Working Document of the NPC Study
Meeting the Dual Challenge:
A Roadmap to At-Scale Development of Carbon Capture, Use, and Storage
Made Available December 12, 2019

Topic Paper #1

SUPPLY AND DEMAND ANALYSIS FOR CAPTURE AND STORAGE OF ANTHROPOGENIC CARBON DIOXIDE IN THE CENTRAL U.S.

On December 12, 2019, the National Petroleum Council (NPC) in approving its report, *Meeting the Dual Challenge: A Roadmap to At-Scale Development of Carbon Capture, Use, and Storage*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Supply and Demand Task Group. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of three such working documents used in the study analyses. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

NATIONAL PETROLEUM COUNCIL

Study on Carbon Capture, Use and Storage

Topic Paper:

Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S.

December 22, 2019

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Contents

List of Figures

List of Tables

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**Jeff was a Lecturer (Stanford Law School) and Research Fellow (Stanford's Steyer-Taylor Center for Energy Policy & Finance) while researching this paper. He joined the University of Wyoming's EORI during final editing. Thanks to both Stanford and EORI for support and help.*

Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S.

Section (1) Introduction

a. Question Investigated

This Topic Paper investigates the following question: ***"What limited policy interventions would be needed for the U.S. anthropogenic carbon capture/storage to scale up to 100-200 million Metric Tons per Annum (MMTPA)*** [1] ***of carbon capture, assuming that capture costs are to be defrayed by (i) existing*** CO_2 ***sequestration tax credits and (ii) net revenues paid at the wellhead by*** CO_2 ***Enhanced Oil Recovery (EOR)***[2] ***operators?"*** The analytical foundations of the paper are based on the best government and private, public and non-public data we could obtain.

This Topic Paper is an outgrowth of the National Petroleum Council's overall report to the Secretary of Energy, *Carbon Capture, Use and Storage,* released December 2019 (NPC-CCUS Report). The authors served on the Coordinating Subcommittee for that Report and specifically advised in the estimation of capture costs as discussed in Chapter 2-CCUS Supply Chains and Economics. However, the focus of this Topic Paper is considerably narrower than that of Chapter 2, which develops a CO_2 abatement curve for up to 1-2 billion MTPA—a range that is an order of magnitude bigger than we consider here. The NPC-CCUS Report defined "at scale" deployment as a smaller 500 MMTPA CO_2, which is 2.5-5.0 times the target scale-up discussed herein.

As will be discussed, there are three reasons to focus upon a volume of 100-200 MMTPA of captured/injected CO_2—a goal we later call a "First Big Step"—in scaling up carbon capture in the U.S. First, the estimated volume of CO_2 captured and injected from anthropogenic sources is approximately 17 MMTPA.[3] Thus an increase to our target of 100-200 MMTPA CO_2 is roughly a one order of magnitude scale-up (10x), an indispensable first step before the ultimate two orders of magnitude (100x) deployed at the high end of the Abatement Curve discussion in the NPC-CCUS Report. Second, linking geographically separated sources and sinks requires multiple very large pipelines—on the scale of 30-40 MMTPA each—in order to keep transport costs in

[1] We use MTPA for Metric Tons per Annum, kMTPA for thousands of MTPA, and MMTPA for millions of MTPA (i.e., Megatons). With this nomenclature we are following customary abbreviations from the power market such as kWh vs. MWh.

[2] See later discussion regarding passive storage in saline formations. We excluded this after multiple analyses showed no significant saline storage—a result of our basic assumption regarding availability of efficient pipelines.

[3] See Section 2 for additional details.

check. Third, our range is comfortably within the volumes that CO_2-EOR experts believe could be purchased by the conventional, onshore, CO_2-EOR industry. Hence, capturing and transporting in three or more geographies inescapably puts us back into the 100-200MMTPA range.

Though we target the 100-200 MMTPA aggregate level of capture, individual carbon capture installations are in the range of 0.5 MMTPA to 2 MMTPA. Thus, success will be built on literally hundreds of projects that must individually prove project feasibility to prospective lenders and investors. For those individual projects the cost challenge that must be met is:

- Capture Cost < [Section 45Q tax credit *plus net* CO_2-EOR sales revenue at the wellhead].
- However, *net* CO_2-EOR sales revenue at the EOR wellhead is equal to the *gross* price paid by the CO_2-EOR operator at its CO_2 receipt point, less the Transport Cost[4] paid by the capturer to move the captured CO_2 to the wellhead.
- So the full equation, with four key variables, would be: Capture Cost < [Section 45Q tax credit *plus gross* CO_2-EOR price *less* Transport Cost]

In order to answer the overall question there are really three broad workstreams.

- First, we need to understand the four variables in the feasibility equation above, i.e., the magnitudes of (i) capture costs from multiple suppliers, (ii) tax credits, (iii) CO_2 sales revenues paid by multiple buyers, and (iv) transportation costs as they pertain to individual potential projects.
- Second, we must combine and sort that data to derive regional supply and demand curves. Once that is done we can estimate regional supply/demand equilibrium, i.e., at a market price of $X/MT, the volume of CO_2 captured in a region equals the volume of CO_2 bought by customers.
- Third, to the extent that the predicted volumes from that aggregate analysis are low (i.e., are too insignificant to meet a reasonable threshold for "scale-up") then what needs to be changed in policy to fix the identified roadblocks?

First, as to the magnitudes of the four key variables, there is a lot of groundwork to be done. The only known variable is the Section 45Q tax credit, which for CO_2 used in EOR ascends at a fixed rate to reach $35/MT by 2026 (rising with CPI inflation thereafter). The other three variables are tougher. Capture costs vary widely across industries, and within industries capture costs vary widely with capture plant size. The current CO_2-EOR market for CO_2 purchases is illiquid and small; and the value of the CO_2 to a particular CO_2-EOR field depends on individual field characteristics. And the

[4] When we analyze an industry with a production cost at Point A and a customer that evaluates price as delivered to Point B, we have to assign transport cost to one party or the other. We choose to treat the transport cost as a reduction in net price obtained by the seller. This is somewhat similar to the concept of a "netback price" in the oil industry. If my natural gas sells for $3/MMBtu in Chicago, but the pipeline cost was $0.25, my "netback" was $2.75/MMBtu. https://www.risk.net/definition/netback-price

cost of pipeline transportation depends primarily on whether a scale-efficient amount of capture projects and CO_2-EOR project are in close enough proximity. Sorting out these three uncertain variables (cost of capture, value to injector, and cost of transport) for hundreds of potential capture sites and hundreds of potential recipient oil fields is a tall order.

Second, as to the economic framework, we don't have to invent any new tools. We utilize the conventional economic approach for regionalized markets with high transportation costs. We assemble the capture cost side into a CO_2 supply curve, with costs rising as total volume sought to be captured increases. We assemble a demand curve combining tax credits, EOR sales, and transport costs; and that demand curve gradually falls with increasing volumes. Market equilibrium occurs where the supply and demand curves cross, where the amount supplied at a price of "X" meets the amount customers are willing to buy at that same price "X".

Third, as to policies, we focus, as discussed below on three main risks: first-mover risk for builders of capture, commodity price risk from fluctuating oil prices, and the risk that adequate transport will fail to develop.

b. General Results & Link to Policy

Our purely quantitative analysis, under four different scenarios, ultimately showed a range of total carbon capture tonnage across three regions that ranged from 65-240 MMTPA. So the raw numbers bracket the investigated 100-200MMPTA range. That is, our results are 35 MMTPA lower on the low end and 40 MMTPA higher on the high end.

There are two main factors driving the 65-220 MMTPA range to be so broad:

- One major wildcard is the "first-mover" investment risk perceived in carbon capture retrofits when most new installations will be 1st through 5th of-a-kind in their industries.
- The other is the "commodity price risk" that oil price volatility could greatly impair the price received by captures from CO_2 sales.

We have come to a conclusion that these two main risk factors—first mover risk and commodity price risk—are not set in stone. At the beginning of our research we though that the "first-mover risk" and "commodity price risk" were just two prominent independent, exogenous variables that needed to be considered in normal sensitivity analysis. However, as we executed the analysis—especially in the context of extensive discussions with industry participants, government experts, regulators and investors—we recognized that limited, targeted policy interventions could greatly reduce these two risks. For instance, an active federal program of cost-sharing grants, plus support for well-funded engineering studies, could create a demonstrable track record of successful projects and thus reduce first-mover risk. Likewise, governments around the world take actions that reduce commodity price risk for sensitive or emerging sectors (e.g., agricultural price supports in the U.S., or Contracts for Differences awarded to certain zero carbon generators in the deregulated U.K. electricity market). Thus, this paper does not stop at quantifying the possible ranges of outcomes: it also considers the policies that could move the likely outcome to the high end of the possible range.

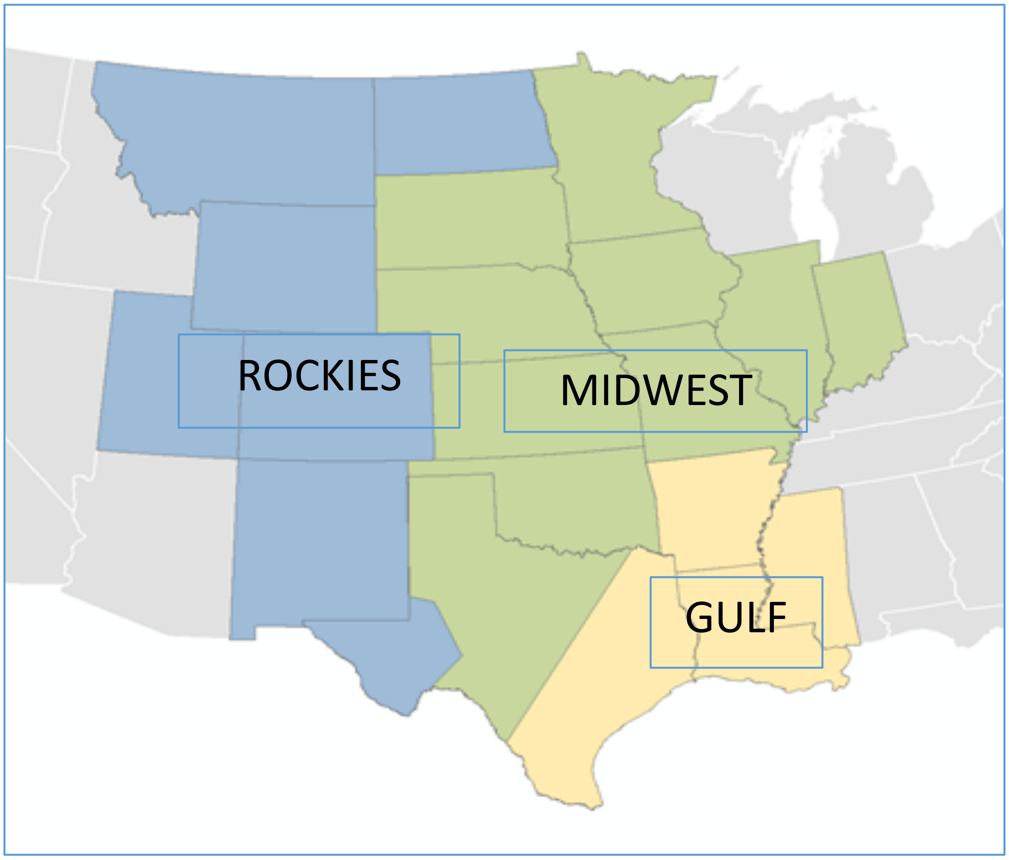
c. Regional and Scenario Results

The Topic Paper examines three major regions of the U.S., each of which could form a nascent CO_2 market. Large emitters (greater than 100,000 MTPA) in the three multi-state areas represent about 53%[5] of U.S. large stationary carbon-dioxide emissions. These states were chosen because they are in the central portion of the U.S. with large numbers of high volume emitters, lower pipeline construction costs, and the only significant U.S. CO_2-enhanced oil recovery markets. The regions (more detail in body of paper) are:

- **Gulf:** Southeast TX, LA, MS, and AR.
- **Midwest:** Northwest TX, OK, MO, IN, IL, KS, IA, NE, and MN.
- **Rockies:** CO, UT, WY, NM, ND, and MT.

[5] See Table 6.1 "All Emitters, Supply Curve Candidate Emitters, and "Capturable Emissions". We had a universe of 1.240 billion MTPA from large emitters (>100,000 MTPA) in these three regions, vs. 2.335 billion from the entire U.S. Source: EPA emitter data from 2017, dated 2017-8-19.

Figure 1.1 Regional Divisions of Central U.S. for Topic Paper



With two major risk factors identified ("first mover risk" and "commodity price risk"), we created four overarching scenarios (i.e., the typical "2x2 matrix" of cases):

1. **Worst/Worst:** Large first-mover risk and low/unstable oil commodity price
2. **Oil Mitigated**: Large first-mover risk, but oil commodity price risk mitigated
3. **1st Mover Mitigated**: Mitigated first mover risk, but low/unstable oil prices continue
4. **Best case**: Both risks mitigated.

