[redacted]

Ohio citizens assume costs and risks of carbon capture

Randi Pokladnik

May 1, 2025 4:30 am

Carbon capture and sequestration (CCS) is a process where supercritical carbon dioxide (1070+ psi and 88 degrees Fahrenheit) is injected into Class VI injection wells, into underground subsurface rock formations to a depth of at least 5,000 feet. The CO_2 gas fills pore spaces located within these formations.

Recently, Ohio's legislators introduced bills HB 170 and SB 136, which will give the Ohio Department of Natural Resources (ODNR) primacy (primary control) over Ohio's Class VI carbon dioxide injection wells. Currently, the U.S. EPA has control and issues the permits for Class VI wells.

H.B. 170 and S.B. 136 will allow the ODNR chief to force non-consenting property owners to surrender use of the "pore space" under their private property.

"A storage operator who has obtained the consent of owners of at least 70 percent of the pore space proposed to be used in a storage facility may submit a statutory consolidation application for the operation of the entire proposed storage facility to the chief of the division of oil and gas resources management," H.B. 170 states.

If the bills pass, private landowners could have no rights or the ability to stop this dangerous asphyxiant from being stored under their homes.

CCS does not remove any existing carbon dioxide from the atmosphere but rather captures carbon dioxide from industrial processes, including ethanol fermentation, methane reforming, Portland cement production, and emissions from fossil fuel power plants. The process is energy intensive and expensive. The CCS equipment can require up to 30% of the energy that a power plant produces.

A recent report by the International Panel on Climate Change found "the levelized costs of electricity (LCOEs) for thermal power generation with CCS are at least 1.5 to 2 times above current alternatives, which include renewable energy plus storage."

In addition to increased electricity bills, taxpayers will be picking up the costs for the 45Q tax credits for carbon dioxide captured. The Inflation Reduction Act established rates per ton of CO_2 sequestered at $85 per ton. Considering that a large coal power plant emits 15 million tons of CO_2 per year; the subsidy would be $1.25 billion in taxpayer dollars per year for one power plant.

There are many concerns about safety throughout the entire process, including the toxic chemicals needed to sequester the CO_2 gas, the pipelines used to transport the gas, and issues with Class VI wells leaking CO_2 gas. Some estimates say at least 900 miles of pipelines would be required to carry CO_2 across the state from sources to injection wells in eastern Ohio.

In 2020, the Mississippi town of Satartia experienced a pipeline rupture in a 24-inch pipe. The pipe spewed out CO_2 at a pressure of 1300 psi for more than three hours. The accident resulted in 200 people being evacuated and 45 taken to the hospital, with many having resulting chronic illnesses.

Nearby cars shut off or failed to start because of lack of oxygen needed to operate internal combustion engines. Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air. It is also an asphyxiant and intoxicant, which makes releases from CO2 pipelines harder to observe and avoid especially when it spreads and migrates off the pipeline right-of-way.

In 2009, concerned citizens living in Darke County successfully mobilized over a 14-month period to stop a proposed carbon sequestration project.

"The 35-member Midwest Regional Carbon Sequestration Project (MRCSP) cancelled the $92.8 million dollar proposal to inject one million tons of carbon dioxide captured over four years from an ethanol plant in Greenville, Ohio," according to a report from Recharge News.

There is no guarantee that the CO2 will remain in the rock strata in perpetuity. Several factors could contribute to leaking of the super-critical CO2 gas from the underground storage locations. One of these is seismic activity.

"The presence of seismic activity, both natural and induced, is of great importance when evaluating CO2 sequestration potential. Extensive fault zones may provide leakage pathways along which CO2 could migrate," according to a study published in Environmental Geosciences.

Additionally, the very act of injecting high-pressure CO2 into continental crusts could induce earthquakes and jeopardize carbon storage.

"Deep borehole stress measurements at the Mountaineer coal-burning power plant on the Ohio River in West Virginia indicate a severe limitation on the rate at which CO2 could be injected without the resulting pressure build-up, initiating slip on preexisting faults," according to a study published in the Proceedings of the National Academy of Sciences of the United States of America.

The fact that Ohio has over 36,000 orphan oil wells also adds to the risks of injecting high pressure CO2 into Ohio's Appalachian counties.

Finally, current CCS projects have shown that the process fails to capture the promised amounts of CO2 and many of the taxpayer subsidized projects have been terminated.

According to the Geoengineering Monitor, after decades of research, "there is no evidence that CCS can address the causes of the climate crisis or significantly reduce greenhouse gas emissions."

CCS is too risky and too expensive.

