REGULATION OF CARBON CAPTURE AND STORAGE: AN ANALYSIS THROUGH THE LENS OF THE WELLINGTON PROJECT

BY

CHARLES C. STEINCAMP,* TIRAZ R. BIRDIE,** DIANA STANLEY,*** EUGENE HOLUBNYAK,**** JENNIFER RANEY,***** & W. LYNN WATNEY*******

Carbon capture, sequestration, and storage (CCUS) is a key transition technology for achieving carbon neutrality by 2050. CCUS works by injecting anthropogenic carbon dioxide into underground formations for long term storage. For years, scientists and legal scholars have wrestled over how to best regulate these projects in order to protect human health and natural resources such as drinking water supplies. In 2013, EPA responded to these concerns by creating a new type of injection well permit: the Class VI Rule. Unfortunately, almost a decade later, few developers have built CCUS projects due to regulatory uncertainty. This Article aims to fill the gap in the legal literature by explaining the regulatory structure

*Managing Partner, Depew, Gillen, Rathbun & McInteer, LC. J.D. 1993, Washburn School of Law; chris@depewgillen.com.

**TBirdie Consulting, Inc., Lawrence, KS. Ph.D. Mechanical Engineering 1998, University of Kansas; tbirdie@tbirdieconsulting.com.

***Associate Attorney, Depew, Gillen, Rathbun & McInteer, LC. J.D. 2020, University of Kansas School of Law.

****Research Associate Petroleum Engineer, Kansas Geological Survey. Ph.D. Candidate Applied Geoscience 2021, Heriot Watt University; Eugene@kgs.ku.edu.

*****CO2 Programs Manager, Kansas Geological Survey. M.S. Environmental Science 2012, University of Kansas.

******Posthumous. Senior Scientific Fellow, Kansas Geological Survey. Ph.D. Geology 1985, University of Kansas.

*This work was supported by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) under Grant DE-FE0006821. This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

behind CCUS project permitting and by providing recommendations for expediting the permitting process for prospective researchers and investors.

I. INTRODUCTION 1151
II. BACKGROUND 1153
III. THE CLASS VI PERMIT AND PERMITTING PROCESS 1157
- *A. Beginning the Project* 1160
  - *1. Attachment B—Area of Review and Corrective Action Plan* 1160
    - *a. Regulatory Framework* 1160
    - *b. Class VI AoR Requirements* 1161
    - *c. Site-Wide Geology and Hydrogeology* 1164
    - *d. Modeling* 1168
    - *e. Corrective Action Plan* 1173
    - *f. AoR Reevaluation* 1175
    - *g. Specific Implementations at the Wellington Site* 1175
      - *i. USDW Determination* 1175
      - *ii. Extrapolating the Hydrogeologic Properties at Well Sites* 1177
  - *2. Attachment G—Construction Details* 1177
    - *a. Regulatory Framework* 1177
    - *b. Class VI Requirements* 1179
    - *c. Wellington Project* 1179
  - *3. Attachment I—Stimulation Program* 1180
    - *a. Regulatory Framework* 1180
    - *b. Class VI Permit* 1181
    - *c. Wellington Project* 1182
- *B. During the Life of the Project* 1182
  - *1. Attachment A – Summary of Operating and Reporting Requirements* 1183
    - *a. Class VI Rules* 1183
    - *b. Wellington Project* 1184
  - *2. Attachment C – Testing and Monitoring Plan* 1185
  - *3. Attachment F – Emergency and Remedial Response Plan* 1197
    - *a. Regulatory Background* 1197
    - *b. Class VI Rule* 1198
      - *i. Scenario I: Well Integrity Failure* 1199
      - *ii. Scenario II: Equipment Failure* 1199
      - *iii. Scenario III: Water-Quality Changes, USDW Endangerment, Migration of CO_2 Out of the Injection Zone, or Release of CO_2 to the Surface* 1200
      - *iv. Scenario IV: Natural Disaster* 1201

v. Scenario V: Induced Seismicity Event 1201
C. Plugging and Post Closure Care 1203
1. Attachment D – Injection Well Plugging Plan 1203
a. Regulatory Framework 1203
b. Class VI 1204
2. Attachment E – Post-Injection Site Care and Site Closure Plan 1205
a. Regulatory Background 1205
b. Class VI Rule 1206
c. Wellington Permit 1209
3. Attachment H - Financial Assurance Demonstration .. 1211
a. Regulatory Background 1211
b. Class VI Rule 1215
c. Wellington Project 1219
IV. CONCLUSION 1219

I. INTRODUCTION

In 1556, a German scientist named Georgius Agricola published one of the world's first treatises on mining: *De Re Metallica*.[1] For the first time, the collective knowledge of European geologists and surveyors was compiled into a usable format for scholars and prospective businessmen.[2] Agricola begins his medieval "how to" manual, however, with an explanation that to be successful in business, a miner must know many disciplines such as medicine, philosophy, mathematics, and architecture.[3] "Lastly, [a miner should be familiar with] the Law, especially that dealing with metals, that he may claim his own rights, that he may undertake the duty of giving others his opinion on legal matters . . . and that he may fulfil his obligations to others according to the law."[4]

Little did Agricola know, but the field he helped create would one day experiment with injecting materials back into the earth. One such

[1] GEORGIUS AGRICOLA, DE RE METALLICA vi (Herbert Clark Hoover & Lou Hentry Hoover trans., 1950), https://perma.cc/569F-N738.

[2] Lutz W. Weber, *Georgius Agricola (1494–1555): Scholar, Physician, Scientist, Entrepreneur, Diplomat,* 69 TOXICOLOGICAL SCI. 292, 293 (2002) ("Agricola's works on mining and related sciences were not the only ones available in his time. However, all other works were steeped in the ideas of alchemists . . . In his 1546 published work on mineralogy, he set initial standards for the science of the future. . . . He brought forth an achievement that was beyond anything contemporary and it remained the miner's handbook for almost 200 years.").

[3] AGRICOLA, *supra* note 1, at 3–4.

[4] *Id.* at 4. This conduct of "giving others his opinions on legal matters" would likely now constitute the unauthorized practice of law. *See Practice of Law*, BLACK'S LAW DICTIONARY (11th ed. 2019) ("Unauthorized practice of law . . . The practice of law by a person, typically a nonlawyer, who has not been licensed or admitted to practice law in a given jurisdiction.").

material is carbon dioxide through a process called carbon capture, utilization, and storage (CCUS or carbon capture).[5] CCUS works by injecting large amounts of pressurized carbon dioxide into underground formations such as depleted oil fields for long term storage.[6] Heralded "as a critical component to meeting internationally established goals related to climate change,"[7] proponents see CCUS as a way to reduce the environmental impact of producers such as coal electrical plants or refineries.[8]

Across the country, a concerted group of lawyers, scientists, and businessmen are working to make carbon capture a reality. Unfortunately, the permitting process for CCUS is new and difficult to navigate. In addition, the legal ramifications of the United States Environmental Protection Agency's (EPA's) permitting regulations have not been thoroughly explored.[9] As a result, burgeoning projects struggle to get off the ground as they run into red-tape and uncertainty.[10] The problem is so acute that Congress created a task force for improving the permitting process as part of its December 2020 Consolidated Appropriations Act.[11] This Article aims to fill the gap in the legal literature by explaining the regulatory structure behind CCUS project permitting, by documenting the key features of the Class VI permit, and by providing guidelines for expediting the permitting process based on lessons learned from the Wellington project.

Part II describes the history of carbon capture regulation and discusses how the current regulatory framework reflects its historical treatment as a tertiary process for oil and gas recovery. Turning to the Class VI application, Part III follows EPA's requirements for the beginning of the project, through its operational phase, and the site's ultimate closure and post-closure care. Finally, Part IV gives parting

---

5 *Carbon Capture, Utilization, and Storage*, U.S. DEP'T ENERGY, https://perma.cc/2Z78-V7UY (last visited Sept. 26, 2021).

6 *Id.*

7 Tara K. Righetti, *Correlative Rights and Limited Common Property in the Pore Space: A Response to the Challenge of Subsurface Trespass in Carbon Capture and Sequestration*, 47 ENV'T L. REP. 10,420, 10,422 (2017).

8 Russell W. Murdock, *The State of CO_2 Sequestration in the State of Texas*, 41 TEX. ENV'T L. J. 65, 65 (2010); Edward Hirsch & Thomas Foust, *Policies and Programs Available in the United States in Support of Carbon Capture and Utilization*, 41 ENERGY L. J. 91, 92, 95 (2020); Chaz Coleman, Comment, *A Policy Analysis of the Driving Factors Behind Carbon Capture and Storage Facilities*, 6 LSU J. OF ENERGY L. & RES. 557, 557, 580 (2018).

9 *See* 40 C.F.R. §§ 146.81–146.95 (2020) (establishing permitting requirements for underground injection of carbon dioxide through wells for geologic sequestration); GEOLOGIC SEQUESTRATION OF CARBON: UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL SITE CHARACTERIZATION GUIDANCE i (2013) [hereinafter UIC CHARACTERIZATION GUIDANCE].

10 Wendy B. Jacobs & Michael Craig, *Legal Pathways to Widespread Carbon Capture and Sequestration*, 47 ENV'T L. REP. 11,022, 11,034, 11,036 (2017).

11 Consolidated Appropriations Act, 2021, H.R. 133, 116th Cong. Div. S § 969(d)(2)(D) (2021). Congress earmarked $50,000,000 of the December COVID stimulus bill toward carbon capture research and projects along with extending the 45Q(d)(1) tax credit for CCUS projects to January, 1, 2026. *Id.* Div. S § 969(e), Div. EE § 121.

thoughts on the Class VI application process and potential areas of reform.

II. BACKGROUND

Despite great enthusiasm,[12] few major CCUS projects have been built in the United States.[13] In the oil and gas context, however, operators have used carbon dioxide in enhanced oil recovery operations for decades.[14] To explain how this works, we can point to the second-oldest carbon dioxide (CO_2) operation—the SACROC unit.[15] Standard Oil "formed the SACROC unit" in 1948.[16] The reservoir contained significant amounts of oil, but the pressure in the reservoir—what makes oil flow into the wellhead—dropped after only a few years.[17]

After a reservoir experiences a pressure drop, the next step in oil production is "secondary recovery."[18] In this step, operators inject large amounts of water into the reservoir to increase pressure.[19] In time, this pressure mechanism also lost its efficacy for the SACROC Unit, leaving large amounts of oil to be recovered.[20] In the early 1970s, the operator decided to inject a CO_2-water based solution.[21] This method was successful and the reservoir began producing again at a higher rate.[22]

One of the unintended consequences of the injection was that about half of the CO_2 stabilized and stayed sequestered in the ground.[23] This

---

[12] *See generally* Righetti, *supra* note 7 (noting that carbon capture is crucial to meeting climate change goals); Shannon Zaret, *Can the Expansion of 45Q Effectively Spur Investment in Carbon Capture?*, SUSTAINABLE DEV. L. & POL'Y, Spring 2019 at 14, 15 (anticipating that a tax credit program will create the financial security needed for billions in private investment in carbon capture technology deployment if successfully implemented).

[13] *See* Deepika Nagabhushan, *Interactive Map of CCUS Projects in Development in the U.S.*, CLEAN AIR TASK FORCE (July 27, 2020), https://perma.cc/6RZ5-5V47 (providing an interactive map of projects in early-stage development).

[14] Phillip M. Marston & Patricia A. Moore, *From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 ENERGY L. J. 421, 423 (2008) ("While interest in CCS is relatively new, the underground injection and effective storage of large quantities of CO_2 is not . . . the United States' oil and gas industry has been transporting CO_2 by pipeline for injection as a tertiary, or enhanced oil recovery (EOR) technique, for nearly forty years.").

[15] Maung Phyoe Wai Aung, Analysis on EOR/CO_2 Sequestration in SACROC Unit, Texas Using a Compositional Simulator 17 (Aug. 2009) (unpublished masters thesis, New Mexico Institute of Mining and Technology).

[16] *Id.* at 19.

[17] *Id.* at 20.

[18] *See id.* (secondary recovery aims to extract remaining original oil in place left after primary recovery).

[19] *Id.*

[20] *Id.*

[21] *Id.* at 21–22.

[22] *See id.* at 22 (Phase II and Phase III areas each saw an increase of 40,000 bbl/d in oil production).

[23] K.D. Romanak et al., *SACROC Research Project*, BUR. OF ECON. GEOLOGY, https://perma.cc/8CRL-N2X8 (last visited Sept. 26, 2021) ("Since 1972, over 175 million metric tons of carbon dioxide (CO_2) have been injected into the SACROC oil field . . . About half of the

happy accident tipped off a world of possibilities. Oil and gas proponents saw it as a lifeline to extend field production.[24] Environmentalists looked to the future of pure sequestration projects.[25]

The history behind the development of CCUS is reflected in the regulatory framework that grew up around it. Oil and gas production tends to produce large amounts of salt water.[26] From the 1860s to the 1930s, brine was usually put in storage ponds or discharged into surface water.[27] In the 1930s and 1940s, operators discovered a method to inject the saltwater back into the ground.[28] These early operators did not always understand how the underground reservoir systems worked and accidentally contaminated aquifers.[29] This, along with high profile incidents involving industrial waste injection, led to comprehensive regulation of underground injections.[30]

Regulators draw their authority for injection programs from the Safe Drinking Water Act.[31] As such, rules surrounding injection wells revolve around protecting water sources.[32] Like the other major environmental statutes, there is a blanket prohibition on injecting fluids into formations:

> No owner or operator shall construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation

CO_2 has been co-produced with oil and recycled . . . The remaining volume is assumed to be sequestered at 6,000 to 7,000 ft below surface.").

24 *See Enhanced Oil Recovery*, OFF. OF FOSSIL ENERGY AND CARBON MGMT., https://perma.cc/UY6W-Z47C (last visited Sept. 26, 2021) ("Secondary recovery techniques extend a field's productive life . . . resulting in the recovery of 20 to 40 percent of the original oil in place.").

25 *See Class VI - Wells Used for Geologic Sequestration of CO_2*, U.S. ENV'T PROT. AGENCY, https://perma.cc/5TAZ-K3SW (last visited Sept. 26, 2021) (explaining that Class VI wells inject carbon dioxide into deep rock formations for the purposes of sequestering carbon from the atmosphere to mitigate climate change).

26 Stephan Owings, *One Man's Trash Is His Community's Treasure: Ownership and Uses of Produced Brine*, 4 OIL & GAS, NAT. RES. & ENERGY J. 35, 36 (2018).

27 Take for example, the Burrton saltwater plume in Kansas. When oil was discovered at the Burrton Oil Field in the 1930s, operators disposed of brine in evaporation pits which seeped into the underlying groundwater. *Burrton Oil Field Brine Encroachment*, KAN. CORP. COMM'N, https://perma.cc/B6QV-QSPK (last visited Sept. 26, 2021); DONALD O. WHITTEMORE, KAN. DEP'T OF AGRIC., DISTRIBUTION AND CHANGE IN SALINITY IN THE EQUUS BEDS AQUIFER IN THE BURRTON INTENSIVE GROUNDWATER USE CONTROL AREA 1 (2012)..

28 DON L. WARNER & JAY H. LEHR, EPA-600/2-77-240, AN INTRODUCTION TO THE TECHNOLOGY OF SUBSURFACE WASTEWATER INJECTION 2, U.S. ENV'T PROT. AGENCY (1977).

29 KAN. DEP'T HEALTH AND ENV'T, UNDERGROUND INJECTION CONTROL PROGRAM QUALITY ASSURANCE MANAGEMENT PLAN 1 (2020).

30 *Id.*; U.S. ENV'T PROT. AGENCY, ANALYSIS OF THE EFFECTS OF EPA RESTRICTIONS ON THE DEEP INJECTION OF HAZARDOUS WASTE 8–9 (1991) (discussing rare instances of contamination of underground sources of drinking water by Class I injection wells).

31 Safe Drinking Water Act of 1974, 42 U.S.C. §§ 300h–h-8 (2018).

32 *See* 40 C.F.R. § 144 (2020) (containing numerous provisions designed to protect underground sources of drinking water).

> of any primary drinking water regulation under 40 CFR part 142 or may otherwise adversely affect the health of persons.[33]

EPA then created a series of well "classes" for which operators could seek permits.[34] For example, Class I wells are used for industrial waste such as pharmaceutical production and the short-lived Class IV wells were for radioactive fluids.[35] Wells for oil and gas fluids, such as brine and enhanced oil recovery CO_2, are classified as Class II.[36] The Safe Drinking Water Act gave states the option to take over primary permitting authority for wells under sections 1422 and 1425 of the Act.[37] Most states—including Kansas—did so for Class II wells.[38]

This brings us back to carbon dioxide and storage. For decades, injecting CO_2 as part of enhanced oil recovery was treated solely as a Class II problem.[39] That makes sense because operators inject limited

---

33 *Id.* § 144.12.

34 *Underground Injection Control Regulations and Safe Drinking Water Act Provisions*, U.S. ENV'T PROT. AGENCY, https://perma.cc/K9YQ-UG37 (last visited Sept. 26, 2021).

35 *Class I Industrial and Municipal Waste Disposal Wells*, U.S. ENV'T PROT. AGENCY, https://perma.cc/ALN9-JHHA (last visited Sept. 26, 2021); *Class IV Shallow Hazardous and Radioactive Injection Wells*, U.S. ENV'T PROTECTION AGENCY, https://perma.cc/5TM9-R5KQ (last visited Sept. 26, 2021).

36 *Class II Oil and Gas Related Injection Wells*, U.S. ENV'T PROT. AGENCY, https://perma.cc/JQA3-P8RE (last visited Sept. 26, 2021).

37 42 U.S.C. §§ 300h-1, 300h-4 (2018). Section 1425 of the Safe Drinking Water Act reads:

> For purposes of the Administrator's approval or disapproval under section 300h-1 of this title of that portion of any State underground injection control program which relates to—
>
> (1) the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or natural gas storage operations, or
>
> (2) any underground injection for the secondary or tertiary recovery of oil or natural gas,
>
> in lieu of the showing required under subparagraph (A) of section 300h-1(b)(1) of this title the State may demonstrate that such portion of the State program meets the requirements of subparagraphs (A) through (D) of section 300h(b)(1) of this title and represents an effective program (including adequate recordkeeping and reporting) to prevent underground injection which endangers drinking water sources.

Id. § 300h-4 ("Approval of State underground injection control program; alternative showing of effectiveness of program by State.").

38 *Primary Enforcement Authority for the Underground Injection Control Program*, U.S. ENV'T PROT. AGENCY, https://perma.cc/JWY6-PRME (last visited Sept. 26, 2021) ("EPA has approved UIC primacy programs for well classes I, II, III, IV, and V in thirty-three states and three territories. Two states have primacy for all well classes (I, II, III, IV, V, and VI). Additionally, there are eight states and two tribes that have primacy for Class II wells only.").

39 *See* ANGELA C. JONES, CONG. RES. SERV., R46192, INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: FEDERAL ROLE AND ISSUES FOR CONGRESS 9 (2020)

amounts of gas, and the underlying purpose of those injections is "secondary or tertiary recovery of oil or natural gas."[40] Projects where geological sequestration is the primary goal of injections do not fit as neatly under Class II. In addition, CO_2 storage presents unique challenges due to the properties of the gas.[41]

To resolve this, EPA created the Class VI permit.[42] In contrast to the energy development-geared Class II permit, the Class VI permit regulates injection of CO_2 and is designed for permanent geologic sequestration.[43] Because of CO_2's buoyancy, the requirements for this class are generally more stringent than for previous classes of injection permits.[44] In particular, the requirements associated with subsurface characterization, injection operations, and plume/pressure monitoring are stricter.[45] As a reflection of that stringency, obtaining the Class VI permit is a multiyear process, requiring a significant investment of time and capital.[46]

In 2013, the U.S. Department of Energy (DOE) sponsored a demonstration project as a test run for EPA's Class VI permitting process.[47] The project's coordinators, which include the authors of this Article, identified a site near Wellington, Kansas.[48] The goal was to inject 26,000 tons of CO_2 into the Cambrian-Ordovician Arbuckle Group, which exists at a depth of 4,000 to 5,000 feet below ground.[49] Unfortunately, the

("Prior to the Class VI rule's effective date in January 2011, injection of CO_2 was permitted under Class II if used for EOR [enhanced oil recovery].").

40 42 U.S.C. § 300h-4 (2018).

41 U.S. ENV'T PROT. AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI IMPLEMENTATION MANUAL FOR UIC PROGRAM DIRECTORS 1-2 (2018) [hereinafter EPA IMPLEMENTATION MANUAL FOR PROGRAM DIRECTORS].

