Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

REGULATORY FRAMEWORKS AND PERMITTING CONSIDERATIONS FOR GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE PCOR PARTNERSHIP REGION

Plains CO_2 Reduction (PCOR) Partnership Initiative
Task 5 – Deliverable 8a

Prepared for:

Joshua Hull

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26505

DOE Cooperative Agreement No. DE-FE0031838

Prepared by:

Kevin C. Connors
David V. Nakles
Katherine K. Anagnost
Susan L. McKenzie
Catherine R. Stevens
John E. Hunt
Joshua G. Regorrah
Erin N. Peck
Caitlin M. Olsen
Amanda J. Livers-Douglas

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

January 2023
Approved April 2023

2023-EERC-04-02

EERC DISCLAIMER

ACKNOWLEDGMENT

This material is based upon work supported by DOE NETL under Award No. DE- FE0031838 and NDIC under Contract Nos. FX-XCI-226 and G-050-96.

DOE DISCLAIMER

NDIC DISCLAIMER

TABLE OF CONTENTS

LIST OF FIGURES iii

LIST OF TABLES iii

EXECUTIVE SUMMARY iv

INTRODUCTION 1

BACKGROUND 3
- Dedicated Versus Associated CO_2 Storage 3
- Regional CCS/CCUS Activity 3

U.S. REGULATORY PERSPECTIVE 4
- EPA – SWDA UIC Program for Class VI Wells 4
- States and Class VI Primacy 5
- IOGCC Model Framework 7
  - Waste Management Framework Versus Resource Management Framework 8
  - State-Managed Cradle-to-Grave Regulatory Model 8
  - Pore Space Ownership and Amalgamation 9
  - Transfer of Long-Term Responsibility 10

REGULATORY DEVELOPMENTS IN THE PCOR PARTNERSHIP REGION 11
- United States 11
  - North Dakota 13
  - Wyoming 15
  - Montana 16
  - Nebraska 17
  - Alaska 17
  - Remaining PCOR Partnership States 18
- Canada 18
  - British Columbia 19
  - Alberta 19
  - Saskatchewan 20
  - Manitoba 20

REGULATORY PERMITTING PROCESS AND TIMELINES 20
- Permitting of Characterization Activities 24
  - Stratigraphic Test Wells 24
  - Geophysical Surveys 24
- Class VI Permitting Process 25
  - EPA Class VI UIC Program 25
  - North Dakota Class VI UIC Program 26
  - Wyoming Class VI UIC Program 31

Continued . . .

TABLE OF CONTENTS (continued)

CCS/CCUS INCENTIVE PROGRAMS ... 34
Federal Tax Incentives ... 34
U.S. Tax Incentives ... 35
Canadian Tax Incentives ... 37
Summary of Federal Incentives ... 38
State Tax Incentives ... 39

CONCLUSIONS ... 40

REFERENCES ... 41

INTERSTATE OIL AND GAS COMPACT COMMISSION MODEL STATUTE ... Appendix A

INTERSTATE OIL AND GAS COMPACT COMMISSION MODEL RULES AND REGULATIONS ... Appendix B

40 CODE OF FEDERAL REGULATIONS (CFR) PART 124 SUMMARY ... Appendix C

40 CODE OF FEDERAL REGULATIONS (CFR) PART 144 AND PART 146 SUMMARY ... Appendix D

LIST OF FIGURES

1 Geographic extent of the PCOR Partnership region comprising ten states and four Canadian provinces 2

2 Active and announced projects under development in the PCOR Partnership region........ 4

3 Current status of Class VI primacy in the United States as of November 2022 6

4 CGS Task Force “cradle-to-grave” regulatory system 10

5 Status of CCS policy and regulatory developments in the PCOR Partnership region related to pore space law, long-term responsibility, and Class VI primacy........ 12

6 AMA for CCS/CCUS project implementation........ 21

7 Generalized timeline for development of a geologic CO_2 storage project in the United States for states with UIC Class VI primacy 23

8 Phases of the geologic sequestration of CO_2 Class VI project from EPA UIC Program Class VI Implementation Manual for UIC Program Directors, January 2018...... 25

9 North Dakota Class VI permitting process involving drilling permits, SFPs, and permits to inject........ 28

10 Map showing conceptualized project boundaries, including the CO_2 plume at the end of injection, the stabilized plume, the storage facility area, the hearing notification area, and the evaluation area for a geologic CO_2 storage project........ 29

11 General timeline of the storage facility-permitting process of North Dakota........ 30

12 WDEQ timeline and process for UIC Class VI permitting 33

13 Carbon-pricing framework across all of Canada........ 38

LIST OF TABLES

1 Primary Drivers for CCS/CCUS Projects........ 34

2 2022 IRA Increase to Federal 45Q Tax Credit Value 35

3 Summary of State Tax Incentives in the PCOR Partnership Region 40

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

REGULATORY FRAMEWORKS AND PERMITTING CONSIDERATIONS FOR GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE PCOR PARTNERSHIP REGION

EXECUTIVE SUMMARY

Carbon capture and storage (CCS) projects in the Plains CO_2 Reduction (PCOR) Partnership region and across the United States are advancing beyond site-screening and feasibility assessments. As they do, the permitting process has been identified as a major barrier to their commercial deployment. Specifically, CCS project developers face an uncertain, multiyear permitting process that does not align with commercial project development timelines. To properly plan, design, and construct a commercial facility, project developers need to have a clear understanding of the regulatory requirements and the duration of the permitting process. Certainty in the regulatory and permitting process has increased dramatically in the United States since the U.S. Environmental Protection Agency (EPA) promulgated its first regulations for a new class of carbon dioxide (CO_2) injection wells—Class VI—and states, such as North Dakota and Wyoming, have received primary enforcement authority of these regulations, otherwise known as primacy, from EPA.

Unlike the waste disposal framework used by EPA to develop Class VI regulations, both North Dakota and Wyoming adopted the resource management framework recommended by the Interstate Oil and Gas Compact Commission (IOGCC) for the regulation of the geologic storage of CO_2. A resource management framework recognizes the regulatory complexity of CO_2 storage and allows for the integration of environmental protection; ownership and management of the pore space; maximization of storage resource; and responsibility for long-term liabilities into an all-encompassing (i.e., cradle-to-grave) regulatory framework. The policy and regulatory framework created by North Dakota has led to a streamlined permitting process, which resulted in an 8-month permitting time frame for two commercial CO_2 storage projects in 2022. Wyoming, the only other state with Class VI primacy in the United States, is advancing a similar regulatory framework and permitting process, with multiple Class VI injection well applications pending.

Concurrent with these regulatory developments, monetary incentives for the commercial deployment of CCS and carbon capture, utilization, and storage (CCUS) projects have also evolved, primarily in the form of federal tax incentives. These incentives, including production and investment credits, master limited partnerships, and private activity bonds, have the potential to reduce the cost of deployment for both the carbon capture technology as well as associated infrastructure and to foster an economic environment of increased investment certainty (e.g., recent

enhancements to the 45Q tax credits) and financing (e.g., U.S. Department of Agriculture and U.S. Department of Energy loans and/or loan guarantees) options.

This report describes the development of regulatory frameworks and approaches to permitting geologic storage of CO_2 under the jurisdiction of EPA and states with Class VI primacy in the PCOR Partnership region. This review includes a federal, state, and provincial legislative and regulatory update and a description of the current landscape of Class VI primacy in the PCOR Partnership region and across the United States. The vital role of the states in regulating geologic storage of CO_2 is also discussed as well as the importance of adopting a resource management framework. Lastly, the learnings from the first permits issued under state Class VI primacy are presented along with a summary of the key federal and state monetary incentives that have been put in place to spur the deployment of commercial CCS/CCUS projects. These regulatory and permitting developments in the states and provinces of the PCOR Partnership region, in combination with the evolving monetary incentives, represent critical factors in providing CCS/CCUS project developers with the regulatory and financial certainty that they need to accelerate the commercial deployment of CCS/CCUS in the region and, perhaps, across the United States.

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

REGULATORY FRAMEWORK AND PERMITTING CONSIDERATIONS FOR GEOLOGIC STORAGE OF CARBON DIOXIDE IN THE PCOR PARTNERSHIP REGION

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, funded by the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE), the Oil and Gas Research Program and the Lignite Research Program of the North Dakota Industrial Commission (NDIC), in combination with more than 230 public and private partners, is advancing the commercial deployment of carbon capture and storage (CCS) and carbon capture, utilization, and storage (CCUS) technologies. The PCOR Partnership is focused on a region comprising ten U.S. states and four Canadian provinces in the upper Great Plains and northwestern regions of North America (Figure 1). It is led by the Energy & Environmental Research Center (EERC) of the University of North Dakota, with support from the University of Wyoming and the University of Alaska Fairbanks. The goal of this joint government–industry effort is to accelerate the commercial deployment of CCS/CCUS throughout the PCOR Partnership region.

As carbon dioxide (CO_2) storage projects emerge and advance beyond site-screening and feasibility assessments, the acceleration of their commercial deployment hinges upon overcoming the barrier of project permitting. Project developers need to have a clear understanding of the regulatory requirements and the duration of the permitting process to secure timely funding and to properly plan, design, and execute on a commercial scale. The certainty of the regulatory and permitting process has increased dramatically in the United States since the U.S. Environmental Protection Agency (EPA) promulgated its first regulations for a new class of CO_2 injection wells—Class VI—and states, such as North Dakota and Wyoming, have received primary enforcement authority of these regulations, otherwise known as primacy, from EPA. Utilizing the resource management framework recommended by the Interstate Oil and Gas Compact Commission (IOGCC) (2007), these states have created a policy and regulatory framework and a streamlined permitting process, which have led to an 8-month permitting time frame for the first two commercial CO_2 storage projects in North Dakota and the submission of multiple Class VI injection well applications in the state of Wyoming in 2022.

The remainder of this report discusses the importance of states in acquiring Class VI primacy combined with adopting a resource management regulatory framework, in lieu of the waste

Figure 1. Geographic extent of the PCOR Partnership region comprising ten states (Alaska, Montana, Wyoming, North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Missouri, and Wisconsin) and four Canadian provinces (British Columbia, Alberta, Saskatchewan, and Manitoba).

disposal framework established by EPA, to the development of both policy and regulations that will provide regulatory certainty to the CCS/CCUS industry and the investment community. In addition, an update of the legislative and regulatory efforts of the federal governments and the state/provincial governments in the PCOR Partnership region, including a description of the current landscape of Class VI primacy in both the PCOR Partnership region and across the United States, is provided. Also presented are the permitting process and important considerations when permitting geologic CO_2 storage under the jurisdiction of EPA, North Dakota, and Wyoming and the learnings from the first state Class VI primacy-issued permits in North Dakota. Lastly, the current and evolving federal/state monetary incentives, which are playing a key role as drivers for the business case of CCS/CCUS, are briefly discussed.

BACKGROUND

Dedicated Versus Associated CO_2 Storage

Projects that capture CO_2 emissions from industrial sources, transport the captured CO_2 via pipeline to an injection well location, and inject the CO_2 deep underground into suitable geologic formations for permanent storage can be broadly divided into two types, dedicated storage of CO_2 (CCS) and associated storage of CO_2 (CCUS). ***Dedicated storage*** involves the underground injection of man-made, or anthropogenic, CO_2 into saline aquifers solely for the purpose of reducing CO_2 emissions to the atmosphere. There are several commercial dedicated storage projects operating around the world, three of which are located in the PCOR Partnership region: 1) the Aquistore Project operated by SaskPower near Estevan, Saskatchewan; 2) the Quest Project operated by Shell in Alberta; and, most recently (i.e., June 2022), 3) the Red Trail Energy, LLC (RTE) CCS project located in Richardton, North Dakota. ***Associated storage*** of CO_2 occurs incidentally as CO_2 is used for the enhanced oil recovery (CO_2 EOR). While oil production is the primary goal of the CO_2 EOR process, nearly 95% of the CO_2 remains in the subsurface as the CO_2 produced with the recovered oil is separated, purified as needed, and reinjected for additional oil recovery (Gorecki, 2019).

Regional CCS/CCUS Activity

Interest in developing CCS/CCUS projects in the PCOR Partnership region has significantly increased, with recent amendments to the federal 45Q tax credit as the primary business driver. At the same time, the combination of these federal 45Q tax credit amendments with the incentives associated with emerging low-carbon fuel standard (LCFS) markets has also expanded the business case for CCS/CCUS to the evolving ethanol and biofuels industry in the region. Lastly, social pressure to decarbonize the economy of the region has also fostered new interest in commercial CCS/CCUS opportunities in the region as environmental, social, and governance metrics for industries are being defined (Peck and others, 2022b).

CCS/CCUS activities began in the PCOR Partnership region in 1986, with these earliest efforts initiated by gas-processing plants that capture CO_2 for transport and use during CO_2 EOR. Since that time, other industries have put CCS/CCUS into practice, with multiple projects located in Canada and the United States, and one cross-border project that captures CO_2 in North Dakota and transports it via pipeline to oil fields in southern Saskatchewan. These projects are capturing CO_2 at a variety of industrial facilities, including a coal-fired power plant, a coal gasification plant, gas-processing plants, a bitumen-upgrading plant, and an ethanol production facility (Figure 2). Each of these projects involve the pipeline transport of CO_2 from the capture site to the storage location, with the pipelines ranging in length from 1 to 500 miles (800 kilometers). Geologic storage is occurring primarily via associated storage, although dedicated storage in saline aquifers is also a component of multiple Canadian and U.S. projects.

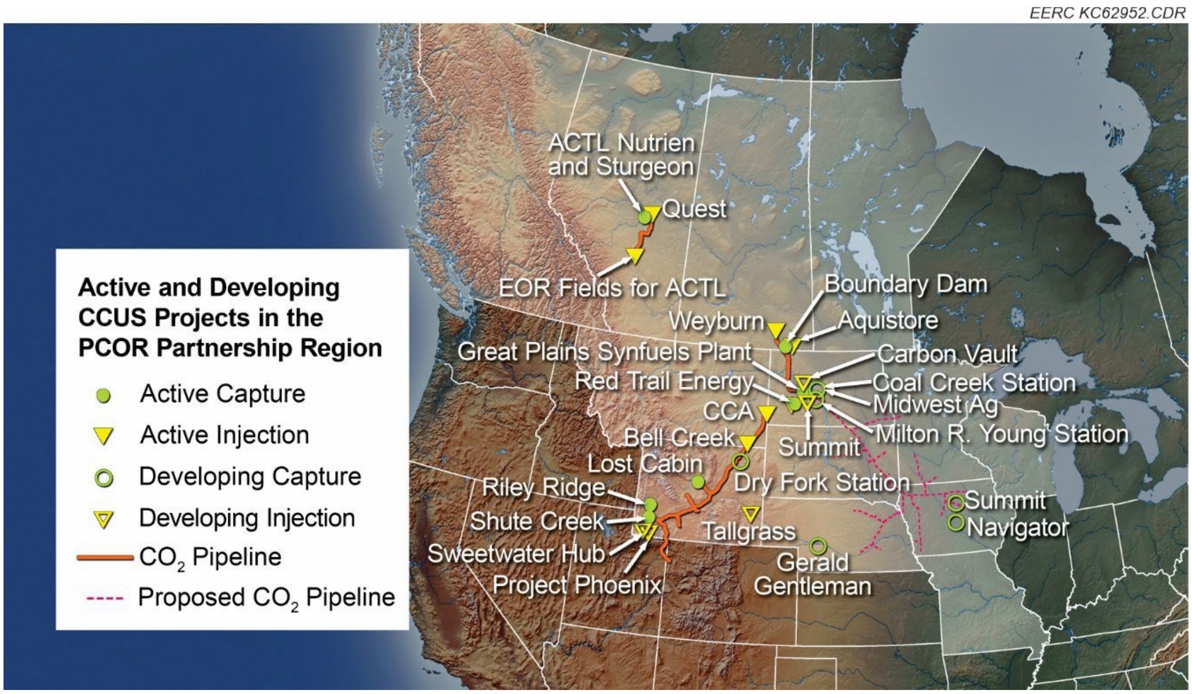

Figure 2. Active and announced projects under development in the PCOR Partnership region.

U.S. REGULATORY PERSPECTIVE

EPA published final regulations for Class VI injection wells in 2010 under the authority of the underground injection control (UIC) program of the Safe Drinking Water Act (SWDA). Since that time, multiple states are in various stages of pursuing Class VI primacy. The efforts of both EPA and these states are described in the remainder of this section.

EPA – SWDA UIC Program for Class VI Wells

The UIC program regulates the injection of fluids underground for the purpose of storage, mineral recovery, or waste disposal with the goal of protecting underground sources of drinking water (USDWs). The UIC program consists of six injection well classes, with Class VI being the newest well classification. Class VI injection wells are used to inject CO_2 into deep subsurface strata for the primary purpose of permanent geologic storage. Injection activities for CO_2 EOR and associated storage of CO_2 are regulated under the Class II UIC program. A brief description of each of the six injection well classes that are regulated as part of the UIC program are as follows:

- Class I wells are used to inject hazardous and nonhazardous wastes into deep, isolated rock formations.

- Class II wells are used exclusively to inject fluids associated with oil and natural gas production, primarily for the disposal of wastewater (i.e., saltwater disposal) or the subsurface emplacement of fluids for enhanced oil and/or gas recovery. The injection of CO_2 for EOR and associated storage is regulated as part of this well class.

- Class III wells are used to inject fluids to dissolve and extract minerals.

- Class IV wells are shallow wells used to inject hazardous or radioactive wastes into or above a geologic formation that contains a USDW. In 1984, EPA banned the use of Class IV injection wells.

- Class V wells are used to inject nonhazardous fluids underground. Most Class V wells are used to dispose of wastes into or above USDWs.

- Class VI wells are used for injection of CO_2 into underground subsurface rock formations for long-term storage, or geologic sequestration.

In December 2010, EPA published regulations for Class VI injection wells. These regulations address the unique considerations of deep underground injection of CO_2 for dedicated storage, including such factors as the buoyancy of CO_2, its subsurface mobility, its corrosivity in the presence of water, and the anticipated large injection volumes. Section 1421 of the SDWA (codified at 40 Code of Federal Regulations [CFR] Part 144) directs EPA to promulgate regulations for UIC programs to protect USDWs and prohibits any underground injection activity except when authorized by a permit or rule; Class VI can only be authorized by permit. At the time of this writing, EPA maintains primacy for all Class VI injection well activities in every state except North Dakota and Wyoming, which are the only two states to have received Class VI primacy. To receive Class VI primacy, a state must adopt rules that meet or exceed the stringency of the UIC Class VI regulations in the protection of USDWs.

EPA created the Class VI well classification under the "as stringent as" EPA standard mandated in Section 1422 of the SDWA. This Class VI well classification differs from the Class II UIC program, which can be regulated either under Section 1422 or Section 1425 of the UIC program, the latter of which requires state Class II primacy programs to be "as effective as" the EPA requirements in protecting USDWs. The Class VI rule, in some instances, exceeds Class I hazardous and nonhazardous waste injection well requirements. The decision of EPA to regulate Class VI wells under Section 1422 and to use Class I waste disposal frameworks as the starting point to develop the national "minimum standards" for these wells, has, along with other economic factors, resulted in minimal commercial CCS deployment over the past decade. However, the more recent interest in the commercial deployment of dedicated storage projects, driven by the 45Q tax credits and other monetary incentive programs, has reinvigorated states to consider pursuing Class VI primacy.

States and Class VI Primacy

The process of obtaining Class VI primacy is both complex and time-consuming. Nevertheless, at the time of the writing of this report, multiple states are in various phases of pursuing Class VI primacy in the PCOR Partnership region and across the United States (Figure 3). North Dakota was the first state in the nation to receive this authority in 2018, following an almost 5-year application process with EPA (Region 8). Wyoming followed North Dakota, also with EPA Region 8, receiving approval in 2 years and 9 months.

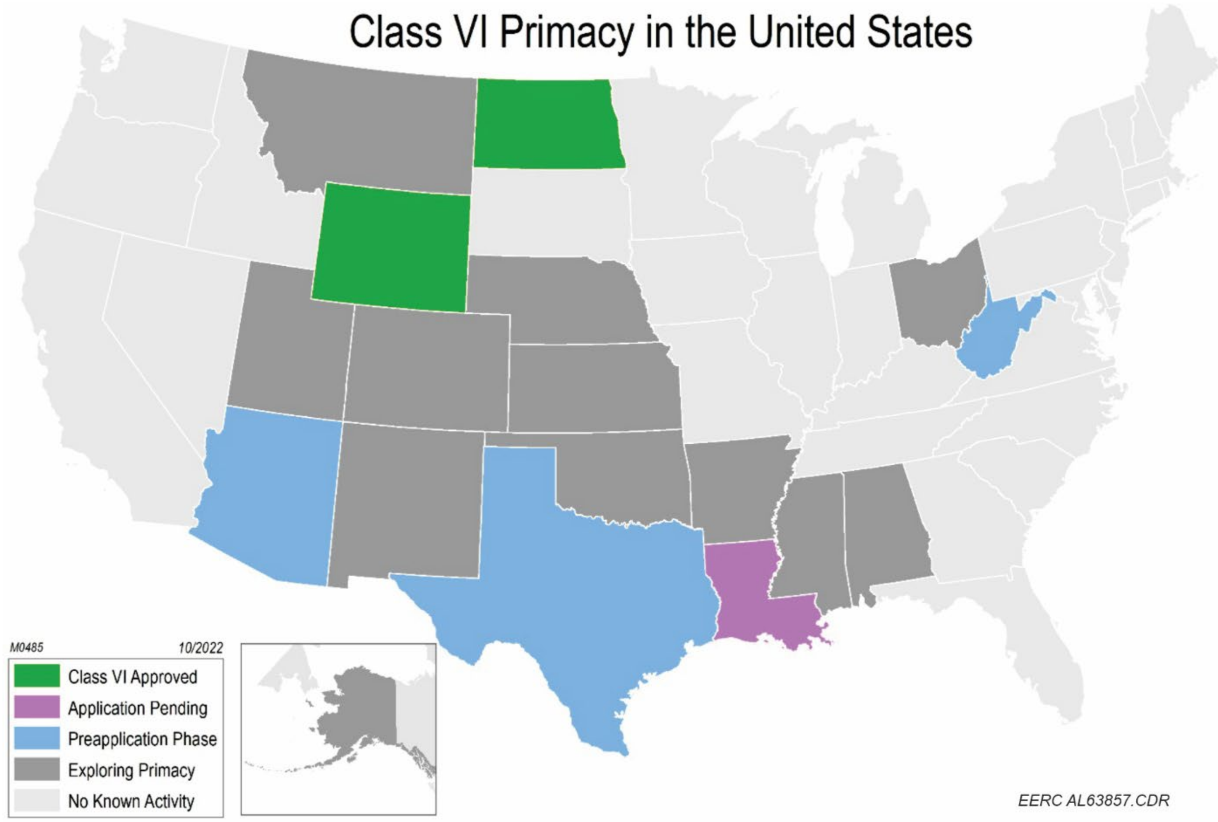

Figure 3. Status of Class VI primacy in the United States as of November 2022.

In nonprimacy states, EPA maintains Class VI regulatory authority. This represents a concern to many CCS project developers as it introduces additional uncertainty and complexities to the permitting process. Of particular concern is these uncertainties and complexities will increase the risk of extending the regulatory permitting process timeline beyond what could be achieved in states with Class VI primacy. For example, the EPA Class VI permitting process is mostly untested, having only been put into action in Illinois (EPA Region V). In this case, the permitting process for a Class VI injection well required nearly 6 years to be approved. On the other hand, permit approvals in states with Class VI primacy have proven to be subject to fewer substantial permitting and regulatory delays. While the sample size of permit approvals is small, the efficacy of the state permitting process appears to be attributable to the states being more responsive, having firsthand knowledge of the local subsurface geology and other ongoing subsurface activities and being more willing to adapt to changing circumstances and to make quicker decisions within their established regulatory frameworks. Perhaps more importantly, states also have an added level of accountability to enforce regulations and environmental safeguards while being simultaneously tasked with promoting the development of geologic CO_2 storage to the benefit of the state and its citizens. It should be noted that one concern of EPA during primacy reviews is that the states do not have the technical bandwidth to properly review and approve a permit application for a geologic storage project. In those instances, the state must also provide evidence to EPA that it has the necessary technical expertise to perform this regulatory function (U.S. Environmental Protection Agency, 2014).

