# MEETING THE DUAL CHALLENGE

## A Roadmap to At-Scale Deployment of CARBON CAPTURE, USE, AND STORAGE

## CHAPTER TWO – CCUS SUPPLY CHAINS AND ECONOMICS

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# Chapter Two

# CCUS SUPPLY CHAINS AND ECONOMICS

## I. CHAPTER SUMMARY

Carbon capture, use, and storage (CCUS) is an essential element in the portfolio of solutions needed to meet the dual challenge of providing affordable and reliable energy while addressing the risks of climate change. The CCUS supply chain involves the capture—separation and purification—of carbon dioxide ($CO_2$) from stationary sources so it can be transported to a suitable location where it is used to create products or injected deep underground for safe, secure, and permanent storage. Stationary $CO_2$ emissions are generated at fixed points and include sources such as power generation and industrial processes.

This chapter will describe the CCUS supply chain and relevant deployments in the United States. The focus on the United States will continue by describing CCUS supply chain enablers as well as the costs associated with at-scale deployment.

In 2019, there were 19 large-scale CCUS projects operating around the world with a total capacity of about 32 million tonnes per annum (Mtpa) of $CO_2$.[1] Ten of these projects are in the United States with a total capture capacity of about 25 Mtpa.

Six of the U.S. projects were enabled by market factors that included availability of a low-cost $CO_2$ supply and a demand for $CO_2$ by enhanced oil recovery (EOR) and food industries. The four remaining projects required significant policy support to be economically viable.

1 Large-scale as defined by the Global CCS Institute.

This chapter will provide a brief description of each U.S. project and what enabled its deployment, as well as the level of incentive needed to achieve at-scale deployment of CCUS in the United States. The United States has a history of developing the legal and regulatory framework needed to enable CCUS projects. Although this chapter mentions that framework, a more detailed discussion about what is required to support at-scale deployment in the United States appears in Chapter 3, "Policy, Regulatory, and Legal Enablers."

In 2019, the United States had more than 6,500 large stationary sources emitting approximately 2.6 billion tonnes of $CO_2$ per year across multiple industrial sectors. These sources represent nearly 50% of the total U.S. $CO_2$ emissions. Although these sources are distributed across the country, many are located near geologic formations suitable for $CO_2$ storage.

The United States has one of the largest known $CO_2$ geological storage capacities in the world. Most states in the continental United States possess some subsurface $CO_2$ storage potential. Though estimates vary, experts generally agree that the geologic resource would be able to store hundreds of years of $CO_2$ emissions from U.S. stationary sources.

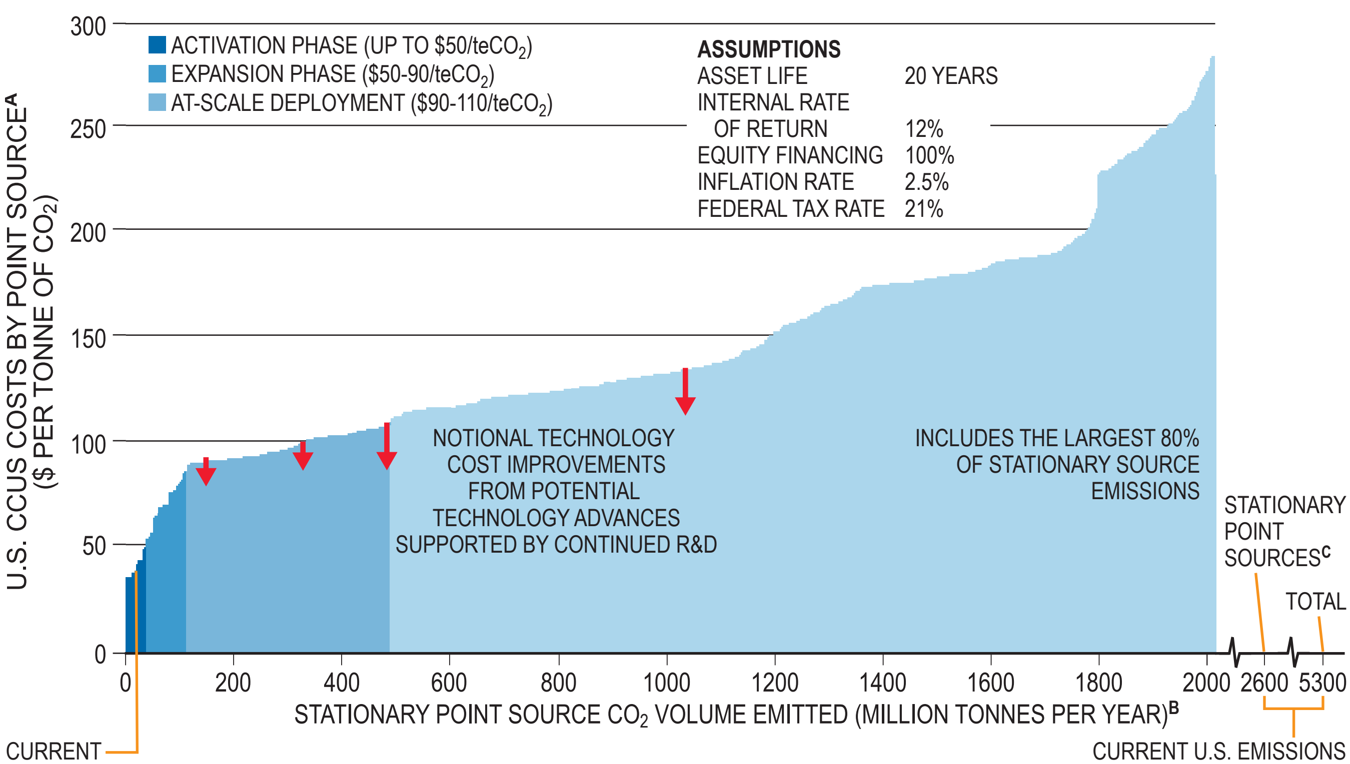
In 2019, there were more than 5,000 miles of $CO_2$ pipelines transporting more than 70 Mtpa of $CO_2$ from both natural and anthropogenic sources. With approximately 85% of the world's $CO_2$ pipelines and 80% of the world's $CO_2$ capture capacity, the United States has established itself as the world leader in CCUS deployment. However, the 25 million tonnes of CCUS capacity in the United

States represents an application to less than 1% of the $CO_2$ stationary sources. Accordingly, the potential for further deployment is significant.

As discussed in Chapter 1, "The Role of CCUS in the Future Energy Mix," U.S. stationary sources of $CO_2$ emissions include power plants, refineries and petrochemical plants, pulp and paper production, natural gas processing, ammonia production, industrial hydrogen production, industrial furnaces (including steel blast furnaces), cement plants, and the ethanol industry. For many of these source types, CCUS is a viable solution to enable emissions reduction.

There must be an economic incentive for all participants in a CCUS supply chain—from emission source and capture to transport and storage—to establish a CCUS project. Creating a supply chain will require significant capital investment and ongoing operating expenses. Furthermore, the costs at each stage are dependent on supply chain-specific circumstances that vary with each CCUS project. Capture costs vary with $CO_2$ concentration, while transport costs vary based on the volume, distance, and terrain over which $CO_2$ is transported. Storage costs also vary depending on location and nature of the storage formation. The variety of $CO_2$ sources, capture processes, transportation methods, and end uses makes many supply chain configurations possible.

This National Petroleum Council (NPC) study assessed the costs to capture, transport, and store $CO_2$ emissions from 80% of the largest U.S. stationary sources. These results are presented in a $CO_2$ cost curve (Figure 2-1), where the cost to capture, transport, and store one tonne of $CO_2$ from each of the largest 80% of stationary sources is plotted against the volume of $CO_2$ abated from that source. This chapter provides a detailed description of the assumptions used to develop




Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total $CO_2$ emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

***Figure 2-1.*** *U.S. CCUS Cost Curve with $CO_2$ Capture Volume by Phase* the cost curve and the types of CCUS projects that could be enabled in the future by implementing the recommendations of this study.

There are three transition points on the cost curve that align with three phases of CCUS deployment projected to occur over a 25-year period to achieve at-scale deployment in the United States. The activation phase requires clarification of existing policies and regulations with current financial incentives of about \$50/tonne of $CO_2$ to enable an additional 25 Mtpa to 40 Mtpa, doubling existing U.S. CCUS capacity within the next 5 to 7 years. The expansion phase broadens existing policies and increases financial incentives to \$90/tonne of $CO_2$. Combining greater financial incentives with a durable regulatory and legal environment could enable an additional 75 Mtpa to 85 Mtpa within the next 15 years. The at-scale phase requires increasing the level of incentives up to about \$110/tonne of $CO_2$, which could drive total U.S. CCUS capacity to approximately 500 Mtpa within the next 25 years.

Although the NPC does not expect CCUS will be applied to all U.S. stationary sources, achieving 500 Mtpa of U.S. CCUS deployment means that CCUS would be deployed on nearly 20% of U.S. stationary emissions, which is a level the NPC has defined as widespread or "at-scale" deployment. It is also worth noting that at an incentive of about \$150/tonne, CCUS could be economically applied to about 1.2 billion tonnes of $CO_2$ emissions, which is just under half of all U.S. stationary emissions and nearly a quarter of total U.S. $CO_2$ emissions.

The specific policy and regulatory improvements and types of stakeholder engagement needed to deploy CCUS within each of the defined phases are detailed in Chapters 3 and 4 respectively.

## II. THE CCUS SUPPLY CHAIN

The CCUS supply chain involves the capture (separation and purification) of $CO_2$ from stationary emissions sources so that it can be transported to a suitable location where it is converted into useable product or injected deep underground for safe, secure, and permanent storage (Figure 2-2).

The CCUS supply chain can take many forms depending on the emissions source, capture technology, transport option, and use or storage disposition. Figure 2-3 uses a Sankey flow diagram to show the breadth of supply chain combinations that can occur with CCUS. A Sankey diagram is a directional flow chart where the width of the streams is proportional to the quantity of flow, and where the flows can be combined, split, and traced through a series of events or, in this case, elements of the supply chain. In this diagram, the width of each link is an illustrative proportion of each component of the existing supply chain. This diagram is intended to show the possible supply chain configurations and does not account for future, or low technology readiness level (TRL), capture technologies currently in development.

While Figure 2-3 shows the possibility of many different supply chain configurations that could be developed to achieve at-scale deployment of CCUS, it also highlights that many of the components have already been demonstrated in the United States.

A description of each step in the CCUS supply chain follows.

### A. Source

$CO_2$ is emitted from a wide range of sources across a broad range of industries. The original source of the carbon in the $CO_2$ is the carbon present in a wide variety of feedstocks used in natural and industrial processes to create and supply the products necessary for modern life. These industrial processes release some or all of the $CO_2$ generated.

