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STUDY

CCU/S in North America - Lessons Learned for Germany

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Disclaimer

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1. Executive Summary

This study provides an **overview** of the current situation with regard to carbon capture, utilization and storage (CCU/S) in North America. When it comes to the use of these technologies, both the US and Canada are considered pioneers on a global scale – accordingly, experiences from these markets can also be informative for the debate in Germany.

While also providing information on the general background and, for instance, funding instruments in both countries, the main focus of the study rests on the applicable regulative framework along the value chain of capture, transport and storage were examined. In this regard it should first be noted that although the beginnings of CCU/S use in both countries go back a long way (in the US to the 1970s), a clear development of the sector towards use on a commercial scale did not start **until around the beginning of the last decade**. Research programs, technology, funding, and legislation have evolved gradually since then.
While the early days were primarily characterized by the use of CO_2 in the oil industry for *enhanced oil recovery*, the development of CCU/S projects can now be seen as part of the **climate policy mainstream** in North America. Both countries now have extensive programs for research and development, as well as funding incentives in the form of tax credits specifically for commercial use.
However, the use of CCU/S is **not entirely uncontroversial** even in North America and has drawn criticism from very different political camps. While some general opponents of an active climate policy reject the technology as unnecessary and too expensive, there are also **climate activists** who fear an extension of the lifetime of fossil power plants. Some environmental associations are skeptical about the involvement of the oil and gas industry, although its existing geological and technological expertise is also a great asset for the development of a sector primarily aimed at geological storage. Against this background, the question of **social acceptance** - in the US even more than in Canada - is considered central to the further dissemination of CCU/S.

In the area of **regulation**, there is no uniform set of rules specifically for CCU/S in any of the countries due to the successive approach. Rather, existing regulations from oil and gas production, mining law, environmental law etc. have been gradually adapted and specifically supplemented to varying degrees at different legislative levels. As a result, there are still regulatory gray areas or even gaps in the US despite its many years of experience - especially with regard to cross-state activities; while in Canada there are enormous differences in the regulatory approach between the provinces/territories.

The large-scale **projects** currently in operation almost exclusively use **EOR**, with only one project each in Canada and the USA using dedicated geological storage. However, this ratio is expected to reverse in the next few years, as EOR receives less (USA) or no direct (Canada) financial support. In the short and medium term, application of CCU/S is expected to increase especially in the industrial sector, in particular in areas where the material streams have a high concentration of CO_2 (e.g., ethanol production). The use of CCU/S in fossil-fuel power plants is envisaged in both countries but, from the current perspective, is more likely to occur in the medium to long term.

As a result, the study comes to the following conclusions:

- An **overarching strategy** for the development of the sector provides the opportunity to clearly communicate fundamental issues regarding the use of CCU/S and has a positive impact on predictability, investment security and social debate.
- A **consistent, comprehensive and binding regulatory framework** in line with this strategy speeds up processes and minimizes legal uncertainties.

- **Social acceptance** is of outstanding importance, especially for pipeline transport and injections. Even though there are no patent remedies in this area, an active dialog with affected communities and groups at the earliest possible stage – also taking regional interests into account if necessary - can be considered a necessary condition for successful project implementation.
- Despite an expected trend toward declining cost, the operation of CCU/S projects will not be economically viable in the foreseeable future without **additional stimuli**. These could be forms of CO_2 pricing, targeted subsidies for project development and operation, or a combination of both.
- With regard to the expertise and the effort required for the **exploration** of geological deposits, reference is often made to the advantages gained from experience in the extraction of mineral resources, which are particularly relevant in the North American context. This relates, for example, to the data available on the geological characteristics of certain areas, but also to the availability of skilled workers.
- The present study is a general **overview** of the situation in North America. In view of the complexity of the subject, not all aspects can be dealt with exhaustively within this framework. Depending on the need for further information, it could make sense to examine additional topics separately in greater detail (e.g., regulations on government assumption of long-term liability).

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List of Abbreviations

ACG	Alberta Carbon Grid
AER	Alberta Energy Regulator
AOSP	Athabasca Oil Sands Project
BCS	Basal Cambrian Sands
BLM	Bureau of Land Management [of DOI]
BOEM	Bureau of Ocean Energy Management [of DOI]
CAA	Clean Air Act
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Use
CCUS	Carbon Capture Use and Storage
CDR	Carbon Dioxide Removal
CEAA	Canadian Environmental Assessment Act
CEPA	Canadian Environmental Protection Act
CER	Canadian Energy Regulator
CFR	Code of Federal Regulation [USA] / Clean Fuel Regulations [Canada]
COA	Canadian Ocean's Act
CPRA	Canadian Petroleum Resources Act
CRS	Congressional Research Service
CSA	Canadian Standards Association
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DAC	Direct Air Capture
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EA	Environmental Assessment
ECCC	Environment and Climate Change Canada
EEZ	Exclusive Economic Zone
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPAP	Enhanced Production Audit Program
EPEA	Environmental Protection and Enhancement Act [Alberta]
ESA	Endangered Species Act [USA]
R&D	Research and Development
FECM	Office of Fossil Energy and Carbon Management [of DOE]
FERC	Federal Energy Regulatory Commission [of DOE]

FLPMA	Federal Land Policy and Management Act [USA]
GCCSI	Global CCS Institute
GHGRP	Greenhouse Gas Reporting Program [der EPA]
IAA	Impact Assessment Act [Canada]
IRA	Inflation Reduction Act [USA]
IRC	Internal Revenue Code [USA]
ITC	Investment Tax Credit
LCFS	Low-Carbon Fuel Standard [California]
Mt	Million tons
MLA	Mineral Leasing Act [USA]
MMA	Mines and Mineral Act [Canada]
MRV	Monitoring, Review, and Verification
MSA	Magnuson-Stevens Fishery Conservation & Management Act [USA]
NEB	National Energy Board [Canada]
NEPA	National Environmental Protection Act [USA]
NMFS	U.S. National Marine Fisheries Service
NPDES	National Pollutant Discharge Elimination System
NRCan	Natural Resources Canada
NSR	New Source Review Program
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Land Act [USA]
OGCA	Oil and Gas Conservation Act [Canada]
PHMSA	U.S. Pipeline and Hazardous Safety Administration
RCRA	Resource Conservation and Recovery Act [USA]
RD&D	Research, Development, and Demonstration
RFA	Regulatory Framework Assessment
RGGI	Regional Greenhouse Gas Initiative
ROWs	Rights-of-Way
RRC	Railroad Commission of Texas
PCSF	Post-Closure Stewardship Fund
PICS	Pacific Institute for Climate Solutions
PSD	Prevention of Significant Deterioration Permit
SEARP	Saskatchewan Environmental Review Panel
SMR	Steam Methane Reforming
TIER	Technology Innovation and Emissions Reduction
UIC	Underground Injection Control Program
USFS	U.S. Forest Service
EIA	Environmental Impact Assessment

1. Introduction

The use of carbon capture and storage (CCU/S) technologies as a **building block for the reduction of greenhouse gas emissions** has long been part of the debate on the implementation of an effective climate mitigation strategy. A number of contributions to the debate (e.g. IPCC) assume that the use of CCU/S makes sense and is necessary as part of a holistic climate mitigation strategy - be it in relation to process emissions that are hard to abate or to accelerate CO2 reduction.

In both Canada and the USA, the use of **CCU/S is an integral part of the respective 2050 strategies** and the first large-scale plants are already in operation; in Germany, the Climate Protection Plan provides for the examination of its use, which has recently gained renewed relevance.

Against this background, this study aims to contribute to the ongoing debate by taking a closer look at developments and experiences in North America. The subject of the analysis is both the general framework and existing support mechanisms as well as regulations along the value chain. The focus is explicitly on the implementation perspective; general considerations on the necessity, opportunities and risks of the technology are not primarily the subject of the study and are only addressed marginally in connection with acceptance issues in the target countries.

For this study, existing primary and secondary sources were first analyzed between March and April 2023. In addition, eight qualitative interviews were conducted between the end of April and the beginning of May with stakeholders from the target countries, including research-oriented think tanks, companies and plant operators.

In order to summarize the different aspects and technologies (CCS, CCU, CCUS), the term CCU/S was chosen for the purpose of this study, following the German government's evaluation report on the Carbon Dioxide Storage Act (BReg 2022). This refers to all processes for the capture of CO2, its transport and subsequent use or geological storage.

The **capture** can take place both from the substance flows of industrial processes (including power plants) and from the atmosphere ("Direct Air Capture", DAC) or biogenic waste gas. The term thus also encompasses processes that are sometimes referred to as "carbon dioxide removal" (in distinction to CCS). The **transport** of compressed CO2 to the utilization/storage site can in principle be carried out by various modes of transport, but for larger quantities the transport via separate pipelines is particularly relevant and is therefore the focus of this study. **Geological storage** (often also referred to as sequestration) refers to storage in deep underground rock formations, for which there are currently only a few large-scale projects in North America. The dominant **use** to date has been through "enhanced oil recovery". In this process, CO2 is injected as a displacement agent to recover oil that cannot be extracted with conventional methods. Depending on the technology, only part of the CO2 remains in the reservoirs. Other forms of use include use in the chemical industry or food industry, but currently still play a minor role in the context of "carbon capture".

The current role of carbon utilization in North America

As distinct from permanent storage, "utilization" of captured CO2 basically includes all forms of use in which the carbon is fed into at least one subsequent use cycle (cf. UBA 2021). In a narrower sense (beyond use in oil production), this includes a wide range of possible uses, ranging from direct use, e.g. in the food industry, to the production of plastics, building materials or synthetic fuels. This sector is also referred to as the "Carbon Based Products Industry" (CBPI).

The actual benefit of these processes for climate protection depends on several factors in each individual case (UBA 2021). Optimistic estimates attest a theoretical potential for the use of 15% of global CO2 emissions by 2030. In both Canada and the USA, there are a variety of initial entrepreneurial approaches in this area, e.g. in concrete production, for synthetic fuels, plastics or conductive nanotubes for use in electrical devices. The DOE is also supporting CBPI within the framework of the Carbon Utilization Program with a total of more than $300 million.

However, the technology plays only a marginal role in practice in North America today. The few projects in this area are almost exclusively research or demonstration plants (a selection can be found at https://database.co2value.eu/, among others). The SkyMine CCU plant (CO2 from cement production for sodium hydrogen carbonate (baking powder) in San Antonio, Texas), which claims to be the "first profitable" CCU plant, can convert up to 50,000 t per year, other plants sometimes considerably less - so even compared to the currently low volumes for permanent storage, the practical relevance currently remains low. Accordingly, interviewees repeatedly emphasized the central role of geological storage compared to CBPI.

C2ES (2019) sees the greatest potential in the medium term in various applications in the building materials industry, but emphasizes existing regulatory hurdles (ASTM standards for building materials; lack of a uniform methodology for specifying the carbon intensity/climate footprint of products in general) and a lack of economic viability. Specific North American regulations for CBPI do not exist as far as is known at present.

Against this background, this study does not provide an in-depth, specific account of the area of carbon utilization.

2. United States

2.1 Background, strategy and government support

In the USA, there is no overarching strategy with regard to the coordinated development of carbon capture, storage and use (CCU/S). The technology is an integral part of the country's decarbonization efforts, as can be seen, among other things, in the federal long-term strategy for climate neutrality 2050 (DOS & Executive Office of the President 2021) or the most recent *Energy Act* (2020), although it is not entirely uncontroversial even in the USA (see also 2.5.1.). In addition to the importance of CCU/S for industries that are difficult to decarbonize, it is assumed that also fossil-fueled power plants with CCS will continue to play a relevant role in electricity production (EPA 08.05.2023) and that carbon dioxide removal technologies will be used in the future. Similarly, the topic is also reflected in the strategies and climate plans of several federal states. According to current estimates, up to one fifth of the targeted greenhouse gas reductions in the USA could be achieved through CCU/S (Burns 17.08.2022).

The technology has been used in the USA for many years and has been actively promoted since the late 1990s. The world's first CCU/S project was launched in 1972 in Terrell, Texas, and is still in operation today. The largest plant in the USA to date also went into operation as early as 1986 - however, the focus in this early development phase was not on climate mitigation aspects, but exclusively on increasing oil production (EOR), which still dominates the US market today (see section 2.2).
In 1997, funds from the federal budget were made available for the first time to finance R&D activities on CCU/S via the Office of Fossil Energy of the U.S. Department of Energy (DOE) - but initially on a very limited scale. This only changed in 2005, when the 10-year research program was included in the *Energy Policy Act* and seven CCU/S demonstration projects were subsequently approved in 2007 (GCCSI 2021).

An important milestone for commercial CCU/S projects is considered to be a law from 2008: The *Energy Improvement and Extensions Act for the* first time included government support for CCU/S application in the form of tax credits. The Internal Revenue Code section **§45Q Credit for carbon oxide sequestration** established a support mechanism specifically for permanent storage or continued use of captured CO_2 (including EOR), although the support amounts were initially small at \$20/t and \$10/t, respectively. The §45Q was increased to \$50/t and \$35/t in the *Bipartisan Budget Act in* 2018 and remains a key instrument for CCU/S promotion in the US to date (see below).[1]

In 2009, a large-scale funding program for the DOE's CCU/S activities was launched under the *American Recovery and Investment Act (*ARRA). However, of the total \$3.4 billion made available, around \$1.4 billion had not been used by the end of the funding period in 2015. More than half of these funds were earmarked for the **DOE flagship project FutureGen, which** was supposed to demonstrate CCS at a coal-fired power plant in Illinois, but had to be discontinued in spring 2015 – due to delays in the approval process and pending lawsuits by environmental groups among other things (CRS 2016).

Current **research, development and demonstration** activities are largely funded under the *Energy Act of* 2020 (totaling \$7.7 billion from 2021 – 2025) and the *Infrastructure Investment and Jobs Act* (IIJA) of 2021 (approx. \$12.5 billion from 2022 – 2026), which is a significant increase compared to previous years. The main focus of the IIJA funding is on pilot plants (\$3.5 billion), storage (\$2.5 billion) and transport infrastructure (\$2.1 billion see below). In addition, for the first time there is also funding specifically for the establishment of up to four DAC hubs (\$3.5 billion) (data taken from ITIF 18.04.2022).

The \$2.1 billion for the **CO_2 transport** projects is implemented through the Carbon Dioxide Transportation Infrastructure Finance and Innovation (**CIFIA**) program. It provides loans, loan guarantees and grants for large CO_2 transport projects (>\$100 million total cost). Eligible projects are pipeline, sea and land transports, whereby the infrastructure must be publicly usable for a "reasonable fee" ("common carrier", cf. DOE 2022).

For **commercial use,** the support via tax credits continues to be very relevant. The corresponding section §45Q of the US Tax Code for carbon storage was most recently amended as part of the ***Inflation Reduction Act* (IRA) of 2022**. In particular, the funding volumes were further increased and at the same time the requirements with regard to minimum capture volumes were lowered, so that smaller plants can also be funded from 2023:

[1] In contrast, the parallel opening of the Investment Tax Credit for the conversion of coal-fired power plants (§48A), which has existed since 2005, also for the application of CCU/S remained largely unused (GCCSI 2021).

Table 1: CCU/S funding according to §45Q IRC[2] as of 2023

Technology	Minimum requirements	Funding amount (Duration 12 years)
Point Source (industry, power plants)	General: • Capture and storage in the USA • No undercutting of local wages ("prevailing wage")[3] • Start of construction before 2033 Power stations: • 18,750 t CO_2 capture per year • 75% separation rate Industry: • 12,500 t CO_2 capture per year	• $85/t for geological storage • $60/t for use (incl. EOR)
DAC	• 1,000 t CO_2 capture per year	• $180/t for geological storage • $130/t for use (incl. EOR)

In principle, the owner of the CCU/S plant is eligible for the subsidy if he/she carries out the capture and storage (or use) of the CO_2 himself/herself or contract it to third parties. At the same time, there is the possibility (limited to 5 years for companies) of a direct payment of the subsidy amount (even beyond the actual tax burden) as well as, in principle, the option of selling claims from the tax subsidy, so that there is a high degree of flexibility with regard to the use of the subsidy in different stakeholder constellations.

