2 during transportation as well as during and after operation. The same operational safeguards also would protect against any potential leakage of formation fluids. In addition, clarifying and communicating relationships between regulatory regimes across marine spaces will be necessary to ensure transparency of roles and responsibilities within the whole-of-government approach to compliance.[66]

RRC, in partnership with EPA, industry, and academic researchers like those at the Gulf Coast Carbon Center, could develop globally leading best practices for the region.

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[64] A coastal natural resource area (CNRA) is defined as a coastal barrier, coastal historic area, coastal preserve, coastal shore area, coastal wetland, critical dune area, gulf beach, hard substrate reef, oyster reef, submerged land, special hazard area, submerged aquatic vegetation, tidal sand or mud flat, water in the open Gulf of Mexico, or water under tidal influence. Tex. Nat. Res. Code Ann. § 33.203(1).
[65] Railroad Comm'n of Tex., Notice to Operators: Texas Coastal Management Program (1997), https://www.rrc.texas.gov/media/2cvgihrp/texascoastalmgprogram.pdf.
[66] 2022 Env't Prot. Agency Ann. Rep. to Cong., *supra* note 58.

Further, the Department of Interior (DOI) is in the process of developing regulations for leasing and permitting carbon storage projects on the Outer Continental Shelf.[67] Once those regulations are established, the need for additional transboundary communication and collaboration will be necessary. The RRC and DOI should enter into a Memorandum of Agreement for transboundary communication and documentation procedures as well as collaboration on data gathering, research, and best practices for gulf water operations.

10. The RRC should strengthen Emergency and Remedial Response Planning requirements for Class VI projects.

The federal Class VI regulations have only high-level, generic requirements for the development and submission of an emergency and remedial response plan.[68] The RRC's provisions on emergency response as articulated in section 5.203(*l*) and in Appendix H provide more specificity, but Texas' approach can and should go further. This is especially true regarding coordinating with, and providing adequate resources for, local emergency responders, who are likely to be among the first on the scene in the event of an incident and the best equipped to interface between the operator and the impacted public.

In particular, the RRC should review Louisiana's House Bill 516, adopted in June 2024.[69] This legislation requires two provisions beyond the RRC framework. First, a copy of the emergency and remedial response plan must be sent to relevant county executives for ultimate distribution to Homeland Security and local emergency preparedness committees, responders, and their agencies. Second, local emergency responders must be incorporated into training and drill exercises.[70]

Adapting these additional requirements into the RRC's regulatory program can ensure more consistent deployment across projects and improve training and coordination with local emergency responders across the state. This is critical in an actual emergency and also helps to build public trust and improve relationships with local officials—factors key to project success and longevity.

EDF also draws the RRC's attention to two additional resources. The first is a model Emergency Response Plan regulation originally designed for underground natural gas storage that is equally pertinent to Class VI operations (see Appendix B). The second is the Emergency Response Planning chapter in the GWPC and IOGCC's Underground Gas Storage: Regulatory Considerations report from 2017, which was developed in response to the Aliso Canyon underground natural gas storage disaster of 2015 in suburban Los Angeles that led to the evacuation of 50,000 residents.[71] Both of these can provide guidance as the RRC evaluates emergency and remedial response plans for Class VI facilities.

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[67] *View Rule: RIN 1082-AA04*, Off. of Mgmt. & Budget, https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202204&RIN=1082-AA04 (last visited July 28, 2025).
[68] 40 C.F.R. § 146.94.
[69] H.B. 516, 2024 Reg. Sess (La. 2024).
[70] *Id.*
[71] Ground Water Prot. Council & Interstate Oil & Gas Compact Comm'n, Underground Gas Storage Regulatory Considerations: A Guide for State and Federal Regulatory Agencies 98-103 (2017),

11. The RRC can improve upon its existing community engagement framework by including mandatory language and prioritizing community input in the rulemaking and permitting processes.

EDF is pleased to see that RRC has taken the initiative to establish an additional program appendix on public outreach and community engagement. However, we note that there are few, if any, regulatory hooks or straightforward commitments to these actions present in text or in regulation. Instead, the appendix reads as an optional menu of approaches. The use of terms like 'may' with respect to basic tenants of appropriate stakeholder participation, such as scheduling public meetings at times convenient for residents with appropriate translation services, is disappointing. At a minimum, RRC should replace this loose language with more proactive terms like "should" or, better, "must." This would make clear RRC's commitment to meaningful public outreach and require the same commitment on the part of applicants.

Outreach should be much more than a top-down, box-checking exercise. Learnings and input of stakeholders should inform both applicant approaches and permitting outcomes. It is vital to the success of carbon storage projects that the RRC and applicants create and maintain open dialogue with the community before and throughout both the application process and the life of the project.

In deference to those with greater expertise and lived experiences on the ground near projects, EDF encourages the Commission to take seriously any additional input from community members and community organizations regarding best practices for meaningful outreach and engagement and participatory justice and adopt their recommendations to the greatest extent possible.

12. Conclusion

In conclusion, EDF recognizes the strong program that RRC is building with respect to Class VI permitting in the state. We do have concerns with respect to the agency's capacity to implement the program soundly at the speed forecasted in the program description, and have provided in these comments recommendations for areas where the RRC can create a more advanced technical program. If the state commits to investing in regulatory capacity and training alongside the cautious development of a protective permitting program, primacy has the potential to positively support the growth of a globally leading carbon management industry in Texas.

EDF believes that full implementation of the Class VI program is necessary—but not alone sufficient—to ensure the environmental integrity of carbon storage projects. We strongly encourage EPA and RRC to consider the recommendations made in these comments in finalizing and improving Texas's permitting program if primacy is authorized.

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https://www.gwpc.org/wp-content/uploads/2022/12/2017_GasStorageRegulatoryConsiderations_reduce.pdf. For more information on the Aliso Canyon incident, see *Aliso Canyon Well Failure*, Cal. Pub. Utils. Comm'n, https://www.cpuc.ca.gov/regulatory-services/safety/gas-safety-and-reliability-branch/aliso-canyon-well-failure (last visited July 31, 2025).