42 40 C.F.R. §§ 146.81–146.95 (2020); *see* UIC CHARACTERIZATION GUIDANCE, *supra* note 9, at ii ("The Class VI Rule establishes a new class of injection well (Class VI) and sets minimum federal technical criteria for Class VI injection wells for the purpose of protecting underground sources of drinking water (USDWs).").

43 40 C.F.R. §§ 146.21, 146.23, 146.81, 146.83 (2020).

44 *See* EPA IMPLEMENTATION MANUAL FOR PROGRAM DIRECTORS, *supra* note 41 ("The Class VI Rule requirements at 40 CFR 146 Subpart H are tailored to the unique nature of carbon dioxide injection for GS, including the large volumes of carbon dioxide injected, the relative buoyancy of carbon dioxide, its mobility within subsurface geologic formations, and its corrosivity in the presence of water to ensure the protection of USDWs.").

45 *Compare* 40 C.F.R. §§ 146.83, 146.88, 146.90 (2020) (setting requirements for Class VI wells) *with id.* §§ 146.22–146.23 (setting parallel requirements for Class II wells).

46 Tiraz Birdie et al., *Wellington Small Scale Carbon Storage Project: Summary of Experience, Conclusions, and Recommendations*, NAT'L ENERGY TECH. LAB'Y, §§ 1.1, 1.6, 2.2, https://perma.cc/YD8S-QYJD (last visited Sept. 26, 2021).

47 *Id.* at §§ 1.1, 1.2; NAT'L ENERGY TECH. LAB'Y U.S. DEP'T ENERGY, U.S. EPA CLASS VI CARBON DIOXIDE INJECTION PERMIT: SALIENT FEATURES AND GUIDELINES 1 [hereinafter CLASS VI PERMIT FEATURES AND GUIDELINES].

48 TIRAZ BIRDIE ET AL., US EPA CLASS VI CO_2 INJECTION PERMIT — REQUIREMENTS AND LESSONS LEARNT FROM THE WELLINGTON, KANSAS, PROJECT, https://perma.cc/N6EB-LA7Q (last visited Sept. 26, 2021).

49 *Id.*

project ran into enough permitting and logistical roadblocks that the project team decided to seek a Class II injection permit.[50]

III. THE CLASS VI PERMIT AND PERMITTING PROCESS

"The Class VI permit consists of . . . nine plans, referred to [by EPA] as attachments:"[51]

A	Summary of Operating and Reporting Requirements
B	Area of Review and Corrective Action Plan
C	Testing and Monitoring Plan
D	Injection Well Plugging Plan
E	Post-Injection Site Care and Site Closure Plan
F	Emergency and Remedial Response Plan
G	Construction Details
H	Financial Assurance Demonstration
I	Stimulation Plan

Confusingly, "[t]he Class VI rule . . . is codified in a 74-page document [that does not refer] to [the] attachments."[52] More generally, the Class VI permit application can be broken down into three stages: 1) the beginning of the project; 2) monitoring during the life of the project; and 3) closure and post-closure care.

To comply with the Class VI permitting requirements, regulators look for four key requirements:

- An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability" and a total dissolved solids (TDS) concentration of greater than 10,000 mg/l.[53]
- A confining zone(s) [above the injection zone] free of transmissive faults [or] fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
- Identification of all underground sources of drinking water (USDW) in which the concentration of TDS is less than 10,000 mg/l to ensure that CO_2 from the injection zone will not migrate into the USDWs.

---

[50] Birdie et al., *supra* note 46, at §§ 1.1, 1.6, 6.0.
[51] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 2.
[52] *Id.*
[53] 40 C.F.R. §§ 146.3, 146.82–146.86 (2020).

- Maintenance of pore pressures in the injection zone at less than 90% of the fracture gradient.[54]

To aid the reader's understanding of the permitting process, each subpart of this Part discusses three aspects of the permit attachments: 1) the regulatory background behind the attachment; 2) the permit requirements; and 3) how the regulatory requirements were applied in the case of the Wellington project.

As a final preface to the permit requirements, applicants should expect extensive data acquisition to 1) characterize the subsurface, 2) conduct model simulations within a probabilistic framework to account for data deficiencies, and 3) develop a robust monitoring and testing plan to ensure safe and efficient injection operation.

Fig. 1. Location of pilot-scale CO_2 storage site at Wellington, Kansas.

54 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 1–2.

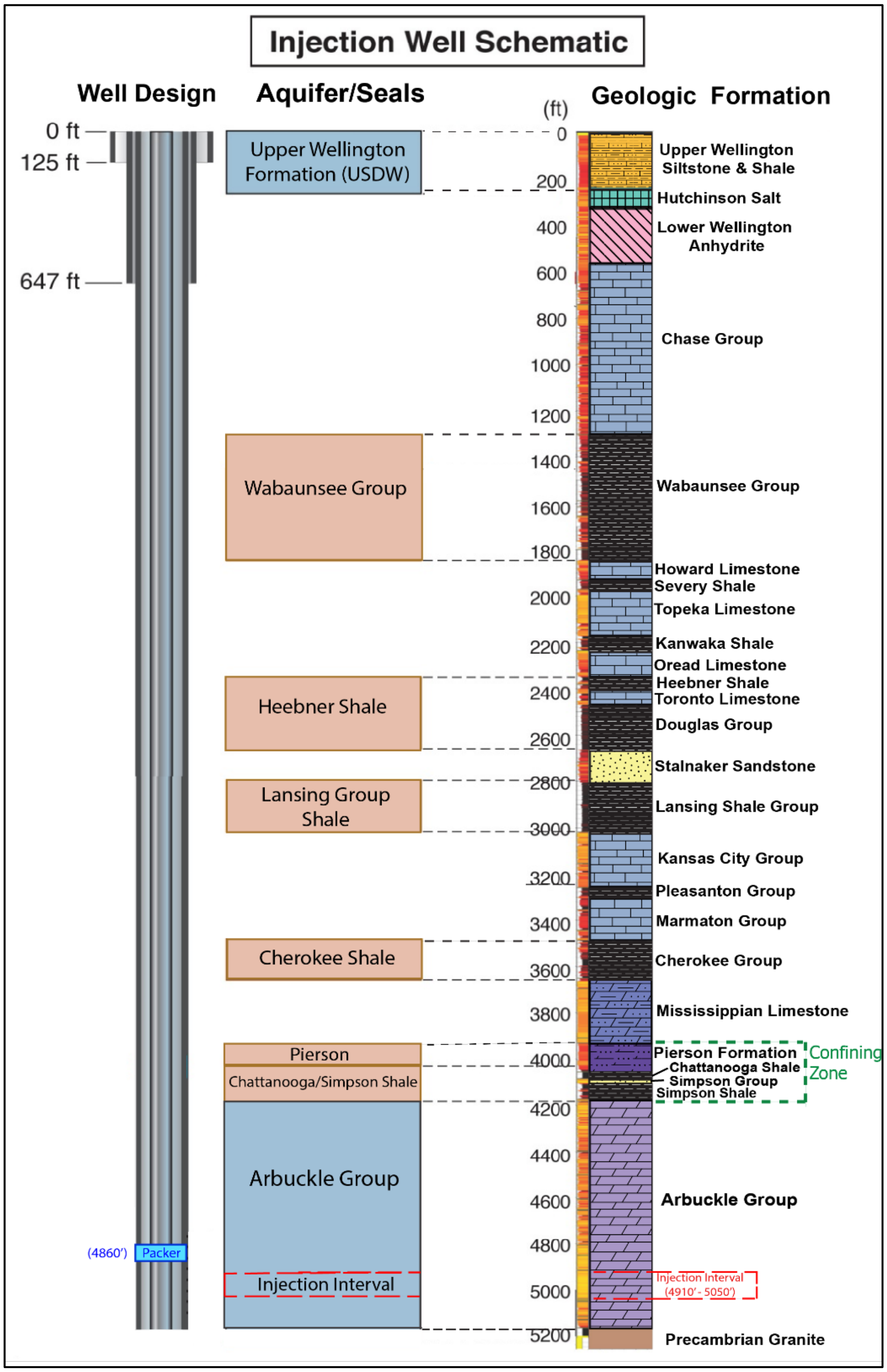

Fig. 2. Schematic of injection well showing geologic formations at Wellington sequestration site.

A. Beginning the Project

"Let's start at the very beginning, a very good place to start."[55] This Part discusses Site Selection (Attachment B, area of review), Construction (Attachment G), and Stimulation (Attachment I). Applicants will likely find that determining the area of review (AoR) is one of the most challenging aspects of the permit process. The AoR analysis requires intensive modeling, and significant requirements—such as what qualifies as an underground drinking water supply—are ambiguous.[56] In contrast, the Stimulation plan does not have any requirements unique to Class VI wells. But applicants should be aware of local state regulations on fracking.

1. Attachment B—Area of Review and Corrective Action Plan

a. Regulatory Framework

"Area of review" is nebulously defined in the Code of Federal Regulations as:

> the area surrounding an injection well described according to the criteria set forth in § 146.06 or in the case of an area permit, the project area plus a circumscribing area the width of which is either 1/4 of a mile or a number calculated according to the criteria set forth in § 146.06.[57]

Put more plainly, an AoR historically has been associated with an analysis "of wells surrounding the proposed injection well, most typically within 1/4 mile radius."[58] The goal behind this analysis is to determine the potential area of harm of injection zone pressures which can cause contaminates to migrate toward underground drinking water sources.[59]

AoR standards for well classes are located under the injection program's general provisions regulations.[60] The agency may determine

[55] Richard Rodgers & Oscar Hammerstein, *Do-Re-Mi*, *in* THE SOUND OF MUSIC (Albert Sirmay ed., 1959).

[56] *See infra* text accompanying notes 69–80.

[57] 40 C.F.R. § 146.3 (2020). Regulation § 146.06 does not appear to exist. The drafters were likely referring to 40 C.F.R. § 146.6, the standards for which are discussed *infra* text accompanying notes 61–62.

[58] Yashesh Jitendra Panchal, Comparison of Class II Injection Well Area of Review Requirements with Area of Evaluation for Hydraulically Fractured Wells 2 (Spring 2013) (unpublished masters thesis, Missouri University of Science and Technology), https://perma.cc/C5FC-M6K4.

[59] 40 C.F.R. § 146.6(a) (2020). This is often summarized as the "zone of endangering influence." *Id.*

[60] *Id.* § 146.1(a) ("This part sets forth technical criteria and standards for the Underground Injection Control Program. This part should be read in conjunction with 40 CFR parts 124, 144, and 145, which also apply to UIC programs."); *Id.* § 146.6.

the AoR[61] by calculating the zone of endangering influence[62] (the area in which the injected substance may migrate) or by using a fixed radius of at least a quarter mile.[63]

A common term used throughout the AoR regulations is "underground source of drinking water (USDW)."[64] EPA defines USDW as an aquifer which either supplies a public water supply or contains sufficient water to supply a public water supply *and* is not an exempted aquifer.[65] An exempted aquifer is a formation that that been formally exempted under agency procedures.[66] These exempted aquifers almost invariably refer to groundwater near Class II wells—and essentially exempt Class II injection wells which predate the enaction of the Safe Drinking Water Act.[67]

b. Class VI AoR Requirements

Unlike the other regulatory classes, Class VI wells have another set of AoR standards. This can complicate matters when an applicant seeks to turn an existing Class II well into a Class VI project.[68] In the Class VI permit context, the AoR refers to the extent within which the injected CO_2 can potentially escape from the injection zone into USDW based on specific calculations of geologic parameters.[69] The AoR is defined as the larger of the maximum extent of a) the free-phase CO_2 plume[70] or b) the pressure boundary within which brines from the injection zone can

---

61 *Id.* § 146.6 ("The area of review for each injection well or each field, project or area of the State shall be deter-mined according to either paragraph (a) or (b) of this section.").

62 *See id.* § 146.6(a) (providing a definition of area of review and an equation to calculate the zone of endangering influence). Calculations of the zone of endangering influence are based on a number of assumed values adopted in the agency's regulations. *Id.*

63 *Id.* § 146.6(b).

64 *Id.* § 146.3.

65 *Id.* As noted elsewhere in this Article, some states may have a modified definition of USDW which could come into play in the event of state primacy. For example, Kansas's definition includes a water quantity aspect. *See* KAN. DEP'T OF HEALTH & ENV'T, CONSIDERATIONS FOR GROUNDWATER POTABILITY AND USE DETERMINATIONS, BER POLICY # BER-RS-045, at 8–10 (2016), https://perma.cc/VGR4-SRN5.

66 40 C.F.R. §§ 144.7(b)(1), 146.3 (2020).

67 *See id.* § 144.7(b)–(c). *See generally* JOHN NOËL, CLEAN WATER ACTION AND CLEAN WATER FUND, AQUIFER EXEMPTIONS: A FIRST-EVER LOOK AT THE REGULATORY PROGRAM THAT WRITES OFF DRINKING WATER RESOURCES FOR OIL, GAS AND URANIUM PROFITS 8, 16 (2015) (discussing the history of the aquifer exemption rule and advocating for stricter regulation).

68 *See* 40 C.F.R. § 144.7(d) (2020) (discussing the aquifer exemption). An incomplete map of the exempted aquifers is available on EPA's website. *Aquifer Exemption Map*, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM, U.S. ENV'T PROT. AGENCY, https://perma.cc/WWN4-JTLG (last visited Sept. 26, 2021).

69 40 C.F.R. §§ 146.84(a), 146.6(a) (2020).

70 *Id.* § 146.81(d) ("Carbon dioxide plume means the extent underground, in three dimensions of an injected carbon dioxide stream.").

migrate into overlying USDW via leaky wells, faults, or breaches in the confining zone.[71]

Applicants must calculate both of these options with a multiphase CO_2-brine transport model, which is constructed from a sophisticated geologic model that accounts for site-specific hydrogeology.[72] EPA's methods for delineating the AoR are defined below, followed by a brief description of the methods and approaches required to develop the complex multiphase simulation model.[73] As previously mentioned, the pressure-based AoR component is the pressure boundary within which brines from the injection zone can migrate into overlying USDW via wells or faults through the confining zone.[74] The Class VI Rule does not itself contain firm guidelines as to what constitutes the plume-based AoR.[75] "However, the EPA has accepted the AoR as the area within which the free-phase plume has a CO_2 concentration of greater than 0.5%. The final AoR for a site is the larger of the pressure- or plume-based AoR."[76] For the Wellington site, the plume criteria resulted in the larger AoR, which is shown in Fig. B-2.

---

71 *Id.* §§ 146.82(a)(2), 146.84(c)(2); *see* U.S. ENV'T PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL AREA OF REVIEW EVALUATION AND CORRECTIVE ACTION GUIDANCE 2 (2013) [hereinafter EPA AREA OF REVIEW GUIDANCE] ("Therefore, the AoR encompasses the region overlying the separate-phase (e.g., supercritical, liquid, or gaseous) carbon dioxide plume and the region overlying the pressure front where fluid pressures are sufficient to force fluids into a USDW."); 40 C.F.R. § 146.81(d) (2020) (defining confining zone as "a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone(s)"); *see infra* text accompanying notes 99–102 (discussing the fracture gradient which the pressure boundary relies on).

72 *See* EPA AREA OF REVIEW GUIDANCE, *supra* note 71, at 11–12 (providing a table with model parameters which "include hydrogeologic characteristics").

73 While not explicitly included in the application attachments, EPA directed the UIC Program Directors to consider "EJ [environmental justice] considerations into the Class VI [injection well] permit application review and approval process." U.S. ENV'T PROT. AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE—UIC QUICK REFERENCE GUIDE*:* ADDITIONAL TOOLS FOR UIC PROGRAM DIRECTORS INCORPORATING ENVIRONMENTAL JUSTICE CONSIDERATIONS INTO THE CLASS VI INJECTION WELL PERMITTING PROCESS 1 (2011). Given that Class VI wells are unlikely to be sited near any population centers in the near future, any impact is likely minimal. Still an applicant may find it advantageous to familiarize themselves with EPA's guidance manual on the subject. *Id.* at 1, 4.

74 *See* CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 5–6 ("The pressure-based AoR is defined by the pore pressure ($P_{i,f}$) isoline of the following magnitude within which brines in the injection zone have a higher pressure than the lowermost USDW or the USDW with the lowest pressure.").

75 *See* 40 C.F.R. § 146.84(c)(1) (2020) (containing requirement for plume calculation but lacking specific guidance on what EPA Directors should consider as part of the AoR).

76 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 6.

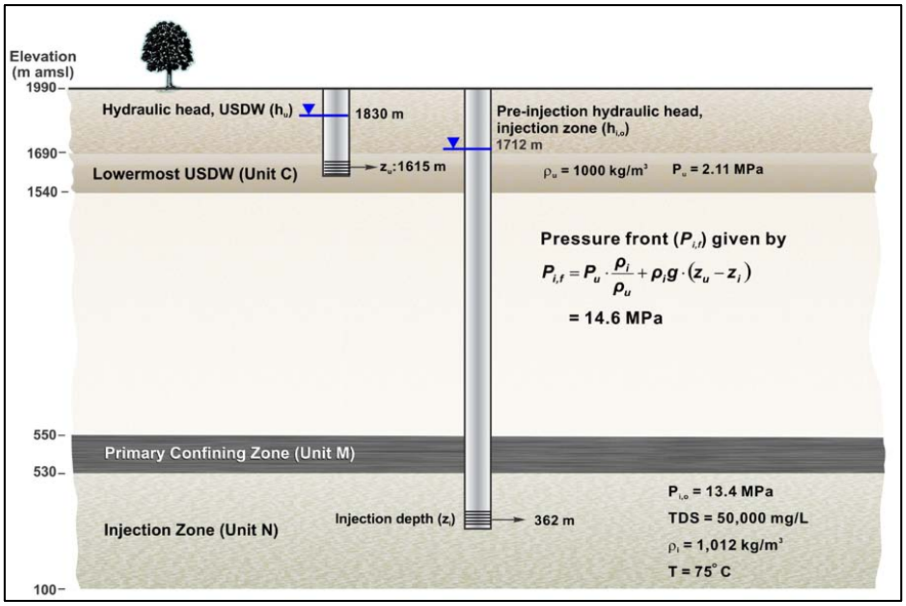

Fig. B-1. Hypothetical geologic sequestration site: Cross sectional schematic and calculations to determine pressure front (source: fttps://www.epa.gov/sites/production/files /2015-07/documents/gs_aor_ca_guidance_draft_final_031611.pdf)

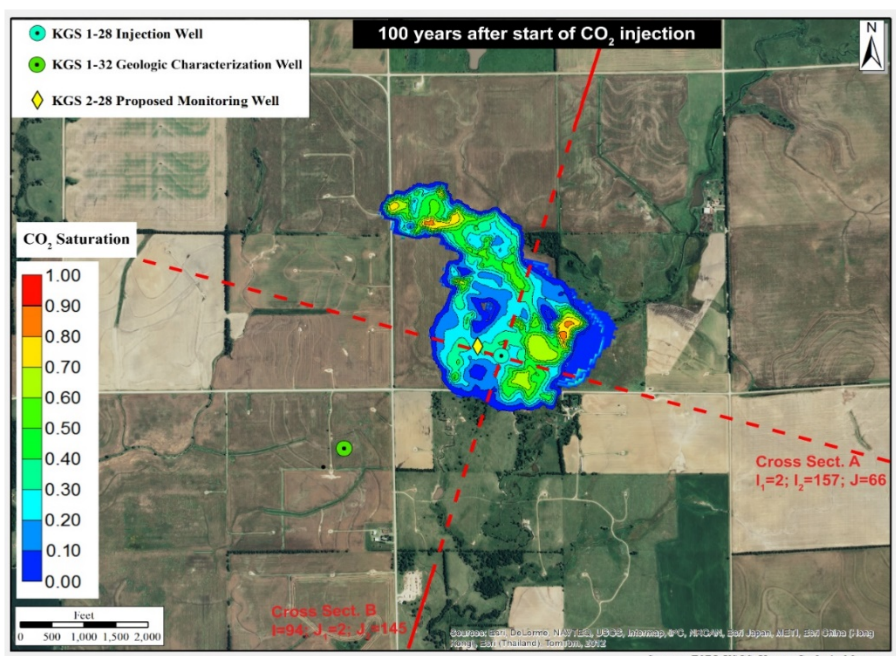

Fig. B-2. Maximum lateral extent of free-phase CO_2 plume at the Wellington, Kansas, sequestration site. (source: YEVHEN HOLUBNYAK ET AL., SMALL SCALE FIELD TEST DEMONSTRATING CO2 SEQUESTRATION IN

ARBUCKLE SALINE AQUIFER AND BY CO2-EOR AT WELLINGTON FIELD, SUMNER COUNTY, KANSAS 72 (2017)).

c. Site-Wide Geology and Hydrogeology

Next, to help EPA determine the effect of the pressure and plume based AoR, the permittee is required to provide a detailed description of the site-wide geology[77] along with information on all USDWs,[78] and "baseline geochemical data."[79] As noted above, the Class VI permit requires identification of all USDWs within the AoR,[80] especially the lowermost USDW, which in most cases is closest to the injection zone.[81] In theory, these USDWs should be relatively simple to locate for proposed Class VI wells. In Kansas and other states, the groundwater in pore space turns into brine at a certain depth.[82] These natural brines usually come from "incorporated sea water" when the sedimentary rocks were initially formed and other geological processes such as the "concentration of dissolved constituents [including salts] through evaporation."[83] Further, well sites are chosen where a competent low permeability geologic seal exists between the injection zone and USDWs—for example, the Wellington site was sited in a dolomite formation which was overlain by multiple low-permeability shale layers, including the Wellington shale which was at or near the surface.[84] A low permeability zone which makes

---

77 *See* 40 C.F.R. § 146.82(a)(3) (2020) (describing the geologic information that the applicant should submit).