In addition, there are other funding programs in some states that can be combined with the federal programs. The Low Carbon Fuel Standard (LCFS) and the associated CCS protocol in California are potentially of great importance (see 2.3.4 below). The LCFS can be used to promote fuels with CCS-related lower life cycle emissions - even if they were produced outside but sold in California, for example. As of 2022, however, no projects have been funded under this provision (CARB 10.05.2022).

2.2 Industry overview

The USA is currently the world leader in the use of CCU/S technologies. Of the almost 45 Mt CO_2 currently captured annually worldwide (IEA 2022b), the USA accounts for about 20 Mt, including the Shute Creek Gas Processing Plant, one of the largest projects currently in existence (7 Mtpa, cf. GCCSI 2022a). There are currently 13 major plants in operation (30 worldwide), a full overview of which can be found in the appendix. The existing US projects have a strong regional concentration in the Midwest and Texas. The commercial plants currently in operation are also characterized by the fact that only a fraction of the captured CO_2 is actually primarily used for geological storage; almost all projects are used for enhanced oil recovery (EOR), in which only part of the CO_2 remains stored underground, depending on the technology. The utilization of captured CO_2 beyond EOR is hardly widespread so far.

The CO_2 source of the CCU/S projects is primarily industrial applications, in particular natural gas processing, fertilizer production and ethanol production. For the application of CO_2 capture in fossil-fueled power plants, which is also relevant in the context of the energy transition discussion, there is currently no operational project - the only commercially operated project by the company Petra Nova in Texas (gas and coal-fired power generation, 1.4 Mtpa) ceased

[2] The requirements for installations that go into operation after 2018 is shown below.

[3] Corresponding requirements are filed with the Department of Labor; as a general rule, these are based on collective agreements.

CCU/S operations in 2020, according to the operator due to sharply lower crude oil prices for EOR, from which 90% of the revenues came (more detailed description in CRS 2022). Another planned CCU/S project at a coal-fired power plant in Illinois was ultimately unsuccessful despite strong regulatory support.

The **costs** for the deployment of CCU/S in the USA are difficult to generalize, as the following comparison of cost estimates shows:

Table 2: Overview of cost estimates[4] for CCS in $/tCO_2$

	IEA 17.02.2021	GCCSI 2021b	Moch et al. 2022
Separation (Point Source)	\$15 - \$120	\$0 - \$125[5]	\$19 - \$205
DAC	\$134 - \$342	n.a.	n.a.
Compression	n.a.	\$13 - \$22	\$12
Transport (pipeline onshore)	\$2 - \$14	\$4 - \$24	\$15
Transport (ship)	n.a.	\$15 - \$25	n.a.
Storage	Approx. \$10	\$3 - \$23	\$11

The potentially largest cost factor, but also the greatest variance, is therefore in the actual capture of the CO_2. The enormous range is partly explained by the location, technology and size of the modelled plants, but mainly by the CO_2 concentration in the source medium. Despite small methodological differences, the studies considered are consistent in their basic statements. Accordingly, one can roughly distinguish three categories:

- **The comparatively lowest capture costs** are found in those processes in which carbon dioxide is separated anyway for technical reasons. These include in particular natural gas processing, fertilizer/ammonia production and ethanol production.
- **Medium costs are** therefore incurred in power plants and typical industrial applications such as cement and steel production.
- By far the **most expensive** processes are those for "carbon removal"; Burns (17.08.2022) even quotes costs of \$250 - \$600/tCO$_2$ for direct air capture.

Thus, almost all plants in operation combine particularly favorable CO_2 production processes with a reduction in storage costs or generation of additional revenues through EOR. Even among the 47 projects that are scheduled to come online by 2027, 35 alone are based on ethanol production in existing biorefineries. The operation of CCU/S in the USA has so far only been economically feasible without further subsidies in rare exceptional cases with an exceptionally favorable combination of framework conditions (including high oil prices). In a recent study of selected projects (3 of them in the USA), Kapetaki and Scowcroft conclude that "the vast majority, if not all projects, have acknowledged the importance of public funding for the development of their business model and business case" (Kapetaki & Scowcroft 2017). In a recent study, Moch et al. also state that only the increased tax incentives since 2018 (pre-IRA) make projects economically viable at all, but even this will probably not be sufficient for some sectors (cement, steel, hydrogen) (Moch et al. 2022). So far, however, the demand for tax credits, at an estimated \$600 million between 2019 and 2023 (ITIF 18.04.2022), remains low compared to the funding amounts for research and development, from which quite a few of the projects in operation have also benefited.

According to several experts interviewed, only the further increase in the funding amounts through the IRA from 2023 will significantly expand the number of economically viable projects and open up new industrial sectors. The importance of EOR for financing future projects will also decrease – experts see the lower dependence on volatile oil prices compared to guaranteed production tax credits as a possible reason for this, in addition to image aspects.

[4] Only Moch et al. refer explicitly to the USA.

[5] The special case of aluminium smelting with significantly higher costs (up to \$300) was left out of consideration here.

Currently, more than 8,000 km of CO_2 pipelines are in operation in the US (compared to about 770,000 km of total US pipelines) (PHMSA 03.04.2023; TLRF 2022) – it is estimated this capacity needs to increase by more than 13-fold to over 100.000 km to achieve the targeted volumes for greenhouse gas neutrality in 2050 (approx. 0.9 - 1.7 billion t CO_2 per year), which would require additional investments of approx. $170 to $230 billion, depending on the scenario (Burns 17.08.2022; Larson et al. 2021).

Practical example: Illinois Industrial Carbon Capture and Storage

The Illinois Industrial Carbon Capture and Storage project (IL-ICCS) is the only operating "commercial" project in the US that geologically stores captured CO_2. This is an extension of the Illinois Basin Decatur Project (IBDP), which injected a total of 1 Mt CO_2 in the Illinois Basin (Mt. Simon Sandstone) primarily for research purposes from 2011 to 2014.

IL-ICCS is managed by the Global CCS Institute as a commercial-scale project of the partners Archer Daniels Midland (ADM), Schlumberger Carbon Services, Illinois State Geological Survey (University of Illinois), and Richland Community College, but the project is formally managed by the DOE National Energy Technology Laboratory (NETL), which also bears the largest share (68%; MIT 2016a) of the $208 million project cost. During the design phase, partial funding by EOR was considered, but was rejected in favor of 45Q funding due to volatile oil prices (Kapetaki & Scowcroft 2017). Like its predecessor, IL-ICCS also serves as a project for the implementation of extensive accompanying research on the geological properties of the reservoir (e.g. interaction of two injection wells) and in particular on environmental monitoring (seismic monitoring, CO_2 flux, groundwater), for which a separate accompanying project of NETL was set up with other project partners (Integrated Monitoring System, IMS).

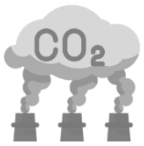
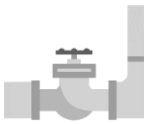
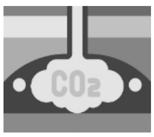
IL-ICCS uses CO_2, which is a waste product from the production of corn-based bioethanol at ADM's plant in Decatur, Illinois. The CO_2 already has a very high concentration at the point of capture, is dehydrated and pressed on site and transported to the storage site via an almost 2 km long pipeline. Storage takes place at around 2 km below the surface in the Illinois Basin, whose capacity is estimated at a total of 27-109 billion tons. The capacity of the IL-ICCS is 1 Mtpa (3,000 t/day).

The application for approval of two Class VI injection wells (UIC Class VI, see section 2.3.4 below) to the U.S. Environmental Protection Agency was submitted by ADM in 2011. (The predecessor project IBDP also had to reapply for a Class VI permit, as these regulations did not exist at the time of the original application and only a Class I permit was given). ADM, as the applicant, assumes the obligations arising from the requirements, which are, however, implemented by subcontractors in each case.
The processing of the application by the EPA took more than three years, during which additional documents were requested several times. After preliminary approval and subsequent public hearings, the final permits were issued in late 2014 and early 2015. This made the project the first ever to receive a permit of this class, which may partly explain the long processing time. Nevertheless, the length of the process has been criticized as a barrier to project development (Locke et al. 2017). CO_2 injection began in April 2017, significantly later than originally planned.

Active public outreach was an integral part of the project from the beginning and was implemented in a lead role by Richland Community College (RCC), which is located in the immediate vicinity of the injection well. These activities included face-to-face meetings with decision-makers and citizens, as well as involvement of local media (especially at the beginning), and eventually the establishment of a National Sequestration Education Centre (NSEC) at the college. RCC sees the successful involvement of the public as a key factor for the success of the project (cf. Brauer 2014).

2.3 Regulatory framework

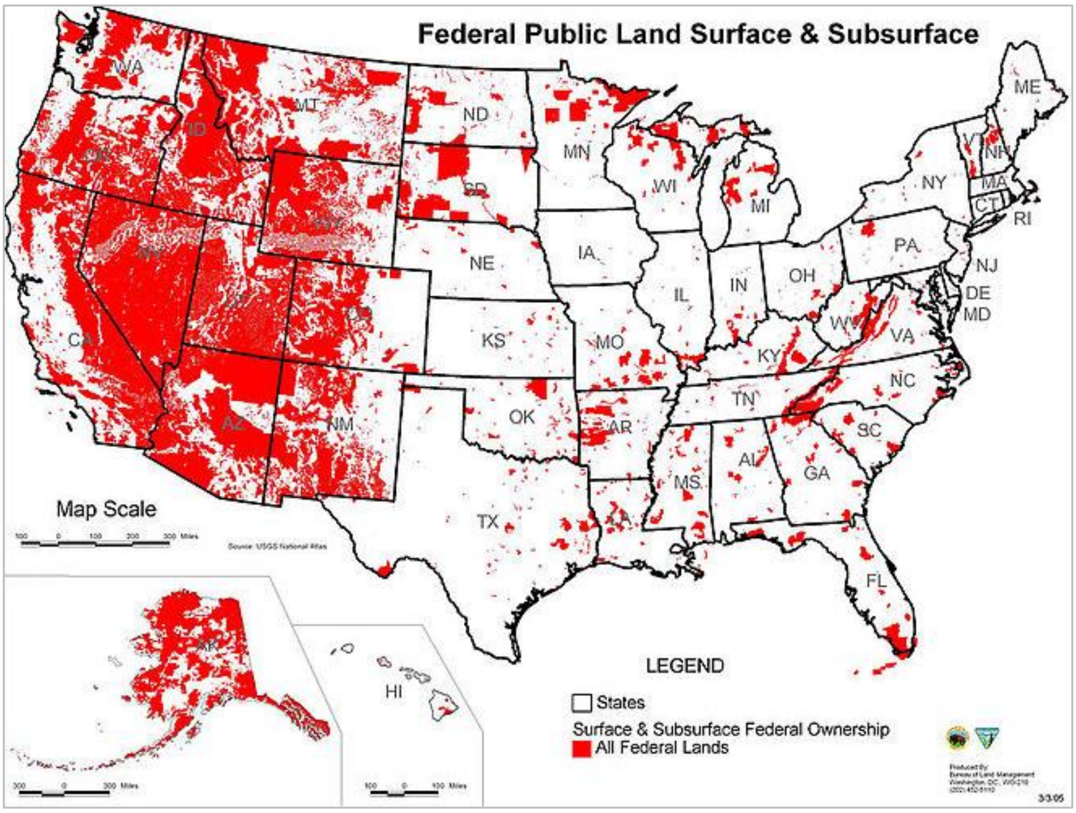
Table 3: Overview of the regulatory framework for CCU/S in the USA

Capture 	Emission protection	Air pollution permits (EPA)
	Reporting and monitoring	CO_2 capture rates (EPA), if applicable.
Transport 	Planning and siting of pipelines	Rights of Way (BLM/ States)
	Safety standards for pipelines	Design, Construction, Leakage (PHMSA/ States) If necessary, additional federal requirements
Storage 	Approval for injection wells (UIC program)	Drinking water and groundwater protection (EPA/ States) CO_2 -data, leakage, pressure etc. (EPA)
	Land and soil rights	Land, mineral, and pore space ownership (BLM/Federal).
	Monitoring, Reporting, Verification (MRV)	Injection and leakage data and MRV plan (EPA)
	Liability	Liability period of the operators (UIC program), Long-term liability, possible assumption of liability by federal states
	Certification and crediting	California's *Cap-and-Trade Program* and *Low Carbon Fuels Standard* (LCFS) *Regional Greenhouse Gas Initiative* (RGGI) (ETS of the New England and Mid-Atlantic States)
All areas	Environmental protection	Environmental permit under NEPA, ESA, etc. (EPA etc./States). Permit for proximity to water bodies and wetlands (U.S. Army Corps of Engineers) Permit for waste water (EPA/ States)

Source: Own representation based on the following information of the chapter.

In the US, there is **no separate regulatory framework** for CCU/S projects **at the federal level.** Instead, the existing regulatory framework from areas such as oil and gas production, industrial facilities and infrastructure development is applied or supplemented accordingly. In addition, there are regulations at the state level. Whether only federal or also state regulations apply depends on whether the project is located on federal, state or private land. Projects on federal land are almost completely subject to federal regulation; projects on state or private land are subject primarily to state regulation, in addition to overarching federal requirements. In the West (e.g. Wyoming), a lot of land is federally owned, so federal laws and permitting authorities play a major role in almost all CCU/S projects there, while in the East (e.g. Illinois), very little land is federally owned, so state laws and authorities often prevail here (Koski et al. 2020).

Illustration 1: Federally (red) and state (white) regulated land in the USA



Note: Most of the land under federal control (white) is privately owned.
Source: Bureau of Land Management (BLM) (2005).

The **regulatory situation in the US states** is very heterogeneous. The most important differences include who owns the land (surface space), the underlying mineral space and the pore space, and how the associated rights are specifically structured (statuary or case law). The resulting different constellations for CO_2 storage and pipeline projects determine, among other things, which laws must be observed, which permits are necessary and which authorities are responsible (Koski et al. 2020). Other important differences between the states relate to the following issues:

- Are specific CCS laws (so-called Carbon Capture and Storage Acts[6]) enacted in the state to support the development of CCS projects through higher regulatory certainty, and how comprehensive are these?
- What kind of expropriation rights (eminent domain) are in place, e.g. for pipeline construction?
- Did a state receive the so-called UIC Class VI primacy by the EPA for the own approval of injection wells for geological storage (see 2.3.4 below)?

In the following, the federal level is presented first and then the general trend regarding the state level approaches is summarized. This is supplemented by examples from Illinois and Texas in particular, but also from other states if their regulations appear particularly interesting and relevant. The states of Texas and Illinois were chosen as the main examples for the following reasons:

Texas has the **most and longest experience with CCU/S**: the oldest CCS plant in the US (Terrell Natural Gas Processing Plant) has been operating in Texas since 1972; currently, the state has the most active CCU/S projects (four commercial, two pilot) with a comparatively

[6] These included, for example, the introduction of state assumption of liability from a certain period after closure of the injection wells and state funds for long-term monitoring (see Chapter 1.3.4), declarations of intent by the states to apply to the EPA for so-called UIC Class VI primacy (see Chapter 1.3.4), as well as regulations on how the existing regulatory framework, e.g. regarding expropriation and land use, is to be applied to CCU/S projects (Ring et al. 2021).

large capture capacity. In addition, there is experience with project failures, such as the Petra Nova carbon capture plant. Also, many (twelve) new commercial CCU/S projects are currently being developed in Texas (Global CCS Institute 2022a). In general, according to expert assessments, Texas has the potential to become a global leader in CCU/S due to its enormous geological storage capacities, both onshore and **offshore,** and due to the know-how already available in Texas from the oil and gas industry (TLRF 2022).

Illinois has the most extensive regulatory CCU/S regime in the US among the eastern states. In addition, Illinois has the first commercial CCS project with geological CO_2 storage in operation. The most important CCS legislation in the state, the Illinois *Carbon Dioxide Transportation and Sequestration Act of* 2011 and the *Clean Coal FutureGen for Illinois Act of* 2011, were part of the so-called "clean coal agenda" in the Midwest, which sought to keep the coal sector future-proof. Industry interest in developing CCS projects in Illinois is high because of the geological storage potential in the Illinois Basin (sedimentary rock) (Chicago Tribune 26.02.2023 ; Koski et al. 2020).