Dr. Randi Pokladnik

MSDS data for CCS chemicals

Carbon Dioxide

If a pipeline is compromised, CO_2 can leak from it. CO_2 is transported at high pressures in a "supercritical" liquid phase, but in the open air, it turns to gas as it rushes out of a ruptured pipe. Dry ice—the solid form of CO_2—may also form at the opening, which could further damage the pipeline.

As a gas, carbon dioxide is heavier than air. When large amounts of it are released, it hugs the ground and can displace oxygen—including in people's lungs. "The biggest risk is it being an asphyxiant," says Herzog. Whether that happens depends on the amount of CO_2 that escapes, the landscape of the region, and the weather. In addition to asphyxiation, breathing in concentrated CO_2 can cause headaches, dizziness, sweating, increased heart rate, and other maladies. If people can get to fresh air, these symptoms typically pass (although treatment with oxygen is recommended)—but if high levels of CO_2 sit in low-lying areas on a windless day, or build up indoors, people could be hurt or killed. After the rupture in Satartia, forty-five people went to the hospital for treatment.

MEA Monoethanolamine

Hazards Identification Potential Acute Health Effects: Very hazardous in case of eye contact (irritant), of ingestion, . Hazardous in case of skin contact (irritant, permeator), of inhalation (lung irritant). Slightly hazardous in case of skin contact (corrosive), of eye contact (corrosive). Liquid or spray mist may produce tissue damage particularly on mucous membranes of eyes, mouth and respiratory tract. Page 1 of 8 MSDS- Monoethanolamine Introduced Date: 01.05.2022 Revision Date:01.05.2025Skin contact may produce burns. Inhalation of the spray mist may produce severe irritation of respiratory tract, characterized by coughing, choking, or shortness of breath. Inflammation of the eye is characterized by redness, watering, and itching. Potential Chronic Health Effects: CARCINOGENIC EFFECTS: Not available. MUTAGENIC EFFECTS: Not available. TERATOGENIC EFFECTS: Not available. DEVELOPMENTAL TOXICITY: Not available. The substance may be toxic to kidneys, lungs, liver, central nervous system (CNS). Repeated or prolonged exposure to the substance can produce target organs damage. Repeated or prolonged contact with spray mist may produce chronic eye irritation and severe skin irritation. Repeated or prolonged exposure to spray mist may produce respiratory tract irritation leading to frequent attacks of bronchial infection.

Ethylene oxide

A. Ethylene oxide can cause bodily harm if you inhale the vapor, if it comes into contact with your eyes or skin, or if you swallow it.

B. Effects of overexposure:

1. Ethylene oxide in liquid form can cause eye irritation and injury to the cornea, frostbite, and severe irritation and blistering of the skin upon prolonged or confined contact. Ingestion of EtO can cause gastric irritation and liver injury. Acute effects from inhalation of EtO vapors include respiratory irritation and lung injury, headache, nausea, vomiting, diarrhea, shortness of breath, and cyaonosis (blue or purple coloring of skin). Exposure has also been associated with the occurrence of cancer, reproductive effects, mutagenic changes, neurotoxicity, and sensitization.

1. EtO has been shown to cause cancer in laboratory animals and has been associated with higher incidences of cancer in humans. Adverse reproductive effects and chromosome damage may also occur from EtO exposure.

a. Reporting signs and symptoms: You should inform your employer if you develop any signs or symptoms and suspect that they are caused by exposure to EtO.