A key requirement for states to receive Class VI primacy from EPA is a demonstration that the state has an established UIC regulatory program that protects USDWs in a manner that is equivalent to the federal Class VI UIC program. This is known as the "as stringent as" standard (SDWA Section 1422). However, states have additional priorities to consider, such as promoting the development of geologic CO_2 storage and maximizing the use of the pore space of storage reservoirs. For this reason, in the preamble to the Class VI rules, EPA recognized the added value, flexibility, and better positioning of states to regulate CO_2 storage at the time the Class VI regulations were being contemplated:

> *EPA believes that States are in the best position to implement UIC–GS (geologic sequestration) programs, and by allowing for independent Class VI primacy, EPA encourages States to take responsibility for implementation of Class VI regulations. The Agency's UIC program believes that this may, in turn, help provide for a more comprehensive approach to managing GS projects by promoting the integration of GS activities under SDWA into a broader framework for States managing issues related to CCS that may lie outside the scope of the UIC program or other EPA programs. This would harness the unique efficiencies States can offer to promote adoption of GS technology that incorporates issues in the broader scope of CCS, while ensuring that USDWs are protected through the UIC regulatory framework. Allowing States to apply only for Class VI primacy will also shorten the primacy approval process. EPA's willingness to accept independent [primacy] applications for Class VI wells applies only to Class VI well primacy and does not apply to any other well class under SDWA Section 1422 (i.e., I, III, IV, and V).* (U.S. Environmental Protection Agency, 2010).

EPA recognizes the limitations of its authority under the SDWA and the Class VI UIC program and acknowledges the ability of the states to broaden the scope of a well-centric regulatory program (i.e., the federal Class VI UIC program) to create a regulatory framework that spans all aspects, from cradle-to-grave, of a dedicated CO_2 storage project. Consistent with these acknowledgments of EPA, it is recommended that the states in the PCOR Partnership region and beyond apply for Class VI primacy authority since achieving primacy at the state level has the potential to accelerate the widespread commercial deployment of CCS in both the PCOR Partnership region and across the United States.

IOGCC Model Framework

The recognition of EPA in 2010 that the states are better-suited for implementing UIC–GS Class VI programs and their willingness to accept independent primacy applications for Class VI wells had its origins in the earlier work of the Carbon Geologic Storage Task Force (CGS Task Force) of IOGCC. The CGS Task Force, with representation comprising IOGCC member states, oil and gas agencies, DOE, and the Regional Carbon Sequestration Partnerships, was formed in 2002 to answer the following question: Are state or federal governments the most appropriate regulator for the dedicated storage of CO_2? The CGS Task Force concluded that to facilitate the orderly development of CO_2 storage projects within state and provincial boundaries, the state or province should take the lead and embrace two basic principles:

1) It is in the public interest to promote the geologic storage of CO_2 to reduce anthropogenic CO_2 emissions.

2) The pore space of the state or province should be regulated and managed as a resource under a resource management framework.

Waste Management Framework Versus Resource Management Framework

The CGS Task Force examined legal, policy, and regulatory issues and the role of the state in regulating this activity, which resulted in the development of a model statute (Appendix A) and model regulations (Appendix B). The intent was for states to adopt this model framework by customizing it to address state-specific preferences or regulatory approaches. By using the overarching regulatory philosophy of the model statute and rule, which was a resource management framework similar to that used in oil and gas regulation, the states would be in a position to develop a unified regulatory framework capable of addressing the regulatory complexities of CO_2 storage, including environmental protection, ownership and management of the pore space, maximization of storage resource, and responsibility for long-term liability. In contrast, the EPA Class VI rule originated from a waste disposal framework (see Call Out Box).

Any state with potential for dedicated storage should consider adopting legislation and promulgating administrative rules using the IOGCC model framework (i.e., model statute and model rules and regulations) combined with the UIC Class VI rule.

State-Managed Cradle-to-Grave Regulatory Model

Another key conclusion of the CGS Task Force was that no other jurisdiction is better positioned than the states to regulate the dedicated storage of CO_2, given their experience and expertise in the regulation of oil and gas production and gas storage. The Task Force also recognized that the states are best positioned to administer a "cradle-to-grave" regulatory system for dedicated CO_2 storage (Figure 4). The work of the CGS Task Force, pointing to the experience and expertise of state regulators and their position as ideal suitors to regulate dedicated storage, is further endorsed by EPA in the previously discussed preamble to the 2010 Class VI rule. The cradle-to-grave regulatory system shown in Figure 4 accounts for the entire life cycle of a dedicated storage project, including regulatory oversight and permitting during early-stage exploration and site access (Phase 1); project and facility permitting, well drilling, and authorization to operate (Phase 2); storage operations (Phase 3); site closure (i.e., postinjection site care [PISC] and facility closure) (Phase 4); and the postclosure caretaker role of a closed site (Phase 5).

Resource management frameworks are preferred over waste disposal frameworks for the regulation of the geological storage of CO_2. The geological storage of CO_2 is one of several viable methodologies for reducing emissions of anthropogenic CO_2 into the atmosphere. Because the production of CO_2 is a consequence of the public's demand for, and use of, fossil energy, it is arguably in the public interest to actively participate along with industry in efforts to reduce CO_2 emissions through geologic storage.

Given the regulatory complexities of CO_2 storage, including environmental protection, ownership and management of the pore space, maximization of storage capacity and management of long-term liability, geologically stored CO_2 should be treated under resource management frameworks as opposed to waste disposal frameworks.

Regulating the storage of CO_2 under a waste management framework sidesteps the public's role in both the creation of CO_2 and the mitigation of its release into the atmosphere and places the burden solely on industry to rid itself of "waste" from which the public must be "protected." Such an approach lacking citizen buy-in with respect to responsibility for the problem as well as the solution could well doom geological storage to failure and diminish significantly the potential of geologic carbon storage to meaningfully mitigate the impact of CO_2 emissions on the global climate.

A resource management framework, as proposed by the CGS Task Force, allows for the integration of these issues into a unified regulatory framework and proposes a "public and private sector partnership" to address the long-term liability, given that the release of CO_2 into the atmosphere is at least partially a societal problem and the mitigation of that release is likewise at least partially a societal responsibility (Interstate Oil and Gas Compact Commission, 2007).

Pore Space Ownership and Amalgamation

The CGS Task Force determined that control of the necessary storage rights should be required as part of the initial storage facility permitting to promote orderly development and maximize the storage resource (i.e., pore space). In the United States, except for federal lands, the acquisition of these storage rights, which are considered property rights, are generally functions of state law (Interstate Oil and Gas Compact Commission, 2007). Therefore, EPA does not address pore space ownership or property interests for purposes of storing CO_2 when permitting Class VI UIC injection wells in nonprimacy states.

Of the ten PCOR Partnership states, four have passed legislation regarding pore space ownership and legal criteria for leasing or accessing the right to use pore space for dedicated storage of CO_2. North Dakota, Montana, Nebraska, and Wyoming have all granted pore space ownership to the surface estate owner; Alaska is the only state in the PCOR Partnership region—and the nation—to find that pore space belongs to the mineral estate owner. This legal precedent

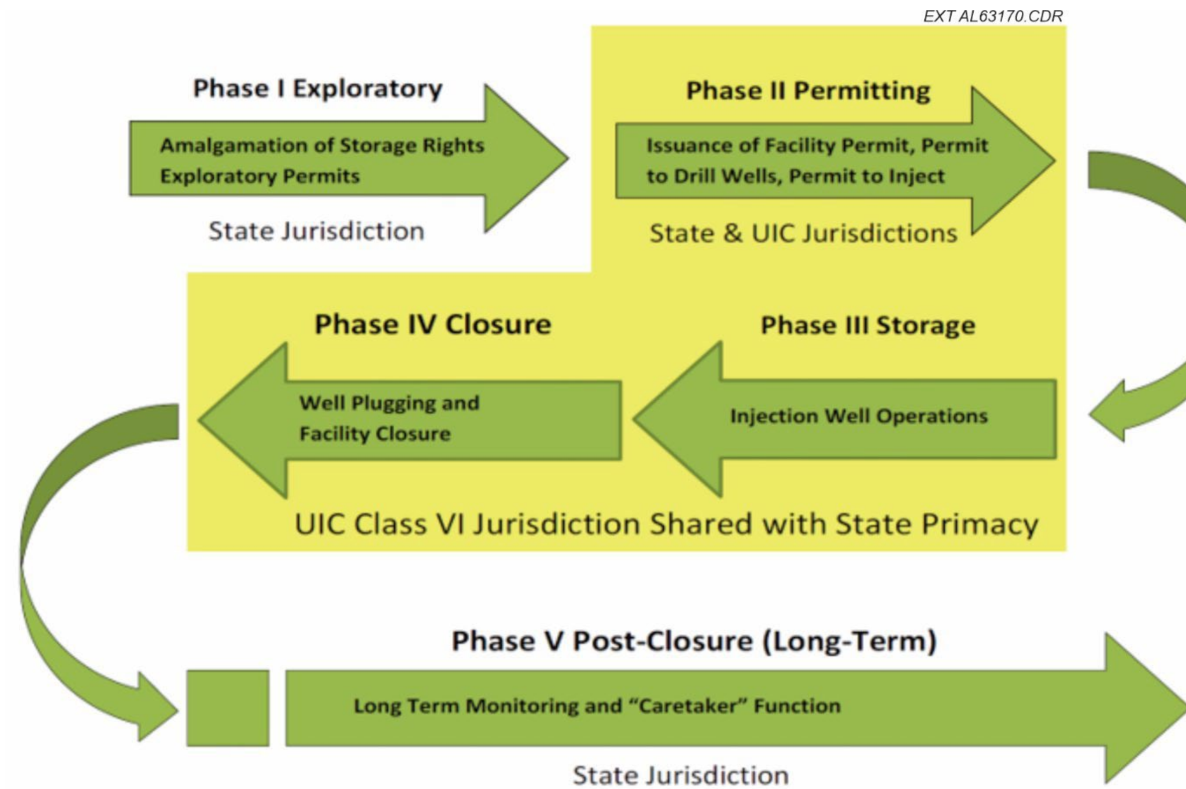

Figure 4. CGS Task Force "cradle-to-grave" regulatory system (Interstate Oil and Gas Compact Commission, 2014).

originated from a 2016 decision of the Supreme Court of Alaska that found pore space ownership to be included under mineral rights, specifically as it pertains to geologic storage of natural gas (Justia US Law, 2016). In the four Canadian provinces within the PCOR Partnership region, pore space defaults as property of the Crown, or Canadian federal government, and can be leased according to provincial regulations. Legislation in Alberta and British Columbia has established a process for leasing pore space from the government; Manitoba and Saskatchewan have not enacted any laws that further specify pore space ownership or leasing (Peck and others, 2022a).

Transfer of Long-Term Responsibility

One challenge that has been identified when discussing dedicated geologic CO_2 storage projects is the management of the long-term liability and regulatory responsibility of a closed storage site and the identification of the responsible party. In the preamble of the final Class VI rule, EPA acknowledged stakeholder interest in liability and long-term stewardship in the context of development and deployment of CCS technology; however, under current SDWA provisions, EPA does not have authority to transfer liability from one entity (i.e., owner or operator) to another. The CSG Task Force recognized this challenge and the fact that companies eventually are sold, merge, or even dissolve over time. After considering other approaches, the CGS Task Force determined that the most efficient methodology to accomplish site closure and ensure long-term liability is adequately managed was to utilize existing state regulatory frameworks that were developed to address abandoned and orphaned oil and gas wells. Accordingly, the CGS Task Force recommended that states and provinces assume responsibility for the long-term monitoring and maintenance (i.e., "caretaking" responsibility) in the final postclosure phase of a dedicated CO_2 storage project. Following this line of thinking, formation of an industry-funded and state-administered trust fund was recommended by the CGS Task Force. The trust fund would be funded by an injection fee assessed to the site operator and calculated on a per-ton basis at the point of custody transfer of the CO_2 from the generator to the storage site operator. This approach provides a logical and effective solution for the long-term oversight of a closed storage project, while ensuring the state or province has sufficient funds in place to take on the role of a long-term caretaker.

The IOGCC model framework establishes a process for operators to transfer title of the stored CO_2 to the state no sooner than 10 years postinjection, after public notice and hearing and after the operator has met all statutory and regulatory criteria, including a demonstration that the CO_2 plume is stable.

The CGS Task Force proposed a two-stage approach that included a closure period and postclosure period. The closure period is defined as that period of time beginning with the plugging of the injection well and cessation of injection activities and continuing for a defined period of time (10 years unless otherwise designated by the state regulatory authority). During this closure period, the operator of the storage site would be responsible for maintaining an operational bond and individual well bonds. The individual well bonds would be released as the wells are plugged. At the conclusion of the closure period, the operational bond would be released and the liability for ensuring the site remains a secure storage site during the postclosure period would transfer to a trust fund administered by the state. During the postclosure period, the financial resources necessary for the state or a state-contracted entity to engage in future monitoring, verification, and remediation activities would be provided by the trust fund (Interstate Oil and Gas Compact Commission, 2007).

REGULATORY DEVELOPMENTS IN THE PCOR PARTNERSHIP REGION

Several states and Canadian provinces within the PCOR Partnership region have or are in the process of developing a regulatory framework for dedicated storage, including legislation for pore space ownership and responsibility for long-term liabilities (Figure 5). This section describes the jurisdictions within the PCOR Partnership region (e.g., federal, state, and provincial) and the status of key policy and regulatory developments for the CCS/CCUS industry.

United States

In the United States, a system of cooperative federalism is in place that permits the federal government to create minimum nationwide standards and offer states the opportunity to apply for, and receive, the authority to implement the federal program within state jurisdiction. The intent of Congress and the American system of cooperative federalism is to recognize the difference in states' priorities while maintaining a minimum standard. The SDWA authorizes EPA to

Figure 5. Status of CCS policy and regulatory developments in the PCOR Partnership region related to pore space law, long-term responsibility, and Class VI primacy.

promulgate federal regulations to establish minimum federal standards for effective UIC programs that ensure the protection of USDWs. The UIC program includes a cooperative process for states to apply for and receive primacy from EPA. State primacy positions the state agency as the lead regulatory authority for implementing the federal program, with EPA as the oversight authority.

The primacy process of the UIC program is well-defined and in alignment with cooperative federalism, in that states are required to demonstrate that the state UIC program is "as stringent as" the federal program in the protection of USDWs. However, the Class VI primacy process has demonstrated significant delays with extended periods of time with no EPA action. These delays by EPA have led to uncertainty in the success of the primacy application, increased the state cost of the application process, and delayed the commercial deployment of CCS projects. By delaying approval of state Class VI primacy applications after the state has demonstrated the "as stringent as" standard has been met, states are experiencing challenges ensuring appropriate staffing levels for the development and submission of the primacy application, followed by a multiyear EPA process forcing states to temporarily reallocate those staff and resources until primacy is granted. EPA must be willing to approve Class VI primacy applications in a timely manner, e.g., 2 years or less, to facilitate the primacy approval process and the commercial deployment of CCS projects across the United States. A more rapid and consistent primacy review and approval process would also be consistent with previous comments of EPA that recognize that states are "best positioned" to regulate the dedicated storage of CO_2. The National Petroleum Council in its report recommended that Congress, through its agency oversight process, also emphasizes the importance of accelerating the EPA review of state applications seeking primacy to implement the Class VI UIC program (National Petroleum Council, 2019).

As mentioned previously in this report, the Class VI framework is a waste disposal framework and has limitations in regulating all aspects (e.g., orderly project development, pore space, responsibility for long-term liability) of a dedicated storage project. Regardless of Class VI primacy, states have a role to play in regulating dedicated CO_2 storage. States that have embraced guidance provided by the CGS Task Force by adopting the resource management frameworks for geologic CO_2 storage in combination with pursuing Class VI primacy are best positioned to regulate CO_2 storage projects from cradle to grave.

Currently, EPA has issued two active Class VI well permits, both submitted by Archer Daniel Midland's ethanol plant in Illinois. A third permit submission is currently pending. In addition, over 20 other applications have been submitted and are pending EPA "preconstruction" review and approval, with Louisiana having the majority at 16; California with 7; and Illinois, Indiana, Ohio, and Texas with 1 to 2 Class VI permit applications pending.

North Dakota

North Dakota has been a leader among the states in developing a regulatory framework for the geologic storage of CO_2. In 2008, North Dakota formed an ad hoc CO_2 storage workgroup, with representatives from the state government, the Oil and Gas Division of NDIC, the Department of Environmental Quality (DEQ), the Attorney General's office, the Lignite Energy Council, the North Dakota Petroleum Council, the EERC, and other energy industry and legal experts. The North Dakota CO_2 Storage Workgroup drafted legislation, based on the IOGCC model statute, that was ultimately introduced and signed into law during the 2009 legislative session. In 2010, the Oil and Gas Division of NDIC promulgated administrative rules following the template of the IOGCC model regulations. At the time, North Dakota became the first state with a complete and comprehensive regulatory framework in place for geologic storage of CO_2. The EPA Class VI rule was published in late 2010, and the Oil and Gas Division was directed by the 2011 Legislature to apply for and obtain Class VI primacy.

The current North Dakota regulations represent a resource management framework and meet the "as stringent as" standard by incorporating the Class VI UIC program requirements. The timeline of these North Dakota's regulatory developments is summarized as follows:

- Effective April 2009: Senate Bill 2139 created North Dakota Century Code (NDCC) Chapter 47-31, Subsurface Pore Space Policy, which granted the title of pore space ownership to the overlying surface estate and prohibited severing the title to the pore space from surface ownership, although leasing is allowed. The relationship between pore space and mineral estates identified the mineral estate as dominant.

- Effective July 2009: Senate Bill 2095 created NDCC Chapter 38-22, Carbon Dioxide Underground Storage, a new statutory chapter that granted regulatory authority to NDIC, established permit requirements that included pore space amalgamation, created an administrative fund and a long-term trust fund, and addressed responsibility for long-term liability through a certificate of project completion (to be issued no sooner than 10 years postinjection following demonstration of a stable CO_2 plume in the subsurface) and transfer of title of the stored CO_2.

- Effective April 2010: North Dakota Administrative Code (NDAC) Chapter 43-05-01, Geologic Storage of Carbon Dioxide, provided a first-of-a-kind state regulatory framework that incorporates permitting, well construction, and detailed engineering and geological data analyses, along with a CO_2 injection plan that includes a description of the mechanisms of geologic confinement to ensure the prevention of horizontal or vertical migration of CO_2 beyond the proposed storage reservoir. The operator is also required to submit for state approval an emergency response plan, worker safety plan, corrosion monitoring and prevention plan, and a facility and storage reservoir leak detection and monitoring plan.

- 2011: House Bill 1014 provided an appropriation of $532,000 from the general fund to the CO_2 storage facility administrative fund, which was established in 2009, creating one full-time position to prepare a Class VI primacy application and secure approval of Class VI primacy for the state of North Dakota.

- Effective April 2013: NDAC Chapter 43-05-01, Geologic Storage of Carbon Dioxide, was amended (effective April 2013) to meet the "as stringent as" standard of the federal Class VI UIC program. EPA required rules to be codified as part of North Dakota's Class VI primacy application.

Following these legislative actions, North Dakota law now addresses permitting, pore space amalgamation (i.e., pore space ownership for the subsurface), responsibility for the long-term liability of a closed storage site, and Class VI UIC program requirements. On June 21, 2013, the official North Dakota Class VI primacy application was submitted to EPA. On April 24, 2018, nearly 5 years later, NDIC was granted Class VI primacy.

North Dakota currently has two permitted CO_2 storage projects: the RTE CCS project located in Richardton, North Dakota, and Minnkota Power Cooperative's Project Tundra, which is 3.4 miles southeast of Center, North Dakota. The RTE CCS project is an ethanol facility that captures CO_2 from its fermentation process and has been injecting CO_2 since June 2022. RTE plans to store 180,000 metric tons of CO_2 per year within the Broom Creek Formation. Project Tundra (a.k.a., North Dakota CarbonSAFE Phase III) plans to capture CO_2 from the Milton R. Young

Power Station and store an average of 4 million metric tons of CO_2 per year in the Broom Creek and Deadwood Formations, requiring separate storage permits for stacked storage reservoirs.

Wyoming

In 2008, the state of Wyoming began developing a legal framework for geologic storage of CO_2. Wyoming passed a series of statutes related to CCS, which enacted the legal underpinnings for establishing pore space ownership and determining long-term stewardship of the facilities utilized for dedicated storage as listed below:

<u>2008</u>

- Senate Bill 1 appropriated over $1.2 million for the evaluation of potential CCS project sites and technologies.

- House Bill 89 granted pore space title to the owner of the overlying surface, although ownership can be severed.

- House Bill 90 authorized the Wyoming DEQ to create regulations for CO_2 geologic storage.

<u>2009</u>

- House Bill 57 deemed the mineral estate dominant over pore space ownership, even if severed from the surface estate.

- House Bill 58 established operator liability for CO_2 during injection and released the pore space owner from liability for effects of CO_2 storage.

- House Bill 80 addressed unitization of CO_2 geologic sequestration sites.

<u>2010–2022</u>

- 2010: House Bill 17 authorized the Wyoming DEQ to specify insurance, bonding, and financial assurance requirements for Class VI permits and establish a revenue account for long-term monitoring expenses, although monitoring by the state does not constitute the assumption of liability.

- 2013: Wyoming Statute § 35-11-313 authorized the Wyoming DEQ to regulate the geologic storage of CO_2 while maintaining the authority for CO_2 EOR authorization under the Wyoming Oil and Gas Conservation Commission (WOGCC).

- 2022: Senate Bill 47 established a long-term liability transfer option to the state.

The Wyoming DEQ developed rules to regulate UIC Class VI injection wells under Chapter 24 of Wyoming's Water Quality Regulatory Program. As part of their effort to meet the "as stringent as" standards of the federal Class VI requirements for primacy, Chapter 24 was revised in July 2016, and the application for Class VI primacy was submitted in January 2018. Based on feedback from EPA, the rules were revised in January 2020, and the Wyoming DEQ received Class VI primacy approval from EPA on September 3, 2020. Following a request of EPA, Wyoming DEQ made additional minor modifications to the rules, with an updated Chapter 24 released on October 9, 2021.

It is important to note that Wyoming DEQ will need to coordinate its issuance of Class VI permits with both WOGCC and the Bureau of Land Management (BLM). Since WOGCC is the agency responsible for regulating the unitization of pore space (Wyoming Statute §§ 35-11-314 through 317,[1] available on the WOGCC website, Chapter 3 [*Operational Rules, Drilling Rules*], Section 43 [*Carbon Sequestration Unitization Process*]), the Wyoming DEQ will not process a Class VI well permit application without WOGCC unitization approval. In addition, the WOGCC is also the authoritative agency for regulating stratigraphic test wells, which may be considered for conversion to Class VI wells during the permitting process. This well conversion will require coordination and engagement between WOGCC and Wyoming DEQ.

As for BLM, nearly 50% of the surface land area in Wyoming is federally owned and managed by it. To develop dedicated CO_2 storage projects on federally managed land, BLM will need to be engaged to complete the permitting of Class VI wells. BLM guidelines related to these permitting efforts are currently under development.