Finally, Class VI wells are only one piece of a carbon management value chain. EDF encourages RRC to pursue additional related protections, such as advanced CO2 pipeline safety requirements, in order to ensure the implementation of a fully protective program. This would include adopting approaches such as the forthcoming American Petroleum Institute (API) recommended practice on CO2 pipeline safety that incorporates responses to the Denbury pipeline rupture; API Recommended Practice 1162 on pipeline public awareness programs; and other relevant best practices.

EDF looks forward to continued opportunities to work proactively with the Commission on these and other issues moving forward.

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Appendix A

Excerpt from RRC Class VI Permit No.55294 for the Brown Pelican CO_2 Sequestration Project, pages 21-22

M. SEISMIC EVENT RESPONSE

1. **Seismic Monitoring**.

(a) Prior to commencing injection, the permittee must deploy and maintain a seismic monitoring system to determine the presence or absence, magnitude, and hypocenter location, of any induced seismic activity of magnitude 1.8 M or above. If, after injection start-up and a subsequent period of sustained injection by all planned injection wells at the maximum permitted rates, the permittee can demonstrate that permanent seismic monitoring is not needed for this project, the Commission may allow the local seismic monitoring to be discontinued and defer instead to state (TexNet) and/or national (USGS) arrays for long-term monitoring.

(b) The system shall be designed with surface monitors and/or downhole monitors as required to meet minimum magnitude of completeness (Mc) of 1.8 M or an alternative site-appropriate minimum magnitude approved by the Director in consultation with the State Seismologust [sic], and to appropriately calibrate event magnitudes and hypocentral locations. The system shall be calibrated with check-shots, sonic logs, or other local velocity information, preferably at depth.

(c) The permittee shall analyze seismic and other relevant data to determine whether the risk of triggering an earthquake of magnitude 3.5 or greater is significantly increased by injection. If, after analysis of seismic and other relevant data, the permittee determines that there is such an increase in risk, the permittee shall notify the Director immediately, and submit to the Director a mitigation plan for the Director's review within 15 days of that determination. The permittee shall implement the plan as approved by the Director.

The appropriate response to seismic events depends on the Magnitude (M) of the seismic event according to the following protocol:

2. **Seismic events not recorded or M less than 2.0** - Continue normal operations.

3. **Seismic events with M equal to or greater than 2.0 but less than 3.**5 - The permittee shall notify the Director (District Director or Technical Permitting Director) of any such event within 24 hours, providing information on the status of the injection site. If the annulus pressure of the well decreases below the set alarm, injection operations shall cease. In that situation, within 30 days the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. If the well fails the mechanical integrity test or the permittee identifies any problems with the injection system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than five (5) days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the circumstances and if the situation

has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the circumstances. Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, the permittee shall submit the results and any other required documentation to the Director in an electronic format. If after the testing the well demonstrates mechanical integrity and issues that might impact USDWs are not identified, the permittee shall provide a report of those findings to the Director for review and approval. Injection operations cannot resume until the Director grants approval to recommence injection.

4. **Seismic Events equal to or greater than M 3.5** – For seismic events equal to or greater than 3.5 M, injection operations shall immediately cease. The permittee shall notify the Director of any such event within 24 hours, providing information on the status of the injection well system. If the annulus pressure decreased below the well's set alarm before shutting in the well, then the permittee shall evaluate the internal mechanical integrity of the well by performing tests in accordance with Section L(2)(a) of this permit. The permittee shall also perform an evaluation of the external mechanical integrity of the well in accordance with Section L(2)(b) of this permit. If the well fails either the internal or external mechanical integrity test or the permittee identifies any problems with the system that might impact a USDW, the injection well shall remain shut-in and the permittee shall submit a report in electronic format as soon as possible but no later than 30 days from the time the permittee becomes aware of the circumstances. The report shall contain a description of the failure and if the failure has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent recurrence of the failure. Upon completion of the steps to ensure mechanical integrity and the subsequent mechanical integrity demonstration, the permittee shall submit the results and any other required documentation to the Director. Injection operations cannot resume until the Director grants approval to recommence injection.

APPENDIX B

Emergency Response Plan.

(a) The operator of a carbon sequestration project shall have an Emergency Response Plan (ERP) approved by the [State Regulatory Agency] and ready for immediate implementation. The ERP shall address minimum guidelines regarding emergency preparedness, response and management. The ERP shall apply to all levels of the operator's management, staff, outside emergency responders, regulatory agencies, potentially affected communities and any other significant stakeholders.

(b) The ERP shall at a minimum address the following regarding ERP planning activities:

(1) Clearly written and communicated ERP policy, goals and objectives

(2) Plan design that identifies overall strategy, tactics, detailed risk assessment practices and a business impact analysis

(3) An appropriate-to-operation incident management system (IMS) designed to address resource management, communication systems, root cause analysis, incident documentation and performance indicators that measure response and recovery with respect to the ERP goals and objectives.

(4) A comprehensive hazard identification process that works in conjunction with the operator's risk management plan. The operator shall provide documentation in the ERP (or Risk Management Plan) that all appropriate operations and their potential consequences have been appropriately risk evaluated.

(5) Based upon the hazard identification and risk evaluation results, the ERP shall include appropriate preventative and mitigative strategies and tactics.

(6) Plan design shall include well defined procedures to address potential emergency scenarios to include but not necessarily limited to

- Collisions involving wellheads as well as critical surface equipment
- Well fires, blowouts and explosions
- Hazardous material spills
- Equipment failures
- Natural disasters and related emergencies
- Surface and subsurface leaks or other well related failures; and
- Medical emergencies.

(c) With respect to implementation, the ERP shall at a minimum, demonstrate and include all of the following:

(1) Detailed written actions plans for all operational phases establishing assigned authority to the appropriately trained and qualified person(s) at a facility for initiating effective emergency response and control;

(2) Recordkeeping programs for all aspects of the operation and ERP;

(3) Accident-response measures that outline response activities, leakage mitigation approaches, and well control processes for well failure and full blowout scenarios;

(4) Prepositioning, as feasible, and identification of all required resources in the form of materials, facilities and personnel necessary to respond to all emergencies, including leaks (including materials and equipment to respond to and stop the leak itself as well as to protect public health), equipment failure, medical emergencies, fires, explosions, natural

disasters affecting operations or any other occurrence posing a threat to public safety, the environment, or natural resource preservation;.