- Biomass absorbs carbon from the air as it grows and can be used to generate liquid fuels, such as ethanol, or burned to create heat and power.
- Natural gas is produced and then processed (natural gas processing) to remove $CO_2$ to meet use specifications. Natural gas can be:
  - Used to generate electricity in power plants
  - Used to provide heat and energy in industrial furnaces and stoves

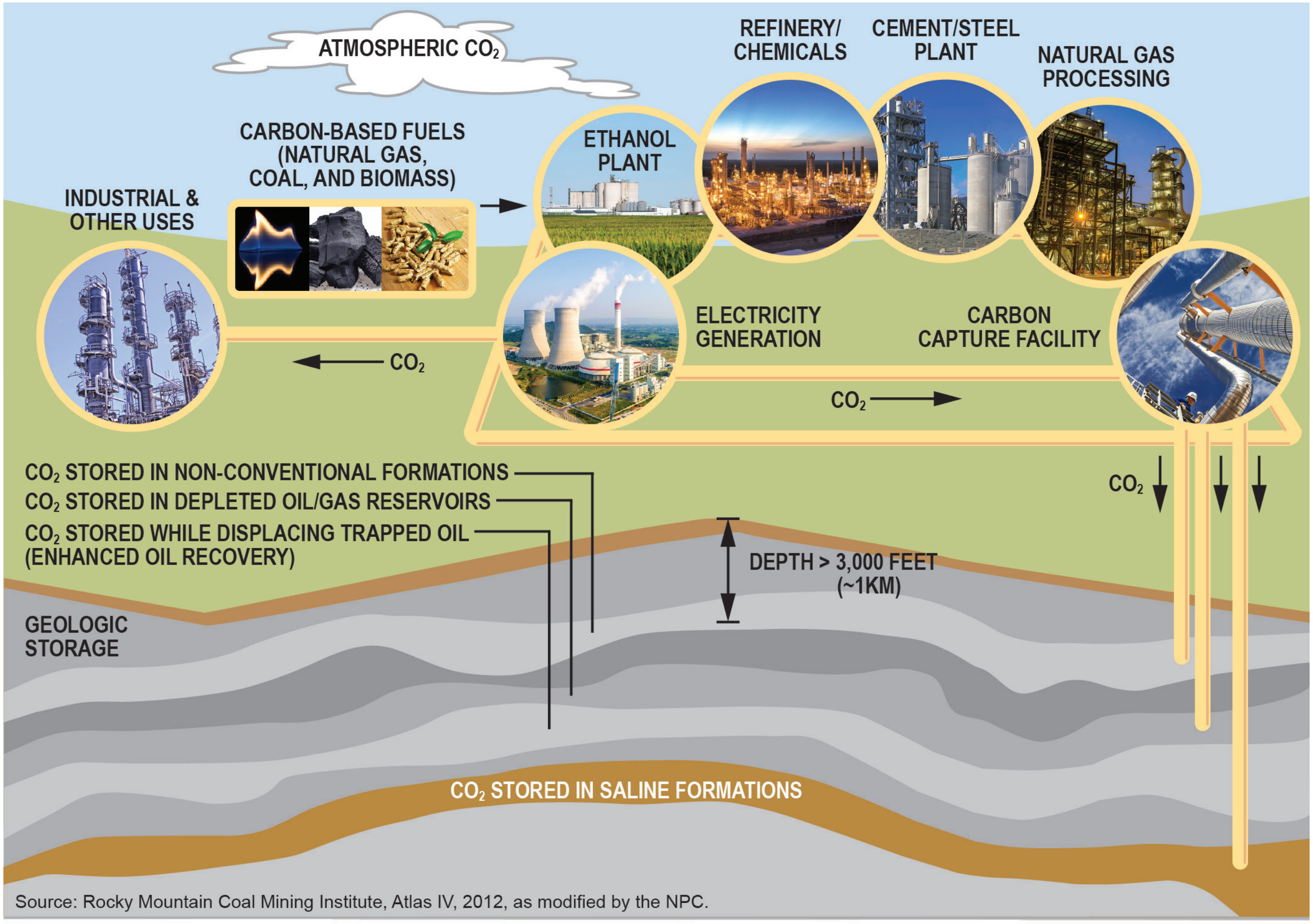



***Figure 2-2.*** *Supply Chain for Carbon Capture, Use, and Storage*

  - Separated to make hydrogen for use in industrial processes and refining, and for the creation of chemicals such as ammonia
  - Used in the production of cement.
- Coal is predominantly burned in power plants to generate electricity, although it is also used to provide high temperature heat to industrial furnaces, steel furnaces, and cement plants.
- Crude oil is processed at refineries to generate gasoline and other hydrocarbon-based products.
- Municipal trash can be burned to generate electricity or gasified and converted to liquid fuels such as diesel and jet fuel.
- $CO_2$ is released from limestone as it is heated to produce cement.
- $CO_2$ is also present in ambient air. This $CO_2$ can be removed from the air through direct air capture technologies.

In these sources, industries, and processes, $CO_2$ is produced in a variety of volumes and concentrations. Some processes, such as natural gas processing, ethanol fermentation, and ammonia production, create streams that have concentrations of 95% to 100% $CO_2$. The concentrated streams produced from these facilities typically require no separation and only dehydration and compression before transport.

Most of the other processes considered in this study produce lower concentration streams that will require further separation before dehydration and preparation for transport. Typical $CO_2$ concentrations are as follows:

- Industrial hydrogen plants: 15% to 95%
- Steel blast furnaces: ~26%
- Cement plants: ~20%
- Refinery fluidized catalytic crackers: ~16%

- Coal power plants: ~13%
- Industrial furnaces: ~8%
- Natural gas power plants: ~4%.

## B. Capture

$CO_2$ is produced in combination with other gases during industrial processes, including hydrocarbon-based power generation. $CO_2$ capture involves the separation of the $CO_2$ from these other gases. This step, which can represent around 75% of the cost of the CCUS supply chain for low concentration streams, presents the largest opportunity to apply technological innovation to help reduce overall cost. Oil and natural gas producers have decades of experience in separating $CO_2$ from hydrocarbons, and other industries are making progress in separating $CO_2$ from their own process streams.

The separation of $CO_2$ can be accomplished through the application of four main $CO_2$ capture technologies:

- Absorption, which is the uptake of $CO_2$ into the bulk phase of another material
- Adsorption, which is the uptake of $CO_2$ onto the surface of another material
- Membranes, which selectively separate $CO_2$ primarily based on differences in solubility or diffusivity
- Cryogenic processes, which chill the gas stream to separate $CO_2$.

Each technology offers advantages and challenges associated with implementation in different industries. Absorption has been utilized as the primary means of separating $CO_2$ from gas mixtures for more than 40 years and is by far the most widely applied of the main capture technologies today. As a result, absorption is substantially more mature than other capture technologies and is expected to be the primary choice for separation in the near- to mid-term.

The appropriate carbon capture technology to use in an industrial application depends on the size (i.e., volume) of the source gas stream to be handled, the concentration of $CO_2$ and the contaminants in the gas mixture, the pressure and temperature of the mixture, the percent of $CO_2$

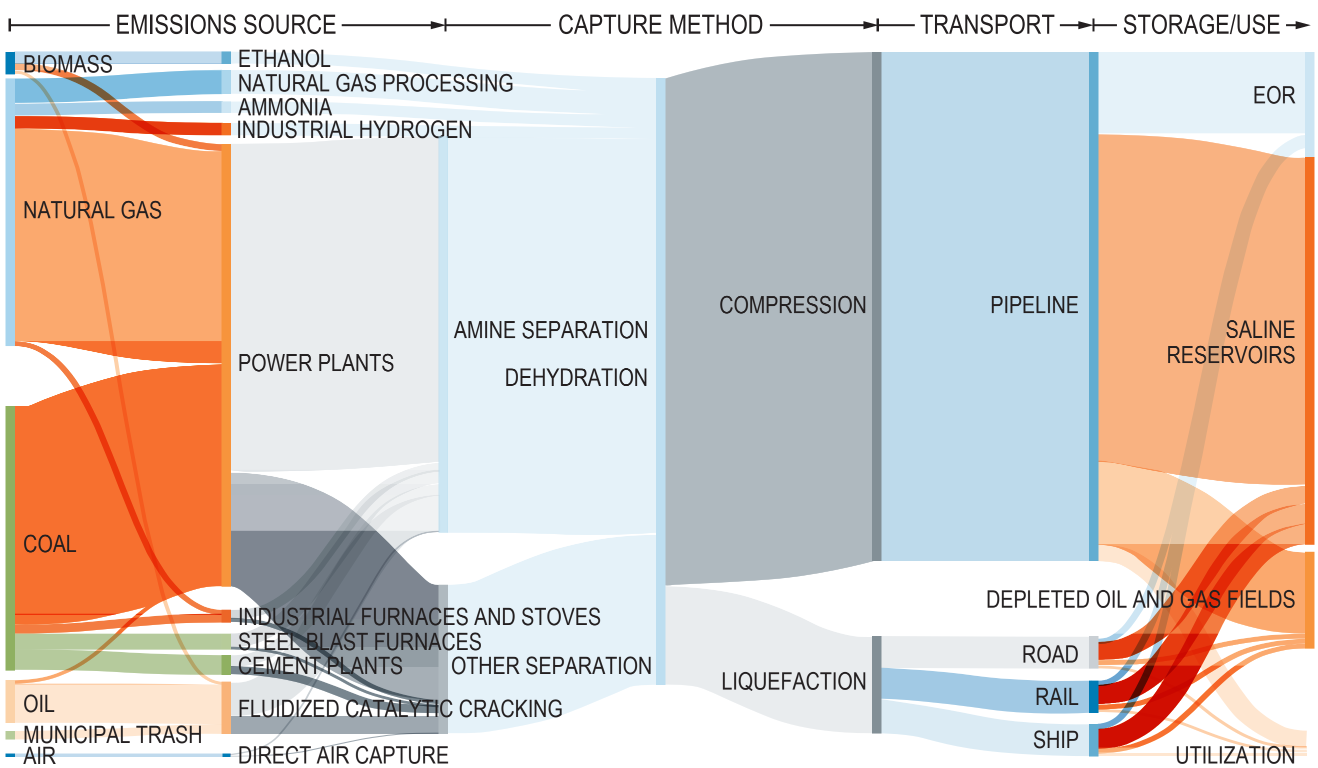



*Figure 2-3. Illustrative Sankey Diagram of CCUS Supply Chain*

| Separation Process | Absorption | Adsorption | Membranes | Cryogenic | Compress and Dehydrate |
|---|---|---|---|---|---|
| Electric Power Generation | X | | R | T | X |
| Petroleum and Coal Products | X | | Z | T | X |
| Pulp and Paper | R | | | T | X |
| Cement Manufacturing | X | | R | T | X |
| Chemical Manufacturing | X | Z | | T | X |
| Iron and Steel | X | | Z | T | X |
| Oil and Natural Gas Processing | X | Z | Z | T | X |
| Pesticide, Fertilizer, Agricultural Chemical Manufacturing | X | Z | | | X |
| Bioethanol Fermentation | | | | | X |

Key: X = primary, Z = secondary, R = research/demo, T = theoretical.

***Table 2-1.*** *Application of Various Separation/Capture Processes in Selected Industries*

to be captured, and the purity of the $CO_2$ desired downstream of the capture process. Each of these considerations will influence determination of the optimum technology, and the associated costs of $CO_2$ capture.

A summary of the industries for which the four separation/capture methods may be employed is provided in Table 2-1. Absorption has the widest range of applicability given the decades of deployment experience that exist with absorption technologies (especially amine scrubbing). Adsorption and membrane technologies offer potential solutions for some industries, although application to date is generally less mature. Finally, cryogenic $CO_2$ capture is at the earliest stage of application but does have potential across several industries.

## C. Transport

In most cases, captured $CO_2$ will need to be transported from the capture location to a location where it can be stored or utilized. Typical modes of transportation are as follows:

- Pipelines are generally the most cost-effective method of transporting large volumes of any fluid, including $CO_2$. In most cases, $CO_2$ is compressed into a dense phase, referred to as a supercritical fluid, before entering a pipeline system. In this state, $CO_2$ can be pumped like other liquids

- Railcars may be cost effective for small to medium volumes of $CO_2$ over longer distances if there are existing rail routes from near the source to the vicinity of the storage. Rail transport may require construction of a liquefaction facility at the point of origin

- Trucks may be cost effective for very small volumes of $CO_2$ traveling short distances. Like rail, trucking can take advantage of existing infrastructure, but also like rail, liquefaction facilities may be needed at the point of origin

- Ship and barge transport is technically feasible but has only been demonstrated in isolated instances. Ship transport of $CO_2$ could potentially move large volumes of $CO_2$ from source locations with limited storage capacity to locations with ample storage capacity located near waterways that can accommodate such vessels.