To date, no Class VI UIC permits have been approved in Wyoming, although there are multiple applications pending, with additional permits anticipated to be submitted in 2022.

Montana

The Montana Board of Oil and Gas Conservation (BOGC) has not applied for Class VI primacy but has begun establishing the groundwork for an application. Montana has drafted legislation (House Bill 498) that addresses pore space ownership and responsibility for long-term liability associated with a geologic CO_2 storage site. Implementation of this and other laws is contingent on Montana applying for, and receiving, Class VI primacy. Until that time, Montana's Class VI wells will fall under federal jurisdiction (EPA Region 8) and will be governed by EPA Class VI regulations. In summary, House Bill 498 (2009) would authorize Montana BOGC to regulate CO_2 storage; grant pore space ownership to the surface estate, allowing severance; address long-term responsibility transfers to the state; outline the unitization process; and establish a geologic storage reservoir program account.

[1] https://wyoleg.gov/statutes/compress/title35.pdf.

Nebraska

The Nebraska Oil and Gas Conservation Commission (NOGCC) has not applied for Class VI primacy. However, recently, Nebraska adopted geologic CO_2 storage regulations following the passage of the Nebraska Geologic Storage of Carbon Dioxide Act (Legislative Bill 650). This legislative bill was passed by the Nebraska Legislature and signed into law in May 2021. An overview of these statutory and regulatory developments is provided below:

- Legislative Bill 650 (2021) authorized NOGCC to implement regulations relating to the geologic storage of CO_2. It granted title to pore space to the owner of the overlying surface estate, providing for severance of the pore space, and established fees and funds related to CCS projects and permits.

- Administrative Code Title 267, Chapter 7[2] is similar to the standards set by EPA and further expanded upon by North Dakota. It incorporated the processes for permitting, well construction, detailed engineering, and geological data analyses, along with a CO_2 injection plan that includes a description of mechanisms of geologic confinement to ensure the prevention of horizontal or vertical migration of CO_2 beyond the proposed storage reservoir. This Nebraska Administrative Code also requires an operator to submit for state approval an emergency response plan, worker safety plan, testing and monitoring and prevention plan, and a facility and storage reservoir leak detection and monitoring plan.

Until Nebraska applies for and receives Class VI primacy, Class VI injection well activities will continue to be regulated through EPA (Region 7). With the adoption of a resource management framework through the enactment of Legislative Bill 650 and the subsequent rule making under Administrative Code Title 267, Nebraska is laying the groundwork for a cradle-to-grave regulatory approach similar to that of North Dakota.

Alaska

In 2022, the University of Alaska Fairbanks, through the PCOR Partnership, worked with the Alaska Department of Natural Resources (DNR) to establish a government–industry workgroup comprising Alaskan stakeholders. The Alaska CCUS Workgroup has four focus areas: 1) developing recommendations for a state CCUS statutory and regulatory framework, 2) tracking and preparing responses for DOE funding opportunities, 3) performing CCUS public outreach, and 4) developing a road map to accelerate commercial CCUS deployment within Alaska. Alaska DNR is using the results from workgroup efforts to inform state decision-making in regard to CCUS policy in Alaska.

[2] www.nogcc.ne.gov/Publications/NE_CodeChapter7.pdf.

Remaining PCOR Partnership States

The remaining states in the PCOR Partnership region have little or no legislative and regulatory activity focused on the geologic storage of CO_2. A summary of the relevant legislative and regulatory activities that have occurred in these states is summarized below:

- **Iowa**: Iowa has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2 nor has it issued any laws or rules to regulate emissions from coal-fired power plants in the state. Currently, EPA Region 7 regulates all UIC well classes in Iowa.

- **Minnesota**: Minnesota has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2. It is, however, an active member of the Midwest Governor's Association, which has studied the development of CCS rules, regulations, and infrastructure. In addition, a bill was enacted in 2007 (SF 2096) that appropriated $90,000 for a study of the geologic sequestration capacity in Minnesota. A Carbon Capture Technology Bill was also introduced in the Minnesota House and Senate in the spring of 2022. It was passed by the Senate; however, it was not voted on in the House. To date, multiple attempts to pass CCS legislation in Minnesota have been unsuccessful, with the most recent 2022 bill simply adding CCS to the state's overall energy strategy. Currently, the Minnesota Department of Health (MDH) regulates oil and natural gas exploration in the state; EPA Region 5 regulates all UIC well classes.

- **Missouri**: The Missouri DNR, through its Oil and Gas Council, proposed amendments to oil and gas drilling and production regulations in October 2015. However, these amendments did not address regulations pertaining to the geologic storage of CO_2. EPA Region 7 regulates all UIC well classes in Missouri.

- **South Dakota**: In 2009, South Dakota passed a bill, HB 1129, which required the Public Utilities Commission to regulate CO_2 pipelines. CO_2 is defined as a fluid that consists of more than 90% CO_2 molecules compressed in a supercritical state. No other legislation or promulgation of regulations pertaining to the geologic storage of CO_2 has been enacted. Senate Bill 63, which was introduced in 2020 to grant pore space title to the surface owner, was deferred. EPA Region 8 regulates all UIC well classes in South Dakota.

- **Wisconsin**: Wisconsin has not yet enacted legislation or promulgated regulations pertaining to the geologic storage of CO_2, and there are no pending legislation or regulations. EPA Region 5 regulates all classes of UIC wells in Wisconsin.

Canada

In general, the Canadian federal government has supplemented the existing legislative and regulatory frameworks of the oil and gas industry to regulate CCS. The jurisdiction for regulating the geologic storage of CO_2 lies primarily with the individual provinces, stemming from their jurisdiction over the direct ownership, management, and regulation of most natural resources. This framework has been expanding in each province to cover the permanent geologic storage and the postabandonment of CO_2 storage operations, including monitoring and remediation, financial assurance, incentives, liability and ownership, and access rights. At the same time, the federal government holds jurisdiction over international and interprovincial issues, including transboundary pipelines, uranium and nuclear power, offshore areas, federal lands, and works declared to be for the general benefit of Canada (e.g., science and technology). Responsibilities for environmental protection are shared between the federal and provincial governments.

Given this distribution of responsibilities and the nature of a geologic CO_2 storage project, the regulation and permitting of these projects in Canada primarily falls to the province. The federal government in Canada ensures a coherent regulatory framework by providing equivalency agreements with the provincial governments to minimize the duplication of environmental regulations. The four provinces that are part of the PCOR Partnership region, i.e., Alberta, British Columbia, Manitoba, and Saskatchewan, have equivalency agreements in place that address the geologic storage of CO_2. In these four provinces, pore space defaults as property of the Crown, or federal government, and can be leased according to provincial regulations. Legislation in Alberta and British Columbia has established the process for leasing the pore space of storage reservoirs from the government; Manitoba and Saskatchewan have not enacted any laws further specifying pore space ownership or leasing.

The status of legislation related to geologic CO_2 storage in each province within the PCOR Partnership region is provided in the remainder of this section.

British Columbia

The Ministry of Natural Gas Development is the agency developing the regulatory policy framework for CCS. Regulations, yet to be finalized, include topics such as site characterization details, CO_2 stream composition, a description of measures to prevent significant leakage, unintended migration, and corrective measures and contingency plans. Regulations will likely require company responsibility for remediation and reclamation of sites once operations end. A CCS demonstration project is currently in development in British Columbia, at Lafarge's Richmond cement plant in which CO_2 is to be captured from the flue gas.

Alberta

Alberta has put in place a regulatory framework that includes technical, environmental, safety, and monitoring requirements for the safe deployment of CCS. This framework also addresses postclosure stewardship to address the long-term liability role of the government associated with site closure. The Alberta Ministry of Environment and Parks (AMEP) is responsible for determining if CCS projects are required to perform an environmental impact assessment (EIA) to demonstrate that the storage site has "suitable containment" properties to ensure that CO_2 will remain in the target storage formations. The EIA requires the development of a monitoring, measurement, and verification (MMV) plan and the conduct of a risk assessment, which will be regularly updated if the movement of the plume and pressure front are different from the modeling predictions. Alberta has two ongoing CCS projects: 1) the Quest project (2015), which captures CO_2 from the Shell Scotford Upgrader, a crude oil-processing facility, and injects it into a saline formation, and 2) the Alberta Carbon Trunk Line (2020) project, a 240-kilometer pipeline that collects CO_2 from industrial sources in Alberta and transports it to oil fields to be used for CO_2 EOR.

Saskatchewan

Saskatchewan, like Alberta, has a CCS regulatory framework in place. The Oil and Gas Conservation Act (OGCA) ensures wells are constructed, operated, and plugged to prevent contamination of water or air and to monitor non-oil-and-gas substances (e.g., CO_2). While the Saskatchewan Ministry of Energy and Resources is responsible for the regulation of the oil and gas industry and other natural resources, the Saskatchewan Ministry of Environment is the agency responsible for conducting environmental assessments to determine if EIAs are necessary for proposed projects. The CCS regulatory framework requires the CCS project developer to have a risk management plan in place, which includes monitoring of project risks in accordance with provincial requirements; the long-term liability for the stored CO_2 is borne by well license holders. There are two ongoing CCS/CCUS projects in Saskatchewan: 1) the Weyburn–Midale project, which has been operating since 2000, receives CO_2 that has been captured in North Dakota and transported by pipeline to the oil field for CO_2 EOR and 2) the Boundary Dam Integrated CCS/CCUS Demonstration Project, which began capturing CO_2 in 2014 from one of six units (Unit No. 3) at a coal-fired power plant and transporting it via pipeline to oil fields for use in EOR; CO_2 not used for EOR is transported to the Aquistore project for dedicated storage in a saline reservoir.

Manitoba

Manitoba is the only province in the PCOR Partnership that has no CCS regulatory framework in place or under development. This is largely because almost all electrical power generated in Manitoba is derived from renewable energy sources, primarily hydroelectric and wind, making the province a relatively small contributor to the overall greenhouse gas (GHG) emissions of Canada.

REGULATORY PERMITTING PROCESS AND TIMELINES

The wide-scale commercial deployment of CCS/CCUS in the United States will be accelerated if federal, state, and local regulators: 1) provide regulatory certainty, 2) have a well-defined permitting process, and 3) streamline permit decision making. The PCOR Partnership is focusing on the creation of such a regulatory environment, with the goal of providing more certainty to the regulated community. A well-defined permitting process and streamlined permit decision process are critical to this effort by laying the foundation for a predictable and certain regulatory environment within which project developers can make both technical and investment decisions.

As commercial CCS projects emerge and advance from site-screening and feasibility assessments to the project design, construction, and permitting phases, project developers need to have a clear understanding of the regulatory requirements to secure the necessary permits as well as the expected duration of the permitting process. With this understanding in hand, project development decisions can be made in the site-screening and feasibility assessment phases of the project that can facilitate the development of the permit and potentially save both time and costs. For example, when drilling a stratigraphic test well as part of site characterization efforts of the feasibility assessment phase of a project, the operator can be sure to collect all data and information required for permit compliance, including the data/information necessary to construct the stratigraphic well to Class VI well construction standards, leaving the possibility to convert the well to an injection or monitoring well sometime in the future. While this approach may result in additional risk to the project, there may be an added benefit in terms of accelerating project development timelines. Project developers will need to weigh the project risks against the potential benefits based on the goals and objectives of the project. A project with the goal of injecting and storing CO_2 as soon as possible will have a different risk tolerance than a project that has a less aggressive schedule.

The PCOR Partnership adaptive management approach (AMA) is a staged approach for the development of a CCS/CCUS project that is designed to better manage project uncertainty and inform the development of project investment strategies. Despite the range of CCS/CCUS project types that may be encountered, each will follow a similar development arc and timeline that consist of key stages (Figure 6). As shown in this figure, these project stages include site screening, a feasibility assessment, design, construction and operation, and site closure/postclosure. During each stage of the project, there are a set of ongoing activities that are focused on site characterization; modeling and simulation; risk assessment; and monitoring, verification, and accounting. Each activity feeds data/information into the next activity, and feedback loops are in place to inform modifications to the scope of each activity that may be required based on new data or findings. This AMA integrates the project activities of each stage to support developers in managing risk and advancing their project from site screening to closure/postclosure.

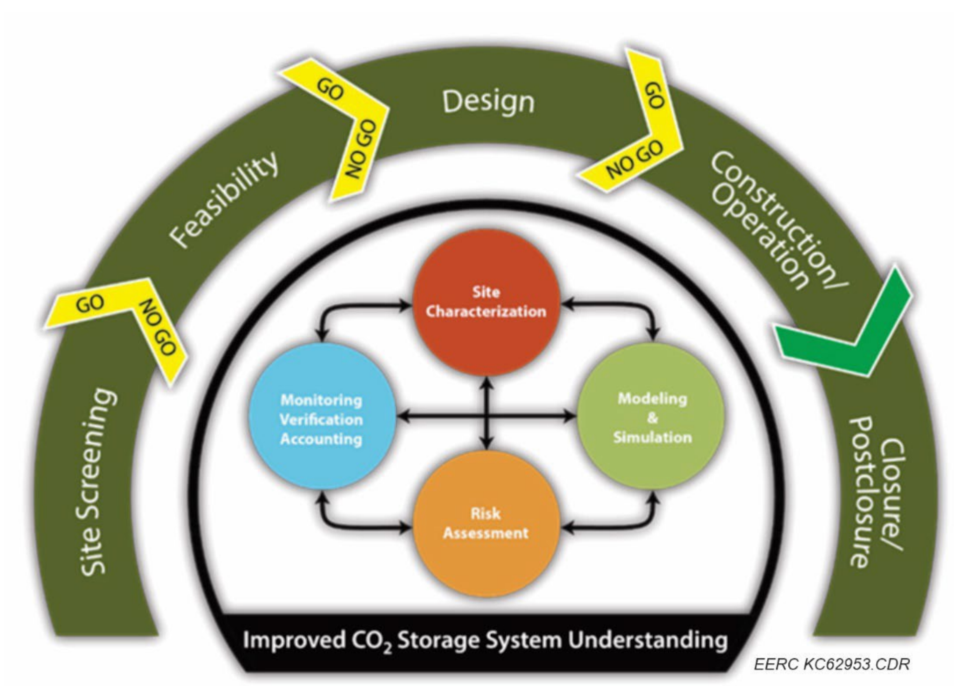

Figure 6. AMA for CCS/CCUS project implementation.

Lessons learned from the development and permitting of the first wave of geologic CO_2 storage projects in North Dakota have revealed that the preparation of a permit application and the time required for its regulatory review necessitates a considerable amount of time. As such, these activities have been incorporated into the AMA process described in Figure 6 to produce a generalized timeline for implementing a geologic CO_2 storage project (Figure 7). This project development timeline adds preparation of the permit application and regulatory review of the permit to the phases on the AMA. Consistent with the AMA, this timeline also includes several go/no-go milestones where decisions regarding progress to the next phase of the project must be made. These milestones should be used by project developers as key decision points to determine if the project continues to be viable, both technically and economically, and, if warranted, to develop a path forward for proceeding with project development. While the timeline in Figure 7 is specific to the North Dakota UIC Class VI permitting process, these development stages are applicable to all geologic CO_2 storage projects (Livers-Douglas and others, 2022).

It is evident from Figure 7 that the development of permit applications and their regulatory review represent an important step to consider when developing a commercial geologic CO_2 storage project. This is particularly true for projects that are looking to take advantage of incentives that may have timing stipulations, such as 45Q tax credits which have deadlines associated with the start of construction and operation. Since the permit review and approval process may take several months or even years depending on what agency has UIC Class VI primacy, it is critical that these activities be accounted for in project budgeting and scheduling. By understanding and planning for regulatory requirements and associated permit review timelines in the planning phases of the project, a project developer will be better informed to make investment decisions for the project (Livers-Douglas and others, 2022).

There are permitting advantages to having a state oil and gas regulatory agency with Class VI primacy regulate dedicated CO_2 storage. Extensive site characterization work is necessary to enable a project developer to determine if advancement of the project to the next phase is warranted, e.g., the go/no-go decision point between feasibility and project design and permit application development, shown in Figure 7. Having a one-stop shop for permitting all aspects of a dedicated storage project, including permits needed for characterization activities (i.e., stratigraphic test well APD [application of permit to drill] and geophysical survey permits), pore space unitization (amalgamation), storage permits, and Class VI injection well permits, facilitates a streamlined permitting process. At the same time, the regulator becomes aware of pre-Class VI permit submission activities at a much earlier stage in the project, which helps inform the permitting of the project as well as project oversight during the operational and postoperational closure phases of a project.

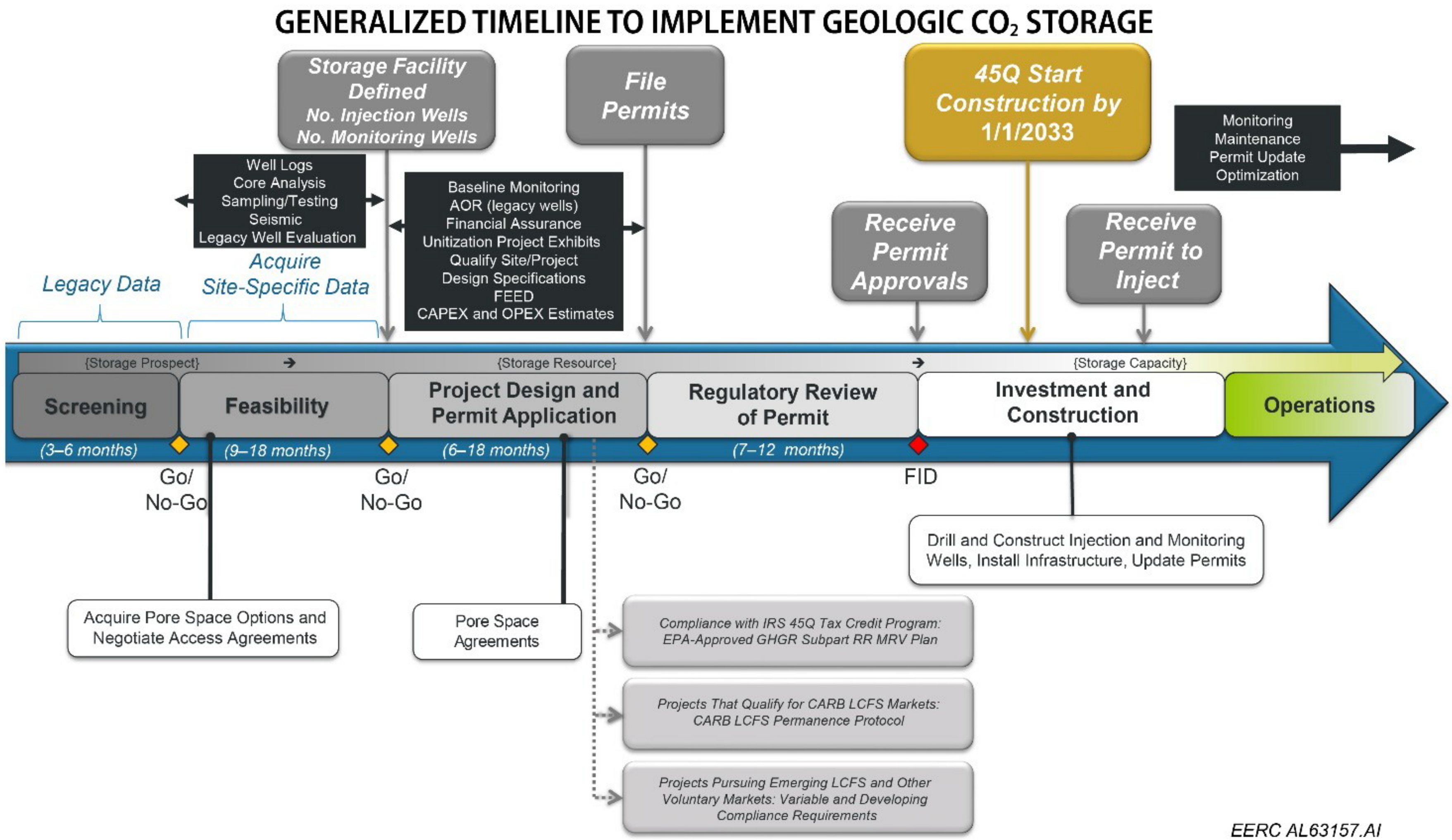

Figure 7. Generalized timeline for development of a geologic CO_2 storage project in the United States for states with UIC Class VI primacy.

The remainder of this section describes the permitting process associated with site characterization activities and important details regarding the Class VI permitting process for geologic CO_2 storage under the jurisdiction of EPA, North Dakota, and Wyoming.

Permitting of Characterization Activities

Stratigraphic Test Wells

State oil and gas agencies typically have the permitting authority for the stratigraphic test wells used to acquire site-specific data to characterize a site for the geologic storage of CO_2 and to support the development of a Class VI permit (e.g., coring, logging, formation testing and sampling). North Dakota is one example of a state where the oil and gas agencies regulates Class VI. In Wyoming, the WDEQ Class VI preapplication package directs the operator to file an APD for the stratigraphic test well with the WOGCC, which currently retains jurisdiction over stratigraphic test wells, allowing the operator to acquire site-specific characterization data for compliance with a future Class VI permit application. It is uncertain whether EPA has the authority to issue permits to drill in nonprimacy states. In these instances, more than likely, project developers will need to work with both EPA and the state to ensure compliance when pursuing an APD for a characterization well. If plans are to transition the stratigraphic test well to a UIC Class VI injection well, project developers must ensure the necessary data (openhole and cased-hole logs, core, formation testing, and fluid samples) are acquired for this purpose and that the well design is compliant with Class VI regulations (Livers-Douglas and others, 2022).

Geophysical Surveys

Geophysical permitting for the 2D or 3D seismic surveys that are used for site characterization is also typically permitted through state oil and gas regulatory bodies. Seismic surveys are the current go-to geophysical method for site characterization over large areas. As part of site characterization for CO_2 storage sites, 2D and 3D seismic data are used to characterize structure, assess interwell heterogeneity, confirm lateral continuity of the injection zone and confining zones, identify potential fluid migration pathways in the confining zones, and optimize well placement. Results of the processed and interpreted 3D seismic data are used to enhance and refine 3D geologic models. The newly acquired 2D and 3D seismic surveys also serve as baseline data sets for time-lapse seismic monitoring of the injected CO_2 (Livers-Douglas and others, 2022). It can be anticipated that 2D and/or 3D seismic surveys will be acquired as part of the site characterization and feasibility efforts, with repeat surveys conducted throughout the operational and postoperational life of the project. Due to the frequency, which could be at least every five years or less, there appears to be a distinct advantage to having the Class VI regulator also oversee geophysical permitting (i.e., the oil and gas regulatory agency) and data acquisition activities associated with the dedicated storage project.

Class VI Permitting Process

EPA Class VI UIC Program

The EPA Class VI permit process was finalized in January 2018. The process addresses four phases of a dedicated CO_2 storage project, which include prepermitting, preconstruction, preoperations, and injection and postinjection (Figure 8). As shown in Figure 8 and discussed below, the project phases of the EPA process encompass those of the PCOR Partnership AMA and generalized project development timeline, i.e., site screening, feasibility, project design and permit application, construction/operation, and closure/postclosure.

