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Reality Check on CO_2 Emissions Capture at Hydrogen-From-Gas Plants

Carbon Capture Essential to Blue Hydrogen Production Has Been Unreliable

Executive Summary

Blue hydrogen is only blue if the carbon capture and storage (CCS) system captures the CO_2 emissions effectively and efficiently over the long term. It is misleading to call it blue if the CCS system only addresses a small fraction of the project's emissions.

Both public relations claims and federal incentive programs for blue hydrogen are based on the notion that projects will have effective CCS systems capturing significant percentages of the CO_2 they produce, transport and inject underground, either in geologic reservoirs or via enhanced oil recovery (EOR) operations.[1]

The fundamental problem? CCS technology has been around for decades,[2] yet its actual, real-world implementation in either the large commercial hydrogen production sector or the utility-scale power production sector has been unreliable and far below the 90 percent to 95 percent capture rate that is considered the industry's prime objective for CCS. Not only that, but among the projects that have been built, substantial failures have occurred. This might have been understandable in the 1970s, 1980s, and possibly even the 1990s. But the fact that the problem persists into the 2020s makes CCS a highly risky investment.

It is also essential for the CCS system to capture the CO_2 generated in all aspects of the hydrogen production facility including (but not limited to) the emissions from the power required to run the CCS system and process equipment. Also, upstream emissions of methane—a powerful greenhouse gas that escapes uncontrolled from natural gas extraction and pipeline leaks—must be eliminated or at least greatly reduced.

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[1] Without carbon capture, natural gas-based hydrogen is called "gray hydrogen." A conventional steam methane reformer (SMR) gray hydrogen system has a mean carbon intensity of approximately 9k g CO_2/kg H_2. See: Argonne National Laboratory, Energy Systems Division, Systems Assessment Center. Updates of Hydrogen Production from SMR Process in GREET®2019. October 2019.

[2] The Global CCS Institute reports that 27 CCS projects are currently operational around the world, at various scales and applications, with four in construction and 58 in "advanced development. See: Global CCS Institute. Global Status of CCS 2021. 2021, p.15.

Instead of long-term high CO_2 capture rates and comprehensive carbon capture coverage, however, IEEFA's examination of the current blue hydrogen industry finds:

- The scope of CCS at hydrogen plants is limited;
- Its effectiveness is not well-documented; and
- Evidence from other settings in which CCS is being used is sparse and discouraging.

A. Commercial-Scale Applications of CCS Are Extremely Limited

A review of the publicly available details for the 27 carbon capture projects currently operating around the world finds:[3]

- **No natural gas-fired electrical power plant in the entire world currently uses CCS.** None are expected to open until after 2025,[4] and natural gas combustion is expected to require greater energy input than coal combustion to achieve a high capture rate.[5]
- **Only one coal-fired power plant in the world currently operates with CCS.** The only other coal-fired power plant with CCS, the Petra Nova project in Texas, suspended operations on May 1, 2020.
- **Only two commercial plants producing hydrogen from natural gas capture more than 1 million metric tons per annum (Mtpa) of CO_2**—one in the United States (Air Products' Port Arthur, Texas, facility) and one in Canada (Quest).[6]
- **No new CCS-equipped plant producing hydrogen from natural gas and capturing 1 Mtpa or more of CO_2 is expected to open until 2024 or later.**[7]

[3] *Ibid.*
[4] Global CCS Institute, *op. cit.*, p.16.
[5] The National Energy Technology Laboratory (NETL) reports that flue gases from natural gas combined cycle plants typically contain about 4% by volume, compared to 12-15% from coal plant flue gas, providing less driving force for CO_2 separation, and thus requiring greater energy input. See: NETL. Post-Combustion CO_2 capture. Accessed January 27, 2022.
[6] Global CCS Institute. Facilities Database. Accessed January 16, 2022. Also see: Global CCS Institute. Global Carbon Capture and Storage Institute Response to the National Hydrogen Strategy Issues Papers. July 2019, pp. 1-2.
[7] *Ibid.*

By comparison:

- U.S. companies installed 15.5 gigawatts (GW) of utility-scale solar capacity in 2021.
- The U.S. Energy Information Administration (EIA) projects that 21.5 GW of utility-scale capacity will be installed in 2022—a 39% year-over-year increase.
- Solar power is expected to account for almost half (46%) of the new utility-scale capacity added in 2022, with the remainder roughly split between natural gas (21 percent) and wind (17 percent).[8] Although supply chain constraints could dampen the outlook, there is broad consensus that solar's difficulties are temporary.[9]

Spending billions on blue hydrogen with promises of 90 percent or higher CO_2 capture rates years down the road is imprudent.