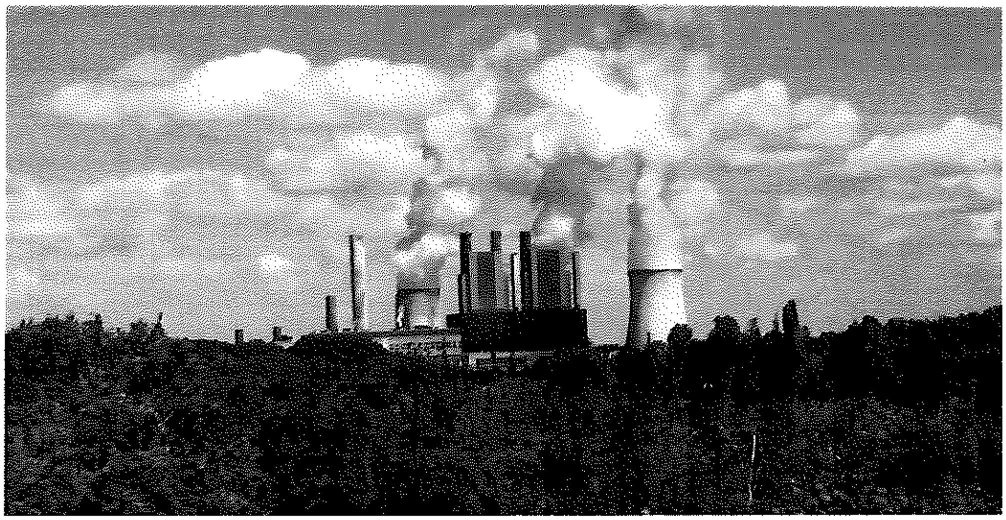
Ammonia

NFPA RATINGS (SCALE 0-4): HEALTH=3 FIRE=1 REACTIVITY=0 EMERGENCY OVERVIEW: COLOR: colorless PHYSICAL FORM: liquefied gas ODOR: pungent odor MAJOR HEALTH HAZARDS: respiratory tract burns, skin burns, eye burns, mucous membrane burns PHYSICAL HAZARDS: Containers may rupture or explode if exposed to heat. POTENTIAL HEALTH EFFECTS: INHALATION:
Page 2 of 9 SHORT TERM EXPOSURE: burns LONG TERM EXPOSURE: burns SKIN CONTACT: SHORT TERM EXPOSURE: burns LONG TERM EXPOSURE: burns EYE CONTACT: SHORT TERM EXPOSURE: burns LONG TERM EXPOSURE: burns INGESTION: SHORT TERM EXPOSURE: burns LONG TERM EXPOSURE: burns.

New research shows hydrological limits in carbon capture and storag

Lorenzo Rosa, Jeffrey A. Reimer, Marjorie S. Went & Paolo D'Odorico

May 4, 2020



Working coal-fired power plant near Aachen, Germany. Image courtesy Jeff Reimer.

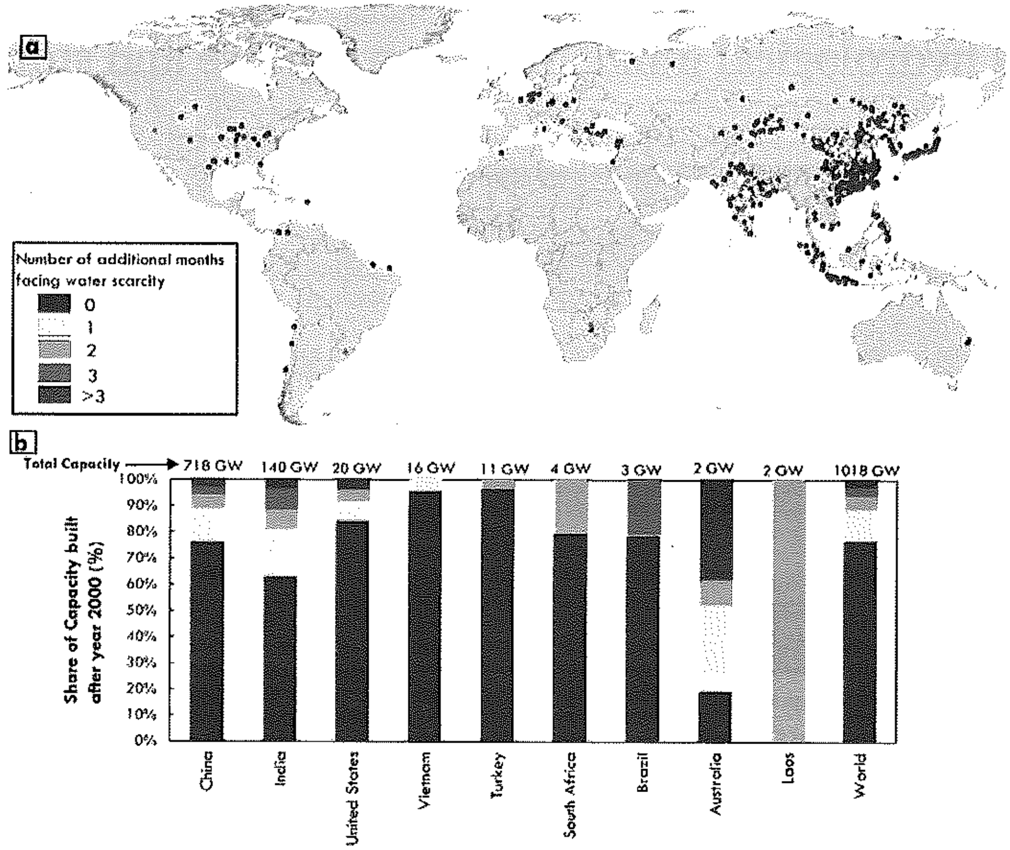
"Water use is an important consideration in the implementation of Carbon Capture and Storage"

Our energy and water systems are inextricably linked. Climate change necessitates that we transition to carbon-free energy and also that we conserve water resources as they become simultaneously more in demand and less available. Policymakers, business leaders, and scientists seeking to address the urgency of climate change are increasingly looking to Carbon Capture and Storage (CCS) to help meet global climate goals. While CCS minimizes emissions from the combustion of fuels, its impact on global water resources has not been widely explored. New research shows that CCS could stress water resources in about 43% of the world's power plants where water scarcity is already a problem. Further, the technology deployed in these water-scarce regions matters, and emerging CCS technologies could greatly mitigate the demand CCS places on water consumption.