## D. Use

While most $CO_2$ captured over the next few decades will likely be stored, it can also be used to produce valuable products. Due to the limits of existing technology, $CO_2$ use will likely be an outlet for only a small fraction of the captured $CO_2$.

$CO_2$ use technologies convert $CO_2$ into valuable products like fuels, chemicals, and materials through chemical reactions and/or biological conversions. There are four primary technology pathways for $CO_2$ use and conversion:

1. Thermochemical $CO_2$ conversion
2. Electrochemical and photochemical $CO_2$ conversion
3. Carbonation (carbon mineralization) of $CO_2$
4. Biological $CO_2$ use.

Overall, $CO_2$ use is the least mature component in the CCUS technology chain. Yet it presents significant opportunities and multiple technology pathways for the development of processes to convert $CO_2$ from captured emissions and waste $CO_2$ into useful products.

## E. Storage

While there are multiple pathways to geologic storage, most of them involve the injection of $CO_2$ into carefully selected subsurface geologic formations for safe, secure, and permanent storage.

### 1. Geologic Storage

Safe and secure geologic storage of $CO_2$ requires that the injection formation have enough pore space, or porosity, within which $CO_2$ can be contained. The formation must also have enough pathways connecting this pore space, which defines its permeability, so that $CO_2$ can be injected and move within the formation. The storage formation also needs to have a geologic seal—an overlying layer of nonporous, impermeable rock that prevents the injected $CO_2$ from leaving the formation. To ensure that the $CO_2$ is stored as a supercritical fluid, which has benefits for storage security and efficient storage space utilization, formations need to be at a depth of about 1 km or more.

Examples of subsurface formations include saline formations, oil and natural gas reservoirs, and un-mineable coalbeds. Globally, there are more than 20 years of experience with $CO_2$ injection for large-scale (more than 1 Mtpa) geologic storage, such as the Sleipner gas field in the Norwegian sector of the North Sea. In the United States, small-scale projects have been operating for nearly as long, while the large-scale Illinois Industrial Carbon Capture and Storage Project has been operating since 2017.

### 2. Enhanced Oil Recovery

$CO_2$ can also be used to produce oil in a process known as enhanced oil recovery. During this process, $CO_2$ is injected into an oil reservoir and mixes with remaining oil, enabling it to flow more easily to a production well. Some of the injected $CO_2$ does not mix with the oil and becomes trapped in the reservoir. As the mixture of oil and $CO_2$ is produced, the mixed $CO_2$ is recovered from the oil and reinjected into the reservoir to repeat the closed-loop cycle. This process is repeated multiple times, with a portion of $CO_2$ being trapped within the reservoir during each cycle. Approximately 99% of the $CO_2$ used in EOR is ultimately trapped in hydrocarbon-producing geologic formations. Further details about each of the CCUS technologies described here can be found in Chapters 5 through 9 in Volume III of this report.

# III. EXISTING CCUS SUPPLY CHAINS IN THE UNITED STATES

In 2019, 19 large-scale CCUS projects were operating worldwide with a total capacity of ~32 Mtpa of $CO_2$. Ten of these projects totaling ~25 Mtpa of $CO_2$ are located in the United States and represent ~80% of global capacity. These projects span a range of CCUS supply chains from multiple industries, including natural gas processing (~17 Mtpa), synthetic natural gas production (~3 Mtpa), fertilizer production (~2 Mtpa), coal-fired power generation (~1 Mtpa), hydrogen production (~1 Mtpa), and ethanol production (~1 Mtpa). The Global CCS Institute estimates that these U.S. projects have captured and stored approximately 160 million tonnes of $CO_2$.

| Plant Name | Start Up Year | State | Operator | Capacity (million tonnes/ year) | $CO_2$ Source | Pipeline Connection (miles) | $CO_2$ Sink | Govt. Fund |
|---|---|---|---|---|---|---|---|---|
| Terrell Gas Processing | 1972 | TX | Occidental Petroleum | 0.5 | Natural Gas Processing | 220 | EOR | |
| Enid Fertilizer | 1982 | OK | Koch Nitrogen Company | 0.7 | Fertilizer Production | 120 | EOR | |
| Shute Creek Gas Plant | 1986 | WY | ExxonMobil | 7.0 | Natural Gas Processing | 142 | EOR | |
| Great Plains Synfuels | 2000 | ND | Dakota Gasification | 3.0 | Coal Gasification | 205 | EOR | $1.6B* |
| Century Plant | 2010 | TX | Occidental Petroleum | 8.4 | Natural Gas Processing | 100 | EOR | |
| Air Products SMR | 2013 | TX | Air Products | 1.0 | Hydrogen Production | 13 | EOR | $235M |
| Coffeyville Gasification | 2013 | KS | Coffeyville Resources | 1.0 | Fertilizer Production | 68 | EOR | |
| Lost Cabin Gas Plant | 2013 | WY | ConocoPhillips | 0.9 | Natural Gas Processing | 232 | EOR | |
| Illinois Industrial CCS | 2017 | IL | ADM | 1.0 | Ethanol Production | 2 | Saline | $141M |
| Petra Nova | 2017 | TX | NRG | 1.4 | Power Generation | 80 | EOR | $190M |

* Government funding was for construction of the synfuels plant, not $CO_2$ capture.

***Table 2-2.*** *Ten Large-Scale CCUS Projects Operating in the United States as of 2019*

Table 2-2 provides data for the 10 large-scale projects operating in the United States as of 2019. In addition to the projects listed in Table 2-2, there are also numerous pilot- and demonstration-scale projects that are operational in the United States.

Of the 10 projects, six were driven exclusively by market factors, including the availability of a low-cost $CO_2$ supply and demand for $CO_2$ from the EOR industry. For these six projects, a high concentration stream of $CO_2$ is produced as part of fertilizer production or natural gas processing. Accordingly, only dehydration, compression, and pipeline facilities are generally required to deliver $CO_2$ to EOR sites, greatly reducing the capital and operating costs. The remaining four projects involved more complex and costly $CO_2$ capture. As a result, all four projects required significant financial support through government policies.

The following is a brief description of the 10 U.S. large-scale projects, with a focus on the commercial drivers that enabled development. Additional details about each of the projects can be found in Appendix C, "CCUS Project Summaries," at the back of this report.

## A. Terrell Natural Gas Processing, 1972

Located in Terrell County in the Permian Basin in western Texas, Occidental Petroleum's Terrell natural gas processing facility processes methane that contains between 18% to 53% of $CO_2$. This

$CO_2$ must be removed from the methane to meet pipeline specifications. Since 1972 the plant has supplied $CO_2$ to EOR operations via a 220-mile pipeline linking the facility to a network of $CO_2$ pipelines in the Permian. To date about 20 million tonnes of $CO_2$ have been prevented from reaching the atmosphere through storage associated with the EOR process.

### B. Enid Fertilizer, 1982

ARCO began $CO_2$ injection into a portion of the Sho-Vel-Tum field in Oklahoma in 1982, and expanded operations in 1998. This demand for $CO_2$ incentivized the construction of capture equipment at the Farmland Industries fertilizer facilities in Enid, Oklahoma. The production of nitrogen fertilizers results in a high concentration $CO_2$ stream that requires cooling, dehydration, and compression to be ready for pipeline transport. About 0.6 million tonnes of $CO_2$ is captured and transported each year.

### C. Shute Creek Gas Plant, 1986

The ExxonMobil Shute Creek Treating Facility in Wyoming processes natural gas production from the LaBarge field with $CO_2$ concentrations up to 66%. The $CO_2$ is removed using physical absorption solvent trains to meet pipeline specifications for natural gas transport. The facility was commissioned in 1986 and undertook major debottlenecking activities to increase gas production in 2004 and 2005. In 2008, an $86 million expansion brought the total capacity up to 7 Mtpa. Around 0.5 Mtpa of the separated $CO_2$ is injected back into the LaBarge field. The remaining $CO_2$ is transported through pipelines to a series of oil fields in Wyoming, Colorado, and Montana for EOR operations.

### D. Great Plains Synfuels, 2000

The Great Plains Synfuels plant near Beulah, North Dakota, produces methane by gasification of a low-quality coal called lignite. The facility was constructed between 1981 and 1984. The project cost $2 billion and was funded by a federal loan guarantee of up to $2 billion to encourage the development of alternative fuel sources. By mid-1985, natural gas prices had dropped so much that the project was abandoned. Dakota Gasification Company was formed in 1988 and purchased the plant from Department of Energy for $85 million and a share of future profits.

The project is currently the only commercial-scale coal gasification plant in the United States. The lignite is gasified at high temperature to produce a mixture of methane, $CO_2$, and other gases. The gas is then cooled, which separates a highly concentrated stream of $CO_2$.

### E. Century Plant, 2010

The Occidental Petroleum Century Plant gas processing facility is located in Pecos Country in the Permian Basin of Texas. It processes natural gas from nearby fields in the Val Verde sub-basin that contain up to 65% $CO_2$. Since 2010, the plant has supplied $CO_2$ to EOR operations via a 100-mile pipeline linking the facility to the $CO_2$ distribution hub in Denver City, Texas. The plant was designed in 2008 with a maximum capacity of 5 Mtpa and brought online in 2010. An expansion in 2012 increased capacity to 8.4 Mtpa.

### F. Air Products Steam Methane Reformer, 2013

Air Products operates two Steam Methane Reformer (SMR) units to produce hydrogen for the Valero Refinery in Port Arthur, Texas. In 2010, Air Products was awarded $253 million by DOE through the American Recovery and Reinvestment Act to retrofit $CO_2$ capture equipment onto the units. The total project cost was $431 million, and the project began operations in May 2013. The output from the SMR units is separated through vacuum swing adsorption, purified, dehydrated, and compressed to make a 97% pure, pipeline-ready $CO_2$ stream due to the SMR units capturing more than 90% of the $CO_2$.

Denbury constructed and operates a 13-mile pipeline to transport the $CO_2$ to Denbury Onshore for use in an EOR project at the West Hastings Field. The maximum capture capacity from both units is about 1 Mtpa, and more than 4 million tonnes has been stored through EOR since the project began.

## G. Coffeyville Gasification, 2013

The Coffeyville nitrogen fertilizer plant was built in 2000 by Farmland Industries, and sold to Coffeyville Resources in 2004. It uses a petroleum coke gasification process to produce hydrogen for use in the manufacture of ammonia for fertilizer. The $CO_2$ is separated from the hydrogen through pressure swing adsorption, and although some captured $CO_2$ was used for urea synthesis, the majority was vented to the atmosphere.

In 2011, Chapparal Energy entered into a commercial agreement with Coffeyville Resources to construct a compressor and a 68-mile pipeline to link oil fields in North Burbank and northeastern Oklahoma to the fertilizer plant. The project came online in 2013, with a capacity to deliver 1 Mtpa for EOR. Chapparal sold their interest to Perdure Petroleum in 2017.

## H. Lost Cabin Gas Plant, 2013

The Lost Cabin Gas Plant in Fremont County, Wyoming, was constructed by Louisiana Land and Exploration in 1995. It processes natural gas production from the nearby Madden field with a $CO_2$ concentration of 19%. The $CO_2$ was originally vented to the atmosphere. In 2006, ConocoPhillips took over operatorship of the plant. The Lost Cabin Gas plant has the capacity to produce about 1 Mtpa of $CO_2$.