78 *See id.* § 146.82(a)(5) ("Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement.").

79 *Id.* § 146.82(a)(6).

80 *Id.* § 146.82(a)(5).

81 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 9.

82 This brine is mostly due to the age of the formations. First, formation layers generally correlate to periods in time. *See Geologic History of Kansas*, *in* REX BUCHANAN, KANSAS ROCKS AND MINERALS (ed. Laura Lu Tolsted & Ada Swineford 1998), *available at* https://perma.cc/96NU-BKD5 (displaying a geologic timetable). Deeper formations are older formations. *See id.* ("[G]roundwater chemistry changes with depth in large sedimentary basins."); FLETCHER G. DRISCOLL, GROUNDWATER & WELLS 96 (2d ed. 1995) ("In deep zone formations, so little water moves through this zone that mineral leaching is extremely active, producing a high content of dissolved solids and a relative increase in the chloride ion."). This process is aided with the presence of seawater. "Chloride occurs as the predominant negatively charged ion in seawater. . . [These] ions eventually become trapped in the water-saturated pores of sedimentary rocks forming on the seafloor. . . . The residence time for chlorides in sedimentary rocks is about 218 million years." *Id.* at 101. For millions of years during the Permian and Cretaceous periods, Kansas was covered by saltwater seas. *See Geologic History of Kansas*, *in* REX BUCHANAN, KANSAS ROCKS AND MINERALS (ed. Laura Lu Tolsted & Ada Swineford 1998), *available at* https://perma.cc/8FQD-JD3T (displaying a geologic timetable and Kansas rock chart). Thus, these formations have a high chloride content because they formed during these seawater periods.

83 Brian D. Hoyle & E. Julius Dasch, *Brines, Natural*, WATER ENCYCLOPEDIA, https://perma.cc/9BVH-862Y (last visited Sept. 26, 2021).

84 *See supra* Figure 2 (schematic of geologic formations at the Wellington site).

a site a good candidate for CCUS makes the zone a poor source for drinking water.[85] Even if the groundwater was accessible, it is usually too difficult to extract to realistically qualify as a potential public water supply.[86]

Unfortunately, EPA has not legally defined water extractability or hydraulic permeability. Instead, the agency proposes that a USDW is any groundwater with less than 10,000 mg/L Total Dissolved Solids—a water-quality based definition.[87] For context, EPA's standard for public water supply systems is 500 mg/L Total Dissolved Solids[88]—twenty times lower than the standard for a USDW. In the agricultural context, most crops require water less than 3,000 mg/L Total Dissolved Solids.[89] As a result of this definition, "[e]ven a tight shale formation can be a potential USDW . . . even though it is technically and economically not feasible to withdraw any meaningful quantity of water from such a formation."[90] As states transition to Class VI primacy, there may be opportunities for a more flexible approach. For example, Kansas adopted EPA's definition for USDW by regulation.[91] But the Kansas Department of Health & Environment also recognizes a groundwater quantity aspect to determining whether a zone contains enough water for "potable use."[92]

An enterprising applicant may attempt to convert a Class II injection well to Class VI to simplify the USDW requirement. Ostensibly, the relevant aquifers could already be exempted. But the Class VI rule also affects these kinds of conversions. An applicant seeking to convert a Class II well would need to seek an expansion for the "areal extent" of an exempted aquifer—in other words, they would need to expand the area

---

85 Tony Hoch, *How Geology Affects Your Well Water Quality,* BARNYARDS & BACKYARDS, Fall 2008, at 19, 20.

86 40 C.F.R. § 146.3 (2020). Under the Kansas Department of Health and Environment's policy document for groundwater potability, one of the agency's tests to determine if there is sufficient water is whether a well site can "yield greater than 100 gallons per day" (the average per capita domestic use). KAN. DEP'T OF HEALTH & ENV'T, *supra* note 65, at 9. And the drilling process also requires considerable water. Mike Price, *Aquifers in the United States – Part 2*, WATER WELL J. (May 1, 2016), https://perma.cc/E3VJ-XDBY. One Kansas water well driller estimated in 2014 that it takes about 50,000 to 100,000 gallons of water to drill to the Ogallala formation (a distance of about 300 to 350 feet). *Id.* In other words, to get a water well in a low-permeable formation, a user would potentially need to use thousands of gallons of water for a well yielding less than one-hundred gallons per day. In addition, users would need to pay the upfront costs of drilling the well, the ongoing costs for running the pump, and likely treat the water for salinity and heavy metals. In short, it would be economically unfeasible to drill or rely on wells from low permeable formations.

87 *Id.* § 146.3.

88 *Secondary Drinking Water Standards: Guidance for Nuisance Chemicals*, U.S. ENV'T PROT. AGENCY, https://perma.cc/B86T-LSGN (last visited Oct. 20, 2021).

89 JOHN A. CONNER ET AL., A TECHNICAL ASSESSMENT OF PROTECTION OF UNDERGROUND SOURCES OF DRINKING WATER UNDER THE UIC RULE AND AQUIFER EXEMPTION PROGRAM 8 (2017).

90 Birdie et al., *supra* note 46, at § 3.2.

91 KAN. ADMIN. REGS. § 28-46-2a (2021).

92 KAN. DEP'T OF HEALTH & ENV'T, *supra* note 65, at 8–10.

included in the exemption.[93] And in order to receive an expansion, the operator must submit "narrative descriptions, illustrations, maps" and other data for all potentially impacted USDWs.[94] Essentially, the operator would need to do the same type of data collection to receive an exemption-expansion that it would need for the AoR.

To obtain the hydrogeologic and geologic data, applicants may consult publications and archives of state geological surveys and the U.S. Geological Survey for regional information.[95] But to have the localized site data required for a Class VI permit, the applicant will need to drill test holes. An alternative to this—which was done in the Wellington project—is to use existing wells prior to plugging.

The applicant will then need to develop a 3-D hydrogeologic model using the localized site data in conjunction with existing regional maps and other petrophysical data.[96] "The characterization wells should at least penetrate [the geologic seal underlying] the injection zone (and preferably into the basement) to acquire logs, collect formation samples, and conduct [field] tests."[97] Table B-1 summarizes the preferred set of logs, tests, and other data as well as key properties that are derived from the datasets. A detailed explanation of how the acquired site data was used to characterize the formation and estimate various hydrogeologic properties in the Wellington project is to be published in a future technical paper.

Geophysical Logs	**Purpose**
Gamma Ray	Estimate stratigraphy and porosity
Resistivity	Identify USDW, estimate porosity
Magnetic Resonance Image	Estimate porosity, permeability, caprock entry pressure
Geochemical	Document geochemistry
Array Compensated True Resistivity	Differentiate connected/unconnected pores
Temperature	Derive multiphase model parameters, such as solubility, equation of state, and brine resistivity
Compensated Spectral Gamma Ray	Characterize mineral composition and geology

93 40 C.F.R. § 144.7(d) (2020).

94 *Id.* § 144.7(d)(1).

95 *See, e.g.*, *Publications and Library Services*, KAN. GEOLOGICAL SURV., https://perma.cc/HRG3-95N9 (last visited Sept. 26, 2021) (providing new publications, maps, and reports focused on Kansas geology); *USGS Publications Warehouse*, U.S. GEOLOGICAL SURVEY, https://perma.cc/J2QV-GJ5V (last visited Sept. 26, 2021) (providing "access to over 160,000 publications written by USGS scientists."); *Kansas Geological Survey—Open-File Reports Online*, KAN. GEOLOGICAL SURV., https://perma.cc/5R8J-H7GB (last visited Nov. 15, 2021) (providing reports on Kansas geology).

96 40 C.F.R. § 146.84(c) (2020).

97 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 8.

Micr olog	Identify permeable zones
Spectral Density Dual Spaced Neutron	Estimate porosity and borehole-compensated photoelectric factor
Annular Hole Volume Log	Identify borehole enlargement
Extended Range Micro Imager Correlation Plot	Characterize fractures and rock texture
Core Samples	Estimate porosity and permeability, mineralogy and soil characterization, CO_2 compatibility
Drill-Stem Test	Measure formation pressure, geochemistry, and permeability
Leak-Off Test	Estimate fracture gradient
Swab Samples	Document geochemistry
Injection Test	Estimate hydrogeologic properties and identify faults
Seismic Data	Perform structure and impedance mapping

Table B-1. Summary of localized datasets required for hydrogeologic characterization of a Class VI injection site.[98]

In addition to the site-wide geological data, applicants will need to determine the fracture gradient.[99] A fracture gradient is the pressure point at which a formation breaks.[100] Overpressurizing formations can lead to leaks or faulty storage due to the creation of fractures in the confining layers.[101] Under the Class VI rule, the pore pressures in the injection zone cannot exceed 90% of the fracture gradient.[102]

98 *Id.* at 8–9.

99 40 C.F.R. § 146.88(a) (2020).

100 Fracture means "[t]he way in which a mineral breaks, other than along planes of cleavage." AM. GEOLOGICAL INST., DICTIONARY OF GEOLOGICAL TERMS 195 (Robert L. Bates & Julia A. Jackson eds., 3d ed. 1984). Fracture gradient means "[t]he pressure required to induce fractures in rock at a given depth." Fracture Gradient, Schlumberger Oilfield Glossary, https://perma.cc/R8UY-ZDQ2 (last visited Oct 5, 2021).

101 D.J. EVANS, AN APPRAISAL OF UNDERGROUND GAS STORAGE TECHNOLOGIES AND INCIDENTS, FOR THE DEVELOPMENT OF RISK ASSESSMENT METHODOLOGY, BRIT. GEOLOGICAL SURV. 44 (2007); INGAA FOUND. INC., PROFILE OF UNDERGROUND NATURAL GAS STORAGE FACILITIES AND MARKET HUBS II-5 (1995).

102 40 C.F.R. § 146.88(a) (2020). The fracture gradient can be derived by conducting a leak-off test which is "[a] procedure used to determine the fracture pressure in the open or exposed formation, usually conducted immediately after drilling below a new casing shoe." AM. PETROLEUM INST., HYDRAULIC FRACTURING—WELL INTEGRITY AND FRACTURE CONTAINMENT 3 (2015). In the absence of such test data, EPA may consider an analytical-based estimate of this parameter. In a tectonically relaxed region such as Kansas, the fracture gradient can be estimated by Eaton's equation, which is a function of the overburden pressure, pore pressure, and Poisson's ratio. *See* Ben A. Eaton, *Fracture Gradient Prediction and Its Application in Oilfield Operations*, 21 J. PETROLEUM TECH. 1353, 1353–60 (1969) (deriving Eaton's equation).

d. Modeling

The next component of the AoR analysis is modeling.[103] EPA's guidance documents indicate that "[o]wners or operators are strongly encouraged to perform geochemical modeling to assess potential impacts of injection on the subsurface."[104] As a practical matter, however, EPA requires a geologic and a multiphase transport model for a successful application.[105] A geologic model (called a conceptual site model in some EPA guidance documents), includes the "major geologic elements . . . and any relevant physical processes."[106] In other words, the geologic model "describes the general features" of the proposed project to show processes that could impact the site over time.[107]

> Development of the geologic model involves a complicated orchestration of well logs, core analysis, seismic surveys, literature, depositional analogs and statistics, seismic data, step-rate test, and drill-stem test information. Sophisticated geostatistical software such as Schlumberger's Petrel™ is required to produce the model. In contrast to well data, the seismic data are spatially extensive and are, therefore, of great value for constraining facies and porosity trends within the geomodel. Petrel's volume attribute processing (i.e., genetic inversion) was used at the Wellington site to derive a porosity attribute from the Pre-Stack Depth Migration ("PSDM") volume [Fig. B-4] along with the neural network processing and upscaling features of the package. Similarly, the permeability model was constructed using Sequential Gaussian Simulation ("SGS"). Isotropic semi-variogram ranges were set to 3,000 ft horizontally and 10 ft vertically. The permeability was collocated and co-kriged[108] to the porosity model using the calculated correlation coefficient (~0.70).[109]

Figure B-5 presents the resulting SGS-based permeability distribution.

---

103 40 C.F.R. § 146.84(a) (2020) ("The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.").

104 UIC CHARACTERIZATION GUIDANCE, *supra* note 9, at 50.

105 EPA itself is not required to conduct its own modeling. FutureGen Industrial Alliance, Inc., 16 Env't Admin. Decisions 717, 728 (2015). The agency must instead complete a thorough review. *Id*.

106 EPA AREA OF REVIEW GUIDANCE, s*upra* note 71, at 33.

107 *Id.* at 34.

108 Co-krigging is a geostatistical analysis tool which analyzes "the spatial relationship between data values" and "between-variable" relationships "to estimate values at unsampled locations." Mark J. Freund, *Cokriging: Multivariable Analysis in Petroleum Exploration*, 12 COMPUTERS & GEOSCIENCES 485, 485 (1986).

109 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 13.

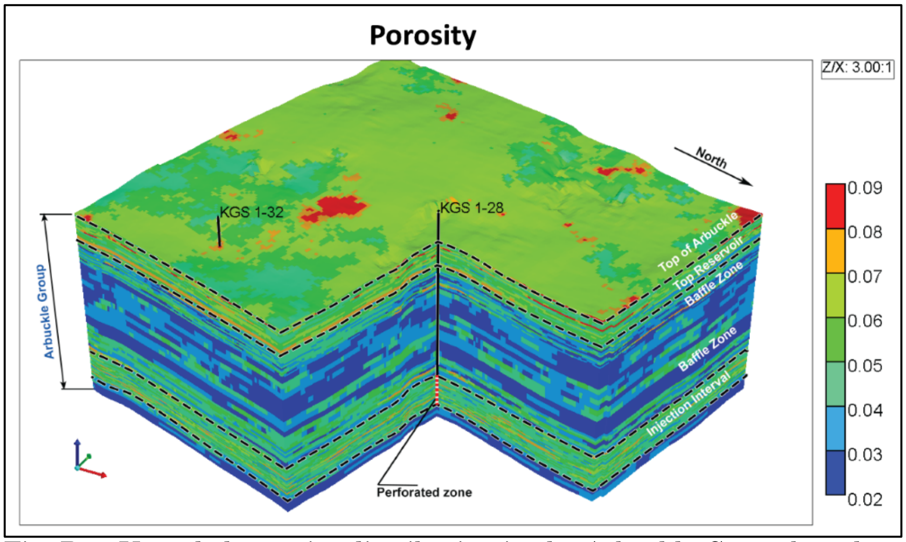

Fig. B-4. Upscaled porosity distribution in the Arbuckle Group based on the Petrel geomodel. (Source: YEVHEN HOLUBNYAK ET AL., SMALL SCALE FIELD TEST DEMONSTRATING CO2 SEQUESTRATION IN ARBUCKLE SALINE AQUIFER AND BY CO2-EOR AT WELLINGTON FIELD, SUMNER COUNTY, KANSAS 53–54 (2017)).

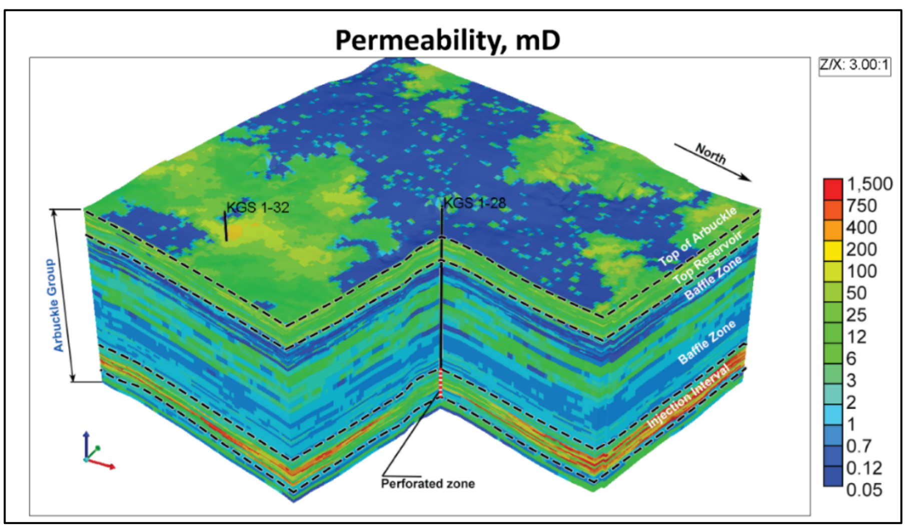

Fig. B-5. Upscaled horizontal permeability (mD) in the Wellington, Kansas, geomodel. (Source: YEVHEN HOLUBNYAK ET AL., SMALL SCALE FIELD TEST DEMONSTRATING CO2 SEQUESTRATION IN ARBUCKLE SALINE AQUIFER AND BY CO2-EOR AT WELLINGTON FIELD, SUMNER COUNTY, KANSAS 53–54 (2017)).

Class VI also requires a multiphase model capable of simulating brine and CO_2 transport in the supercritical, liquid, or gaseous phases.[110] In the oil and gas industry, CMG,[111] Eclipse,[112] and Tough[113] are commonly used modeling software packages.[114] Early EPA guidance on Class VI modeling suggested the agency would work with these existing programs.[115] EPA, however, uses Pacific Northwest National Laboratory's STOMP modeling software.[116] Therefore, applicants using other modeling software should also reproduce their results in STOMP to ensure compatibility and prevent delays in the permitting process due to STOMP's limitations.[117] For example, users should avoid a non-structured mesh, as STOMP only supports a structured mesh.[118]

A mesh discretizes[119] the volume of the earth being modeled into small cubes—called cells[120]—in which a uniform value is specified for

---

[110] 40 C.F.R. § 146.84(c)(1) (2020) (providing that the applicant must "[p]redict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases").

[111] *General Release,* COMPUTER MODELING GROUP LTD., https://perma.cc/FQ2L-C5H4 (last visited Sept. 26, 2021).

[112] *ECLIPSE Industry-Reference Reservoir Simulator*, SCHLUMBERGER: SOFTWARE, https://perma.cc/Y4NE-GYAL (last visited Sept. 26, 2021).

[113] *TOUGH: Suite of Simulators for Nonisothermal Multiphase Flow and Transport in Fractured Porous Media*, LAWRENCE BERKELY NAT'L LAB'Y, https://perma.cc/A9X3-DTXA (last visited Sept. 26, 2021).

[114] Jeffrey S. Brown, A Compositional Simulation Model for Carbon Dioxide Flooding with Improved Fluid Trapping 9, 37 (2014) (Ph.D. dissertation, Colorado School of Mines).

[115] EPA AREA OF REVIEW GUIDANCE, *supra* note 71, at 28–29.

[116] *See e.g.*, Archer Daniels Midland Co., 17 Env't Admin. Decisions 380, 388 n.7 (2017) (noting EPA's use of STOMP modeling program to delineate the AoR).

[117] *STOMP: Subsurface Transport Over Multiple Phases*, PAC. NW. NAT'L LAB'Y, https://perma.cc/7JCU-FA24 (last visited Sept. 26, 2021). The question of modeling software was subject to an administrative appeal for the Archer Daniels Midland CCUS project. Archer Daniels Midland Co., 17 Env't Admin. Decisions 380, 388–92 (2017) (EPA allowed the permittee to use a proprietary model while only checking the inputs. The Environmental Appeals Board ruled that the agency had adequately reviewed the AoR by only reviewing the inputs and modeling assumptions). Whether EPA would make this exception for future permits remains to be seen.

[118] *See* EPA AREA OF REVIEW GUIDANCE , *supra* note 71, at 21–22 (explaining that grid blocks are mesh); *Top 6 Reasons to Choose Structured Grids in CFD,* DESIGN ENG'G (Nov. 15, 2017), https://perma.cc/28EH-X9EF (explaining that 3D structured grids are hexahedral); M.D. While et al., *Fully Coupled Well Models for Fluid Injection and Production*, ENERGY PROCEDIA 3960, 3962 (2013) (explaining that STOMP's grid cells must be hexahedral).