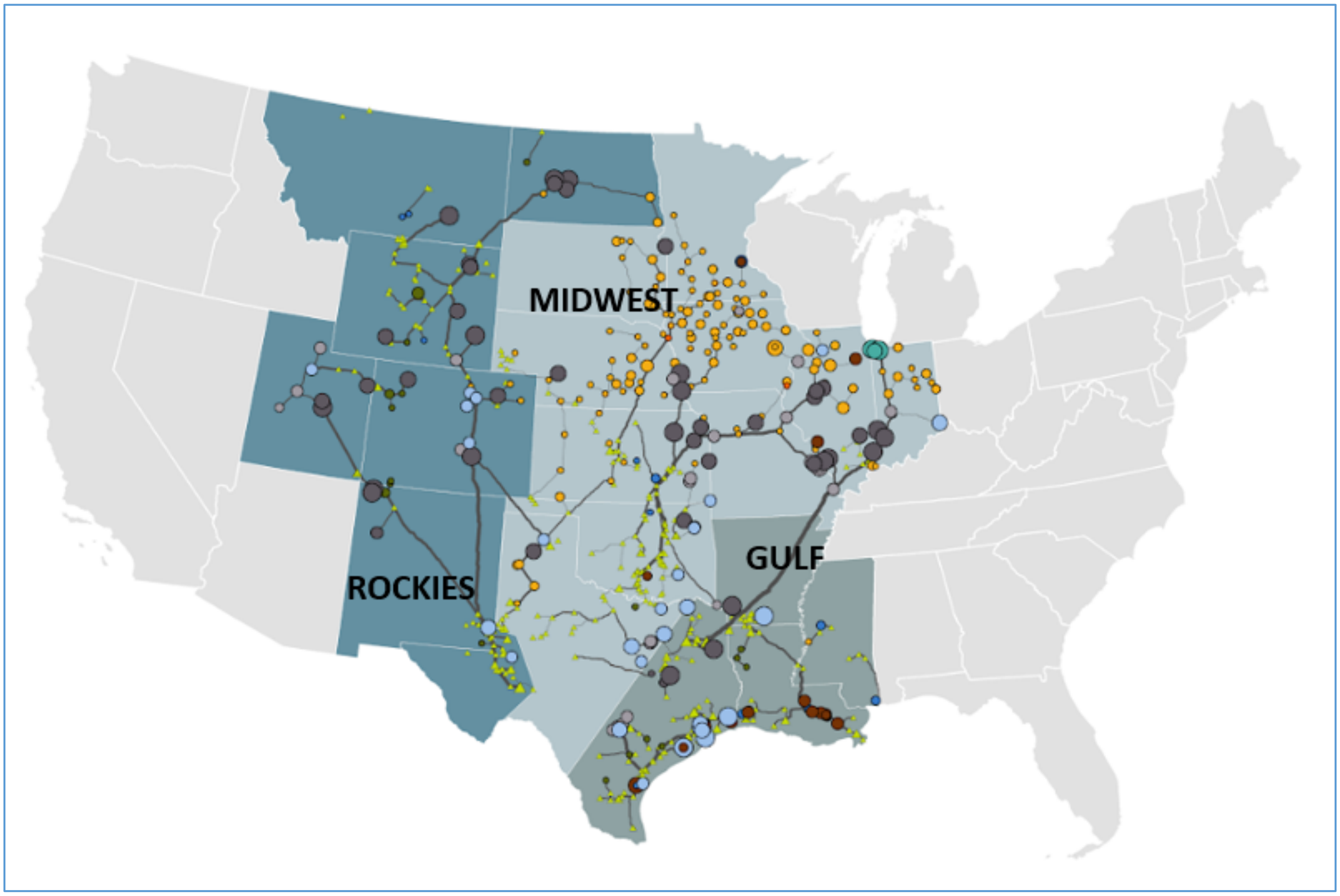
The table below summarizes the tonnage of CO_2 captured and injected in our three regions in these four cases. Figures are in million metric tonnes per annum (MMTPA).

Table 1.1 Annual CO_2 Volumes (in MMTPA) Captured in Three Regions x Four Cases				
	Commodity price risk not addressed: Low/unstable oil		**Commodity price risk addressed: High/stable oil**	
"First-mover" risk not addressed: High capture cost.	**#1 Worst/Worst**		**#2 Oil Mitigated**	
	Gulf	15	Gulf	38
	Midwest	45	Midwest	103
	Rockies	5	Rockies	27
	All three	**65**	**All three**	**168**
"First-mover" risk addressed: Lower capture cost	**#3 1st Mover Mitigated**		**#4 Best Case**	
	Gulf	28	Gulf	55
	Midwest	45	Midwest	135
	Rockies	15	Rockies	50
	All three	**88**	**All three**	**240**

The map below shows the pipeline optimization routing for "#4 Best Case" for the three regions. This routing was developed by using as inputs each region's capture projects based on our analysis and a private database of possible new CO_2-EOR floods.[6] The capture projects and CO_2-EOR floods were linked by a pipeline network generated by Los Alamos National Laboratory's *SimCCS*[2.0] program: new capture projects and new floods were tested under thousands of iterations until supply and demand volume were equal, marginal cost of capture was equal to marginal price received by the capturer, and network shipping tariffs had been minimized.

[6] This is the Advanced Resources International database described in detail in Section 7.

Figure 1.2 Regional Pipeline Summary (Best Case)



d. Definition of Key Risks

Before going forward we want to briefly summarize what we meant by first-mover risk and commodity price risk, plus discussing how we treated the third risk of not obtaining transport:

- **First-mover risk on early capture projects in each sector:** The basic carbon capture technologies (i.e., the equipment, chemistry, and process controls) are well-known, totally proven, and widely deployed worldwide in various CO_2-capture applications *unrelated to pollution control*. But a plant owner who is among the first 1-5 plants in his/her industry to install a capture system *for pollution control purposes* faces a nerve-wracking situation. The plant owner can try to convince his/her Board of Directors, contractors, investors, and lenders that logically nothing ought to go wrong—but the Board is unlikely to be persuaded without hard evidence. In the absence of hard evidence they are likely to require large set-asides of funds in case something goes wrong (i.e., large project and process contingency funds) and assign rates to debt and equity appropriate for high risk projects.

- **Commodity price risk:** CO_2-EOR operators' ability to pay for captured CO_2 depends on the price of oil produced. I.e., if a field can get an extra 2 barrels of oil per MT of CO_2 injected, the field can afford to pay a higher price per MT of CO_2 if the produced oil sells for $100/bbl than at $50/bbl. Thus, most CO_2 sales contracts are directly indexed to oil prices, and oil prices are terribly volatile. That commodity risk, if unaddressed, will make financing prohibitively expensive (other than for a few well-capitalized industry giants financing on their own internal balance sheets).
- **Pipeline customer coordination risk:** Conventional financing for long distance pipelines for products like natural gas requires a half-dozen to two dozen solid companies to simultaneously pre-subscribe for transportation service. For a brand-new industry, with major investments required on both the capture side and for new CO_2-EOR floods, the chances of such a coordinated subscription process are poor. This is different than saying that the economics of a pipeline system would be infeasible—we are saying that the organizational and logistical obstacles seem nearly insurmountable in the absence of coordinated government and industry action. Thus, while we analyzed favorable and unfavorable cases for the prior two risks, removing the roadblock of pipeline customer coordination "risk" is more like a deal-breaker precondition. If such a pipeline system exists, the four cases in the 2x2 matrix are possible. If such a system does not exist the industry is likely to roll out at a snail's pace.

e. Organization of the Paper

This Topic Paper is organized into the following Sections:

Section (1) Introduction
Section (2) Overall approach to the research
Section (3) Review of the use of industry supply and demand curves to estimate equilibrium market prices and volumes.
Section (4) The actual results of applying this analysis to three potential regional CO_2 markets, which we labeled the Midwest, Gulf, and Rockies. Since most readers would like to get to results first, and hear fine points of methodology second, we go straight to the bottom line early.
Section (5) The methodology for determining carbon capture costs in various industries, including the various arguments and uncertainties about what "costs" may really be given the lack of experience in applying the old technology of carbon capture in new industrial settings.
Section (6) The methodology by which the most attractive industrial and power plant sites can be identified and by which the CO_2 tonnes reasonably available for capture at affordable cost can be quantified.
Section (7) The methodology for determining possible CO_2-EOR demand. Who and where are possible incremental CO_2-EOR operators who would pay cash for

captured CO_2 so as to elicit extra production from existing old oil fields, or in certain cases, from new types of formations such as the Residual Oil Zone (ROZ).

Section (8) The values for tax credits available for capture and injection in the context of both CO_2-EOR and passive sequestration. Note that tax credits could also be earned by companies emerging in the business of "utilizing" CO_2 to manufacture construction materials and liquid fuels, but these are not large enough to have any measurable impact on determination of equilibrium CO_2 prices in the near-term.

Section (9) We review the transportation costs to move CO_2 in a network comprised of dozens to hundreds of producers and consumers. In early analysis we used a variety of simple models to roughly estimate transportation costs. Ultimately, we used the powerful modeling capabilities of the *SimCCS*$^{2.0}$ software developed by researchers at the Los Alamos National Laboratory to develop minimum cost pipeline configurations that would connect all capturers who would produce, and all consumers who would buy, at a market equilibrium price.

Section (10) Overall conclusions of the study,

Section (11) Implications for policy and fruitful avenues for future investigation.

Section (2) Summary of Topic Paper

a. Goal of Topic Paper: Find Feasibility of a First-Big Step in CCUS Scale-up

The focus of this Topic Paper is to assess the probability of making a "First Big Step" in the carbon capture industry under current economic, energy price, and incentives. As of 2017, EPA counted 2.6 billion MTPA of CO_2 emitted from U.S. reporting stationary sources.[7] We seek to determine whether there is a set of feasible, or near-feasible projects that is much larger than the current carbon capture industry, even if that subset of projects can't address all of those 2.6 billion tonnes. As stated in the Introduction, we define intermediate success as something in the 100-200 MMTPA level. A detailed rationale for aiming for this particular level is in Subsection (h) below.

- Current capture and injection: Prior to the 2018 increase in tax credits for CO_2 capture/injection, total anthropogenic CO_2 capture/injection tonnage was estimated to be 17MMTPA, or 0.7% of the total 2.6 billion MTPA.[8] That small volume captured is almost exclusively derived from low-cost pure CO_2 sources such as ethanol, natural gas processing, gasification complexes, and excess CO_2 at ammonia plants—mostly with costs in the sub $20/MT area and obtaining revenues from sales to CO_2-EOR operations.
- First Big Step—cherry-picking for low cost/high revenue opportunities: This Topic Paper tests the hypothesis that a "First Big Step" of an incremental ~100-200 MMTPA of anthropogenic CO_2 captured/injected *may* be possible *without* major changes in $/tonne[9] tax credits or new $/tonne carbon emissions fees—though other supportive policy measures would likely still be required.[10] We would aim for: (i) lower cost capture projects in industries with processes that emit large, concentrated

[7] See Figure 4 at https://www.epa.gov/ghgreporting/ghgrp-reported-data#emissions-ghg.

[8] See https://www.epa.gov/ghgreporting/capture-supply-and-underground-injection-carbon-dioxide. See table "Primary End Uses for CO_2 Captured and Produced." EPA showed 21MMTPA captured from anthropogenic sources, but 8MMTPA went to food & beverage and various industrial uses, most of which do not create any long-term storage, leaving 13MMTPA. Data was as of 2014 and cannot be verified independently because most capture and injection is treated as Confidential Business Information. If adjusted for Petra Nova (1.5+MMTPA), ADM (1MMTPA), and Port Arthur (1MMTPA) projects that went on stream after 2014, the figure would be ~17MMTPA.

[9] Note: We are using "tonne" in this paper because tonne is typically the way that Metric Tons (2205 lbs/MT) are abbreviated, as opposed to "short-tons", "s-tons", or "English tons" which are 2,000 lbs. EPA typically reports in tonnes, where some other government publications report s-tons. We had to pick one or the other.

[10] Here we are hypothesizing that a number of projects may be feasible on paper, given costs and revenues without increases in per-tonne subsidies; but that the projects may be blocked by lack of infrastructure (e.g., pipelines) or rendered infeasible because of commodity or first-mover risks. Other issues can be lack of key regulatory measures (e.g., attractive EOR fields in states that lack needed unitization rules). We do not believe, and our research does not support, that ~100-200 MMTPA could be developed with zero changes in current regulations, R&D/deployment policies, infrastructure, or financial incentives based on tonnage incidentally stored or sequestered.

volumes (both factors drive capture cost downwards), (ii) in favorable geographies near to injection points and/or with low pipeline construction costs, and (iii) in volumes that could be sold to cash-paying CO_2-EOR customers. Without seeking to define "at scale" here, 100-200 MMTPA would be approximately one order of magnitude bigger than the current capture/injection volume. Saving that much CO_2 by displacing gas power plants with solar photovoltaic and wind turbine electricity would require ~230,000 MW of new wind and solar capacity, roughly tripling current U.S. installed PV and wind capacity.[11]

- <u>The ultimate challenge of carbon capture at the billion MTPA level</u>: What about capturing an incremental 1-2 billion MTPA above current and First Big Step amounts, hitting 50% or more total capture vs. the current 2.6 billion MTPA? That exact analysis was done in the "Abatement Curve" analysis in the main Chapter 2 of the NPC-CCUS report. Capturing that much CO_2 is far more difficult because of high costs and low revenues:
    - ~50% of emissions occur along/near the eastern and western coasts, often (but not always) located far from major CO_2-EOR operations or large known saline formations: moving CO_2 to injection points would require expensive long pipelines running through densely populated areas.
    - 80% of emitting sites emit less than 250,000 MTPA, meaning they would suffer high costs from disadvantageously small capture facility scale, as well as being disqualified from collecting 45Q tax incentives in most cases.[12]
    - Some capture prospects are inherently difficult for physical and operational reasons:
        - Over 500MMTPA of emission come from a fleet of 300 coal plants older than 35 years and with heat rates above 10,000 Btu/kWh, a cohort of coal plants that operates at a low capacity factor (48% average) and that emits nearly double current SO2 standards.[13]
        - 422MMTPA of emissions are "stationary combustion", primarily smaller furnaces creating industrial heat from natural gas combustion.[14]

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[11] This 230,000 MW is simply an example to show the significance of 200MMTPA of carbon capture. *It is not intended to show that carbon capture should displace PV or wind.* The US Energy Information Agency shows total U.S. installed wind and solar capacity as 125,000 MW for 2018. The 230,000 MW was derived as follows: (230,000 MW x 30% capacity factor x 8760 days per year x 0.33 MT/MWh fossil displaced) = 200MMTPA. The 0.33 MT/MWh is based on a 6,200 Btu/MWh natural gas combined cycle power plant heat rate and natural gas carbon intensity of 118 lb/MMBtu CO_2 emissions.