In 2010, Denbury entered into an agreement to take the $CO_2$ from ConocoPhillips, which subsequently constructed the capture facility. Denbury constructed a 232-mile pipeline to transport the $CO_2$ to the Bell Creek oil field. To date the $CO_2$ EOR operations have injected over 10 million tonnes of $CO_2$. The total amount of $CO_2$ that will be trapped in the field at the end of operations is estimated to be about 12 million tonnes. Denbury is currently extending the pipeline another 110 miles northeastward into Montana to commence EOR.

## I. Illinois Industrial CCS, 2017

The Illinois Industrial Carbon Capture and Storage (IL-ICCS) project is the only saline reservoir carbon storage project in the United States. The project is located at the Archer Daniels Midland Company (ADM) agricultural processing and biofuels complex in Decatur, Illinois, where a highly concentrated stream of $CO_2$ from the ethanol fermentation process is captured, dehydrated, compressed, and injected into the Mount Simon Sandstone reservoir adjacent to the facility. The project has a capacity of about 1.1 Mtpa, and has stored about 2 million tonnes since injection began in April 2017. This project's main objectives are to demonstrate an integrated system for collecting $CO_2$ from biofuel production and compressing, transporting, and injecting the $CO_2$ into a saline formation.

In October 2009, the DOE selected the IL-ICCS project for Phase 1 funding ($141 million) under the Industrial Carbon Capture and Storage program, funded by the American Recovery and Reinvestment Act of 2009. Under this program, ADM was able to secure a grant and structure the project's nonfederal cost-share obligation in a way that reduced the amount of upfront capital and associated risk. Following 2018 expansion of the Section 45Q tax credit, ADM began claiming the credits in 2019.

## J. Petra Nova, 2017

The Petra Nova project is the world's largest operational, post-combustion capture system applied to power generation. It was retrofitted to a unit of the W.A. Parish coal-fired power plant near Houston, Texas, and began operations in January 2017. It has the capacity to capture 1.4 Mtpa, which is transferred through an 80-mile pipeline to Hilcorp's West Ranch oil field for storage through EOR. The project uses proprietary amine scrubbing absorption technology to capture the $CO_2$ from power plant flue gas. Total project cost was about $1 billion.

Although the project is in an oil and natural gas producing region where many oil fields would benefit from EOR, the price for $CO_2$ for EOR did not support the investment in the capture plant. The Petra Nova project solved this problem by combining the EOR activity with the $CO_2$ capture facility project, creating a financial structure with enough return from the integrated CCS-EOR project.

NRG initially planned for a 60-Megawatts-electric (MWe) capture system but ultimately increased the system capacity to 240 MWe, enabling use of technology from Mitsubishi Heavy Industries America, Inc., which already had a successful demonstration plant capturing $CO_2$ from coal-fired flue gas. The DOE provided $190 million in grant funding. In May 2013, JX Nippon purchased 50% of Petra Nova, bringing much needed capital and access to debt financing for project funding.

## IV. ENABLERS OF U.S. CCUS SUPPLY CHAINS

The United States has become the world leader in CCUS by:

- Executing successful $CO_2$ capture projects
- Investing in $CO_2$ pipeline infrastructure
- Establishing a supportive regulatory framework
- Enacting world-leading policy support
- Investing in research, development, and demonstration (RD&D).

### A. $CO_2$ Pipeline Infrastructure

In addition to possessing approximately 80% of the world's capture capacity, the energy industry has constructed more than 5,000 miles of $CO_2$ pipelines in the United States (Figure 2-4), representing approximately 85% of the total $CO_2$ pipeline mileage in the world.[2] The $CO_2$ transported through this pipeline network is a mix of anthropogenic and natural $CO_2$ and is primarily used for EOR.

### B. EOR and Storage Potential

The U.S. oil industry leads the world in $CO_2$ EOR deployment and has been safely injecting $CO_2$ underground for nearly 50 years, extending the life of older fields and maximizing the value of U.S. hydrocarbon resources. Today, more than 95% of U.S. anthropogenic $CO_2$ is used in EOR. It is expected that EOR will continue to be the

2 IEAGHG, "$CO_2$ Pipeline Infrastructure," 2013/18, December 2013. https://ieaghg.org/docs/General_Docs/Reports/2013-18.pdf.


*Figure 2-4.* *Schematic Map of $CO_2$ Pipelines in the United States*

prominent disposition for anthropogenic $CO_2$ for at least the next decade, though its potential to store $CO_2$ is relatively small when compared to the total U.S. onshore $CO_2$ storage resource including saline formations.

The United States also has one of the largest known $CO_2$ geologic storage capacities in the world, with much of the continental U.S. possessing some subsurface $CO_2$ storage potential, as shown in Figure 2-5. While estimates of U.S. storage resource vary, most indicate that this resource is adequate to store hundreds of years of $CO_2$ emissions from U.S. stationary sources. Studies also suggest that offshore storage capacity in the United States may be as large as the onshore potential.[3]

## C. U.S. Regulatory Framework

Beyond action taken by commercial entities, the U.S. government has actively pursued the establishment of a strong regulatory framework to assure safe and secure transport and storage of $CO_2$. The Environmental Protection Agency (EPA) has developed specific regulatory and permitting frameworks under the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water during injection operations. These include the Class II (oilfield injection) and Class VI (saline formation storage of $CO_2$) permitting programs for $CO_2$ injection wells. The EPA also maintains the Greenhouse Gas Reporting Program and has developed accounting protocols under the Clean Air Act for the injection of $CO_2$ for geologic storage. The $CO_2$ pipelines are regulated by the Pipeline and Hazardous Materials Safety Administration within the Department of Transportation, which sets the standards for permitting and operation. A number of policy, regulatory, and legal actions are needed to enable at-scale deployment of CCUS, as described in Chapter 3, "Policy, Regulatory, and Legal Enablers," and the United States is well positioned to take these next steps.

3 Sweatman, R. E., Crookshank, S., and Edman, S. (January 1, 2011). "Outlook and Technologies for Offshore $CO_2$ EOR/CCS Projects," Offshore Technology Conference, doi:10.4043/21984-MS.

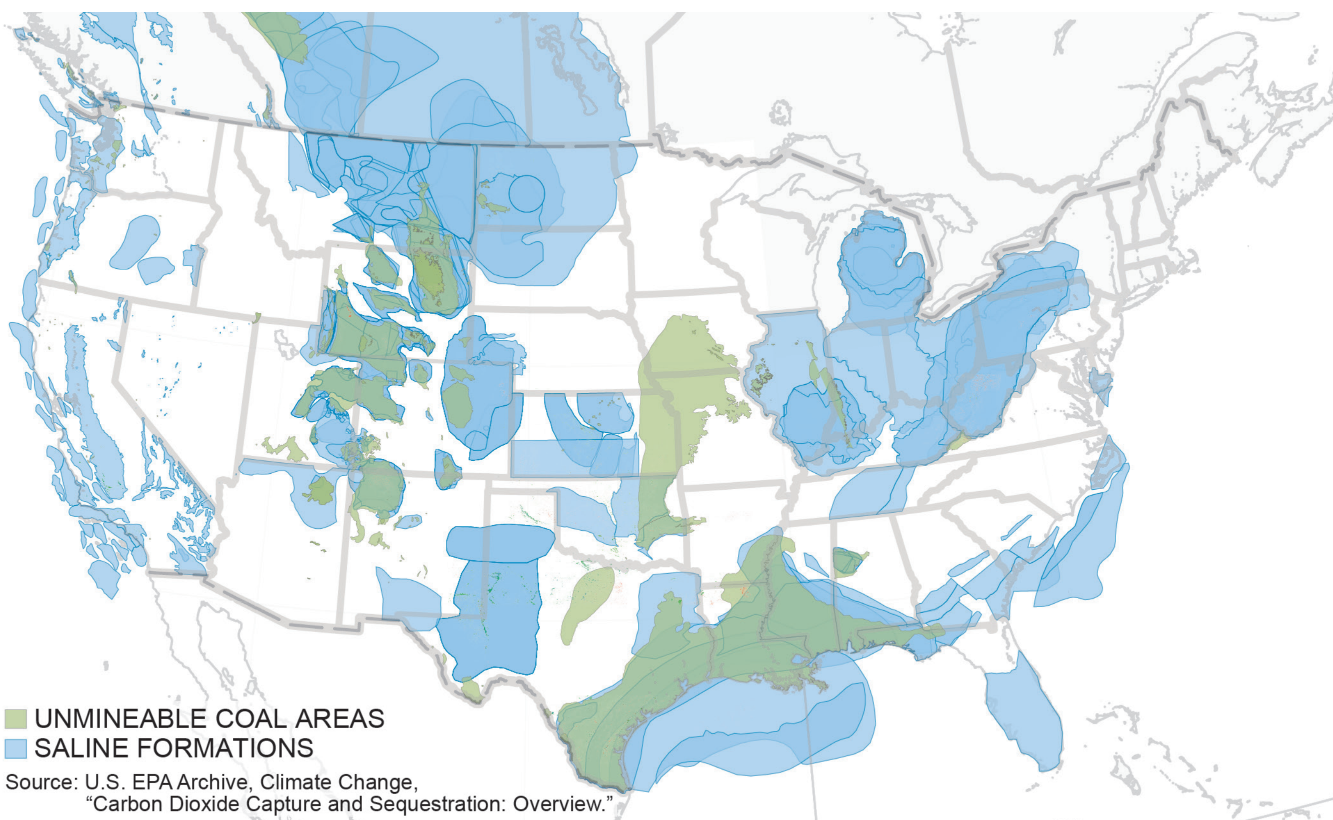



*Figure 2-5. U.S. Assessment of Geologic $CO_2$ Storage Potential*

## D. Financial Support: Demonstration Projects

As noted earlier, four of the 10 large-scale projects in the United States required significant policy support to be economically viable. In 2009, the American Recovery and Reinvestment Act (Recovery Act; P.L. 111-5) provided the U.S. DOE \$3.4 billion for CCUS[4] projects and activities. The large and rapid influx of funding for industrial-scale CCUS projects was intended to accelerate development and demonstration of CCUS in the United States. As described earlier in this chapter, three projects that are currently in operation, the Air Product Steam Methane Reformer $CO_2$ capture project, the ADM Illinois Industrial CCS project, and the NRG Petra Nova $CO_2$ capture project, all greatly benefited from this funding. The fourth project, the Great Plains Synfuels project, was, as noted earlier, initially constructed from 1981 to 1984 with major financial support from the U.S. government to encourage the development of alternative fuel sources. In 2000, following the construction of an international $CO_2$ pipeline and entry into a supply agreement, the facility began delivering $CO_2$ to two oil fields in Canada.

## E. Financial Support: Broad Policies

CCUS has also benefited from federal tax policy as well as state and regional incentives. The 2018 FUTURE Act amended Section 45Q of the U.S. tax code for operators of carbon capture equipment, increasing the tax credit from \$20 to \$50 per tonne of $CO_2$ stored in dedicated geologic storage and from \$10 to \$35 per tonne for $CO_2$ stored through EOR or used. The legislation also removed some limits on the size of projects that can qualify and the total amount of credits that can be claimed. It is worth noting that the International Energy Agency (IEA) has estimated that the amended 45Q could "trigger new capital investments of as much as \$1 billion for CCUS over the next six years."[5] Although no final investment decisions have been announced since the revision of Section 45Q was enacted, the NPC expects multiple projects will be incentivized by this revision, assuming the tax policy and regulatory clarifications recommended in the activation phase, as detailed in Chapter 3, are addressed.

4 Folger, P. (2016). "Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects," Congressional Research Service, February 18, 2016, 24 pp. https://fas.org/sgp/crs/misc/R44387.pdf.

5 IEA Tracking Clean Energy Progress, CCUS in power. (May 24, 2019). https://www.iea.org/tcep/power/ccus/. Accessed November 19, 2019.