Energy-producing facilities such as coal-fired power plants consume large amounts of cooling water. The type of cooling method used in a power plant (wet cooling towers, once-through cooling, or air-cooled condensers) affects water consumption. Installing CCS at these facilities requires that they produce additional energy to compensate for the energy used by the CCS process. With that comes additional cooling water consumption. In addition, the CCS process itself adds to the overall water consumption in a fashion that depends upon the CCS technology deployed.

Most CCS projects currently operational worldwide use *absorption* technologies. Common absorbents are aqueous bases containing amine groups that bind to carbon dioxide, separating it from other gases in the flue mixture. The process of absorption of CO_2 into these solvents and subsequent regeneration of the solvents require energy withdrawal from the power plant. The circulation of large quantities of solvents results in water loss by evaporation. Other state-of-the-art CCS technologies use far less water as they separate the carbon dioxide from flue gas by *adsorption* onto solid materials, or pass the exhaust gas through membranes. These technologies potentially reduce both the energy load *and* water consumption.

In this research we examine how CCS can be implemented sustainably without compromising water resources. Specifically, does the addition of CCS to coal-fired power plants impact water consumption in any region of the world significantly enough to induce or exacerbate water scarcity? We modeled the hypothetical implementation of four different CCS technologies at every global coal-fired power plant of significant size currently operating around the world and studied the impact on regional water withdrawals and consumptions. Using a global biophysical monthly hydrological analysis, we assessed where, when, and to what extent water scarcity could constrain the implementation of CCS.



Additional water scarcity with carbon capture amine absorption technology. The figure shows the number of additional months of water scarcity per year that CFPP built after year 2000 would face in the event they were retrofitted with the commercially available amine absorption technology. Detail (a) shows the geographical distribution of CFPP built after year 2000 and the number of months of additional water scarcity they would face if retrofitted with amine absorption, (b) shows country-specific share of coal-fired capacity built after year 2000 that would face additional months of water scarcity if retrofitted with amine absorption. Countries are listed in descending order based on additional capacity facing water scarcity.

Somewhat surprisingly, we found that in cases where water scarcity does not already exist, the addition of CCS will not generally induce scarcity. However, we also found that 43% of the current installed global coal-fired power capacity is located within regions that now experience water scarcity for at least one month a year, and over 30% of global capacity faces scarcity for five or more months a year. In these regions, implementation of CCS technologies worsens the water stress. Retrofitting power plants with less water-intensive capture technologies could mitigate competition for freshwater resources, and the choice of cooling *methods becomes increasingly important.*

Our results enable a more comprehensive understanding of water use by coal-fired plants with, and without, carbon capture. Careful trade-offs need to be considered, and the choice of carbon capture technology is very relevant. We believe that this work will serve as a guide to policymakers as we ramp up the implementation of CCS around the world.

Research is online here: *Nat Sustain* (2020) https://doi.org/10.1038/s41893-020-0532-7

TOPICS

Carbon Capture and Storage
College of Chemistry

Failed or cancelled CCS projects

Kemper County project
In 2008, Southern Company proposed a flagship "clean coal" project in Kemper County, Mississippi. The project aimed to capture CO_2 from a lignite-fired Integrated Gasification Combined Cycle (IGCC) power plant and the captured CO_2 was to be used for EOR. Construction of the power plant began in 2010, commissioning was announced for 2014 and the project was expected to cost US$ 2.4 billion. Ultimately, the project's commercial commissioning date was repeatedly delayed by more than three years in total, and the cost more than tripled to US$ 7.5 billion. In 2017, the Mississippi Public Service Commission ordered Southern Company to stop construction of the coal gasification project with CCS at Kemper, because it was never operational and costs were skyrocketing. The huge increase in costs was caused by technical problems and failures, including construction problems and design flaws. According to press reports, Southern Company secured nearly one billion dollars in federal grants and tax credits for the Kemper CCS project.

Indiana Gasification project
The Indiana Gasification project was announced in ~2006 and cancelled in 2015. The project planned to capture CO_2 from a coal gasification plant in Spencer County, Indiana and the captured CO_2 was to be transported via a 400 kilometres pipeline to EOR projects in Texas and Mississippi. The project was declared unviable and unfinanceable.