B. CCS Misses the Majority of the Emissions From a Hydrogen Plant

Spending billions on blue hydrogen with promises of 90 percent or higher CO_2 capture rates years down the road is imprudent. A recent study noted that government policies on blue hydrogen tend to assume a carbon capture rate of 90 percent. The researchers cautioned:

> "While these high capture rates are assumed in many national strategies and major reports, they have not yet been achieved in a large-scale commercial plant and have only recently been achieved in the Tomakomai CCS demonstration project, which required very high expenditure (which was \$127/t CO_2)."[10]

Although blue hydrogen developers claim high carbon capture potential, actual performance rates are rarely reported. The scant data that exists indicates that consistent 90 percent carbon capture performance, even on the targeted emission stream, has not been achieved over the long term. Consistent performance at a 90

[8] EIA. Solar power will account for nearly half of new U.S. electric generating capacity in 2022. January 10, 2022.
[9] E&E News EnergyWire. Solar could boom this year if supply chains don't collapse. January 11, 2022.
[10] T. Longden, *et al.* Clean hydrogen? – Comparing the emissions and costs of fossil fuel versus renewable electricity-based hydrogen. Applied Energy. 306. January 2022, p. 5. The cost figure is in U.S. dollars.

percent or higher capture rate—not merely sporadic attainment—is the goal for CCS.

The scope of the CCS capture system is extremely important as well. A recent study found that applying CCS to the hydrogen manufacturing process gas waste stream only targets "about two-thirds of the total emissions on-site."[11] The remaining emissions are released by burning methane onsite as fuel to provide the energy to run the process. The comparatively diluted flue gases from combustion "are more difficult, and expensive, to capture."[12] The study further noted that energy is also required to compress the CO_2 for transport and storage, which is "not well defined and depends on the distance to suitable geological storage facilities."[13]

The scant data that exists indicates that consistent 90% CCS performance has not been achieved over the long term.

The U.S. Argonne National Laboratory, a U.S. Department of Energy (DOE) multidisciplinary science and engineering research center, analyzed the carbon emissions from gray hydrogen, which is produced from natural gas using the steam methane reform (SMR) process but without using a CCS system. It reported that the mean estimate for carbon content from gray hydrogen is 9 kilograms of CO_2 per kilogram of hydrogen (9kgCO_2/kgH2). The figure is a total that includes both process emissions and emissions from onsite power generation.[14] Some hydrogen production facilities export steam while others do not, which affects the ratio of the shares of emissions from feedstock natural gas and fuel combustion of natural gas for the project.[15] The Argonne research examined emissions from both types of SMR facilities. It reported that the comparative share of carbon dioxide emissions are as follows:

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[11] *Ibid.*, p. 4.
[12] *Ibid.*
[13] *Ibid.*
[14] Argonne National Laboratory, Energy Systems Division, Systems Assessment Center. Updates of Hydrogen Production from SMR Process in GREET®2019. October 2019. Also see: P. Sun, *et al.* Criteria sir pollutants and greenhouse gas emissions from hydrogen production in U.S. steam methane reforming facilities*.* Environ. Sci. Technol. 53(12):7103-13. April 2019.
[15] P. Sun, op. cit.