2.3.1 General requirements: Environmental Impact Assessments

Some regulatory measures affect all stages of the CCS project cycle (capture, transport and storage). These requirements are primarily designed to **protect the environment** (and cultural heritage). For example, under the *Clean Water Act (*CWA) Section 404, all projects (on both federal and state lands) must obtain a permit from the U.S. Army Corps of Engineers if they are located near water bodies or wetlands (Bachtel et al. 04/22/2022). Any discharges from CCU/S projects are regulated by the National Pollutant Discharge Elimination System (NPDES) (CEQ 2021).

Any **project with a federal nexus** is also subject to the **environmental permitting process of** the *National Environmental Protection Act* (NEPA). A federal nexus exists when the project is located on federal land, requires federal approvals, receives federal funding, or is related to federally managed infrastructure. Depending on the nature of the federal connection (e.g., pipelines or injection wells on federal land), the relevant agency is responsible for the NEPA process (BLM, U.S. Army Corps of Engineers, EPA, etc.). In 2011, EPA published 20 conditions under which federally related activities, and thus federally related CCU/S projects, can be exempt from the NEPA process (Categorical Exclusion), for example, if just less than 500,000 tons of CO_2 are geologically stored or if there is a low risk of seismicity (Kerscher & Pullins 29.01.2021). If a NEPA process is necessary, either an Environmental Assessment (EA) (low environmental risk) or an Environmental Statement (EIS) (high environmental risk) are required, depending on the likelihood and severity of environmental impacts (EFI 2021).

Projects on federal land must also comply with a number of **species protection regulations**, including the *Endangered Species Act* (ESA), which aim to prevent so-called "takes", i.e. damage, killing, etc. of animal species. **Historic preservation regulations** are regulated under the *National Historic Preservation Act* and provide for the involvement of affected stakeholders (Kerschner & Pullins 29.01.2021).

In addition to these federal requirements, **state environmental laws** must often be complied with when projects are located (in part or in whole) on private or state lands: **Illinois**, for example, has a mandatory siting program (under the Illinois Environmental Protection Act) that requires a state permit before operating a sequestration facility, and requires that revenues from fee-based permit applications be deposited into an environmental protection fund (Koski et al. 2020).

In **Texas**, a permit must be obtained from the Texas Railroad Commission (RRC) for the construction and operation of a CO_2 storage facility. The issuance of the permit requires that the RCC determines that the geology of the storage area makes induced seismicity from CO_2 injection unlikely and that CO_2 injection and storage will not harm mineral or water sources. Finally, operators are also required to provide financial security in form of a bond or guarantee and prove their financial viability to the RRC before injection can begin (Koski et al. 2020; TLRF 2022).

2.3.2 CO_2 capture

The EPA defines CO_2 streams in its Underground Injection Control (UIC) Program (based on the *Safe Drinking Water Act of* 1974), which regulates the injection of various substances into wells and is central to the regulation of CCU/S measures in the US. According to this, a CO_2 stream includes carbon dioxide captured from an emission source plus incidental by-products derived from the source materials and the capture process, and any substances added to the stream to enable or enhance the injection process (40 CFR 146.81(d)). More precise specifications or standards regarding the composition of CO_2 streams are not available[7] (CEQ 2021).

For a long time, there was uncertainty as to whether CO_2 streams qualify as hazardous waste under *Resource Conservation and Recovery Act* (RCRA) Subtitle C. To address these uncertainties, EPA has now explicitly exempted CO_2 streams from categorization as hazardous waste under RCRA Subtitle C if they are geologically stored in UIC Class VI wells on a long-term basis (see 2.3.4 below). Other requirements are that (1) the CO_2 streams are transported in accordance with DOT or federal regulations, (2) no other hazardous wastes are mixed with the CO_2 streams, and (3) the operators[8] of the storage facility sign and annually renew two certification statements assuring compliance with (1) and (2) (40 CFR 261.4(h); CEQ 2021).

Emission protection

Depending on the location and size of the facility, operators must apply for various permits under the federal *Clean Air Act* (CAA). In October 2020, the EPA decided that facilities that undergo modifications, such as the installation of CCU/S technologies, are also covered by the **New Source Review (NSR) Permitting Program**, provided they are classified as a major source (the threshold for classification as a major source is 100 tons per year for each air pollutant). The location of the facility and quantity of emissions determine which of three NSR permits must be obtained. If the facility is located in an area where air quality standards are met, a Prevention of Significant Deterioration (PSD) Permit must be obtained; in areas where these standards are not met, a Nonattainment NSR Permit must be obtained. If the emission levels of the installation are below the NSR-thresholds, a Minor Source Permit is sufficient. The permits are usually issued by local air pollution control authorities (CEQ 2021; EPA 23.11.2022). Facilities subject to the NSR and classified as major source must also obtain a **Title V permit** under the CAA. The permit ensures that emission limitations, procedural requirements and other CAA requirements are met (Bachtel et al. 22 Apr 2022; CEQ 2021). The state level plays only a minor role in regulating capture facilities overall. However, Texas has its own EPA-approved PSD program, which is implemented under the *Texas Clean Air Act* (Koski et al. 2020).

Reporting/ Monitoring

Data on the amounts of CO captured$_2$ are only collected to a limited extent in the USA. Under the CAA, the EPA regulates air pollution from emissions. The **Greenhouse Gas Reporting Program (GHGRP)** as part of the CAA requires operators of facilities that emit more than 25,000 t/CO_{2e} per year to communicate GHG emissions; for CCU/S the sections Subpart UU, Subpart PP and Subpart RR are relevant (EPA 01.12.2022; EPA 10.01.2023). Only Subpart PP, which deals with CCU, requires the communication of captured CO_2 quantities (40 CFR 98.422). In the case of EOR (Subpart UU) and geological storage (Subpart RR), operators must communicate, among other things, the mass of CO_2 received, meaning that the CO_2 may also come from external sources (40 CFR 98.442(a); 40 CFR 98.472).

[7] The safety regulations for pipelines (see also 2.3.3) also do not contain any information on the CO_2 stream composition or purity (CEQ 2021).

[8] According to 40 CFR 261.4(h), certification statements may be signed by an "authorised representative", defined in 40 CFR 260.10 as the "person responsible for the overall operation of a facility or operating unit (i.e. part of a facility), such as the plant manager, superintendent or person with similar responsibility".

2.3.3 CO_2 transport

Sequestered CO_2 can basically be transported by pipeline, ship, train or truck. While the US government promotes all transport options under the CIFIA program, the focus at both project and regulatory level is on pipeline transport. According to interview experts, this is mainly due to economies of scale that cannot be achieved with other transport options. Accordingly, this section focuses on regulations regarding the transport of CO_2 by pipeline.

Planning and siting of pipelines

In the USA, the states generally regulate the design, construction, operation and maintenance of intrastate and interstate CO_2 pipelines on their territory (CEQ 2021; Koski et al. 2020; TLRF 2022). If a pipeline crosses federal land, the Bureau of Land Management (BLM) is responsible for regulating siting and construction, as well as the preparation of resource management plans. Under the *Mineral Leasing Act* (MLA) or, since 2022, the *Federal Land Policy and Management Act (FLPMA)*, the BLM is authorized to grant rights-of-way (ROWs) in connection with CCU/S projects (GCCSI 16.05.2023). Under FLPMA, ROWs are granted for a minimum of 30 years with an option to renew, provided a monitoring program and financial assurances are in place for the life of the project (BLM 08.06.2022). However, there is uncertainty as to who regulates the siting of interstate pipelines on federal land/with a federal nexus, as so far neither the Federal Energy Regulatory Commission (FERC), which is responsible for interstate gas pipelines, nor the Surface Transportation Board (STB) or the BLM have clearly assumed responsibility for these cases (Koski et al. 2020).

In **Illinois,** CO_2 transport in pipelines for sequestration, EOR and other purposes was declared "in the public interest" under the *Carbon Dioxide Transportation and Sequestration Act of* 2012, among other things to facilitate the application of eminent domain law in this context. The Act requires CO_2 pipeline developers or operators to obtain a construction and operating permit for the transportation of CO_2 from the Illinois Commerce Commission. This permit then also entitles the holder to acquire rights of way or possession of land under the Eminent Domain Act. If no agreement can be reached between project developers and landowners, the final decision rests with the courts (Koski et al. 2020).

In **Texas,** the Railroad Commission of Texas (RRC) regulates all intrastate gas, oil and CO_2 pipelines as well as interstate pipelines on Texas soil (Koski et al. 2020). Texas already has a comparatively large network of CO_2 pipelines (about 4,200 km out of about 8,500 km in the US) connecting natural and industrial CO_2 sources to largely depleted oil fields for CO_2 -EOR purposes. All six major CO_2 pipelines in the region converge at the *Denver City CO_2 Hub*, and many smaller pipelines distribute the CO_2 from here to the oil fields (CRS 03.06.2022; DOE 2015; Koski et al. 2020; PHMSA 03.04.2023).

Pipeline safety standards

The U.S. Department of Transport (DOT) is responsible for regulating pipeline safety standards (CRS 2022a; GCCSI 2020). The Pipeline and Hazardous Safety Administration (PHMSA), which is subordinate to the DOT, assumes the task of safety monitoring. Under the *Hazardous Materials Transportation Act*, PHMSA oversees the design, construction, operation, maintenance and spill management of intrastate and interstate CO_2 pipelines (CEQ 2021). However, this only applies to pipelines transporting CO_2 in the “supercritical liquid state” and not in the “subcritical fluid and gaseous state”. Since CO_2 streams are predominantly transported in the liquid state, the PHMSA is responsible for a large part of the transported CO_2. In addition, the DOT is examining the extent to which existing regulations for gas pipelines are applicable to CCU/S projects (Kerschner & Pullins 29.01.2021). Relevant regulations have been announced for 2024, until then the regulatory situation and responsibility for the safety of pipelines transporting CO_2 in the gaseous state remains unresolved (Energywire 03.03.2023; IER 08.03.2023). Some states have been delegated authority to control PHSMA standards for pipelines, but there are differences as to whether they may regulate only pipeline transport of gases or also liquids - as well as liquid CO_2 (CEQ

2021; Kerschner & Pullins 29.01.2021; Koski et al. 2020). Liability for CO_2 pipelines generally lies with the operators.

While the first CO_2 pipelines in the 1970s were still regulated according to the standards of gas pipelines (49 CFR 192), since 1981 special safety, construction, operation and maintenance standards have been set for pipelines transporting hazardous substances and CO_2 (49 CFR 195.1; GCCSI 2020). Although CO_2 is categorized as a non-flammable gas in DOT regulations and thus not classified as a hazardous substance, CO_2 pipelines are subject to the same safety standards as hazardous substances (49 CFR 172.101; CRS 03.06.2022). After a pipeline explosion in Satartia, Mississippi in 2020, PHMSA now wants to increase the safety regulations for monitoring CO_2 pipelines even further (PHMSA 26.05.2022a).

PHMSA's safety standards are generally minimum standards, some of which are implemented by state authorities for intrastate pipelines and supplemented by state standards where appropriate. **Illinois**, for example, has introduced additional requirements within the framework of the *Illinois Carbon Dioxide Transportation and Sequestration Act for* CO_2 pipelines, which is intended to further strengthen technical safety monitoring. In addition, the Illinois Commerce Commission can impose additional regulations on the construction, maintenance and operation of pipelines, associated facilities and equipment to ensure their safety. In **Texas,** the RRC also imposes stricter standards in certain situations (Koski et al. 2020).

2.3.4 CO_2 storage

Regulation of injection wells

Much of the federal regulation at this stage is based on the EPA's **Underground Injection Control (UIC) program** (Figueiredo et al. 2007; TLRF 2022). The UIC program regulates the storage and disposal of water, other liquids and gases in injection wells and aims to protect underground sources of drinking water. It covers the construction, operation, authorization and closure of injection wells. Regulatory jurisdiction for injection wells rests with the EPA, but responsibility can also be delegated to states and tribes. Depending on the liquid and injection location, the UIC program distinguishes between six injection well classes; injection well classes II and VI are relevant for CO_2 storage. Class II provisions concern injection wells drilled for EOR, acid gas storage and oil and gas for later use. Class VI provisions explicitly concern wells intended for geological storage of CO_2.

Before wells for Class VI wells can be approved, operators have to provide the following:

- Geological maps and the location of fractures,
- Evidence of suitable construction methods (depth, pressure, alarm systems, etc.) and materials (cement and other materials that meet the standards of the American Petroleum Institute, ASTM International or similar and can withstand direct contact with CO2),
- Monitoring and testing plan with measures to be taken during the injections and, as a rule, 50 years later (including regular mechanical integrity tests (MITs), monitoring of groundwater quality, pressure drop tests at least every five years, etc.),
- Availability of funding throughout the life of the project (accepted financial instruments include trust funds, insurance, etc.), and
- Planning measures for the closure of the well(s) (esp. flushing the well with a buffer fluid and placing cement in the well) (40 CFR 146.86; 40 CFR 146.90; 40 CFR 146.93; EPA 2012; EPA 2013; IEA 2022).

According to expert assessments, the requirements for Class VI wells are the most stringent of all UIC well classes and therefore also associated with higher costs than e.g. for EOR injection wells (Class II wells). In particular, the monitoring scope for wells is larger, as it includes observation, modelling and prediction of the subsurface moving extent of the CO_2 plume. In addition, more comprehensive performance requirements and shorter periods between mandatory tests and reports apply; monitoring of seismicity, injection pressure, pressure front and groundwater quality is mandatory throughout the life of the project (Koski et al. 2020). EOR injection wells (Class II wells), which are typically designed for lower injection pressures and fluid volumes and different physical and chemical properties of the injection stream, are subject to less stringent requirements than Class VI wells (CRS 16.06.2020). According to the EPA, they can in principle also be used for CO_2 storage. A conversion from a Class II to a Class VI permit is only necessary (case-by-case review) if oil production is no longer an essential aspect of the permitted well and the conversion to mainly geological storage could result in an increased risk to underground drinking water sources (among other things by increasing the injection pressure)[9] (EPA 2015). While the demand for permits for new geological storage wells has been increasing recently, the conversion of EOR injection wells to Class VI wells seems to be hardly relevant so far (as of June 2020, no such conversions had taken place yet) (CRS 16.06.2020). Overall, experts see little incentive so far to convert existing Class II wells for EOR to Class VI wells for geological storage due to the higher requirements and non-mandatory need for conversion (Koski et al. 2020).

States can apply to the EPA for UIC program implementation responsibility, provided they have the necessary implementation capacity. In the case of Class VI wells, this so-called **Class VI primacy** has so far been transferred to Wyoming (2020) and North Dakota (2018). Arizona, Louisiana, West Virginia and Texas are currently in the transfer process. Other states have expressed their interest in this transfer of responsibility to the EPA (EPA 09.12.2022). Experts consider a transfer of jurisdiction and implementation to the states often as very advantageous for projects, as many of them already have experience and capacities for geological projects (especially in states with a lot of oil and gas production and coal mining) and since this can significantly reduce the complexity and duration of the permitting process (Koski et al. 2020; TLRF 2022). While EPA permitting processes take around three years, North Dakota implements them in under a year, with Wyoming aiming for a similar duration. Accordingly, the Biden administration is supporting the necessary measures to transfer responsibility to the state level with a $50 million grant program (EPA 09.12.2022).

Land and soil rights for storage facilities

Approval under the UIC program is a prerequisite for the allocation of **land rights on federal land**. The BLM and, in rare cases, the USFS allocate and control these land rights. Federal land accounts for approximately 28% of the total land area in the USA (Koski et al. 2020). As in the case of pipelines, the BLM or the USFS must prepare resource management plans (CEQ 2021).