Medicine Bow
The Medicine Bow project was a coal-to-liquid power plant with CO_2 capture proposed by DKRW Advanced Fuels to be located in Carbon County, Wyoming. The goal of the project was to capture more than half of the CO_2 produced during the coal refining process and pipe it to oil fields in Wyoming for EOR. After being postponed twice, the project was cancelled for financial reasons.

Antelope Valley project
The Antelope Valley project was located at Basin Electric's Antelope Valley Station in North Dakota. The aim of the project was to capture CO_2 from a lignite-fired power plant and the captured CO_2 was to be fed into the neighboring Dakota pipeline for EOR in Canada. Despite grants and loans from the US-DOE and USDA in the hundreds of millions, the project was cancelled for financial reasons. Basin Electric justified this decision on the grounds that the project costs would probably be 30 percent higher than originally assumed.

FutureGen project
The FutureGen project was to retrofit a coal-fired power plant in Meredosia, Illinois, with a CO_2 capture unit and install a 30-mile pipeline to transport the captured CO_2 for injection into saline aquifers in Morgan County, Illinois. The US-DOE terminated its agreement with the project in 2015, because of years of delays and the project's inability to complete financing. Of the US$ one billion in federal funding allocated for the project, US$ 200 million have been disbursed.

Hydrogen Energy California project
SCS Energy's Hydrogen Energy California project in Kern County, California, proposed a commercial-scale IGCC coal-fired power plant with CO_2 capture. The company planned to transport the captured CO_2 via a pipeline for EOR in an Occidental's oil field. SCS Energy applied to an US-DOE funding programme and received funding. In 2016, the US-DOE terminated the agreement with the project "*after extensive budget and schedule overruns and repeatedly missed milestones*".

Summit Texas Clean Energy project
Summit Power proposed a IGCC coal plant with CO_2 capture in Ector County, Texas. Some of the captured CO_2 was to be used for industrial production, while most was to be piped for EOR in the

Permian Basin. In 2009, the US-DOE approved US$ 350 million in federal funding for the project. In 2016, the US-DOE terminated its agreement with the project, due to delays and unauthorized expenditures.

CEMEX CCS project
CEMEX and RTI International aimed to develop and demonstrate CO_2 capture technology at a CEMEX cement plant in Texas. Although US$ 1.1 million was allocated to the project under a US-DOE program in 2009, plans for the site were cancelled. CEMEX and its industrial partners "concluded *that commercial-scale CCS in the cement industry is not yet ready for deployment*".

Boise White Paper Mill project
In ~2014, a CCS project at a Boise White Paper LLC paper mill in Walla Walla County, Washington State was cancelled for financial reasons, because costs were too high, the project was not selected for further governmental funding and the revenue forecasts for CO_2 injections were too uncertain.

BP Texas City Refinery project
Praxair Inc proposed a commercial demonstration of CO_2 capture from an existing hydrogen production facility at an oil refinery in Texas City, Galveston County, Texas. The captured CO_2 was to be piped to a Denbury oil field for EOR. After a two-year project definition phase, Praxair concluded that the project costs and integration risks in Texas City were disproportionate to the potential benefits of the project, and the project was discontinued.

Projects that failed to capture predicted amounts

Only a few CCS projects have published CO_2 capture capacity results. For those projects for which data are available, the actual capture capacity is often significantly, up to 70 percent, lower than the nominal capacity – despite the fact that the technology is already a hundred years old. Some examples are presented below.

Terrell Gas Processing Plant
The oldest operating CCS project in the U.S. has a nominal CO_2 capture capacity of 0.5 million tonnes of CO_2 per year. In its report on the Global Status of CCS in 2021, the GCCSI describes that the Terrel plant has captured a total of twenty million tonnes of CO_2. Since Terrel's CO_2 capture plant has been in operation since 1972, this corresponds to an annual CO_2 capture volume of 0.4 million tonnes – and ***only 80 percent of the project's potential maximum capture capacity***.

Enid Fertilizer project
For the second oldest operating CCS project in the U.S., a nominal capacity of 0.7 million tonnes of CO_2 per year was specified until 2019. The actual capacity is only 0.1 to 0.2 million tonnes of CO_2 per year, ***less than 30 percent of the nominal capacity***.

Shute Creek Gas Processing facility
The third oldest operating CCS project in the U.S. had an annual nominal capacity of 4.3 million tonnes since 1986 and a nominal capacity of seven million tonnes of CO_2 per year since 2010. The power plant has on average fallen short of ***about 36 percent of its capacity*** during its lifetime. According to the US-based Institute for Energy Economics and Financial Analysis (IEEFA), "*Shute Creek became a "Sell or Vent" project. It could either sell the CO_2 to third parties or vent the CO_2 when prices were low and EOR was uneconomic. The excess CO_2 that could not be sold for EOR has been vented over the years. [...] Essentially, just half of CO_2 emissions captured and the other half vented*".