[12] Power plants must capture more than 500,000 MTPA to receive Section 45Q tax credits and other emitters must capture more than 100,000 MTPA. There is a smaller 25,000 MTPA threshold for "utilization."

[13] Calendar year 2018 data obtained from ABB Energy Velocity proprietary data base. Screening criteria age > 35 years and HR>10,000. The weighted average SO2 emission/MWh is 2.4 pounds in this group, versus a 1.4 lb/MWh 2006 EPA standard published in Federal Register February 27, 2006 re 40 CFR Part 60.

[14] EPA GHGRP data from "FLIGHT", sum of Subpart C for reporting year 2017.

- Experts estimate that the incremental annual absorptive capacity of the conventional onshore CO_2-EOR industry is not in excess of 300MMTPA[15], meaning that most of the incremental 1 billion MTPA would bear an expense of [$5-15/MT] paid to storage facility operators instead, of receiving positive cash revenues from EOR operators.

As with other energy-related sectors that require specialized transport systems, the particulars of the future carbon capture industry will vary significantly by region. The opportunity for CCUS in Vermont isn't the same as in Texas or Iowa. Thus, this Topic Paper explores the future carbon capture industry in the context of three specific test regions, or CCUS clusters.

In seeking to answer find whether a First Big Step could be feasible, this Topic Paper relied on information and work from prior chapters of this NPC report. We also performed considerable original research and analysis, especially in the two areas of estimating capture cost and culling good from poor capture prospects. We then analyzed that information from the commercial viewpoint, the same way bankers, developers, or feasibility consultants do. We also attempted to identify policy changes that could overcome roadblocks to successful implementation.

b. Improved Outlook for CCUS

While there are many obstacles facing the CCUS industry, the overall outlook for broad and successful deployment of CCUS in the United States has meaningfully improved in the last few years. Reasons for this improved prognosis include:

1. Technology to separate/capture CO_2 from other gases is already broadly used on a worldwide basis in several industries, including the fertilizer industry, the natural gas processing/LNG industry, and the coal gasification industry (especially in China). Though these industries use CO_2 separation/capture technology in the normal course of their manufacturing processing—and not in order to reduce CO_2 emissions—this deployment track record forms an experiential foundation for broad application of carbon capture.
2. Recent well-conceived, path-breaking projects have successfully applied these already-existing CO_2 capture technologies for a different purpose: capturing and sequestering CO_2 to avoid atmospheric emissions. Examples include NRG's coal retrofit project in South Texas, Shell's Quest project in Saskatchewan, and Norway's Snohvit project in the Barents Sea. These projects demonstrate that capturing carbon for the purpose of pollution control is no easier, and no harder, than capturing carbon plant for the purpose of synthesizing organic chemicals. The equipment doesn't care about the purpose for which it is being employed.

[15] Figure is subject to considerable argument. This 300MMTPA is intended to represent conventional formations on-shore, excluding Residual Oil Zone and offshore US Gulf.

3. The recent improvements to the Section 45Q "carbon sequestration" tax credit raised the amount of the credit per tonne of CO_2 that is captured and sequestered/injected. The credit values per tonne captured/injected of CO_2 are now more in line with, though still lower than, incentive per tonne CO_2 avoided that can be imputed from the existing solar ITCs and wind Production Tax Credits.[16] In addition, as described in previous sections of this NPC report, the revisions to Section 45Q also made these tax credits easier to use by virtue of allowing the tax-owner of the capture equipment to claim the credit and allowing the tax-owner to assign the credit to the injector.[17]
4. The CO_2-EOR industry has begun to demonstrate that the CO_2 floods can achieve incidental long-term storage of CO_2 in connection with oil production from new types of reservoirs, such as the Residual Oil Zone. This means that the ultimate amount of CO_2 that can be disposed of in connection with CO_2-EOR is larger than had previously been believed.
5. Oil prices have recovered after having reaches sub-$30/bbl daily lows in the winter of 2015/2016. Current prices in the mid-$50s make it likelier, though by no means certain, that a new generation of CO_2 floods would occur if adequate CO_2 supplies were reliably available. Since the CO_2-EOR industry is the only large-scale paying customer for captured CO_2, better industry conditions in the oil patch translate directly into better feasibility for carbon capture projects.
6. The possible scope and cost of future sequestration of very large CO_2 volumes in saline formations (a.k.a. "passive sequestration") is better known, following extensive government, academic, and industry work over the last decade. In the near-term, a

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[16] We realize that in this sentence we are comparing apples and oranges: capture cost of CO_2 vs. CO_2 avoided by renewable electric generation. See Table 5.8 Capture vs. Avoided Costs herein for discussion of avoided cost of CO_2. However, no U.S. tax credits are based upon the metric of "avoided tonnes" of CO_2. It would be quite difficult to do that, since avoided costs are subjective and variable, year-to-year and place-to-place. Thus different U.S. tax incentive programs have used different metrics that are hoped to roughly correspond to avoided tonnes of CO_2. The 45Q CO_2 tax credits are targeted per metric tonne (MT or tonne) *captured* and sequestered/injected, not "avoided." Solar Investment Tax Credits are based on the capital cost of the solar project regardless of electricity produced or CO_2 avoided. The wind production tax credit (PTC) is based on electricity generated, with no attempt to measure the CO_2 thereby avoided. That said, one can roughly impute, after the fact, the cost to taxpayers per tonne avoided. Example: the current wind PTC is $23.68 per MWh. If the electric generation displaced by production of 1 MWh of wind is 1 MWh of natural gas-fueled generation from a Natural Gas Combined Cycle plant with a 6,200 Btu/kWh Heat Rate, the CO_2 savings are 0.33MT. The $23.68 PTC per MWh ÷ 0.33 MT of CO_2 saved per MWh of wind generation implies an incentive of $71/MT CO_2 avoided. The current 45Q credit per CO_2 tonne captured and injected in Enhanced Oil Recovery is $35/tonne. Accounting for the 0.2 tonne carbon emissions typically associated with operation of carbon capture equipment, the 45Q tax credit of $35/tonne captured is in the range of $44/tonne CO_2 avoided. [The 0.2 tonne figure is calculated by 3.0 MMBtu of natural gas x 0.05 MT/MMBtu plus 0.15 MWh x 0.33MT tonne/MWh. Typical amine solvent capture systems use the natural gas to make steam and use electricity to run fans, pumps and compressors.]

[17] The credit was formerly only available to the party that was the tax-owner of the CO_2 emitting plant, and only if that party also operated the capture facility. Going forward, the credit is, in the first instance, available to the party that is the tax-owner of the capture facility as long as tax-owner operates, or contractually provides for the operation of, the capture facility. In addition, both under the old and revised provisions of 45Q, the claimant must itself inject the CO_2, or must contractually provide for the CO_2 to be injected in an EOR field or saline formation.

carbon capturer that can reach an EOR field would rather *receive cash by selling* to an EOR field than to consume cash by paying disposal fees to a storage site. But in the long-term, research on, and demonstrations of, passive sequestration shows the way forward if and when the absorptive capacity of CO_2-EOR reservoirs becomes constrained.[18]

These six factors all have created a more favorable climate for deployment of CCUS in the United States. The open question, which this Supply/Demand Analysis Topic Paper examines, is whether we have finally reached a point where the CCUS industry can successfully scale up, or whether we are only tantalizingly closer to that elusive goal.

c. Financial Indispensability of CCUS

Much less heralded, but of great importance, is the emerging view among energy modeling experts that full exploitation of carbon capture technology is financially indispensable if we wish to limit atmospheric CO_2 concentrations to ~450ppm CO_2eq. By "financially indispensable" we mean that the amount of investment funds needed to tackle climate change is limited; and without using every cost-effective technology, including carbon capture, we are unlikely to be able to accomplish the task.[19] The figures in the points below are also shown in the bar chart Figure 2.1 below.

1. Commonly accepted estimates from entities such as the International Energy Agency are that if we fully deploy all available technologies in an efficient manner, required new global capital investment in low/no-carbon energy and energy efficiency projects will be in the range of $2.3 trillion *per annum* between today and 2040.[20]
2. To put the ~$2.3 trillion/year of clean energy spending need in context, Boston Consulting Group's tracking of "global assets under management" estimates total new deposits by all worldwide investors into the hands of institutional money managers—that is, fresh funds that can be discretionarily deployed into such clean energy projects—averaged only $1.27 trillion/year in the 2014-2018 period. [21] [22]

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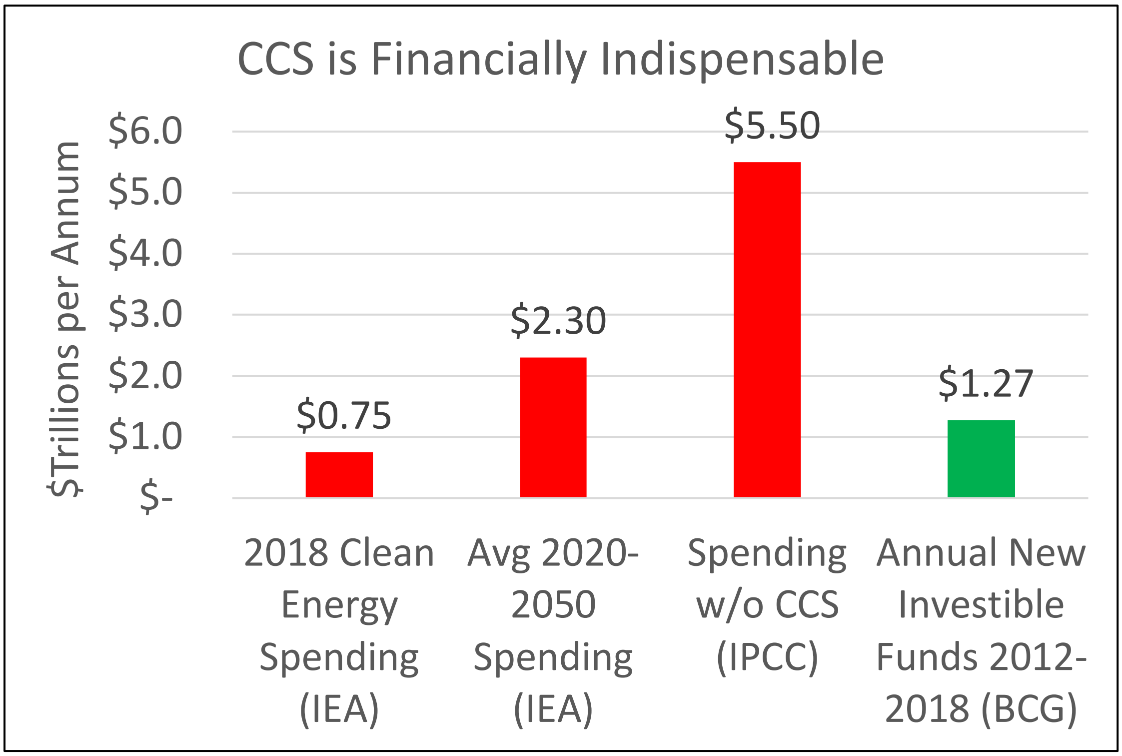
[18] This paper does not analyze saline storage extensively because we treated a pipeline system as a precondition to industry scale up. If capturers have access to a pipeline, early capturers will make more money selling to EOR than paying for passive storage. We originally included the "opportunity" for saline storage in our regional analyses; saline storage was on the menu, but nobody ordered it. So we removed saline storage for simplicity's sake.
[19] A full discussion of the scope of available savings that can be deployed into climate investments is beyond the scope of this paper. A paper that examined the available pool of capital can be found at https://energy.stanford.edu/sites/g/files/sbiybj9971/f/stanfordcleanenergyfinanceframingdoc10-27_final.pdf.
[20] Data from IEA's "World Energy Outlook 2016," Table 2.4 on p. 82, subtracting fossil fuel expenditures.
[21] This information was extracted from five successive years of the Boston Consulting Group (BCG) Assets Under Management (AUM) report. The BCG AUM report includes funds managed by global pension funds, insurance companies, mutual funds, sovereign wealth funds, and private equity firms. The most recent can be viewed at https://www.bcg.com/en-us/publications/2018/global-asset-management-2018-digital-metamorphosis.aspx.
[22] New funds put to work by global institutional money managers is relevant because those are fresh funds flows available for new projects. The value of existing stocks, bonds, insurance policies, and pension assets represent claims on already-existing companies and their already-built physical assets. By way of analogy, the net Property, Plant, and Equipment on a corporation's balance sheet is not available to deploy on new projects this year. The amount of money available is annual retained earnings minus mandatory replacement/capital improvements on

Thus, $2.3 trillion/year of clean energy spending appears to be a lot of money, in the context of global capital flows and investing.

3. Meanwhile, in connection with its Fifth Assessment Report, the IPCC revealed estimates that the required capital investments to achieve decarbonization (i.e., IEA's ~2.3 trillion/year) would increase by a factor of 238% (i.e., to ~5.5 trillion/year) unless there is broad deployment of CCUS in many applications, including the industrial sector, the power sector, creation of low-carbon transportation fuels, and in combination with biofuels ("BECCS" or bio-energy carbon capture and sequestration).[23]

Figure 2.1 Requirements and Sources for Clean Energy/Efficiency Investments



existing assets. Oddly it is very hard to get estimates of actual world investment in productive fixed capital, net of depreciation, i.e., money spent on bricks, mortar and machines other than simply fixing what wore out. The best world estimates seem to be from the IMF's Fiscal Affairs Department (FAD). FAD figures show that all gross worldwide public, private, and PPP investment was $26 Trillion in 2015, but the *net increase* was $8 Trillion. So, roughly 70% of investment replaces depreciation and 30% is new. That net$8 Trillion is not all available for clean energy: it includes roads, hospitals, private houses, cars, refrigerators, shoe factories, and tractors!