Table 1: Shares of Feedstock Natural Gas and Process Fuel Combustion Natural Gas in Typical SMR Hydrogen Plants With/Without Steam Export

SMR Hydrogen Plant	Feedstock Share in Total Natural Gas Use	Process Fuel Combustion Share in Total Natural Gas Use
With steam export	59.4%	40.6%
Without steam export	67.2%	32.8%

One analysis puts the fuel combustion share of carbon emissions at an average of 28.4%.[16] This suggests that even if CCS performance were improved to achieve consistent 90% to 95% CO_2 capture, it will not be able to meet the Infrastructure Investment and Jobs Act (IIJA) threshold for funding of 2kgCO_2/kgH_2 for SMR production of hydrogen unless the CCS equipment also is applied to the onsite power generation source. This concern is illustrated more clearly when reviewing carbon capture performance and scope at the two existing commercial plants producing hydrogen from natural gas with CCS capturing more than 1 Mtpa of CO_2—the Air Products Port Arthur plant and the Quest project at a bitumen upgrader plant.

Example: Air Products Port Arthur Hydrogen Plant

The Air Products hydrogen plant in Port Arthur, according to U.S. Environmental Protection Agency (EPA) data, produced an average of 1.82 Mtpa of CO_2 from its production process (excluding on-site combustion for power).[17] The CCS system was designed to capture only 1 Mtpa, a goal it met in a May 2013 performance test.[18] The company reported to DOE that testing proved the capture rate can exceed its goal of 75% of the CO_2 from a treated stream containing least 10% CO_2 by volume based on a 2013 capacity test.[19] Nevertheless, during a 2014-17 DOE demonstration period, the facility captured an average of less than 50 percent of the CO_2 generated by the hydrogen production process.[20]

Given that the facility did not capture any of the CO_2 released from the production of power to run the hydrogen production units and carbon capture system, the effective onsite CO_2 capture rate was well below 40%.[21] Also, the reports do not

[16] *Ibid.*
[17] Environmental Protection Agency (EPA). Facility Level Information on Greenhouse Gases Tool (Flight). Also see: EPA. Environmental Protection Agency. Air Products Port Arthur Facility.
[18] International Energy Agency Greenhouse Gas Program (IEAGHG). The Carbon Capture Project at Air Products' Port Arthur Hydrogen Production Facility. December 2018, p. 95.
[19] Air Products & Chemicals, Inc. Demonstration of Carbon Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production, Air Products and Chemical. March 2018, p. 3.
[20] EPA. Facility Level Information on Greenhouse Gases Tool (Flight).
[21] The facility's total CO_2 emissions averaged 2.5 Mtpa from 2010-20. The combustion emissions for onsite power—not equipped for CCS—comprised roughly 0.684 Mtpa of the total. The sum of the production process emissions that escaped the CCS equipment and the uncontrolled CO_2 from onsite power production is roughly 64% of total CO_2 emissions, leaving 36% as the facility-wide

appear to include CO_2 emissions from the energy required to compress and transport the captured gas for injection.

Example: Quest CCS Project at Hydrogen Production Units of Bitumen Plant

The Quest CCS project is part of Shell's operations at the Scotford bitumen upgrader facility near Edmonton in Alberta, Canada. The Scotford facility adds hydrogen to the bitumen to create synthetic crude oil.[22] It produces the hydrogen onsite from natural gas.[23] The CCS equipment is installed only on the three hydrogen manufacturing units.[24] Quest's capture rate goal is 80 percent,[25] but the actual capture rate for the system's emissions is much lower. It achieves only an average 68.3% capture rate when the CO_2 emissions for the CCS, transport and storage portions of the process are included. The total hydrogen-and-CCS capture rate may be even lower because it appears the emissions of the hydrogen production units' power source are not included.[26] Thus, although Shell reports an average 80 percent capture rate, that is based solely on the hydrogen production stream,[27] which excludes the emissions from other relevant parts of the hydrogen production system. Because the hydrogen production units are embedded within a bitumen upgrader plant, Shell reports that the overall Scotford facility only captures about 35 percent of its total onsite CO_2 emissions.[28]

Neither the Air Products nor Quest facilities demonstrate that CCS can capture 90 to 95 percent of the CO_2 produced at a hydrogen production facility over time. Quest reported in 2020 that one of the "challenges" during its 2020 reporting period was that flame instability at higher CO_2 capture rates caused degradation of the reformer burners in the hydrogen units.[29] Its average carbon capture rate has declined every year since its first full year of operation. Releasing roughly 50% to 60% or more of carbon dioxide emissions to the ambient air would not qualify a natural gas-based hydrogen plant as a low-carbon source.