[119] Discretize: "Represent or approximate (a quantity or series) using a discrete quantity or quantities." *Discretize*, OXFORD DICTIONARY, https://perma.cc/PVW8-QCLY (last visited Sept. 26, 2021).

[120] *See* Lauriane Bouard, Refinable Resolution & Precision for Volume Mesh Compression & Simulation in Geosciences 75 (doctoral thesis, Université Côte d'Azur 2021) ("After modeling the system of equations, the solution is calculated on the control volume. To obtain results at different points, the volume is discretized into small blocks.").

hydrogeologic properties such as porosity or permeability.[121] EPA, as previously noted, only supports a structured mesh. Additionally, STOMP requires a uniform mesh—meaning that the number of rows and columns (in the horizontal plane) are the same in all discretized vertical layers.[122] CMG and Eclipse do not have such requirements in order to fit the undulating and pinched-out geologic surfaces.[123] Therefore, meshes produced in CMG and Eclipse may not be transportable to STOMP unless these uniformity requirements are implemented.

---

121 *STOMP User Guide: Subsurface Transport Over Multiple Phases*, PAC. NW. NAT'L LAB'Y, https://perma.cc/CGM3-2M5X. *See* EPA AREA OF REVIEW GUIDANCE , *supra* note 71, at 21–22 (explaining that computational models are made up of model grid cells, i.e. mesh, which can be assigned a unique parameter value for permeability and porosity).

122 M.D. WHITE & M. OOSTROM, PAC. NW. NAT'L LAB'Y, STOMP: SUBSURFACE TRANSPORT OVER MULTIPLE PHASES VERSION 2.0 64 (2000).

123 *See* Thomas Viard, *Toward an Unstructured Future*, SCHULMBERGER, https://perma.cc/GZ8Q-3SK4 (last visited Nov. 3, 2021) (discussing the use of unstructured grids in Schlumberger's INTERSECT program which is used in Eclipse modeling).

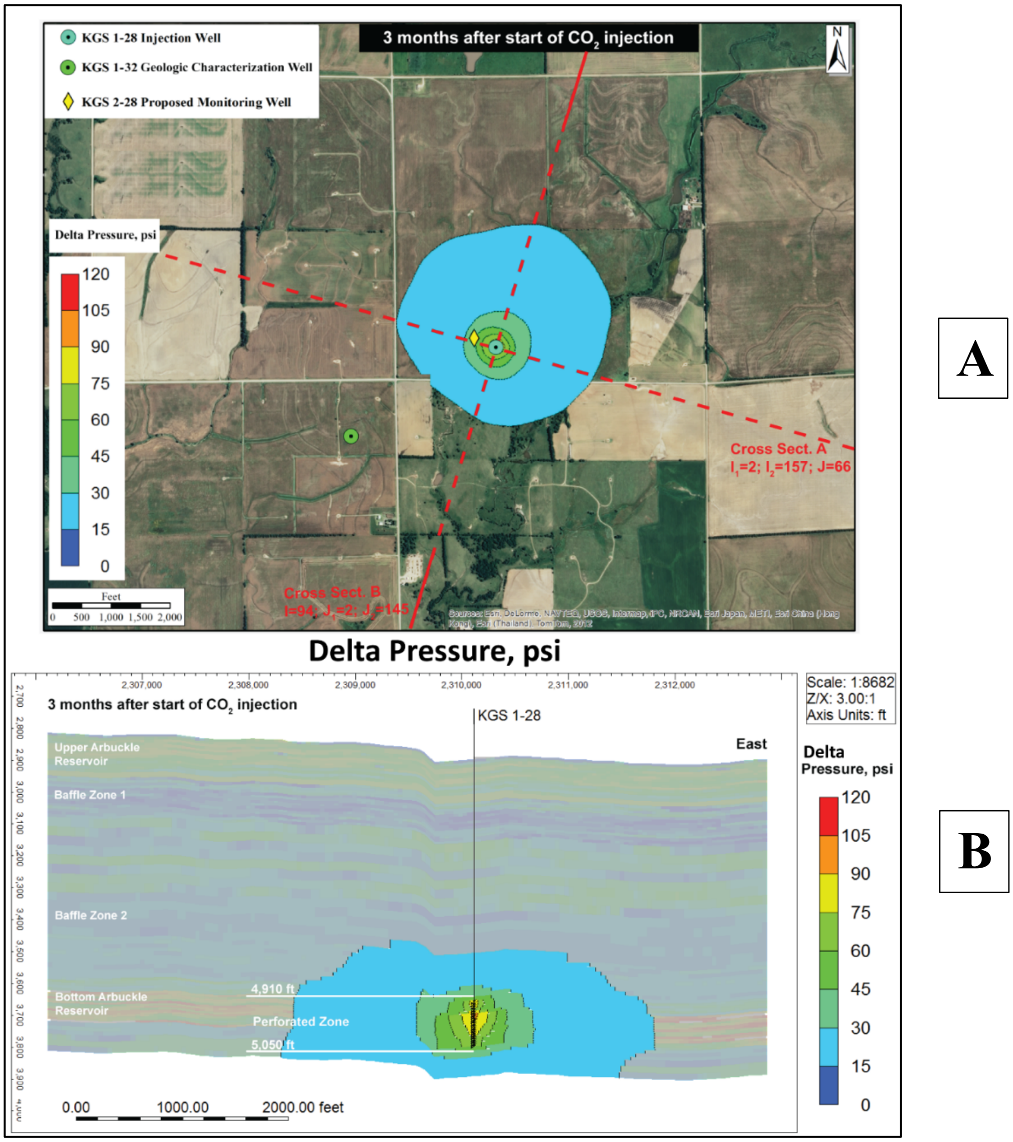

Fig. B-6. Simulated increase in pressure in (a) plan and (b) cross-sectional views at three months from commencement of injection. (Source: CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 17).

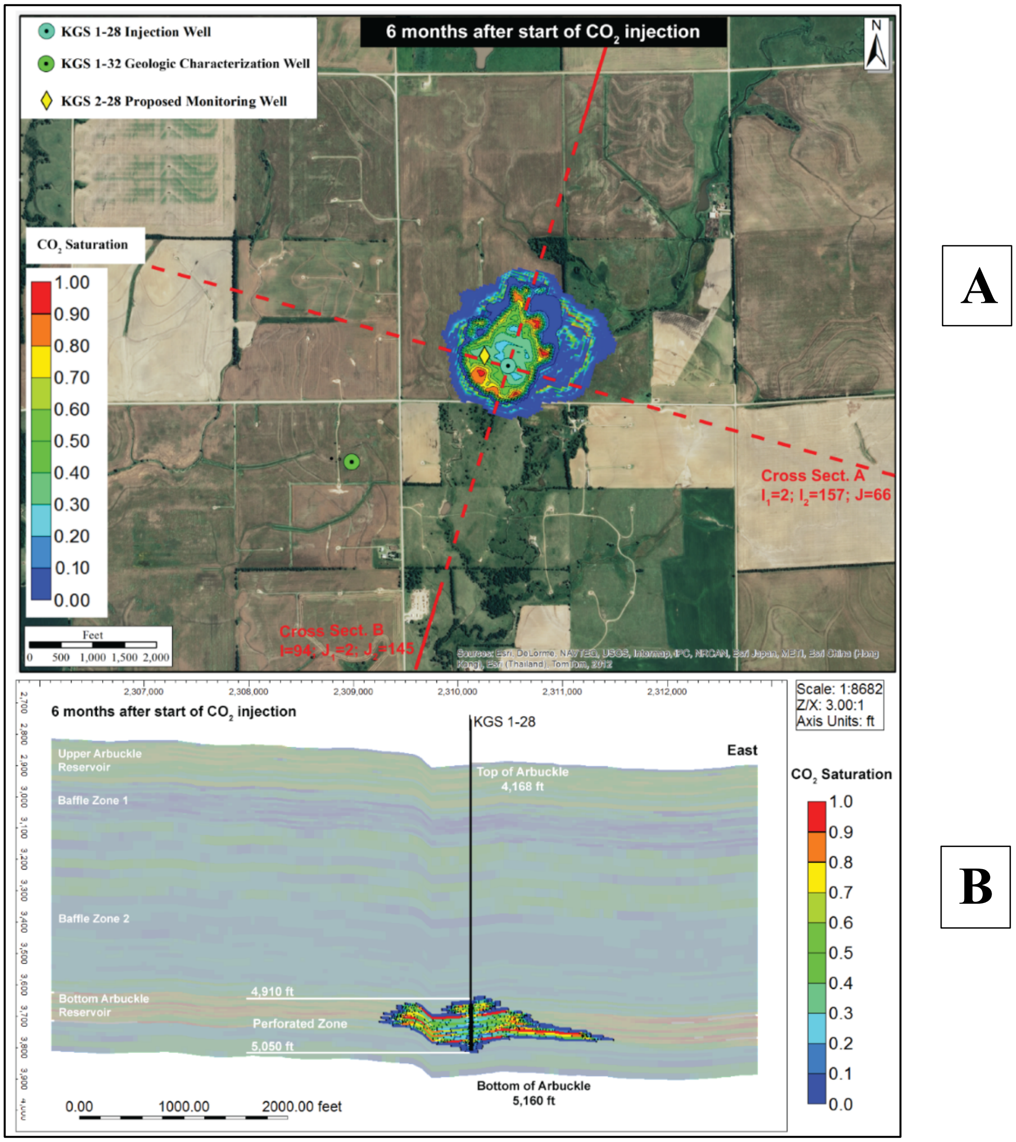

Fig. B-7. Spatial distribution of dissolved CO_2 in (a) aerial and (b) cross-section views six months after commencement of injection.

e. Corrective Action Plan

In addition to delineating the AoR, the Class VI permit also requires applicants to have a corrective action plan for wells that penetrate the upper confining zone within the AoR.[124] "Corrective action means the use

[124] 40 C.F.R. § 146.84(b)(2)(iv), (d) (2020).

of Director-approved methods to ensure that wells within the [AoR] do not serve as conduits for the movement of fluids into any [USDW]."[125] In other words, applicants must determine if there are any other wells in the AoR and if those wells were "plugged in a manner that prevents the movement of carbon dioxide."[126]

This is no small endeavor.

> Class VI applicants must evaluate wellbore integrity at *all* operational and abandoned wells which penetrate the confining zone within the AoR to ensure that these wells do not form a pathway for migration of gaseous-phase CO_2 or brines from the injection zone.[127] This can be an expensive process involving a review of operational and [field-]test[] data at existing wells, review of well plugging information at abandoned wells, and field evaluation of plugs at abandoned wells without plugging records.[128]

As a practical matter, this requirement may not even be possible. The prime candidates for CCUS projects are often older oil-field formations that are no longer producing and abandoned.[129] Considering that many states have been producing oil since the 1850s and 1860s, there are millions of inactive wells in the United States.[130] Few of these early wells were closed properly under modern standards[131] and state records of their locations are incomplete.[132] Further, a CCUS developer's problems do not stop at locating and identifying abandoned wells. While considerable ink has been spent on the problem of abandoned wells,[133] an underappreciated issue is the sheer difficulty of plugging certain wells.[134] Even if an applicant can successfully plug these wells, it may not be to the extent desired by EPA under the regulations. Applicants should have an open discussion with their EPA Regional team at the start of the application process on how to best resolve these issues.

---

[125] *Id.* § 146.81(d).

[126] *Id.* § 146.84(c)(3).

[127] *Id.* § 146.84(c)(2).

[128] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 18–19.

[129] JJ DOOLEY ET AL., CARBON DIOXIDE CAPTURE AND GEOLOGIC STORAGE 17 (Global Energy Tech. Strategy Program ed., 2006) (describing depleted natural gas and oil reservoirs as principal conditions for CCUS storage).

[130] *See* JACQUELINE HO ET AL., PLUGGING THE GAPS IN INACTIVE WELL POLICY 3 (2016) (noting that one estimate suggests only 825,000 of 3.5 million wells are actively in production).

[131] *See, e.g.*, S. TAKU IDE ET AL., CO_2 LEAKAGE THROUGH EXISTING WELLS: CURRENT TECHNOLOGY AND REGULATIONS (2006) (discussing early well closure).

[132] Permitted wells not in the public record do not need to go through corrective action. *In re* FutureGen Industrial Alliance, Inc., 16 Env't Admin. Decisions 717, 745 (2015).

[133] HO ET AL., *supra* note 130 at 3; KAN. CORP. COMM'N, ABANDONED OIL & GAS WELL STATUS: ANNUAL REPORT 2020 1 (2020).

[134] *See infra* Part III.C.1 for a discussion of injection well plugging.

f. AoR Reevaluation

Finally, the AoR must be periodically evaluated. By default, the applicant and EPA must reevaluate the AoR every five years,[135] at the termination of injection, and before site closure.[136]

> The AoR is also required to be reevaluated if the following events occur, which could suggest the potential for material change in the projected plume and pressure front:
>
> a. Initiation of competing injection projects within the same formation at close proximity to the injection well;
>
> b. A significant deviation [from model predictions] of wellhead operational data, formation pressure, or the CO_2 plume and pressure front;
>
> c. Seismic events or other emergency events that trigger an AoR reevaluation as specified in the Emergency and Remedial Response Plan;
>
> d. Newly acquired data at the site deemed to significantly alter the hydrogeologic properties specified in the reservoir model.
>
> If the monitored data suggest a significant deviation from the model-predict[ions] . . . of the plume and pressure front, then the reevaluation process will involve the following:
>
> - Revising the site conceptual model based on new site characterization, operational, or monitoring data,
> - Recalibrating the model and redelineating the AoR,
> - Applying corrective action to any deficient wells in the newly delineated AOR.[137]

g. Specific Implementations at the Wellington Site

i. USDW Determination

> The USDW is defined strictly on the basis of water quality (TDS < 10,000 mg/l). The permeability of the formation, which may affect the ability to draw water from a formation, is not a factor for consideration. Therefore, even an ultra-low permeability shale formation would be classified as a USDW if the TDS concentration in the unit was less than 10,000 mg/l.

---

135 40 C.F.R. § 146.84(e) (2020). This is the minimum requirement. In the past, EPA has required more frequent reevaluations. *FutureGen*, 16 Env't Admin. Decisions 717, 736 (2015) (noting more frequent reviews required for the FutureGen project).

136 EPA AREA OF REVIEW GUIDANCE, *supra* note 71, at 68.

137 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 19.

> Water-quality information is generally available for shallow formations. Estimating TDS in deeper formations to the satisfaction of the EPA can be more challenging. A two-step approach involving a) estimating NaCl [sodium-chloride] content from resistivity logs [which are sensitive to the amount of salt ("NaCl")] and b) using known TDS-NaCl relationships from swab samples to estimate TDS was implemented for the Wellington project as described [in the footnote] and approved by the EPA.[138]

Figure B-8 shows the estimated TDS concentration from near land surface to the basement at the Wellington site.

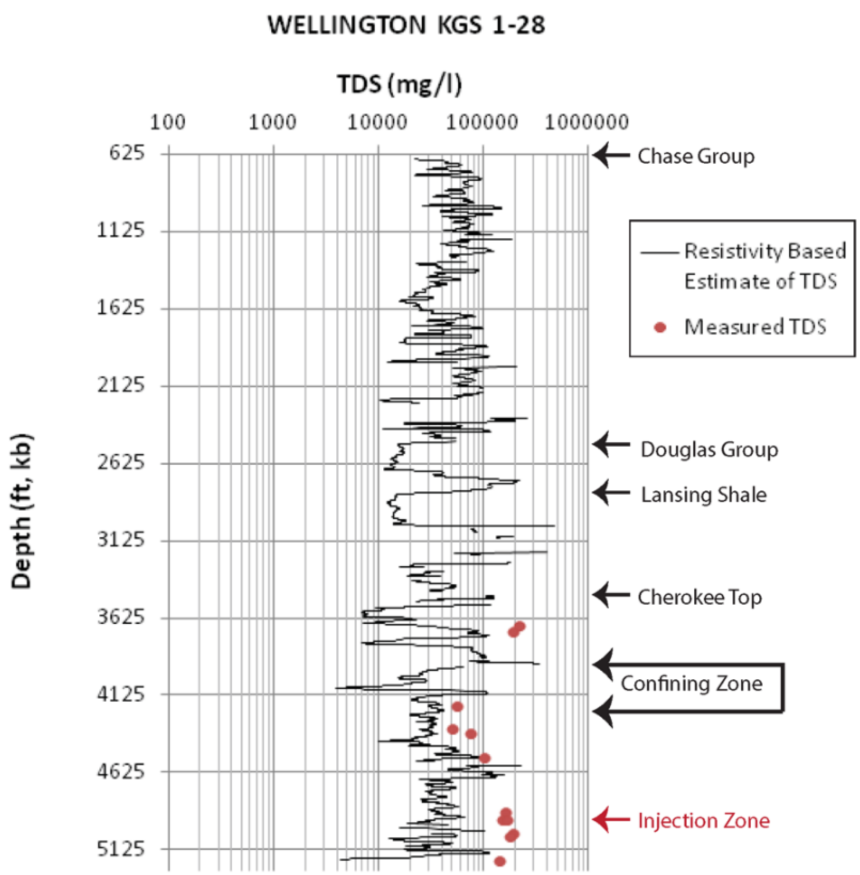

Fig. B-8. TDS (mg/l) estimated from resistivity logs at the Wellington site.[139]

[138] *Id.* at 9. "The salinity (NaCl, mg/l) can be calculated using a variant of Archie's equation." *Id.* "The subsurface water in [a reservoir] is generally of similar type [throughout the formation]. In Kansas, the TDS . . . in the Arbuckle is 1.045 times NaCl (by weight), suggesting that Na and Cl are the dominant minerals in this formation." *Id.* at 10.

[139] *Id.* at 11.

ii. Extrapolating the Hydrogeologic Properties at Well Sites

"Sensitivity studies [at the Wellington site] indicated that due to the buoyant nature of" carbon dioxide "the plume and the pressure fronts are [strong]ly influenced by the vertical resolution of petrophysical properties" such as horizontal and vertical permeability, porosity, etc.[140] Using a layered-cake simulation model can therefore provide misleading results. Consequently, the Wellington team went to significant effort to characterize the injection and confining zones at high resolution and to develop methodologies to extrapolate (upscale) the hydrogeologic properties throughout the model domain. "Spectral gamma ray, triple combo log suite, magnetic resonance image (MRI), and dipole sonic were used to characterize pore volume. The permeability was calculated by relating core-based Flow Zone Indicator (FZI) to the function $1/(S_{wir} * \emptyset)$."[141]

2. Attachment G—Construction Details

Returning to the next permit attachment, the next stage of the Class VI application is construction.

a. Regulatory Framework

Construction requirements for wells vary depending on well class and geological formations. New Class II wells should be "cased and cemented to prevent" fluids from entering USDWs, and technical specifications depend on factors such as the depth of the injection zone and the nature of formation fluids.[142] As most states have assumed primacy for Class II wells, operators also need to consider local well-construction regulations.[143] Prior to drilling the actual well, operators must develop a testing and data acquisition plan.[144] Major testing components for this plan—as opposed to the testing that may be done for an AoR—are deviation checks.[145] Deviation checks test to see if the borehole is vertical.[146] Operators want vertical boreholes because they help determine the flow path of the well and reduce the risk of "divergent"

140 CLASS VI PERMIT FEATURES AND GUIDELINES *supra* note 47, at 12.

141 *Id.*

142 *See* 40 C.F.R. § 146.22(b) (2020) (listing all requirements); *see also id.* § 144.28(e) (listing similar well requirements for Class II wells authorized by rule).

143 *See, e.g.*, KAN. ADMIN. REGS. § 82-3-106 (2015) (listing surface casing and cement requirements for well operators in Kansas); *Chapter 1: Federal and State Laws*, R.R. COMM'N TEX., https://perma.cc/T64Y-JATX (last visited Nov. 13, 2021) (explaining the commission's program for Class II injection wells).

144 *See* 40 C.F.R. § 146.22(f), (g) (2020 (listing all testing and data requirements).

145 *Id.* § 146.22(f)(1).

146 U.S. ENV'T PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL CONSTRUCTION GUIDANCE 10 (2012) [hereinafter EPA CONSTRUCTION GUIDANCE].

holes—where a pilot hole is expanded and two holes are created in the drilling process.[147]

Finally, injection wells need to demonstrate mechanical integrity and to complete a pressure fall-off test.[148] A well has mechanical integrity if "there is no significant leak" (internal integrity) and "[t]here is no significant fluid movement into a [USDW]" (external integrity).[149] Mechanical integrity is generally assessed using a mechanical integrity test (MIT).[150] The most common type of internal MIT is a pressure test[151] on either the "annulus above the packer" or on the casing for wells without a packer.[152] Operators may test external integrity by a temperature or noise log[153]—or in the case of a Class II well—cementing records showing "adequate cement" to prevent fluid migration.[154] A pressure fall-off test examines how the well and reservoir respond when the well is "shut in"[155] so that no new fluids may enter it.[156] The operator then "measur[es] the pressure falloff" to see "the magnitude, length, and rate fluctuations of the injection period."[157] This type of testing is useful to measure formation properties such as permeability and injection potential—and to monitor for changes which could affect pressure over time.[158]

147 *Id.*

148 40 C.F.R. § 146.90(e), (f) (2020).