Century Plant
For the Century Plant a nominal capture capacity of 8.4 million tonnes of CO_2 per year was specified until 2019. The actual capacity is only five million tonnes of CO_2 per year, ***less than 60 percent of the nominal capacity.***

Great Plains Synfuels Plant
The lignite-fired Great Plains Synfuels Plant has a nominal capacity of three million tonnes of CO_2 per year and an actual annual capacity of ~1.9 million tonnes, ***a 35 percent shortfall from the nominal capacity***.

Farnsworth EOR Project
The Farnsworth project was conducted from 2013 to 2018 and had a total nominal CO_2 injection capacity of one million tonnes. A total of 0.6 million tonnes of CO_2 was injected, ***only 60 percent of the planned capacity***.

Core Antrim Shale plant
The CCS project at Core Energy's Antrim Shale gas processing plant has a nominal capture capacity of 0.35 million tonnes of CO_2 per year. The plant captured two million tonnes of CO_2 from 2003 to 2015, this corresponds to an annual quantity of 0.167 million tonnes, ***a 47.6 percent shortfall***.

Petra Nova CCS project
The Petra Nova CCS project had a lifetime of three and a half years, experienced more than 360 downtime days from 2017 to 2019 due to technical problems ***and has only achieved 83 percent of its CO_2 capture target.***

Illinois Industrial CCS Project
The Illinois Industrial project aimed to capture one million tonnes of CO_2 per year. The actual capture capacity is approximately ***50 percent of the nominal capacity***.

Lake Charles Methanol (GCCSI: advanced development)
The project has been "in development" since 2007 and was discontinued in 2015 and then resumed. Fifteen years after it was announced, the project is not yet under construction, has reduced the planned CO_2 capture volume by almost 80 percent, announced seven times higher construction costs per tonne of CO_2 captured, and has been supported with substantial public subsidies.

Gorgon

The Gorgon carbon capture and storage (CCS) project is the world's largest CCS project, located at Chevron's Gorgon LNG facility on Barrow Island just off the coast of Western Australia. The project removes carbon dioxide (CO2) that is mixed with the natural gas extracted from the reservoir, and then captures and stores it underground. The project was approved on the condition that it would capture 80% of the CO2 it removed from its reservoir on a five-year rolling average from July 2016. However, it only started injecting CO2 in August 2019, three years behind schedule, and to date it has captured 44% of the CO2 removed between FY2019-20 and FY2023-24.

Particularly concerning is the fact that Gorgon's performance has decreased over time, with a marked drop in the percentage of CO_2 captured in the past three years. In FY2021-22, it captured 33% of the CO_2 it removed, in FY2022-23 34%, and in FY2023-24 just 30%, its lowest performance to date. Since the start of its operation, the project has not achieved its target to capture 80% of the CO_2 it removes in any single year. Instead, over the last five years, it underperformed by 45% against that target, and over the last three years by 60%.

Source: https://www.geoengineeringmonitor.org/the-current-state-of-ccs-in-the-u-s-resume-after-100-years-of-co2-capture-and-25-years-of-extensive-federal-funding

Disadvantages:

- CO_2 may spread after injection; some models suggest that a fracture 8 km from the injection site may leak CO_2 after 250 years (IEA, 2008).
- Future drilling may cause fractures and leakage. Preventing leakage may involve replacing cap-rocks with engineered materials, like cement and well-casing, which may have unfavorable properties. Of the nine documented cases of significant leakages from the 470 natural gas storage facilities in the US, with a capacity-weighted median age of 25 years, five were related to the integrity of the wells. Although CO_2 is more corrosive than methane to metal parts, natural gas systems are more susceptible to caprock leakages because of rapid changes in pressure, so this experience can be taken to show minimum CO_2 storage performance (Intergovernmental Panel on Climate Change, 2008). Abandoned oil wells are sealed, but if the well penetrates a storage zone, the stored CO_2 may react with the cement plug and weaken it, eventually causing a leak (IEA, 2008). Though CO_2 resistant cement exists it does add 25% to total cementing costs (IFC International, 2008).
- Vertical fractures may occur, allowing CO_2 to leak into other aquifers or to seep into hydrocarbon resources and the soil, potentially harming plants and sub-soil ecosystems. Also, SO_2 or O_2 contaminants may leech heavy metals from the surrounding rock matrix, posing an environmental risk. Contamination of surrounding areas may also occur if brine is displaced by injected CO_2 (Intergovernmental Panel on Climate Change, 2008).
- Not all saline aquifers are suitable for CO_2 sequestration. Some may not have sufficiently impermeable cap-rocks above them, or have too many previous drilling sites in the vicinity to ensure secure storage. Crystalline, metamorphic, and volcanic rocks are often too impermeable to hold much CO_2 and too fractured to securely hold CO_2. Those found in mountain-forming areas would also be more susceptible to leaks (IEA, 2008) While basins formed in mid-continent locations are likely to be stable and structurally favorable and those found behind mountains formed by plate collisions are likely to have high storage potential, areas closest to the actual mountain-forming faults should be used only with caution (Intergovernmental Panel on Climate Change, 2008).
- Any impurities in injected CO_2 may negatively impact the compressibility of the CO_2 stream, thus decreasing the storage capacity (Intergovernmental Panel on Climate Change, 2008).
- Pilot sites generally have comprehensive monitoring programs, but injection rates per volumes are low compared to potential commercial projects, while current commercial projects inject larger volumes of CO_2, but monitoring programs are often limited (In Salah, Alberta acid-gas), or reservoir properties are "unrepresentatively good" (relatively high permeability at Sleipner). Also, better technology must be developed for seismic imaging of CO_2 and detecting leaks, and more cost-effective methods must be found and tested (Michael *et al*, 2009)
- Current CO_2 storage capacity estimates are imperfect (Intergovernmental Panel on Climate Change, 2008).
- Currently, more investigation is needed of risks associated with possible leakage, impacts on underground microbes and human health need further investigation, and effective monitoring strategies (Intergovernmental Panel on Climate Change, 2008).
- The risk of CO_2 leakage can be reduced by producing brine from the aquifer and re-injecting it at some distance from the CO_2 injection wells. This technique can increase the percent of CO_2 dissolved in the aquifer in 200 years from about 8% to up to 50%. For an energy cost of <20% of that needed for CO_2 compression, brine re-injection can increase dissolution 5-fold, reducing environmental risk, since free-phase CO_2 poses the greatest risk. Running the pumps for 200 years, at a 2.4Mt/yr brine production and reinjection rate, would incur energy costs of about $15 million, at $0.05/kWh. Additional costs Increasing brine injection rate increases the pressure in the aquifer and does not always increase dissolution rate (Hassanzadeh, 2009)

Source: https://igutek.scripts.mit.edu/terrascope/?page=terrestria

CO_2 transmission pipelines pose different risks than traditional hydrocarbon transmission pipelines Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air, and is an asphyxiant and intoxicant, making CO_2 pipeline releases harder to observe and avoid especially as a released plume spreads and migrates well off the pipeline right-of-way. CO_2 properties differ from those for materials moved in hazardous hydrocarbon liquid or natural gas transmission pipelines. CO_2 pipeline releases significantly increase the possible "affected" or "potential impact" area identified in federal regulations addressing hydrocarbon transmission pipelines upon pipeline rupture release, and CO_2 pipeline ruptures have a greater potential to endanger the public. Current federal pipeline safety regulations do not incorporate these important CO_2 differences to assure safety to the public. Federal pipeline safety regulatory changes are warranted if CO_2 pipeline mileage is to be increased dramatically in the U.S., especially under CCS. CO_2 transmission pipelines have many unique failure dynamics such that a rupture may impact significantly greater geographic areas than hydrocarbon pipelines. In particular, a combination of CO_2 phase/temperature changes may result in explosive pipe release forces as the CO_2 converts to gas. Moreover, CO_2's lack of odor and invisibility means that it may not be possible for citizens and first responders to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. It is important that anyone using such CO_2 detection meters assure that such equipment has been properly calibrated/maintained and users properly trained in their use and limitations. Once a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume.

The CO_2 released from a pipeline will be heavier than air, and the high-rate release from a pipe rupture will form cold dense gas fog clouds comprised of dry ice particles and visible water vapor as the humidity in the air condenses from the extreme cooling. Such high-rate releases can produce areas of low visibility from "fog," both from dry ice particles and water condensation. The CO_2 pipeline rupture fog becomes transparent when eventually warmed by the surrounding environment. Upon warming, the CO_2 plume can flow considerable distances from the pipeline unobserved, traveling over terrain, displacing oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline or diesel powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off, and cause pilot lights on furnaces, stoves, and natural gas fireplaces to go out. Oxygen displacement by CO_2 gas can cause asphyxiation of humans and animals, that can lead to death. Further, CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving, using power equipment, or exposed to cold weather.

It is vitally important to not underestimate the potential distance that a CO_2 pipeline rupture plume can reach and affect, especially in nonlevel terrain. Additional safety margins should be employed in populated areas when using dispersion modeling results for CO_2 pipeline releases. Before the U.S. is blanketed with a major increase in CO_2 transmission pipeline mileage driven by CCS efforts, substantial changes need to be implemented in federal pipeline safety regulations specifically addressing the unique dangers of CO_2 in transmission pipelines in any phase.