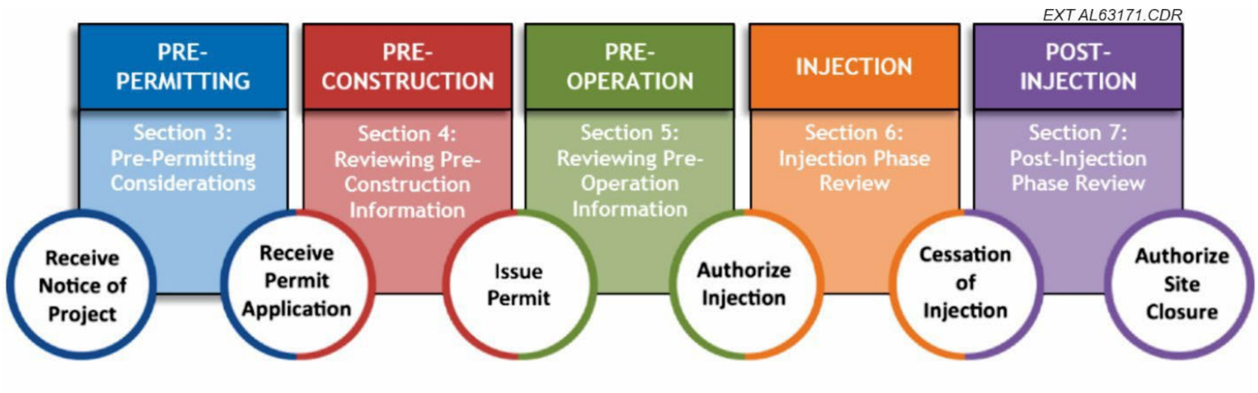

Figure 8. Phases of the geologic sequestration of CO_2 Class VI project from EPA UIC Program Class VI Implementation Manual for UIC Program Directors, January 2018.

The EPA Class VI permit application is comprised of 12 sections: 1) site characterization, 2) area of review (AOR) and corrective action plan, 3) financial assurance demonstration, 4) well construction details, 5) preoperational test plan, 6) proposed operating conditions, 7) testing and monitoring plan, 8) the injection well plugging plan, 9) PISC and site closure plan, 10) emergency and remedial response plan, 11) injection depth waiver application, and 12) aquifer exemption expansion (U.S. Environmental Protection Agency, 2021). EPA has a Class VI permit application checklist available on its website to facilitate the submission of a complete permit application by CCS project developers.

Similar to the PCOR Partnership AMA, the EPA process includes a screening-level analysis and project feasibility assessment using regional data and preliminary geomodeling. The process of completing the geologic characterization used in geomodeling is accomplished either through an extensive review of existing site-specific data or by drilling a stratigraphic test well, or both. Injection simulations, process engineering, storage operations, testing and monitoring plans, and financial assurance for the proposed Class VI project are addressed as part of the project design phase.

The EPA regulators encourage communication during the development of the permit application to ensure that the applicant is aware of all required permits and approvals and that all required permitting activities are performed. Applicants under EPA authority for Class VI projects also need to communicate with state and/or other applicable federal agencies, as the EPA UIC program does not regulate geophysical data acquisition, drilling permits, pore space access, certain surface facility appurtenances, pipelines and flowlines, and other critical project-specific areas. It is important to note that the federal UIC program is a well-centric regulatory framework that focuses on well integrity and the protection of USDWs from risks posed by the injection operations.

The UIC Program Director has a public health protection role and may examine the potential risks of a proposed Class VI injection well, especially risks to populations in or near the delineated AOR. The EPA UIC Program Class VI Implementation Manual for UIC Program Directors (U.S. Environmental Protection Agency, 2018) provides recommendations for reviewing the submitted information to verify that the project continues to be protective of USDWs and that, following site closure, the injection and monitoring wells at the site will not endanger USDWs.

Lastly, an environmental justice assessment is recommended by EPA but not explicitly required in the CFR as part of a comprehensive EPA UIC Class VI permit application review. Environmental justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies (U.S. Environmental Protection Agency, 2011). The permit applicant may consider developing an outreach package that addresses environmental justice for the project before the draft Class VI permit is publicly noticed.

North Dakota Class VI UIC Program

Prior to the commencement of injection activities, the North Dakota Class VI UIC program requires all owners or operators planning to inject CO_2 for the purpose of geologic storage to obtain a storage facility permit (SFP) for the storage reservoir, followed by a permit to drill (deepen, convert, or reenter) and a permit to operate (Department of Mineral Resources, 2013). With the extensive site characterization work that is required to complete a SFP application, it is more than likely that a stratigraphic test well will need to be drilled by the storage operator and that new or existing 2D or 3D seismic surveys will need to be acquired to construct a geologic model of the storage reservoir. The storage operator will need a geologic model to simulate CO_2 injection and determine the predicted extent of the CO_2 plume as well as satisfy other key information required for the SFP.

NDIC's Oil and Gas Division is responsible for permitting stratigraphic test wells, permitting geophysical surveys, performing the technical evaluation of CO_2 injection well permit applications, and the drafting of permit provisions for Class VI wells. Given that the primary objective of the UIC program is the protection of USDWs, state statute requires that NDIC consult with the North Dakota DEQ, which is the agency responsible for the protection and maintenance of water quality in the state, before issuing an SFP (North Dakota Legislative Branch, 2022). The DEQ review ensures that the state's standards of quality, such as protecting public health and welfare including present and prospective future use of public water supplies, are met as part of the SFP applications (Anagnost and others, 2022).

Permitting Process

There are three permit types that are required for geologic storage of CO_2 in North Dakota: 1) the APD, which permits the operator to drill, deepen, convert, or reenter a well; 2) the CO_2 SFP application; and 3) the permit to operate an injection well or authorization to inject CO_2. Injection activities may not commence until construction of the injection well is complete, a permit to operate has been obtained, and an SFP has been issued (Anagnost and others, 2022). More details regarding the SFP application, APD, and authorization to inject are provided below:

- SFP application: The SFP requires that the storage operator demonstrate that the reservoir and associated pore space for CO_2 storage are controlled, allowing for the orderly development and maximum utilization of the reservoir. Additionally, the operator must submit detailed engineering and geological data, along with a CO_2 injection plan that includes a description of mechanisms of geologic containment that would prevent horizontal or vertical migration of CO_2 beyond the proposed storage reservoir, for state approval. The operator is also required to submit for state approval an emergency and remedial response plan, worker safety plan, corrosion monitoring and prevention plan, and facility and storage reservoir leak detection and monitoring plan.

- APD: Following receipt of an SFP, the storage operator must obtain a permit to drill, deepen, convert, operate, or, upon demonstration of mechanical integrity, reenter a previously plugged and abandoned well for storage purposes. Well types include stratigraphic test wells, CO_2 injection and CO_2 storage wells, gas storage wells, injectivity test wells, monitoring wells, and more (Department of Mineral Resources, 2022).

- Authorization to Inject: Within 30 days after the conclusion of well drilling and completion activities (including the filing of a well completion report), the storage operator must submit a permit application to operate an injection well in accordance with the requirements set forth in NDAC § 43-05-01-09. The permit to operate requires proof that the well casing is adequately cemented so that CO_2 injected is confined to the storage reservoir.

The North Dakota permitting process from beginning (e.g., drilling of a stratigraphic test well for site characterization) to end (e.g., receipt of a permit to operate a Class VI CO_2 injection well) is presented in Figure 9.

Pore Space Amalgamation

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (NDCC Chapter 47-31 Subsurface Pore Space Policy). Furthermore, prior to initiating the storage of CO_2, North Dakota statutes mandate that the storage operator make a good faith effort to obtain consent from all owners of the storage reservoirs pore space; however, a storage project can proceed if consent of landowners who own at least 60% of the pore space of the storage reservoir is obtained and all nonconsenting pore space owners are, or will be, equitably compensated. North

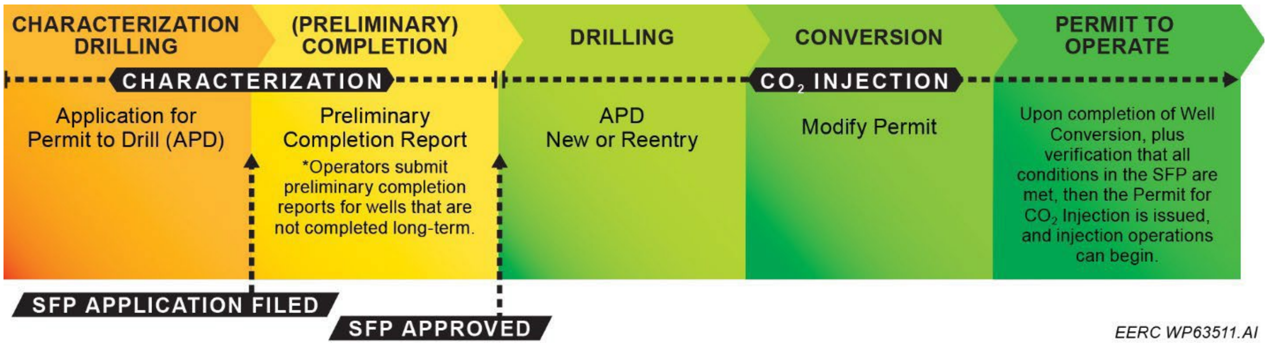

Figure 9. North Dakota Class VI permitting process involving drilling permits (APD), SFPs, and permit to operate.

Dakota law grants NDIC the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space is considered at the administrative hearing as part of the regulatory process required for approval of the SFP application (Anagnost and others, 2022).

North Dakota regulations also require a buffer area to be defined beyond the predicted outer boundary of the areal extent of the subsurface CO_2 plume (see Storage Facility Area, Figure 10). This buffer area defines the areal boundaries of the storage facility and provides additional assurance that the CO_2 will not migrate beyond these boundaries. The buffer extent is squared off to approximately the nearest ¼–¼ section to facilitate legal description of the storage facility area (Peck and others, 2022c, in progress). The storage facility area is the permitted and amalgamated area. The hearing notification area, ½ mile beyond the storage facility area boundary, is the area within which the applicant is required to notify all landowners (surface/pore space), mineral owners, lessees of both land and mineral, and operators of mineral extraction activities at least 45 days prior to the public hearing for the SFP application. The evaluation area is 1 mile beyond the storage facility area boundary and is the minimum AOR required in North Dakota. The Class VI UIC program AOR may be larger and is site specific; therefore, North Dakota has a minimum evaluation area. This evaluation examines wellbores that penetrate the upper confining formation of the storage reservoir, all the existing information on all geologic strata overlying the storage reservoir, including the immediate cap rock containment characteristics, and all subsurface zones to be used for monitoring. The evaluation must also identify any existing or potentially productive mineral zones that are present within the facility area and any USDWs. NDCC § 43-05-01-05 contains a full list of requirements for the technical evaluation area (Peck and others, 2022a).

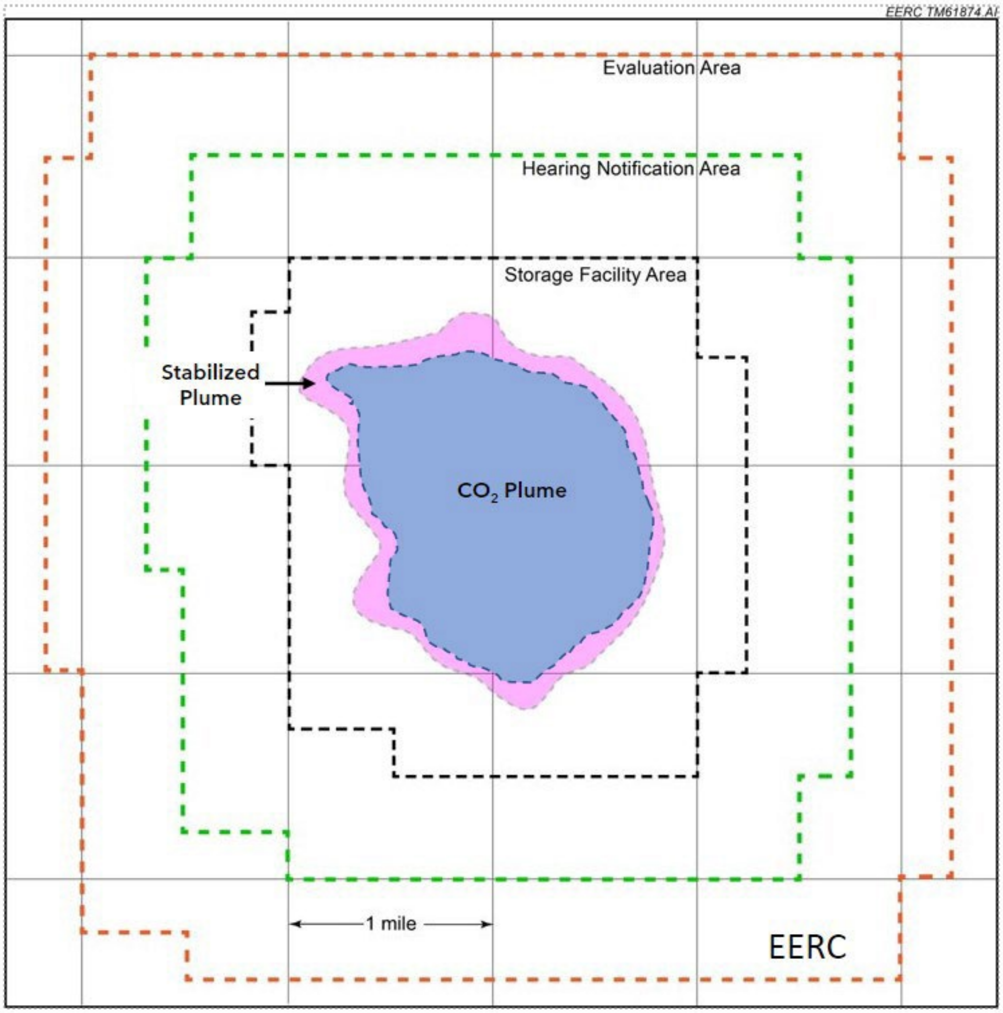

Figure 10. Map showing conceptualized project boundaries, including the CO_2 plume at the end of injection (blue plume), the stabilized plume (pink plume), the storage facility area (black hashed line), the hearing notification area (green hashed line), and the evaluation area for a geologic CO_2 storage project (red hashed line).

SFP Hearing and Timeline

SFP Hearing

NDIC is required to hold a public hearing before issuing an SFP. At least 45 days prior to the hearing, the applicant is required to give notice of the hearing to each of the following groups of individuals within the storage facility area and within the Hearing Notification Area (see Figure 10):

- Owner of record of minerals
- Mineral lessee of record
- Operator of mineral extraction activities

- Surface owner of record
- Pore space owner and each lessee of record

NDIC is required to give at least a 30-day public notice and comment period prior to the public hearing. The state follows public notification requirements, such as advertising in a newspaper of general circulation in the county where the project is proposed.

SFP Timeline

Upon official submission of an SFP, NDIC will proceed with a technical review and determination of the application's completeness. NDIC will either a) return the application as deficient or b) accept the application as complete and create a draft permit within 60 days (see Figure 11). As previously noted, the draft permit is shared with North Dakota DEQ at this time as part of a required statutory consultation period.

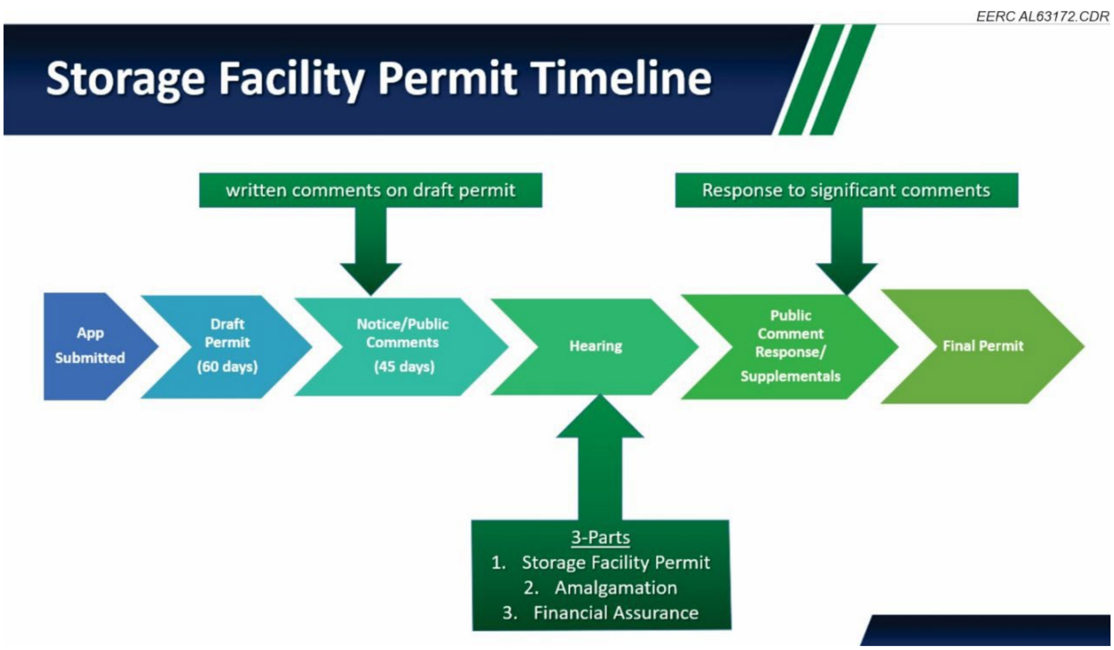

Figure 11. General timeline of the storage facility-permitting process of North Dakota.

Following the conclusion of DEQ's consultation period (approximately 2 months into the process), NDIC and the applicant will schedule a public hearing, allowing for sufficient time to provide the required 45-day notice by the applicant to landowners, pore space owners, mineral owners, and lessees within the notification area (see Figure 10). NDIC then publishes a 30-day public notice of the hearing and public comment period.

Approximately 4–6 months into the permitting process, a public hearing for the SFP application takes place, where the applicant will provide expert testimony before NDIC's Oil and Gas Division staff, along with cross-examination by commission staff. Based on testimony and cross-examination, the applicant may be required to submit supplemental documentation or information into the record. The hearing process is also an opportunity for any interested parties to learn about the geologic storage project and provide verbal or written testimony.

Although one comprehensive SFP application is submitted per storage complex, the NDIC hearing includes testimony and cross-examination on three separate cases combined for the purposes of the hearing: 1) authorization for CO_2 geologic storage in the amalgamated storage reservoir pore space; 2) determination of the amalgamation of storage reservoir pore space (pursuant to a geologic storage agreement for pore space use); and 3) determination of the amount of, and supporting assurance plan for, financial responsibility for the CO_2 geologic storage (Anagnost and others, 2022).

Approximately 2 months following the hearing, and at a regularly scheduled NDIC meeting, the Oil and Gas Division Director will present the SFP cases and subsequent commission orders to the North Dakota governor, attorney general, and agriculture commissioner for a final decision. After approval of the SFP, the applicant can then submit individual injection well permits based on the project design presented in the SFP. A final regulatory decision regarding the individual well permits is typically received within a 4–6-week time frame.

The first three SFPs in North Dakota were approved within 8 months from the date of the official submission to NDIC. This timeline could be extended if there is substantial opposition at the public hearing or through public comment, although NDAC § 43-05-01-05 Subsection 3 states that "The commission has one year from the date an application is deemed complete to issue a final decision regarding the application."

Wyoming Class VI UIC Program

Wyoming Class VI UIC program requirements are similar to those of the EPA, in that each Class VI injection well is permitted independently, even if located within a multiwell storage project. In other words, WDEQ does not have a project permitting process (e.g., North Dakota's SFP); rather, each Class VI well permit includes individual AOR delineations, monitoring plans, emergency response plans, financial assurance demonstrations, etc. As stated previously in this report, WOGCC is responsible for the unitization permitting process associated with geologic CO_2 storage in Wyoming. WDEQ also requires a prescribed risk assessment and analysis as well as a minimum of a 20-year PISC period before the operator can apply to transfer the responsibility for long-term liability to the state of Wyoming.

The WDEQ website provides information, guidelines, and forms to assist storage operators in applying for a geologic sequestration permit, also referred to as a Class VI permit. A variety of topics are addressed on the website including 1) recommendations for when to request informational and preapplication meetings, 2) regulatory considerations for collecting site characterization data, such as drilling stratigraphic test wells and geophysical seismic surveys (if necessary), 3) general information on using a geologic sequestration Class I permit application, 4) a list of project risks targeted for analysis; 5) injection well depth waivers, and 6) expansion to the areal extent of existing Class II injection well aquifer exemptions for Class VI injection wells.

WDEQ also provides a sequence of permitting events for the CCS project from screening to long-term stewardship that is very similar to that of North Dakota (Figure 12). The first three steps of the process—site-screening, feasibility, project design and permit application—are the responsibility of the project operator. Prospective operators of a geologic sequestration site are recommended to meet with the Water Quality Division of WDEQ early in the project to ensure that the information required to complete the Class VI injection well and facility permit applications are identified, with a preapplication meeting being required at least 45 days prior to an application being submitted. Project operators are also encouraged to assess their project for eligibility for the 45Q tax credit program and the low-carbon fuel markets for additional incentives early in the permitting process.

Site-Screening and Project Design

During the site-screening process, the injection formation must be identified as a non-USDW; currently, EPA is not allowing new aquifer exemptions for Class VI injection wells. Additionally, if the injection formation is located above the lowermost USDW, the operator may request an injection depth waiver from the EPA regional office (i.e., Region 8), provided they can demonstrate the USDW will not be endangered.

If a stratigraphic test well is needed for the collection of geologic data, an APD will be required through WOGCC. After geologic data are collected, the operator may consider constructing the stratigraphic test well to Class VI well construction requirements and temporarily abandoning the well for a future conversion after the Class VI permitting process is complete. WOGCC allows 1 year from the date the well was spud to plug and abandon the wellbore or to request an extension to accommodate its conversion to a Class VI well.

WDEQ Regulatory Review of Permit

Following submission of the Class VI permit to WDEQ, applications will be reviewed for completeness and technical adequacy, with a determination within 60 days. If an application is deemed complete and technically adequate, a draft permit will be prepared by WDEQ, and notifications will be provided to interested parties. A mandatory 60-day public comment period is required. A public hearing will be scheduled on the last day of the public comment period in the county in which the project is located. If no comments are provided during the public comment period, the Director of WDEQ can make a final determination for permit issuance or denial within 60 days after the public comment period. If unitization is required, a permit may not be issued until the unitization order is issued by WOGCC.

Construction of the Well(s)

Upon issuance of the project certificate by WDEQ, construction of the injection well and associated monitoring wells may commence. Modifications to the application may be needed after the wells are completed, pending any observed differences in geologic data or changes required to the program plans. Modifications will undergo the WDEQ review process, including public notice requirements and financial assurance requirements. Following a determination that the review is complete, an authorization to inject will be issued by WDEQ.