## F. U.S. DOE Leadership

The United States has benefited from more than 20 years of DOE leadership, funding support, and public-private partnerships between government, academia, and industry. Since 1997, the DOE has invested more than \$4.5 billion in CCUS RD&D programs. This funding has been a major contributing factor to the United States becoming the world leader in CCUS technology and deployment capability.

Much of this development was accomplished through the DOE's Regional Carbon Sequestration Partnership program, which includes 40 states and four Canadian provinces. The regional partnerships combined academic, research, and industrial experience to deliver 27 small-scale $CO_2$ injection pilots and seven large-scale $CO_2$ injection test projects delivering more than 11 million tonnes of $CO_2$ storage. To date, more than 20 million tonnes of $CO_2$ have been stored through DOE supported CCUS projects.

# V. COST TO DEPLOY CCUS IN THE UNITED STATES

As part of this study, the costs to capture, transport, and store $CO_2$ emissions from the largest 80% of U.S. stationary sources were assessed. The purpose of this assessment was to understand the level of incentive needed to enable the creation of a multi-hundred-billion-dollar CCUS industry in the United States (e.g. wide-scale deployment). The analysis comprises approximately 850 U.S. stationary sources of $CO_2$ emissions. The largest 80% of emitting sources in the 2018 EPA Facility Level Information on GreenHouse gases Tool (FLIGHT) database, which tracks and reports U.S. $CO_2$ emissions, are included. In addition, fermentation emissions from ethanol plants larger than 100,000 tonnes/year that are not reported in the EPA FLIGHT database were added to the sources and are included in the curve.[6] In

6 These ethanol plants report only combustion emissions to the EPA. To estimate the ethanol fermentation $CO_2$ emissions, the yearly output of ethanol for each plant was multiplied by the stoichiometric conversion factor of ethanol to $CO_2$ to arrive at $CO_2$ emissions.

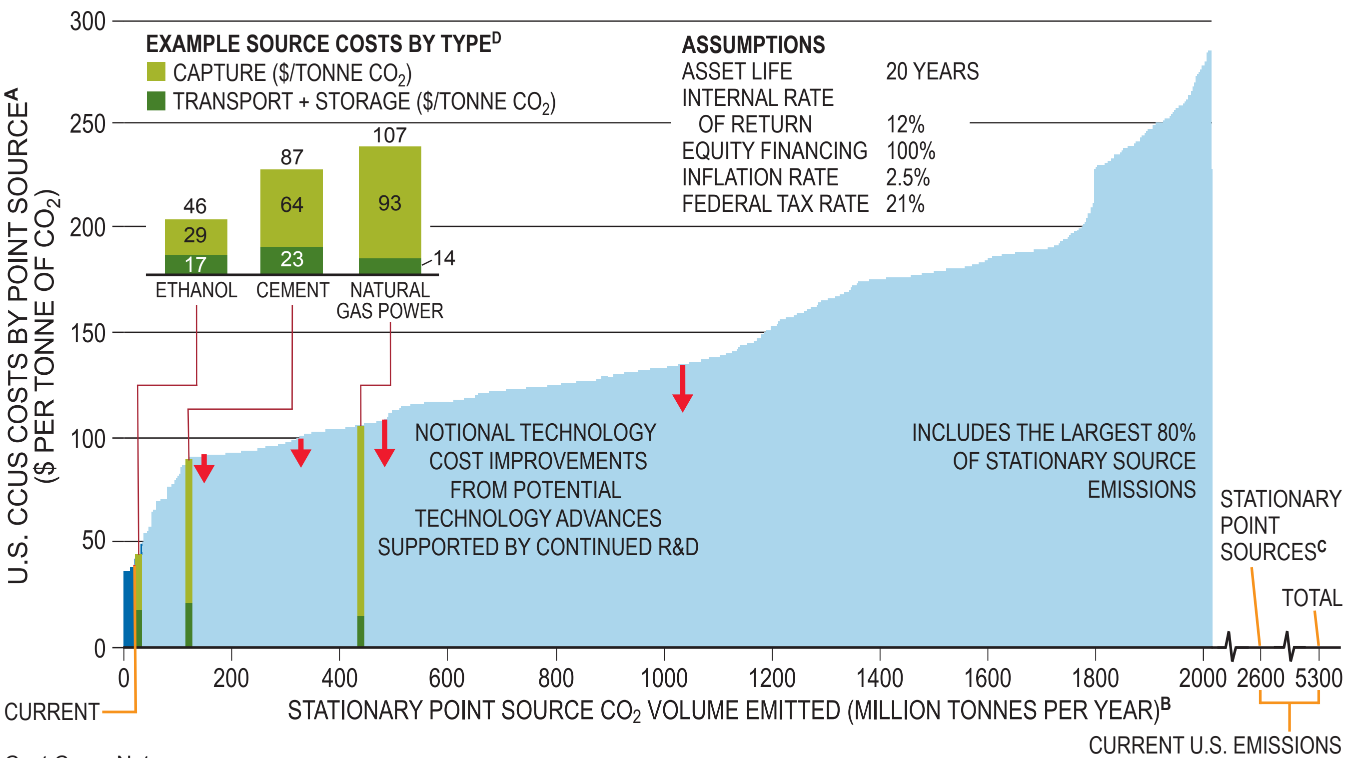
total, the curve includes approximately 850 U.S. stationary sources of $CO_2$ emissions.

The results are presented as a $CO_2$ cost curve (Figure 2-6), where the total cost to capture, transport, and store one tonne of $CO_2$ from stationary sources is plotted against the volume of $CO_2$ abatement it could provide. The curve is arranged in a marginal cost manner, such that the sources with the lowest combined cost to capture, transport, and store $CO_2$ from each source (shortest bars) are to the left of the curve and sources with the highest combined cost (tallest bars) are to the right of the curve. The cost per tonne gives an indication of the minimum financial revenue or benefit needed to incentivize supply chain development. Today, these incentives come from revenue generated through the sale of $CO_2$ and from $CO_2$ tax credits.

The cost curve shown in Figure 2-6 was developed using costs associated with currently available and deployed technologies. The red down arrows in the curve represent an illustrative view of notional 10% to 30% cost improvements that could be expected over the next 20-30 years based on technology advances supported by continued research and development.[7] Although the cost curve is not time based, the length of the red arrows represents the notional cost reductions in the context of the phases of deployment described in this report.

The results of the curve are highly dependent upon the assumptions used in the analysis. Using "reference cases" and standard economic assumptions was essential to developing the cost curve, formulating recommendations, and assessing the potential impact of those recommendations on CCUS deployment at a national level. Costs for

7 IEAGHG. (2019). "Further Assessment of Emerging $CO_2$ Capture Technologies for the Power Sector and their Potential to Reduce Costs," p. 278.




Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total $CO_2$ emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

D. Bar width is illustrative and not indicative of the volumes associated with each source.

***Figure 2-6.*** *U.S. CCUS Cost Curve* individual projects will vary based on location factors and the economic assumptions specific to each project.[8]

In order to provide a useful public resource and ensure transparency of this work, the cost assessment tool, created by Gaffney, Cline & Associates, has been made available.[9] The tool will allow interested parties to change the cost and financial assumptions to generate their own view of costs.

Each of the largest 80% of U.S. $CO_2$ emissions from the EPA FLIGHT data, about 850 sources, is included in the cost curve depicted in Figure 2-6 with the X-axis representing the combined volume of each source. The Y-axis represents the total estimated cost to capture, transport and store the $CO_2$ emissions from each source. The costs presented in this study are based upon a variety of project types across a broad spectrum of industries in the United States. A significant driver of variation in capture costs is the concentration of $CO_2$ in the total gas stream for each emissions source. For example, point sources with high $CO_2$ concentration (e.g., ethanol, natural gas processing, etc.) will typically have relatively small capture costs and are seen in the lower cost area of the curve (i.e., left side). However, for most $CO_2$ emissions sources, capture will account for the majority of the overall cost of CCUS. Figure 2-7 provides an illustrative view of the combined cost for capture, transport, and storage for a single source of emissions. These costs vary by source type, distance from facility to storage location, and characteristics of the storage location.

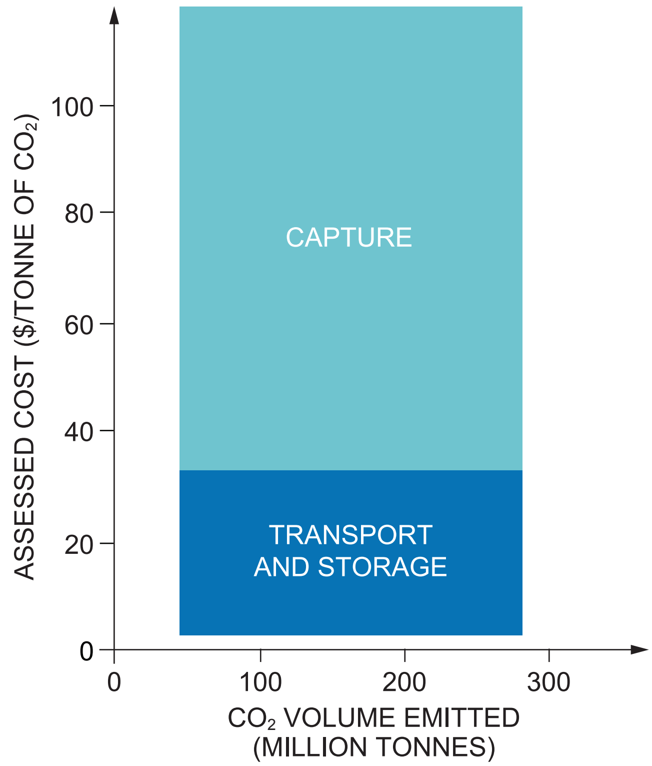



***Figure 2-7.*** *Cost Associated with CCUS for a Single Source of $CO_2$ Emissions*

## A. Financial Assumptions

The total calculated cost of each source comprises a capture, transport, and storage component. Each of the components was assessed using a cash flow model with the following assumptions:

| | |
|---|---|
| Asset Life | 20 years |
| Internal Rate of Return (after tax) | 12% |
| Equity Financing | 100% |
| Tax Rate | 21% |
| Inflation | 2.5% |
| Depreciation | 7-year MACRS[10] |

These financial assumptions reflect the collective view of the study participants regarding the conditions that need to exist to incentivize widespread deployment of CCUS in the United States over the next two decades. The IRR of 12% was selected as the level required for large-scale implementation of CCUS in the United

8 Examples of differences for individual projects include:

Costs for individual projects will be different based on specific scale and local market conditions for labor and equipment supply and can therefore result in alternative economic results for individual projects.

Operating costs for individual projects will be different based on their ability to integrate with existing operations and can therefore result in alternative economic results for individual projects.

Financing for individual projects will be different based on specific risks and market conditions. For example, the National Engineering Technology Laboratory (NETL) baseline cost estimates for coal and gas power (Revision 4) assume an IRR of ~8% for 45% equity and an interest rate of ~3% for 55% debt financing and can therefore result in alternative economic results for these types of projects.