The danger zone for human life for hazardous hydrocarbon liquid and natural gas pipeline releases is generally measured in feet, albeit many thousands of feet for larger diameter higher pressure pipelines. In contrast, a CO_2 pipeline's impact area may be measured in miles, not feet. This is likely because:

- CO_2 pipeline ruptures can release many tons of CO_2,

- the compressed CO_2 will expand into gas phase upon pipeline rupture and fill a much larger volume that it did inside the pipe, and

- the CO_2 may not disperse quickly because it is heavier than air, meaning that it will tend to flow toward and settle in low lying areas including ravines, valleys, and basements.

SOURCE: Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S. prepared for the Pipeline Safety TRUST Credible. Independent. In the public interest. http://www.pstrust.org/ by Richard B. Kuprewicz President, Accufacts Inc. kuprewicz@comcast.net March 23, 2022

-

IOP Publishing Environ. Res.: Infrastruct. Sustain. 3 (2023) 015008 https://doi.org/10.1088/2634-4505/acbed9

ENVIRONMENTAL RESEARCH
INFRASTRUCTURE AND SUSTAINABILITY

OPEN ACCESS

RECEIVED
1 December 2022

REVISED
17 February 2023

ACCEPTED FOR PUBLICATION
24 February 2023

PUBLISHED
10 March 2023

PAPER

US power sector carbon capture and storage under the Inflation Reduction Act could be costly with limited or negative abatement potential

Emily Grubert[1,*] and Frances Sawyer[2]

[1] Keough School of Global Affairs, University of Notre Dame, Notre Dame, IN, United States of America
[2] Pleiades Strategy, San Francisco, CA, United States of America
[*] Author to whom any correspondence should be addressed.

E-mail: egrubert@nd.edu

Keywords: carbon capture and storage, coal, natural gas, electricity, Inflation Reduction Act, scenario modeling

Supplementary material for this article is available online

Abstract

The United States' (US) largest-ever investment in expected climate mitigation, through 2022's Inflation Reduction Act (IRA), relies heavily on subsidies. One major subsidy, the 45Q tax credit for carbon oxide sequestration, incentivizes emitters to maximize production and sequestration of carbon oxides, not abatement. Under IRA's 45Q changes, carbon capture and storage (CCS) is expected to be profitable for coal- and natural gas-based electricity generator owners, particularly regulated utilities that earn a guaranteed rate of return on capital expenditures, despite being costlier than zero-carbon resources like wind or solar. This analysis explores investment decisions driven by profitability rather than system cost minimization, particularly where investments enhance existing assets with an incumbent workforce, existing supplier relationships, and internal knowledge-base. This analysis introduces a model and investigates six scenarios for lifespan extension and capacity factor changes to show that US CCS fossil power sector retrofits could demand \$0.4–\$3.6 trillion in 45Q tax credits to alter greenhouse gas emissions by −24% (\$0.4 trillion) to +82% (\$3.6 trillion) versus business-as-usual for affected generators. Particularly given long lead times, limited experience, and the potential for CCS projects to crowd or defer more effective alternatives, regulators should be extremely cautious about power sector CCS proposals.

1. Introduction

Decarbonization, and specifically a goal of eliminating net anthropogenic greenhouse gas (GHG) contributions to climate change (reaching 'net zero') by mid-century in order to increase the likelihood of keeping climate change-driven global temperature increases at or below the Paris Agreement's target of well below 2 °C, with a goal of 1.5 °C, has become a major policy driver in the energy sector and elsewhere (Pye *et al* 2017, Eyre *et al* 2018, Waisman *et al* 2019, Sun *et al* 2021, White House 2021, Allen *et al* 2022). In the United States (US), pollution control policies have historically involved mainly command-and-control regulatory approaches aimed at limiting or eliminating pollution of a specific type from a particular source, or market-based approaches aimed at limiting total pollution of a specific type from a group of sources by incentivizing the lowest-cost actions (Kraft 2000). For climate pollution, particularly from the energy sector, command and control (e.g. fossil fuel bans or net-zero laws) and direct market-based approaches (e.g. carbon taxes and cap-and-trade) have seen some limited uptake at the state and regional levels. The most common recent federal mechanism for climate policy, however, has been to subsidize zero-emissions technologies and greenhouse gas controls in the power sector, including investment and production tax credits (PTC) for renewable electricity and carbon dioxide (CO_2) capture and storage (CCS). This approach relies on the theory that making a desirable outcome (in this case, less GHG intensive electricity generation) cheaper than a less desirable outcome (more GHG intensive electricity generation) will ultimately result in