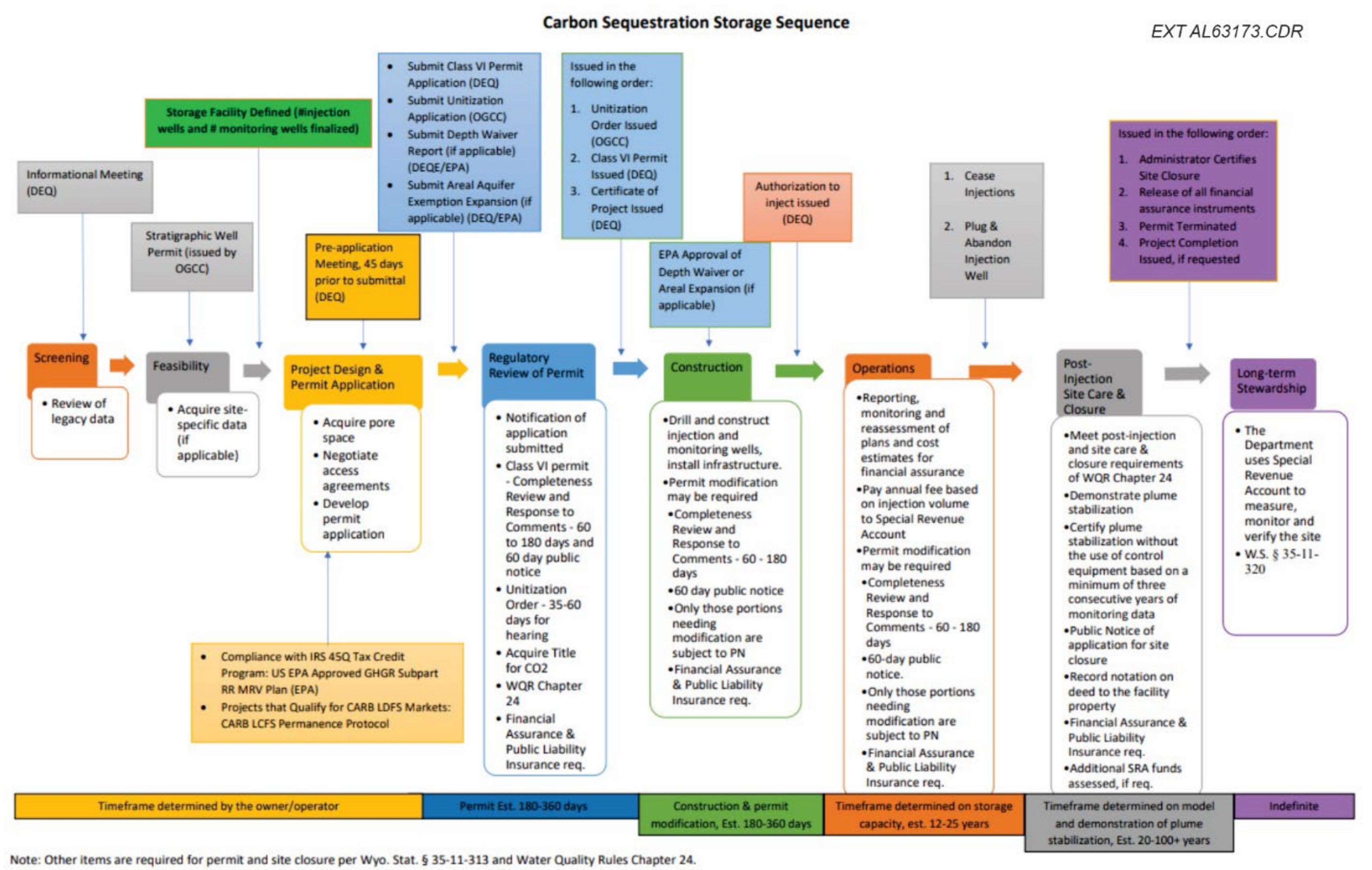

Figure 12. WDEQ timeline and process for UIC Class VI permitting (Wyoming Department of Environmental Quality, 2022).

CCS/CCUS INCENTIVE PROGRAMS

The primary financial drivers for existing and announced CCS/CCUS projects, regardless of the contractual arrangements (i.e., business model) between the three primary project components (i.e., CO_2 capture, transport, and storage), are tax incentives (credits or avoidance) and CO_2 sales (Table 1). Supporting drivers include premium markets for lower-carbon intensity fuels that meet LCFS as well as regulatory/financial policies affecting the handling of the long-term responsibility of CO_2 stored in the subsurface and the impact of environmental, social, and corporate governance (ESG) metrics on the financial viability of a project. Lastly, constructing and operating a CCS project in a state with Class VI primacy provides a project developer with added certainty regarding the cost of meeting the requirements and timeline that are necessary to permit and start-up a project, which will allow for the project to be financially vetted for investors. For an industry to move forward with a CCS/CCUS project, a business model catalyzed with one or more viable drivers (e.g., CO_2 EOR, tax credits) must be adopted that does not negatively impact a company's bottom line (Peck and others, 2022b).

Table 1. Primary Drivers for CCS/CCUS Projects

Tax Incentives	Product Sales	Other
Section 45Q	CO_2/offtake	Assumption of long-term liability
Investment Tax Credit	Hydrocarbons	State Class VI primacy
Tax Penalty Avoidance	LCFS markets for lower-carbon intensity fuel	Tax penalty avoidance

More specifically, over the past 30 years within the PCOR Partnership region, the existence of viable business models and drivers has produced a diverse commercial CCS/CCUS industry, which has recently shifted in the United States from resource recovery (CO_2 EOR and associated CO_2 storage) to green growth dominated by dedicated storage in saline aquifers. This fundamental shift is evident based on the list of newly announced CCS/CCUS projects within the U.S. portion of the region. Although these projects include CO_2 EOR, most are being driven by the 45Q tax credit or product value enhancement, such as LCFS credits associated with low-carbon intensity fuels (Peck and others, 2022b). On the other hand, the green growth business model described by Ku and others (2020) is in play in Canada. This business model, which supports CO_2 emission reduction through government regulations, incentives, or social pressure, is being implemented in the form of an actively evolving carbon tax policy (essentially a CO_2 levy on fossil fuels). This could be an important driver for commercial CCS/CCUS projects in the Canadian provinces.

Federal Tax Incentives

Recently, developing U.S. and Canadian federal tax policies have strengthened the business case for commercial deployment of CCS/CCUS projects. Specific examples include the U.S. Inflation Reduction Act (IRA) of 2022, which provides a business-friendly update to the U.S. Internal Revenue Code (IRC) Section 45Q tax credits (Table 2), and legislative approvals for a

Table 2. 2022 IRA Increase to Federal 45Q Tax Credit Value

Capture Facility	CO_2 Utilization	2018 45Q Tax Credit, $/metric ton	2022 45Q Tax Credit, $/metric ton
Industrial Facility	Yes	35	60
	No	50	85
Direct Air Capture	Yes	35	130
	No	50	180

Canadian investment tax credit program. In addition, other federal tax incentive programs, such as IRC § 43, § 48A, and 48B tax credits of the Energy Policy Act (EPACT) of 2005 and the Canadian carbon-pricing framework, will continue to provide financial support to operating and newly proposed CCS/CCUS projects and may also be expanded in the future. These programs are briefly described in the remainder of this section.

U.S. Tax Incentives

U.S. IRC Tax Credits

The IRC § 43 tax credit was first enacted into U.S. law in 1986 and was last updated in 2005. Under Title 26 of the U.S. Code (USC) § 43, project developers with U.S. CO_2 EOR operations may qualify for tax credit in an amount equal to 15% of the taxpayer's qualified EOR costs (paid or incurred) for the taxable year. The qualified 15% may be reduced in situations where the prior year's reference oil price exceeds $28, multiplied by an inflation adjustment factor for the prior year.

45Q Tax Credit

Qualifying Criteria and Credit Values

The Section 45Q tax credit, which was enacted into law under the Energy Improvement and Extension Act of 2008, provided an initial tax credit of $20 for each ton of CO_2 stored in a dedicated storage project and $10 for each ton of CO_2 stored during an associated storage project. As part of the Bipartisan Budget Act (BBA) of 2018, the Section 45Q tax credit was modified, and the tax credit was increased to $50 for each ton of CO_2 stored in a dedicated storage project and $35 for each ton of CO_2 stored during an associated storage project; most recently, these tax credits were increased again in the IRA of 2022 to $85 per ton of CO_2 and $60 per ton of CO_2, respectively.

In addition to increasing the tax credits, BBA and IRA also modified some of the key qualifying criteria for a storage operator:

- BBA removed a 75-million-ton cap on total qualified CO_2 captured or injected but required the relevant taxpayer to claim the credit over a 12-year period after operations begin. Additionally, eligible facilities must be operating or must begin construction before 2026.

- IRA made the following modifications: 1) substantially increased the availability of the federal income tax credits available for domestic CCS/CCUS projects (International Revenue Service, 1986), 2) made it easier for CCS/CCUS projects to qualify for 45Q credits, and 3) provided significant new avenues for monetizing 45Q credits (Congress.gov, 2022). The IRA also extended the deadline to begin construction on 45Q credit-eligible projects from 2026 to 2033.

Under 26 USC § 45Q, project developers of either CCS or CCUS projects may qualify for credit equal to the sum of CO_2 volumes captured and permanently stored in the subsurface in the taxable year. A premium was placed on every metric ton of CO_2 stored for dedicated storage as compared with utilization-focused projects. In addition, project developers of dedicated storage projects must report CO_2 volumes under EPA Greenhouse Gas Reporting Program (GHGRP) Subpart RR, while CO_2 EOR operators are not required to do so. As of June 2021, a total of 12 projects were reporting under Subpart RR, including 11 CO_2 EOR projects and one dedicated storage project (Congressional Research Service, 2021).

Monitoring Requirements – EPA GHGRP MRV Plan

For dedicated storage projects to qualify for the Section 45Q tax credit, IRC requires an approved monitoring, reporting, and verification (MRV) plan as described in EPA's GHGRP Subpart RR. MRV plan requirements are provided in Title 40 Chapter I Subchapter C Part 98.448. This program has been in place for over a decade, with numerous approved plans available, for reference, on EPA's website (www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide). For example, approved MRV plans for Tundra SGS LLC and Red Trail Energy, LLC, which were approved in April 2022 for dedicated CO_2 storage, are available on this website.

A proposed MRV plan must be submitted within 180 days of a CCS operator receiving formal approval of a Class VI permit or, in North Dakota, an SFP. A one-time filing extension of up to an additional 180 days is allowed but requires approval of a formal request. To submit an MRV plan, operators must first establish a certificate of representation through the GHGRP's Electronic Greenhouse Gas Reporting Tool (e-GGRT, https://ghgreporting.epa.gov) at least 60 days prior to submitting the plan or filing an extension. All MRV plans, extensions, and annual reports must be submitted electronically through e-GGRT.

The proposed MRV plan must include 1) the delineation of the maximum and active monitoring areas, 2) the identification of potential surface leakage pathways within the maximum monitoring area, 3) a strategy for detecting and quantifying any surface leakage of CO_2 as well as establishing baselines for monitoring CO_2 surface leakage, and 4) an explanation of how site-specific variables will be calculated using the mass balance equations provided by EPA. A summary of the details of the CO_2 capture facility is also required as part of the MRV plan.

Following submission of the proposed MRV plan, the pathway to approval is as follows:

- EPA will send a notification of receipt and initiate a completeness check. If EPA determines the submitted MRV plan is incomplete, the operator will have up to 45 days to submit an updated plan. Once determined to be complete, EPA will initiate a 60-day technical review of the MRV plan, after which EPA may request additional information from the operator. If EPA requests additional information, the operator will be given a timeline to fulfill the request.

- Formal approval of the submitted MRV plan occurs following a satisfactory technical review; at which time, EPA issues a final decision to the operator. The operator must implement the approved MRV plan on the day or day after it becomes finalized. If an operator is dissatisfied with EPA's final decision, an appeal may be made to the Environmental Appeals Board.

- If revisions to the approved MRV plan are needed, then the operator must submit an updated MRV plan to EPA for approval within 180 days of the proposed start for the new plan. Examples for plan modifications include but are not limited to changes to the monitoring and/or operations not originally anticipated, a change in the permit class of the injection well, or a notification by EPA of substantive errors in the existing MRV plan. While the revised MRV plan is pending approval, the operator must continue to report under the most recently approved plan.

EPACT § 48A and 48B Tax Credits

Initially established under EPACT of 2005 and most recently updated in 2009, § 48A and 48B tax credits were designed to primarily reward emission-reducing upgrades to coal-fired power plants and gasification units. Under Title 26 USC § 48A and §48B, tax credits are available for qualifying advanced coal and gasification projects, respectively, based on capital invested to construct capture facilities that reduce the project's total carbon emissions by at least 65%.

Canadian Tax Incentives

Canadian Investment Tax Credit Program

Similar to the IRC tax credits of the United States, Canadian project developers may soon be able to qualify for credits by investing in clean technology with qualifying scientific research and experimental development (SR&ED) expenditures. The government of Canada is currently reviewing legislation passed for the Investment Tax Credit (ITC) program. Under this legislation, project developers may choose to reduce the net income of the project for tax purposes in the taxable year or deduct them in a future year by at least 15% and up to 35% of qualifying SR&ED expenditures.

Canadian Carbon-Pricing Framework

Since 2019, every governmental jurisdiction in Canada has officially put a price on carbon pollution. The government of Canada has set a federal benchmark (backstop), or minimum price, for carbon pollution, although provinces and territories have the option to design their own pricing systems. Facilities with emissions (net-positive carbon pollution) must pay based on the established pricing framework, which ranges based on geographic region. Figure 13 illustrates the carbon-pricing frameworks established across Canada.

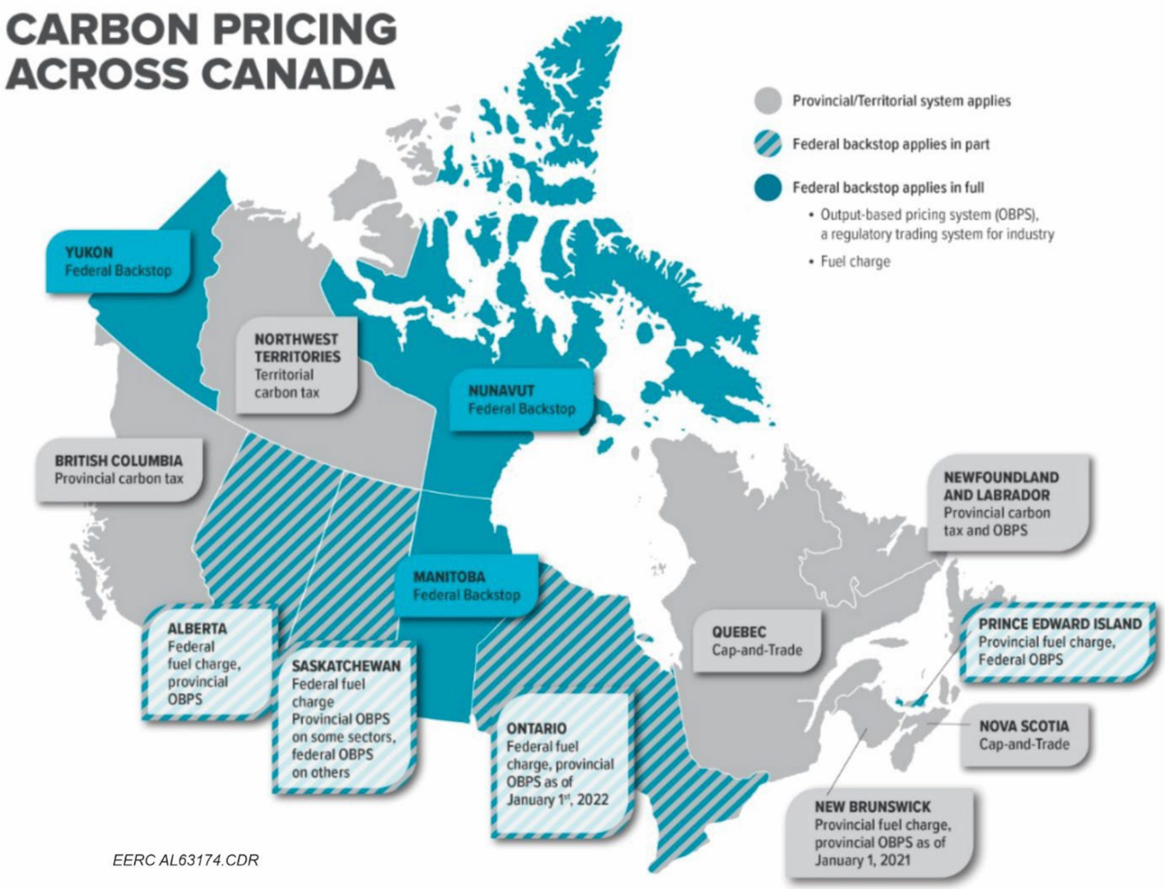

Figure 13. Carbon-pricing framework across all of Canada (Government of Canada, 2022).

Summary of Federal Incentives

A main goal of federal tax incentives is to bridge any gaps between the start-up project costs of capture, transport, and storage and the lagging project revenues. Federal support reduces the costs of technology and infrastructure deployment (e.g., production and investment tax credits, master limited partnerships, private activity bonds) and creates an environment of increased investment certainty (e.g., recent extension of the 45Q tax credit start of construction provision from 2026 to 2033) and financing feasibility (e.g., U.S. Department of Agriculture [USDA] and DOE loans and/or loan guarantees, tax-exempt bond financing, or enhanced 45Q transferability) (Abramson and others, 2020; Minge, 2019). Many of the existing and planned CCS/CCUS projects have been or will be heavily supported by federal, state, and/or provincial dollars (e.g., Shell Quest, the Alberta Carbon Trunk Line [ACTL], and Project Tundra). Beyond direct financial support, tax credit programs in the United States and Canada are poised to support several new CCS/CCUS projects (e.g., the Midwest Carbon Express CCS and the Great Plains CO_2 Sequestration Projects).

State Tax Incentives

Several states in the PCOR Partnership region offer tax incentives to encourage and support CCS/CCUS projects. Most of these existing state tax incentives are related to either the capture of CO_2 or the use of CO_2 in relation to EOR projects. The only state to offer a tax incentive for the dedicated storage of CO_2 is Alaska. Alaska offers a tax incentive related to the federal 45Q tax credit, in which the credit amounts determined by 45Q are increased to 18% and applied against state corporate net income taxes. Incentives offered by other states include the following.

- Montana offers up to 19 years of property tax rate reductions for coal gasification facilities sequestering at least 65% of CO_2 emissions as part of its special property tax applications related to renewable energy, new energy technology, and clean coal programs. The state also incentivizes investment in CO_2 pipelines and sequestration equipment with property tax abatements.

- North Dakota offers a reduction in coal conversion tax dependent on the amount of CO_2 that is captured. Facilities that capture 20% of their CO_2 emissions are eligible for a 20% reduction of the state general fund share based on gross receipts. This reduction can reach 50% for facilities that capture 80% or more of their carbon emissions. North Dakota also incentivizes CCUS with an extraction tax exemption on oil produced by CO_2 EOR and a 10-year property tax exemption on equipment used for transporting CO_2 for EOR.

- Wyoming state statutes formalize a sales tax exemption on CO_2 used in EOR.

North Dakota and Wyoming both have authorized their relative pipeline authority to financially support CO_2 pipeline development and infrastructure in the form of grants, loans, or bonds.

The tax abatements available in PCOR Partnership states exist as part of expanding regulatory frameworks that encourage the development and maintenance of CCS/CCUS projects from start to finish. Financial incentives indicate support of projects at the state level and will continue to be influential in the successful commercial deployment of CCS/CCUS projects. A more detailed summary of current state incentives in the PCOR Partnership region is presented Table 3.

Table 3. Summary of State Tax Incentives in the PCOR Partnership Region

State	Incentive
Alaska	AS 43.20.021(d) – federal tax credits from the 45Q tax credit are scaled to 18% to be applied to state corporate net income tax.
Montana	House Bill 3 (2007) – coal gasification facilities sequestering at a rate of at least 65% may qualify for an abatement of property tax of 50% of the taxable value on up to the first $1 million of the value of the equipment at the facility for up to 19 years.
Montana	House Bill 156 (2015) – carbon sequestration equipment may be taxed at 1.5% of its reduced market value; certified CO_2 pipelines to be taxed at 3% of market value.
North Dakota	Senate Bill 2034 (2009) – oil produced by CO_2 EOR is exempt from oil extraction tax.
North Dakota	Senate Bill 2221 (2009) – CO_2 carbon tax credit for coal conversion facilities capturing at least 20% of emissions, allowing for up to a 50% tax reduction of the state general fund share of tax based on the gross receipts of a given facility.
North Dakota	NDCC §54-17-7 – North Dakota Pipeline Authority is authorized to make grants, loans, or other forms of financial assistance to support pipeline development, including CO_2 transportation pipelines.
North Dakota	Senate Bill 2318 (2015) – 10-year personal property tax exemption for equipment (e.g., pipelines) that transports CO_2 for EOR; sales and use tax exemptions for personal property used to expand carbon capture systems, including the sale of CO_2 for EOR.
Wyoming	WY §§ 37-5-102, 104, 107 – Wyoming Pipeline Authority is authorized to issue bonds and provide loans for pipeline infrastructure, including CO_2 transportation pipelines. Wyoming Pipeline Authority has been incorporated into Wyoming Energy Authority.
Wyoming	WY § 39-15-105 – sale of CO_2 used for EOR is exempt from state sales tax.

CONCLUSIONS

The United States and Canada have made great progress toward improving and/or developing policies and regulatory frameworks to advance the commercial deployment of CCS/CCUS projects. The PCOR Partnership is fostering the development of state-led regulatory frameworks for commercial CCS/CCUS projects and is now poised for the accelerated commercial deployment of this industry across the region, supported by federal tax credit programs in both the United States and Canada. In addition, several states in the PCOR Partnership region offer tax incentives to encourage and support CCS/CCUS projects.

State and federal policies/regulations continue to influence CCS deployment, with permitting identified as a major barrier. Individual states have embraced guidance provided by the IOGCC CGS Task Force by adopting resource management frameworks for geologic CO_2 storage, in combination with pursuing Class VI primacy. If states continue to follow this model, the permitting barrier facing commercial CCS deployment will continue to be removed, similar to the recent success in North Dakota. States are best positioned to create a positive regulatory environment for CCS by providing more regulatory certainty, a well-defined permitting process, and a streamlined permit decision-making process.

North Dakota's regulatory program has created a new comprehensive model by maintaining the resource management framework and combining it with the environmental protections provided by the UIC Class VI primacy program. States in the PCOR Partnership region and beyond are interested in adopting the North Dakota approach, following the IOGCC model of a resource management framework combined with Class VI primacy. One example is Wyoming, which has adopted the same overarching regulatory strategy as North Dakota but implements it using a different state regulatory approach. In Wyoming, WDEQ has the Class VI primacy authority while the WOGCC is authorized to regulate unitization of the storage reservoir. At the same time, North Dakota has established a streamlined permitting process, and the implementation of Wyoming's permitting process, which is very similar, is currently being tested. The learnings from these first state Class VI primacy programs and the process they follow to permit geologic CO_2 storage projects will contribute to the development of a future permitting process that is both streamlined and protective of the environment. It is important to note that at the time of writing this report, EPA has over 20 Class VI permit applications pending and distributed across EPA regions, with Region 6 and Region 9 having the vast majority of those applications. As long as EPA maintains permitting authority, the ability to permit dedicated storage projects will continue to face delays and other regulatory challenges that may slow down the commercial deployment of the industry.

EPA has multiple states that have applied for, or are currently preparing to apply for, Class VI primacy. For a state to reach the point of applying for Class VI primacy, it has already made a significant financial investment (e.g., on the order of hundreds of thousands of dollars) and an investment of time (i.e., multiple years of effort). The Class VI primacy application process is dependent on EPA upholding the system of cooperative federalism. States that are pursuing Class VI primacy and have demonstrated meeting the "as stringent as" standard should be granted this authority by EPA in 2 years or less from the date the state Class VI primacy application was submitted to EPA.

Since 2019, the PCOR Partnership has experienced unprecedented growth as we look toward 20 years of applied research in CCS/CCUS. This growth and the significant increase in the number of emerging projects is a strong indication that a commercial CCS/CCUS industry has emerged. The PCOR Partnership has been a catalyst for CCS/CCUS projects in the region, focused on finding solutions and removing the technical, policy, and regulatory barriers facing commercial deployment.

REFERENCES

Abramson, E., McFarlane, D., and Brown, J., 2020, White paper on regional infrastructure for mid- century decarbonization: Great Plains Institute, June.

Anagnost, K.K., Peck, W.D., Regorrah, J.G., Livers-Douglas, A.J., and Connors, K.C., 2022, North Dakota CarbonSAFE Phase III—permitting geologic storage of carbon dioxide: North Dakota CarbonSAFE Phase III topical report, Task 5, Deliverable 6, for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0031889, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

Congress.gov, 2022, H.R. 5376 – Inflation Reduction Act of 2022, www.congress.gov/bill/117th-congress/house-bill/5376/text (accessed September 2022).