(5) The ERP shall include provisions for accurately assessing damage, responding appropriately to such damage, and communicating adequately internally and externally. It shall also contemplate appropriate procedures for incident termination and business resumption if applicable;

(6) Protocols for emergency reporting and response to appropriate government agencies;

(7) Specification of personnel roles, responsibilities and accountabilities;

(8) All required Emergency contact information including area codes; and

(9) A protocol for public notice of a large, uncontrollable leak to any potentially impacted community, as defined in the risk management plan, if the leak cannot be controlled within 24 hours of discovery by the operator.

(d) The ERP shall have a robust training and education program. The program shall at a minimum have clearly stated goals, objectives, training programs, testing standards and methods whereby organizational competency can be clearly demonstrated. Also, at a minimum, the program will address:

(1) The type and frequency of training that will cover all applicable operational and emergency topics and conform to all regulatory requirements;

(2) Specific training for outside agencies regarding pertinent facilities and operations;

(3) Appropriate public education regarding project operations and the ERP. The ERP must document all training. Such documentation shall be readily available for examination.

(e) The ERP shall establish appropriate plans for ERP exercises, drills and plan improvement and update. At a minimum, the ERP shall incorporate the following considerations:

(1) The ERP shall have a clear schedule for carrying out exercises and drills designed to validate the effectiveness of the operator's ERP.

(2) Drills shall be an appropriate combination of tabletop, workshops and field exercises (e.g., annual no-notice exercises) with all stakeholders participating. The drills and exercises shall be designed to test all aspects of the plan and involve management, staff, regulators and all pertinent first responders. Drills shall combine specific operational functions as well as comprehensive drills covering a wide breadth of likely emergency scenarios.

(3) First responders shall be included in the planning, development and evaluation of exercises and drills for informational purposes as well as providing critical professional input.

(4) Drills and exercises shall be thoroughly evaluated after the fact for effectiveness and lessons learned by independent and objective parties, such as the operator's audit department.

(f) The operator shall annually review and submit for [State Regulatory Agency] approval an updated ERP to accommodate lessons learned, regulatory updates, organizational modifications, performance objective enhancements and changing environmental and operational conditions at a minimum. All updates shall incorporate an effective management of change process that engages all internal and external stakeholders that is timely and communicated clearly.

(g) The most current ERP shall be provided to the county executive and local emergency response agency and, subject to the [State Open Records Requirements], posted on a [State Regulatory Agency] website.

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Title: Strategies for Attaining CO2 Sequestration with Environmental Integrity

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Abstract

This paper presents the technical and regulatory considerations essential for the environmental integrity of geological carbon sequestration. In this context, environmental integrity is defined as a site experiencing no CO2 leakage into the atmosphere, no groundwater contamination, and no significant earthquakes. At a time when geological sequestration is increasingly recognized as a necessary building block to the carbon-neutral economy, this paper presents a path towards its achievement with environmental integrity.

The central pillar of the paper delineates sixteen technical recommendations for ensuring environmental integrity, tracking the lifecycle of a CO2 geologic sequestration project. Within the technical realm, special attention is given to topics beyond a site's lifecycle, such as geology types, and CO2 sequestration via enhanced oil recovery. Lastly the paper discusses the governance factors essential to ensuring a legal and regulatory regime that can support these technical considerations. Though the paper draws extensively from US examples, it is designed for global applicability.

These recommendations are rooted in the authors' combined decades of experience as non-governmental actors in the CO2 sequestration space. Together with a consortium of leading subject matter experts across the United States and Europe, the authors developed the sixteen core recommendations, and used study of regulatory frameworks for geologic sequestration to inform the principles provided.

As the funding, scale, and need for carbon capture projects accelerates dramatically, it is essential that industry and regulators are aligned toward ensuring environmental integrity – the industry's social license to operate, and the climate, will depend on it.

Introduction

Geological sequestration of carbon dioxide – whether captured from industrial sources, through direct air capture or related to bioenergy – is increasingly seen as a critical building block for a carbon-neutral economy (National Petroleum Council 2019; International Energy Agency 2020). In recent years, investment in carbon capture and sequestration space has increased dramatically, with over USD$4 billion expected in 2022, USD$20 billion by 2025, and a cumulative requirement of USD$655 billion - $1.28 trillion globally by 2050 to limit warming by 2 degrees Celsius (Baker 2022; Global CCS Institute 2021). The 2022 IPCC report analyzed 97 pathways to keep warming below 1.5C and found a median of 665 GT cumulatively captured and stored by 2100 – a huge increase over the 197MT that have been stored from 1996 to 2020 to date, mostly as part of enhanced oil recovery projects (IPCC 2022; Bright & Lockwood 2022; Zhang *et al.* 2022).

In order for carbon capture and carbon removal projects to achieve the climate mitigation that experts project is needed from these technologies, it is essential that regulatory frameworks and oversight mechanisms are designed and capable of ensuring "environmental integrity." The three pillars of environmental integrity with regard to geologic sequestration are: 1) No CO2 leakage to the atmosphere; 2) No groundwater contamination; and 3) No significant earthquakes. In the absence of these conditions, geologic carbon sequestration will fail to achieve its potential, either because of literal leakage of sequestered CO2 back into the atmosphere, or because project proponents will fail to gain or retain a social license to operate, or both.

This paper provides sixteen technical recommendations and three additional regulatory oversight recommendations that are necessary for environmental integrity and demonstration of secure geological storage of CO2. Because this paper's scope is limited to geologic storage, it does not address issues related to other vitally important components of CO2 capture and removal – such as air quality considerations, transportation risks, or other potential mechanisms for sequestration or utilization of CO2. The recommendations presented in this paper related to geological sequestration of CO2 are applicable in both the onshore and offshore context, with some variation.