[23] See "Climate Change 2014, Mitigation of Climate Change. Working Group III Contribution to the 5th Assessment Report of the Intergovernmental Panel on Climate Change", Cambridge University Press, 2014. Refer to Table SPM.2 (p. 33/1454) and Table 6.24 (p. 471/1454).

d. What can we learn from the Analysis?

In answering the question investigated—i.e., whether and how we could accomplish the First Big Step—we are inevitably drawn to find the biggest, cheapest, most conveniently located emitters to which carbon capture could be applied. Most other studies have been focused on either estimating cost of capture for a typical plant in a single industry, or upon estimating the feasibility of a single project. Here we are obliged to look across all industries in a region, to find the very best candidates for carbon capture, and to see if these promising candidates add up to a critical mass. In scaling up CCUS nationwide, we have to walk before we run, and we are looking for the best spots to walk: that's the way advances in pollution control have always progressed, and that gradualist approach is inescapable when there are no serious U.S. statutes that prohibit, tax, or limit CO_2 emissions.

There is no known pollution control precedent for going from zero emissions control to near-perfect emissions control on each facility. Consider the precedent of water pollution abatement: U.S. sewage treatment progressed from uncontrolled dumping to primary, secondary and tertiary treatment of sewer pipe effluent; then to avoidance of combined sewage overflows; and finally to gradual attempts to address "non-point sources." Though many engineers or regulators immediately gravitate to a figure of "90% carbon capture" from entire emission sites (i.e. whole factories including many different operations), both precedent and economic theory support the idea that a modest amount of pollution abatement at many sites is far cheaper than perfect abatement at a few sites.

The idea of going after the cheapest tonnes first makes even more sense because there is no law taxing or limiting emissions of a pollutant. In the U.S. today there is neither a compliance-based policy to reduce CO_2 emissions from these stationary sources, nor is there an incentive high enough to make carbon capture generally feasible.[24] So, absent voluntary efforts, CO_2 will only be abated when so doing creates positive cash flows for the abating enterprise. Our hypothesis is that there *may* be sufficient current tax incentives, aided by *possible* revenues from CO_2-EOR sales, to make feasible capture from *some* of the biggest and easiest-to-treat CO_2 sources in the center of the U.S., sources that likely comprise 5-10% of the 2.6 billion MTPA of stationary sources. [25]

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[24] California has a cap-and-trade policy that presently results in CO_2 values of $15/MT, a figure insufficient to motivate carbon capture, especially in the context of the complexity of recent adopted state sequestration rules. Prices in the New England/New York RGGI market are at about $5/MT. https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2019_Q1.pdf

[25] Please note that this study did not have the time or resources to explore some regions that may feature cheap abatement and reasonable transportation prospects, including the Ohio Valley, Colorado/Utah, and Northeast Texas. Those regions are certainly worth additional study, in an extension of this effort.

We can learn a lot from following an organized, documented approach towards determining regional CCUS feasibility, regardless of how favorable or unfavorable the answer may be. A solid conclusion that we are close to feasibility, but haven't actually arrived, is not terrible news. It means that some serious, creative, well-coordinated actions—actions that are well-precedented in terms of scope and cost for the U.S. government—could be enough to close the gap within a period of years, instead of decades. That conclusion, if followed by action, would make a major difference for U.S. industry, jobs, and emissions reductions.

- If this industry analysis, founded upon the best facts and figures we can obtain, shows that we are impossibly far from such a First Big Step scale-up, then there is little to do other than working for some distant future technological breakthrough that will reduce costs of capture, transport, disposal, and/or utilization of CO_2.
- If the analysis, on the other hand, were to show that a significant cohort of CCUS projects are solidly in the black, with firm economic feasibility, there also would be little to do for policy-makers, other than to avoid derailing the industry inadvertently.
- This Topic Paper ultimately concludes that we are in a precarious in-between phase, with significant bands of uncertainty among leading industry experts both as to the installed equipment cost of carbon capture plants, and as to the volumes and prices at which CO_2 can be absorbed in EOR. As shown in Table 1.1, depending on whether we are at the favorable or unfavorable ends of the relevant ranges, the First Big Step could encompass as much as 240 MMTPA a year or as little as 65 MMTPA.

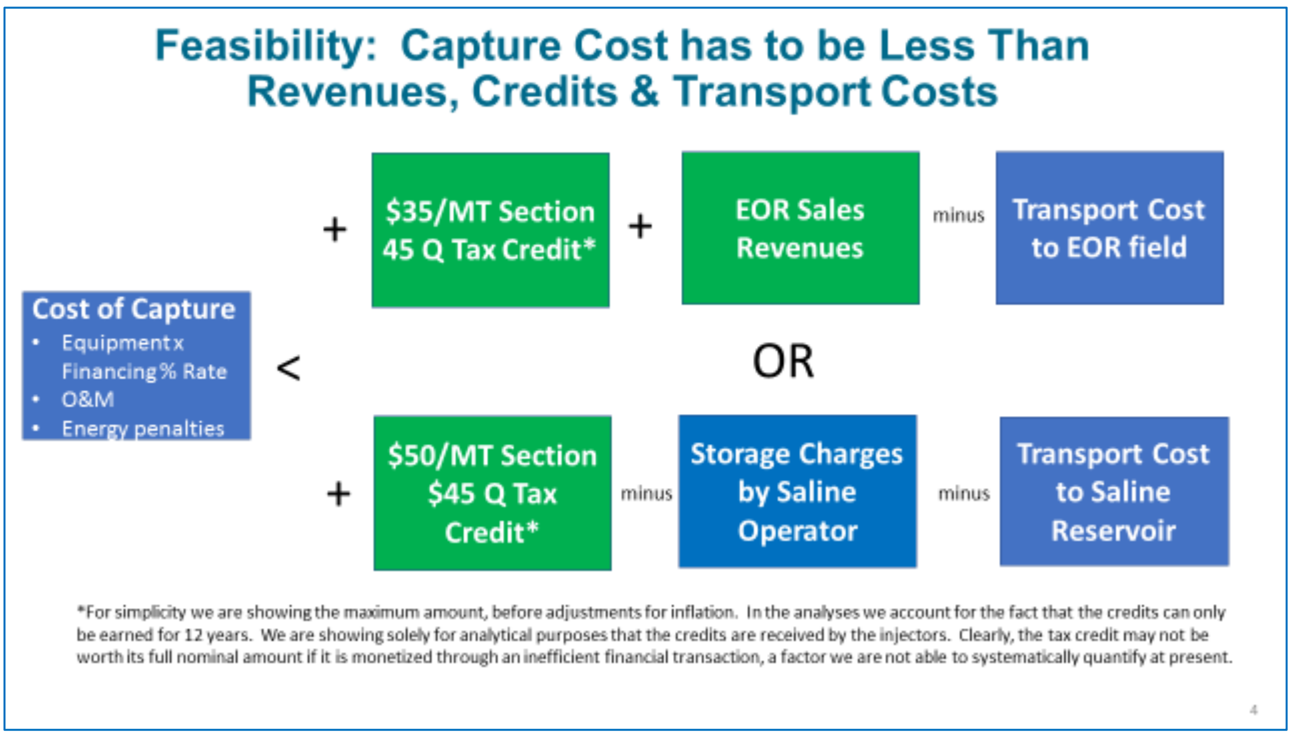
e. What Makes Capture at a Particular Location Economically Feasible?

At a high level, a CO_2-emitting plant (or operator) will decide to install carbon capture equipment if the price it can receive at its plant gate will reliably cover its fixed and variable operating costs for the capture operation, plus enough additional cash flow to repay the lenders and investors who put up the funds for the original acquisition of the capture equipment. For analytical purposes we have chosen to show Section 45Q credits as earned by the customers who will inject CO_2 and the transportation borne by the customer. [26] There are two possible "customer types" available to capturers at present:

[26] When transportation costs are a major factor in an industry, it is customary to either frame analysis based upon the price paid at the buying customer's plant gate (a price that must cover both production and transportation costs from the producer's location to the customer's site) or based upon a price paid at the producer's plant gate (a price that only covers only production cost, since the customer is paying for shipping). For this Topic Paper, there are typically two possible "customers", CO_2-EOR fields or saline formation storage sites, each likely to have different transportation costs. Thus, we chose to frame the analysis as though both competing customer types were vying for CO_2 at the capturer/producer's plant gate, with each customer type taking its unique transportation cost into account in the price offered at the capturer/producer's plant gate. Similarly, since the Section 45Q tax credit is different for EOR and passive sequestration, solely for analytical purposes we show the Section 45Q tax credit as earned by the injector. That arithmetic assumption doesn't matter to results. If the customer gets the tax credit in a competitive market, it will boost its maximum offered price by the amount of the credit. If the capturer gets the tax credit in a competitive market, it can reduce its minimum accepted sale price by the amount of the credit.

- CO_2-EOR producers. In the case of CO_2-EOR producers the capturer can expect to get an offered price comprised of three parts: (i) the $35/MT Section 45Q credit, plus (ii) the value to the EOR operator of a tonne of CO_2 injected into its oilfield, minus (iii) the transportation cost to reach the oilfield.
- Passive Saline operators. In the case of saline operators, the capturer can expect to get an offered price comprised of a different three parts: (i) the $50/MT Section 45Q credit, minus (ii) the saline operator's cost of operating the storage site, minus (iii) the transportation cost to reach the oilfield. [Note: Of course the saline operator isn't a customer in a conventional sense, but since the $50/MT tax credit is likely to exceed storage and transport costs, it offers a net cash positive revenue opportunity to the capturer and can be thought of as a customer for our purposes.]

Figure 2.2 Feasibility Calculations for Capture plus CO_2/EOR or Saline Sequestration



f. Methodology

We use traditional microeconomic tools of supply and demand curves to assess the feasibility of our First Big Step because we are currently dealing with a purely economic problem. If there were legal limits on CO_2 emissions, then we'd merely have a cost problem; and if CO_2 capture were quite cheap to build and fund, we might have opportunities for wide-spread voluntary implementation; but those conditions don't exist:

1. No emissions limits on CO_2: At present, neither the U.S. government nor any state government has economically meaningful, predictable, binding constraints on CO_2 emissions.[27] So any large-scale action taken by a private party to limit CO_2 emissions must achieve feasibility based upon incentives now on the books and scalable revenue opportunities that are currently proven. This contrasts starkly with the situation for regulated conventional pollutants: removing SO2, another "acid gas" molecule, from industrial vent stacks costs $400-$1,200/MT[28]; but capital expenditure on SO2 capture equipment is necessitated by law and thus doesn't require a "business model" or demonstration of economic feasibility.
2. High capital costs of capture equipment: Technology that is well-tested and commercially available for "capture" (i.e., separation of CO_2 from other gases either in a mixed gas stream within a process, or at a vent stack at the end of a process) has high capital equipment cost, the expense of financing which represents approximately 60% of capture cost per tonne. The carbon capture systems occupy a relatively large footprint within an industrial area and consume a not-insignificant amount of energy. This doesn't make carbon capture infeasible: it just means that capturers need to be judicious about where and how the expensive equipment is deployed. Thus, for near-term deployment we focus on the industries, and on particular portions of manufacturing processes within such industries, that will maximize equipment utilization rates, thus counteracting high equipment costs and space constraints. Thus, we also focus on means of providing for the energy needs of carbon capture systems with the least-carbon intensive and capital-intensive processes reasonably available.[29]
3. High funding cost: Since a corporate owner of a CO_2-emitting facility is not subject to legal constraints on its CO_2 emissions and therefore will only install CO_2 capture equipment if so doing is economically viable, CO_2 capture equipment must compete

[27] Some states have attempted various schemes, but the prices for emissions limitations aren't predictable or high enough to matter. As an example, the State of California has a "cap-and-trade" system, but since the annual "cap" is set as a fixed amount of emitted tonnes, the value of a captured tonne depends on factors such as the overall economy (in a booming economy more tonnes would be emitted and the cap binds more tightly), periodic readjustment of the cap, issuance of "allowances" to economically exposed industries, etc. Thus the system doesn't provide a firm foundation upon which to make long-term capital expenditure decisions. In 12 of the last 18 auctions for "future vintage" allowances, the "price" has been the state-set floor or "reserve price" and sellers could not actually sell all of the allowances they offered. The reserve price was $11.34 in 2014 and rose to $14.53/MT by 2018.

[28] William D. Baasel (1988) Capital and Operating Costs of Wet Scrubbers, JAPCA, 38:3, 327-332, DOI: 10.1080/08940630.1988.10466384

[29] Example: The most common CO_2 separation systems wash exhaust gases with a solution of "amine solvent", with the solution then being re-boiled to release the captured CO_2. That process and balance of the system typically require per MT captured ~0.15 MWh of electricity to run equipment and 2-3 MMBtu of fuel to make steam. A number of studies we reviewed prescribed building expensive small coal power plants inside the fence line of the CO_2 emitting facility in order to provide that electricity and steam, often generating surplus electricity then sold onto the power grid. These studies failed to consider simpler alternatives such as buying power from the grid (no capital equipment and typically a much lower carbon intensity of electricity) and using an off-the-shelf natural gas-fired "package boiler" to make the steam.

for funding with other projects the corporation could approve. The "cost of financing" used to evaluate capture projects is thus likely to be the internal "corporate hurdle rate" used by a company's executives and Board of Directors, a financing cost likely to be far higher than many analysts would expect. That is, if an industrial gases company must choose whether to pursue adding carbon capture equipment to an existing hydrogen plant vs. capitalizing on a new opportunity to build a new Air Separation Unit in an attractive location, the CO_2 project needs to be *relatively* attractive compared to the ASU opportunity: being reasonably profitable on an *absolute* basis won't win the day. We have allowed for this factor by using, especially in sensitivity cases, relatively high financing costs factors.[30]

So, in the absence of compulsion to implement carbon capture, and with the presence of high equipment costs and funding costs, the limits on the amount of carbon capture that can occur in the near-term are economic, not technical.[31] CO_2 is a commodity; and commodity markets work like a pair of scissors. There is a supply-side blade and there is a demand-side blade. The two cut together to determine a market price/quantity equilibrium. Private parties will buy CO_2 if so doing is profitable.[32] Private parties will capture CO_2 if doing so is profitable. [Note: See Section 3 for short review of supply/demand curve analysis for readers unfamiliar with the theory.]