The basis for BLM's leasing of federal lands is the requirements of the *Federal Land Policy and Management Act (FLPMA)* (see also 2.3.3). Under Title V of FLPMA and its implementing regulations, 43 CFR Part 2800, BLM may grant use rights of federal pore space for CO_2 injections and geologic storage of CO_2 (BLM 08.06.2022). For geological storage, this was not clarified in detail until recently, which led to regulatory uncertainties and thus hurdles in the development of CCU/S projects. In cases of so-called split estates, where the U.S. government either owns only the surface estate and the mineral estate is privately owned, or vice versa, separate, early clarifications of the pore rights are necessary (Koski et al. 2020).

In **Illinois**, for example, mineral space is generally owned by the owners of the land, who can sell the associated mineral rights to others, but the ownership of pore space remains mostly unresolved. In 2010, Illinois' Commission for Carbon Capture and Sequestration Legislation presented a report on the ownership of pore space, based on which the government proposed a law in March 2020 that would transfer pore space ownership rights to the surface owner and prohibit the separation of pore space ownership from surface ownership. However, this bill has not yet made it past the House Energy and Environment Committee (Chicago Tribune 26.02.2023; Koski et al. 2020).

[9] For details on the criteria for increased risk, see 40 CFR 144.19(b) Transitioning from Class II to Class VI, https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-144/subpart-B/section-144.19.

Monitoring, reporting and verification (MRV)

Monitoring of storage sites is fundamentally regulated by the UIC program (see above; 40 CFR 146.90) and is significantly supplemented by the subchapter RR of the GHGRP (see 2.3.2). This requires that facility operators of geological storage (both onshore and offshore) collect the following data on a quarterly basis and submit it to EPA annually: The amount of CO_2 in storage; the amount of CO_2 from oil or gas production or other fluid wells; the amount of CO_2 released from surface leaks; the amount of CO_2 released from equipment leaks and vented; and CO_2 emissions from sources between the injection flow meter and injection wellhead and between the production flow meter and production wellhead; the amount of CO_2 trapped in geological formations (by subtracting the above CO_2 emissions from the amount of CO_2 injected) and the cumulative amount of CO_2 reported as sequestered since the start of operations. In doing so, the quantities of sequestered CO2 must be recorded using flowmeters[10] (or weigh bills, scales, or load cells if the CO2 is delivered in containers) (40 CFR 98.444). Leakage (from equipment) can be identified using optical gas imaging instruments, infrared laser beam illuminators, or acoustic leak detectors, among other methods (40 CFR 98.444; 40 CFR 98.234)[11] . In addition, the operator must submit to EPA, among other things, information on the source of the CO_2 received (e.g., ethanol plant, gas plant, etc.) and the CO_2 concentration in the CO_2 stream, as well as a report with information on, among other things, the monitoring technologies used, potential anomalies, and uncertainties (EPA 2011; IEA 2022)[12]. An EPA-approved **Monitoring, Review and Verification Plan (MRV)** must also set out the following factual information: The monitoring area, a summary of CO_2 data sources, UIC-relevant data (e.g., well number), and the date on which data collection is to begin (40 CFR 98.448(a)).

Liability

Long-term liability for CCU/S projects is generally regulated in the USA via the UIC program and is supplemented by the requirements in the GHGRP. According to this, the owners or operators of CO_2 storage sites are liable for damage caused by CO_2 leakage for up to 50 years after their closure. The period can be shortened if the operators can show that the CO_2 stream is stable and does not pose a risk to drinking water. This requires the operator to provide some analytical evidence, including the expected time frame for the pressure drop in the injection zone and for the termination of migration of the CO_2 plume, and analyses of the subsurface, including mineralization processes of the CO_2 and potential channels for fluid movement (40 CFR 146.93).[13] Liability issues beyond the 50-year period have not yet been resolved (Bachtel et al. Apr. 22, 2022; EFI 2021; GCCSI 2019; GCCSI 2020). EPA only states in its Class VI rule that it does not have the authority to establish ownership or transfer liability from one owner to another, and that the existing federal regulatory framework does not provide for release or transfer of liability from the owner to other persons (Koski et al. 2020).

At the state level, the regulations regarding long-term liability for CO_2 storage facilities vary in some cases. In principle, in most states, the person who injected the CO_2 is legally liable for it. In many states, however, this aspect has not yet been explicitly regulated by law (e.g. California, Illinois, New Mexico, Pennsylvania), so that the UIC regulation described above applies there. In other states, such as Indiana, Louisiana, Montana, North Dakota, Nebraska

[10] The flowmeters must be permanently in service and used in accordance with the standard methods of a consensus-based standards organisation, such as ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API) and the North American Energy Standards Board (NAESB) (40 CFR 98.444).

[11] For a complete list of approved methods, see eCFR :: 40 CFR 98.444 -- Monitoring and QA/QC requirements. and eCFR :: 40 CFR Part 98 Subpart W -- Petroleum and Natural Gas Systems.

[12] Reporting under the GHGRP is a prerequisite for obtaining the 45Q tax credit, but is not verified by external third parties or the EPA. In the case of EOR (Subpart UU), operators can choose to report under the GHGRP to receive the credit or to follow the requirements of the ISO 27916 standard for EOR projects. In the latter case, certification of the information by an independent engineer or geologist is required (IEA 2022).

[13] A complete list of evidence to be provided can be found here : eCFR :: 40 CFR 146.93 -- Post-injection site care and site closure.

and Wyoming, special frameworks for CCU/S projects have been introduced, so-called Carbon Capture and Storage Acts, which include procedures for state assumption of liability and monitoring. In other states, such policies are currently being developed (Texas). Under the state assumption **of liability** option, the state can assume ownership of the CO_2 sequestration facility and the associated long-term liability and responsibility for the stored CO_2 from the operator/owner either directly or after a certain period of time following closure of the facilities. However, this only takes place after the issuance of a certificate of project completion by the state, for which a number of requirements[14] must be met, such as:

- Proper sealing of the injection well;
- Compliance with all relevant laws and regulations;
- Proof that the stored CO2 does not escape, is stationary or chemically bound, and does not migrate into other geological formations;
- Demonstrate that all wells, equipment and facilities to be used in the post-closure phase are in good condition and maintain their mechanical integrity; and
- Completion of the necessary renovation work.

If this evidence is provided, then responsibilities for the facilities can subsequently transfer to the state in the long term. In some states, such as Wyoming and North Dakota, the text of the law also contains a (provisional) addition that can subsequently make a transfer of liability from the state to the federal government possible, but a corresponding regulation does not yet exist at the federal level (Koski et al. 2020; Ring et al. 2021; TLRF 2022).

Table 4: Options for the assumption of liability by the US states

State	At what point is the assumption of liability, management and monitoring by the state legally possible after the closure of the geological storage facility?
Indiana	Directly
Nebraska	Directly
Texas	Direct (only for offshore storage projects, not applied so far)
Louisiana	10 years
North Dakota	10 years
Illinois	10 years (only for FutureGen project (failed))
Wyoming	20 years
Montana	25 years (monitoring), from 50 years (liability)

Source: Ring et al. 2021; TLRF 2022
Note: Only those states have been listed here that have already passed laws in this context.

To **finance the state monitoring and management of the plants** (incl. liability and reparation), previously listed states have introduced special CO_2 trust funds. These are financed, for example, through fixed levies by operators per ton of CO_2 stored (e.g. in Indiana) or through other fees (e.g. in Nebraska) as well as through grants, donations and amounts from public or private sources (e.g. in Louisiana). In some states (e.g. Wyoming), the size of these funds limits the maximum amount of possible compensation payments (TLRF 2022).

In addition, some states have introduced **legal restrictions on the scope of liability to** make the implementation of CCU/S projects more attractive. In Indiana, for example, the operator is only liable for local damage (e.g. water pollution, soil contamination, etc.) during the operation of the plant, but not for CO_2 emissions into the atmosphere. In Louisiana, potential non-economic damage claims in civil lawsuits against owners/operators of a CO_2 storage facility (before and after transfer to the state), a CO_2 pipeline, or owners of CO_2 transported and stored by a pipeline/storage facility are limited to $250,000 or $500,000 (for serious health injuries) per occurrence. Lawsuits because of environmental and climate damages resulting from potential CO_2 leakages are not included so far in any of the states mentioned (TLRF 2022).

[14] Lists of all the requirements of the states mentioned for the assumption of liability can be found, for example, in TLRF 2022.

Whether states should create a regulatory framework for assumption of monitoring and liability is controversial. According to experts and interviewees, the argument in favor is that such an assumption creates necessary certainty and thus simplifies the financing of projects, especially for small and medium-sized project developers, who are more often dependent on outside investors than large companies. In addition, a state assumption of liability addresses the legal uncertainties that may arise if an operating company ceases to exist in the long term (Chicago Tribune 26.02.2023;TLRF 2022). According to the Environmental Defense Fund, the argument against a state takeover is that, in principle, there is no significant liability risk if the operators carry out their work according to the highest technical standards. If a liability assumption were to be introduced, there would have to be the possibility that liability could revert to the operator in cases of lack of due diligence (as in the EU). However, the example of Texas, where many CCU/S projects are currently being developed, shows that investors are entering the sector even without state assumption of liability (EDF 03.05.2022).

Certification and crediting

At the US federal level, as well as in most states, there are no certification systems in place for stored CO_2. Exceptions are Texas and Wyoming for EOR projects (Koski et al. 2020). However, it can be assumed that the introduction of certification systems is now stimulated or even necessary by the large-scale and extensive application of the increased 45Q tax credits.

In the existing emissions trading systems in North America, CCU/S processes have so far only been partially integrated: In the cap-and-trade system of the **Regional Greenhouse Gas Initiative (RGGI)**, which covers the power sector of the New England and Mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Virginia), no regulations for CCU/S projects have been implemented yet (Koski et al. 2020; RGGI 2018)

In **California's cap-and-trade programme,** which has been in place since 2012, CCU/S is not yet recognized as a means by which a covered facility can reduce its emissions and compliance obligations. The only CCS-relevant provisions relate to CO_2 suppliers that capture CO_2 from production processes or extract or produce CO_2 as a by-product of oil production and then deliver the CO_2 to others for use or geological storage, but so far these provisions do not allow a covered facility to reduce its ETS obligations. However, CARB has already announced that the existing CCS protocol, which is already part of the *California Low Carbon Fuel Standard* (LCFS), will now be included in the cap-and-trade regulation to advance CCS/CCU and CDR.

California's **Low Carbon Fuel Standard (LCFS)** was introduced in 2007 and sets carbon benchmarks for transport fuels. The program awards credits or deficits to fuel producers based on whether the fuel produced falls below or exceeds the limits for that fuel, and allows credits to be traded among producers. Since 2018, onshore (but not offshore) CCU/S activities can earn credits. For this, the capture facility does not have to be located in California, but the fuel must be sold in California (for DAC, the credits are credited regardless of location). In principle, it is the capture facility and not the operator of the storage facility that receives the credits. The following "project types" can apply for credits: DAC plants, alternative fuel producers (e.g. CO_2 from fermentation in ethanol production), refinery investments (e.g. CO_2 from methane steam reforming in a refinery) and innovative crude oil projects (e.g. CO_2 from methane steam reforming in a bitumen refiner). The requirements for project implementers are largely the same as those in the UIC program, but operators of the storage facility must monitor it for twice as long and meet more extensive financial assurance requirements (CARB 13/08/2018; CARB 2022; Israel & Pickerill 15/07/2022). Furthermore, in California, Senate Bill 90587 in August 2022 legislated the development of a Carbon Capture, Removal, Utilization and Storage Program while prohibiting CO_2 -EOR (CARB 10.05.2022; La Hoz Theuer & Olarte 2023; Ring et al. 2021)

2.4 Offshore CO2 storage in the USA

To date, there is **little practical experience with offshore storage of** CO_2 in the USA and there are no offshore CO_2 storage or EOR projects already in operation. This status quo can be attributed, among other things, to the great potential for geological storage onshore and the rather restrictive/prohibitive and in many areas unclear US regulatory regime for offshore projects to date (Koski et al. 2020; NPC 2021; TLRF 2022). However, **two large-scale offshore CCS projects are** currently **under development in the Gulf of Mexico** (see below).

As in Germany, the **coastal area of the USA is divided into two zones**: The first three (or nine in Texas and Florida) nautical miles are owned and under the regulatory control of the states (so-called state waters); the adjoining part up to 200 nautical miles off the coast is classified as federal land and is regulated by the US government (so-called federal waters).

In the **state waters,** the previously described UIC program applies in principle, so that here too, class VI wells must be applied for from the EPA (or in the case of state primacy, from the states). Under the *Coastal Zone Management Act* (CZMA), EPA must consult with the affected state to ensure that the project does not conflict with other planning in the coastal zone (Webb & Gerrard 2019). However, of the US states, only **Texas** has so far enacted specific regulations for offshore CO_2 storage in 2009 (Texas Clean Air Act). The law provides, among other things, that the Texas School Land Board (SLB) (under the General Land Office), makes the final decision on a suitable storage site and acquires ownership of the injected CO_2 immediately after closure of the facilities, whereupon the CO_2 producer, but not the operator of the storage project, is released from long-term liability (House Bill 1796 ; TLRF 2022).

In the **federal waters,** also known as the Outer Continental Shelf (OCS), the regulations for CO_2 storage projects were largely unresolved until recently, so there was a great deal of uncertainty (Meckel et al. 2021; Webb & Gerrard 2019). In 2021, the US government amended the *Outer Continental Shelf Lands Act* (OCSLA) as part of the *Infrastructure Investment and Jobs Act (*IIJA) so that, in addition to fossil and renewable energies, offshore storage of CO_2 is now also included and lies within the regulatory jurisdiction of the Department of the Interior (DOI) (Grauberger, Wiegand & Buffa 28.11.2022). Central to this is that the DOI is now authorized to grant leases and rights of way in the OCS. Also important is the exclusion of CO_2 streams from the definition of "material" in the *Ocean Dumping Act*, which prohibits any disposal of "material" in marine waters (including state waters), which has led to great uncertainty among CCU/S project developers and investors (Navaro et al. 03.12.2021).
The IIJA originally set a deadline of one year for the DOI to publish specific CCS regulations, which has not yet happened, leaving many questions unanswered for the time being, for example regarding long-term liability, monitoring and qualification of injection wells under the UIC program in the OCS. Regulations are now expected in 2023 (Grauberger, Wiegand & Buffa 28.11.2022). What is clear is that offshore permits will also be required under the ESA and NEPA program, as this is federal land. In addition, the *Magnuson-Stevens Fishery Conservation & Management Act* (MSA) takes effect, requiring operators to consult the National Marine Fisheries Service (NMFS) to determine if areas designated as "essential fish habitat" are affected.

Currently, the US's **first large-scale offshore CO_2 storage project** ("Bayou Bend CCS") is under development in federal waters off Beaumont and Port Arthur, Texas. The project is being developed by Chevron, Talos Energy and Carbonvert, with CO_2 injection expected to begin in 2026. In 2021, the joint venture was awarded the US's first tendered lease area for CO_2 storage offshore by the Texas General Land Office. The Bayou Bend project's CO_2 storage area is approximately 40,000 hectares offshore and also 100,000 hectares onshore (in Jefferson County, Texas) and is said to be capable of achieving a theoretical gross storage capacity of more than one billion tons of CO_2, of which 225-227 million tons will be offshore. Currently, the project is preparing for stratigraphic test drilling before applying to the EPA for a permit for the Class VI injection wells (Chevron 06.03.2023; Offshore Energy 07.03.2023) .

Another offshore project is under development off the coast of Louisiana (South Timbalier Lease Area, OCS). The **Louisiana Offshore CO_2 Hub Repurposing Infrastructure to**

Decrease Greenhouse Emissions (Project Lochridge), which most recently received an \$8.4 million DOE funding commitment under the CarbonSAFE program, intends to construct a commercial offshore CO_2 storage complex to geologically store up to 300 million tons of CO_2. The CO_2 will come from industrial emitters in and around Geismar, Louisiana. As part of the project, offshore oil production veteran Crescent Midstream will retrofit a 177 km pipeline corridor it previously built and operated for offshore oil production to transport CO_2. Cox Operating, Repsol, Southern States Energy Board (SSEB), Louisiana State University and Southern University at Shreveport are also involved in the project (Pipeline & Gas Journal 09.05.2023; DOE n.d.; Crescent Midstream 09.05.2023).