149 *Id.* § 146.8(a).

150 *Id.* § 146.8(b); *See, e.g.*, KAN. ADMIN. REGS. § 82-3-407 (2021) (Kansas regulations concerning mechanical integrity requirements).

151 Efe Kermen, CATO-2 Deliverable WP 3.4-D18: Design Specifications of Well Integrity Tests 9 (Alexander Nagelhout & Jens Wollenweber eds. 2014).

152 KAN. ADMIN. REGS. § 82-3-407 (2021). "Annulus means the space between the well casing and the wall of the bore hole; the space between concentric strings of casing; the space between casing and tubing." EPA CONSTRUCTION GUIDANCE, *supra* note 146, at vii. "Packer means a device lowered into a well to produce a fluid-tight seal." 40 C.F.R. § 146.3 (2020).

153 "Noise logging tools are wireline tools that are essentially very sensitive microphones." U.S. ENV'T PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL TESTING AND MONITORING GUIDANCE 23–24 (2013) [hereinafter EPA TESTING AND MONITORING GUIDANCE]. They measure turbulence generated by "channel cross sections" in cement. *Id.*

154 40 C.F.R. § 146.8(c) (2020). A temperature log could likely only be used during construction because it is done by measuring the temperature of the cooling cement when it is initially injected to create the well casing. *Id.* § 146.66.

155 To shut in a well is to "close down a . . . well temporarily, for repair, cleaning out, building up reservoir pressure, . . . etc." Patrick H. Martin & Bruce M. Kramer, *S-Terms*, *in* 8 WILLIAMS & MEYERS, OIL & GAS L. SCOPE, LexisNexis (database updated 2021).

156 EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 50.

157 U.S. ENV'T PROT. AGENCY, UIC PRESSURE FALLOFF TESTING GUIDANCE 1 (2002).

158 U.S. ENV'T PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL PROJECT PLAN DEVELOPMENT GUIDANCE 32 (2012) [hereinafter EPA DEVELOPMENT GUIDANCE].

b. Class VI Requirements

EPA's Class VI rule guidelines for cementing and construction are similar to those for Class II wells that are constructed for CO_2-EOR.[159] In fact, the construction requirements are so similar that EPA noted that Class II wells use similar construction and materials in its 2012 well construction guidance.[160] EPA has broad latitude to specify the type of casing and cement[161] or any other aspect of construction needed to ensure the well is "constructed and completed" to prevent the contamination of USDWs.[162]

Like Class II wells, new Class VI well sites need a pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection and confining zones.[163] The program should include a combination of logging, coring, formation hydrogeologic testing (e.g., a pump test and/or injectivity tests), and other activities during drilling and construction of the CO_2 injection well, monitoring well(s), and any stratigraphic characterization well(s).[164] The pre-operational testing program should determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the injection zone, the overlying confining zone, and other relevant geologic formations.[165] In addition, applicants must obtain formation fluid characteristics from the injection zone to establish baseline data against which future measurements may be compared after the start of injection operations. Table B-1 lists the wireline logs and tests that are typically required by the EPA.[166]

c. Wellington Project

For the Wellington project, EPA required that

> [t]he casing and tubing of the injection and monitoring wells in the injection zone should be constructed of J-55 (or better) material with corrosion resistant lining in the tube (Duoline, Tubocope's TK-70XT, or similar). The [agency] prefers that the packer have hydrogenated nitrile seals with chrome-plated carbon steel. Borehole deviation checks are to be

---

[159] 40 C.F.R. §§ 146.82(11)–(12), 146.86(b) (2020).

[160] *See* EPA CONSTRUCTION GUIDANCE, *supra* note 146, at 1 (noting that "[t]he materials and techniques for constructing wells in a way that prevents the migration of fluids along the well bore are well documented").

[161] *Id.* at 13.

[162] 40 C.F.R. § 146.86(a) (2020).

[163] *Id.* § 146.87.

[164] *Id.*

[165] *Id.*; *See id.* § 146.90 (describing the requirements for the testing and monitoring plan which the owner or operator must prepare, maintain, and comply with).

[166] *See supra* Part III.A.1.c.; CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 8–9.

> recorded at depth intervals of approximately every 1,000 feet [during drilling].[167]

The EPA requires that specific procedures be followed for the MITs and the pressure fall-off test.[168] "Those procedures are documented in the . . . QASP [Quality Assurance and Surveillance Plan of the project]. For the fall-off test, the EPA recommends continuing the test three to five times beyond the beginning of radial flow[169] so that a well-developed semi-log straight line occurs."[170]

3. Attachment I—Stimulation Program

a. Regulatory Framework

The history of well stimulation traces back over 150 years to the filing of Edward Roberts' patent for an "oil well torpedo."[171] Roberts—a Civil War veteran—designed a method that combined explosives with water to fracture the rock and enhance oil flow.[172] Over the years, oil producers tried many other technologies—some more orthodox than others. For example, in the early 1970s, researchers in Colorado detonated a 40-kiloton nuclear bomb in the subsurface to stimulate fractures.[173] Today, one of the most popular stimulation methods is hydraulic fracturing.[174] This process involves injecting large amounts of water and sand into a formation to fracture the rock.[175] The same types of technologies may be used for injection wells. The injection program regulations define well stimulation as "processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for wastewater to move more readily into

---

167 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 39.

168 EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 10, 12, 19, 29, 50, 52; CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 40.

169 "Radial-flow: having the working fluid flowing mainly along the radii of rotation." *Radial-flow*, MERRIAM WEBSTER DICTIONARY, https://perma.cc/XW4K-5K7N (last visited Sept. 28, 2021).

170 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 40.

171 *Shooters – A "Fracking" History*, AM. OIL & GAS HIST. SOC'Y, https://perma.cc/ZN9N-SPEH (last updated April 7, 2021); Kat Eschner, *A Civil War Colonel Invented Fracking in the 1860s*, SMITHSONIAN MAG. (Apr. 25, 2017), https://perma.cc/NE65-5R37.

172 Kat Eschner, *supra* note 171.

173 Grace Hood & Jim Hill, *Remember The First Time Colorado Tried Fracking With A Nuclear Bomb?*, CPR NEWS (Sept. 6, 2019), https://perma.cc/E4PG-A993; HOWARD A. TEWES, LAWRENCE LIVERMORE LAB'Y, SURVEY OF GAS QUALITY RESULTS FROM EXPERIMENTS BY NUCLEAR EXPLOSIONS 1 (Univ. Cal. 1979).

174 U.S. ENV'T PROT. AGENCY, HYDRAULIC FRACTURING FOR OIL AND GAS: IMPACTS FROM THE HYDRAULIC FRACTURING WATER CYCLE ON DRINKING WATER RESOURCES IN THE UNITED STATES 4 (2016) [hereinafter EPA HYDRAULIC FRACTURING FOR OIL AND GAS] ("Hydraulically fractured oil and gas production wells . . . account[] for slightly more than 50% of oil production and nearly 70% of gas production in 2015.").

175 *Id.* at 3–4.

the formation, and includes (1) surging, (2) jetting, (3) blasting, (4) acidizing, (5) hydraulic fracturing."[176]

Well stimulation technologies come with two risks relevant to storing carbon dioxide. First, EPA is concerned about the impact of creating a "fracture network"—the new spaces between the rocks—because "[d]ata on the relative location of induced fractures to underground drinking water resources are generally not available."[177] The other concern is the risk of increased seismicity. Injected fluids are sometimes injected near "hydraulically connected . . . faults."[178] The fluids increase pressure on these faults which "makes earthquakes more likely to occur."[179] An additional complicating factor is that induced earthquakes do not always occur near the point of injection.[180]

Remember that one of the key requirements for the Class VI permit was that the confining zone(s) (above the injection zone) needed to be "free of transmissive faults or fractures . . . to contain the injected carbon dioxide stream and displaced formation fluids and [to] allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)."[181] Increased seismicity—particularly in areas where earthquakes were previously uncommon like Kansas—potentially makes meeting this permit requirement more difficult.[182] In the event that an injection well permit applicant needs to stimulate the well bore, the operator should consult any relevant state hydraulic fracturing regulations and restrictions.[183]

b. Class VI Permit

"There are no particular Class VI requirements for well stimulations as injectivity enhancement can be accomplished using conventional means and fluids."[184] The Class VI rule provides that applicants should submit, a "[p]roposed stimulation program, a description of stimulation

---

176 40 C.F.R. § 146.3 (2020).

177 EPA HYDRAULIC FRACTURING FOR OIL AND GAS, *supra* note 174, at 26–27.

178 *How Does the Injection of Fluid at Depth Cause Earthquakes?*, U.S. GEOLOGICAL SURV., https://perma.cc/HM5L-6FFP#qt-news_science_products (last visited Sept. 26, 2021).

179 *Id.*

180 *Are Earthquakes Induced by Fluid-Injection Activities Always Located Close to the Point of Injection?*, U.S. GEOLOGICAL SURV., https://perma.cc/VHU8-WBLA#qt-news_science_products (last visited Sept. 26, 2021).

181 40 C.F.R. § 146.83(a)(2) (2020).

182 *See Kansas Area Seismicity (1973-8/9/2017)*, U.S. GEOLOGICAL SURVEY (2017), https://perma.cc/3HFM-PHMG (showing a map of earthquakes in Kansas and northern Oklahoma over time).

183 Keith B. Hall, *Regulations Relevant to Injection-Induced Seismicity* 61 ROCKY MTN. MIN. L. INST. 1, 3 (2015), https://perma.cc/R44W-7F7Z.

184 CLASS IV PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 45.

fluids to be used and a determination that stimulation will not interfere with containment."[185] However, not all CCUS wells need stimulation.[186]

c. Wellington Project

The Wellington project did not require a stimulation plan though the applicants proposed industry-standard acid stimulation if it became necessary.[187] Neither was a plan prepared for the Archer Daniels Decatur project.[188] Applicants should anticipate that if stimulation becomes necessary later in the life of the project, they will need to develop an EPA approved stimulation plan "prior to conducting any stimulation."[189]

B. During the Life of the Project

After the applicant sufficiently establishes where a CCUS project can be sited safely and how they will build it, they need to inform EPA how they plan to operate the site.[190] This includes topics such as a summary of operating and reporting standards they will maintain they will do (Attachment A) and their plan for how they will maintain safety standards (Attachment C).[191] Finally, EPA requires an attachment on emergency response planning—a plan for addressing issues if monitoring systems detect a problem or a natural disaster occurs (Attachment F).[192] As the operating and monitoring elements are fairly unique to the Class VI permit, the regulatory framework sections were omitted for Attachments A and C.

---

185 40 C.F.R. § 146.82(a)(9) (2020).

186 *See* EPA CONSTRUCTION GUIDANCE, *supra* note 146, at 40 (explaining that in some cases, a well stimulation program may be necessary to achieve the desired injectivity of the Class VI injection well, but not in all cases).

187 NAT'L ENERGY TECH. LAB'Y U.S. DEP'T ENERGY, ORIGINAL CLASS VI PERMIT: FILE J-PROPOSED OPERATING INFO 8-19 (2014), https://perma.cc/Y4TG-VG5W (select "File J - Proposed Operating Information" then select "FE00006821-J—-Proposed-Operating-Information.pdf").

188 *See* U.S. ENV'T PROT. AGENCY, ATTACHMENT I: STIMULATION PLAN 1 (2016), https://perma.cc/YBK7-QHEH (select "ADM CCS2 Attachment I Stimulation Program (PDF)") (indicating that no stimulation plan was developed for the Decatur project).

189 *Id.*

190 40 C.F.R. § 146.82 (a)(7)–(9) (2020).

191 *Id.* §§ 146.88–146.91; CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 3–4, 20–26.

192 40 C.F.R. §§ 146.93–146.94 (2020); CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 30.

1. Attachment A – Summary of Operating and Reporting Requirements

a. Class VI Rules

EPA requires a summary of the operating and reporting requirements as part the permit application.[193] The main goal is to ensure that the injection tubing can withstand the maximum anticipated downhole axial, burst, and collapse stresses shown in Figure 3.[194] This attachment is unique in that the majority of specific requirements are not found in either the Class VI Rule or the agency's guidance documents. Tables A-1 and A-2 summarize these requirements for the Wellington project.[195]

Parameter	**Permitted Values**
Maximum bottomhole pressure	90% of fracture gradient
Maximum surface pressure	(Bottomhole pressure necessary to inject CO_2 into the formation) + (specific gravity of CO_2 * injection depth * 0.433) – atmospheric pressure
Minimum annulus pressure	As necessary to prevent "burst" or "collapse" of tubing
Minimum annulus pressure/tubing differential	Between 100 and 1,200 psig (at discretion of the EPA Director)

Table A-1. Injection well operating condition.[196]

Activity	**Minimum Reporting Frequency**
CO_2 stream characterization	Semi-annually
Pressure, flow, rate, volume, pressure on the annulus, annulus fluid level, and temperature	Semi-annually
Financial responsibility updates	Within sixty days of change in financial condition
Mechanical integrity tests (MIT)	Within thirty days of completion of test
Pressure fall-off testing	In the subsequent semi-annual report
Groundwater quality monitoring	Semi-annually

193 40 C.F.R. § 146.82 (a)(7), (9), (15), (21), (c)(8) (2020).
194 *Id.* § 146.89–146.90; EPA CONSTRUCTION GUIDANCE, *supra* note 146, at 16.
195 40 C.F.R. §§ 146.82 (a)(7), 146.88(e) (2020).
196 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 3.

Plume and pressure front tracking	In the subsequent semi-annual report
Corrosion monitoring	Semi-annually

Note: All testing and monitoring frequencies and methodologies are described in Attachment C (Testing and Monitoring Plan) of this Article.
Table A-2. Class VI reporting frequencies.[197]

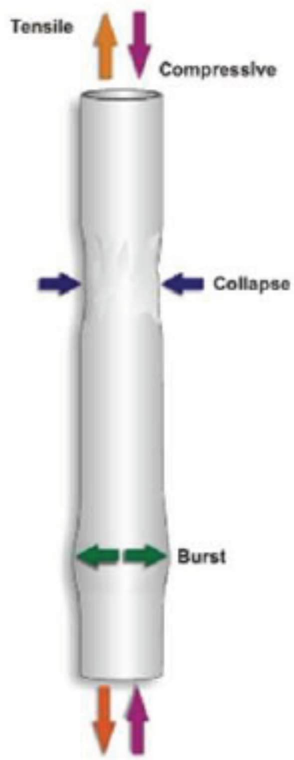

FIGURE 3

Attachment A also specifies "[s]pecial procedures related to startup of operations, monitoring, and reporting during the first several months" of operations.[198] Typically, these procedures include a gradual increase in injection rates to the planned operating "rate over a period of one week. The applicant may be required to provide interpretation of microseismic and operating data on a monthly basis during the startup period."[199]

b. Wellington Project

The fracture gradient at the Wellington site was estimated as the commonly assumed value of 0.75 psi/ft in Kansas and approved by the EPA.[200] To incorporate a factor of safety, 70% of this fracture gradient was approved by EPA resulting in a maximum bottomhole injection pressure of 2,651 psi.[201] The minimum and maximum surface injection pressures of 0.0 and 1,200.0 psi were approved by the EPA, which also resulted in the allowed Annulus/Pressure/Tubing Differential of 1,200 psi.[202]

[197] *Id.*
[198] *Id.* at 4.
[199] *Id.*
[200] YEVHEN HOLUBNYAK ET AL., SMALL SCALE FIELD TEST DEMONSTRATING CO2 SEQUESTRATION IN ARBUCKLE SALINE AQUIFER AND BY CO2-EOR AT WELLINGTON FIELD, SUMNER COUNTY, KANSAS 46 (2017).
[201] U.S. ENV'T PROT. AGENCY, ATTACHMENT A: SUMMARY OF REQUIREMENTS, CLASS VI OPERATING AND REPORTING CONDITIONS A1–A2 (2017), https://perma.cc/N296-PHHN (under "Latest Class VI Permit" select "Attachment A: Summary of Requirements").
[202] *Id.*

2. Attachment C – Testing and Monitoring Plan

This plan describes three components of the injection program: 1) how monitoring and testing data will be used to demonstrate that the injection well is operating safely; 2) that the CO_2 plume and pressure front are moving as predicted; and 3) that USDWs are not endangered.[203] If ongoing monitoring shows deviations from the projected results, it may prompt a recalibration of the model or trigger a remedial response according to the AoR and Corrective Action Plan (Attachment B), the Emergency and Remedial Response Plan (Attachment F), and other permit conditions.

The ongoing testing requirements can be best framed as a series of questions and answers:

<u>What testing does the operator need to do to the carbon dioxide before they inject it?</u>

EPA requires operators to test carbon dioxide before it is injected to ensure that the injectate does not contain any hazardous waste chemicals that can react in a manner that may hinder the sequestration processes.[204] The test samples can be collected either at the CO_2 source site or at the sequestration site.[205] The complete list of parameters to be tested will depend on the source of the anthropogenic CO_2 (e.g., coal, ethanol, etc.).[206] Table C-1 lists a summary of typical analytical parameters to be tested and the associated testing methods.[207] Table C-2 specifies the EPA's preferred sampling frequency.[208]

Parameters	**Analytical Methods**
Oxygen	ISBT 4.0 (GC/DID)
Nitrogen	ISBT 4.0 (GC/DID)
Carbon monoxide	ISBT 5.0 (GC/DID)
Oxides of nitrogen	ISBT 7.0 (DT)
Total hydrocarbons	ISBT 10.0
Methane	ISBT 10.1 (GC)

[203] *See* 40 C.F.R. § 146.90 (2020) (explaining the requirements of a testing and monitoring plan).

[204] EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 29–30; *See* 40 C.F.R. §146.90(a) (2020) (requiring testing "with sufficient frequency").

[205] EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 30.

[206] UIC CHARACTERIZATION GUIDANCE, *supra* note 9, at 53, 67.

[207] The Table C-1 chart and associated values were decided in the Archer Daniels Midland Co. Class VI permitting process. U.S. ENV'T PROT. AGENCY, ATTACHMENT C: TESTING AND MONITORING PLAN C1–C2 (2017), https://perma.cc/Y4FH-2T4U [hereinafter ATTACHMENT C: TESTING AND MONITORING PLAN] (select the document titled "ADM CCSR2 Att C Testing and Monitoring Plan (pdf)").

[208] The quarterly testing requirement was likewise a decision in the ADM permitting process. *Id.* at C1.

Parameters	**Analytical Methods**
Acetaldehyde	ISBT 11.0 (GC)
Sulfur dioxide	ISBT 14.0 (GC)
Hydrogen sulfide	ISBT 14.0
CO_2 purity	ISBT 2.0
Ethanol (if source)	ISBT 11.0 (GC/FID)

Table C-1. Summary of analytical parameters for CO_2 gas stream.[209]

Class VI Rule Requirement	**Activity**	**Frequency — Pre-Injection Phase**	**Frequency — Injection Phase**	**Frequency — Post-Injection Phase**
CO_2 stream analysis	Direct CO_2 stream samplin g	One sample at each supply plant	Quarterly	N/A

Table C-2. Sampling and testing frequency for CO_2 stream analysis.[210]

<u>What testing does the operator need to conduct on the gas stream and wellhead during and after the injection?</u>

Table C-3 specifies the monitoring and testing activities to be conducted at the injection well and briefly describes key EPA requirements for the activities. First, the operator must "continuous[ly] . . . monitor injection pressure, rate, and volume."[211] In other words, the operator must monitor how fast the gas is flowing into the well. The injection rate can be measured with either a mass[212] or flow meter.[213] If a flow meter, such as an Orifice-Plate differential meter,[214] is used, density needs to be estimated first using equations of state, pressure, and

[209] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 20.

[210] *Id.* at 21.

[211] 40 C.F.R. § 146.90(b) (2020).

[212] EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 34 ("If flow rate is measured on a mass basis (e.g., kg/sec), pressure and temperature measurements can be used to determine fluid density and convert mass values to volumetric measurements.").

[213] *Id.* at 34–35. *See also* "Flow meter: A device designed to measure the quantity of a fluid passing through a meter." Patrick H. Martin & Bruce M. Kramer, *F-Terms*, *in* 8 WILLIAMS & MEYERS, OIL & GAS L. SCOPE, LexisNexis (database updated 2021).