Also, the actual efficiency rate for total CO_2 capture as described above is for on-site emissions only. Neither project quantifies nor reports the greenhouse gas impact of

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capture rate, rounded up to 40 for the purposes of this report. See: EPA. Facility Level Information on Greenhouse Gases Tool (Flight). Also see: EPA. Air Products Port Arthur Facility.

[22] Shell. Scotford. Accessed February 3, 2021.

[23] Global CCS Institute. Blue Hydrogen. April 2021, p. 8. The Quest project is 90% owned by Canadian Natural Resources and 10% by Shell.

[24] International Energy Agency Greenhouse Gas Program (IEAGHG). Quest CCS Project Presentation. September 2019, slide 5.

[25] Shell. Quest CO_2 Capture Rate Performance, February 19, 2021, p. 6.

[26] Shell. Project Quest Carbon Capture and Storage Project: Annual Summary Report for 2020 (hereafter, Project Quest Annual Summary for 2020). March, p. 4-1. The average covers the years from 2016 through 2020.

[27] Quest CO_2 capture ratio performance *op. cit.*, p. 6.

[28] *Ibid*., p. (i). Also see: Shell. Quest CCS facility captures and stores five million tonnes of CO_2 ahead of fifth anniversary. July 9, 2020. Also see: Shell. Quest CCS Project: Presentation at PCCC2 Conference, Bergen, Norway. September 19, 2013, slide 4.

[29] Project Quest Annual Summary for 2020, *op. cit.*, pp. ii and 4-1.

methane leaks upstream during extraction, processing and transportation, or CO_2 leaks downstream before injection.

New hydrogen projects employing CCS are planned, and corporation promises about carbon removal efficiency are extremely optimistic. Air Products, for example, claims that the CCS system at its methane-based hydrogen project planned for Ascension Parish in Louisiana will capture more than 95 percent of the CO_2 from the natural gas feedstock.[30] It reportedly hopes to power its process with hydrogen-fueled electricity to reduce on-site emissions.[31] But the plant is not expected to start operations until 2025-26.[32] It is unclear whether Air Products actually will be able to achieve anywhere near a 95% on-site capture rate over time; the upstream methane emissions from natural gas extraction and pipeline transportation still will be an issue; and we expect that little to no operational data will be available for at a some period after the project commences operations.

Corporation promises about carbon removal efficiency are extremely optimistic.

The feasibility of adding CCS to existing gray hydrogen plants is questionable. Air Product's Port Arthur demonstration worked largely as intended, but the International Energy Agency (IEA) noted in a review of the project that the Port Arthur plant is an industry outlier. Hydrogen production from Port Arthur and similar energy efficient units comprise just 1 percent of installed worldwide SMR capacity.[33]

The disappointing performance of CCS at existing hydrogen plants is consistent with the problematic history of CCS use in coal plants.

Example: Boundary Dam 3 Coal Plant

SaskPower's Boundary Dam 3, the only project in the world capturing CO_2 from a coal plant, has failed to meet its 90% capture rate CCS target. The company's operational data show the actual capture rate from October 2014 through December 2021 was approximately 53 percent.[34] The facility reportedly achieved only a 33

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[30] ESG Review, *op. cit*.
[31] Argus Media. Air Products rockets to green hydrogen. October 26, 2021.
[32] Global CCS Institute. Facilities Database. Accessed January 16, 2022.
[33] IEAGHG. The Carbon Capture Project at Air Products' Port Arthur Hydrogen Production Facility. December 2018, p. 95.
[34] IEEFA analysis of the monthly Boundary Dam 3 Status Updates available online from SaskPower, the owner of the unit. See: SaskPower. BD3 Status Update: December 2021. January 14, 2022.

percent carbon capture rate in 2021,[35] far below the plant's initial 90 percent target capture rate.