Technical recommendations

Around the world, regulatory frameworks and industry standards have been developed to guide the safe and secure operation of geologic CO2 sequestration projects. This paper identifies sixteen technical areas of consideration to ensure the environmental integrity of geological CO2 sequestration projects. For each of these elements, recommendations are provided, based on leading regulatory practices worldwide and expert input:

i. Carbon Dioxide Stream Characterization

While it is not essential for the stream to be absolutely pure, it is vital that the CO2 stream consists overwhelmingly of carbon dioxide. The composition of the stream is important for the integrity of operations, as other substances may adversely affect well, storage matrix or transport infrastructure (i.e., pipelines). Although regulatory programs may not allow waste or other components to be added for the purpose of disposal, regulatory programs generally allow for incidental associated substances that may be present due to the technical capture and injection processes, or trace substances that are useful in monitoring and verifying CO2 migration. Testing and monitoring requirements should include CO2 stream analysis with sufficient frequency to ensure representative data throughout the project (EU directive section 12.1; Class VI, 146.90(a); ISO 27914: 2017 3.7; ISO 27916: 2019 3.7).

ii. Site Selection and Characterization

The IPCC has persistently emphasized that if a geological storage site is "appropriately selected and managed" injected CO2 can effectively be permanently isolated from the atmosphere. For this reason, proper site selection and accurate site characterization is a fundamental and essential step toward environmental integrity. The siting requirements should be performance-based and data-driven, thorough, and focused on storage capability and containment. Good practices for regulatory programs around site selection include but are not limited to: using available data and information; conducting stratigraphic tests and using other means to collect the data necessary to obtain the permit to construct a well; conducting additional logging and testing, including formation testing with CO2; assuring that corrective actions on improperly abandoned wellbores within the Area

of Review are completed before obtaining authorization to inject (see also v. Area of Review (AoR) Delineation and Modeling); and avoiding problematic pressure interference with nearby storage sites. (40 CFR § 146.83 (a); IRS Notice 2009-83 5.02(b)(i)(A); ISO 27914: 2017 5.1; ISO 27916: 2019 5.2; EU Directive 2009/31/EC Art. 4, Annex I; IEA Greenhouse Gas R&D Programme 2009; IPCC 2005; IPCC 2022; Ringrose *et al*. 2019).

iii. Storage unit adequacy

Sites must have sufficient storage capacity and trapping means to enable long-term containment of stored CO_2. Storage of CO_2 streams should only be allowed in reservoirs and saline formations that have sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream to be stored at the planned injection rate without exceeding acceptable pressure or allowing leakage of CO_2 or formation fluids before or after site closure. The storage unit must also have a confining zone and, if necessary, other containment means sufficient to prevent leakage of CO_2 or formation fluids from the storage unit. Regulatory and permitting programs should be designed to ensure that operators of CO2 sequestration projects demonstrate to the regulating authority that their selected geologic systems meet these requirements (40 CFR § 146.83 (a)(1) & (2); ISO 27914: 2017; ISO 27916: 2019; EU Directive 2009).

iv. Demonstration/verification of secure storage

Ensuring the environmental integrity of storage requires a comprehensive demonstration, based on all available geologic data, monitoring efforts and fluid-flow modeling, that no leaks to the subsurface environment, atmosphere, or surface water or the ocean are expected to occur for a meaningful period of time – e.g. 1,000 years or more – and that no such leaks are actually occurring during the operation of the project. This includes preventing leakage of stored CO_2 or other formation fluids from the storage complex, which includes both the actual storage reservoir unit and the containment seals (e.g., caprock). Assuring containment within the storage complex is more important to ensuring environmental integrity and secure storage than knowing exactly the size, shape and location of the CO_2 injectate plume. Demonstration of secure storage should include both the absence of detectable leakage in accordance with the monitoring plan along with sufficient documentation to demonstrate with high confidence that injected CO_2 will be safely contained long-term within the storage complex (via modeling that is regularly checked against monitoring data). Regulations should require verification of this demonstration. (Class VI Rule 40 CFR § 146.84(c)(1) & (2); ISO 27914: 2017; ISO 27916: 2019). See also ix. Testing and Monitoring.

v. Area of Review (AoR) Delineation and Modeling

The AoR is the region surrounding a geologic sequestration project where injection activity might endanger protected zones or otherwise create a risk of leakage or negative environmental impact. Operators should have a plan to fully delineate and understand the AoR, periodically reevaluate that delineation, and perform any corrective actions necessary to prevent impacts (e.g., plugging or otherwise repairing existing wells in the area that may present leakage pathways) – this effort ensures an operator is comprehensively assessing the impact of injection in a manner that ensures environmental integrity over time. An AoR should be delineated using computational modeling that accounts for the physical and chemical properties of the injected CO_2 stream, injection pressure impact, and displaced formation fluids, and should be based initially on available site characterization, monitoring, and operational data. Using these data, the modeling should predict the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until long-term containment is demonstrated and site closure requirements are otherwise met, and should assure that spacing of injection wells will avoid problematic pressure interference or loss of containment. Model inputs, approach, assumptions, and uncertainties should be presented to the regulator and rigorously reviewed and approved by the regulator. Model uncertainty that affects project success should be acknowledged and strategically reduced through monitoring, reporting, and adjustments as each project and its site's characteristics are increasingly understood. Because of changes in project parameters and conditions in and around sequestration sites over time, an AoR analysis should be repeated at regular intervals) (Class VI Rule 40 CFR § 146.84; ISO 27914: 2017).

vi. Leakage pathway assessment

Once the AoR has been sufficiently delineated, all potential leakage pathways within the AoR should be adequately assessed. Storage sites that are properly selected, operated and thoroughly characterized to assure

containment should not be expected to leak, provided the absence of transmissive natural and artificial leakage pathways within the AoR. Overall experience and site-specific evaluations should be used to identify all potential leakage pathways for formal risk assessment. Once identified, each potential leakage pathway should be analyzed, assessed and evaluated for mitigation and monitoring approaches appropriate for minimizing leakage risks. Accordingly, regulations should require the identification, formal risk assessment, and monitoring as deemed necessary from the risk assessment for potential leakage pathways associated with the AoR, including faults, fractures, and wells within the AoR which penetrate the storage reservoir or containment structures. Data collection requirements for leakage pathway assessments should provide fluid attribution criteria to distinguish leakage from other changes – i.e., to enable understanding of the source of leak based on the composition of the leaking fluid (40 CFR § 146.84(c); IRS Notice 2009; ISO 27914: 2017; ISO 27916: 2019).