2.5 Current debates

2.5.1 Social and political acceptance

According to several interviewees, social acceptance of CCS technologies is a particularly important factor in the further development of the sector. The motives for rejection in the USA are diverse, regionally different and not always congruent. They include (cf. a. CRS 2022):

- Fundamental climate policy considerations (CCS as a life extension for fossil-fueled power plants and for the production of fossil fuels, feared CO_2 leaks in geological storage, tying up funds that could be used more effectively elsewhere for climate mitigation)
- Environmental impacts (e.g. contamination of groundwater due to potential damage/leakage from CO_2 pipelines and geological storage facilities; health hazards; in part also not CCS-specific, but directed against industrial plants in general).
- Safety concerns (explosions, risk of suffocation at high CO_2 concentrations)
- Economic aspects (devaluation of land, erosion of agricultural land, impact on tourism)
- Social and equity aspects[15] (routes in already disadvantaged communities; partly also not CCS-specific, e.g. feared loss of local jobs in the fossil industry due to climate mitigation in general)

CCU/S proponents emphasize that not all of the reasons given are rational and that acceptance can therefore be increased through education. In fact, a survey conducted in 2018 suggests that people with prior knowledge of CCU/S are more likely to believe that the technology will have positive effects on society and the climate. Another factor influencing perceptions of the technology is the distance of individuals to negative climate change impacts. Respondents who perceive themselves closer to climate change impacts had a more positive attitude towards CCUS (Pianta et al. 2021).

A current example of **massive local resistance** (for different reasons) is a planned project by Air Products to produce blue hydrogen (through steam methane reforming with CCS) in Louisiana (detailed description in Dermansky 17.2.2023). Pipeline projects are also currently under criticism, fueled by the **pipeline accident in Mississippi** in 2020 (see text box for details).

Opponents of the CO_2 pipelines have often already institutionalized themselves (e.g. Citizens Against Heartland Greenway Pipeline) and partly receive support from environmental groups (e.g. Sierra Club, Eco-Justice Collaborative) (Chicago Tribune 26.02.2023). The focus is on the large-scale projects of *Summit Carbon Solutions* and *Navigator* CO_2 *Ventures,* each of which plans to build pipelines over several thousand kilometers across five states in the Midwest.

[15] In the context of the adoption of the UIC primacy by individual states, the EPA points out that aspects such as environmental justice and equity are now to be fully integrated into the approval procedures for injection wells (EPA 09.12.2022).

CO_2 pipeline accident in Satartia, Mississippi

On 22 February 2020, a CO_2 pipeline belonging to Denbury Inc. in Satartia, Mississpi, ruptured, releasing approximately 30,000 barrels (approximately 4.8 million litres) of liquid CO_2. Local weather conditions and the topography of the accident site prevented the CO_2 from dissipating quickly. Affected people reported that a green fog had spread and they had breathing problems. Forty-five people required medical treatment and 200 residents were evacuated. Two years after the event, the responsible authority PHMSA published its investigation report on the event on 26 May 2022. PHMSA suspects that heavy rainfall (in combination with non-cohesive soil conditions) had triggered a landslide, causing the pipeline to be axially loaded on a steep slope and subsequently rupture at a circular weld. The report found no evidence of inadequate mechanical properties of the pipeline or chemical composition anomalies. However, PHMSA found that Denbury Inc. had not sufficiently considered the high risk of local landslides (and other geohazards) already known to them, had not been prepared for such an incident and had failed to inform local safety forces in time (at the latest one hour after the accident became known) as well as to inform residents about possible risks in advance. These measures are required of pipeline operators under the *Hazardous Liquid Pipeline Safety Act* and federal pipeline safety regulations (CEQ 2021). Due to these facts, PHMSA is now asking Denbury Inc. to pay a penalty of $3.9 million. In addition, PHMSA is currently revising its CO_2 pipeline safety regulations, particularly with respect to emergency preparedness and response, and has revised a fact sheet for pipeline operators to provide greater awareness of geologic and environmental risks and their impact on pipeline stability (Mississippi Today 06/13/2022; PHSMA 02/06/2022; PHSMA 05/26/2022a; PHSMA 05/26/2022b).

Social acceptance is central to pipeline projects, as it enables voluntary agreements to transfer rights of way or ownership (incl. high compensation payments) with landowners. Alternative solutions, on the other hand, are accompanied by numerous uncertainties. Although expropriation is generally possible, its application is usually linked to site approval by the relevant state regulatory authorities (e.g. Illinois Commerce Commission). Since approval procedures vary from state to state, securing rights of way for cross-state projects is thus not guaranteed. Moreover, these regulatory processes could be followed by court actions, such as in Illinois against the Carbon Dioxide Transportation and Sequestration Act. In addition, there have been recent regulatory interventions and legislative efforts to limit the states' eminent domain rights. In Illinois, for example, several counties have independently passed moratoria on pipeline permitting (Chicago Tribune 26.02.2023; E&E News 10.03.2022).

In contrast, fundamental reservations are less frequently heard in the **political debate**. Even if the Biden administration argues primarily with climate considerations, supporters can be found far into the conservative camp if they expect positive effects on their constituency (e.g. through EOR or lifetime extension of otherwise unprofitable coal-fired power plants). Many of the regulations outlined in section 2.3 (e.g. the IIJA) were passed with votes from both political camps. Depending on the motivation, however, details of the support policy are disputed; this includes both technical requirements and, for example, the level of support. Finally, some voices consider government funding obsolete altogether and rely entirely on market-driven development (CRS 2022).

2.5.2 Enhancement of the regulatory framework

Despite years of experience, especially in the area of EOR but also increasingly with other CCU/S technologies, there are still some regulatory uncertainties/ ambiguities in the US as well, both at the federal and state level, that are seen as hurdles to project development. For the development of a significant number of large-scale, commercial CCU/S projects, timely

clarification of these uncertainties will be crucial (Koski et al. 2020). This also applies to states where CCS projects already exist, such as Texas (TLRF 2022). However, there are regional differences here as well; according to experts and interviewees, the regulatory framework is already largely attractive in some states (e.g. Wyoming, North Dakota, Louisiana), while elsewhere it is seen as rather deterrent/unattractive (e.g. in Pennsylvania, Ohio) (Koski et al. 2020; Ring et al. 2021).
Significant uncertainties currently exist regarding the expansion of a pipeline network. The question of who regulates the siting of interstate pipelines (on federal land) will become increasingly urgent as CCU/S projects expand across the county. Experts and interviewees see a need for clarification of responsibilities at the federal level and opportunities to harmonize existing state regulations or introduce federal backstop regulations to facilitate the development of interstate pipelines (Koski et al. 2020).

It is also largely unresolved whether and how existing pipelines (for gases or hazardous substances) can be used to transport liquid CO_2. This could prove difficult for two reasons: First, PHMSA cannot change the design standards of existing pipelines (for gas pipelines, the original 49 CFR 192 standards would have to be converted to 49 CFR 195 standards) due to the lack of jurisdiction over pipeline siting (this rests with the states or BLM if the pipeline crosses federal land within a state); second, there are design challenges, particularly with regard to maximum pressure (this is approximately 700 PSI/48 bar higher than for gas pipelines), and the use of suitable materials (CEQ 2021; DOE/NETL 23./24.02.2022, Institute for Carbon Removal Law & Policy 10.11.2021).

In a workshop conducted by the DOE and NETL with project developers, government representatives and other stakeholders, the participants also criticized the heterogeneity and associated uncertainties regarding ownership of the pore space. The fact that ownership rights are not regulated uniformly at the federal level and that in some states there are still uncertainties regarding ownership rights to the pore space (e.g. in **Illinois)** is seen by experts as a major hurdle in project development. There are also uncertainties regarding the conversion of existing injection wells into Class VI wells (DOE/NETL 23./24.02.2022; Koski et al. 2020).

Furthermore, there are uncertainties regarding long-term liability. According to the UIC program, operators are liable for any damage caused by leakage for 50 years. Beyond this period, liability is unclear. Although experts point out that often about 95% of the injected CO_2 is mineralized after 50 years, in the absence of long-term empirical data, such a regulatory gap may create hesitation or reluctance among investors and operators and thus slow down the development of CCU/S projects. States with their own liability regimes, including the option of long-term state assumption of liability after a certain number of years, could become preferred locations.

Since the announced DOI regulations for offshore CO2 storage are still pending, many questions remain unanswered. These include the method by which the DOI will issue permits for offshore CCS projects (lease, easement, right of way or a combination thereof), long-term liability for spills, minimum distances between lease areas and the use of existing OCS infrastructure. Overall, the knowledge development on offshore CCS is dynamic; for example, BOEM will conduct three national environmental study programs in agency-regulated offshore areas (Atlantic, Gulf of Mexico, Pacific, and Alaska) in the period 2023-2025 (Grauberger, Wiegand & Buffa 28.11.2022).

In addition to clarifying existing regulatory uncertainties, experts suggest that regulations and requirements for CCS projects could be harmonized between states as well as between the state and federal level in many of the areas addressed to further support the development of the sector (GCCSI 16.05.2023; Koski et al. 2020; Ring et al. 2021).

2.5.3 Market development

Even before the adoption of the IRA, CCU/S was seen globally as a growth market with a market volume of several billion dollars, whereby the growth expectations for the next few years differ and range between 10 - 15% p/a. There is broad agreement among the interviewed experts that the focus of this growth will continue to be in North America (cf. a. Extrapolate 2022) and will tend to be broadened (i.e. extended to additional industry sectors and also smaller projects) and accelerated by the increased IRA funding. As in other sectors of the economy, the binding 12-year funding perspective through the IRA is also highlighted in this context. According to a study by the Rhodium Group, a total CCU/S and DAC volume of approximately 100-103 Mt CO_2 in 2030 and 266-313 Mt CO_2 in 2035 could be achieved in the USA under the current framework conditions (Larsen et al. 2022).

This is linked to the expectation of falling prices for the use of CCU/S technologies, for which, however, no qualified estimates are available. Some experts interviewed also expect that in the medium term the hitherto very subsidy-centered approach in the USA could be supplemented by additional requirements or mechanisms such as the introduction of cap-and-trade systems, which would create additional incentives for CCU/S. The existence of the ETS in the EU is seen as a regulatory advantage in this context. In principle, it is assumed that in the short and medium term, industrial applications with low capture costs will continue to be developed in preference (see also Larson et al. 2021) and that use in power plants, in contrast, will remain of secondary importance.

In addition to fundamental questions of acceptance and regulatory gaps (see above), a possible stumbling block for market development is seen in particular inadequate staffing with specialised personnel at central points in the approval process. For example, there are currently more than 70 applications for injection wells at the federal EPA, many times the total number of applications approved to date. Against this background, the transfer of "primacy" to the states is welcomed (and also promoted by the DOE), especially since the authorities there often have extensive geological expertise from the extraction of mineral resources.

In addition, efforts are being made to shorten the duration of the approval process. With the passage of the *Consolidated Appropriations Act 2021,* it is possible for CCU/S projects to be considered under Title 41 of *the Fixing America's Surface Transportation* (FAST) *Act.* This program aims to make environmental permitting processes for infrastructure processes faster, more transparent and more predictable. This is achieved through coordinated review and approval overseen by the Federal Permitting Improvement Steering Council (Permitting Council). Empirical data demonstrates the time savings achieved as a result: While from 2010 to 2018 the average approval time for an Environmental Impact Statement under the NEPA process without the FAST 41 process was 4.5 years, projects subject to the FAST 41 process take an average of 2.5 years to do so (Bipartisan Policy Center 02.08.2021; CEQ 2021). So far, according to interviewed experts, no CCU/S project has applied for consideration under the FAST 41 process, so it remains to be seen whether this measure will be applied and lead to a substantial acceleration in the approval of CCU/S projects.

3. Canada

3.1 Background, strategy and government support

Canada's federal **climate change plan** of December 2020 aims to position the domestic industry as environmentally friendly and competitive, including through the large-scale application of CCUS technologies (e.g. in the oil and gas industry and in the production of hydrogen). For this reason, a federal **Carbon Management Strategy** is currently being developed by Natural Resources Canada (NRCan) in cooperation with experts and stakeholders (NRCan 2020a). In addition, blue hydrogen (based on SMR and CCS) already plays a very important role in Canada's 2020 **Hydrogen Strategy** and the use of DAC has been identified by the Canadian government as one of the key technologies for the production of synthetic fuels (NRCan 2020 b).

Canada's “CO_2 Capture and Storage Technology Roadmap" was already published in 2008, with the primary goal of strengthening the oil and gas industry in the long term. In the same year, a "Canadian Carbon Capture and Storage Network" was established to stimulate a thematic exchange between the governments of Canada's provinces and territories. Implicitly linked to the topic is the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations, which* came into force in 2015 and sets a maximum emissions intensity for coal-fired power plants of 410 gCO /kWh$_2$ (Environment and Climate Change Canada (ECCC) 2018).

In order to support the development of CCU/S projects, various instruments have been established for funding and support by the Canadian government and the provinces/territories:

A **CCUS Investment Tax Credit** (in short: ITC) was integrated into Canada's 2022 budget (Finance Canada 2022). By 2030, C$8.6 billion ($6.4 billion) is to be provided by the Canadian government for this purpose (Canadian Climate Institute 2023). This is intended to accelerate the technology ramp-up and achieve an annual saving of 15 Mt CO_2 (Finance Canada 2021). The ITC can be claimed by companies that make eligible CCU/S expenditures from 2022 onwards and provided that the captured CO_2 is permanently stored through an eligible use. Eligible uses of CO_2 include geological storage and storage of CO_2 in concrete, but not EOR (Finance Canada 2022). Another requirement to receive the credit is the public provision of the technology knowledge, which is intended to force cost reductions for future projects. DAC projects receive a 10% higher tax credit (60%) than other CCU/S projects (Finance Canada 2022).

Table 5: Canada's CCUS Investment Tax Credit

Project type	2023-2030	2031-2040	After 2040
CO_2 capture technologies for DAC	60%	30%	0%
CO_2 capture technologies for other projects (non EOR)	50%	25%	0%
Technologies for transport, storage and use of CO_2	37,5%	18,75%	0%

Source: Own representation based on Finance Canada (2022)

In addition to the ITC, CCU/S projects can gain further financial benefits through the recognition of stored CO_2 as carbon credits, under Canada's Clean Fuel Regulations (CFR) or through the national and provincial CO_2 tax systems.

The **Clean Fuel Regulations** adopted in 2022 aims to reduce the carbon content of fuels by 15% by 2030 relative to 2016 and support the transition to cleaner fuels. Fuel production facilities can comply with the regulations by integrating CCU/S projects, in addition to earning carbon credits for excess carbon reductions. These can then be sold to companies that would not meet their emissions targets (ECCC 2023 a). Since CFR credits are only applicable to domestically consumed fuels, the value of the credit can vary greatly from production site to production site as well as due to market dynamics (Canadian Climate Institute 2023).

Canada's *Greenhouse Gas Pollution* Pricing *Act of* 2019 introduced a **CO_2 pricing system at the federal level**, which acts as a so-called backstop whenever the provinces/territories have not introduced their own comparable pricing systems and sets the national CO2 price level. It consists of a CO_2 tax (fuel charge) of currently C$50/t, which is to increase continuously to C$170/t in 2030, and a so-called Output-Based Pricing System (OBPS), a kind of emissions trading system for industry (ECCC 2023b). Under the OBPS, companies can receive "Greenhouse Gas Offset Credits" for reduced emissions, which can then either be offset against their own emissions or traded (ECCC 2023c). In principle, this also includes the use of CCU/S technologies, but the details on offsetting are still being developed by the ECCC (Resilient LLP 28.02.2023).

However, most Canadian provinces/territories (except Yukon, Nunavut and Manitoba) have introduced their own **subnational CO_2 pricing systems** or apply a combination of the federal CO_2 pricing system and their own regulations (ECCC 2023), in which emission reductions from CCU/S projects are in principle always integrated/allowed in the system, but often no associated detailed regulations regarding accounting and certification have yet been established.