9 Cost assessment tool can be found at http://gaffney-cline-focus.com/npc-ccus-cost-assessment-tool.

10 Modified Accelerated Cost Recovery System is the current tax depreciation system in the United States.

States, considering the inherent financial risks of these types of projects. This level of return was deemed by the study team to be adequate to attract investment from corporate equity investors, independent equity investors, and non-governmental (unsubsidized) debt sources. It was also recognized that these assumptions would likely not be appropriate to assess individual CCUS project opportunities, as individual project circumstances can vary widely. While these financial assumptions were applied uniformly in the cost analysis, capital investment, fixed operating cost, and variable operating cost including energy were individually assessed based on industry type and location. As discussed in the next section, capture costs vary as a function of the circumstances in which the technologies are employed. As previously noted, the model used to develop this cost curve has been made publicly available, giving the user the opportunity to change the financial assumptions to reflect alternative views.

| Facility Type | Reference Plant Size | Capacity Utilization % | Stream Flowrate (tonnes/hour) | $CO_2$ in Exhaust % | $CO_2$ Separation Technology | $CO_2$ Volume Captured (tonnes/year) | Separation Notes |
|---|---|---|---|---|---|---|---|
| Natural Gas Processing | 140 MMCF/D | 85 | 21 | 95-100 | None | 24,000 | Vented only, not combustion |
| Ethanol Production | 150 million gal/yr | 85 | 49 | 95-100 | None | 342,000 | Vented only, not combustion |
| Ammonia Production | 907,000 tonnes/yr | 85 | 53 | 95-100 | None | 389,000 | Vented only, not combustion |
| Hydrogen Production | 87 MMCF/D | 85 | 59 | 45 | Amine | 340,000 | Process only, not combustion |
| Cement Plants | 1 million tonnes/yr | 85 | 431 | 21 | Amine | 842,000 | Both process and combustion |
| Refinery Fluidized Catalytic Cracking (FCC) Plants | 60,000 barrels/day | 85 | 272 | 16 | Amine | 374,000 | Process only, not combustion |
| Steel/Iron Plants | 2.54 million tonnes/yr | 85 | 1,381 | 26 | Amine | 3,324,000 | Both process and combustion |
| Coal Power Plants | 550 MW net | 85 | 2,829 | 13 | Amine | 3,089,000 | Combustion |
| | | 55 | | | | 1,999,000 | |
| | | 35 | | | | 1,272,000 | |
| Industrial Furnaces (refining/chemicals) | 4x150 MMBTU/hr | 85 | 247 | 8 | Amine | 220,000 | Combustion |
| Natural Gas Power Plants | 560 MW net | 85 | 3,707 | 4 | Amine | 1,279,000 | Combustion |
| | | 55 | | | | 827,000 | |
| | | 35 | | | | 527,000 | |

***Table 2-3.*** *Cost Curve Assessed Industries with Key Capture Cost Variables*

## B. Capture Costs Assessment

Capture costs were estimated based on specific industrial process conditions and the capture technologies applied. In general, $CO_2$ capture systems include three major processes, (1) separation of $CO_2$ from other gases, (2) removal of water from $CO_2$, which is generally referred to as dehydration, and (3) compression of $CO_2$ to a supercritical phase, making it ready for transport. The cost assessment assumes the application of currently available capture systems to existing large-scale $CO_2$ emissions sources. On that basis, the capture costs developed reflect retrofits to existing facilities and includes the purchase of electricity and natural gas necessary to run the capture equipment and prevent any significant parasitic load reducing output.

Costs were estimated for each industry sector, taking into consideration the unique processes and other conditions associated with the facility type deemed most relevant. To assess costs, a reference plant size and capacity utilization were identified for each industry in an effort to portray a typical facility. For each reference plant within the facility type, an exhaust volume and an associated molar $CO_2$ concentration was assumed. For facility types with an exhaust $CO_2$ molar concentration greater than 95%, no separation costs were included—only dehydration and compression costs were assumed. For facility types with an exhaust $CO_2$ molar less than 95%, separation costs were estimated based on the application of amine absorption technology, with dehydration and compression facilities assumed for the reference plant size.

The costs developed for this model were based on an assessment of historical studies, published industry experience, and insights from a wide range of industry experts who reliably design, construct, and operate such large-scale, technically challenging, commercially complex, and capital-intensive energy and industrial projects. The range of capture costs (e.g., low to high) developed for this model is intended to reflect differences in the economies of scale between individual facilities, the various ways to integrate power and heat requirements within existing facilities, and a range of equipment delivery and labor costs.

Table 2-3 lists the key capture cost variables within each assessed industry. For each reference plant within a facility type, capital and operating costs were estimated based on the key variables described in the following sections.

### 1. Capital Costs

As previously noted, the process to separate $CO_2$ from other exhaust gases generally uses amine absorption separation technology. This technology is effective over a wide range of $CO_2$ concentrations and pressures. However, the level of capital and operating costs will vary significantly based on the concentration of $CO_2$ versus other gases. Figure 2-8 illustrates the size and complexity of the equipment needed for $CO_2$ capture at the NRG/JX Petra Nova project near Houston, Texas. The facility uses post-combustion amine absorption technology to capture approximately 90% of the $CO_2$ in the processed flue (vent) gas stream from one of the facility's four coal-fired units.


Source: NRG Energy Case Studies, *Petra Nova, Carbon capture and the future of coal power.*

***Figure 2-8.*** *The NRG/JX Petra Nova $CO_2$ Capture Project Near Houston, Texas*

Amine absorption involves the molecules of $CO_2$ being dissolved into the bulk of a liquid solvent. Flue (vent) gas, which can contain a range of $CO_2$ concentrations, and the liquid solvent contact each other in a column called an absorber tower or unit. The tower provides an interface area between the gas and liquid phases. The separation of $CO_2$ from flue gas primarily occurs through the high solubility of $CO_2$ in the solution relative to that of other flue gas constituents. The $CO_2$-rich solution is then sent to a regenerator, also called a stripper tower. In the stripper tower, the solution is typically heated to liberate $CO_2$ from the solution. The warm, $CO_2$-lean solution is then cooled in a heat exchanger and recycled back to the absorber tower for reuse, and the process continues. Amine solvent systems (e.g., amine acid gas scrubbing systems) are often used in industries such as natural gas processing and fertilizer manufacture.

While the application of amine absorption technology is similar for most applications, separating $CO_2$ at lower concentrations generally increases costs. The absorption of $CO_2$ in solvent occurs in a packed column. The diameter (area) of the column is determined by the limiting velocity of the gas containing the $CO_2$ moving through the packed column. The packed column is proportionally larger for dilute gas streams because more gas must move though the column for the same amount of $CO_2$ in these dilute gas streams than for the same amount of $CO_2$ in a more concentrated stream. In addition, the ducts and fans that bring the gas containing $CO_2$ to the packed column must also be larger for more dilute streams. The increase in equipment size for the more dilute streams adds additional costs. Because the fans used to move the gas to the absorber are larger, they also consume more energy than for more concentrated streams. Generally, the cost per tonne of $CO_2$ captured from a natural gas combined cycle plant with a 4% $CO_2$ concentration in the flue gas is approximately 20% greater than the cost per tonne of $CO_2$ captured from a coal-fired power plant at

| Facility Type | Reference Plant Size | Capacity Utilization % | $CO_2$ Volume Captured (tonnes/year) | Capital Cost Low-High ($ millions) | Unit Capital Cost 20-Year Life Low-High ($/tonne) |
|---|---|---|---|---|---|
| Natural Gas Processing | 140 MMCF/D | 85 | 24,000 | 17-28 | 7-12 |
| Ethanol Production | 150 million gal/yr | 85 | 342,000 | 21-36 | 6-10 |
| Ammonia Production | 907,000 tonnes/yr | 85 | 389,000 | 24-41 | 6-11 |
| Hydrogen Production | 87 MMCF/D | 85 | 340,000 | 59-98 | 19-33 |
| Cement Plants | 1 million tonnes/yr | 85 | 842,000 | 148-247 | 17-29 |
| Refinery Fluidized Catalytic Cracking (FCC) Plants | 60,000 barrels/day | 85 | 374,000 | 136-227 | 43-72 |
| Steel/Iron Plants | 2.54 million tonnes/yr | 85 | 3,324,000 | 805-1342 | 26-44 |
| Coal Power Plants | 550 MW net | 85 | 3,089,000 | 891-1485 | 33-55 |
| | | 55 | 1,999,000 | | 54-91 |
| | | 35 | 1,272,000 | | 89-149 |
| Industrial Furnaces (refining/chemicals) | 4x150 MMBTU/hr | 85 | 220,000 | 92-153 | 49-83 |
| Natural Gas Power Plants | 560 MW net | 85 | 1,279,000 | 399-666 | 34-58 |
| | | 55 | 827,000 | | 57-95 |
| | | 35 | 527,000 | | 92-155 |

***Table 2-4.*** *Estimated Capital Investment Costs for Reference Plants by Facility Type*

13% concentration in the flue gas. Note that in this comparison, both gas streams are near atmospheric pressure.[11]

In addition to the deployment of amine absorption, the cost associated with ancillary facilities was considered for the purposes of this study. These costs do not include any additional impurity cleanup costs that may be required in some applications of the $CO_2$ capture process to meet transport or storage/use specifications. The following provides examples of other capital investment considerations:

- Ducting to move exhaust gases from the vent stacks to the inlet of the capture system
- Cooling systems to cool exhaust gas
- Pre-treatment systems if the inlet gas contains contaminants
- Water treatment systems
- Storage bins and tanks for materials, including reserves of solvent.

Capital costs for separation, dehydration, and compression were estimated for each reference plant within a facility type based on an assessment of historical studies, published industry experience, and insights from a wide range of industry experts. All new projects were assumed to have a 3-year construction period, with 20% of the required capital spent in the first year, 50% in year 2 and 30% in year 3. Table 2-4 provides the capital investment costs that were estimated for each facility type assessed.

## 2. Operating Costs

Operating costs associated with $CO_2$ capture facilities are divided into four major categories:

- Annual fixed costs (taxes, insurance, overhead, general plant salaries)
- Semi-variable costs (major and minor repairs, maintenance, overhauls)
- Variable non-energy costs (replacement of process chemicals, water, water treatment, etc.)
- Variable energy costs (electricity to drive compressors, motors, pumps and fans; steam to strip $CO_2$-laden solvent).

11 Comparisons with other gases at high pressure or temperature (>200°C) are not appropriate.

| Facility Type | $CO_2$ Volume Captured (tonnes/year) | Non-energy O&M % of CAPEX |
|---|---|---|
| Natural Gas Processing | 24,000 | 6% |
| Ethanol Production | 342,000 | 7% |
| Ammonia Production | 389,000 | 5% |
| Hydrogen Production | 340,000 | 5% |
| Cement Plants | 842,000 | 7% |
| Refinery Fluidized Catalytic Cracking (FCC) Plants | 374,000 | 4% |
| Steel/Iron Plants | 3,324,000 | 5% |
| Coal Power Plants | 3,089,000 | 4% |
| | 1,999,000 | |
| | 1,272,000 | |
| Industrial Furnaces (refining/chemicals) | 220,000 | 4% |
| Natural Gas Power Plants | 1,279,000 | 5% |
| | 827,000 | |
| | 527,000 | |

***Table 2-5.*** *Estimated Non-energy Operating Costs for Different Facility Types*

Considering that the deployment of a similar separation technology (amine absorption) was assumed for all facilities within an industrial sector, fixed, semi-variable and non-energy variable annual operating costs were estimated as a percentage of capital investment (CAPEX) for an industrial sector.

Table 2-5 depicts the non-energy operating cost assumptions.

Energy costs associated with operating amine absorption equipment were estimated based on industry experience and a survey of recent studies. A list of the relevant assumptions related to energy use requirements and pricing follows:

- Electricity required for compression and dehydration was assumed to be 0.1 MWh per tonne of $CO_2$.
- Electricity required to operate an amine system was assumed to be 0.05 MWh per tonne of $CO_2$,

with minor differences dependent on facility type.

- Electricity prices were assumed at $50/MWh. For reference, the EIA average price for February 2019 was $51.80 per MWh of electricity for industrial customers in West South Central (AR, LA, OK, and TX).
- Fuel required to operate the amine system was assumed to be 2.5 to 3.5 MMBTU per million tonnes of $CO_2$, dependent on facility and solvent type.