vii. Well construction and completion

Wells used for CO2 sequestration should be constructed and completed in a way that prevents leaks of CO2 and other fluids. Construction and completion requirements, including well control requirement, casing and cementing quality and emplacement requirements, zonal isolation requirements, and testing requirements, should prevent the movement of fluids into or between unauthorized zones. Regulations can prevent undue deterioration of the materials of construction by requiring compatibility with the fluids with which the materials may come into contact. The regulations should also provide flexibility by allowing the permitting authority to approve modifications and alternatives that will also provide containment. Any regulations that accommodate the transitioning of wells from alternative uses to geologic sequestration should ensure that such wells were engineered and constructed to fully prevent the movement of fluids into or between any unauthorized zones, require adequate testing prior to operation to ensure they continue to meet performance standards, and remediated if not (40 CFR § 146.86 (a); ISO 27914: 2017; ISO 27916: 2019).

viii. Well operation

CO2 geologic storage projects can operate for many years, and during this long phase, regulations should require operational containment assurance using engineering data, reservoir management, well integrity monitoring, pressure monitoring, and other practices. Regulatory provisions should: ensure that the injection does not initiate new fractures or propagate existing fractures in the confining zone; require maintaining internal and external mechanical integrity except during authorized maintenance; and allow for flexibility, efficiency, and ingenuity in achieving compliance. Recording and monitoring provisions should be adopted to ensure appropriate pressures and integrity are maintained, including alarms and automatic down-hole shut-off systems, where necessary, as well as procedures for rapid response in the case of a shutoff.

ix. Testing and monitoring plan

Ongoing testing and monitoring support the environmental integrity of storage by requiring the operator to regularly verify that the project is operating as permitted without causing leakage or any danger to protected areas. Regulatory provisions should require a testing and monitoring plan that is based on a formal risk assessment and is designed to detect potential unintended migration of CO2 streams or formation fluids into unauthorized formations, the sea (if offshore) or surface (if onshore), or the atmosphere through potential leakage pathways. This monitoring is also used to calibrate the model and to track plume movement during project life to support Post-Injection Site Care and closure. The monitoring efforts may include varying combinations of direct, well-based monitoring (e.g., pressure, temperature, fluid composition measurements) and indirect, geophysical methods (e.g., time lapse seismic, microseismic, electrical, electromagnetic, and gravity surveys). Risk-based monitoring should be dynamic, flexible and conducted with varying spatial density based on real assessed risk relating to the probability of unwanted migration and the consequence of that potential migration. Furthermore, the risk-based monitoring network should be adaptive as the monitoring needs change with time during project progression, recognizing that monitoring needs can be dramatically different during different phases of a GS project. Project operators should be required to include details in a testing and monitoring plan that describe how the project operator will meet the requirements and how monitoring of potential leakage pathways will be used for history matching and improved modeling. The permitting staff should be equipped with tools and knowledge necessary to independently review and approve the plan (40 CFR § 146.90; ISO 27914: 2017; ISO 27916: 2019; EU Directive 2009/31/EC).

x. Emergency and remedial response plan

Emergencies can occur with any industrial activity, and planning ahead can help mitigate environmental, public health and safety and reputational damage resulting from such incidents. Project operators should be required to develop, update, and comply with a risk-based emergency and remedial response plan that provides a framework to support operational project decisions in response to deviations in project conformance or monitoring network observations of leakage (40 CFR § 146.94; ISO 27914: 2017; ISO 27916: 201; Environmental Defense Fund 2020).

xi. Post-injection site care (PISC)

The PISC is the period that begins when injection ceases and ends when closure is complete. During this period, the CO2 plume will continue to evolve and migrate and must be monitored along with diffusion of formation pressure to ensure ongoing environmental integrity of the project. Post-injection monitoring requirements should help determine that the CO2 plume is currently within and will stay within the target reservoir and behave as predicted. Monitoring should be designed to gain a comprehensive understanding of the site and project and to conduct conformance assessments and history matching. Conformance assessment should (1) evaluate the subsurface geologic storage system as measured by the agreement between model forecasts of the system and measurements of static and dynamic field data, and (2) determine the ability of the system to contain CO2 while remaining within acceptable, projected risk thresholds. During operation and PISC, conformance assessment and modeling, with any necessary adjustments, can be used to revise the project parameters as well as the PISC timeframe (40 CFR § 146.93(a); ISO 27914: 2017; ISO 27916: 2019; EU Directive 2009/31/EC).

xii. Injection well plugging

Injection well plugging is essential to prevent fluid migration. Prior to the approval of site closure, wells should be required to be plugged in accordance with regulation and an updated and approved plugging plan that meets regulatory requirements based on industry standards and will prevent fluid movement into or between unauthorized zones through the well or along the outside of the well (40 CFR § 146.92; ISO 27914: 2017; ISO 27916: 2019).

xiii. Site closure

Require approval for site closure following the PISC period based on a showing that a storage operator meets robust criteria (i.e. the absence of detectable leakage or open conduits to the surface; the wells do not permit fluid migration out of the storage complex; there is compliance with all well decommissioning and plugging requirements; facilities and ancillary equipment associated with the project have been removed unless approved to be retained for alternative uses; and any risks and uncertainties associated with CO2 sequestration were managed during the life of the project) and provides modeling based on monitoring data that adequately demonstrates long-term containment of the CO_2 plume and risk-based assurance against migration drinking water aquifers, to a point of release onto the surface or into the sea or atmosphere. Closure authorizations should relieve operators of ongoing, routine monitoring duties and should trigger a release of financial assurance instruments designed to cover only the operational and PISC periods. However, closure authorizations should not relieve an operator of responsibility for leaks or other harms later determined to be caused by an operator's failure to adhere to applicable regulatory requirements in place at the time or approved plans regarding construction, operation, or closure of the project. See also the section below on adequately liability regimes for additional considerations related to operator liability. (40 CFR § 146.93(b)(2); ISO 27914: 2017; ISO 27916: 2019; EU Directive 2009/31/EC, Texas 81(R) HB 1796 § 382.508(a) (2009).