Congressional Research Service, 2021, The tax credit for carbon sequestration (Section 45Q): https://crsreports.congress.gov/ (accessed September 2022), Report #IF11455, 2 p.

Department of Mineral Resources, 2013, North Dakota Class VI Underground Injection Control Program (1422) description: Oil & Gas Division, www.regulations.gov/document/EPA-HQ-OW-2013-0280-0004 (accessed September 2022).

Department of Mineral Resources, 2022, North Dakota Statewide Tracking and Reporting System (NorthSTAR) User Manual Application for Permit, Version 2: 02.07.20, www.dmr.nd.gov/dmr/sites/www/files/documents/Oil%20and%20Gas/NorthSTAR/User%20Manual%20-%20APD%20-%20V2%20Posted%2002.07.19.pdf (accessed September 2022).

Gorecki, C.D., 2019, Plains CO_2 Reduction Partnership Phase III final report: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 13 Deliverable D62 (October 1, 2007 – December 31, 2019) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592 and Final Report for North Dakota Industrial Commission Contract Nos. FY08-LXIII-162 and G-015-030; EERC Publication 2019-EERC-12-15, Grand Forks, North Dakota, Energy & Environmental Research Center, December.

Government of Canada, 2022, Carbon pollution pricing systems across Canada: www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work.html (accessed September 2022).

Internal Revenue Service, 1986, Part I, Section 45Q – credit for carbon oxide sequestration: 26 Code of Federal Regulations 1.45Q-1, Rul. 2021-13, www.irs.gov/pub/irs-drop/rr-21-13.pdf (accessed September 2022).

Interstate Oil and Gas Compact Commission, 2007, CO_2 storage—A legal and regulatory guide for states, https://iogcc.ok.gov/sites/g/files/gmc836/f/co2_storage_summary-road_to_a_greener_ energy_future-2007.pdf (accessed September 2022).

Interstate Oil and Gas Compact Commission, 2014, Guidance for states and provinces on operation and postoperational liability in the regulation of carbon geologic storage: Energy Procedia, DOI:10.1016/j.egypro.2014.11.703, December, www.researchgate.net/publication/

272380381_Guidance_for_states_and_provinces_on_operational_and_postoperational_lia bilit y_in_the_regulation_of_carbon_geologic_storage (accessed September 2022).

Justia US Law, 2016, City of Kenai V. Cook inlet natural gas storage Alaska, LLC, City of Kenai v. Cook Inlet Natural Gas Storage Alaska, LLC https://law.justia.com/cases/alaska/supreme-court/2016/s-15682.html (accessed September 2022).

Ku, A.Y., Cook, P.J., Hao, P., Li, X., Lemmon, J.P., Lockwood, T., Mac Dowell, N., Singh, S.P., Wei, N., and Xu, W., 2020, Cross-regional drivers for CCUS deployment: Clean Energy, 2020, v. 4, no. 3, p. 202–232. doi: 10.1093/ce/zkaa008.

Livers-Douglas, A.J., Christianson, C.C., Richards, T.L., Dalkhaa, C., Massman, N., Crocker, C.R., Connors, K.C., and Vettleson, H.M., 2022, Project development and permitting strategies from the first wave of geologic CO_2 storage projects in North Dakota, Task 4 Deliverable D8b for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0031838, Grand Forks, North Dakota, Energy & Environmental Research Center [in progress].

National Petroleum Council, 2019, Meeting the dual challenge—a roadmap to at-scale deployment of carbon capture, use, and storage: Prepared for the U.S. Department of Energy, Washington, D.C., dualchallenge.npc.org (accessed 2022).

North Dakota Legislative Branch, 2022, North Dakota Century Code Chapter 61-28, control, prevention, and abatement of pollution of surface waters: www.ndlegis.gov/ cencode/t61c28.pdf (accessed September 2022).

Minge, J., 2019, Preview of NPC study on CCUS: National Petroleum Council, September.

Peck, W.D., Regorrah, J.G., Doll, T.E., Nakles, D.V., Pekot, L.J., and Connors, K.C., 2022a, Pore space—technical and legal considerations for CO_2 storage in North Dakota: Plains CO_2 Reduction (PCOR) Partnership Initiative: White Paper for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0031838, Grand Forks, North Dakota, Energy & Environmental Research Center [in progress].

Peck, W.D., Nakles, D.V., Ayash, S.C., and Connors, K.C., 2022b, CCUS business models in the PCOR Partnership region: Plains CO_2 Reduction (PCOR) Partnership Initiative Task 5 Deliverable 4 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0031838, EERC Publication 2022-EERC-01-05, Grand Forks, North Dakota, Energy & Environmental Research Center, 29 p.

Peck, W.D., Regorrah, J.G., Doll, T.E., Nakles, D.V., Pekot, L.J., and Connors, K.C., 2022c, Pore space—technical and legal considerations for CO_2 storage in North Dakota: Plains CO_2 Reduction (PCOR) Partnership Initiative: White Paper for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0031838, Grand Forks, North Dakota, Energy & Environmental Research Center [in progress].

U.S. Environmental Protection Agency, 2018, UIC program Class VI implementation manual for UIC program directors: Office of Water (4606M), EPA 816-R-18-001, January, www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_ 010318.pdf (accessed September 2022).

U.S. Environmental Protection Agency, 2010, Federal Register, Part III, 40 CFR Parts 124, 144, 145 et al. December 10, 2010. (EPA preamble page 77242) www.govinfo.gov/ content/pkg/FR-2010-12-10/pdf/2010-29954.pdf (accessed September 2022).

U.S. Environmental Protection Agency, 2011, 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, June.

U.S. Environmental Protection Agency, 2014, Geologic sequestration of carbon dioxide—underground injection control program Class VI primacy manual for state directors, April.

U.S. Environmental Protection Agency, 2021, Class VI permit application completeness checklist www.epa.gov/system/files/documents/2022-07/UIC%20Class%20VI%20Completeness%20Checklist.pdf (accessed November 2022).

Wyoming Department of Environmental Quality, 2022, https://deq.wyoming.gov/water- quality/ groundwater/uic/class-vi/ (accessed September 2022).

APPENDIX A

INTERSTATE OIL AND GAS COMPACT COMMISSION (IOGCC) MODEL STATUTE

INTERSTATE OIL AND GAS COMPACT COMMISSION (IOGCC) MODEL STATUTE [1]

GEOLOGIC STORAGE OF CARBON DIOXIDE

Section 1. Legislative Declaration; Jurisdiction [2]

(a) The Legislature of the State of declares that (1) the geologic storage of carbon dioxide will benefit the citizens of the state and the state's environment by reducing greenhouse gas emissions; (2) carbon dioxide is a valuable commodity to the citizens of the state; and (3) geologic storage of carbon dioxide gas may allow for the orderly withdrawal as appropriate or necessary, thereby allowing carbon dioxide to be available for commercial, industrial, or other uses, including the use of carbon dioxide for enhanced recovery of oil and gas (EOR).

(b) The State Regulatory Agency shall have the jurisdiction and authority over all persons and property necessary to administer and enforce effectively the provisions of this article concerning the geologic storage of carbon dioxide. In exercising such jurisdiction and authority granted to it, the State Regulatory Agency may conduct hearings and promulgate and enforce rules, regulations, and orders concerning geologic storage of carbon dioxide.

(c) Nothing in this article shall apply to the use of carbon dioxide as a part of or in conjunction with any enhanced recovery methods where the sole purpose of the project is enhanced oil or gas recovery. The State Regulatory Agency is expressly authorized to develop rules to allow conversion of an existing enhanced recovery operation into a Carbon Dioxide Storage Project.

Section 2. Definitions

Carbon dioxide. For purposes of this statute, carbon dioxide is defined as an emissions stream containing carbon dioxide of sufficient purity and quality as to not compromise the safely and efficiency of the reservoir to effectively contain the carbon dioxide.

Oil or gas. Oil, natural gas, or gas condensate.

Reservoir. Any subsurface sedimentary stratum, formation, aquifer, or cavity or void (whether natural or artificially created) including oil and gas reservoirs, saline formations and coal seams, suitable for or capable of being made suitable for the injection and storage of carbon dioxide therein.

---

[1] Canadian provinces should replace "state" with "province" as appropriate.
[2] The purpose of this section is to make clear that the primary goal is to permanently store carbon dioxide to mitigate its impact on global climate change; however, given the commodity status of carbon dioxide, under certain circumstances states need statutory authority to regulate withdrawal of previously stored carbon dioxide for EOR and other uses that do not involve release to the atmosphere.

Carbon Dioxide Storage Project. The underground reservoir, underground equipment, and surface buildings and equipment utilized in the storage operation, excluding pipelines used to transport the carbon dioxide from one or more capture facilities to the storage and injection site. The underground reservoir component of the Carbon Dioxide Storage Project includes any necessary and reasonable areal buffer and subsurface monitoring zones designated by the State Regulatory Agency for the purpose of ensuring the safe and efficient operation of the Carbon Dioxide Storage Project for the storage of carbon dioxide and shall be chosen to protect against pollution, invasion, and escape or migration of carbon dioxide.

Storage operator. Any person, corporation, partnership, limited liability company, or other entity authorized by the State Regulatory Agency to operate a Carbon Dioxide Storage Project.

Geologic storage. Permanent or short-term underground storage of carbon dioxide in a reservoir.

Section 3. State Regulatory Agency Approval; Recordation or Order, Certificate of Operation of Carbon Dioxide Storage Project

The use of a reservoir for storage of carbon dioxide is hereby authorized, provided that the State Regulatory Agency shall first enter an order, after public notice and hearing, approving such proposed geologic storage of carbon dioxide and designating the horizontal and vertical boundaries of the geologic storage. In order to establish a Carbon Dioxide Storage Project for carbon dioxide, the State Regulatory Agency shall find as follows:

That the Carbon Dioxide Storage Project is suitable and feasible for the injection and storage of carbon dioxide.

That a good faith effort has been made to obtain the consent of a majority of the owners having property interests affected by the Carbon Dioxide Storage Project and that the operator intends to acquire any remaining interest by eminent domain or otherwise allowed by statute.

That the use of the Carbon Dioxide Storage Project for the geologic storage of carbon dioxide will not contaminate other formations containing fresh water or oil, gas, coal, or other mineral deposits.

That the proposed storage will not unduly endanger human health and the environment and is in the public interest.

Upon the State Regulatory Agency's issuance of an order of approval as set forth above, said order, or a certified copy thereof, shall be filed for record in the probate court [or other appropriate entity of jurisdiction where land records are filed] of the county or counties in which the Carbon Dioxide Storage Project is to be located.

Prior to commencing injection of carbon dioxide, the storage operator shall record in the county or counties in which the Carbon Dioxide Storage Project is located, and with the State Regulatory Agency, a certificate, entitled "Certificate of Operation of Carbon Dioxide Storage Project," which shall contain a statement that the storage operator has acquired by eminent domain or otherwise all necessary ownership rights with respect to the Carbon Dioxide Storage Project, and the date upon which the Carbon Dioxide Storage Project shall be effective.

If any depleted pool for any previously established field(s) or producing unit(s) for hydrocarbons is contained within the boundaries of the geologic storage, the State Regulatory Agency may, after public notice and hearing, in its order of approval for such Carbon Dioxide Storage Project order that such field(s) or unit(s) shall be dissolved as of the effective date of the Carbon Dioxide Storage Project as set forth in the Certificate of Operation of Carbon Dioxide Storage Project.

Section 4. Protection Against Pollution and Escape of Carbon Dioxide

The State Regulatory Agency shall issue such orders, permits, certificates, rules, and regulations, including establishment of appropriate and sufficient financial sureties as may be necessary, for the purpose of regulating the drilling, operation, and well plugging and abandonment and removal of surface buildings and equipment of the Carbon Dioxide Storage Project to protect the Carbon Dioxide Storage Project against pollution, invasion, and the escape or migration of carbon dioxide or other formation fluids so as not to endanger USDWs.

Section 5. Eminent Domain or Other Applicable Statutory Authority[3]

a) Any storage operator is hereby empowered, after obtaining approval of the State Regulatory Agency as herein required, to exercise the right of eminent domain provided by law, to acquire all surface and subsurface rights and interests necessary or useful for the purpose of operating the Carbon Dioxide Storage Project, including easements and rights-of-way across lands for transporting carbon dioxide among facilities constituting said Carbon Dioxide Storage Project. Such power shall be exercised under the procedure provided by other applicable laws relating to eminent domain.[4]

b) No rights or interests in storage facilities acquired for the injection, storage, and state authorized withdrawal of carbon dioxide by a party who has obtained an order from the State Regulatory Agency under the provisions of Section 2, shall be subject to the exercise of the right of eminent domain authorized by the article. The State Regulatory Agency, however, may reopen an earlier order for the purpose of balancing the

[3] Although the Task Force determined that the most likely mechanism for amalgamating the property rights (surface or subsurface) necessary for the permitting and operation of a Carbon Dioxide Storage Project is eminent domain, the Task Force also recognizes that particular states might have other mechanisms more appropriate for this purpose, e.g., unitization. It is important to note, however, that the Task Force has concluded that the amalgamation of property rights is absolutely necessary to properly permit, construct, and operate a carbon dioxide storage project. Further, the eminent domain power outlined in this model statute is an eminent domain authority solely authorized within the carbon dioxide storage statute and is in addition to any eminent domain authority that may already be possessed by a non-government entity such as a public utility.

[4] In the exercise of the power of eminent domain, a state might consider allowing a storage operator the right of early entry if such right is not otherwise specifically authorized in those circumstances where the eminent domain process may be lengthy.

interests of both projects. Nothing in this article shall alter or revise any power of eminent domain that may exist under any other authority.

c) The right of eminent domain granted in this section shall not prevent the right of the owner of said land or of other rights therein to drill through the geologic storage so appropriated in such manner as shall comply with the rules and regulations of the State Regulatory Agency issued for the purpose of protecting the Carbon Dioxide Storage Project against pollution or invasion and against the escape or migration of carbon dioxide. Furthermore, the right of eminent domain granted in this section shall not prejudice the rights of the owners of said lands or other rights or interests therein as to all other uses not acquired for the Carbon Dioxide Storage Project.

Section 6. Establishment of Carbon Dioxide Storage Project Trust Fund[5]

There is hereby established the Carbon Dioxide Storage Project Trust Fund to be administered by the State Regulatory Agency. There is hereby levied on the storage operator[6] a tax or fee equal to $------- on each ton of carbon dioxide injected for storage for the purpose of funding the Carbon Dioxide Storage Project Trust Fund. The trust fund shall be utilized solely for long-term monitoring of the site, including remaining surface facilities and wells, remediation of mechanical problems associated with remaining wells and surface infrastructure, repairing mechanical leaks at the site, and plugging and abandoning remaining wells under the jurisdiction of the State Regulatory Agency for use as observation wells. The trust fund shall be administered by the State Regulatory Agency.

Section 7. Administration Expenses for this Article Relating to Geologic Storage of Carbon Dioxide

For the purpose of funding the administration and enforcement of these laws relating to geologic storage of carbon dioxide by the State Regulatory Agency during the operational phase of the Carbon Dioxide Storage Project, and for the purpose of compliance inspections including the expense of inspecting, testing, and monitoring the geologic Carbon Dioxide Storage Project, there is hereby levied on the storage operator a per ton tax or fee collected as a percentage of the fee or tax levied in Section 6. The State Regulatory Agency may utilize these monies as it deems appropriate solely for administering and enforcing this article.

[5] The purpose of the Trust Fund will be to provide the State Regulatory Agency with sufficient funds to provide long-term "caretaking" of the facility and to allow the operator and the producer of carbon dioxide the necessary regulatory certainty that ultimately includes release from liability. Based on a particular state's requirements, each state will have to determine the methodology used to provide adequate funding, which would need to include a detailed analysis of the costs anticipated over the lengthy project "caretaking" time frames contemplated.

[6] It is contemplated that the tax or fee will be assessed to and paid by the state-permitted entity. However, in all likelihood the facility operator would recover the tax or fee from the generator of the carbon dioxide.

Section 8. Liability Release[7]

Ten years[8] or other time frame established by rule) after cessation of storage operations, the State Regulatory Agency shall issue a Certificate of Completion of Injection Operations, upon a showing by the storage operator that the reservoir is reasonably expected to retain mechanical integrity and remain emplaced, at which time ownership to the remaining project, including the stored carbon dioxide, transfers to the state. Upon issuance of the Certificate of Completion of Injection Operations, the operator and all generators of any injected carbon dioxide shall be released from all further State Regulatory Agency liability associated with the project. In addition, upon the issuance of the Certificate of Completion of Injection Operations, any performance bonds posted by the operator shall be released and continued monitoring of the site, including remediation of any well leakage, shall become the responsibility of the Carbon Dioxide Carbon Dioxide Storage Project Trust Fund.

Section 9. Cooperative Agreements

The State Regulatory Agency is authorized to enter into cooperative agreements with other governments or government entities for the purpose of regulating carbon dioxide storage projects that extend beyond state regulatory authority under this article.[9]

Section 10. Certifying Storage Amounts.

a) The State Regulatory Agency may also make such certification for carbon dioxide stored under this chapter. The State Regulatory Agency, under procedures and criteria it may adopt, may certify the amount of injected carbon dioxide stored in a Carbon Dioxide Storage Project or during or in connection with enhanced recovery of oil or natural gas.

b) The purpose for certifying storage amounts is to facilitate using the stored carbon dioxide for such matters as reporting, carbon credits, allowances, trading, emissions allocations and offsets, and for other similar purposes.

---

[7] The intent of this section is to provide a methodology whereby the operator and the generator of the carbon dioxide can be released from future liability. This aspect of the statute will allow for regulatory certainty by the industry and help to promote the development of carbon dioxide storage.

[8] While the task force decided that a 10-year time frame prior to release of the operator and carbon dioxide generator from liability might allow adequate time to determine that there are no known issues as to the integrity of the Carbon Dioxide Storage Project, the amount of time prior to release of the operator and generator from liability is ultimately a state decision. Time periods ranging from 3 to 10 years were discussed, as well as times longer than 10 years. The task force, however, believed that a transfer of caretaking responsibility of a stabilized project would be necessary to encourage timely development.

[9] Such an agreement might allow the state that hosts the injection well to take the lead in permitting and might allow other affected states the right to “certify” a project in much the same way as is done under the current program under Section 404 of the Clean Water Act in the United States.

APPENDIX B

INTERSTATE OIL AND GAS COMPACT COMMISSION (IOGCC) MODEL RULES AND REGULATIONS

INTERSTATE OIL AND GAS COMPACT COMMISSION (IOGCC) MODEL GENERAL RULES AND REGULATIONS

GEOLOGIC STORAGE OF CARBON DIOXIDE

Section 1.0. Applicability

The following rules and regulations shall govern the geologic storage of CO_2 in geologic reservoirs. These rules apply to all CO_2 storage operations occurring within the territorial jurisdiction of the state.[1]

Section 2.0. Definitions

The following terms, as used in these regulations for geologic CO_2 storage facilities, shall have the following meanings:

CO_2 means an emissions stream containing carbon dioxide of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir to effectively contain the CO_2.

CO_2 Facility (CF) means all surface and subsurface infrastructure including wellhead equipment, down hole well equipment, compression facilities and CO_2 flow lines from injection facilities to wells within the Geological Storage Unit (GSU), monitoring instrumentation, injection equipment, and offices. CF does not include the main transportation pipeline to the GSU and pump stations along that pipeline.

CO_2 Flow Lines means the pipeline transporting the CO_2 from the CF injection facilities to the wellhead.

CO_2 Injection Well means a well-used to inject CO_2 into and/or withdraw CO_2 from a reservoir.

CO_2 Storage Project (CSP) means the project in its entirety, including CF and GSU.

CSP Closure Period means that period of time (10 years unless otherwise designated by the State Regulatory Agency [SRA]) from the permanent cessation of active CSP injection operations until the expiration of the CSP performance bond, unless monitoring efforts following the operational period demonstrate to SRA that a different time frame is appropriate.

CSP Operational Period means the period of time in which injection occurs.

[1] This document is drafted using the word "state." Canadian provinces should substitute either the word "province" or "provincial" as required. Similarly, Canadian provinces should substitute as appropriate the definitions of Underground Sources of Drinking Water (USDW) and Safe Drinking Water Act (SDWA) here and in the following text.

CSP Operator means that entity required by SRA to hold the permit.

CSP Permit means the permit issued by the state or province to operate a CSP.

CSP Post Closure Period means that period of time after the release of the CSP performance bond.

Formation Fracture Pressure means the pressure, measured in pounds per square inch, which, if applied to a subsurface formation, will cause that formation to physically fracture.

Fresh Water means USDW unless otherwise defined by SRA.

Geological Storage Unit (GSU) means the reservoir used by an entity that holds the SRA permit authorizing CO_2 injection activities.

Geologist or Engineer means a person qualified by education and experience to be recognized as an expert by SRA.

Reservoir means for the purposes of these rules any subsurface sand, stratum, formation, or cavity or void (whether natural or artificially created), including oil and natural gas reservoirs, saline formations, and coal seams, suitable for or capable of being made suitable for the injection and safe and efficient storage of CO_2 therein.

SRA means the State Regulatory Agency designated by the state as responsible for administering these regulations.

Subsurface Observation Well means a well either completed or re-completed for the purpose of observing subsurface phenomena, including the presence of CO_2, pressure fluctuations, fluid levels and flow, temperature, and in situ water chemistry. Underground Sources of Drinking Water (USDW) means:

(1) An aquifer or its portion:

- (A) Which supplies any public water system.
- (B) Which contains a sufficient quantity of ground water to supply a public water system.
  - (i) Currently supplies drinking water for human consumption.
  - (ii) Contains fewer than 10,000 mg/L total dissolved solids.

(2) An aquifer or its portion which is not an exempted aquifer as defined in the U.S. Safe Drinking Water Act[2] (SDWA).

[2] 42 U.S.C. § 300(h) (1) (1976).

Section 3.0. General Requirements

Section 3.1. Site Access

SRA shall, at all times, have access to and may inspect all CO_2 storage operations and records for the purpose of determining that performance is being conducted in accordance with the CSP permit, or the requirements pursuant to Sections 3.0–9.0, or in accordance with the orders of SRA approving CO_2 storage operations.

Section 3.2. CSP Permit Transfer

Transfer Notification by Transferor: The CSP operator shall notify SRA, in writing, in such form as SRA may direct, of the sale, assignment, transfer, conveyance, exchange, or other disposition of the CSP by the operator of the CSP as soon as is reasonably possible, but in no event later than the date that the sale, assignment, transfer, conveyance, exchange, or other disposition becomes final. The operator shall not be relieved of responsibility for the CSP until SRA acknowledges the sale, assignment, transfer, conveyance, exchange, or other disposition, in writing, and the person or entity acquiring the CSP is in compliance with all appropriate requirements. The operator's notice shall contain all of the following:

(1) The name and address of the person or entity to which the CSP was or will be sold, assigned, transferred, conveyed, exchanged, or otherwise disposed.

(2) The name and location of the CSP, and a description of the land upon which the CSP is situated.

(3) The date that the sale, assignment, transfer, conveyance, exchange, or other disposition becomes final.

(4) The date when possession was or will be relinquished by the operator as a result of that disposition.

Transfer Notification by Transferee: Every person or entity that acquires the right to operate a CSP, whether by purchase, transfer, assignment, conveyance, exchange, or other disposition, shall, as soon as it is reasonably possible, but not later than the date when the acquisition of the CSP becomes final, notify SRA in writing, of the person's or entity's operation. The acquisition of a CSP shall not be recognized as complete by SRA until the new operator provides all of the following material:

(1) The name and address of the person or entity from which the CSP was acquired.

(2) The name and location of the CSP, and a description of the land upon which the CSP is situated.

(3) The date when the acquisition becomes final.

(4) The date when possession was or will be acquired.

(5) Performance bonds required by Geologic CO_2 Storage regulations 4.0 (10) and (11).