Table 2-6 provides the specific energy use assumptions used for each facility type.

| Facility Type | Reference Plant Size | Electricity & Gas | |
|---|---|---|---|
| | | MWh/ tonne $CO_2$ | MMBTU/ tonne $CO_2$ |
| Natural Gas Processing | 140 MMCF/D | 0.10 | 0.0 |
| Ethanol Production | 150 million gal/yr | 0.12 | 0.0 |
| Ammonia Production | 907,000 tonnes/yr | 0.10 | 0.0 |
| Hydrogen Production | 87 MMCF/D | 0.18 | 2.6 |
| Cement Plants | 1 million tonnes/yr | 0.16 | 2.6 |
| Refinery Fluidized Catalytic Cracking (FCC) Plants | 60,000 barrels/ day | 0.14 | 2.6 |
| Steel/ Iron Plant | 2.54 million tonnes/yr | 0.16 | 2.6 |
| Coal Power Plants | 550 MW net | 0.16 | 2.6 |
| Industrial Furnaces (refining/ chemicals) | 4x150 MMBTU/ hr | 0.16 | 2.6 |
| Natural Gas Power Plants | 560 MW net | 0.16 | 2.8 |

***Table 2-6.*** *Amount of Electricity and Fuel Required for Reference Plants by Facility Type*

By adding the calculated capital and operating costs described, Table 2-7 provides a summary of estimated annualized capture costs per tonne of $CO_2$ captured for each reference plant within a facility type. High and low ranges are provided to reflect potential differences within a facility type or industry. For example, the range provided for coal power and natural gas combined cycle (NGCC) reference plants are intended to reflect the potential differences in capacity utilization of various plants, ranging from 35% to 85%, with a midpoint of 55%. The ranges for the other sources reflect regional variations in construction costs, labor costs, and commodities transport. For most sources, midpoint of the range was used to assess costs.

Several publicly available studies on the cost of CCUS were considered during development of the capture cost assumptions and, where appropriate and supported by data, the assumptions were used as the basis to develop the costs shown in Table 2-7.[12]

The capture costs presented in this chapter are commonly referred to as the total spent

12 Studies reviewed include (among others):

National Energy Technology Laboratory and Booz Allen, "Cost of Capturing $CO_2$ from Industrial Sources," https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_011014.pdf.

U.S. Department of Energy, National Energy Technology Laboratory. (2016). "Eliminating the Derate of Carbon Capture Retrofits," https://www.netl.doe.gov/energy-analysis/details?id=2886.

International Energy Agency. (June 2019). "The Future of Hydrogen: Seizing Today's Opportunities," https://www.iea.org/reports/the-future-of-hydrogen.

Kuramochi, T., Ramirez, A., Turkenburg, W. C., and Faaij, A. (2012). "Comparative Assessment of $CO_2$ Capture Technologies for Carbon-Intensive Industrial Processes," *Progress in Energy and Combustion Science* 38(1):87-112, https://www.researchgate.net/publication/251576085_Comparative_assessment_of_CO2_capture_technologies_for_carbon-intensive_industrial_processes.

Rubin, E. S., Herzog, H. J., and Davison, J. E. (2015). "The Cost of $CO_2$ Capture and Storage," *International Journal of Greenhouse Gas Control* 40, https://www.researchgate.net/publication/282489683_The_cost_of_CO2_capture_and_storage.

Bechtel. (October 2018). "Retrofitting an Australian Brown Coal Power Station with Post-Combustion Capture," http://www.co2crc.com.au/wp-content/uploads/2018/10/Retrofitting_Australian_Power_Station_with_PCC.pdf.

Carbon Utilization Council. (July 25, 2018). "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," http://www.curc.net/webfiles/Making Carbon a Commodity/180724 Making Carbon a Commodity FINAL with color.pdf.

| Facility Type | Reference Plant Size | $CO_2$ Volume Captured (tonnes/year) | Unit Capital Cost 20-Year Life Low-High ($/tonne) | Unit Non-Energy Cost 20-Year Life Low-High ($/tonne) | Unit Energy Operating Cost ($/tonne) | Unit Total Cost 20-Year Life Low-High ($/tonne) |
|---|---|---|---|---|---|---|
| Natural Gas Processing | 140 MMCF/D | 24,000 | 7-12 | 8-13 | 9 | 23-35 |
| Ethanol Production | 150 million gal/yr | 342,000 | 6-10 | 8-13 | 11 | 24-34 |
| Ammonia Production | 907,000 tonnes/yr | 389,000 | 6-11 | 6-10 | 9 | 21-30 |
| Hydrogen Production | 87 MMCF/D | 340,000 | 19-33 | 15-26 | 28 | 61-88 |
| Cement Plants | 1 million tonnes/yr | 842,000 | 17-29 | 22-37 | 28 | 64-95 |
| Refinery Fluidized Catalytic Cracking (FCC) Plants | 60,000 barrels/day | 374,000 | 43-72 | 28-47 | 29 | 97-150 |
| Steel/Iron Plants | 2.54 million tonnes/yr | 3,324,000 | 26-44 | 22-38 | 29 | 75-113 |
| Coal Power Plants | 550 MW net | 3,089,000 | 33-55 | 22-37 | 30 | 83-124 |
| | | 1,999,000 | 54-91 | 35-59 | 26 | 113-178 |
| | | 1,272,000 | 89-149 | 57-95 | 23 | 166-268 |
| Industrial Furnaces (refining/chemicals) | 4x150 MMBTU/hr | 220,000 | 49-83 | 33-55 | 31 | 110-171 |
| Natural Gas Power Plants | 560 MW net | 1,279,000 | 34-58 | 29-49 | 31 | 93-140 |
| | | 827,000 | 57-95 | 47-79 | 26 | 122-192 |
| | | 527,000 | 92-155 | 75-126 | 23 | 179-290 |

Note: The addition of unit CAPEX and OPEX costs in the above table may result in rounding errors when compared to actual unit total costs provided.

***Table 2-7.*** *Total Estimated Capture Cost ($/tonne) for Reference Plants by Facility Type*

costs. There are other ways to express capture costs, including "avoided costs," which considers the total amount of $CO_2$ emissions avoided and includes the costs and $CO_2$ impact of the energy required to operate the capture process to produce the same level of useful energy. These costs are frequently described in terms of a cost per unit of energy produced (e.g., per MWh of electricity). It is worth noting that when capture costs for coal and natural gas are compared, the avoided cost for natural gas power plant can be lower due to lower fuel costs and higher rates and conversion efficiency of fuel to power. For purposes of determining the level of incentives needed to achieve widespread CCUS deployment, this study uses total spent costs.

## C. Transport Cost Assessment

Transport costs were estimated based on the assumption that a pipeline system is generally the most economical means of moving $CO_2$ from sources to storage locations (sinks). Transportation from source to sink was assessed for the largest 80% of emitting sources in the 2018 EPA FLIGHT database. In total, approximately 900 source-to-sink combinations were assessed. It was assumed that if the combined volume from multiple sources within 0.5-degree latitude by 0.5-degree longitude grid was greater than 2 Mtpa, a pipeline was justified. Truck or rail transport was assumed for the remaining sources. As previously noted, although not included in the 2018 EPA FLIGHT database, ethanol plants with emissions greater than 100,000 Mtpa were included in this study. These emissions were calculated by state and assumed to originate from a single point within that state.

A pipeline network was designed that connected sources to the nearest sink assuming the shortest distance between source and sink. A factor of 20% was added to those distances to account for routing the pipelines around obstacles, away from populated areas, and along existing rights-of-way. Some segments of the local pipelines naturally fell into logical routes for trunk lines (larger diameter pipelines that connect a number of smaller pipelines). Those segments were therefore upsized into three trunk lines located in the Midwest, South Central, and Eastern parts of the United States.

Individual pipeline segment diameters were sized according to the $CO_2$ flow rate to be transported. The resultant pipeline diameters were rounded up to the nearest inch. The cost to construct the pipeline segments was estimated on an inch-mile basis formulated from historical construction costs, with pumping station spacing built into the regional pipeline cost. For purposes of modeling the cost, the United States was divided into four longitudinal regions—Western, Rockies, Central, and Eastern. Pipeline costs within each region were estimated using a regional construction cost basis. The longitudinal division between each region, and the estimated costs to construct pipelines within the regions, are shown in Table 2-8.

Installed costs for trunk lines were estimated based on historic data with the Midwest and South-Central lines costing $80 thousand/inch-mile and the Eastern trunk line being more expensive, at $100 thousand/inch-mile. Each of the trunk lines was designed with a capacity of 100 Mtpa.

The transport cost for each point source was estimated by multiplying the straight-line distance between each source and its associated sink by the capacity needed to transport the source $CO_2$ volume on a cost per tonne-mile basis. This transport cost ranges between $2 and $38 per tonne for a 20-year project.

| Region | Longitude | | Pipeline Cost ($ Thousands/ inch-mile) |
|---|---|---|---|
| | min | max | |
| Western | | -114.75 | 120 |
| Rockies | -114.75 | -102.50 | 150 |
| Central | -102.50 | -85.75 | 80 |
| Eastern | -85.75 | | 100 |
| Midwest Trunk line | 80 | | |
| South-Central Trunk line | 80 | | |
| Eastern Trunk line | 100 | | |

***Table 2-8.*** *Estimated $CO_2$ Pipeline Costs by Region*

To address the modeling assumption that $CO_2$ pipelines are instantly present at a given source and have a large enough diameter to transport the emissions, an additional $5 per tonne cost was added to the first 100 Mtpa of pipeline capacity. This reflects the estimation of a $500 million incentive for the upfront investment needed to start installation of the $CO_2$ pipeline infrastructure.

## D. Storage Cost Assessment

Storage cost assumptions were based upon the September 2017 version of the National Energy Technology Laboratory's FE/NETL $CO_2$ Saline Storage Cost Model (FE/NETL Model).[13,14] The 684 individual subsurface formations in the FE/NETL Model were aggregated into five storage regions as shown in Figure 2-9.

The FE/NETL Model assumes that captured $CO_2$ would be directed to the lowest cost storage

13 Grant, T. and Morgan, D., "FE/NETL $CO_2$ Saline Storage Cost Model: Model Description and Baseline Results," DOE/NETL-2014/1659, July 18, 2014.

14 National Energy Technology Laboratory. (2017). "FE/NETL $CO_2$ Saline Storage Cost Model." U.S. Department of Energy. Last Update: September 2017 (Version 3), https://edx.netl.doe.gov/dataset/fe-netl-co2-saline-storage-cost-model-2017.

formations within each region. For purposes of this study, that resulted in four regions with a storage cost threshold of $15/tonne, and one region North Central, with a threshold of $22/tonne, due to higher overall costs associated with that region. Formations with costs higher than the defined thresholds were excluded, as were formations along the Atlantic coast and in South Florida because they are unlikely locations for significant volumes of $CO_2$ storage. According to the FE/NETL Model, 620 gigatonnes of total U.S. storage capacity is potentially available in formations with estimated storage cost at, or below, the threshold costs, which is adequate to accommodate future captured $CO_2$ volumes.

Storage volume-weighted average costs were calculated for each region using the FE/NETL Model assumptions, but included the following exceptions:

- The ratio of monitoring wells to injection well was reduced to 2:1 from 9:1. The study assumed that on average, each injection well has one in-zone well and one above-zone well to measure pressure and saturation, and that the two monitoring wells would need to be placed at different locations optimized to address site-specific risk.
- The number of seismic surveys was reduced to six (one for site selection and characterization, three during operations, and two during post-injection site care [PISC]) from 16 (one for site selection and characterization, six during operations, and 10 during PISC).