Past studies of CO_2 markets in the U.S. are generally one-bladed scissors. There are many studies that describe costs of capture without estimates of whether anyone could/would pay those costs. There are studies that show possible CO_2 demand in various U.S. regions, but without analysis of sources and costs of the CO_2. Those one-blade studies are path-breaking and valuable—this Topic Paper is built upon those studies—but it is hard to base policy upon them in isolation. This may be the first time that an attempt to create supply and demand curves for CO_2 has been attempted for the

[30] Example: the International Energy Agency's study of adding carbon capture to hydrogen plants used a 10% financing cost with investment paid back over 20 years, leading to annual payment rates of 11.7% (cite), while Air Products used an annual payment rate (or "capital recovery factor") of 17% (cite, p. 55/57).

[31] That is, a very significant (i.e., ~50 million tonnes/yr) amount of CO_2 from gas processing and ethanol fermentation only requires compressors and pipeline access, thus presenting zero technical challenge. Another ~1.5 billion tonnes a year (coal power plants and certain portions of integrated steel mills, oil refineries, cement plants, and hydrogen plants) have concentrated CO_2 streams that can easily be addressed with traditional amine solvent CO_2 scrubbing systems plus compressors and pipeline access, again presenting no technical challenge. There is just an economic issue: do project cash flows pencil out for a private actor that is under no regulatory compulsion to limit CO_2 emissions?

[32] We did not add to the complexity of this Topic Paper by including alternative disposition of CO_2 in passive storage in saline formations. The reason is simple: having presupposed a scale efficient multi-regional set of CO_2 pipelines in order to reach a 100-200MMTPA scale, and based upon the data available on EOR demand, passive storage was always outbid by demand in oilfields. I.e., we did the analysis including the opportunity for passive storage, but never got any takers for passive storage. Hence, we excised that portion of the work.

most relevant portion of the U.S.[33] For an industry that has been studied so extensively by academics, industry participants, governments, and international organizations, it seems odd that the literature does not seem to contain this kind of supply and demand analysis.

At the end of the day, this type of economic analysis cannot confidently predict what owners of CO_2 emitting facilities *will* ultimately do, nor what operators of oilfields or saline storage sites *will* ultimately do. However, such economic analysis can show what they *won't do willingly*: routinely engaging in money-losing activities, capturing CO_2 at a cost of $60/MT in return for compensation of $30/MT.

g. **Data Difficulties**

The void in the literature mentioned above—the lack of industry supply/demand analysis for U.S. CCUS—could be explained by the difficulty of getting reliable, comprehensive information. Much information we need doesn't exist in the public domain, and the information that does exist requires laborious effort to assemble and collate. In this study we did the best we could, with the best data we could collect, in the time allowed, and subject to funding constraints.[34] We did so on the grounds that a comprehensive analysis of CO_2 abatement supply and demand was critical to inform policymakers, business, and the public. Even if this first yearlong volunteer-staffed analysis were not perfect, we could at least jumpstart the process and leave a trail to follow for future analysts. We don't have perfect confidence in the precision of our analysis, but we strongly believe that the results are accurate enough to provide solid guidance for decision makers.

Here is a short list of the data difficulties that face a team attempting industry supply/demand analysis for U.S. CCUS:

- <u>Emissions quantities</u>: Emissions data were only comprehensively collected with the initiation of the EPA's Greenhouse Gas Reporting Program (GHGRP) in 2010, and some source categories did not started reporting until 2016.
    - Even within the GHGRP, some key emissions aren't reported (e.g., fermentation emissions in ethanol plants), and emissions from the same type of equipment may be reported differently in different industries (e.g., "captive" hydrogen plants inside oil refineries report combustion emissions differently than "merchant" hydrogen plants). Some natural gas processing

[33] Ryan Edwards and Michael Celia did an excellent analysis that could be viewed as a forerunner of the approach we are using in this paper. See "Infrastructure to enable deployment of carbon capture, utilization, and storage in the United States", PNAS vol. 115, no. 38, E8815-E8824.

[34] Funding constraints: A subsequent, well-funded study would be able to access proprietary industry and consulting firm studies and data bases in industries such as cement, steel, industrial gases, and fertilizer that would raise accuracy of results. We were fortunate to have access to the ABB/Data Velocity power industry data base via Stanford University, which aided significantly in the effort to sort out power plant emissions. See also later footnote 36 acknowledging help from ARI.

facilities appear to net off CO_2 captured and sold from total emissions while others don't.
  - Power plants that don't sell to the grid (e.g., inside-the-fence power projects in a refinery or paper mill) aren't listed as power sector emissions. Rather, they are simply listed as "combustion emissions" the same way process heat generation would be treated.
  - Sometimes CO_2 reported as "emitted" isn't really emitted at the site (e.g., CO_2 captured and used to make urea at fertilizer plants is still reported as "emitted", leading analysts to over-estimate amounts available).
  - If an analyst seeks to identify the best targets for capture at in an industry that features complex industrial sites, such as the oil refining sector, the analyst must hunt through 10-40 page pdf filings for each site. As a typical example, one modest-sized refinery had 33 separate vent stacks that reported emissions totaling over 4MMTPA. However, just 4 of the 33 vents represented ~90% of the CO_2 emissions, with 3 vents (50% of plant-wide CO_2) representing concentrated emissions that would be economically capturable today.[35]
- <u>Capture costs</u>: There are lots of estimates in the literature of capture costs and/or avoided cost of CO_2 in various industries. However:
  - Many studies only report the bottom line of "capture cost per tonne" with very little supporting detail.[36] They may be interesting to note, but one can have no confidence in their methodology, nor can one cross-check them against the exemplary studies that do show their work. One also cannot simply average the results of these black box studies to obtain a "representative cost" in which anyone would have confidence.
  - Other studies make it impossible to distinguish commodity units from commodity prices (e.g., they report natural gas fuel expense rather than units x price).
  - Still others have cost figures that are hard to translate because they were derived at a unique time and place (e.g., how to translate northern Alberta costs during an oil boom to Oklahoma cost today).

[35] See "as reported data" for WRB Refining LP, Roxana, Illinois. Four units made up 3.7 MMTPA of 4.3 MMTPA total emissions: Two catalytic cracking units, the hydrogen plant, and the main refinery fuel gas furnace. Feasible capture would be approximately 90% of the cat cracker emissions and 60% of the hydrogen plant. [We assumed that the three vents at the hydrogen unit could be combined via ducting.] https://ghgdata.epa.gov/ghgp/service/html/2017?id=1007518&et=undefined

[36] Comparing studies requires that each has a detailed cost build up for significant pieces of equipment that segregates equipment, material, construction, engineering, contingencies, etc. Analysts need to learn the purpose of any ancillary systems added in (such as pollution controls, electric generation, or boilers), see drawings of the planned facility with corresponding heat and material balance tables, get information on prices and quantities of commodities consumed, and understand any operational impacts on the emitting process. We need enough information to understand whether capture cost for Site X is higher than Site Y because two experts have materially different views as to the cost of similar equipment, or in the alternative whether the expensive site's team was more conservative in allowing for unexpected costs or, perhaps, added in unnecessary ancillary equipment.

- In addition, some studies are plagued with odd assumptions or outright mistakes.

- CO_2 demand from EOR industry: No public data is available that permits an analyst to comprehensively examine possible CO_2 demand from individual oilfields across the country. Some oil companies have data but are not in a position to release it. The U.S. National Energy Technology Laboratory has data, but licensing agreements don't permit that information to be released. We were extraordinarily fortunate to have access to a data set provided by Advanced Resources International[37] ("ARI") that contained both oilfield economic information and latitude/longitude, so transportation issues could be examined. [We can only report that ARI information on an aggregated basis in order to protect confidentiality of proprietary work.] Further, there are non-economic constraints such that can block actual development of otherwise attractive prospects shown in the ARI database, such as the difficulty of achieving "unitization" of potential new CO_2-EOR production areas in many states.[38]
- Saline formations: Though there has been a decades-long attempt to collect information on the location, capacity, and cost of saline formations, the actual physical coordinates of the storage sites aren't included on the comprehensive nationwide dataset we obtained. Further many experts comment that the geological data we obtained is much too aggregated to permit proper estimation of capacity and operating costs. Certain participants in the NPC study have asserted that the estimates of cost contained in the NETL data base are excessively high because storage project configurations include a higher-than-needed number of monitoring wells per injection/disposal well. Several studies are underway, but not complete, that are expected to be more useful.

h. Rationale for 100-200 MMTPA target

This Topic Paper seeks to understand whether carbon capture is likely[39] to be able to reach *significant industrial scale* given current carbon capture costs, tax incentives, opportunities for sale to EOR companies, resources for passive storage in saline formations, and CO_2 pipeline costs. If the answer is "no" we look for modest policy

[37] ARI, located in Arlington, Virginia and Melzer Consulting, located in Midland, Texas are widely regarded as the best independent analysts of potential for U.S. CO_2-EOR. Both firms have been extremely helpful and generous in their support of this study. In addition, because the US DOE relies so extensively upon ARI analyses and data—proprietary or not—we feel quite comfortable relying upon ARI data in a report whose main audience is the Secretary of Energy. Representatives of some major oil company participants in the NPC-CCUS study stated that they believe the ARI data is over-optimistic, but it was not possible to learn the exact basis for that belief.

[38] Unitization is an agreement of mineral rights owners to develop a field in common, typically with a single operator, with costs and production being shared pro rata. Unless a field can be unitized, non-participating mineral rights owners can benefit from extra production without paying their share of costs. Some states—e.g., Texas—do not have a mechanism of "forced unitization" to block this free-rider problem. Others require a very high percentage threshold of agreement to implement forced unitization. See "Fieldwide Unitization" by S.M. Rogers, Arkansas Law Review, Vol. 68: 436 https://law.uark.edu/alr/PDFs/68-2/68ArkLRev425-454Rogers.pdf

[39] To us, "likely" means at least a 50% probability.

adjustments that might change the answer to "yes." We would define accomplishment of significant industrial scale as the development of at least 2-4 regional U.S. CO_2 markets comprised of scale-efficient transportation systems that link a diverse portfolio of CO_2 capturers with numerous injectors/users of that CO_2. Since scale-efficient long-distance pipelines need to be sized in the 25-35MMTPA range, such a goal is the equivalent of an incremental 50-140MMTPA of capture in the U.S. We rounded those numbers up in our reference to "~100-200MMTPA" elsewhere in the study.

The rationale for our particular definition of significant industrial scale is supported by the detailed analysis herein. The summary of that rationale is:

- **Sources of CO_2 and possible injection points are usually geographically separated.** With the exception of internal Texas markets, a meaningful increase in the CCUS industry requires capturing CO_2 in regions that have many large emitters but limited EOR or saline storage, and then transporting those volumes to regions that have few emitters but are rich in EOR or saline storage opportunities. Given the geographies involved, such transport will often need to span distances of 500 miles or more.[40] Thus transportation cost will be an important factor in overall economics.
- **Connecting the sources and injection points requires scale-efficient pipelines**. Pipeline costs per tonne of transportation capacity fall very rapidly with volume transported. Hence, a long-distance pipeline carrying 35 MMTPA 600 miles would need to charge shippers ~$13/MT, whereas a smaller 1 MMTPA line running only 200 would need to charge ~$25/MT shipped.[41]
- **There isn't enough "low hanging fruit" concentrated in one place to fill up a scale- efficient pipeline**. There is on the order of 40MMTPA[42], of low-cost, man-made "pure" CO_2. These are "cheap tonnes" because they only require compression[43] equipment before transport. However, because those "cheap tonnes" are scattered over a wide area among generally small-volume emitters, they cannot easily be gathered into a single, scale-efficient pipeline—a pipeline that can offer low tariffs to shippers.[44]
- **Thus a viable regional CO_2 market must include the higher cost CO_2 sources as well as the "low hanging fruit."** To capture enough volume in a regional market to keep pipeline shipping costs low will require combining the small volume of "cheap

[40] The existing Cortez CO_2 pipeline is approximately 500 miles long, connecting a geologic CO_2 source, McElmo Dome, to Texas oilfields.
[41] See Section 9, footnote 118 for backup.
[42] Aggregate of estimated natural gas processing and ethanol fermentation emissions for sources > 150,000 MT/year, excluding certain emitters already known to be supplying to the EOR industry. We chose 150,000 because operational levels vary greatly, and if the emitter captures below 100,000 MTPA it cannot collect Section 45Q tax credits. The 40 million figure is comprised of 34MMTPA of ethanol and 6MMTPA of natural gas processing. No ammonia industry emissions are included since most low-cost CO_2 available in U.S. fertilizer plants is already captured and used to create granular urea and other urea products.
[43] The term compression here also is intended to include cooling, dehydration, etc.
[44] Edwards and Celia, "Infrastructure to enable deployment of carbon capture, utilization, and storage in the United States", PNAS vol. 115, no. 38, E8815-E8824.

tonnes" (~$20/MT capture cost) with a much larger volume of intermediate- (~$40/MT) and higher-cost (~$60/MT) emitters. As well as compression equipment, the intermediate- and higher-cost sources require special systems to separate CO_2 at 15-30+% concentration from the other mixed gases in an industrial vent stack.