Section 4.0. CO_2 Storage Project (CSP) Permit

Section 4.1. CSP Permit Requirements

No CSP shall be constructed or operated without:

(1) The CSP operator holding the necessary and sufficient property rights for construction and operation of the CSP. The CSP operator is deemed to be holding such rights for any individual property to the extent that the applicant has initiated unitization or eminent domain proceedings related to that property and thereby gained the right of access to the property. The intention of the CSP operator to employ unitization or eminent domain to acquire property rights shall be included in public notice as defined in Section 5.0; and

(2) Obtaining a license from SRA.

Application for a CSP permit shall be submitted to SRA as required and shall include the following:

(1) A current site map showing the boundaries of the GSU, the location and well number of all proposed CO2 injection wells, including any subsurface observation wells and the location of all other wells, including cathodic protection boreholes, and the location of all pertinent surface facilities within the boundary of the CSP;

(2) A technical evaluation of the proposed CSP, including but not limited to, the following:

(A) The name of the GSU.

(B) The name, description, and average depth of the reservoir or reservoirs to be utilized for geologic CO_2 storage.

(C) A geologic and hydrogeologic evaluation of the GSU, including an evaluation of all existing information on all geologic strata overlying the GSU, including the immediate caprock containment characteristics and all designated subsurface monitoring zones. The evaluation shall include any available geophysical data and assessments of any regional tectonic activity, local seismicity, and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation shall focus on the proposed CO_2 storage reservoir or reservoirs and a description of mechanisms of geologic confinement, including but not limited to, rock properties, geochemical interactions, regional pressure gradients, structural features, and sorption characteristics with regard to the ability of that confinement to prevent migration of CO_2 beyond the proposed storage reservoir. The evaluation shall also identify any productive oil and natural gas zones occurring stratigraphically above, below, or within the GSU and any freshwater-bearing horizons known to be developed in the immediate vicinity of the GSU. The evaluation shall include exhibits and plan view maps showing the following:

(i) All wells, including but not limited to, water, oil, and natural gas exploration and development wells, and other man-made subsurface structures and activities, including coal mines, within one mile of the outside boundary of the GSU.

(ii) All manmade surface structures that are intended for temporary or permanent human occupancy within the GSU and within one mile of the outside boundary of the GSU.

(iii) Any regional or local faulting.

(iv) An isopach map of the proposed CO_2 storage reservoir or reservoirs. (v) An isopach map of the primary and any secondary containment barrier. (vi) A structure map of the top and base of the storage reservoir or reservoirs.

(vii) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored CO_2 or associated fluids.

(viii) An evaluation of the potential displacement of in situ water and the potential impact on groundwater resources, if any.

(ix) Structural and stratigraphic cross-sections that describe the geologic conditions at the reservoir.

A geologist or engineer shall conduct the geologic and hydrogeologic evaluation required under this paragraph. As appropriate, existing geologic, geophysical, or engineering data available on the proposed GSU may be incorporated into the evaluation;

(D) A review of the data of public record for all wells within the CSP Permit, which penetrate the reservoir or primary and/or secondary seals overlying the reservoir designated as the CO_2 storage reservoir, and those wells that penetrate the geologic CO_2 storage reservoir within one mile, or any other distance as deemed necessary by SRA, of the boundary of the GSU. This review shall determine if all abandoned wells have been plugged in a manner that prevents the movement of CO_2 or associated fluids from the geologic CO_2 storage reservoir. A geologist or engineer shall conduct the review required under this paragraph.

(E) The proposed calculated maximum volume and areal extent for the proposed GSU using a method acceptable to and filed with SRA.

(F) The proposed maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in psig, shall be approved by the SRA and specified in the permit. In approving a maximum injection pressure limit, the SRA shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The SRA shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner that endangers a USDW.

(3) The extent of the CO_2, determined by utilizing, as appropriate, all available geologic and reservoir engineering information and reservoir analysis, and the projected response and storage capacity of the GSU.[3]

(4) A detailed description of the proposed CF public safety and emergency response plan. The plan shall detail the safety procedures concerning the facility and residential, commercial, and public land use within one mile, or any other distance as deemed necessary by SRA, of the outside boundary of the CSP Permit. The public safety and emergency response procedures shall include contingency plans for CO_2 leakage from any well, flow lines, or other permitted facility. The public safety and emergency response procedures also shall identify specific contractors and equipment vendors capable of providing necessary services and equipment to respond to such CO_2 injection well leaks or loss of containment from CO_2 injection wells or the CO_2 storage reservoir. These emergency response procedures should be updated as necessary throughout the operational life of the permitted storage facilities.

(5) A detailed worker safety plan that addresses CO_2 safety training and safe working procedures at the CF.

(6) A corrosion monitoring and prevention plan for all wells and surface facilities.

(7) A CF leak detection and monitoring plan for all wells and surface facilities. The approved leak detection and monitoring plan shall address:

(A) Identification of potential release to the atmosphere.

(B) Identification of potential degradation of groundwater resources with particular emphasis on USDWs.

[3] Reservoir analysis may include but not be limited to the use of any of various computational type models, if appropriate for characterization.

(C) Identification of potential migration of CO_2 into any overlying oil and natural gas reservoirs.

(8) A GSU leak detection and monitoring plan utilizing subsurface observation wells to monitor any movement of the CO_2 volume outside of the permitted GSU. This may include the collection of baseline information of CO_2 background concentrations in groundwater, surface soils, and chemical composition of in situ waters within the GSU. The approved subsurface leak detection and monitoring plan shall be dictated by the site characteristics as documented by materials submitted in support of the application with regard to CO_2 containment and address:

(A) Identification of potential release to the atmosphere.

(B) Identification of potential degradation of groundwater resources with particular emphasis on USDWs.

(C) Identification of potential migration of CO_2 into any overlying oil and natural gas reservoirs.

(9) The proposed well casing and cementing program detailing compliance with Section 6.0.

(10) A CSP performance bond shall be sufficient to provide financial assurance to SRA to cover the abandonment or remediation of the CSP should the CSP operator not perform as required or cease to exist. The CSP bond shall be maintained after closure of the facility in accordance with Section 9.0 below.

(11) A well performance bond for each CO_2 injection and subsurface observation well to SRA in an amount established by SRA. The amount of the bond shall be sufficient to provide financial assurance to SRA to cover the plugging and abandonment or the remediation of a CO_2 injection and/or subsurface observation well should the CSP operator not perform as required in accordance with the permit or cease to exist.

(12) The payment of the application fee.

(13) Any other information that SRA requires.

(14) A closure plan.

Section 4.2. Amendment to CSP Permit

The following changes to the original CSP permit conditions will require compliance with all the provisions of Section 4.1 above:

(1) Any change in the original areal extent of the CSP permit.

(2) Utilization of other reservoirs not specified in the original CSP permit.

(3) Any proposed increase in the permitted CO_2 storage volume.

(4) Any change in the chemical composition of the injected CO2 from the CO_2 composition at the time of permitting.

Other significant changes to approved operational parameters contained in the original CSP permit will require compliance with Section 4.1(b).

Section 5.0. Amalgamation of Subsurface Rights to Operate GSU

Each application required under Section 4 shall include a public hearing before SRA for the purposes of joining the necessary property ownership rights, as defined by the state or before the state regulatory agency responsible for amalgamating these rights. These hearings at the discretion of the state regulatory agencies may be combined and heard simultaneously.

Each applicant for a CSP shall give notice of the filing of an application on or before the date the application is filed with SRA by mailing notice via first class mail to the following:

(1) Each operator of hydrocarbon or other mineral extraction activities, or mineral lessee of record within one-half mile external to the boundary of the proposed CSP Permit.

(2) Each owner of record of the surface property and minerals within the boundaries of the proposed CSP Permit.

(3) Each owner of record of the surface property and minerals within one-half mile external to the boundary of the proposed CSP Permit.

(4) Any other parties as required by SRA.

The above notice shall contain a legal description of the proposed CSP Permit along with the date, time, and place of the hearing before SRA and include notice of the right to file comments.

In addition to mail notice to the above parties, public notice via publication shall be required. The public notice shall indicate that an application has been filed with SRA for a CSP and indicate the location of the proposed project and the date, time, and place of the hearing before SRA to determine issuance of the application. Publication shall be in a newspaper of statewide circulation and in a local newspaper in a county or parish newspaper of each county/parish in which the CSP is located. The notice shall indicate that objections may be filed within 15 days of the date of publication.

Objections received by SRA shall be in writing and specify the nature of the objection.

Upon review of the application submitted in accordance with Section 4 and following the Rights Amalgamation Hearing specified in this section, authorization to commence construction of the CSP shall be issued following approval by SRA.

Section 6.0. CSP Wells

Section 6.1. CSP Well Permit Application Requirements

Following receipt of authorization to commence the CSP issued by SRA in accordance with Section 4, the applicant shall submit applications to drill, convert, or, upon demonstration of mechanical integrity, re-enter a previously plugged and abandoned well for CO_2 storage purposes. Application for permits to drill, deepen, convert, re-enter (drill out a previously plugged well) or operate a well shall be submitted on a form prescribed by SRA and shall include at a minimum:

(1) A plat prepared by a licensed land surveyor showing the location of the proposed CO_2 injection or subsurface observation well. The plat shall be drawn to the scale of one (1) inch equals one thousand (1,000) feet, unless otherwise stipulated by SRA and shall show distances from the proposed well to the nearest GSU boundary. The plat shall show the latitude and longitude of the well in decimal degrees to five (5) significant digits. The plat shall also show the location and status of all other wells that have been drilled within one-fourth (¼) mile, or any other distance deemed necessary by SRA, of the proposed CO_2 injection or subsurface observation well.

(2) A prognosis specifying the drilling, completion, or conversion procedures for the proposed CO_2 injection or subsurface observation well.

(3) A well bore schematic showing the name, description, and depth of the proposed reservoir and the depth of the deepest USDW; a description of the casing in the CO_2 injection or subsurface observation well, or the proposed casing program, including a full description of cement already in place or as proposed; and the proposed method of testing casing before use of the CO_2 injection well.

(4) A geophysical log, if available, through the reservoir to be penetrated by the proposed CO_2 injection well or if a CO_2 injection or subsurface observation well is to be drilled, a complete log through the reservoir from a nearby well is permissible. Such log shall be annotated to identify the estimated location of the base of the deepest USDW, showing the stratigraphic position and thickness of all confining strata above the reservoir and the stratigraphic position and thickness of the reservoir.

No later than the conclusion of well drilling and completion activities, a permit application shall be submitted to operate a CO_2 injection well and shall include at a minimum:

(1) A schematic diagram of the surface injection system and its appurtenances.

(2) A final well bore diagram showing the name, description, and depths of the reservoir and the base of the deepest USDW; a diagram of the CO_2 injection well depicting the

casing, cementing, perforation, tubing, and plug and packer records associated with the construction of the CO_2 injection well.

(3) A complete dual induction or equivalent log through the reservoir of the CO_2 injection well. Such log for wells drilled for CO_2 injection operations shall be run prior to the setting of casing through the CO_2 storage reservoir. Logs shall be annotated to identify the estimated location of the base of the deepest USDW, showing the stratigraphic position and thickness of all confining strata above the reservoir and the stratigraphic position and thickness of the reservoir unless previously submitted. When approved in advance by SRA, this information can be demonstrated with a dual induction or equivalent log run in a nearby well or by such other method acceptable to SRA.

(4) An affidavit specifying the chemical constituents of the injection stream other than CO_2 and their relative proportions.

(5) Proof that the long string of casing of the CO_2 injection well is cemented adequately so that the CO_2 is confined to the GSU. Such proof shall be provided in the form of a cement bond log or the results of a fluid movement study or such other method specified by SRA.

(6) The results of a mechanical-integrity test, if applicable to well type, of the casing in accordance with the pressure test requirements, of this section, if a test was run within one calendar year preceding the request for issuance of a conversion permit for a previously drilled well.

Section 6.2. Permit Issuance

Upon review and approval of the application to drill, deepen, convert, re-enter, (drill out a previously plugged well) or operate a CO_2 injection well, submitted in accordance with Section 6.1, SRA shall issue permits to drill and operate.

A permit shall expire twelve (12) months from the date of issuance if the permitted well has not been drilled or converted.

Section 6.3. CSP Well Operational Standards

Surface casing in all newly drilled CO_2 injection and subsurface observation wells drilled below the USDW shall be set 100 feet below the lowest USDW and cemented to the surface or other protective measures as deemed appropriate by SRA.

The long-string casing in all CO_2 injection and subsurface observation wells shall be cemented with a sufficient volume of cement to fill the annular space to a point 500 feet above the top of the storage reservoir.

Any liner set in the well bore shall be cemented with a sufficient volume of cement to fill all of the annular space between the liner and the adjacent casing.

All cements used in the cementing of casings in CO_2 injection and subsurface observation wells shall be of sufficient quality to maintain well integrity in the CO_2 injection environment.

All casings shall meet the standards specified in either of the following documents, which are hereby adopted by reference:

(1) The most recent American Petroleum Institute (API) Bulletin on performance properties of casing, tubing, and drill pipe.

(2) "Specification for casing and tubing (U.S. customary units)," API specification 5CT, as published by the API in October 1998.

(3) Other casing as approved by SRA.

All casings used in new wells shall be new casing or reconditioned casing of equivalent quality that has been pressure-tested in accordance with the requirements of paragraph (e). For new casings, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill the requirements of paragraph (e).

The location and amount of cement behind casings shall be verified by a cement evaluation log, or any other evaluation method approved by SRA, that is capable of evaluating radial cement quality and identifying the location of any channels.

All CO_2 injection wells shall be completed with and injection shall be through tubing and packer.

All tubing strings shall meet the standards contained in paragraph (e) of this regulation. All tubing shall be new tubing or reconditioned tubing of equivalent quality that has been pressure-tested. For new tubing, the pressure test conducted at the manufacturing mill or fabrication plant may be used to fulfill this requirement.

All wellhead components, including the casing head and tubing head, valves, and fittings, shall be made of steel having operating pressure ratings sufficient to exceed the maximum injection pressures computed at the wellhead and to withstand the corrosive nature of CO_2. Each flow line connected to the wellhead shall be equipped with a manually operated positive shutoff valve located on or near the wellhead.

All packers, packer elements, or similar equipment critical to the containment of CO_2 shall be of a quality to withstand exposure to CO_2.

An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. Gauges shall be calibrated as required by SRA and evidence of such calibration shall be available to SRA upon request.

All newly drilled wells shall establish internal and external mechanical integrity as specified by SRA and demonstrate continued mechanical integrity through periodic testing as determined by SRA. All other existing wells to be used as CO_2 injection wells will demonstrate mechanical integrity as specified by SRA prior to use for CO_2 injection and be tested on an ongoing basis as determined by SRA using these methods:

(1) Pressure tests. CO_2 injection wells, equipped with tubing and packer as required, shall be pressure-tested as required by SRA. A testing plan shall be submitted to SRA for prior approval. At a minimum, the pressure shall be applied to the tubing casing annulus at the surface for a period of 30 minutes and shall have no decrease in pressure greater than 10% of the required minimum test pressure. The packer shall be set at a depth at which the packer will be opposite a cemented interval of the long string casing and shall be set no more than 50 feet above the uppermost perforation or open hole for the CO_2 storage reservoir.

(2) SRA may require additional testing such as bottom hole temperature and pressure measurements, tracer survey, temperature survey, gamma ray log, neutron log, noise log, casing inspection log, or a combination of two or more of these surveys and logs, to demonstrate mechanical integrity.

Supervision of mechanical integrity testing. SRA may witness all mechanical integrity tests conducted by each CSP operator for regulatory purposes.

If a CO_2 injection well fails to demonstrate mechanical integrity by an approved method, the operator of the well shall immediately shut in the well, report the failure to SRA, and commence isolation and repair of the leak. The operator shall, within 90 days or as otherwise directed by SRA, perform one of the following:

(1) Repair and re-test the well to demonstrate mechanical integrity.

(2) Plug the well in accordance with state requirements.

(3) Comply with alternative plan as approved by SRA.

All CO_2 injection wells shall be equipped with shutoff systems designed to alert the operator and shut in wells when necessary.

Additional requirements may be required by SRA to address specific circumstances and types of projects not specified in these rules.

Section 6.4. Amendment to CSP Well Permits

An amendment to the CSP Well Permit for (1) a change in injection formation, and/or (2) a modification of maximum allowable injection rate and pressure, shall comply with the provisions of Section 6.1 (c)(5) and (6), 6.3 (b), (g), (h), (i), (l) and (m) above.

Modification of well construction shall comply with the provisions of Section 6.1 (b) (3) and 6.3 (m).

Section 7.0. CSP Operational Standards

Section 7.1. Safety Plans

Each operator of a CSP shall implement an SRA-approved CF public safety and emergency response plan and the worker safety plan proposed in Section 4. This plan shall include emergency response and security procedures. The plans, including revision of the list of contractors and equipment vendors, shall be updated as necessary or as SRA requires. Copies of the plans shall be available at the CF and at the nearest operational office of the holder of the CSP Permit.

Section 7.2. Leak Detection and Reporting

Leak detectors or other approved leak detection methodologies shall be placed at the wellhead of all CO2 injection and subsurface observation wells. Leak detectors shall be integrated, where applicable, with automated warning systems and shall be inspected and tested on a semi-annual basis and if defective, shall be repaired or replaced within 10 days. Each repaired or replaced detector shall be re-tested if required by SRA. An extension of time for repair or replacement of a leak detector may be granted upon a showing of good cause by the operator of the CSP. A record of each inspection, which shall include the inspection results, shall be maintained by the operator for at least five years and shall be made available to the state oil and natural gas regulatory agency upon request.

The operator of a CSP shall immediately report to SRA any leaks detected at the surface facility and associated well equipment specified in (a) above.

The operator of a CSP shall immediately or, as soon as practicable, report to SRA any pressure changes or other monitoring data from subsurface observation wells that indicate the presence of leaks in the GSU indicating the lack of confinement within the reservoir of the CO_2.

The operator of a CSP shall immediately report to SRA any other indication of lack of containment of CO_2 to the reservoir not associated with wells and surface equipment.

Section 7.3. Other General Requirements

Each operator shall be required to conduct a corrosion monitoring and prevention program approved by SRA.

Identification signs shall be placed at each facility in a centralized location and at each well site and show the name of the operator, the facility name, and the emergency response number to contact the operator.

Section 8.0. Operational Review and Reporting Requirements

Section 8.1. Operational Injection Reports

The volume of CO_2 injected since the last reporting, the average injection rate, average composition of the CO_2 stream, wellhead and down hole temperature and pressure data and/or other data pertinent to or storage certification as required by SRA shall be reported quarterly or as required by SRA.

These quarterly reports shall be compiled and summarized annually to provide updated projections of the response and storage capacity of the GSU. The projections shall be based on actual GSU operational experience, including all new geologic data and information. All anomalies in predicted behavior as indicated in the most current permit conditions shall be explained and, if necessary, the permit conditions amended in accordance with Section 4.1.

Section 8.2. Annual Operational Report and Review

An annual operational report shall be required by the SRA and include:

(1) A comprehensive review of all monitoring and operational data to determine whether a re-evaluation of the area of review is required.

(2) Whether an update of any required monitoring, safety, corrosion, or other required operational plans are necessary or warranted.

An annual operational report and its findings may be submitted to the SRA as an affidavit signed by an appropriate company official confirming that the company has conducted the required annual review, which will include the submission of any updated or modified plan for the review and approval of the SRA.

Following the annual review, the SRA may require additional information, modification, or revision of the submitted plans before approval.

Section 9.0. CSP Closure

Prior to the conclusion of the operational period the CSP permit holder shall provide an assessment of the operations conducted during the operational period, including but not limited to, the volumes injected, extracted, any and all chemical analyses conducted, summary of all monitoring efforts, etc. The report shall also document the position and characteristics of the areal extent of the CO_2 and a prediction of the extent and movement of the CO_2 volume anticipated during the CSP closure period.

The permittee shall submit a monitoring plan for the CSP closure period for approval by SRA, including but not limited to a review and final approval of which wells will be plugged and which wells will remain unplugged to be used as CSP closure and post-closure period subsurface observation wells.

Following well plugging, all associated surface equipment shall be removed and the well site returned to its original land use to the extent possible.

The well casing shall be cut off at a depth of 5 feet below the surface and a steel plate shall be welded on top identifying the well name and that it was used for CO_2 injection.

In conjunction with the permittee, SRA shall develop a continuing monitoring plan for the CSP Closure Period, including but not limited to, a review and final approval of which wells shall remain unplugged for use as monitoring wells.

All remaining wells not used for monitoring purposes shall be properly plugged and abandoned, all CF equipment and facilities shall be removed, and the CSP site reclaimed in accordance with SRA requirements.

Section 10.0. Post Closure Period

Prior to authorization to begin the Post-Closure Period, the owner or operator must demonstrate to the SRA, based on monitoring, other site-specific data, and appropriate modeling, that no additional monitoring is needed to assure that the CSP does not pose an endangerment to USDWs.

The SRA shall approve the transition to the Post-Closure Period if the owner or operator demonstrates the following:

(1) The estimated extent of the CO_2 plume and the area of elevated pressure.

(2) That there is no significant leakage of either CO_2 or displaced formation fluids endangering USDWs.

(3) That the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into a USDW.

(4) That the injection wells at the site completed into or through the injection zone or confining zone are plugged and abandoned in accordance with these requirements.

SRA shall have full control of and responsibility for the remaining unplugged wells to be used by SRA as CSP post-closure period subsurface observation wells or for other purposes as deemed necessary by SRA.

At the conclusion of the CSP closure period, the CSP performance bond maintained by the CSP operator may be released, and continued monitoring of the site, remediation of any well leakage, including wells previously plugged and abandoned by the CSP operator, shall become the responsibility of designated state or federal agency programs and the CSP operator and generator of the CO_2 shall be released from further SRA regulatory liability relating to the CF.

APPENDIX C

40 CODE OF FEDERAL REGULATIONS (CFR) PART 124 SUMMARY

40 CODE OF FEDERAL REGULATIONS (CFR) PART 124 SUMMARY

40 CFR PART 124 - PROCEDURES FOR DECISIONMAKING			
Section	**Title**	**Action Applicable To Applicant Or Interested**	**EPA**
124.3	**Application for a permit**	1. Submit a complete, signed Class VI permit application. 2. Failure to respond to deficiencies will require further action by EPA, such as a denial of the application.	Within 30 days review application for completeness. 1. If incomplete: provide notice of deficiency and date for submitting responses. 2. Effective date of the application is the date EPA notifies the applicant the application is complete and provides a project decision schedule. 3. Project schedule will specify target dates EPA will: a. Prepare a draft permit b. Give public notice c. Complete the public comment period, including any public hearing d. Issue a final permit
	Consolidation of permit processing	Applicant may recommend whether or not the processing of their application should be consolidated.	1. Consolidation of permit processing is allowed at EPA's discretion. 2. Each Class VI well is required to have an approved Class VI permit.
124.5	**Modification, revocation and reissuance, or termination of permits**	1. Submit the applicable request for modification, revocation and reissuance, or termination of a permit. 2. Denial – may be informally appealed to EAB.	1. Denial of modification or reissuance – EPA sends permitee a written response with reason for denial. a. Denial requests are not subject to public notice, comment, or hearings. 2. Permit modifications, revocation and reissuance, and termination require public notice, public comment, and possibly a public hearing. a. Modification (Causes for modification are defined in § 144.39). i. EPA ***may*** require the submission of an updated application. ii. Only those conditions to be modified are reopened for public review and comment. b. Reissuance (Causes for revocation and reissuance § 144.39). i. EPA ***will*** require the submission of an updated application. ii. The entire permit is reopened for public review and comment and possible hearing. c. Denial or Termination (Causes for termination or denial of permit renewal of permits § 144.40). i. Non-compliance. ii. Misrepresentation of facts. iii. Endangerment to human health or the environment.
–	**Transfer of permits**	Submit an applicable minor modification, modification, or reissuance.	Class VI permits cannot be automatically transferred (§ 144.38(b)).