The plant was supposed to capture more than 1 Mtpa, to be used for EOR, but an IEEFA briefing note in mid-2021 documented that it has achieved its planned 3,200 metric tons of CO_2 daily capture rate only sporadically and has never done so over any extended period.[36] For example, the International CCS Knowledge Centre (half-owned by the owner of the Boundary Dam facility), admitted that during the first 3 ½ years of plant operation, the CCS system only achieved its design capture capacity for three days.[37] Last year, the Centre provided data indicating the CCS system has continued to fall short of its design goal.[38] The project was roughly 2 ½ years late in meeting its 4 Mtpa capture goal, marking the milestone in March 2021 instead of October 2018.[39]

The extent to which the missed capture goal target is due to inadequacies of the CCS equipment or plant outages is not entirely clear, but IEEFA notes that failing to capture projected amounts of CO_2 due to outages of the non-capture portions of the plant represents a risk that SaskPower, the plant's owner, accepted when it retrofitted Unit 3 with CCS. Serious issues with the compression system in 2020 and 2021,[40] for example, highlight the complexity of the process; when part of the system fails, the entire system fails.

The feasibility of applying CCS to existing gray hydrogen plants is questionable.

More importantly, SaskPower's monthly Boundary Dam 3 status reports show the project no longer has a target of capturing 90% of the CO_2 it produces—the target is now just 65%, a precipitous drop in expected capture efficiency.[41] However, as noted earlier, Boundary Dam 3 has failed to capture even 65% of the CO_2 it produces.

SaskPower shut down Boundary Dam 4 in December 2021 and plans to close Boundary Dam 5, as well.[42] In 2018, the government official explained there was

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[35] S&P Global Market Intelligence. Only still-operating carbon capture project battled technical issues in 2021. January 6, 2022.
[36] IEEFA. Boundary Dam 3 Coal Plant Achieves CO_2 Capture Goal Two Years Late. April 2021.
[37] International CCS Knowledge Centre. Boundary Dam 3: Upgrades, updates and performance optimization of the world's first fully integrated CCS plant on coal. June 9, 2019.
[38] International CCS Knowledge Centre. SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability. March 2021.
[39] International CCS Knowledge Centre. Derates and Outages Analysis – A Diagnostic Tool for Performance Monitoring of SaskPower's Boundary Dam Unit 3 Carbon Capture Facility. March 2021.
[40] E&E News EnergyWire. CCS 'red flag?' World's sole coal project hits snag. January 10, 2022.
[41] IEEFA, *op. cit*.
[42] SaskToday. Unit 4 at Boundary Dam slated to be retired on Dec. 1. November 10, 2021.

"simply not a business case" to retrofit the two units.[43] It appears unlikely that CCS will be installed on the largest unit, Boundary Dam 6, which reaches its expected 50-year end of life in 2028. SaskPower and the Saskatchewan government disclosed they would not retrofit any more coal-fired units with CCS in the near future and did not expect to make further decisions about expanding CCS until 2024.[44]

Example: Petra Nova Coal Plant

The Petra Nova plant, which cost $1 billion to build, began operations in 2017. The CO_2 traveled via 80-mile pipeline to an oil field near Houston for use in EOR operations.[45] The target CCS capture rate was 90%, but the actual CO_2 capture rate from a slipstream of W.A. Parish Unit 8's flue gas averaged 70% from January 2017 to December 2019. This does not include emissions from the gas-fired combustion turbine used to power the facility. Adding those emissions lowers the overall on-site capture rate to 58 percent. The unit was taken offline in May 2020.