[214] "Orifice meter: A devise that measures the volume of gas delivered through a pipe." Patrick H. Martin & Bruce M. Kramer, *O-Terms*, *in* 8 WILLIAMS & MEYERS, OIL & GAS L. SCOPE, LexisNexis (database updated 2021); *see also* EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 35. For a more detailed explanation of orifice meter measurement, *see* EMERSON, FUNDAMENTALS OF ORIFICE METER MEASUREMENT 2–9 (2020).

temperature readings to calculate the mass flow rate.[215] If a mass meter is used, density needs to be estimated to determine the weight of the CO_2 in the tubing for reporting and verification purposes. Density can be estimated using the correlation developed by Ouyang.[216]

Class VI Rule Requirement	**Activity**	**Frequency — Pre-Injection Phase**	**Frequency — Injection Phase**	**Frequency — Post-Injection Phase**
Continuous recording of injection pressure/rate/volume and annular pressure	Injection rate and volume (via flow meter)	N/A	Continuous, every five to thirty seconds	N/A
	Wellhead injection pressure (via pressure gauge)	N/A	Continuous, every five to thirty seconds	N/A
	Annular pressure (via pressure gauge)	Continuous	Continuous, every five to thirty seconds	Continuous
Corrosion monitoring	Corrosion coupons, and potentially multiple fingers caliper or ultrasonic/ electro-magnetic tools	N/A	Quarterly to annually	N/A

[215] *See* EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 35 (explaining that differential pressure meters, such as orifice-plates, depend upon temperature, pressure, and density).

[216] Liang-Biao Ouyang, *New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations*, OPEN PETROLEUM ENG'G J., 2011, at 13, 14.

Class VI Rule Requirement	**Activity**	**Frequency — Pre-Injection Phase**	**Frequency — Injection Phase**	**Frequency — Post-Injection Phase**
External mechanical integrity testing	Temperature and/or radioactive tracer, noise, oxygen activation, or pulsed-neutron capture log[1]	One test	Annually	Annually
Internal mechanical integrity testing, in addition to continuous monitoring	Annular pressure test (via pressure gauge)	One test	Annually	Annually
Pressure fall-off testing	Pressure fall-off test (via pressure gauge)	One test	Several tests to be decided by EPA Director	One test

[1]The PNC logging tool is to be run twice during each event: once in the gas-view mode to detect CO_2 and once in the oxygen-activation mode to detect water.

Table C-3. Summary of testing and monitoring requirements for the injection well and monitoring wells in the injection zone.[217]

The next testing requirement examines if the gas is corroding the casing after injection.[218] When supercritical carbon dioxide combines with water, it creates carbonic acid.[219] The carbonic acid, in turn, reacts with

[217] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 21.

[218] 40 C.F.R. § 146.90(c) (2020). Carbonic acid is generally considered a weak acid. *See* Ari Manuel, *Carbon Dioxide*, *in* REFERENCE MODULE IN BIOMEDICAL SCIS. 1 (2020) ("Carbon dioxide combines with water to form carbonic acid, a weak acid with a pH of 3.5.").

[219] W.K. O'Connor et al., Carbon Dioxide Sequestration by Direct Mineral Carbonation with Carbonic Acid 2 (2000).

the surrounding minerals to create solid carbonate.[220] Like all acids, carbonic acid is corrosive.[221]

> [A]pplicant[s] will be required to monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that well components meet the minimum standards for material strength and performance. The applicant is required to monitor corrosion using corrosion coupons of material used in the pipeline, casing, tubing, wellhead, and packer.[222]

> A coupon is a small, carefully manufactured piece of metal (such as a strip or ring) placed in an appropriate location in the injection well to measure corrosion . . . It is weighed, subjected to the well environment for a period of time, and then removed and weighed again.[223]

> The coupons [can] be clamped in the line between the CO_2 storage tank and the injection well. Table C-4 lists the methods to be used for analyzing the corrosion coupons [and the detection limit accepted by EPA]. A corrosion rate of greater than 0.3 mils/year will likely initiate more frequent sampling and corrective action. In addition to the corrosion coupons, the EPA may require the permittee to monitor corrosion in the tubing and casings using caliper, ultrasonic, or electromagnetic logs.[224]

Parameters	**Analytical Methods**	**Detection Limit**	**Typical Precisions**
Mass	NACE RP0775-2005 (or equivalent)	0.05 mg	± 3%
Thickness	NACE RP0775-2005 (or equivalent)	0.01 mm	± 0.05 mm

Table C-4. Summary of analytical parameters for corrosion coupons.[225]

The final type of testing that the operator will need to do during the injection phase is to monitor for leaks in the Class VI wells via MITs and pressure-fall off tests.[226] The MIT standards must be met not only in the injection well, but in all monitoring wells in the injection zone.[227] It is a

---

220 *Id.*

221 Jessica Korcok, *The Effects of Carbonic Acid*, ITSTILLRUNS, https://perma.cc/EL8K-23NZ (last updated Sept. 15, 2017).

222 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 22.

223 EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 44.

224 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 22.

225 *Id.*

226 *See supra* Part III.A.2.a for a discussion of MITs and pressure fall off tests; 40 C.F.R. § 146.90(e)–(f) (2020) (requiring external MITs and pressure fall off tests).

227 *See* U.S. ENV'T PROT. AGENCY, UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI WELL PLUGGING, POST INJECTION SITE CARE, AND SITE CLOSURE GUIDANCE x

good practice to shut in the well during the injection phase for a period of thirty-six hours before obtaining the temperature log.[228] "The EPA's specific guidelines for conducting the pressure fall-off test are defined in the project's [QASP]. A successful test [is assumed if] the casing pressure holds for one hour with less than 3% loss or gain in pressure."[229]

<u>What testing and monitoring is required for the injection zone?</u>

In addition to monitoring the gas during the injection period, the applicant will also need to monitor the injection zone within the AoR.[230] Unlike the general review of the AoR which is done for Attachment B, this focuses on how to track the CO_2 plume and pressure front in the injection zone once the carbon dioxide is in the subsurface.[231] The permittee is required to employ direct and indirect methods to track the CO_2 plume and pressure front in the injection zone.[232] The methods acceptable to the EPA to achieve these goals are discussed below and "Table C-5 lists the direct and indirect methods for monitoring the pressure front and typical monitoring frequencies preferred by the EPA."[233]

(2016) ("EPA encourages owners or operators to perform periodic mechanical integrity and corrosion testing of monitoring wells to ensure that they do not allow for fluid movement that may endanger a USDW.") [hereinafter EPA PLUGGING GUIDANCE].

228 UIC CHARACTERIZATION GUIDANCE, *supra* note 9, at 21.

229 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 22.

230 40 C.F.R. § 146.90(d)–(g) (2020).

231 *Id.*; CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 20–24.

232 40 C.F.R. § 146.90(g) (2020); EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 73–74, 78.

233 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 23.

Type	Activity	Monitoring Location(s)	Frequency — Pre-Injection Phase	Frequency — Injection Phase	Frequency — Post-Injection Phase
Direct	Downhole pressure/temperature gauge (temperature can also be recorded with a fiber-optic distributed temperature sensor)	Injection and monitoring wells in the injection zone	A minimum of one week of reading (every thirty seconds)	Continuous (every thirty seconds)	Continuous (every thirty seconds)
Indirect	Interferometric synthetic aperture radar (InSAR) with continuous GPS (cGPS)	Radar data acquired in the imaging mode: StripMap—up to three meter resolution, scene size should extend well beyond the AoR GPS station: adjacent to injection site	InSAR—monthly, cGPS (sampling frequency of fifteen seconds averaged into a daily location)	InSAR—monthly, cGPS (sampling frequency of fifteen seconds averaged into a daily location)	InSAR—monthly, cGPS (sampling frequency of 15 seconds averaged into a daily location)
	Passive seismic	Seismometer network at surface and/or borehole seismic station.	Continuous (one year preferred)	Continuous (downloaded monthly)	Continuous (downloaded monthly)

Type	Activity	Monitoring Location(s)	Frequency — Pre-Injection Phase	Frequency — Injection Phase	Frequency — Post-Injection Phase
	Tiltmeter	Site wide within the AoR	Continuous (one year preferred)	Continuous (downloaded monthly)	Continuous (downloaded monthly)

Table C-5. Pressure-front monitoring of the injection zone.[234]

> Direct measurement involves collecting fluid samples using a sampler that can retain the CO_2 phases at the [well] perforation, such as Lawrence Berkley Laboratories U-tube or Schlumberger's Westbay multilevel monitoring system. Table C-6 lists commonly used plume monitoring techniques and the EPA's preferred monitoring frequency. The EPA Director may require one or more indirect methods to be used for the project.[235]

Table C-7 lists the sample testing perimeters.

Type	Activity	Monitoring Location(s)	Frequency — Pre-Injection Phase	Frequency — Injection Phase	Frequency — Post-Injection Phase
Direct	Direct sampling using a device that retains CO_2 phase in the injection zone	Injection well and monitoring wells in the injection zone	A minimum of one sampling event	Variable frequency after commencement of injection until plume arrives at the monitoring well(s); thereafter, quarterly and decreasing to annually	Quarterly to annually

[234] *Id.*
[235] *Id.*

Type	**Activity**	**Monitoring Location(s)**	**Frequency — Pre-Injection Phase**	**Frequency — Injection Phase**	**Frequency — Post-Injection Phase**
Indirect	CASSM (continuous active source seismic monitoring)	Injection well and monitoring wells in the injection zone	A minimum of one week of readings	Continuous (approx. 24-hr temporal resolution), until plume arrival at monitoring well(s)	At the discretion of the EPA
	Crosswell seismic	Injection well and monitoring wells in the injection zone	One survey	One or more during injection	None
	2-D seismic survey	Multiple seismic lines	Once	One or more during injection	Once
	3-D seismic survey	Site wide	Once	One or more during injection	Once
	Pulsed neutron capture/reservoir saturation tool	Monitoring wells	Once	Quarterly to annually	Discretion of the EPA
	Time lapse 3-D vertical seismic profile (VSP) survey	Cover plume-based AoR	Once	Discretion of the EPA	Discretion of the EPA

Type	Activity	Monitoring Location(s)	Frequency — Pre-Injection Phase	Frequency — Injection Phase	Frequenc y — Post-Injection Phase
	Time-lapse gravity	Gravity stations located site wide within the AoR.	N/A	Quarterly to annually	N/A

Table C-6. Direct and indirect methods of plume monitoring.[236]

What should be monitored above the confining zone?

A confining zone is "a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement."[237] As part of Attachment C, an applicant must provide a plan for monitoring groundwater quality and geochemical changes above the confining zone.[238] "Typically, monitoring is required in all USDWs and [the first] reservoir" above the primary confining zone above the injection zone.[239] The Underground Injection Control (UIC) Program Director may also require monitoring "within additional zones . . . [if] necessary to protect USDWs."[240] "The acquired samples will be tested for all constituents listed in Table C-7, at the frequencies specified in Table C-8."[241]

Parameters	Analytical Methods
Upper Wellington	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3, SO_4	Ion Chromatography, EPA Method 300.0
Cyanide (Cn-)	SW846 9012A/B

236 *Id.* at 24.
237 EPA AREA OF REVIEW GUIDANCE, *supra* note 71, at ix.
238 40 C.F.R. § 146.90(d) (2020).
239 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 25; EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 55.
240 EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at 55.
241 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 25.

Parameters	Analytical Methods
Mercury	CVAA SW846 7470A
Dissolved CO_2	Coulometric titration, ASTM D513-11
Total dissolved solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	SM 2450
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Oxidation-reduction potential (field)	SESDPROC-113-R1
Sulfur hexaflouride	Busenberg and Plummer, 2000 (https://perma.cc/7A3W-C5MY)
Hydrogen sulfide	SM4500-S2D
Acetaldehyde	EPA Method 8315A
Total Inorganic Carbon (TIC)	SW846 9060A
Total Organic Carbon (TOC)	SW846 9060A
Volatile Organic Analysis (VOA)	SW846 8260B
Stable Carbon Isotope	Gas Bench for $^{13/12}C$
Gravimetric Total Dissolved Solids (TDS)	Gravimetric Method Standard Methods 2540C

Table C-7. Summary of parameters for groundwater samples and geochemical testing methods.[242]

[242] *Id.* at 24–25.

Class VI Rule Requirement	**Activity**	**Frequency — Pre-Injection Phase**	**Frequency — Injection Phase**	**Frequency — Post-Injection Phase**
Groundwater monitoring above the confining zone	Direct monitoring — all USDWs and other productive formations	A minimum of two samplings at different dates	Quarterly to annually	Every six months to a year

Table C-8. Monitoring activities and frequency above the confining zone.[243]

Beyond groundwater monitoring, "[i]f CO_2-based enhanced oil recovery (EOR) is occurring in another formation at the site, then the EPA will require the addition of a tracer in the CO_2 stream."[244] The reasoning behind this is that in the event of a USDW contamination, the agency can more easily determine the source of the contamination.[245] In the Wellington Project, EPA found sulfur hexafluoride (SF_6), a trace anthropogenic gas found in the atmosphere at 7–8 parts per trillion (ppt) as a suitable tracer.[246] "SF_6 is a conservative gas that does not sorb onto the matrix or react/decompose into daughter products. Only minute quantities of [SF_6] are required as the detection limit in the dissolved phase is 0.1 Femtomoles/liter,[247] which equates to a concentration of $1.5E^{-08}$ micrograms/liter."[248]

<u>What are the requirements for earthquake monitoring?</u>

As noted in the discussion of Attachment I – Well Stimulation, regulators are becoming increasingly concerned about seismic activity caused by injection wells and hydraulic fracking operations. The EPA requires monitoring seismicity for Class VI wells.[249] "The EPA may require the installation of a ring of seismometers around the injection well(s). . . [D]ata from the seismometer[s] are to be downloaded and analyzed monthly. The primary goal is to ensure that" injection activities

---

243 *Id.* at 26.

244 *Id.*

245 EPA TESTING AND MONITORING GUIDANCE, *supra* note 153, at A-6.

246 Birdie et al., *supra* note 46, at § 2.5.

247 "A unit of concentration (molarity unit) equal to one quadrillionth of a mole (10E-15 mole) of solute in one liter of solution." *Femtomole per Liter*, NCI THESAURUS, https://perma.cc/NH6C-5R27.

248 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 26.

249 *Id.*

related to either sequestration or EOR do not cause an earthquake of magnitude 2.5 or larger.[250] Seismometers installed for this purpose should be capable of detecting earthquakes of magnitude 1.0 or greater.[251]

How does an operator and the agency know the testing and monitoring results are accurate?

The EPA requires "[a]n extensive quality assurance protocol . . . to ensure the validity of the monitored data and to derive statistically defensible conclusions. The QASP details standard operating procedures and methods related to sample acquisition, handling, preservation, testing, and reporting."[252]

What does the operator need to do with their testing and monitoring results?

The results of all testing and monitoring activities are to be described in a report submitted to the EPA every six months.[253]

3. Attachment F – Emergency and Remedial Response Plan

a. Regulatory Background

"The Emergency and Remedial Response Plan (ERRP) [from the Class VI Rule] describes actions that the permittee [must] take to address movement of injection or formation fluids that may endanger a USDW/injection well or safe functioning of infrastructure at the site."[254] This requirement is one of the distinguishing aspects between Class VI wells and other injection well classes.[255] Class II EOR wells may have a somewhat analogous requirement to provide Spill Prevention, Control, and Countermeasure (SPPC) Plans.[256] SPCC plans draw their authority from the Clean Water Act and require oil operators to provide contingencies and planning in the event of an aboveground oil spill into navigable surface water.[257] Significantly, since other major environmental statutes do not regulate the injection of CO_2, well owners would be exempt from other reporting and response requirements such as under the Comprehensive Environmental Response, Compensation,

---

[250] *Id.*
[251] *Id.*
[252] *Id.*
[253] *Id.*
[254] *Id.* at 30.
[255] *See also* JONES, *supra* note 39, at 11–12 (discussing the new EPA requirements unique to Class VI wells and several unique risk factors to USDWs).
[256] 40 C.F.R. § 112.1 (2020) (providing that SPCC plans are required for "any owner or operator of a non-transportation-related onshore . . . facility engaged in drilling, producing . . . or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful . . . into or upon the navigable waters of the United States").
[257] *Id.* § 112 app. F.

and Liability Act (CERCLA) or the Emergency Planning and Community Right-to-Know Act.[258]

b. Class VI Rule

For permit applications, EPA accepted five potential emergency scenarios outlined in Table F-1.[259] "Each scenario constitutes an emergency and triggers the ERRP. The response activities for each scenario, however, will depend on the nature of the failure and the severity of the event, as described in Table F-2."[260]

Emergency Scenario Requiring Remedial Response
Well integrity failure, including annulus pressure failure
Equipment failure, including damage to the wellhead or a well blowout
Water-quality changes, USDW endangerment, migration of CO_2 out of the injection zone, or release of CO_2 to the surface
Natural disaster
Induced seismicity event

Table F-1. Emergency scenarios for Class VI project identified by EPA.[261]

Emergency Condition	**Definition**
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions should be initiated in coordination with local authorities.
Serious Emergency	Event poses potential serious (or significant) near-term risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Table F-2. Degrees of risk for emergency events.[262]

[258] JONES, *supra* note 39, at 14. Class VI Wells would be subject to the Greenhouse Gas Reporting Program under the Clean Air Act. *Id.* at 15. It is unclear, however, if a Class VI injection well would be subject to the Clean Air Act's spill response requirements as contemplated by Section 112 of the CAA. Clean Air Act § 112, 42 U.S.C. § 7412 (2018).

[259] U.S. ENV'T PROT. AGENCY, ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN F2 (2017), https://perma.cc/ZZJ7-9KVL [hereinafter ADM EMERGENCY PLAN] (select the document titled "ADM CCSR2 Att F Emergency and Remedial Response Plan (pdf)").

[260] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 30.

[261] *Id.* at 26.

[262] *Id.* at 31.

"For all emergency scenarios," the operator must "[n]otify the [EPA] UIC Program Director within 24 hours of the emergency event" and "[d]etermine the severity of the event, based on the information available, within 24 hours of notification."[263] In the event of "a major or serious emergency (i.e., release)," the operator must:

"Initiate immediate shutdown.

Evaluate the cause of the violation, characterize the release, and mitigate if necessary.

If contamination is detected, identify and implement appropriate remedial actions specified for each scenario discussed below."[264]

For a minor emergency, the operator should "[c]onduct an assessment to determine whether there has been a loss of mechanical integrity. If there has been a loss of mechanical integrity, [the operator should] initiate [a] gradual shutdown plan. [The operator should then] [c]onfirm well integrity before restarting injection."[265]

i. Scenario I: Well Integrity Failure

"A loss of integrity in the injection well and/or monitoring well may endanger a USDW. Integrity loss may have occurred if" mechanical integrity test results identify a problem or automatic shutdown devices are activated.[266] Two examples of where automatic shutdown devices may be activated are 1) if "wellhead pressure exceeds the shutdown pressure specified in the permit [or 2) the a]nnulus pressure indicates a loss of external or internal well containment."[267] Depending on the severity of the event, the operator should implement the steps specified for either major or minor emergencies.[268]

ii. Scenario II: Equipment Failure

"This scenario includes equipment failure, damage to the wellhead, or a well blowout."[269] In the event of a major or serious emergency (release), operators should "[r]eview downhole, wellhead, and annulus pressure data."[270] "If contamination is detected, identify and implement appropriate remedial actions."[271] First, "[i]solate the nearby area, if needed; establish a safe distance and perimeter using a hand-held air-

263 *Id.*
264 *Id.*
265 *Id.*
266 *Id.* at 31–32.
267 ADM Emergency Plan, *supra* note 259, at F3.
268 *Id.*
269 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 32.
270 *Id.*
271 *Id.*

quality monitor."[272] Second, obtain appropriate well log(s) in consultation with the EPA Director "to detect CO_2 movement outside of casing."[273]

Next,

> [e]valuate the cause of the failure, and mitigate if necessary (i.e., repair equipment). In the event of a well blowout, 'kill' the well by pumping fluid to stop the well from flowing. If there is damage to the wellhead, repair the damage and conduct a survey to ensure wellhead leakage has ceased.[274]

If mechanical or electrical malfunctions trigger a shut off, "repair faulty components."[275]

iii. Scenario III: Water-Quality Changes, USDW Endangerment, Migration of CO_2 Out of the Injection Zone, or Release of CO_2 to the Surface

This section of the application attachment should describe a range of activities that may need to be taken to address a release. For example, the operator may need to conduct a Hall Plot analysis,[276] sample and test water quality in monitoring wells above the confining zone; or conduct pressure fall-off tests.[277] They may also need to validate plume detection with U-Tube sampling[278] (or other in-situ instrument) or obtain InSAR[279] scene and analyze for a caprock[280] breach (if necessary and deemed feasible).[281] "If CO_2 is detected in a reservoir other than the injection zone, then available wells in those formations will be used to release CO_2. A 2-D seismic survey may also be required to identify the extent of plume migration."[282] In the event of water quality incident, the operator may need to "[a]rrange for an alternate potable water supply" if the incident

---

[272] *Id.*

[273] *Id.*

[274] *Id.*

[275] *Id.*

[276] The Hall Plot method "is a plot of pressure integral versus cumulative injection volume. . . . [to] obtain information about changes in injection conditions." Yangyang Chen, Hall Plot Analysis for Horizontal Well Injectivity 1 (May 2017) (master's thesis, University of Texas at Austin).