For example, **Quebec's** ETS, which is linked to California's ETS, recognizes the use of CCU/S and allows for the deduction of GHG emissions that have been captured, stored, reused, disposed of or removed from the verified emissions of the covered installation (GHG Reporting Regulation)[16] . However, Quebec's ETS does not yet include a large CCU/S facility and only 4% of large emitters covered by the ETS benefit from the CCU/S provisions. So far, the CCU/S part in the mandatory GHG declaration of emitters is analyzed individually by the province and the calculation of stored, reused, disposed or transferred emissions is done on an ad hoc basis at individual installations, as no specific measurement protocols or general MRV requirements have been introduced yet (La Hoz Theuer & Olarte 2023).

Of particular note, however, is the province of **Alberta's** recently amended ***Technology Innovation and Emissions Reduction Regulation (TIER)***, which recognizes stored CO_2 from industry as "capture recognition tonnes", bringing the value of CCU/S emission reductions close to the applicable CO_2 price. In addition, this regulation allows CCS facilities at refineries, for example, to receive both CFR and TIER credits. The interaction of the CCU/S ITC, the CFR and the Canadian CO_2 pricing schemes can create high financial incentives for CCS projects in Canada. The Canadian Climate Institute, using the example of CCS application in oil sands extraction in Alberta (with costs of around C$150/t CO_2), estimates that the total financial incentive from ITC, CFR and TIER can range between $135-275/t CO_2 stored in 2030, higher than the 45Q tax credit in the US (Canadian Climate Institute 2023).[17]

In addition to the funding mechanisms outlined above, Canada has several comprehensive programs and funds that support CCU/S projects, among others: The **National Climate Plan** provides C$3 ($2.2) billion over five years for the decarbonization of industry (*Strategic Innovation Fund - Net Zero Accelerator)* and C$1.5 ($1.1) billion to support the production and use of so-called low-carbon fuels (*Low-Carbon and Zero-Emissions Fuels Fund*) (ECCC 2022). A further C$319 million will be provided to NRCan via the **Energy Innovation Programme** from the 2021 budget to advance research, development and demonstration of CCU/S technologies along the process chain (NRCan 2023). Other funding programs include the **Clean Energy Fund** and **ecoENERGY Technology Initiative**, which have each invested

[16] Chapter Q-2, r. 15 - Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere (GHG Reporting Regulation): https://www.legisquebec.gouv.qc.ca/en/document/cr/Q-2,%20r.%2015

[17] This Canadian Climate Institute estimate breaks down into C$10-30/t CO_2 for CCUS ITC, C$115-135/t CO_2 for TIER (CO_2 pricing) and C$10-C$110/t CO_2 for CFR. For details on the calculation, see Canadian Climate Institute (2023).

approximately C$200 million in CCU/S projects since 2009. In the 2022 budget, another funding instrument called **Canada Growth Fund** was established with C$15 ($11) billion over 5 years to help Canadian companies finance decarbonization measures, e.g. through guarantees, carbon contracts for difference, or loans. The exact design of these various new financing instruments is to be determined in the first half of 2023 (Mentor Works 02.01.2023; Finance Canada 2022).

In addition, the **Canadian Infrastructure Bank** has existed since 2017 and is intended to provide financial support to important infrastructure projects, such as pipelines (investments via public-private partnerships). Within an 11-year period, the bank has C$35 billion at its disposal (Canada Infrastructure Bank 12.05.2023).

3.2 Industry overview

Canada has been active in the field of CCU/S for more than 15 years, with the main focus being on the further use of the captured CO_2 for EOR. The activities are mainly concentrated in the provinces of Alberta and Saskatchewan in Western Canada - two of the three most important oil and natural gas producing regions in the country - but pilot projects have also been carried out in British Colombia.

Currently, **four major CCUS projects are in operation in Canada**: The Boundary Dam, the Alberta Carbon Trunk Line, the North West Redwater Recovery Unit and the Quest project (IEA 2023). The commercial projects in operation capture CO_2 from fossil sources, such as oil sands refineries, natural gas reforming and coal-fired power generation, and use it mostly for EOR (see Appendix, Table 6). Only the Quest project injects the CO_2 into a saline aquifer for permanent storage (GCCSI 2021c). Due to the increasing incentives for CCU/S application also in other industries, a number of smaller demonstration and pilot projects have also emerged, including in other parts of the country. As of 2021, 17 CCU/S test facilities were active (GCCSI 2021c).

In contrast to the projects currently underway, more than 60% of the projects under development aim to geologically store CO_2 in the long term without carrying out EOR (IEA 2023). As of May 2023, **eleven commercial projects are under development**, three each for hydrogen production and at conventional power plants (GCCSI 2023).

According to experts, the Canadian CCU/S industry benefits on the one hand from the **many years of experience** of some highly specialized companies and on the other hand from regulatory experience of the public authorities. In addition, the provinces in Western Canada in particular have **high CO_2 storage potentials** thanks to former oil and natural gas reservoirs, but also natural geological formations or non-extractable coal deposits. In total, Western Canada (Alberta, Saskatchewan, Manitoba and British Columbia) accounts for 390 Gt of the identified total storage potential amounting to 398 Gt. Further considerable, albeit significantly lower, storage potentials have also been identified in the provinces of Ontario and Quebec (International CCS Knowledge Center April 2021).

Project example: SaskPower's Boundary Dam 3

The Boundary Dam 3 CO_2 capture plant is operated by SasksPower, a company owned by the Saskatchewan provincial government. The plant uses the Shell/Cansolv amine-based carbon capture technology in an existing coal-fired power plant (GCCSI 2014). According to the operator, the capture rate of CO_2 is 90%, and in addition 100% of sulphur dioxide and 50% of nitrogen oxides would be captured (International CCS Knowledge Center n.d.). The Boundary Dam plant is one of two operating plants capable of capturing CO_2 from gas streams with only a low CO_2 concentration (<20%) (CRS 2022a; FECM 2022). The decision to build the CCUS plant was made due to the tightening of Canadian emission thresholds for coal-fired power plants at the end of their life cycle, as continued operation of the power plant unit would otherwise not have been possible (Kepetaki & Scowcroft 2017).

The captured CO_2 is mainly used for tertiary oil production and is transported through a 41 km pipeline to the Weyburn oil fields. CO_2 that is not used in the EOR is fed to the Aquistore pilot project, where it is injected into a 3.4 km deep sandstone formation with the aim of exploring permanent storage in deep saline formations. Attached to BD3's commercial CCS facility is also a CCS test facility and an emission control research facility where new CO_2 capture technologies can be tested and analyzed.

The total project cost for Boundary Dam was C$1.5 billion, of which about C$800 million was for the CCS plant. About 30% of the project cost (C$240 million) was covered by the Canadian national government (MIT 2016b). The financial sustainability of the plant is ensured on the one hand by selling the CO_2 for EOR use, and on the other hand by enabling the continued operation of the coal-fired power generation.

3.3 Regulatory Framework

Regulation regarding the capture, transport and storage of CO_2 in Canada is largely the **responsibility of the respective provinces/territories,** provided that the projects are implemented entirely within their borders. Only environmental impact assessments have been mandatory across provinces since 2019. In the following, the development of the regulatory framework is briefly outlined, which was primarily developed in the course of the implementation of large CCU/S demonstration projects. This is followed by a description of the requirements within the framework of the environmental impact assessment, the complex regulations for the respective process chains (capture, transport, storage) and relevant liability issues.

Saskatchewan was the **first Canadian province to deal** with the regulation of CCU/S projects, as Shell submitted its first application for approval of an EOR pilot project as early as 1980. The first applications to permit CO_2 transport and storage activities were filed in 1984 (Larkin et al. 2019a). Since then, regulation at the provincial level has been characterized by different approaches. While the Saskatchewan government concluded, even in the 2010s when reviewing the Boundary Dam project as the first large-scale CO_2 capture project, that existing regulations were largely sufficient to regulate the submitted project proposal even without CCU/S-specific additions, the province of **Alberta** developed a set of specific regulations and review processes for CCU/S projects over the past decade. The province of Alberta thus has a fairly well-developed regulatory framework, which also serves as an example for regulatory development processes in other Canadian regions. For example, the Ontario government announced in November 2022 that it will develop a specific regulatory framework for CO_2 storage. The government of Saskatchewan also announced its intention to expand the existing regulatory framework in order to clarify existing uncertainties regarding ownership of storage reservoirs and long-term commitment and liability issues.

The province of **Alberta** has taken a leading role in the development of a legal and regulatory framework for CCU/S projects over the last decade due to its excellent geological setting. The regulatory framework addresses a variety of regulatory challenges, such as ownership of pore space, storage and disposal of captured CO_2, license entitlements, land rights and long-term liability. Most of the regulations have been incorporated into existing oil and gas industry regulations in the form of amendments, e.g. the *Mines and Mineral Act* (MMA) and the *Oil and Gas Conservation Act* (OGCA). These laws are supplemented by guidelines from the Alberta Energy Regulator (AER). Due to the particularly well-developed regulatory framework in Alberta, the following sections primarily describe the regulations of this province.

3.3.1 General requirements: Environmental impact assessments

At the federal as well as provincial level, various **Environmental Assessment Acts** regulate which projects must conduct an environmental impact assessment. Following the recast of the legal framework in the form of the ***Impact Assessment Act* (IAA) in 2019**, the federal legislation now provides that environmental impact assessments to consider the climate impact of a project - regardless of provincial requirements - must be carried out as a matter of law. The IAA also creates a single government authority for impact assessments (evaluation and consultations), sets requirements for the assessment of environmental, health, social and economic impacts, and allows the Minister of Environment to approve projects when it is in the public interest to do so. It also establishes an early planning and engagement phase and timetables for impact assessments and decisions, and sets out opportunities for public participation and financing. The environmental impact assessment is intended to provide for inter-jurisdictional cooperation and transparency in decision-making, while also allowing for the assessment of cumulative impacts on a regional basis (assessment of federal policies, plans and programs). However, after coming into force in 2019, the IAA was found to be potentially unconstitutional following a lawsuit by the province of Alberta, as it interferes with provincial legislative competences, and is therefore being renegotiated.

In **Alberta,** the ***Environmental Protection and Enhancement Act* (EPEA)** is the provincial legislation for the protection, enhancement and wise use of the environment. It describes the activities that require an environmental impact assessment and sets out the process for obtaining the related permits (AER n.d.b). As part of that, there are mandatory, voluntary and discretionary project types. If an activity is not specifically listed in the regulation, or if another environmental director or the applicant requests a decision on the need for an EIA report, an environmental impact assessment (EIA) procedure may be initiated. There are a total of six associated regulations, two codes of practice and 12 listed standards and guidelines.

In **Saskatchewan,** projects with potential environmental impacts - regardless of the stage of the CCU/S value chain - have so far been submitted to the Ministry of Environment for review under the *Environmental Assessment Act.* The project application must be submitted to the Saskatchewan Environmental Review Panel (SEARP), whose members are the provincial ministries and agencies that have an interest in their development or regulate these projects (GOS 2021). Based on an initial technical project description and planned environmental protection measures, a decision is made as to whether an in-depth environmental impact assessment must be submitted or whether an exemption (possibly specifying restrictions and minimum requirements) will be granted. In the case of the Boundary Dam facility, it was decided that no in-depth environmental assessment is required (Larkin et al. 2019b).

3.3.2 CO_2 capture

The capture of CO_2 falls within the regulatory framework of **industrial facilities and processes**. There are no specific requirements in Canada for the capture of CO_2 for use or storage. Requirements that regulate capture processes for DAC and BECCS technologies have been analyzed by Alberta Law Review and are listed below (Craik et al. 2022).

DAC projects operate as industrial facilities and are therefore subject to provincial environmental regulations for process emissions and waste disposal, which are embodied in the *Environmental Protection and Enhancement Act* (RSA 2000, c E-12). Should multiple capture facilities be required, land use issues may be raised that are subject to provincial land use legislation under the *Alberta Land Stewardship Act* (SA 2009, c A-26.8) *and the Public Lands Act* (RSA 2000, c P-40). In order to ensure efficient DAC processes, the necessary energy should be sourced from renewable energy sources, which entails land use issues and regulatory requirements for the transport of CO_2 when using DAC with a variety of capture facilities.

BECCS occurs in several phases, with biomass and bioenergy production triggering different laws. Bioenergy production concerns legal frameworks that relate to the procurement and production of biomass feedstock and its combustion for energy. Most laws and regulations that apply to forest biomass harvesting are at the provincial level, as more than 90% of Canada's forest land is owned by the provinces. However, the regulatory regime relating to the supply, use and purchase of biomass for heat and energy applications has been developed without reference to CCU/S applications.

3.3.3 CO_2 transport

The Canadian *Energy Regulator Act establishes* the legal framework for the planning, construction, operation and decommissioning of federally regulated pipelines in a manner that is safe for the public and the environment. The Canadian Energy Regulator (CER, formerly the National Energy Board) is an independent federal agency responsible for regulating cross-border pipelines in Canada. At the national level, pipelines regulated by the CER must comply with the specifications of the **Canadian Standards Association** (CSA). The CSA standard Z662 (Oil and Gas Pipeline Systems) sets the technical standards for the design, construction, operation, maintenance and decommissioning of Canadian oil and gas pipelines. At the same time, the CER is also responsible for conducting environmental impact assessments for the projects it regulates in accordance with the *Impact Assessment Act* (IAA). The regulations classify CO_2 pipelines as a type of commodity pipeline without specific standards, where requirements were set on an ad hoc basis. This was guided by the procedures applicable to other pipelines, supplemented by specific analysis of individual applications (IEAGHG 2010).

Unless provincial or international boundaries are crossed, **provincial regulatory requirements** apply. Regulatory requirements for pipelines in Alberta are governed by the *Pipeline Act* (Part 4), Pipeline *Rules*, Directive 077 (Pipelines - Requirements and Reference Tools) and the Canadian Standards Association (CSA) National Standard Z662-19. None of these standards refers specifically to the transport of CO_2. Only Guideline 056 (Energy Application for construction and operation of the pipeline) provides specific requirements. This guideline states that due to the unique properties of CO_2, special considerations are required in the design of pipelines for transportation. Since some design considerations are not included in CSA Z662, the Alberta Energy Regulator (AER) reviews all applications to construct or modify pipelines for CO_2 transport to ensure that the design is based on sound engineering practices. Accordingly, the applicant must include the following information with its application:

- Specific operating pressure ranges and pressure drops to avoid unnecessary phase changes,
- Corrosion protection and monitoring issues due to water content and other impurities,
- Specific material considerations to minimize the risk of fracture propagation,
- Emergency plan considerations and dispersion modelling

- Safety precautions to be taken during operation and repair of the pipeline.

In **Saskatchewan**, CO_2 transport is also regulated by the Pipeline Act, which is supplemented by the technical requirements of the Saskatchewan Pipelines Code. The latter contains requirements for technical assessment prior to licensing, monitoring, emergency plans and pipeline design depending on population density. However, no specific requirements are set for the transport of CO_2 (GOS 2022).

3.3.4 CO_2 storage

The **provinces** (and territories) are responsible for setting requirements for testing storage potentials, regular monitoring and approval procedures, but they must comply with the national minimum requirements. The level of regulatory development for CCU/S applications varies across the provinces. Also with regards to storage, Alberta has developed the most comprehensive requirements, legislation and guidelines, which is why the province's regulations are explained in more detail below.

Since 2014, upstream oil and gas regulatory functions have been administered by the Alberta Energy Regulator (AER) under the *Environmental Protection and Enhancement Act* (EPEA) and the *Water Act.* The AER acts as the regulatory body for the development of the energy industry, bringing together various permitting processes from application and exploration, through construction and development, to decommissioning, reclamation and remediation (AER o.D.a).