- **Beyond this transportation cost-based argument, meaningful reduction in U.S.** CO_2 **emissions can only be accomplished if we successfully tackle these harder-to-capture** CO_2 **emissions in many different industries.** For example, in 2017, the cement industry alone emitted over 60 million MT—or 1.5X the ~40MMTPA accessible volume of "low hanging fruit." However, the need to tackle many different industries does not mean we have to invent a new capture technology for each industry. Instead, we can use the same basic technology to address virtually all of the mixed-gas industrial emissions streams that are large enough, and have high enough CO_2 concentrations, to be cost-effectively treated.
- **"More costly capture" does not mean "prohibitively expensive capture."** As will be described in this Topic Paper, our research reveals that carbon capture projects that are ruthlessly focused on capturing the most CO_2 for the least amount of money are surprisingly inexpensive both in absolute terms, and in comparison to other already-deployed means of avoiding CO_2 emissions.

i. CO_2 Capture Sectors of Interest

This Topic Paper focuses on nine carbon capture industry sectors ranging from high purity/concentration streams of CO_2 to direct air capture. In terms of the techno-economic issues presented by carbon capture those nine carbon capture industry sectors fall into four larger categories as shown below in Table 2.1. In some of these industries we have only focused on the very largest and most concentrated sources of CO_2 emissions, since this Topic Paper seeks to identify the very best opportunities for near-term deployment. Hence, though there are often dozens of vent stacks that emit CO_2 at oil refineries, Fluidized Catalytic Cracking Unit (FCCU) units are typically far bigger and 3-4x higher in concentration than other refining-related sources.[45] Similarly, there are many emitting stacks at a conventional steel mill, but the biggest and most concentrated are those that vent exhaust from combustion of Blast Furnace Gas (BFG).

In green shading, the Table 2.1 below shows these nine carbon capture industry sectors, grouped into four broad categories, along with the general characteristics of the gas stream treated and broad capture cost ranges.

At the bottom of Table 2.1 are two other sectors that deserve serious attention but that we do not analyze in this Topic Paper because low concentration, small size, or both make them uneconomic in today's environment. Addressing emissions from industrial furnaces and stoves, which amount to approximately 0.4 billion MTPA of U.S. emissions, is a

[45] By refining-related we mean stacks reported as emitting under subpart MM-Ref. Refineries may or may not have very large power plants reporting under subpart C and hydrogen plants reporting under subpart P.

critical problem in the longer term. At some point, direct air capture (DAC) may also be a crucial technology. Capture prospects that are within the range of feasibility today are our focus here, so we had to leave out industrial heat and DAC for the present.

Table 2.1 Characteristics of Industry Sectors Studied (or Deferred for Future Study)		
Sector	Category	Characteristics
1. Ethanol 2. Natural Gas Processing 3. Ammonia[47]	Pure Streams	100% CO_2 produced, only dehydration and compression needed, capture cost[46] \$15-20/MT
4. Industrial Hydrogen Plants (Refinery and Stand-alone)	Hydrogen Plants	15-20% concentration at ~375psi, requires CO_2 separation, capture cost ~\$40-50/MT
5. Coal Power Plants 6. Refinery Fluidized Catalytic Cracking (FCC) 7. Cement Plants 8. Steel Blast Furnace Gas (BFG) Combustion	Large Concentrated Sources	Concentrations ~13% for coal power plants, 16% FCC, 20% Cement, & 26% for BFG. These four sources are typically combusting coal or coke fuels. Capture cost \$55-65/MT.
9. Natural Gas Power Plants	Large Dilute Sources	Concentration in ~4% range, with capture cost in \$70+/MT range.
Industrial furnaces & stoves [Deferred for future study]	Small Dilute Sources	Typically natural gas fired with concentration in ~4% range, but approximately 1/10th to 1/40th the size of gas power plant. Cost > \$100/MT
Atmosphere [Deferred for future study]	Direct Air Capture	Atmospheric air with CO_2 concentration of 0.04% or 1/100th of gas power plant emissions. Cost estimated > \$200/MT.[48]

[46] Whenever we use the term "capture cost" in this report we specifically mean incremental fixed and variable costs to the emitter to separate CO_2 from other gases, dehydrate the CO_2 if water vapor is present, remove any trace contaminants that would prevent the CO_2 from being transported in a CO_2 pipeline, and compress to pipeline pressure of ~2,000 psi. Fixed costs include financing cost for equipment, calculated as a percentage capital recovery factor multiplied times original equipment cost as constructed.

[47] Note: Because of the way in which ammonia/fertilizer plant emissions are reported and the complexity of the multi-product nature of nitrogen fertilizer plants, the amount of CO_2 available is incorrectly perceived as fairly large. In fact most available CO_2 at fertilizer plants is used in the synthesis of urea fertilizer and is not emitted on site.

[48] Recent articles state that Carbon Engineering's process is now in the \$200/tonne range but could reach costs at the \$94/tonne level "as part of a much larger scale effort." https://www.insidescience.org/news/capturing-carbon-dioxide-air-cheaper-originally-thought

Section (3) Review of Supply and Demand Curve Analysis

Figure 2.2 regarding project feasibility in the prior Section 2(e) only looked at the situation from the point of view of two actors, a capturer/producer and an injecting customer. In reality, in any region, there will be hundreds of potential capturer/producers and similar numbers of potential customers. Economists use the concepts of "supply curves" and "demand curves" to show how the actions of all these potential market participants ultimately arrive at an "equilibrium solution" in which amounts produced and consumed match and a single market price is determined. Use of supply and demand curves does not constitute a "model" but rather is a way of ordering the relative attractiveness of buyers and costliness of suppliers, dating from the first use of the concept by Alfred Marshall in his 1890s classic *Principles of Economics*.

In this subsection we quickly review how the analysis works for readers who aren't familiar with the terminology.[49] *[NB: We used purely hypothetical values of prices on the "y" axis and quantities on the "x" axis. Please see the next Section for actual analysis.]*

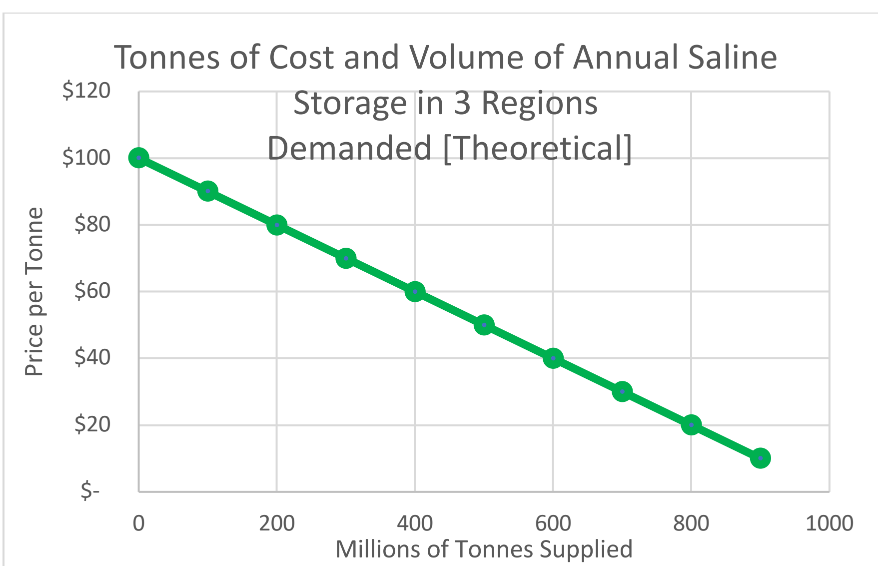
[49] Note: This section is not intended to be an economics textbook. Yet, supply and demand curve analysis is quite unfamiliar to many highly experienced and sophisticated parties. As an example, most engineers find supply and demand curves infuriating because "price", which economists put on the "y" axis, is actually the independent variable; and thus any competent scientist would put price on the "x" axis. Likewise a scientist would put the dependent variable, quantity, on the "y" axis where it belongs.

a. Demand Curve

A "demand curve" is simply a tool to rank order potential customers from those with strongest demand to weakest demand. Demand curves can either be "short-term" curves that only take account of possible incremental demand from existing consumers, or "long-term" curves that take account of possible demand from new customers who would purchase CO_2 if oil prices were high enough and CO_2 prices low enough that starting a new flood would make economic sense, including return on capital invested in new floods. In this case we are using long-term demand curves.

- At the high (left) end of the demand curve chart below, measured by the maximum price they would theoretically willing to pay to get the product, are consumers who desperately want CO_2. Thus, on the far left side of the green line, CO_2 is worth up to almost $100/tonne to a very few customers.
- At the low end are customers who are more or less indifferent and need big price cuts to make the purchase decision. For instance, unless CO_2 is very cheap, they may just be satisfied to continue with existing low-yielding waterfloods.
- As will be described in more detail in the following sections on methodology, this process of ranking potential customer from high to low is exactly what we did, based on information gleaned from a number of different sources for EOR fields and possible saline storage sites.
- Importantly, the market doesn't know or care what a customer was theoretically willing to pay. If the ultimate price settled on by the market is $60/tonne some customers who were willing to pay $80/tonne get a great deal, and others who were only willing to pay $20/tonne are priced out of the market. All buyers pay $60/tonne.

Figure 3.1 Demand Curve for CO_2 [Theoretical]

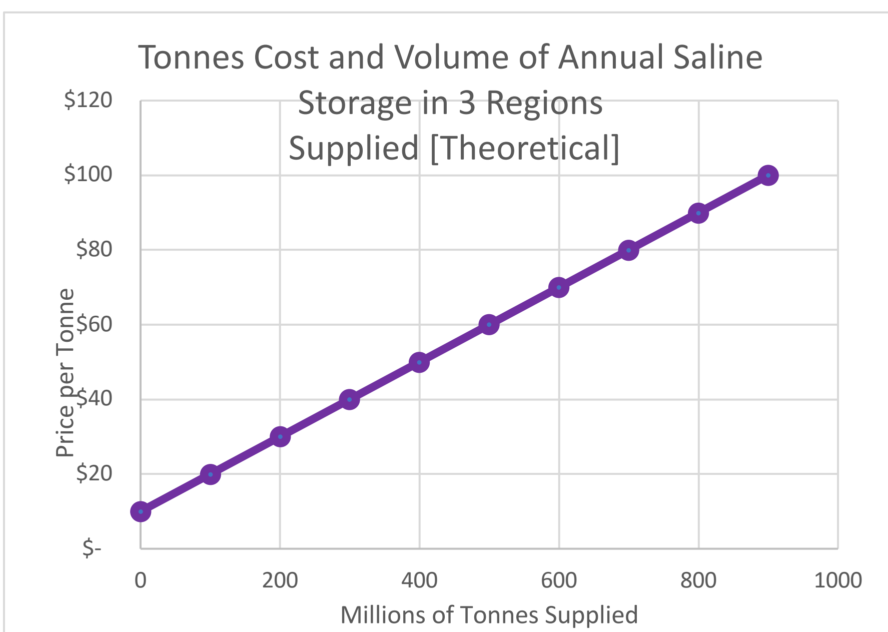


b. Supply Curve

A "supply curve" is simply a tool to rank order potential producers, from low cost to high cost. Supply curves can either be "short-term" curves that only take account of cash production costs of existing suppliers, or "long-term" curves that take account of the full production costs including cost of financing purchase of equipment for companies that could enter the industry if prices are high enough. We are using long-term supply curves.

- At the low (left) end of the supply curve chart below, measured by the minimum price they would theoretically be willing accept in order to supply CO_2, are a fortunate few suppliers with extremely low costs. Thus, on the far left side of the purple line, CO_2 production costs are down to almost $10/tonne for a very few lucky producers.
- At the high end are producers who would have to make big capital investments and incur high operating costs to capture CO_2. Unless prices are expected to be sustained at a high level, these high-cost capturers will not bother to produce.
- As will be described in more detailed following sections on methodology, this process of ranking potential producers from low to high cost is exactly what we did, based on information gleaned from a number of different sources on emissions by individual site and cost of capture estimates from a large number of techno-economic studies we reviewed.
- Importantly, the market doesn't know or care the break-even price at which an emitter was theoretically willing to capture CO_2. If the ultimate price settled on by the market is $60/tonne some capturers who were theoretically willing to supply at $10/tonne make a tidy profit, and others whose production cost is $100/tonne are priced out of the market. All producers get $60/tonne.