[277] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 32.

[278] *Id.*

[279] "InSAR (Interferometric Synthetic Aperture Radar) is a technique for mapping ground deformation using radar images of the Earth's surface that are collected from orbiting satellites." *InSAR—Satellite-Based Technique Captures Overall Deformation "Picture"*, U.S. GEOLOGICAL SURV., https://perma.cc/7WSN-TKLH (last visited Sept. 26, 2021).

[280] Cap Rock: "A comparatively impervious stratum immediately overlying an oil- or gas-bearing rock." *Cap rock*, DICT. OF GEOLOGICAL TERMS 195 (Robert L. Bates & Julia A. Jackson eds., 3d. ed. 1984).

[281] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 32.

[282] *Id.* at 33.

caused an exceedance of drinking water standards to any water supplies.[283]

> If the presence of CO_2 or indicator parameters is confirmed, [the operator should] evaluate the cause and extent of the violation and implement the following measures. [First, i]f water-quality changes or CO_2 migration [are] determined to be a consequence of well failure, attempt to identify the source location in the wellbore. This may involve obtaining a suite of wireline logs to pinpoint the source location. [Then, r]emediate using appropriate methods. On completion of the remedial work, [the operator should] acquire a new set of logs and perform a pressure test to evaluate well integrity before restarting injection. If water-quality changes or CO_2 migration [are] determined to be due to confining zone failure or flow along structural features, develop a plan to identify the extent of the problem and perform remedial measures. This may involve installing additional wells near the affected groundwater well(s) to delineate the extent of contamination, and conducting additional modeling to predict the fate of the CO_2 and/or brine. If CO_2 is detected above the confining zone, then the modeling will involve predicting the [effects on] any surrounding wells and water resources. [The operator should c]ontinue groundwater remediation and monitoring on a frequent basis until unacceptable adverse [effe]cts have been fully addressed.[284]

iv. Scenario IV: Natural Disaster

> Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster, such as earthquake, tornado, or lightning strike which may affect normal operations of the injection well. For a major or serious emergency[, the operator should first s]hut in the well (close flow valve) [and v]ent CO_2 from surface facilities. [Then, they should m]onitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. [Next, the operator must d]etermine whether any leaks to USDW or surface water have occurred. [Finally, i]dentify and . . . implement appropriate remedial actions (in consultation with the UIC Program Director).[285]

v. Scenario V: Induced Seismicity Event

"Responses to seismic events are to be implemented according to an agreed-upon Seismic Action Plan (SAP), which lists remedial actions that are to be initiated if certain seismic threshold levels are exceeded. These limits and the associated response action for the Wellington project are specified in Table F-3" and are expected to be similar for other

[283] ADM EMERGENCY PLAN, *supra* note 259, at F5; EPA DEVELOPMENT GUIDANCE, *supra* note 158, at E-5.
[284] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 33.
[285] *Id.*

sequestration projects.[286] "The response items are to be implemented only if the epicenter of the seismic event is within an agreed-upon distance from the injection well."[287] This distance is project dependent and based on the pressure field induced by CO_2 injection.[288]

Seismic Event Magnitude Threshold Condition[1]	**Response Action Plan**
Seismic event greater than M2.0 and less than M2.5[2] and no felt report[3]	Continue site activities per permit conditions. Document event for reporting to the EPA in semi-annual reports.
Seismic event greater than M2.5[2] and no felt report[3]	Continue site activities per permit conditions. Within 24 hours of the incident, notify UIC Program Director of the operating status of the facility. If it is determined that gradual shutdown of the well is appropriate, reduce injection rate such that the downhole pressure does not exceed 80% of the maximum pressure observed during the 24-hour period preceding the seismic event. Review seismic and operational data. Report findings to the UIC Program Director and perform corrective action, if necessary.
Seismic event greater than M2.5[2] or local observation or felt report [3]	Initiate immediate shutdown. Within 24 hours of the incident, notify UIC Program Director of the operating status of the facility. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). Determine whether leaks to groundwater or surface water occurred. If a leak is detected: Notify the UIC Program Director within 24 hours of the determination.

[286] *Id.* at 34.
[287] *Id.*
[288] ADM Emergency Plan, *supra* note 259, at 7 (defining an 8-mile radius from the wellhead based on project operating conditions specific to Archer Daniel Midlands project).

	Identify and implement appropriate remedial actions (in consultation with the UIC Program Director). Review seismic and operational data. Report finding to UIC Program Director and perform corrective actions.[4]

[1] Seismic event within an agreed-upon distance from the injection well.
[2] Determined by a local seismometer network or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center (NEIC) using the national seismic network.
[3] Confirmed by local reports of felt ground motion within an agreed-upon distance from the injection well or reported on the USGS "Did You Feel It?" reporting system.
[4] Within 30 days of change in operating status.
Table F-3. Seismic Action Plan threshold limits and corresponding response action plan for the Wellington project.[289]

> In addition to [specify]ing measures to be implemented for various emergency scenarios, the EPA also [require]s the existence of a monitoring-based rapid-response plan to proactively deal with deviations [of the CO_2 plume and pressure front] from expected conditions in the monitored data. . .. The warnings trigger an analysis to identify the cause(s) of the deviation, potentially revise the expected trajectory of the plume based on the revised modeling, and execute a set of enhanced monitoring activities to ensure safe injection.[290]

C. Plugging and Post Closure Care

Assuming that the operator is operating and monitoring the well according to Attachments A, C, and F, the Class VI well should be safe throughout the life of the project. But no operator will continue to inject into the same formation forever. Lest a CCUS operation become a project without an ending, the Class VI rule requires permit applicants to submit a well-plugging plan and anticipated post-closure care (Attachments D and E).[291] This is the final stage of the project.

1. Attachment D – Injection Well Plugging Plan

a. Regulatory Framework

Eventually, formations reach their capacity for storage. Once that happens, operators permanently close the well to ensure the injected

---

[289] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 34.
[290] *Id.* at 35.
[291] 40 C.F.R. § 146.82(a)(16)–(18) (2020).

fluids stay in the ground.[292] This process is called well plugging.[293] A "plug" is a seal inserted in the borehole to stop fluids from entering or exiting the well.[294] It is usually made of a cement or mud mixture.[295] The Underground Injection Control Program regulations give general guidance on acceptable plugging methods.[296] Since well plugging originated with irrigation and oil and gas wells under state jurisdiction, CCUS applicants should also consult state regulations. For example, the Kansas Corporation Commission has standard requirements that apply both to the regular production wells and Class II wells.[297]

After the well plugging, operators must "submit a report to the Regional Administrator" that the well was plugged according to a previously submitted plan or submit an "updated version of the plan" showing how the well was actually plugged.[298] The updated plan should include explanations for why the operator varied from the original plan.[299] The reporting requirement, however, is only for programs where EPA has primacy.[300] Where EPA has transferred primacy to states, applicants in those jurisdictions should consult state reporting requirements.

b. Class VI

The Class VI plugging requirements can be found at 40 C.F.R. § 146.92. As a precaution, the operator must first "flush" the well with a buffer fluid, then "determine bottomhole reservoir pressure,[301] and perform a final external [MIT]."[302] The buffer fluid is a brine solution meant to force CO_2 into the formation.[303] The external MITs may be done "using a temperature, noise, or oxygen activation log."[304] For the permit application, the operator will need to prepare a plan to conduct the bottomhole reservoir pressure and MIT tests, along with the type and placement of the proposed well plugs.[305]

---

292 *Id.* § 146.10(a)(1).

293 *See id.* § 146.3 ("Plugging means the act or process of stopping the flow of water, oil or gas into or out of a formation through a borehole or well penetrating that formation.").

294 EPA PLUGGING GUIDANCE, *supra* note 227.

295 *Id.* at xi.

296 *See* 40 C.F.R. § 146.10 (2020) (providing plugging methods).

297 *See* K.A.R. § 82-3-114 (2008) (proving "methods and procedure for plugging a well drilled for exploration of oil or gas, for underground porosity gas storage, or for injection").

298 40 C.F.R. § 144.51(p) (2020)).

299 *Id.* § 144.51(p)(2).

300 *Id.* § 144.51(p).

301 "Bottom hole pressure: [t]he reservoir or rock pressure at the bottom of the hole, whether measured under flowing conditions or not." Patrick H. Martin & Bruce M. Kramer, *B-Terms*, *in* 8 WILLIAMS & MEYERS, OIL & GAS L. SCOPE, LexisNexis (database updated 2021).

302 40 C.F.R. § 146.92(a) (2020). For a discussion of the MIT process, *see supra* Part III.A.2.

303 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 27.

304 *Id.*

305 40 C.F.R. § 146.92(b) (2020).

In contrast to the plugging requirements for other injection wells, the operator will also need to notify the EPA Regional Director "at least 60 days before plugging."[306] This time frame gives the agency a chance to approve any changes to the well plugging plan from the original permitting process.[307] Finally, after the well is plugged, the owner needs to submit a plugging report[308] that the process was actually completed.[309] It is not entirely clear how the post-plugging report requirement in § 146.92 interacts with the general reporting requirement in § 144.51. What would likely happen is that if something unexpected happened during the plugging proces which was not addressed in the plugging plan, then operators could submit that information along with the other required information such as well flushing activities, and borehole pressure.[310]

For materials, the Class VI rule requires that the interval within the injection zone and USDWs be filled with CO_2-resistant cement.[311] In practice, that means that Class VI wells have stricter plugging material requirements than the Class II wells which also store CO_2. EPA's justification for this is that Class VI wells are designed to store considerably more CO_2 in the long run and as such, these wells pose special risks due to "the corrosive nature of wet supercritical carbon dioxide."[312]

2. Attachment E – Post-Injection Site Care and Site Closure Plan

a. Regulatory Background

Post-closure care is another area where the Class VI Rule diverges from the other well class permits. While the other classes do have various regulations and guidance principals for closing, an operator's obligations after it closes a site are limited.[313] If the site was closed correctly with agency approval, the site should be safe.[314] In contrast, the Class VI rule

306 *Id.* § 146.92(c).

307 *Id.*

308 *See* CLASS I WELL PLUGGING REPORT, KAN. DEP'T OF HEALTH & ENV'T (2012) (serving as an example of a Class I injection well plugging report).

309 40 C.F.R. § 146.92(d) (2020).

310 *See* EPA PLUGGING GUIDANCE, *supra* note 227, at 22–23 (describing what is required in a well plugging report along with EPA suggestions for information to include in the report regarding well preparation and remediation).

311 *Id.* at 15.

312 *Id.*

313 *See* 40 C.F.R. § 146.72 (2020) (establishing the post-injection site care and site closure requirements); *Cf id.* § 146.73 (establishing financial responsibility requirements for post-closure care).

314 *Requirements for all Class I Wells and Class I Hazardous Waste Wells*, U.S. ENV'T PROT. AGENCY, https://perma.cc/2BEC-UYBF (last visited Sept. 26, 2021); *Class II Well Requirements*, U.S. ENV'T PROT. AGENCY, https://perma.cc/7VRZ-B6YW (last visited Sept. 26, 2021); *General Requirements for Class III Wells*, U.S. ENV'T PROT. AGENCY, https://perma.cc

has lengthy and onerous post-closure requirements.[315] EPA appears to have drawn these requirements from similar post-closure requirements for hazardous waste treatment, storage and disposal facilities.[316]

Hazardous waste facilities such as landfills are regulated under the Resource Conservation and Recovery Act (RCRA).[317] Before closing a landfill, EPA requires operators to monitor and maintain liners and install systems for leachate collection and leak detection.[318] EPA sets a default period of thirty years for monitoring, but this can be shortened or extended on a case-by-case basis by the permitting authority.[319] As part of a hazardous waste facility permit application, the operator must submit "a written post-closure plan."[320] And if operators wish to amend the plan, they must go through a set of permit modification procedures.[321] Finally, RCRA-permitted operators must keep their monitoring records "for a period of at least 3 years."[322]

b. Class VI Rule

In the CCUS context, the Post-Injection Site Care (PISC) and Site Closure Plan describes the activities that the applicant will perform to monitor groundwater quality and track the position of the carbon dioxide plume and pressure front after cessation of injection.[323] These activities are to continue until it can be demonstrated that no additional monitoring is needed to ensure that the project does not pose a danger to any USDWs.[324]

/HE6M-9JKG (last visited Sept. 26, 2021); *Class IV Well Requirements*, U.S. ENV'T PROT. AGENCY, https://perma.cc/G25V-AVS4 (last visited Sept. 26, 2021); *Federal Requirements for Class V Wells*, U.S. ENV'T PROT. AGENCY, https://perma.cc/S833-MTSF (last visited Sept. 26, 2021).

315 EPA PLUGGING GUIDANCE, *supra* note 227, at 53–57.

316 *Closure and Post-Closure Care Requirements for Hazardous Waste Treatment, Storage and Disposal Facilities*, U.S. ENV'T PROT. AGENCY, https://perma.cc/JEK9-DRCP (last visited Sept. 26, 2021); In fact, the overlap in regulations led to a lawsuit in the Court of Appeals for the District of Columbia. Carbon Sequestration Council v. U.S. Env't Prot. Agency, 787 F.3d 1129, 1132 (D.C. Cir. 2015). After the Class VI Rule was promulgated, EPA helped a separate rulemaking on the question of if injected carbon dioxide could be regulated under RCRA. *Id.* Several oil producers that had been interested in developing Class VI wells challenged EPA's determination that the injected carbon dioxide was a "waste" underneath RCRA. *Id.* The Court dismissed the case, finding that because no one had yet received a Class VI permit, the operators lacked Article III standing. *Id.*

317 Resource Conservation and Recovery Act of 1976, 42 U.S.C. §§ 6901–6992k (2018) (amending Solid Waste Disposal Act, Pub. L. No. 89-272, 79 Stat. 992 (1965)).

318 *See* 40 C.F.R. § 264.117 (2020) (referring to closure and post-closure requirements found in "subparts F, K, L, M, N and X").

319 *Id.* §§ 264.117(a), 265.117(a).

320 *Id.* § 264.118(a).

321 *Id.* §§ 264.118(d)(1), 270.42.

322 *Id.* § 270.30(j)(2).

323 *Id.* § 146.93(a)–(b); EPA PLUGGING GUIDANCE, *supra* note 227, at 24.

324 40 C.F.R. § 146.93(b) (2020).

Before the EPA authorizes site closure, the permittee is required to submit a report that demonstrates that USDWs are not in danger of contamination.[325] As part of this plan, the applicant will need to submit a summary of existing monitoring data, along with evaluations of the carbon dioxide plume and reservoir pressure.[326] Tables C-1 to C-8 of Attachment C – Testing and Monitoring Plan (Part III.B.2) document the monitoring and testing activities to be conducted during the post-injection phase.

> After the EPA's approval of non-endangerment demonstration and authorization of site closure, . . . [permittees must] prepare[] and submit[a site closure report] within 90 days, documenting the following:
>
> - Plugging of all injection and monitoring wells,
> - Details of site restoration activities,
> - Location of sealed injection well on a plat survey that has been submitted to the local zoning authority,
> - Notifications to state and local authorities,
> - Records regarding the nature, composition, and volume of the injected CO2,
> - Pre-injection, injection, and post-injection monitoring records, and
> - Certifications that all injection and storage activities have been completed.327

The owner or operator will also need to "record a notation on the [property] deed" to provide notice of the Class VI well to future purchasers.[328]

Perhaps the most contentious issue in the post-closure care attachment is the default time period. EPA set a fifty-year default with the caveat that operators could reduce the time frame with sufficient evidence that there was no risk of endangering USDWs.[329] Some commentators on the rule argued that the fifty-year default made CCUS infeasible for industrial users wanting to sequester carbon from their

325 *Id.* §§ 146.82(a)(17), 146.93(a)(2). The operator will need to "notify the Director in writing at least 120 days before site closure." *Id.* § 146.93(d).

326 *See id.* § 146.93(a)(2) (providing all of the requirements of the site closure plan).

327 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 29.

328 40 C.F.R. § 146.93(g) (2020).

329 Response to Greenpeace International, Responses to Public Comments on Financial Responsibility, E.P.A.

plants.[330] As one commentator from the Council of Industrial Boiler Owners wrote,

> The 50-year post-closure period for continuing liability, from a practical perspective, is not workable . . . It is difficult to imagine a generator taking on liability that would include the construction of a generating plant, the long term operation of that plant, and then the 50-year period after closing the well site. Compounding that difficulty is the possibility that the closure of the well does not coincide with the shut down of the power plant, potentially extending liability to 100 years or beyond, per the discretion of the Director . . . This raises the question of why a company would take on a 100-year liability that is essentially out of their control and not really a part of their business.[331]

Others took the opposite approach. For example, Greenpeace criticized the time-frame as insufficient, writing:

> It must be reiterated that monitoring and verification of CO2 storage sites is a long-term task. It does not end when the storage reservoir is capped. Post-operational monitoring over hundreds of years is essential. Significant risks continue to exist and must be monitored both to prevent a catastrophic short term release as well as long-term slow leakage.[332]

EPA's response to these criticisms is as interesting as is troubling. First, EPA responded to the Council of Industrial Boiler Owners that the agency based the fifty-year default on prior studies and that the current test allowed for shorter closure time frames upon sufficient evidence.[333] To Greenpeace, however, the agency emphasized that they had continuing recovery mechanisms against operators:

> [E]ven if a site closure is approved under §146.93, an owner or operator may be held liable for regulatory noncompliance (including violation of 40 CFR 144.12) in certain circumstances. For example, an owner or operator may be held liable for regulatory noncompliance even after site closure was approved if the Director relied on erroneous information (e.g., erroneous modeling data) provided by the owner or operator when approving site closure.[334]

In other words, even if a site was closed according to its post-closure plan and with the EPA approval, the agency can still pursue an operator if the underlying data was incorrect. Given that some of the data in

---

330 *Id; infra* text accompanying note 396.

331 Response to Greenpeace International, Responses to Public Comments on Financial Responsibility, E.P.A.

332 *Id.*

333 *Id.*

334 *Id.*

determining the AoR and other modeling variables is based on educated guesses, this is far from comforting.[335]

Also, worth examining is the option for an alternative time period. EPA allows for a reduction of the default period if the applicant can demonstrate through modeling (and other means) that the plume and pressure fronts will stabilize in a shorter period.[336] The Class VI Rule includes lengthy lists of documentation requirements for this option.[337] The topic was also the subject of the EPA Guidance Document on Well Plugging, Post Injection Site Care, and Site Closure Care.[338] Despite this guidance, EPA has not specified what its stabilization criteria are. Without additional official guidance, applicants should consult with their EPA Region early in the application process on this issue to attempt to head off problems later. Otherwise, it will be nearly impossible to shorten the post-closure period. Shortening this period is crucial to making the project profitable and for meeting the financial assurance requirements.[339]

c. Wellington Permit

To support a non-endangerment finding for the Wellington project, EPA focused on five main data areas.[340] First, the applicants needed to submit "[a] summary of all previous monitoring data collected at the site."[341] EPA asked for "a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site."[342] The data was then "compared with baseline data collected during site characterization and throughout the duration of the project."[343]

Second, the applicant must submit "[a] summary of the computational modeling conducted for the project."[344] "The summary should include a narrative explanation of the computational modeling history, such as verification and validation activities, modifications to the

---

[335] Diana H. Bacon et al., *Probabilistic Risk-Based Area of Review (AoR) Determination for a Deep-Saline Carbon Storage Site*, 102 INT'L J. OF GREENHOUSE GAS CONTROL 103,153, 103, 153 (2020); ("Regulatory oversight of a geologic carbon sequestration (GCS) project relies on iterative estimations, throughout the project lifetime, of the area where increased risks to underground sources of drinking water (USDWs) may occur due to injection of CO_2 . . . The inherent uncertainty in input parameters used in reservoir modeling therefore affects the accuracy of determining the AoR for a project.").

[336] 40 C.F.R. § 146.93(c) (2020).

[337] *Id.*

[338] EPA PLUGGING GUIDANCE, *supra* note 227, at 24.