These adjustments to the FE/NETL Model assumptions were made on the basis that injection projects target the best-quality lowest-risk sites. As a result, sites that the FE/NETL Model assumed would require monitoring would likely be excluded during initial site selection and characterization in the model presented here. These adjustments to the assumptions had the effect of reducing the cost of storage by approximately 50% compared with the FE/NETL Model assumptions as well as reducing the total available U.S. storage capacity.

Table 2-9 summarizes the volume-weighted average storage cost calculated for each region using these assumptions. Because limited work has been done to identify specific storage sites within each storage region, these average storage costs were assumed to apply uniformly throughout each region. Some sites will be more expensive, and some sites will be less expensive

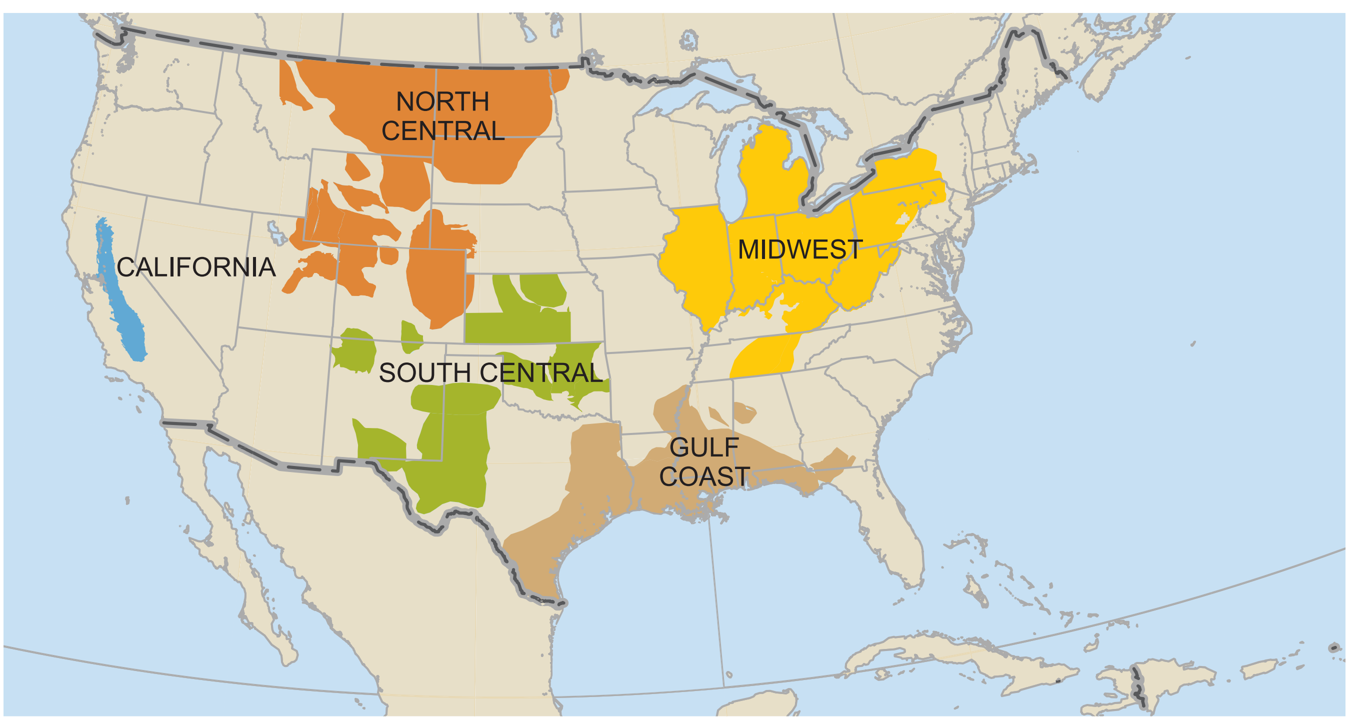



***Figure 2-9.*** *Regional Groupings of Select USGS Basins*

| Region | Average Cost ($/tonne) | Storage Volume (gigatonnes) |
|---|---|---|
| California | $7 | 11 |
| Midwest | $7 | 54 |
| North Central | $11 | 85 |
| Gulf Coast | $7 | 135 |
| South Central | $8 | 129 |
| Overall Average/ Total | $8 | 413 |

***Table 2-9.*** *Volume-Weighted Storage Cost by Region*

within a region, so an average cost is uniformly applied to the entire region.

## E. Additional Considerations and Assumptions

The long-term nature of a CCUS investment suggests that financiers will require assurance that the source of $CO_2$ will be available for the entire financing period (i.e., 20 years). For industries, less likely to invest in CCUS on their own, it is envisaged that a long-term $CO_2$ offtake agreement between the emitter and the industries that are willing to invest in the CCUS equipment and capture the emissions may be required. The offtake agreement commits the emitter to providing $CO_2$ volumes for that financing period. These emitters will likely require an incentive as compensation for entering into the long-term commitment of a $CO_2$ offtake agreement and having capture equipment adjacent to their facilities. For purposes of the cost curve modeling, an emitter incentive (CCUS cost) of $5 per tonne was applied to all industry emitters other than oil, natural gas, and power generation.

For power plants, the capture cost per tonne is affected by the power plant utilization. As power plant utilization rates decline, primarily due to increased use of renewable forms of energy, the effective cost to capture and separate $CO_2$ increases. To account for this, each third of total power plant capacity was assumed to be running with utilizations of 85%, 55%, and 35%.

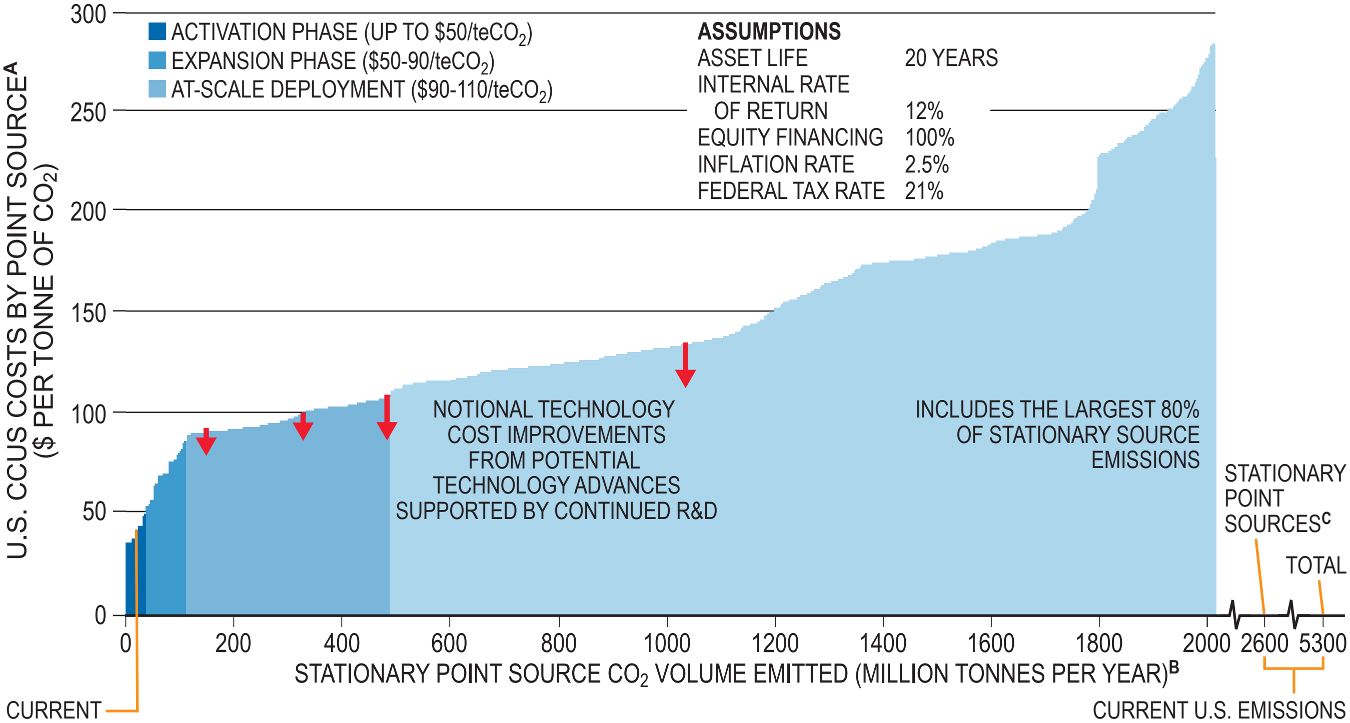
# VI. ENABLING FUTURE CCUS PROJECTS

As described earlier, at-scale deployment of CCUS in the United States will require an economic incentive for all participants in the supply chain—from emission source and capture to transport and storage. Creating these supply chains will require significant capital investment as well as ongoing operating expenses. Figure 2-10 depicts the estimated cost to deploy CCUS, assuming a 12% return on investment as shown on page 1-15 and in Figure 2-6.

Within the cost curve, three transition points were identified and denote three phases of CCUS deployment projected to occur over a 25-year period—activation, expansion, and at-scale. A set of actions has been identified for each phase of implementation to enable the growth of CCUS in the United States over the next 25 years. The phases are based upon enabling the lowest cost supply chains first, with consideration given to ease and speed of implementation.

- Activation Phase — Aligns existing policies and regulations with existing incentives of up to $50/tonne enabling an additional 25 Mtpa to 40 Mtpa, doubling existing CCUS capacity within the next 5 to 7 years. It is important to note that under existing policies, capacity in this phase will likely remain at the lower end of the range, primarily due to the 12-year life of the Section 45Q tax incentive.
- Expansion Phase — Extends and broadens existing policies, bringing total incentives up to $90/tonne and enabling an additional 120 Mtpa within the next 15 years. This phase also requires developing a durable regulatory and legal environment.
- At-Scale Phase — Brings total CCUS capacity to ~500 Mtpa, enabled by incentives of about $110/tonne.

While the NPC does not expect CCUS will be applied to all U.S. stationary sources, at this level, CCUS would be deployed on nearly 20% of U.S. stationary emissions, which is a level the NPC has defined as at-scale deployment. It is also worth noting that at an incentive of ~$150/tonne,




Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total $CO_2$ emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

***Figure 2-10.*** *U.S. CCUS Cost Curve with $CO_2$ Capture Volume by Phase*

CCUS could be economically applied to about 1.2 billion tonnes of $CO_2$ emissions, which is just under half of all U.S. stationary emissions and nearly a quarter of total U.S. $CO_2$ emissions. Achieving that level of CCUS deployment, when combined with continued RD&D and infrastructure development, will drive down technology costs and could also create other carbon management pathways including greater use of hydrogen, bioenergy with CCS, and direct air capture.

Put into context, 500 Mtpa of CCUS capacity is roughly equivalent to 14 million barrels of oil, which is larger than the volume of U.S. domestic production in 2019. Achieving CCUS deployment at that level will require a total cumulative investment over 25 years of approximately $680 billion, of which about $28 billion is for $CO_2$ pipeline infrastructure development. This level of investment and infrastructure development has the potential to generate $21 billion in annual GDP and support 233,000 annual jobs.[15]

Chapter 3, "Policy, Regulatory, and Legal Enablers," describes the existing policy and regulatory framework in the United States for CCUS and explains the challenges it presents for further deployment. It details the specific policy driven financial incentives and the regulatory improvements that will be needed to enable deployment across the three phases of implementation: activation, expansion, and at-scale. The chapter also describes the critical role that RD&D plays in improving performance, reducing costs, and advancing alternative CCUS technologies, making the case for continued investment by both government and industry to decrease the cost of $CO_2$ capture technology and to identify and characterize suitable large-scale storage locations.

15 See ERM memo, Appendix D.