IEEFA observed that NRG Energy, which had taken the lead on the project, had recorded three impairment charges related to the plant and to Petra Nova Parish Holdings, the subsidiary that operates the facility. The charges, recorded in 2016, 2017 and 2019, totaled $310 million.[46] NRG Energy had written off essentially all its investment in the project. This is striking, given that Petra Nova benefitted from a $190 million grant from the U.S. Energy Department and received $250 million in concessionary lending from the Japan Bank for International Cooperation (JBIC) and Mizuho Bank, Ltd.[47]

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[43] Regina Leader-Post. Sask. Not moving forward on carbon capture expansion. July 10, 2018.
[44] CBC News. Decisions on carbon capture future could be up to 7 years away, says SaskPower CEO. September 11, 2018.
[45] U.S. Department of Energy. Petra Nova: W.A. Parish Project. Accessed January 12, 2022. Also see: Global CCS Institute. Facilities Database. Accessed January 16, 2022.
[46] IEEFA. Mothballing of Petra Nova carbon capture project shows likely fate of other coal-fired CCS initiatives. August 3, 2020, p. 6. Also see: NRG Energy. NRG 10-K for the year ended December 31, 2016. 2017. Also see: NRG Energy. NRG 10-K for the Year Ended December 31, 2017. 2018. Also see: NRG Energy. NRG 10-K for the Year Ended December 31, 2019. 2020.
[47] IEEFA, *op. cit*. Also see: JX Nippon Oil and Gas Exploration Corporation. Petra Nova CCUS Project in USA. June 8, 2018, Slide 8.

Table 3: Comparison of Petra Nova (Before Suspension) and Boundary Unit 3 Coal Plants[48]

Project Name and Location	Status	Scale	Production CO_2 Capture % Goal	Production CO_2 Capture Achieved[49]	Efficiency Gap for Production	Actual CO_2 Capture Rate for Total Site[50]
Boundary Dam 3 SaskPower[51] Saskatchewan, Canada	Operating since 2014 but other units were not CCS-equipped	150 MW	90% Lowered to 65%	53%	37 percentage points	**53%**
Petra Nova Petra Nova CCS I[52] Thompson, Texas	**Opened in 2017[53] but suspended in May 2020**	240 MW	90%[54]	70%[55]	20 percentage points	Estimated 58%[56]

Other major commercial-scale CCS failed efforts in the United States coal sector include:

- The Kemper project (Southern Company) was designed to gasify lignite and capture the carbon before combustion. The cost initially was estimated at $3 billion with a start date of 2014, but it ballooned to $7.5 billion. Also, the project's coal gasification process did not operate reliably during pre-operational testing and the CCS capture portion of the project was scrapped. The unit now runs solely on natural gas with no CO_2 controls.[57]

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[48] Data source for Table 1, unless otherwise noted, is Global CCS Institute. Facilities Database. Accessed January 16, 2022.
[49] Sources for the projects' actual capture rates are IEEFA analyses of data: Office of Scientific and Technical Information, *op. cit.*, and the monthly Boundary Dam 3 Status Updates available online from SaskPower, the owner of the unit. See: SaskPower, *op. cit*. The percentage figure for Boundary Dam 3 covers the period from October 2014 to December 2021. The percentage figure for Petra Nova covers the period from January 2017 to December 2019.
[50] The percentage figure for the total on-site capture rate includes the production stream plus—for Petra Nova— the dedicated combustion turbine to power the carbon capture facility. Boundary Dam Unit 3's CCS system is powered by the coal plant; it has no dedicated combustion turbine for its CCS system.
[51] NS Energy. What are the top carbon capture and storage projects around the world? July 19, 2019.
[52] Petra Nova CCS I is a joint venture of Petra Nova (subsidiary of NRG Energy) and JX Nippon Oil & Gas Exploration (subsidiary of JX Nippon). NS Energy, *op. cit.*
[53] Technically, it achieved commercial operation on December 29, 2016. The project demonstration period commenced January 1, 2017. See: U.S. Department of Energy. W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project: Final Scientific/Technical Report – Petra Nova. March 31, 2020, p. 3.
[54] Office of Scientific and Technical Information, *op. cit.*, p. 6.
[55] The 70% figure is based on actual operations, taking into account downtime of the CCS system and its power source. Petra Nova's carbon capture system, as well as the cogeneration facility that powered it, experienced multiple days of downtime from 2017 through 2019. Office of Scientific and Technical Information, *op. cit.*, p. 41.
[56] Percentage figure is for operations from January 2017 to December 2019.
[57] New York Times. Piles of dirty secrets behind a model 'clean coal' project. July 5, 2016. Also see: E&E News EnergyWire. The Kemper project just collapsed. What it signifies for CCS. October 26, 2021.