xiv. Financial assurance

A combination of financial tests and instruments should be required for all phases of a project's life, through closure, sufficient to cover the updated estimated costs of emergency and remedial response, corrective action, injection well plugging, and post-injection site care and through closure (40 CFR § 146.85(a) and (b); EU Directive 2009/31/EC).

xv. Safety and environmental protection

CO2 sequestration regulatory programs should endeavor to ensure broad safety and protection of public health, protected natural resource areas and sensitive ecosystem receptors. For example, in the offshore environment, storage operations must be conducted in a safe manner designed to protect against harm or damage to life (including fish and other aquatic life), property, natural resources (including any mineral deposits both in areas leased and not leased), national security or defense, or the marine, coastal, or human environment. This includes potential harms resulting indirectly from CO_2 injection, such as the migration of subsurface brine to the sea floor if it leads to deleterious changes in water chemistry (30 CFR § 250.400).

xvi. Induced seismicity

CO2 sequestration regulatory programs should guard against significant induced seismicity. Regulations should require operators to evaluate potential sites for induced seismicity potential (e.g. understanding baseline stress and pressure conditions; identification of individual faults of fault zones; characterization of basement rock when injection occurs in proximity to the basement). A seismicity monitoring system should be deployed and maintained in order to detect the presence or absence, magnitude, and hypocenter of induced seismicity in the vicinity of the storage complex at or above a magnitude specified by the regulator. Such seismic monitoring may be conducted with a surface array, subsurface array, satellite telemetry, or a combination, depending on the site characteristics, and calibrated appropriately (it may be possible for the monitoring to be temporary rather than permanent). Based on the monitoring data a risk analysis should be performed to determine whether the project is creating a significantly elevated risk of induced seismicity of a magnitude that the regulator finds unacceptable. If the analysis determines there is such an elevated risk, mitigation should be required. The regulator may consider additional requirements for particularly large projects or where multiple projects occur in proximity (e.g. at storage hubs) (California Air Resources Board 2018 C.4.3.2.3.(a); Ground Water Protection Council and Interstate Oil and Gas Compact Commission 2021).

Additional observations

In addition to the sixteen principles outlined above, three additional observations merit discussion.

Permanence

For CCS to have meaningful climate impact, geological sequestration of CO2 must be essentially permanent. The IPCC special report on CCS (2005) says that with proper site selection and characterization, it is likely that 99% of the CO2 will remain sequestered for at least 1000 years (Working Group III of the Intergovernmental Panel on Climate Change (UNEP) 2005). The IPCC Sixth Assessment Report (Working Group III) goes on to say that "[i]f the geological storage site is appropriately selected and managed, it is estimated that the CO2 can be permanently isolated from the atmosphere" (Working Group III of the Intergovernmental Panel on Climate Change (UNEP) 2022). This is an important finding, and the threshold for considering CCS as a viable climate solution. While permanence is fundamental, a definition of permanence does not necessarily have to be expressed in terms of a number of years. Instead, permanence should be defined as a condition where the CO2 plume has become predictable and reliably contained in line with modeled results. Depending on the site and the circumstances, such a state could be reached in a matter of a few years after injection is complete, or in an extreme case could take hundreds of years. (Working Group III of the Intergovernmental Panel on Climate Change (UNEP) 2005). In any case, permanence should not be defined as a set number of years, as some subnational jurisdictions in the U.S. have done – in particular, 100 years does not constitute permanence in and of itself (California Air Resources Board 2018).

Geology

Several types of geology have been proposed for CO2 sequestration, primarily saline formations and depleted oil and gas fields, but also basalt formations. Saline formations are generally less well characterized than depleted oil and gas fields, but also tend to have fewer penetrations (i.e. old oil and gas wells) that could act as fluid conduits and allow CO2 migration into groundwater or to the atmosphere (Working Group III of the Intergovernmental Panel on Climate Change (UNEP) 2005). Basalt formations have received attention recently,

though the science around secure geologic sequestration in these formations is not mature, and more research is needed "on potential contamination of nearby aquifers, and on the time evolution of the carbonate-forming reaction front, to get feedback about reaction rates, the three-dimensional distribution of reaction products, and permeability evolution" (Kelemen 2019). As emphasized in the sixteen technical principles, site selection is perhaps the most significant factor in ensuring secure geologic storage of CO2, and not every formation will be appropriate for storage.

CO2-EOR

As acknowledged in the introduction, the majority of CO2 sequestration to date has occurred as part of CO2-EOR projects (National Petroleum Council 2019). While it is true that large volumes of CO2 can be stored this way, they are offset to varying degrees by the emissions associated with the production, refining and use of the resulting oil. Furthermore, generally, regulations pertaining to CO2-EOR usually do not require demonstration of secure geological storage of the CO2 used in the operation, especially with respect to modeling, monitoring, and ensuring a confining zone capable of arresting CO2 migration. A prime example of this is the U.S. EPA's Class II regulations governing CO2-EOR, which, unlike Class VI, do not require demonstration of secure storage of CO2 (See, e.g. Congressional Research Service 2020). Any claims of CO2 sequestration for compliance or credit purposes, including from CO2-EOR, should be verified against regulations designed to assess and ensure the long-term sequestration of injected CO2 – such as those that encompass the sixteen principles outlined in the prior section.