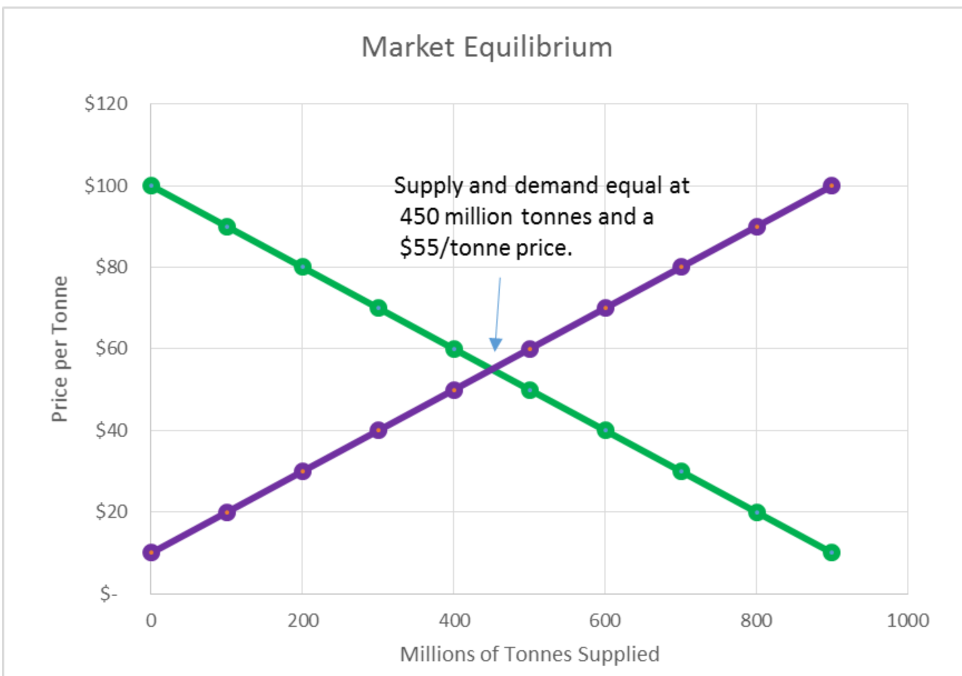
Figure 3.2 Supply Curve for CO_2 [Theoretical]



c. Market Equilibrium: Supply=Demand at Same Price

The “market equilibrium” solution is graphically shown as the spot where the supply and demand curves intersect, at a single price and single quantity. The intuitive meaning of the intersecting curves is that, at equilibrium, the very last reluctant consumer was persuaded to pay $X, while at the same time the very last reluctant producer made one last unit and received a price of $X that just barely covered his full costs. The *next* possible customer is only willing to pay $X-1, whereas the *next* possible supplier wants a price of $X+1 to turn on his machines. They are both priced out of the market.

Figure 3.3 Supply/Demand Equilibrium [Theoretical]



Section (4) Regional Analysis and Results: Three U.S. Regions

a. Regional Identification: Choosing Three Regions

This Topic Paper analyzed supply and demand for anthropogenic CO_2 in three U.S. regions. These geographically bounded theoretical regional market areas were selected because the three areas have often been discussed as likely spots for early deployment, as well as because they have quite different mixes of industry, opportunities for CO_2-EOR, and resources for passive sequestration. The three regions are:

- **Gulf:** Southeast TX, LA, MS, and AR.
- **Midwest:** Northwest TX, OK, MO, IN, IL, KS, IA, NE, and MN.
- **Rockies:** CO, UT, WY, NM, ND, and MT.

The "Gulf" area including South and East Texas, Louisiana, Arkansas, and Mississippi. Capture opportunities here are dominated by the massive oil refining, industrial gases, and petrochemical sectors stretching along the Gulf of Mexico. There are a number of good opportunities for capture in coal power plants, newer natural gas combined cycle power plants, and cement as well.

The "Midwest" begins in Illinois/Indiana and the northern plains states of South Dakota, Nebraska, Iowa, and Minnesota. It then slants southwestward, running through Kansas, Missouri, and Arkansas, ultimately reaching Oklahoma, North Texas and Permian Basin oilfields. The area is complex to analyze because, rather than being a simple sources-to-injection-points configuration, there are potential EOR injection points (and ultimately saline) all along the route such as the oilfields of Kansas. The potential capture sources run across a very wide and deep cross section of industries, including steel, oil refining, power plants, cement, hydrogen plants, and others.

The "Rockies", encompassing Montana, North Dakota, Wyoming, Utah, and New Mexico. Oil activities exist in Montana, North Dakota, Wyoming, and New Mexico areas. [50]

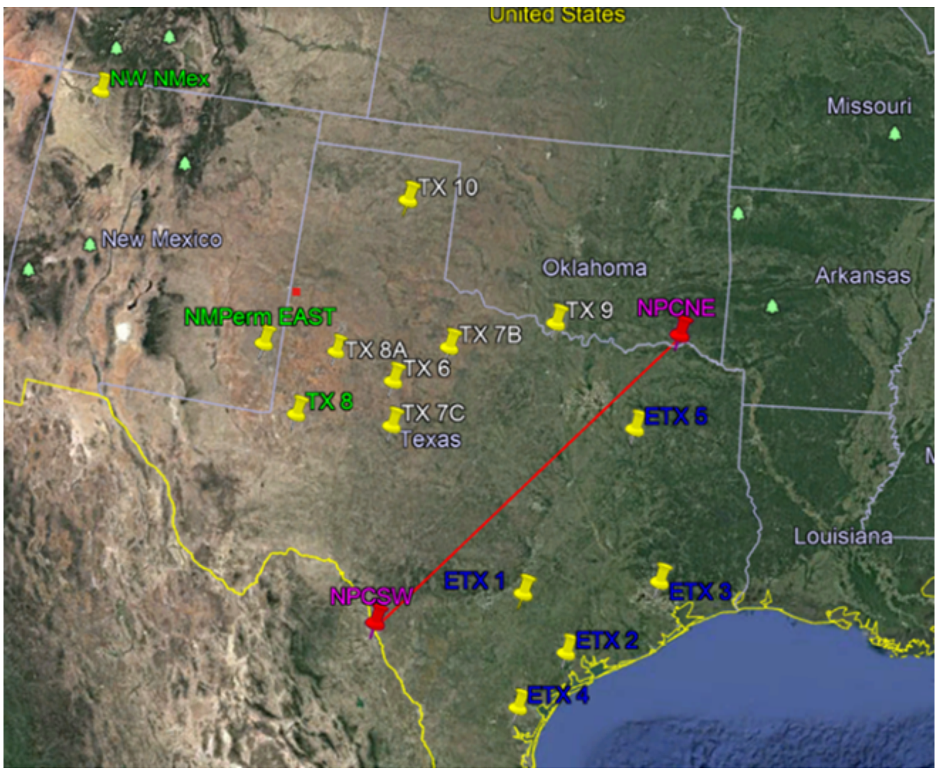
For simplicity in this particular regional division of the middle of the U.S., the only state that was divided was Texas, as shown on Figure 4.1. It was important to divide Texas because that state is the major potential cash-paying "importer" of captured anthropogenic CO_2 from the other regions. Texas can easily absorb both its own feasibly-captured CO_2 and additionally absorb significant excesses from each of other regions. Thus, we divided Texas diagonally along the red line in the map below, running

[50] The "Rockies region" includes one cluster of oilfields in far West Texas that is more or less contiguous to the New Mexico Permian fields in Southeast New Mexico. See next paragraph.

from the points “NPCSW” to “NPCNE”. Eleven Texas oilfield regions, as categorized by ARI, are marked with yellow push pin icons.

- The five oilfields with blue font, lying below and to the right of the red line were recipients of CO_2 for the “Gulf.” We also mapped emitters below and to the right of the red line to the “Gulf.”
- Six oilfields above and left of the red line were mapped to the “Midwest”. We also mapped emitters above and to the left of the red line to the “Midwest.”
- One Texas oilfield, TX8 (green font, far left), was assigned to “Rockies.” This was done because the in-region demand in the Rockies states—at equilibrium prices more or less consistent with equilibrium prices in other regions—wasn’t sufficient to absorb supply. TX8 is located very close to the New Mexico Permian Basin fields just across the border and would be a logical interconnection point.

Figure 4.1 Assignment of Texas EOR Fields to Regions



b. Supply and Demand Curve Scenarios

As described in the introduction, and as will be further detailed below in sections on methodology, we ultimately decided upon the use of two possible supply curves and two possible demand curves for CO_2 in each of the three regions.

Supply Curve Scenarios. For supply curves, the main concern we had was the strong differences of opinion among experts on two matters relating to the cost of carbon capture: (i) the amount of additional budgeting for capture projects—known as "contingency funds"— that should be provided in case of unexpected costs due to application of the carbon capture technology itself, or due to complexities engendered by inserting a substantial carbon capture operation into the midst of a pre-existing industrial of power plant site and (ii) the appropriate annual financing factor, or "capital recovery factor" that should be used in the analysis.

In some sense the divergent views on these two matters don't necessarily represent divergent views about the ultimate long-term costs once carbon capture has been fully commercially demonstrated in the relevant emitting industries. Some analysts point to the example of falling costs and rising efficiencies through successive generations of combined cycle natural gas turbines. Others may say, "We have no specific evidence that costs will actually fall after the first four or five carbon capture projects in Industry X."

We ultimately decided to show one high-cost supply curve and one low-cost supply curve. Both curves used the same fundamental processes, configurations, capture goals, and equipment/construction costs, and owner's costs, and factors for cost of funds during period of project construction.

- The high-cost supply curve—which could serve as a proxy for an *unsubsidized* 1st-5th of a kind— used the unfavorable end of the assumptions range for both set-asides for contingencies (40% of basic cost of equipment, construction, and engineering) and for the capital recovery factor (13%). Of course, government grants could buy down high costs for the first few brave pioneers, should such policies be adopted.
- The low-cost supply curve—which could serve as a proxy for "6th-Nth of a kind"— used the favorable end of the assumptions range for both set-asides for contingencies (20% of basic cost of equipment, construction, and engineering) and for the capital recovery factor (10%).

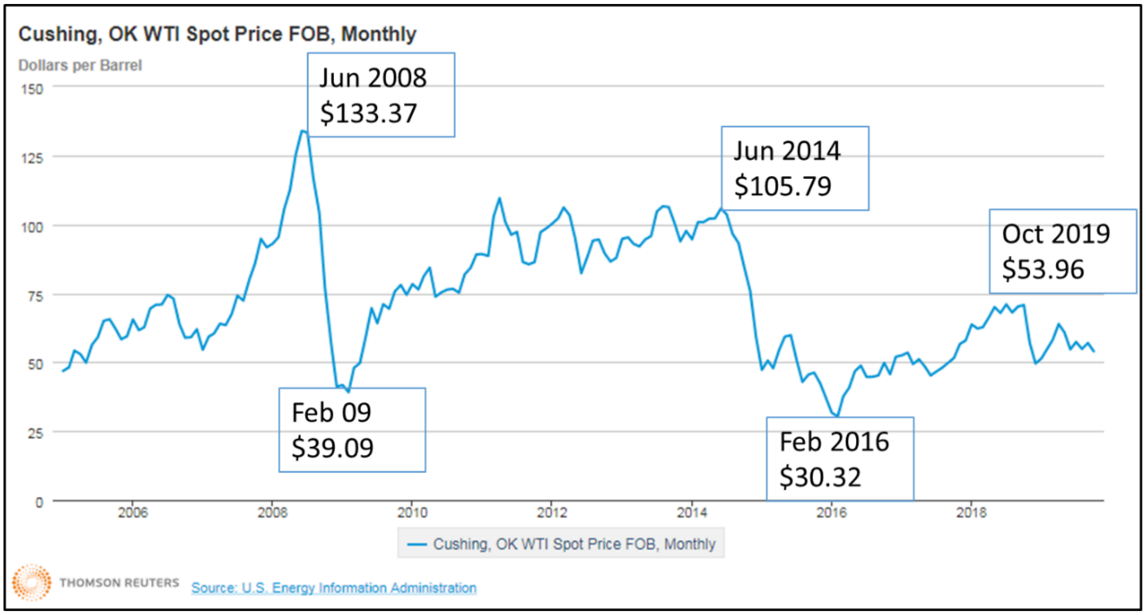
To give the reader a fundamental sense of the impact of these sensitivities, for a capture project that has a basic cost of equipment, construction, and engineering of $250 per MTPA of CO_2 capture capability (i.e. $250 million for a project that can capture 1.0 MMTPA), the combined costs of paying capital providers plus operations & maintenance expense (ex-fuel and electricity) would be approximately $45/MT captured in the low-cost supply curve case and $63/MT captured in the high-cost supply curve case.[51]

Demand Curve Scenarios. For demand curves from CO_2-EOR consumers of CO_2, we also used a low-demand and a high-demand case. For October 2019 WTI averaged

[51] ($250 basic cost x 120%)*(10% CRF + 5% O&M)= $45/MT
($250 basic cost x 140%)*(13% CRF + 5% O&M)= $63/MT

$53.96/bbl but as the 10-year price chart of WTI below illustrates, relying on any particular oil price level is a poor bet.

Figure 4.2 WTI Price History Since 2009[52]



We had available to use three different families of possible demand curves derived from ARI scenarios at $40/bbl, $60/bbl, and $80/bbl WTI oil prices. We decided to use the $60/bbl as the high-demand case and the $40/bbl as the low-demand case. We disregarded the $80/bbl case given current oil price levels.