The ***Mines and Minerals Act*** (MMA) is relevant for the development of CCU/S projects. Part 9 of the MMA (*Sequestration of Captured Carbon Dioxide*) regulates the rights to conduct **exploratory drilling** (Rogers et al. 2023). This includes, among other things, requirements regarding:

- injection of captured CO2 for sequestration (monitoring, measurements, reporting, decommissioning plan),
- restrictions on the transfer of the agreement,
- obligations upon termination of injection,
- certificates of decommissioning (periods, conditions),
- assumption of liability (e.g. obligations of the operator),
- obligations towards the Post-Closure Stewardship Fund (PCSF).

Section 115 of the MMA regulates the government's rights to drill exploratory wells to determine suitability for CO_2 storage. The Sequestration Tenure Regulations (CSTR) allow the government to grant this approval if fees have been paid and a Monitoring, Measurement and Verification (MMV) plan has been submitted. Section 116 of the MMA next allows government approval for the **injection of CO_2** into the subsurface, subject to the same conditions as in section 115. In addition, the operator must sufficiently demonstrate that the subsurface is suitable for injection and must already submit a plan for decommissioning the facility (Section 18, CSTR). The section 116 permit is valid for 15 years, but does not include the production or extraction of minerals from the subsurface.

Within the *Mines and Minerals Act* (MMA), reference is also made to the ***Oil and Gas Conservation Act*** (OGCA) and the ***Environmental Protection and Enhancement Act*** (EPEA). The former was originally designed for oil and gas production and regulates the conditions under which one can obtain a license. Section 39(1)(d) of the *Oil and Gas Conservation Act* (OGCA), for example, gives the Alberta Energy Regulator (AER) the power to approve individual CCU/S storage programs. In doing so, the AER must ensure that the injection does not affect the production and storage of oil and gas or other formations used in the subsurface for storage. Sections 11 and 12 of the Oil and Gas Conservation Rules (OGCR) govern the rights to operate injection wells, i.e. a facility operating license and production rights for a well. The requirements for this are described in Guideline 067.

The EPEA regulates the legal requirements for air, water, soil and biodiversity. The *Surface Rights Act* (SRA) is also referred to within the MMA. This generally regulates the rights of entry for mining, drilling, pipelines, but also power and telephone lines.

In addition to the laws, various requirements for the different process chains of CO_2 storage and use also apply in the form of **guidelines**. These guidelines are listed in Table 7 in the appendix. Guideline 065 (Resources Applications for Oil and Gas Reservoirs) differentiates between the permanent storage of CO_2 underground (Unit 2: Disposal / Storage) and the use and simultaneous storage within the framework of EOR technologies (Unit 4: Conservation). The main differences and similarities between the requirements are shown in Table 8 in the appendix. The requirements differ in particular by extending the need for analysis to the entire connected pore space in the case of the use and storage of CO_2.

In addition to the requirements in the respective guidelines, specifications are made for regular measurements and external verification by third parties (**Measurement, Monitoring and Verification Plans**). Operational wells, production and processing facilities are audited annually by field inspectors for various characteristics, e.g. company performance and past compliance, sensitivity of the area in which the operation takes place (proximity to water bodies), frequency of environmental incidents in the area or inherent risk in the event of an incident and complexity of the operation. Special audit programs such as the Enhanced Production Audit Program (EPAP) are designed to encourage companies to improve their measurement and reporting procedures, while at the same time improving compliance and reducing the number of on-site inspections and audits conducted.

In **Saskatchewan,** CO_2 injection wells are regulated as disposal wells under the provisions of the *Oil and Gas Conservation Act.* This sets minimum standards for the drilling, completion and abandonment of injection wells and also includes standards for the collection of relevant data from drilling and production (Condor & Wilson 2013). In addition, the regulation sets requirements for protection against leakage even after closure of the reservoir, as well as proper decommissioning and surface remediation. (Larkin, Leiss & Krewski 2019). The *Oil and Gas Conservation Act* also regulates inspection provisions. Unlike in Alberta, however, hardly any CCU/S-specific requirements are defined.

Liability

In Canada, according to an overview by the Global CCS Institute**,** all liability provisions for CCU/S activities in **Alberta, British Columbia and Saskatchewan** fall to the provinces (GCCSI 2019). This includes provisions on ownership of the pore space (Alberta only), operator liabilities during the operational phase, requirements for MMV plans, transfers of liability (Alberta only), conditions for transportation (Alberta only), time limits for transfer of liability after a facility ceases operation (Alberta only, no time requirements enshrined), scope of transfers of liability (Alberta only) and financial security requirements.

According to the Global CCS Institute (2019), the concept of liability for CCU/S applications is divided into three sub-areas: **civil**, **administrative** and **climate change-related**. Civil forms of liability include actions by the operator in the context of CCU/S activities that affect the interests of third parties, which may lead to damages or restraining orders if the activity continues. Administrative forms of liability refer to costs incurred under CCU/S-specific legislation, as well as general national energy and environmental legislation, which are to be borne by the operator (due to the power of the competent authority to oblige the operator to take measures, e.g. to respond to a pollution problem and to achieve practicable results). It contains wide-ranging obligations and the possibility of reimbursement of costs if an authority is forced to act on behalf of an operator. Liability issues in terms of climate change arise in cases where, for example, some kind of guarantee is given for the safe storage of CO_2, here the operator is liable in case of leakage.

Alberta's *Mines and Minerals Act* regulates the **ownership of pore space by the Crown**[18]. It allows ministers to "enter into agreements for the use of the pore space". If a CCU/S facility is

[18] In the Canadian system of government, the power to govern is vested in the Crown, but the government is charged with exercising it on behalf of and in the interests of the people.

approved, legal responsibility is transferred to the **operator of the facility** during the storage process until decommissioning in accordance with the requirements of the Sequestration Tenure Regulations (CSTR). A mandatory Post-Closure Stewardship Fund (PCSF) has been established to address potential ongoing costs following decommissioning or closure of an injection well or storage horizon and the assumption of post-closure obligations by the Crown (e.g. ongoing monitoring). This is financed by fees to be paid by tenants during the operation of the plant.

The liability rules in **Alberta** can be summarized as follows:

1) All liabilities remain with the operator until closure occurs and the closure certificate is issued. After decommissioning, liability then reverts to the national government / Crown under the provincial *Mines and Mineral Act.*
2) The Alberta regulations further provide for operators to fund the transfer of statutory liabilities, as well as certain other liabilities (the risk of abandoned injection wells that have not been successfully capped and the continued monitoring, metering and verification of these, but not third-party liability) through contributions to the PCSF.

In Alberta, a CCU/S operator may receive offset credits for captured CO_2 and thus be liable for any subsequent leakage. The Regulatory Framework Assessment (RFA) already recommended in 2013 that this potential liability should also be transferred to the Crown and, furthermore, that this liability should also be the responsibility of the PCSF (Alberta 2013). In contrast to Alberta, the long-term liability of injection wells in **Saskatchewan** remains with the injection well owner. The obligation to make good any CO_2 leaks even after the end of the operating period remains with the licensee/company (Larkin et al. 2019).

3.4 Offshore CO_2 storage in Canada

The possibilities for overcoming barriers to offshore CO_2 storage were discussed in a Columbia Law School study (Webb & Gerrard 2019). The study explains that Canada claims jurisdiction over offshore waters up to 200 nautical miles from the 'baseline', which corresponds to a low water line along the coast. This can be adjusted in certain cases (e.g. rugged and built-up coastlines such as in British Columbia) for convenience. However, the Canadian provincial government of British Columbia does not have jurisdiction over the seaward facing waters, including the subsoil (continental shelf), as this is the responsibility of the federal government.

The province of **British Columbia has the** largest offshore CO_2 storage potential due to its location on the coast with the large submarine basalt formations of the Cascadia Basin. According to the responsibilities described above, this basin falls under the competences of the federal government. The Cascadia Basin straddles US and Canadian waters, which is why future offshore CCU/S projects are subject to the regulations of both countries. The biggest problem arises from the fact that both states have not enacted comprehensive legislation for offshore CCU/S projects, but seek to regulate offshore CCU/S projects under existing regulations. Similar to the US until recently, almost all projects in Canada are prevented by the Canadian *Ocean Dumping Act*. This prohibits any disposal of "material" in marine waters and is enshrined in the *Canadian Environmental Protection Act* (CEPA). The definition of "storage [of material/substances] in the subsoil of the seabed" also affects CO_2 injections and corresponding CCU/S projects. The storage of CO_2 falls under the category of storage or injection of material in the subsoil beneath the seabed. Although there are a few exemptions for "wastes and other substances", CO_2 is not included in this list (CDJ 01.05.2021). For this reason, the responsible minister (Minister of Environment and Climate Change) cannot issue a permit for CO_2 storage.

In addition, other laws can also hinder the development of offshore projects, such as the need for leases for seabed rights, due to the Canadian Oceans Act (COA). This declares that the federal government has exclusive rights over the continental shelf, including submarine areas below the Exclusive Economic Zone (EEZ). The Canadian Petroleum Resources Act (CPRA) empowers the Minister of Natural Resources to grant third parties rights to the continental shelf, but only for oil and gas resources. However, there is no law for granting rights of use for offshore CCU/S projects.

Although there is currently no comprehensive legal framework for offshore CO_2 storage in Canada, there is some interest in using geological formations under the seabed for storage. The Cascadia Basin is therefore being investigated as a possible site by the Pacific Institute for Climate Solutions (PICS). As part of this research, a study was published in which proposals and overviews of existing regulations for individual components and process chains relevant to CCU/S use were developed (Webb & Gerrard 2021). The necessary permits and applicable laws are presented together with relevant authorities such as the Canadian Energy Regulator (CER), ECCC, NRCan and Transport Canada (see Appendix, Table 9). The study concludes that the installation of offshore industrial facilities (wind turbines, platforms, pipelines) involves numerous laws and requires permits, with particular uncertainties regarding permits for wells in the submarine subsurface.

Practical example: Quest Carbon Capture and Storage Project, Alberta

The Quest capture plant is operated by Shell Canada Energy on behalf of the Athabasca Oil Sands Project (AOSP), a joint venture between Canadian Natural Resources Limited, Chevron Canada Limited and Shell Canada Limited. At the Quest plant, CO_2 is separated from the process gas streams at three hydrogen production units as part of the processing of bitumen into synthetic fuels. For this purpose, CO_2 is first absorbed in an amine solution and then regenerated to achieve the required concentration of 95% (NRCan 2021). In a second step, the CO_2 bound in amine solution is compressed, dehydrated and piped in liquid form via a 65 km pipeline north to old oil wells near Thorhild, Alberta. There it is injected into a saline rock formation (basal Cambrian sandstones) more than 2,000 meters below the surface for permanent geological storage. The pore space for storage was selected between 2008 and 2013; influencing factors for the decision were the properties of the rock formation, the number of old wells in the vicinity, and the distance to densely populated areas. Shell Canada applied for and was granted the sole pore space right for the selected storage space (NRCan 2021).

Since commissioning in September 2015, the plant has permanently stored 6.8 million tons of CO_2 and achieved an annual capture rate of between 77.4% and 83% (median 78.8%) (NRCan 2021). The total project cost was approximately C$1.35 billion, of which approximately 9% was covered by the Canadian government and 55% by the Alberta provincial government (MIT 2016c). The plant also generates revenue through offset credits under Alberta's emissions trading scheme (Technology Innovation and Emissions Reduction Regulation).

The planning, construction and commissioning phase of the project lasted a total of 6 years and started in 2009 (NRCan 2021). Approximately 22 months elapsed between the submission of the project application and the granting of approval (MIT 2016c). The components of the process chain were subject to CEAA screening (*Canadian Environmental Assessment Act*) and EPEA (*Alberta Environmental Protection and Enhancement Act*) due to the use of federal funding. Central contents of the project application mainly included an environmental impact assessment, a measurement, monitoring and verification plan as well as reports on the stakeholder consultations conducted. To assess the site risks of carbon storage (regulated under the Carbon Sequestration Tenure Regulation), particular consideration was given to the risk categories of air quality, public health and safety, emergency planning, injection well safety, acid gas storage system, and risks of accidents, malfunctions and unplanned events. During the 20-month review and approval process, updates, amendments, errors, supplementary information requests from regulators, submissions from dispute resolvers and responses were documented in a total of approximately 4,000 pages in 400 documents (Larkin et al. 2019b). In addition, since commissioning, Shell has published extensive information on performance, monitoring activities and metrics, and operationally relevant changes in relation to all stages of the CCU/S chain (splitting, transport and storage). With regard to storage, the results of the emission indicators and the results of the hydrological and geological investigations are also published (NRCan 2021). Construction of a pipeline at a depth of 1.5m started in 2013. Safety requirements included the installation of interruption valves and flow meters for leak detection, regular on-site monitoring and proactive corrosion management (NRCan 2021).

3.5 Current debates

3.5.1 Social acceptance

Several surveys have been conducted on the acceptance of CCU/S projects in Canada, most of which date back several years, but still offer insight into the challenges and possible solutions to increase social acceptance of CCU/S projects.

A University of Ottawa study found that according to interview participants, CCU/S meets the criteria for "clean tech" (Larkin, Bird & Gattinger 2021). In the course of the evaluation, it was found that communicating the fact that CCU/S is not only suitable for fossil fuel use and production, but also offers many potential applications for decarbonization in hard-to-abate sectors, is crucial for better public understanding. Demonstration and effective communication of current and potential future success stories is also central to CCU/S technological and economic progress.

Another study uses a representative survey of 1,479 Canadians to examine descriptive statistics to understand public perceptions and analyse the relationship between risk perceptions, views on climate change, and trust in government and support for or opposition to CCU/S technology development and funding (Boyd et al. 2017). The results show that support for CCU/S in Canada is low. However, results vary when participants' proximity to projects is considered (61.4% oppose CCU/S projects within 25 km, 8.9% would support a CCU/S project, 19.7% are neutral, and 9.9% do not know). The results show four main facts:

- Support is independent of gender, education or income;
- Low level of awareness of CCU/S: more knowledge leads to more acceptance;
- Positive perceptions correlate with support for technology;
- 40% of respondents believe that the government should fund the development of this technology, with around 30% not sharing this view and 30% were unsure about this.

According to the experts interviewed, acceptance on the part of the population varies on the one hand with the actual localization of the projects and on the other hand with the proximity of the interviewees to the project sites. Practical experience supports these findings: in regions with a high population density in particular, comparatively extensive measures to involve the population have been implemented in the past (e.g. QUEST), while resistance from the population was low in the case of the Boundary Dam project. Moreover, projects will extend into indigenous areas, which is why indigenous people will also have to be sufficiently involved in the future. The increasing number of projects and the resulting cumulative impacts (e.g. possible accidents) will also show to what extent they can affect the trust of the population.

But CCU/S technology also continues to be debated at the political level. In 2021, over 500 organizations, including Canadian environmental and legal associations, but also the Taxpayers' Alliance, expressed deep concern about government support for CCU/S technologies and wrote an open letter to policymakers. They criticized CCU/S for not contributing to solving the climate crisis. The technology is (1) not necessary, as renewable energy is available as an alternative, (2) not functional, as it does not deliver on its promises, (3) not economic, as it only contributes to reducing industrial emissions and investments should flow into renewable energy, (4) it would cause more emissions and other pollutants through capture, (5) pose an additional risk to communities through transport and storage, and (6) favour polluters, as mainly the oil and gas industry benefits (CIEL 2021).

3.5.2 Enhancement of the regulatory framework

A central topic regarding the further development of regulation in Canada is the discussion about the entry into force of the amended ***Impact Assessment Act*** (IAA). With the amendment in 2019 (POC 2019), important adjustments were implemented from the perspective of environmental organizations, e.g. the first mandatory environmental impact assessment in Canada, in which environmental and social impacts of infrastructure projects (including pipelines, mining) must be addressed (EDC 20.03.2023). However, after the province of Alberta filed a lawsuit, the IAA was deemed unconstitutional because it posed an existential threat to provincial rights and interfered with provincial rights under the Constitution Act (GOS 20.03.2023). For this reason, the IAA is currently being renegotiated, which could overturn the mandatory federal regulation to conduct an environmental impact assessment. Most provinces support this process.