Legal and regulatory recommendations

The topics outlined above constitute the key technical considerations and observations for CO2 sequestration project operators. As a threshold matter, national and subnational regulatory programs overseeing CO2 sequestration should address each of the issues identified in this paper. As an example, the U.S. EPA's Class VI regulations, which govern CO2 sequestration in saline formations, cover all of these topics except for marine life protection (because Class VI is only for onshore wells), atmospheric leakage, and induced seismicity (beyond prohibiting siting in "seismically active" locations) (See, e.g., Dhanesha 2022; Carpenter 2021; Chapa & Wethe 2022; Hampton 2022; Gonzales 2022; Walsh & Zoback 2015; Kuchment 2019; Chang, K. & Yoon, H. 2022; California Air Resources Board 2018). The EU directive on CCS, as well as the ISO standards for saline storage and CO2EOR also generally address these topics. Regulatory regimes that do not currently address these topics should be reformed to do so.

Beyond the regulations, there are three additional governance factors essential to ensure the environmental integrity of CO2 sequestration: 1) sufficiently trained and funded oversight; 2) robust transparency and reporting; and 3) maintaining appropriate incentives for quality work through adequate liability regimes.

<u>Sufficiently trained and funded oversight</u>

Getting the rules right is a necessary but not sufficient precondition for CO2 sequestration with environmental integrity. How those rules are implemented is just as, and possibly even more important. This means having a trained regulatory staff for permitting, inspections, model assessment, site closure, and any other functions related to CO2 sequestration project for its lifetime.

In the United States, regulation of Class VI wells will often fall to oil and gas agencies in the states that receive primacy from the EPA. Whether it falls to an oil and gas agency or an environmental agency, these regulators will need to be trained in topics that are specific to CO2 sequestration, which is more complex and technically different than oil and gas production, and typically involves longer time frames, greater pressure implications in the geology, and more complex modeling than these regulators are used to overseeing. In addition to training programs sponsored by the U.S. EPA, efforts are underway to develop a comprehensive training program for U.S. CO2 sequestration regulators covering the following topics:

i. Review of permit-relevant properties and characteristics of CO2
ii. Assessing the sufficiency of storage site characterization data and model inputs
iii. Evaluating fluid flow modeling and assessing proposed area of review
iv. Understanding and reviewing site-specific risk analyses
v. Assessing, reviewing, and enhancing monitoring plans
vi. Evaluating monitoring and model results toward assessing long-term secure storage
vii. Preparing for contingencies with corrective action and remediation plans
viii. Closure and post-injection site care considerations
ix. Comparison of storage in EOR, depleted fields and saline formations
x. Understanding of financial assurance issues for geologic storage

This list of topics was developed by a consortium of geologists, engineers, regulators and academics, and is designed to form the basis of a curriculum of study (Ground Water Protection Council 2022). It is essential that the overseers of CO2 sequestration projects are familiar with all of these topics in order to be able to critically assess what they are being shown by projector operators and to ensure that CO2 sequestration oversight is not merely a "check the box" operation.

Just as important as training, the regulatory program needs to be adequately funded to ensure timely and high-quality permitting and regulatory oversight (Infrastructure Investment and Jobs Act, 2021). In the United States, it is estimated that a single Class VI permit will take 1500 person-hours just to process (U.S. state and federal regulators, 2022; Groundwater Protection Council 2021). Inadequately funded regulators will either slow down the progress of CO2 sequestration, or more ominously, could lead to less rigorous evaluation of permits and operating sites. This is not an industry where corner-cutting is acceptable, because of the environmental and climate risks posed by poorly regulated sites, and the need to maintain the technology's social license to operate.

Transparency and reporting

Public trust in CO2 sequestration is currently low (See, e.g., Batres et al 2021; Sokol et al. 2021; Center for International Environmental Law 2021, Environmental Justice Leadership Forum on Climate Change; The Climate Center 2022; Costley, D., U.S. News 2022; Food and Water Watch 2020; Morris, J., Forbes 2021). This is due in part to the relative novelty of CO2 sequestration at the scale envisioned. But it may also be due to an historic lack of trust in the oil and gas industry, which is, for the near future, one of the principal industries that will be pursuing CO2 geologic storage projects. In order to rebuild trust and demonstrate that CO2 sequestration is a viable climate mitigation strategy, any framework for CO2 storage must ensure public accountability for both permits and claims tied to geologic storage of carbon dioxide.

A key element of transparency is for project operators to provide accurate and verifiable data on how much CO2 has been sequestered on a net basis along with documentation, preferably third-party verified, of the quantification of those stored volumes, generally through a regulatory accounting schema like the U.S.'s Greenhouse Gas Reporting Program's Subpart RR or proposed Subpart VV (U.S. Environmental Protection Agency Subpart RR; U.S. Environmental Protection Agency 2022; Congressional Research Service 2021). Merely accounting for CO2 volumes received at a site – rather than quantifying and demonstrating the long-term secure storage of those volumes – is insufficient for projects claiming to permanently sequester CO2 (U.S. Environmental Protection Agency 2010). This is especially critical where financial incentives like the U.S. federal 45Q tax credit, California's Low Carbon Fuel Standard, or upcoming voluntary carbon credit standards for CO2 sequestration, are directly tied to the amount of verifiable CO2 permanently stored in the geology (Congressional Research Service 2021; see generally: California Air Resources Board, Verra).

Recently, the US EPA proposed amendments to its Greenhouse Gas Reporting Program designed to explicitly plug a transparency and reporting gap left by the U.S. Treasury's approval of the ISO 27916 standard for CO2EOR operators as an approved alternative method to Subpart RR for the demonstration of secure storage necessary to obtain the federal 45Q tax credit (U.S. Environmental Protection Agency 2022; U.S. Department of the

Treasury 2021). The new subpart incorporates ISO's extensive provisions for quantification and containment assurance (see generally, Christensen, J. & Wade, S. 2019).

In addition to trustworthy CO2 storage data being made available regularly to the public, it is also essential that the public have opportunity for input during various phases of project development, but particularly on completed applications and proposed permits. The public intuitively does not trust what it does not have input on. And public comments can serve to improve project quality by providing key information about particular locations (e.g., a local landowner having particular knowledge about orphan wells in a project location that could cause fluid migration), and merely by subjecting a project proposal to scrutiny from unsympathetic stakeholders. Further, there may be cases where a CO2 geologic sequestration project should not proceed in a particular location, perhaps because of adverse impacts on overburdened communities, and it is in public commenting where such situations may be surfaced and managed. It should be noted that while public comment is essential, it is not a substitute for a thorough and substantive accounting of environmental justice implications of projects and mitigation to ensure no disproportionate burden – though this topic is generally outside the scope of this paper.