[339] *See supra* text accompanying notes 329–331.

[340] CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 27–28.

[341] *Id.* at 27.

[342] *Id.*

[343] *Id.*

[344] *Id.*

modeling approach, and changes in the AoR delineation over the life of the project."[345]

Third, over the life of the project, EPA determined that the Wellington operator would need "to demonstrate non-endangerment to USDWs by showing that the carbon dioxide plume behaved as predicted and did not migrate to unintended areas. A good correlation between the observed data and the values predicted by the model will provide evidence of the model's ability to represent the [hydrologic] system."[346] Fourth, the operator would need "to submit all direct and non-direct data to demonstrate that the pressures within the injection zone have decreased as predicted by the model. A good agreement between the actual and predicted values will help validate the accuracy of the model and support a demonstration of non-endangerment."[347] Finally, the permittee would need "to summarize any emergencies or other unanticipated events that occurred during the injection and post-injection phases and explain how they [were] resolved such that there is no . . . endangerment of the USDWs. Such events may include (but are not limited to) the scenarios presented in Table E-1."[348]

Scenario	**Example of Activities Used to Demonstrate Resolution**
Identification of previously unidentified well(s) within the AoR that penetrate the confining zone	Documentation of the determination of whether the well(s) require corrective action and, if applicable, records of any corrective action completed
Detection of CO_2 or other unanticipated parameters/levels of parameters above the confining zone	Documentation of associated monitoring activities (e.g., groundwater samples, 2-D seismic surveys) and data analysis, an explanation of the cause of the anomalous results and any impacts, and any follow-up actions taken
Any divergence from planned operational parameters	Documentation of the divergence/change (e.g., pressure, total volume) and data analysis, an explanation of any impacts, and any follow-up actions taken

345 *Id.*
346 *Id.* at 28.
347 *Id.*
348 *Id.*

Scenario	**Example of Activities Used to Demonstrate Resolution**
Indication that any fault(s) in the AoR is affecting CO_2 containment	Documentation of associated monitoring activities (e.g., pressure monitoring, passive seismic monitoring) and data analysis, an explanation of any impacts, and any follow-up actions taken
Evidence of induced seismic event(s)	Documentation of associated monitoring activities (e.g., passive seismic monitoring) and data analysis, an explanation of any impacts, and follow-up actions, if undertaken
Non-compliance with any other Class VI permit condition, any event that triggers an unscheduled AoR reevaluation according to the AoR and Corrective Action Plan, or any event that triggers action according to the approved Emergency and Remedial Response Plan	A description of how the approved Emergency and Remedial Response Plan was implemented (including references to relevant reporting) and the actions taken to return to compliance

Table E-1. Examples of unanticipated events at a sequestration site.[349]

3. Attachment H - Financial Assurance Demonstration

a. Regulatory Background

In Book V of Tolstoy's *War and Peace*, the novel's youthful protagonist, Count Pierre Bezukhov, confronts his steward for mismanagement of his estate and over-taxation of serfs.[350] In response, the steward presents Pierre with an array of reforms which are, in reality, meaningless gestures or hidden additional costs hoisted on the peasantry.[351] Financial assurance requirements in environmental law can evoke this exchange—though it is not always clear if the federal government is the foolish young noble or the shrewd steward.

---

349 *Id.*
350 LEO TOLSTOY, WAR AND PEACE Book V, 387 (Louise & Aylmer Maude trans., 2016).
351 *Id.*

Financial assurance turns on a relatively simple principle: operators should bear the cost of paying for environmental harms.[352] Unfortunately, by the time that people discover contamination on a site, the operator may be long dissolved or bankrupt.[353] A classic example of this phenomenon is a landfill. Before the passage of RCRA, landfills could accept any and all types of waste.[354] There were no requirements for a post-closure maintenance fund like one might see for cemeteries.[355] Eventually, the landfill would close, and the operator would sell the land and dissolve the business entity.[356] By the time that locals discovered a problem, there would be no one left to sue and the burden would shift to the state and federal governments.[357]

As a remedy, regulators require some showing that operators have the capacity to pay for long-term environmental liabilities.[358] This showing of proof is called "[f]inancial assurance."[359] Most of the major federal environmental statutes include financial assurance requirements. For example, CERCLA,[360] RCRA,[361] the Surface Mining Control and Reclamation Act,[362] and the Clean Water Act[363] all contain financial assurance provisions.

While the guiding principle behind financial assurance is simple, its application can be complicated—especially for small businesses.[364] EPA has several mechanisms for financial assurance including letters of

352 JAMES BOYD, FINANCIAL RESPONSIBILITY FOR ENVIRONMENTAL OBLIGATIONS: ARE BONDING AND ASSURANCE RULES FULFILLING THEIR PROMISE? 1 (2001).

353 *Id.*

354 William Todd Keller Jr., Comment, *Texas Landfills: The Need for Administrative Reform of the Texas Commission on Environmental Quality's Permitting Process*, 51 ST. MARY'S L.J. 187, 193 (2020).

355 *See, e.g.*, Kan. Stat. Ann. § 17-1311 (West 2021) (requiring cemeteries to have a permanent maintenance fund).

356 Boyd, *supra* note 352, at 4.

357 *See id.* ("Environmental cost recovery can also be defeated if a polluter has legally dissolved prior to the realization of liabilities or performance of obligations.").

358 Boyd, *supra* note 352, at 1.

359 *Id.*

360 *See* Comprehensive Environmental Response, Compensation, and Liability Act of 1980, 42 U.S.C. §§ 9601–9675 (2018) (containing financial assurance provisions in § 9608(a)–(b)).

361 Resource Conservation and Recovery Act of 1976, 42 U.S.C. §§ 6901–6992k (amending Solid Waste Disposal Act, Pub. L. No. 89-272, 79 Stat. 992 (1965)); 42 U.S.C. § 6924(a)(6) (2018); 40 CFR § 264.145 (2020).

362 *See* Surface Mining Control and Reclamation Act of 1977, 30 U.S.C. §§ 1201–1328 (2018) (containing financial assurance provisions in § 1257(f)).

363 *See* Federal Water Pollution Control Act, 33 U.S.C. §§ 1251–1388 (2018) (containing financial assurance provisions in § 1321(p)(1)).

364 *See* U.S. ENV'T PROT. AGENCY, RESEARCH AND ANALYSIS IN SUPPORT OF UIC CLASS VI PROGRAM FINANCIAL RESPONSIBILITY REQUIREMENTS AND GUIDANCE 21, 24 (2010) [hereinafter EPA CLASS VI FINANCIAL ASSURANCE GUIDANCE] (explaining various financial assurance mechanisms used and the associated risks).

credit, surety bonds, insurance, trust funds, and corporate financial tests.[365] These mechanisms can be used alone or in combination.[366]

A letter of credit is a financial instrument where the "issuer"—typically a bank—agrees to pay a "demand . . . made by a third party" if the demand meets conditions stipulated in the instrument.[367] The main problem with letters of credit is that the lender typically requires the operator to give them collateral or keep deposit accounts at the institution in the amount guaranteed in the letter of credit.[368] This money, in turn, is not available to operate the business. Another issue with using letters of credit for long-term projects with long post-closure periods—such as a Class VI well—is that they are typically granted on "an annual period" and must be renewed.[369] This may make the coverage vulnerable in the event of a credit drop for the operator.[370]

Surety bonds, also called performance bonds, are "bond[s] given by a surety [such as a bank or an insurance company] to ensure timely performance of a contract."[371] For a surety bond, operators pay an annual premium.[372] In the environmental context, the surety then pools liabilities from various operators and purchases insurance for the pool.[373] In the event of a claim, the operator pays first, followed by the surety company if the operator becomes insolvent.[374] The main difficulty with using surety bonds is that they are also ill-designed for long-term liabilities.[375] "[S]urety bonds are as reliable as the surety company itself," meaning that a payout on a project decades after the initial premiums could jeopardize the financial health of the surety company. [376] As such, operators may have considerable difficulty securing a bond where the time frame is lengthy and uncertain.[377]

---

365 *Id.* at 6–7.

366 40 C.F.R. § 146.85(a)(6) (2020).

367 *Letter of Credit*, BLACK'S LAW DICTIONARY (11th ed. 2019).

368 Boyd, *supra* note 352, at 23–24.

369 EPA CLASS VI FINANCIAL ASSURANCE GUIDANCE, *supra* note 364, at 52–53.

370 *Id.*

371 *Performance Bond*, BLACK'S LAW DICTIONARY (11th ed. 2019).

372 This varies depending on the type of bond. A contract bond (that one might see for a project like a building) is typically a one-time premium. A plugging bond—like what one would see for an oil and gas well—is an annual payment.

373 *Bond Pool (Reclamation)*, NEV. DIV. OF MINERALS, https://perma.cc/MCH8-YWCU (last visited Sept. 26, 2021); *See* Jason Malone & Tim Winslow, *Financial Assurance: Environmental Protection As A Cost of Doing Business*, 93 N.D. L. REV. 1, 13 (2018) (explaining bond pools). Note that this mechanism differs from other applications of surety bonds—"[U]nlike insurers, sureties do not pool premiums to spread risk; instead, the surety premium is based on individual contract factors such as the size of the underlying contract, the financial stability of the principal, and the likelihood of default." Airlines Reporting Corp. v. United States Fid. & Guaranty Co., 31 Cal. App. 4th 1458, 1464 (1995).

374 Boyd, *supra* note 352, at 12.

375 *Id.* at 24.

376 EPA CLASS VI FINANCIAL ASSURANCE GUIDANCE, *supra* note 364, at 53.

377 *Id.*

Another option for financial assurance is insurance.[378] In exchange for an annual premium, the insurer agrees to cover covered risks. A key difference between insurance and surety bonds is that the insurer pays out first, regardless of the financial health of the operator.[379] As such, insurance tends to be more expensive to reflect the risk assessments.[380] One of the main difficulties for using insurance as a financial assurance mechanism is that there must be a market for it.[381] When dealing with a new type of environmental risk, companies can be slow to offer specialty insurance.[382] This can drive up premium prices in the interim.[383]

Next, an operator or permitting authority could set up a trust fund.[384] The advantage of a trust fund is that it typically has a lower administrative burden.[385] Instead of intense monitoring of the operator's financial health, the agency just needs to ensure that the operator is making ongoing payments into the trust.[386] But the main disadvantage for site-specific trust funds is that they are funded over time.[387] That means that they are not fully funded at the start of a project and may remain unfunded if the operator becomes insolvent.

Finally, larger companies may seek a corporate financial test, also called the self-demonstration test.[388] These tests allow a company to prove that it has sufficient assets on hand to address any contamination that might arise.[389] On the outset, this makes sense. For example, if Microsoft decided to sponsor a carbon capture storage project, no one would seriously doubt the company's ability to pay for remediating a contaminated site. But the financial assurance test has its own problems. First, a company may have sufficient assets, but not readily available liquid capital.[390] As such, it can make collecting capital to address problems difficult.[391] Second, if a large company fails suddenly, financial assurance obligations may be dischargeable in bankruptcy.[392] Third, given the dizzying amount of accounting variables and the potential for fraud, it can be difficult to tell if a particular company is healthy enough to meet the test standards.[393]

---

[378] Jason Malone & Tim Winslow, *Financial Assurance: Environmental Protection as a Cost of Doing Business*, 93 N.D. L. REV. 1, 14 (2018).
[379] Boyd, *supra* note 352, at 23.
[380] *Id.* at 20.
[381] *Id.* at 19.
[382] Malone & Winslow, *supra* note 378.
[383] *Id.* at 14–15.
[384] EPA CLASS VI FINANCIAL ASSURANCE GUIDANCE, *supra* note 364, at 28.
[385] *Id.*
[386] *Id.* at 49.
[387] Boyd, *supra* note 352, at 25; *FutureGen*, 16 Env't Admin. Decisions 717, 765 (2015).
[388] Boyd, *supra* note 352, at 26.
[389] *Id.* at 26, n.110.
[390] *Id.* at 26.
[391] *Id.*
[392] *Id.* at 20.
[393] U.S. ENV'T PROT. AGENCY, SELF-INSURANCE FOR COMPANIES WITH MULTIPLE CLEANUP LIABILITIES PRESENTS FINANCIAL AND ENVIRONMENTAL RISKS FOR EPA AND THE

Fourth, the self-demonstration test disrupts the market.[394] As larger companies do not need to tie up large amounts of their revenue into deposit accounts or trust funds, it gives them a competitive edge against smaller businesses.[395] Finally, the default time-frame makes the financial test unworkable in the long term. In theory, a corporation may exist in perpetuity, but in practice it does not. As analysts at McKinsey have noted, "[i]n 1935, the life expectancy of an S&P 500 company was 90 years. By 2010, it was 14 years."[396] Even if a corporation seems stable today, there is no guarantee that will be true when a spill is discovered.

In the injection well context, regulators have used differing levels of financial assurance requirements depending on the well class. Class II wells typically require a low-cost type of surety bond called a plugging bond.[397] These are typically meant to cover the cost for plugging the well. In contrast, Class I wells for hazardous waste have stricter financial assurance requirements and companies need to demonstrate their ability to address problems in the post-closure period.[398]

b. Class VI Rule

The Class VI rule's financial assurance regime resembles an upgraded version of the Class I permit financial requirements. The "rule requires that the applicant demonstrate [that it has the] financial ability to successfully complete all tasks associated with performing well corrective action, well plugging, post-injection site care, site closure, and implementation of the emergency remedial plan during the periods specified in Table H-1."[399]

Activity	**Period of Performance**
Performing corrective action	As needed

PUBLIC 8 (2017) (In one report, EPA focused on the data and regulatory constraints hampering the financial analysis. A company may not need to disclose all of its "environmental liabilities" and EPA "lacks . . . [the] technical ability needed to validate self-insurance for companies with multiple environmental liabilities").

394 *Contra* Boyd, *supra* note 352, at 67 ("Self-demonstrated assurance . . . may hamper cost recovery.").

395 Financial Responsibility Requirements Under CERCLA § 108(b) for Classes of Facilities in the Hardrock Mining Industry, 82 Fed. Reg. 3388, 3441 (2017), (EPA acknowledged this phenomenon in its draft rule on proposed financial responsibility requirements for hardrock mining in 2017, "Analyses conducted by EPA of the financial test options considered offers evidence, however, that fewer small businesses are likely to possess the credit ratings and net worth necessary to qualify for self-insurance. EPA, therefore, solicits comment on whether the availability of a financial test would thus create a competitive disadvantage for small businesses").

396 Christopher Handscomb & Shail Thaker, *Activate Agility: The Five Avenues to Success*, MCKINSEY & CO. (Feb. 1, 2018), https://perma.cc/M4HL-KKE5.

397 HO ET AL., *supra* note 130, at 22.

398 40 C.F.R. § 146.73 (2020).

399 CLASS VI PERMIT FEATURES AND GUIDELINES, *supra* note 47, at 41.

Plugging injection and monitoring wells	One time
Post-injection site care	Throughout the post-injection phase
Site closure	One time
Emergency/remedial response	As needed

Table H-1. List of project activities that require financial assurance.[400]

> For each of these [categor]ies, the applicant [must] prepare a cost estimate, which should . . . close[ly] agree[] with the range of costs estimated by the EPA. Table H-2 lists the [project tasks for which the applicant needs to provide a cost estimate to] the EPA. The largest cost . . . [is] associated with treating a USDW that may be accidentally contaminated due to sequestration operations at the site.[401]

For the Wellington project, the EPA initially estimated an expense ranging between $3.2 million and $62.8 million for this task.[402]

> [I]f the applicant can successfully demonstrate the absence of a USDW, it can significantly reduce its financial burden. The second largest cost . . . is associated with creating and maintaining a hydraulic barrier to prevent CO_2 from escaping the injection zone due to a breach in the confining zone, reactivation of fault(s), or escape through leaky well(s).[403]

For the Wellington project, the EPA estimated the cost for this activity to range between $3.9 million and $5.6 million.[404]

Project task
Performing corrective actions on deficient well(s) in the AoR
Rent maintenance rig (clean out deficient wells)
Flush deficient wells
Plug deficient wells
Log deficient wells
Plugging injection well
Rent maintenance rig (clean out injection well)
Perform mechanical integrity test before plugging injection well
Flush injection well with a buffer fluid before plugging
Plug injection well

400 *Id.*
401 *Id.*
402 *Id.*
403 *Id.*
404 *Id.*

Log injection well
Post-injection site care
Post-injection operation and maintenance for monitoring wells
Post-injection seismic survey
Post-injection groundwater monitoring
Post-injection monitoring reports to regulators
Site closure
Rent maintenance rig (clean out monitoring wells)
Perform mechanical integrity test before plugging monitoring wells
Flush monitoring wells
Plug monitoring wells (occurs at end of PISC)
Log monitoring wells (occurs at end of PISC)
Remove surface equipment and restore vegetation for injection wells
Remove surface equipment and restore vegetation for monitoring wells (occurs at end of PISC)
Document plugging and closure process
Emergency and remedial response
Stop CO_2 injection
Create hydraulic barrier
Install chemical sealant to stop CO_2 leaks
Treat contaminated water from USDW

Table H-2. Project activities that require demonstration of financial responsibility.[405]

> The cost of using a bond, insurance, or trust fund can be expensive and approach 3% of the face value annually. For coverage of $70M, the cost can approach $2M annually. Because the applicant has to demonstrate the ability to meet financial obligations from the injection phase to site closure, which can span a period of 50 years (the default), the overall cost of coverage can be quite high. The EPA, however, allows for self-insurance if the applicant can demonstrate that it has the financial strength to meet all financial obligations. To qualify for self-insurance, several financial thresholds specified in Table H-3 must be met. Additionally, the applicant must be capable of satisfying the financial ratio tests listed in Table H-4.[406]

As noted previously, self-insurance is usually suited best for larger corporations and has its own challenges.

[405] *Id.* at 42.
[406] *Id.* at 43.

Financial Indicator	**Description**	**Requirement at 40 C.F.R. 146.85(a)(6)(v)**
Net Working Capital (NWC)	Short-term financial health (current assets minus current liabilities)	NWC must be at least six times the sum of the current cost estimates for all required geosequestration (GS) activities.
Total Assets	Combined value of economic resources and all items of monetary value owned by a firm	Assets in the United States must a) amount to at least 90% of total assets or b) amount to at least six times the sum of the current cost estimates for all required GS activities.
Tangible Net Worth (TNW)	The value of a company that is liquefiable, i.e., total assets (not including intangible assets) minus liabilities.	Although the rule does not specify a minimum TNW amount, a TNW of at least six times the sum of the current cost estimates for all sequestration activities listed in Table H-1 is required.

Table H-3. EPA financial coverage criteria.[407]

Type of ratio	**Financial Ratio**	**Threshold**
Debt — Equity	Total Liabilities/Net Worth	< 2.0
Assets — Liabilities	Current Assets/Current Liabilities	> 1.5
Cash Return on Liabilities	(Net Income + Depreciation + Depletion + Amortization)/Total Liabilities	> 0.10
Liquidity	(Current assets – Current Liability)/(Total Assets)	>0.10
Net profit	Net profit	>0

Table H-4. Financial ratios criteria and thresholds for self-insurance.[408]

[407] *Id.*
[408] *Id.*

c. Wellington Project

The Wellington planning team experienced hesitancy among insurers and re-insurers due to EPA's special coverage requirements for problems such as seismicity.[409] Further, AIG—which had previously invested time and effort to understand how to evaluate risks for geologic sequestration projects—is no longer providing coverage in this field.[410] On calculating the amount of necessary insurance, EPA declined to reveal how it calculates the cost of certain remedial measures or specify the types of technology which it would require. As a result, the applicants would have been required to commit and find an insurer for EPA's estimated financial assurance requirement without being able to run independent cost analyses or provide such data to a potential insurer.

IV. CONCLUSION

The Class VI permit is the most onerous of all EPA underground injection programs. The agency promulgated the Class VI Rule specially to address the buoyant nature of CO_2. As compared to a Class II well, the duration and costs associated with permitting a Class VI well are much higher and the technical approach related to delineating the EPA AoR is much more challenging. The testing and monitoring plans involve an extensive suite of modern technologies such as satellite-based monitoring of land surface deformation and multiple seismic surveys to track the CO_2 plume. Finally, the financial assurance requirements necessitate the applicant to be well capitalized and allocate substantial funds to meet future obligations associated with potential CO_2 leakage and project failure. Despite these challenges, EPA and permit-seekers have laid the groundwork for future projects. Hopefully, there will be many more to come.

409 BIRDIE ET AL., *supra* note 48, at § 4.5.

410 *Id.* PAUL E. GUTERMANN ET AL., STORM CLOUDS AHEAD: CLIMATE CHANGE AND THE INSURANCE INDUSTRY 4–5 (2008).