Despite Alberta's intervention in the IAA, supposedly driven by oil and gas industry interests, the province's regulatory framework for CCU/S projects is a model for the rest of the provinces, which do not yet have a regulatory framework for such projects or still have a moratorium on CCU/S projects. **Ontario** plans to develop a regulatory framework for CCU/S that supports the industry, contributes to innovation in the sector and reduces emissions (GOO 11.04.2023). The plan is to have a ready-made regulatory framework in 2025. As a first step, proposals have been made to lift the bans on CO_2 injection under the Oil, Gas and Salt Resources Act so that they can be used in oil and gas production (Resilient LPP 11.03.2022). It also aims to strengthen corporate accountability and allow the issuance of orders to prevent risks to the environment and the public. **Québec** also expressed intentions in 2016, with the support of the province of Saskatchewan, to expand its expertise and promotion of CCU/S technologies (CU 17.06.2016). Pilot projects are being developed to verify the suitability of the underground in the region (CCJ 16.09.2021). However, adjustments to the regulatory framework are also being discussed further in **Alberta.** For example, the government plans to impose requirements on license owners, such as ensuring open and affordable access to CO_2 infrastructure/ hub use and fair and reasonable cost recovery for the contract holder (Rogers et al. 2023).

With regard to **liability issues,** a 2019 report by the Global CCS Institute identified four key areas for further regulatory development (Global CCS Institute 2019): (1) the inclusion of a minimum period after closure to issue the certificate of closure, (2) the establishment of performance criteria for the closure of storage sites, (3) the transfer of CO_2 credits to the Crown (represented by the government) following the transfer of liability after closure, and (4) operator obligations on financial expenditures and securities following the closure and recultivation of a site.

In Canada, there is also a geographical dimension to the issue. The largest emitters tend to be located in the industrialized east of Canada, but the more suitable underground formations for storing CO2, as well as the specialist expertise from the oil and gas industry, are located in the west of the country. To address this **distribution problem**, there is discussion in Canada about whether captured CO2 should be transported across the country via pipelines in the future or whether storage in the provinces in the east of the country should be considered. As previously described, the development of regulation and exploration of suitable storage horizons is therefore being pursued in the eastern provinces. However, the regulatory and possible liability issues in the expansion of pipeline systems across several provinces or states are partly unresolved. In the event of a leak in a cross-provincial pipeline, both operators and authorities of the respective provinces would be involved in the process. Currently, a proposal to build an Alberta Carbon Grid (ACG) from 2021 is being discussed (ACG 2023). In this proposal, a 650 km pipeline network is to be built, which will bring together several industrial CO_2 sources (mainly from the oil sands industry) across the provinces. This project promises to engage with relevant government regulators during implementation to ensure safe transport.

3.5.3 Market development

So far, large-scale demonstration projects for the storage and use of CO_2 have dominated in Canada. All projects were dependent on state funding mechanisms and are not economically viable on their own. In order to further develop the market for CO_2 storage and use, reference is often made in Canada to the **CO_2 price.** There are different views on the extent to which a sufficient CO_2 price leads to the possible self-financing of projects and the resulting possibility of commercial application of CCU/S projects. According to some stakeholders in Canada, the targeted CO_2 price of C$170/t CO_2 in 2030 corresponds to the calculated break-even point for CCU/S projects. However, other representatives do not share this view and do not believe that CCUS projects can be realized in the future without financial government support. It is stressed that further tailor-made entrepreneurial incentives need to be created in order to achieve commercialization of such projects. The flexibility of the incentives that are currently being created will be crucial for this. For example, the Tax Credit now covers half of the project costs and, in combination with the CO_2 price, must ensure that projects become profitable. In the future, both EOR and pure geological storage projects will be developed, although due to better acceptance, the application for hard-to-abate sectors seems more appropriate. The oil and gas sector nevertheless want to continue investing in CCU/S, even if the government is reluctant to approve such projects, which only mitigate emissions and do not reduce them, and therefore prefers cooperation with other sectors.

In addition to the existing large-scale demonstration projects, **mainly smaller projects** are currently being planned. These include, for example, a hub for the capture, use and storage of CO2 near a cement plant in Edmonton (Alberta), in which 1 million t of CO_2 from the cement production and the combined heat and power plant integrated in the capture process are to be stored annually (Alberta 2023). In British Columbia, the construction of a commercial plant is planned to produce fuel from atmospheric CO2 (CE 14.10.2021). This will use special DAC technologies to produce up to 100 million liters of low-carbon fuel. In addition, some projects for the **use of CO_2** are also being planned.

To drive market development, there are networks and special support programs for so-called carbontech start-ups. The "carbonNEXT" network supports Canadian innovation through acceleration programs, industry-related innovation programs, investor and showcase events, sector-specific training and fund development offerings, as well as research and marketing campaigns to reduce barriers and encourage investment. Emerging CCU/S technology developers and service providers are a mix of technology start-ups, consultancies and existing energy service companies from the oil and gas industry.

It should be noted that market development in Canada is **actively supported** to increase the number of innovative technology providers. In addition, the focus is also on the development of smaller CCU/S plants and less on the development of large demonstration sites.

4. Conclusion

- Both the literature and interviews regularly emphasize the central role of a **consistent and binding regulatory framework** for CCU/S projects. In North America, regulation has evolved gradually with the CCU/S market, which has sometimes led to uncertainty - for example, the final regulations for Class VI wells were not yet known at the time the first large-scale project in Illinois was designed. In some areas regulatory uncertainties still exist today for this reason, which can have a detrimental effect on the duration of approval procedures and investment security. Since many different areas of law are affected due to the complexity of the projects, this requires a particularly high degree of coordination.
- The basis for this should be a **clear overarching strategic and political vision** about the goals and purpose of the technology in the respective regional context. Several interviewees pointed out that the motivations for supporting or rejecting CCU/S in North America are highly diverse and in part strongly driven by particular interests. For example, CCU/S in conjunction with state subsidies is seen in part as a vehicle for continuing to operate otherwise unprofitable coal-fired power plants. The continued promotion of EOR in the USA also points in this direction.
- **Social acceptance** is of paramount importance, especially for pipeline transport and injections. Experience from North America shows that insufficient or delayed public involvement can pose massive challenges to project developers. Even if there are no patent solutions in this area, an active dialogue with affected communities and groups at the earliest possible stage - and, if necessary, taking regional interests into account - can be considered a necessary condition for successful project implementation.
- The operation of CCU/S projects will not be economically viable in the foreseeable future without **additional stimuli**, despite the trend of falling costs**.** These can be in form of CO_2 pricing, targeted subsidies for project development and operation (as in the USA) or a combination of both (as in parts of Canada). In this context, some experts point out that it can make sense to prioritize the areas with the lowest capture costs (cf. 1.2) in order to accelerate the market ramp-up.
- With regard to the expertise and effort required for the **exploration of geological storage sites**, reference is often made to the advantages gained from experience in the extraction of mineral resources, which are particularly relevant in the North American context. This includes the availability of data on the geological characteristics of certain areas, but also the accessibility of skilled labor.
- The present study is a **general overview** of the situation in North America. Given the complexity of the topic, not all aspects can be dealt with exhaustively in this framework, such as the emerging different liability regimes in different US states and Alberta, or the issue of verification, which is already more advanced in California in particular. Depending on the need for further information, it could make sense to examine these or other topics separately in greater depth.

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Appendix

Table 6 Large-scale CCU/S pro jects in Canada

Project	Provin ce	Stage of the process chain	CO -source₂	Location	Amount of CO_2
Boundary Dam Carbon Capture Project (in operation)	Saskat chewan	CO_2 capture (Armin-based absorption)	Coal-fired power plant	Oil sand fields EOR <10% for testing purposes in Aquistore project	1 Mt/a 41 km Pipeline to Weybourn Field
Alberta Carbon Trunk Line (in operation)	Alberta	CO_2 -transport via pipeline	Various sources (e.g.: oil sands refinery and fertiliser production).	Oil reservoir EOR	240 km long pipeline 14.6 mio t CO2/a capacity
Weybourn-Midale Project$_2$CO (in operation)	Saskat chewan	Storage via EOR	Coal gasification and power generation in North Dakota, USA	Carbonate fields EOR	3 Mt/a (Transport via souris valley pipeline)
Quest Carbon Capture and Storage Project (in operation)	Alberta	Entire chain: CO_2 -separation from refinery -> transport -> storage in aquifer	Methane reforming (Armin-based absorption)	Aquifer	1.1 Mt/a 65 km pipeline Storage in porous rock formations
Genesee CCS Project (under construction)	Alberta	Entire chain: CO_2 capture (coal-fired power plant) + transport to industrial hub?	Coal-fired power plant	Nanotube production	Target 3 Mt/a

Table 7Overview of the requirement criteria within the process chains and project phases and the associated guidelines in Alberta.

Directive	Process chain / project phases	Requirement criteria
020	Deconstruction of injection wells	Requirements for abandonment of wells, removal of casing, abandonment of individual zones, and cementing and decommissioning of injection wells
051	Injection and disposal wells: Well types, completion, measurements and tests	Well design requirements, well integrity measurements, operational monitoring and reporting for the use of injection wells
056	Applications and timetables for energy production	Requirements for facilities and pipelines carrying CO_2 and requirements for wells injecting CO_2
065	Applications in oil and gas reservoirs	Requirements for CCS and CCUS process underground
071	Emergency preparedness and response requirements in the petroleum industry	Requirements for the preparation and implementation of an emergency plan
087	Well integrity management	Requirements for testing, reporting and repairing insulation packers, venting currents in the casings, gas migration and well failure.

Table 8: Regulatory differences in the approval of CCS and CCUS projects in Alberta (Policy 065).

Unit 2 (CCS)	Unit 4 (CCUS)
Definition of storage capacity and estimation of injectivity	Definition of storage capacity, inclusion potential and estimation of injectivity
Development of models and execution of simulations to predict the spatial expansion of CO_2 in the free phase (incl. prevailing pressure gradients over the life cycle)	Develop models and run simulations to predict the spatial expansion of CO_2 in the free phase (incl. prevailing pressure gradients over the life cycle and the maximum connected pore volume).
Prediction of the behavior of the hydrocarbon CO_2 phase	Calculation of the maximum injected fluid volume
Confirmation on the safety and effectiveness of the proposed system	Determination on the safety and effectiveness of the proposed system
Preparation of a site-specific risk assessment that enables thorough risk management over the entire life cycle	
Establishing baseline conditions for the design and implementation of a monitoring program	
Assessment of risks associated with storage and remediation strategies in the event of loss of containment	

Table 9Overview of necessary permits for offshore applications.

Process chain	Location	Permits required	Government agency	Comments
CO - separation $_2$	Territorial Sea	Seabed license (platform anchored to seabed)	NRCan	There is no law that explicitly allows for the licensing of offshore DAC platforms on the seabed. The NRCan has indicated that licenses could be issued under the Federal Real Property and Federal Immovables Act (FRPFIA), but this is uncertain. New legislation may be required.
		Permit under the Canadian Navigable Waters Act (CNWA)	Transport Canada	There is a set procedure for issuing permits under the CNWA. Permits issued are subject to the installation of warning devices on the platform for vessel traffic.
	EEZ / Continental Shelf	Seabed license (platform anchored to seabed)	NRCan	There is no law that explicitly allows the licensing of offshore DAC platforms on the seabed. No licenses can be issued under the FRPFIA for the use of the continental shelf. New legislation may be required.
CO_2 pipeline	Territorial Sea	License for the seabed	NRCan	There is no law that explicitly allows the licensing of seabed carbon dioxide pipelines. The NRCan has suggested that licenses could be issued under the FRPFIA, but this is uncertain. New legislation may be needed.
		Certification within the framework of CERA	CER	There is a set procedure for the certification of pipelines. Depending on the size of the pipeline and its location, an impact assessment may be required before certification.

	EEZ / Continental Shelf	License for the seabed	NRCan	No law explicitly allows for the licensing of CO_2 pipelines on the seabed. No licenses can be issued under the FRPFIA for the use of the continental shelf. New legislation may be required.
		Certification within the framework of CERA	CER	There is a set procedure for the certification of pipelines. Depending on the size of the pipeline and its location, an impact assessment may be required before certification.
CO_2 injection	EEZ / Continental Shelf	License for the seabed	NRCan	There is no law that explicitly allows the issuing of licenses for the injection of carbon dioxide on the seabed. No licenses can be issued under the FRPFIA for the use of the continental shelf. New legislation may be required.
		Canadian Environmental Protection Act ("CEPA") Permit	Environment and Climate Change Canada	No permits can be issued for the injection of carbon dioxide under the seabed.

Table 10 Large-scale CCU/S projects in the USA

	Name, place	CO2 source	CO2 use	CC capacity	CO2 transport	Runs since
Texas	Air Products Steam Methane Reformer, Port Arthur	SMR	EOR	1.0 Mtpa	The CO2 is then delivered to Denbury's Green Pipeline Texas via a 12-mile interconnector pipeline. The CO2 is transported 101-150 km before being injected into Denbury's onshore operations for EOR.	2013
Texas	Terrell Natural Gas Processing Plant (formerly Val Verde Natural Gas Plants)	Natural gas processing	EOR	0.4-0.5 Mtpa.	Val Verde Pipeline to McCamey, Texas, from there connection to other pipelines.	1972
Texas	Century Plant	Natural gas processing	EOR	5.0 Mtpa	Pipeline transport to the Permian Basin (West Texas/New Mexico)	2010
Texas	Petra Nova Carbon Capture Project, near Houston	Gas and coal-fired power plant	EOR	1.4 Mtpa	The captured CO2 will be transported via pipeline to an oil field near Houston for enhanced oil recovery.	2017 (operation suspended since 2020)
Louisiana	PCS Nitrogen	Fertiliser production	EOR	0.2-0.3 Mtpa	Captured CO2 sold to Denbury Resources, transported via pipeline and used for EOR. No exact details about pipeline properties	2013
Oklahoma	Enid Fertilizer (Koch Fertilizer Facility)	Fertiliser production (nitrogen)	EOR	0.2 Mtpa	Onward transportation for EOR in southern Oklahoma	1982
Kansas	Arkalon CO_2 Compression Facility	Ethanol production	EOR	0.29 Mtpa	Onward transportation for EOR at Farnsworth Oil Field Texas, USA	2009

Kansas	Coffeyville Gasification Plant	Fertiliser production	EOR	0.9 Mtpa	CO_2 will be transported via 70 miles of pipeline, to Coffeyville's North Burbank unit in Osage County	2013
Kansas	Bonanza BioEnergy CCUS EOR	Ethanol production	EOR	0.1 Mtpa	CO captured during ethanol production$_2$ is used for EOR at Stewart Field.	2012
Illinois	Illinois Industrial Carbon Capture and Storage, Decatur	Ethanol production	Geological storage	1 Mtpa	Pipeline to the nearby Mt. Simon Sandstone	2017
Wyoming	Shute Creek Gas Processing Plant	Natural gas processing	EOR	7 Mtpa	Pipeline transport to oil production sites in Wyoming and Colorado. In August 2022, ExxonMobil Corp. received approval from the US Bureau of Land Management (BLM) to expand the CCUS at its LaBarge, Wyoming facility.	1986
Wyoming	Lost Cabin Gas Plant	Natural gas processing	EOR	0.9 Mtpa	The Lost Cabin Gas Plant delivers CO_2 to compression facilities near the plant to enable CO_2 transport by pipeline. Since 2013, CO_2 has been delivered via a newly built pipeline to the Bell Creek oil field in Montana, where it is used for EOR.	2013 (stopped since 2018 due to fire) tbc.
North Dakota	Red Trail Energy CCS	Ethanol production	Geological storage	0.18 Mtpa	Storage nearby in the Broom Creek Formation, transport method unknown.	2022
North Dakota	Great Plains Synfuels Plant and Weyburn-Midale	Coal gasification	EOR	3 Mtpa	Pipeline transport to Saskatchewan, Canada (Weyburn Oil Unit, Midale Oil Unit) for EOR	2000
Michigan	Core Energy CO_2 - EOR, Otsego County	Natural gas processing	EOR	0.35 Mtpa	Not specified	2003

Sources: GCCSI 2022a; IEA 2023; GCCSI 2023.