Adequate liability regimes

In order to ensure CO2 sequestration with environmental integrity, it is essential to hold operators accountable for damages when they fail to live up to their responsibilities (See Anderson, S. 2022). Generally, within the oil and gas industry and in most contexts, operators are held liable for damages caused by their actions (or failures to act) (43 CFR 3162.7 1(d)). In the case of CO2 sequestration, some have argued for, and some U.S. states have legislated, removing long-term liability from operators after project completion, with either the government taking on the liability, or by eliminating liability altogether (LA Rev Stat § 30:1109; W.S. 35-11-319 et seq.; NDCC 38-22-17).

This trend gravely threatens the environmental integrity of CO2 sequestration for two primary reasons.

First, liability exemption creates a moral hazard where operators are perversely incentivized, e.g., to conduct poor quality work and to make false claims about a project's status. It is essential for there to be financial consequences for failure to abide by regulation and best practices. Such consequences are why we trust the skyscrapers we live and work in, the bridges we drive over, and the airplanes we fly in.

Second, liability exemption sends a decidedly mixed message to an already skeptical public about the long-term safety of CO2 sequestration operations. When the public is told by operators and governments that CO2 sequestration is safe and well-understood and not cause for alarm, but at the same time operators insist that they cannot and will not proceed with CO2 sequestration projects in the absence of liability exemption, it leads the public to wonder what these operators are worried about, and it makes the public worried as well – threatening CO2 sequestration's social license to operate.

Sophisticated operators and insurers know that with a properly selected and managed site, the risk of long-term harms, and the economic damage associated with such possible harms, are actually quite minimal (Global CCS Institute 2019). To the extent there are lingering risks posed by projects after the Post-Injection Site Care period has ended and the operator has received an equivalent of a closure certificate, such risks can in fact be managed by private insurance markets, as in other industries, with better operators presumably paying lower premiums. But blanket liability exemption encourages shoddy operators to enter the market, with potentially dire consequences for the climate, environment, and the industry as a whole.

While exemption from long-term liability for CCS projects operators is both unnecessary and bad public policy, there may be value in the creation of long-term stewardship programs where the state takes on responsibility for long-term monitoring and basic maintenance (e.g. NDCC 33-22-15(2); NDCC 33-22-17(6)). Such programs can be funded by an injection fee or through other means and would be helpful especially in cases where the operator goes bankrupt or otherwise ceases to exist. Overall, for good sites that are properly managed, the burden of long-term monitoring and maintenance is likely to be fairly minimal.

Should a jurisdiction nevertheless pursue liability exemptions, in order to avoid moral hazard, exclusions from such liability exemptions should include the following as a minimum: situations where owner or operator provided deficient (EU Directive) or erroneous (EPA Class VI Preamble 2010, 75 FR 77272) information to support approval of site closure; situations where a geologic trust fund or similar account contains inadequate funds to address any duty, obligation, or liability that may arise after a certificate of completion or similar closure authorization (LA Rev Stat § 30:1109); situations where there is fluid migration that causes or threatens imminent and substantial endangerment to protected groundwater (EPA Class VI Preamble 2010, 75 FR 77272); intentional torts (EPA Class VI Preamble 2010, 75 FR 77272); gross negligence (EU Directive); willful deceit or willful concealment of relevant information (EU Directive); and criminal offenses.

Conclusion

Ensuring the environmental integrity of CO2 geologic sequestration projects is essential for CCS to reach its climate potential, and for the industry's social license to operate. This paper has delineated sixteen core technical site-level principles that must be followed to achieve environmental integrity, along with additional supporting technical and governance considerations including sufficient oversight and training for regulators, transparency and reporting in permitting and throughout the life of a project, and adequate liability regimes that are designed to incentivize quality projects. While the scope of this paper was limited to secure geologic storage of CO2, other issues pertaining to the entire project lifecycle including CO2 capture and transport, e.g. air quality, pipeline safety, environmental justice, and energy use considerations deserve significant attention in subsequent analyses.

Environmental integrity of CO2 geologic sequestration is achievable through adequate planning and reasonable precautions, but precautions but will require strong and continuous oversight from qualified regulatory authorities and universal compliance by project operators.

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- 40 CFR § 146.84, generally;
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- Art. 9.9,
- Art. 13, Annex II;
- Art. 17;
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- Sec. (A)(2) (…release from liability will not apply to the owner or last operator of record of a storage facility if the Carbon Dioxide Geologic Storage Trust Fund has been depleted of funds such that it contains inadequate funds to address or remediate any duty, obligation, or liability that may arise after issuance of the certificate of completion of injection operations.)

- Upon the issuance of the certificate of completion of injection operations, the storage operator, all generators of any injected carbon dioxide, all owners of carbon dioxide stored in the storage facility, and all owners otherwise having any interest in the storage facility, shall be released from any and all duties or obligations under this Chapter and any and all liability associated with or related to that storage facility which arises after the issuance of the certificate of completion of injection operations.

NDCC 38-22, available at https://www.ndlegis.gov/cencode/t38c22.pdf#nameddest=38-22-17.

- NDCC 33-22-15(2)
- 33-22-17(6). Once a certificate is issued: Title to the storage facility and to the stored carbon dioxide transfers, without payment of any compensation, to the state... c) the storage operator and all persons who generated any injected carbon dioxide are release from all regulatory requirements associated with the storage facility

W.S. 35-11-319 et seq, available at https://www.wyoleg.gov/Legislation/2022/SF0047.

- Upon the issuance of a certificate of project completion under subsection (a) of this section: In exchange for assuming responsibility and liability for the stored carbon dioxide as provided in this section, title to the stored or injected carbon dioxide, and any facilities used to inject or store the carbon dioxide, without payment of any compensation, shall be transferred to the state.