- The Duke Energy Edwardsport Integrated Gasification Combined Cycle plant initially planned to include CCS. Proposed in 2006 at an estimated cost of $1.8 billion, the costs at its 2013 completion had jumped to more than $3.5 billion, resulting in well-above-market power prices of as much as $140 per megawatt-hour. Duke Energy decided not to add CCS to the plant when a company study found the costs would have been excessive.[58]

C. After Years of Investment, a Long-Term 90% CO_2 Capture Rate Has Not Been Shown to Be Technologically or Financially Viable, and There Is No Proof That the Technologies Now Being Promoted Will Do Any Better

CCS is not a new concept. It has been used for decades in a variety of settings.[59] Yet as shown above, the technology has racked up limited achievements despite years of public and private investment. A 2021 analysis comparing blue and green hydrogen concluded:

> "Carbon avoidance costs for high capture rates tend to be above $80/t CO_2. In contrast, the cost of producing zero-carbon hydrogen from electrolysis could fall in the foreseeable future, and be cost-competitive with fossil fuel options. This means that the economic case for fossil fuels with CCS is generally limited."[60]

Given the public and private investments, made over decades, the outlook is not hopeful.

The Department of Energy began investing in CCS technology 13 years ago. Since FY2010, Congress has appropriated $14.2 billion for CCS-related research and development, including:

- $7.3 billion for funding within DOE's carbon management office;
- $3.4 billion in the 2009 recovery act for CCS development; and
- $3.5 billion in the 2021 IIJA for carbon capture activities.[61]

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[58] Power Magazine. Duke hit hard by exorbitant O&M costs at Edwardsport IGCC facility. September 27, 2018.
[59] IEEFA. Carbon Capture and Storage Is About Reputation, Not Economics: Supermajors Saving Face More Than Reducing Emissions. July 2020.
[60] T. Longden, *op. cit.,* p. 9.
[61] Congressional Research Service. Carbon Capture & Sequestration (CCS) in the United States. October 2021, p. 1. IILJ allocation includes direct air capture as well as industrial and utility-based CCS..

Through one initiative, the DOE spent roughly $1.1 billion on specific CCS demonstration projects, primarily targeting commercial viability for coal plants and the industrial sector.[62] The Government Accountability Office (GAO) audited the effort in 2021. Of the 11 projects the DOE accepted into the program:

- Only three—one coal project and two industrial projects—actually were built and entered operations.
- The single coal project, Petra Nova, halted operations in 2020. The two industrial projects remain operational.
- The other projects were not completed, as the GAO reported, "primarily in response to factors affecting their economic viability."[63]

The technology has racked up limited achievements despite years of public and private investment.

In contrast, DOE launched the "SunShot Initiative" in 2011 to reduce solar energy costs by 75 percent, to make it competitive on a large scale without subsidies by decade's end. The cost reduction goal corresponds to utility-scale solar costing about 6 cents per kilowatt-hour (kWh). In September 2017, DOE announced the SunShot Initiative had met its target three years earlier than expected. The project's goal for 2030 goal is 3 cents per kWh, which DOE reports would make it among the least expensive options for new power generation.[64]

Even if CCS technology is shown to be able to achieve a 90% capture rate, that won't happen for years—allowing three years for permitting and design, two to three years for construction, and several years of operations. By that time in the late 2020s, we expect that the cost of producing green hydrogen will have fallen below that of blue hydrogen. As a result, much of the investment and government subsidies for blue hydrogen production facilities and related CCS will be stranded and/or consumers and taxpayers will be forced to bail out another declining industry.

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[62] Congressional Research Service, *op. cit*., p. 2.
[63] Congressional Research Service, *op. cit*., p. 7.
[64] U.S. Department of Energy. The SunShot Initiative. Accessed January 18, 2022. Also see: Climate Scorecard. The SunShot Initiative in the U.S. April 17, 2021.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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