Continued . . .

40 CFR PART 124 - PROCEDURES FOR DECISIONMAKING			
Section	**Title**	**Action Applicable To Applicant Or Interested**	**EPA**
–	**Minor modification**	Submit an applicable minor modification or reissuance.	1. Minor modifications are defined in § 144.41. a. May allow for a change in ownership or operational control of a facility where the Director determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittees has been submitted to the Director. 2. Minor modifications are not subject to the procedures of 40 CFR Part 124.
124.6	**Draft permits**	An appeal of the UIC permit may be taken under §124.19.	1. EPA's denial of the permit application request. a. A notice of intent to deny is a type of draft permit that follows the same procedure as a draft permit. b. If EPA's final decision that the tentative decision was incorrect, EPA will withdraw the notice of intent to deny and proceed with preparing a draft permit. 2. EPA's approval and preparation of a draft permit will contain: a. Permit conditions. b. Compliance schedules. c. All monitoring requirements. 3. Draft permits will be accompanied by: a. Fact sheet (§ 124.8) or statement of basis (§ 124.7) based on the administrative record (§ 124.9). 4. Draft permit will be: a. Public noticed (§124.10), made available for public comment (§ 124.11), given an opportunity for a public hearing (§ 124.12).
124.7 **124.8**	**Statement of basis fact sheet**	Applicant will receive a copy of the statement of basis or fact sheet prepared by EPA.	EPA will prepare a fact sheet or statement of basis for every draft permit for a Class VI UIC injection well. 1. The statement of basis shall briefly describe the derivation of the conditions of the draft permit and the reasons for them or, in the case of notices of intent to deny or terminate, reasons supporting the tentative decision. 2. The fact sheet shall briefly set forth the principal facts and the significant factual, legal, methodological, and policy questions considered in preparing the draft permit.
124.9	**Administrative record for draft permits**	UIC Program is exempt from performing an Environmental Impact Statement (EIS) under section 101(2)(C) and an alternatives analysis under section 101(2)(E) of NEPA under a functional equivalence analysis.	EPA's draft permit shall be based on the administrative record and consist of: 1. The application, if required, and any supporting data furnished by the applicant. 2. The draft permit or notice of intent to deny the application or to terminate the permit. 3. The statement of basis (§ 124.7) or fact sheet (§ 124.8). 4. All documents cited in the statement of basis or fact sheet. 5. Other documents contained in the supporting file for the draft permit.

Continued . . .

40 CFR PART 124 - PROCEDURES FOR DECISIONMAKING			
Section	**Title**	**Action Applicable To Applicant Or Interested Person**	**EPA Action**
124.10	**Public notice of permit actions and public comment period**		1. Scope a. The Director shall give public notice that the following actions have occurred: i. A permit application has been tentatively denied. ii. A draft permit has been prepared. iii. A hearing has been scheduled. b. No public notice is required when a request for permit modification, revocation and reissuance, or termination is denied. Written notice of that denial shall be given to the requester and to the permittee. c. Public notices can describe more than one permit or permit actions. 2. Timing a. Public notice of the preparation of a draft permit (including a notice of intent to deny a permit application) shall allow at least 30 days for public comment. b. Public notice of a public hearing shall be given at least 30 days before the hearing. i. Public notice of the hearing may be given at the same time as public notice of the draft permit and the two notices may be combined. 3. Method of public notice. a. Mailing a copy of the notice to applicant and other agencies listed in §124.10(c)(1). b. For Class VI UIC permits also includes mailing or emailing a notice to State and local oil and gas regulatory agencies and State agencies regulating mineral exploration and recovery, the Director of the Public Water Supply Supervision program in the State, and all agencies that oversee injection wells in the State. 4. Contents as listed in § 124.10(d). 5. Public notice for hearings as listed in § 124.10(e).
124.11	**Public comments and requests for public hearings**		During the public comment period, any interested person may submit written comments on the draft permit and may request a public hearing, if no hearing has already been scheduled. A request for a public hearing shall be in writing and shall state the nature of the issues proposed to be raised in the hearing. All comments shall be considered in making the final decision and shall be answered in the response to comments (§ 124.17).

Continued . . .

40 CFR PART 124 - PROCEDURES FOR DECISIONMAKING			
Section	**Title**	**Action Applicable To Applicant Or Interested**	**EPA**
124.12	**Public hearings**	1. Any person may submit oral or written statements and data concerning the draft permit. 2. Reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing may be required.	1. EPA shall hold a public hearing when on the basis of requests, a significant degree of public interest in a draft permit(s). 2. EPA may also hold a public hearing on his or her discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision. 3. Public notice of the hearing is required. 4. The public comment period will automatically be extended to the close of any public hearing.
124.13	**Obligation to raise issues and provide information during the public comment period**	1. All persons, including applicants, who believe any condition of a draft permit is inappropriate or that EPA's tentative decision to deny an application, terminate a permit, or prepare a draft permit is inappropriate, must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting their position by the close of the public comment period. 2. Any supporting materials which are submitted shall be included in full and may not be incorporated by reference, unless they are already part of the administrative record in the same proceeding, or consist of State or Federal statutes and regulations, EPA documents of general applicability, or other generally available reference materials.	1. Commenters shall make supporting materials not already included in the administrative record available to EPA as directed by the Regional Administrator. a. A comment period longer than 30 days may be necessary to give commenters a reasonable opportunity to comply with the requirements of this section. b. Additional time will be granted to the extent that a commenter who requests additional time demonstrates the need for such time.
124.14	**Reopening of the public comment period**	Comments filed during the reopened comment period shall be limited to the substantial new questions that caused its reopening. The public notice will define the scope of the reopening.	1. EPA may order the public comment period reopened to help expedite the decision-making process. 2. Public notice of shall identify the issues to which the requirements to reopen the public comment period apply and identify the scope of the reopening. 3. A public comment period longer than 60 days may be necessary to give commenters a reasonable opportunity to comply with requirements.
124.15	**Issuance and effective date of permit**		1. After the close of the public comment period on a draft permit, EPA will issue a final permit decision. 2. EPA will notify the applicant and each person who has submitted written comments or requested notice of the final permit decision including procedure for appealing a decision under § 124.19. 3. A final permit decision means a final decision to issue, deny, modify, revoke and reissue, or terminate a permit.

Continued . . .

40 CFR PART 124 - PROCEDURES FOR DECISIONMAKING			
Section	**Title**	**Action Applicable To Applicant Or Interested**	**EPA**
124.16	**Stays of contested permit conditions**		1. If a request for review of a UIC permit under appeal is filed, the effect of the contested permit conditions shall be stayed and shall not be subject to judicial review pending final agency action. 2. Uncontested conditions which are not severable from those contested shall be stayed together with the contested conditions. EPA will identify the stayed provisions of permits for existing injection wells. All other provisions of the permit for the existing injection well become fully effective and enforceable 30 days after the date of the notification from the EAP of the filing of a petition for review. 3. After receiving notification from the EAB of the filing of a petition for review, EPA will notify the EAB, the applicant, and all other interested parties of the uncontested (and severable) conditions of the final permit that will become fully effective enforceable as of the date specified in 2 above.
124.17	**Response to comments**		1. At the time that any final permit decision is issued EPA will issue a response to comments that will: a. Specify which provisions, if any, of the draft permit have been changed in the final permit decision, and the reasons for the change. b. Briefly describe and respond to all significant comments on the draft permit. 2. Any documents cited in the response to comments will be included in the administrative record for the final permit decision.
124.18	**Administrative record for final permit**		EPA's final permit decision will be based on the administrative record. The administrative record will be complete on the date the final permit is issued.
124.19	**Appeal of UIC permits**	A petition for review must be filed with the Clerk of the EAB within 30 days after EPA notice of the issuance of a UIC final permit decision.	A petition is filed when it is received by the Clerk of the Environmental Appeals Board.
124.20	**Computation of time**	When a party or interested person may or must act within a prescribed period after being served and service is made by U.S. mail, EPA's internal mail, or reliable commercial delivery service, 3 days shall be added to the prescribed time. The prescribed period for acting after being served is not expanded by 3 days when service is made by personal delivery, facsimile, or email.	1. Any time period scheduled to begin on the occurrence of an act or event shall begin on the day after the act or event. 2. Any time period scheduled to begin before the occurrence of an act or event shall be computed so that the period ends on the day before the act or event. 3. If the final day of any time period falls on a weekend or legal holiday, the time period shall be extended to the next working day.

APPENDIX D

40 CODE OF FEDERAL REGULATIONS (CFR) PART 144 AND PART 146 SUMMARY

APPENDIX D. 40 CODE OF FEDERAL REGULATIONS (CFR) PART 144 SUMMARY

40 CFR Part 144 - Underground Injection Control Program			
Section	**Title**	**Regulation Summary**	**EPA Action**
Subpart A	**General Provisions**		
144.1(f)(1)	**Structure of the UIC Program**	This part sets forth the permitting and other program requirements that must be met by UIC Programs, whether run by a state or by EPA. Describes general elements of the program, including definitions and classifications.	
144.1(f)(1) (i)	**Subpart A**	Describes general elements of the program, including definitions and classifications.	
144.1(f)(1) (viii)		Requirements for owners or operators of Class VI injection wells set forth in Subpart H of Part 146.	
144.1(g)(1)	**Scope of the permit**		EPA shall not expand the areal extent of an existing Class II EOR or enhanced gas recovery aquifer exemption for Class VI injection wells, and EPA shall not approve a program that applies for aquifer exemption expansions of Class II–Class VI exemptions as part of the program description.
144.3	**Definitions**		
	Geologic sequestration	Means the long-term containment of a gaseous, liquid, or supercritical CO_2 stream in subsurface geologic formations. This term does not apply to CO_2 capture or transport.	
144.4	**Considerations under federal law**	Other federal laws by apply to issuance of permits.	
144.5	**Confidentiality of information**	CBI material must be claimed and identified at the time of submission.	
144.6(f)	**Classifications of wells: Class VI**	Wells that are not experimental in nature that are used for geologic sequestration of carbon dioxide beneath the lowermost formation containing a USDW; or, wells used for geologic sequestration of carbon dioxide that have been granted a waiver of the injection depth requirements pursuant to requirements at § 146.95 of this chapter.	
144.7	**Identification of USDW and exempted aquifers**	Even if an aquifer has not been specifically identified by EPA, it is an USDW if it meets the definition in § 144.3.	An updated list of EPA-approved aquifer exemptions is maintained in EPA Regional offices (§ 147.102).

Continued . . .

40 CFR Part 144 - Underground Injection Control			
Section	**Title**	**Regulation**	**EPA Action**
Subpart A	**General Provisions**		
144.7	**Identification of USDW and exempted aquifers**	Other than EPA-approved aquifer exemption expansions that meet the criteria set forth in § 146.4(d), new aquifer exemptions shall not be issued for Class VI injection wells.	EPA approval is required for expansion to the areal extent of a Class II EOR/EGR aquifer exemption for geologic sequestrations.
144.7(d)(1)	**Owner or operator of Class II EOR or EGR wells may request EPA approve an expansion of the areal extent for the exclusive purpose of Class VI injection for geologic sequestration**	EPA will treat the request as a revision to the applicable Federal UIC program under part 147 or as a substantial program revision to an approved state UIC program under § 145.32 of this chapter (requires public notice) and will not be final until approved by EPA.	EPA may exempt other aquifers or portions, according to applicable procedures, without codifying such exemptions in part 147. An updated list of aquifer exemptions will be maintained in the EPA Regional office.
144.7(d)(2)		Operator of a Class II EOR or EGR must define and describe in geographic and/or geometric terms, all aquifers or parts thereof that are requested to be designated as exempted using the criteria in § 146.4.	EPA's considerations to confirm the request to expand the areal extent of the Class II EOR or EGR aquifer exemption for geologic sequestration meets the criteria in § 146.4: i. Current and potential future use of the USDWs to be exempted as drinking water sources. ii. The predicted extent of the CO_2 plume and mobilized fluids that may result in degradation of water quality over the lifetime of the GS project. iii. Whether the areal extent of the expanded aquifer exemption is sufficient to account for possible revisions resulting from AOR reevaluations. iv. Any information submitted to support a waiver request made by the owner or operator under § 146.95, if appropriate.
144.8	**Noncompliance and program reporting by the Director**	All Class VI program reports shall be consistent with reporting requirements set forth in § 146.91.	
Subpart B	**General Program Requirements**		
144.12(b)	**Prohibition of movement of fluid into USDWs**		If any monitoring of an USDW indicates the movement of any contaminant into the USDW, except as authorized under part 146, the Director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to prevent such movement. These additional requirements shall be imposed by modifying the permit in accordance with § 144.39, or the permit may be terminated under § 144.40 if cause exists, or appropriate enforcement action may be taken if the permit has been violated.
144.15	**Prohibition of non-experimental Class V wells for geologic sequestration**	The construction, operation, or maintenance of any non- experimental Class V geologic sequestration well is prohibited.	

Continued . . .

40 CFR Part 144 - Underground Injection Control			
Section	**Title**	**Regulation Summary**	**EPA Action**
Subpart B	**General Provisions**		
144.18	**Requirements for Class VI wells**	Owners or operators of Class VI wells must obtain a permit. Class VI wells cannot be "authorized by rule" to inject carbon dioxide.	
144.19	**Transitioning from Class II to Class VI**	(a) Owners or operators that are injecting CO_2 for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit when there is an increased risk to USDWs compared to Class II operations. In determining if there is an increased risk to USDWs, the owner or operator must consider the factors specified in §144.19(b).	(b) The Director shall determine when there is an increased risk to USDWs compared to Class II operations and a Class VI permit is required. In order to make this determination the Director must consider the following: 1) Increase in reservoir pressure within the injection zone(s). 2) Increase in carbon dioxide injection rates. 3) Decrease in reservoir production rates. 4) Distance between the injection zone(s) and USDWs. 5) Suitability of the Class II area of review delineation. 6) Quality of abandoned well plugs within the area of review. 7) The owner's or operator's plan for recovery of carbon dioxide at the cessation of injection. 8) The source and properties of injected carbon dioxide. 9) Any additional site-specific factors as determined by the Director.
Subpart D	**Authorization by Permit**		
144.3	**Permit application, timing, completeness**	Each Class VI well must be authorized by permit, the operator's duty to obtain a permit, EPA will not issue a permit before receiving a complete application except for an emergency permit.	
	Information requirements	(e) Applicants for Class VI permits shall follow the criteria provided in § 146.82.	
144.32	**Signatories to permit applications and reports**	Signatory for a Class VI permit application is dependent on the type of company applying for the permit as defined in § 144.32(a). The required certification statement is stated in § 144.32(d).	
144.33	**Area permits**	Area permitting is not allowed for Class VI wells (144.33(a)(5))	
144.34	**Emergency permits.**		
	(a)Coverage (b) Requirements for issuance	(b) Any temporary permit shall be only for the time required to prevent the hazard. Public notice of any temporary permit must be published within 10 days of the issuance of the permit. The temporary permit under this section may be either oral or written. If oral, it must be followed within 5 calendar days by a written temporary emergency permit. The temporary permit will be conditioned as necessary to ensure that the injection will not result in the movement of fluids into USDW.	(a) EPA may temporarily permit a specific underground injection activity if an imminent and substantial endangerment to the health of persons will result unless a temporary emergency permit is granted.

Continued . . .

40 CFR Part 144 - Underground Injection Control			
Section	**Title**	**Regulation Summary**	**EPA**
Subpart D	**General Provisions**		
144.35	**Effect of a permit**	(a) Compliance with a Class VI permit during its term constitutes compliance, for purposes of enforcement, with Part C of the SDWA. However, a permit may be modified, revoked and reissued, or terminated during its term for cause as set forth in §§ 144.39 and 144.40. (b) The issuance of a permit does not convey any property rights of any sort, or any exclusive privilege. (c) The issuance of a permit does not authorize any injury to persons or property or invasion of other private rights, or any infringement of State or local law or regulations.	
144.36	**Duration of permits**		UIC permits for Class VI wells shall be issued for the operating life of the facility and the postinjection site care period. EPA shall review each issued Class VI well UIC permit at least once every 5 years to determine whether it should be modified, revoked and reissued, terminated or a minor modification made.
144.37	**Continuation of expiring permits**	Conditions of an expired permit continue in force until the effective date of a new permit if a timely complete application has been submitted or EPA, through no fault of the permittee, does not issue a new permit. Permits continue to remain fully effective and enforceable.	
144.38	**Transfer of permits**	A permit may be transferred by the permittee only if the permit has been modified or revoked and reissued, or a minor modification has been made to identify the new permittee and include other requirements necessary under the SDWA.	Modifications and revoked and reissued permits require a draft permit and allow public notice and participation as required in Part 124, minor modifications do not.
144.39	**Modification or revocation and reissuance of permits**	Modifications: Only the conditions subject to modification are reopened for EPA review and also for public comment. Causes for modification described in §144.39(a). Revocation and reissuance: The entire permit is reopened by EPA and subject to revision and reissued for a new term. Public notice will also include the entire permit. Causes for modification are noted in §144.39(b).	If cause for modification or revocation and reissuance of a permit exists, EPA may modify or revoke and reissue the permit and may request an updated application, if necessary. § 144.39(a)(5) Additionally for Class VI permits EPA may determine permit changes are needed based on AOR reevaluations, amendments to the various required plans, or review of monitoring or testing results.
144.40	**Termination of permits.**	Termination of a permit will require public notice and participation as required in Part 124.	EPA may terminate an approved permit or deny a permit renewal application for noncompliance, failure to fully disclose or misrepresent faces.
144.41	**Minor modifications of permits.**	Reasons for minor modification are listed in § 144.41(a).	EPA may modify a permit to make minor corrections without additional public participation.

Continued . . .

40 CFR Part 144 - Underground Injection Control			
Section	**Title**	**Regulation Summary**	**EPA**
Subpart E	**Permit Conditions**		
144.51	**Conditions applicable to all permits**	List of conditions that apply to all UIC permits are listed in § 144.51. Topics include: Duty to comply, duty to reapply, need to halt or reduce activity not a defense, duty to mitigate, proper operation and maintenance, permit actions, duty to provide information, inspection and entry, monitoring records, reporting requirements, requirements prior to commencing injection, duty to establish and maintain mechanical integrity. The permit does not convey any property rights of any sort, or any exclusive privilege.	EPA will incorporate all applicable conditions into the permit or by reference. If incorporated by reference, a specific citation to these regulations must be included in the permit.
144.52	**Establishing permit conditions**	Class VI permits will contain conditions meeting the requirements of 40 CFR Subpart H.	
144.53	**Schedule of compliance**	The permit may, when appropriate, specify a schedule of compliance leading to compliance with the SDWA and parts 144, 145, 146, and 124.	
144.54	**Requirements for recording and reporting of monitoring results**	Permits will specify requirements on the proper use, maintenance, and installation of monitoring equipment, required monitoring, and applicable reporting requirements.	
144.55	**Corrective action**	Corrective action for Class VI wells is discussed in §146.84.	

APPENDIX D. 40 CFR PART 146 SUMMARY

40 CFR PART 146 - UNDERGROUND INJECTION CONTROL PROGRAM: Criteria and Standards		
Subpart H	**Criteria and standards applicable to Class VI wells**	Subpart H regulation summary taken from Figure 1-1: Overview of the Federal Class VI Rule Requirements in the UIC Program Class VI Implementation Manual for UIC Program Directors Guidance Document. (Jan 2018).
Section	**Title**	**Regulation Summary**
146.1	**Applicability and scope**	This part sets forth the technical criteria and standards that must be met in permits as required by part 144.
146.2	**Law authorizing these regulations**	The Safe Drinking Water Act, 42 U.S.C. 300f et seq. authorizes these regulations and all other UIC program regulations referenced in 40 CFR part 144. Certain regulations relating to the injection of hazardous waste are also authorized by the Resource Conservation and Recovery Act, 42 U.S.C. 6901 et seq.
146.3	**Definitions**	Definitions that apply to the underground injection control program.
146.4(d)	**Criteria for exempted aquifers**	The areal extent of a Class II EOR or EGR aquifer exemption may be expanded for a Class VI injection well for geologic sequestration (§ 144.7(d)) if it meets all of the following: 1. It does not currently serve as a source of drinking water 2. The TDS content of the formation is > 3,000 mg/l and < 10,000 mg/l 3. Is not reasonably expected to supply a public water system
146.5	**Classification of injection wells**	Class VI Wells that are not experimental in nature are used for geologic sequestration of carbon dioxide.
Subpart H	**Criteria and Standards Applicable to Class VI Wells**	
146.81	**Applicability**	Criteria and standards for UIC program to regulate any Class VI well.
146.82	**Required Class VI permit information**	Establishes the information that owners or operators must submit to obtain a Class VI permit.
146.83	**Minimum criteria for siting**	Establishes that Class VI wells must be located in areas with a suitable geologic system, including an injection zone that can receive the total anticipated volume of carbon dioxide and confining zone(s) to contain the injected carbon dioxide stream and displaced formation fluids.
146.84	**Area of review and corrective action**	Requires the use of computational modeling to delineate the AOR for proposed Class VI wells and the preparation of, and compliance with, an AOR and Corrective Action Plan for delineating the AOR, performing all necessary corrective action, and periodically reevaluating the AOR and amending the plan if needed.
146.85	**Financial responsibility**	Establishes that owners or operators must demonstrate and maintain financial responsibility for performing corrective action on improperly abandoned wells in the AOR, injection well plugging, postinjection site care (PISC) and site closure activities, and emergency and remedial response.

Continued . . .

40 CFR Part 144 - Underground Injection Control Program		
146.86	**Injection well construction requirements**	Specifies the design and construction of Class VI wells using materials that are compatible with the carbon dioxide stream over the duration of the Class VI project to prevent the endangerment of USDWs.
146.87	**Logging, sampling, and testing prior to injection well operation**	Outlines activities, including logs, surveys, and tests of the injection well and formations, that must be performed before injection of carbon dioxide may commence.
146.88	**Injection well operating requirements**	Provides operational measures for Class VI wells to ensure that the injection of carbon dioxide does not endanger USDWs, along with limitations on injection pressure and requirements for automatic shut-off devices.
146.89	**Mechanical integrity**	Specifies continuous monitoring to demonstrate internal mechanical integrity and annual external mechanical integrity tests.
146.90	**Testing and monitoring requirements**	Defines the elements that must be included in the required Testing and Monitoring Plan submitted with a Class VI permit application and implemented throughout the project to demonstrate the safe operation of the injection well and track the position of the carbon dioxide plume and pressure front.
146.91	**Reporting requirements**	Establishes the periodic timeframes and circumstances for the electronic reporting of Class VI well testing, monitoring, and operating results and requirements for keeping records.
146.92	**Injection well plugging**	Specifies that a Class VI injection well must be properly plugged to ensure that the well does not become a conduit for fluid movement into USDWs in the future.
146.93	**Postinjection site care and site closure**	Addresses activities that occur following cessation of injection. The owner or operator must continue to monitor the site for 50 years following the cessation of injection, or for an approved alternative timeframe, until it can be demonstrated that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs; following this, they must plug the injection and monitoring wells and close the site.
146.94	**Emergency and remedial response**	Specifies that owners or operators of Class VI wells must develop and maintain an approved Emergency and Remedial Response Plan that describes the actions to be taken to address events that may cause endangerment to a USDW or other resources.
146.95	**Class VI injection depth waiver requirements**	Provides a process under which Class VI well owners or operators can seek a waiver from the injection depth requirements in order to inject carbon dioxide into non-USDWs that are located above or between USDWs. Including injection depth waiver provisions in a state’s regulation is optional.