Thus each of the regions we therefore had two supply curves (high and low cost) and two demand curves ($40/bbl and $60/bbl), enabling us to estimate a different market quantity/price equilibrium point under four different conditions:

[52] Figure downloaded from USEIA website November 24, 2019. https://www.eia.gov/opendata/embed.php?geoset_id=&type=chart&relation_mode=line&series_id=PET.RWTC.M&date_mode=range&start=200501&end=201911&periods=

Table 4.1 Descriptions of Four Scenarios

<table>
<tr><td colspan="2" rowspan="2">Scenario Descriptions (2 Supply x 2 Demand)</td><td colspan="2">Demand Curve Scenarios</td></tr>
<tr><td>Low-Demand ($40/bbl)</td><td>High-Demand ($60/bbl)</td></tr>
<tr><td rowspan="2">Supply Curve Scenarios</td><td>High-Cost (40% contingency & 13% CRF)</td><td>Least Favorable</td><td>Mixed</td></tr>
<tr><td>Low-Cost (20% contingency and 10% CRF)</td><td>Mixed</td><td>Most Favorable</td></tr>
</table>

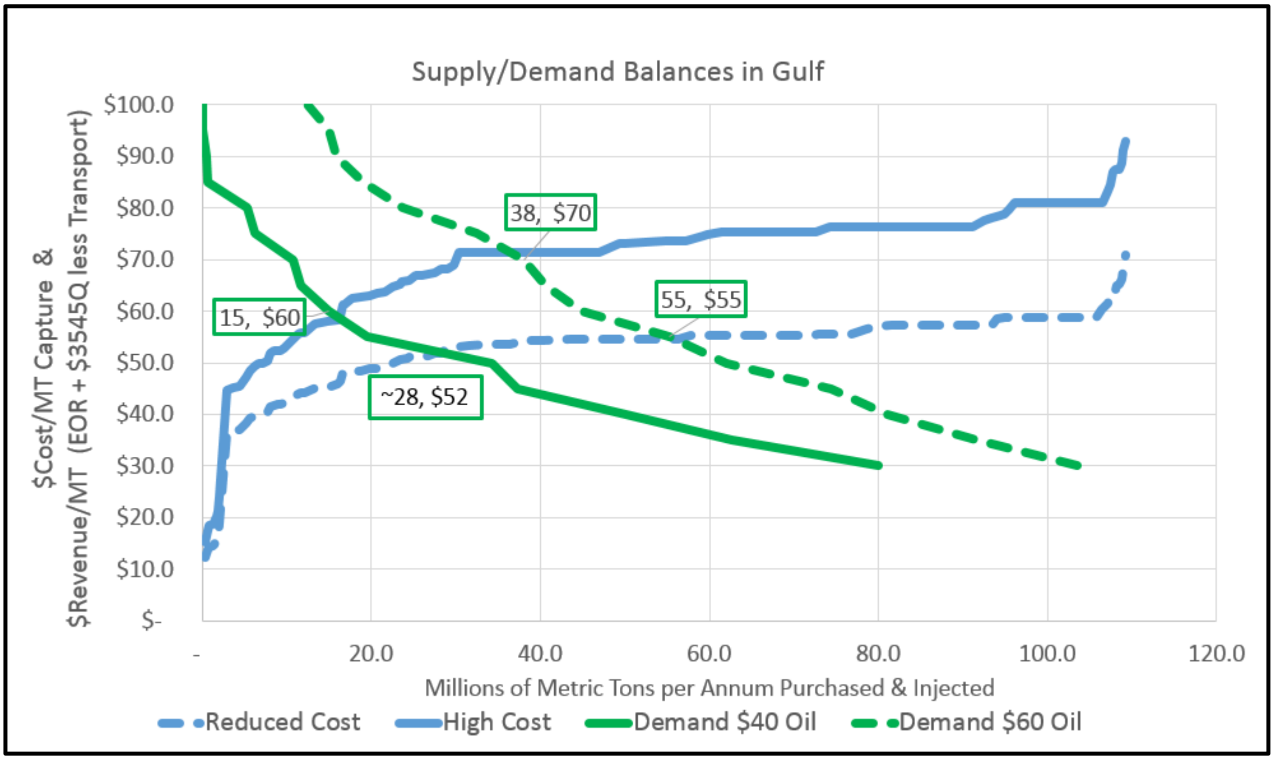
c. Region 1: Gulf Region Supply and Demand

The following graph depicts our estimate of supply and demand in the Gulf—Southeast Texas, Louisiana, Mississippi and Arkansas. Note that EOR demand estimates provided to us did not include the *offshore* Gulf of Mexico. The "x, y" values of each possible supply/demand pairing are shown in boxes.

So, on the far right, the box where "Reduced Cost" supply and "Demand $60 Oil" intersect has the values "55, $55, or 55 MMTPA at $55/MT. That point is an "equilibrium" because suppliers having cost at or below $55/MT would willingly supply 55 MMTPA. Meanwhile, buyers who can afford to pay at or above $55/MT would willingly buy 55 MMTPA.

For the supply curves (the blue lines) the "y" axis values represent purely the cost of capture and compression. For the demand curves (the green lines) the "y" axis values represent the sum of three items: a $35 §45Q tax credit, *plus* the value of the CO_2 to the CO_2-EOR operator at his receipt point, *minus* the pipeline tariff. Thus the $55/MT shown in the far right box does not mean CO_2-EOR producers by themselves paid $55/MT. Rather the $55/MT represents $35/MT §45Q, plus $25/MT from CO_2-EOR @ $60/bbl oil, minus a $5/MT transport tariff.

Figure 4.3 Supply/Demand Balances in Gulf



The supply situation in the Gulf contains very few low cost tonnes. [Note: That is why the blue supply curves hit $40-50/MT at only a few MMTPA.] However, the presence of a number of hydrogen plants and cement plants provides relatively continuous supply curve function with amounts that can be captured rising relatively gradually from 0 to 40MMTPA as costs rise from the $40/MT to $65/MT range (low cost supply case, solid purple line). The more expensive supply, in the $70/MT range, is comprised of capture from the FCCU's of oil refineries and portions of natural gas combined cycle power plants.

The demand curves reflect possible participation from a very large number of Texas fields with some additional demand in Mississippi and North/South Louisiana. However, Texas demand is predominant, generally comprising about 90% of the total.

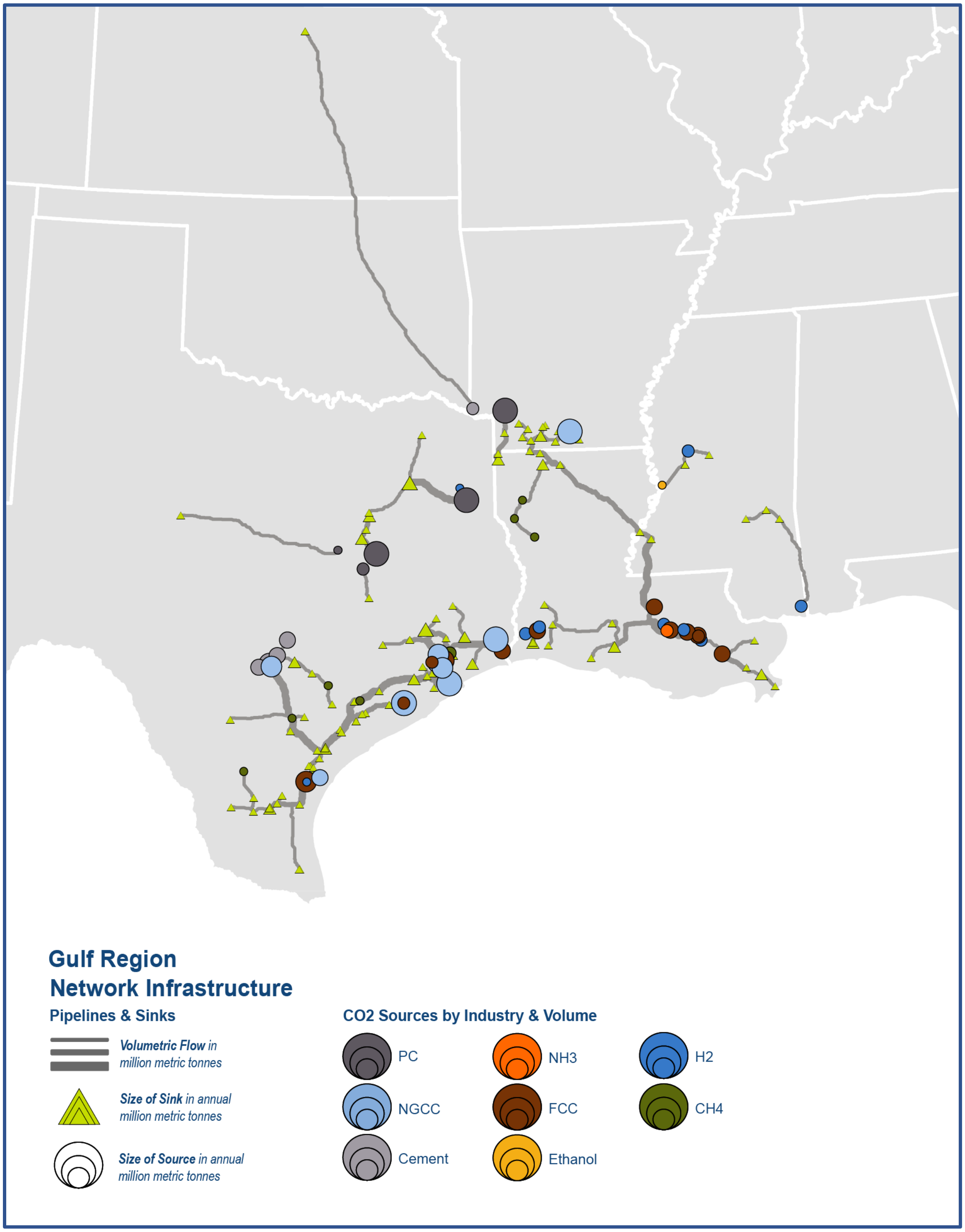
The table below categories the four equilibrium points where the two pairs of supply curves and two pairs of demand curves intersect in the graph above.

Table 4.2 Gulf Region Four Scenarios Results

Gulf Scenarios		Demand Curve Scenarios	
		Low-Demand ($40/bbl)	High-Demand ($60/bbl)
Supply Curve Scenarios	High-Cost (40% contingency & 13% CRF)	15 MMTPA CO_2 price = $60/MT	38 MMTPA CO_2 price = $70/MT
	Low-Cost (20% contingency and 10% CRF)	28 MMTPA CO_2 price = $52/MT	55 MMTPA CO_2 price = $55/MT

The map following shows the pipeline routing that LANL's models developed for the Gulf area. The network-wide tariff per MT delivered over this routing was ~$5/MT. This was half the tariff required for the Midwest and Rockies areas discussed next, since those regions are simply much more spread out. [Note: LANL's model cannot easily solve for a cost-of-service based allocation to each particular customer. Hence, for now, we must use what is referred to as a "postage stamp" charge, meaning everyone using the system pays the same price.]

Figure 4.4 Gulf Region Network Infrastructure

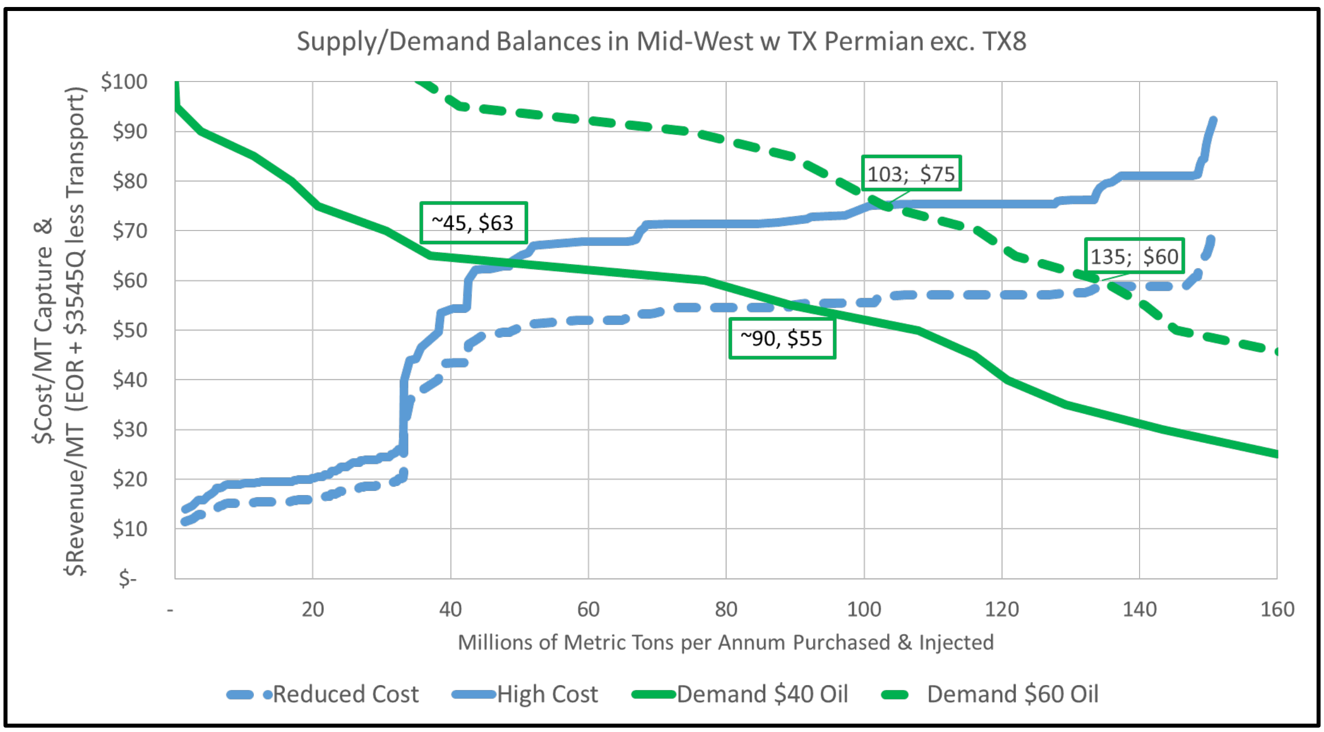


d. Region 2: Midwest Region Supply and Demand

The following graph depicts our estimate of supply and demand in the Midwest. The boxed numbers are "x, y" coordinates for tonnage and price. Thus, the far right 135 $60 box means an equilibrium at 135 MMTPA volume with a clearing price of $60/MT.

For the supply curves (the blue lines) the "y" axis values represent purely the cost of capture and compression. For the demand curves (the green lines) the "y" axis values represent the sum of three items: a $35 §45Q tax credit, *plus* the value of the CO_2 to the CO_2-EOR operator at his receipt point, *minus* the pipeline tariff. Thus the $60/MT shown in the far right box does not mean CO_2-EOR producers by themselves paid $60/MT. Rather the $60/MT represents $35/MT §45Q, *plus* $35/MT from CO_2-EOR @ $60/bbl oil, *minus* $10/MT transport tariff. [Note that this is a much smaller region than the Gulf or Midwest, so the "x" axis scale runs from zero to 80 MMTPA, whereas Gulf graph and Midwest "x" axes' maximum values are 160MMTPA and 120 MMTPA, respectively.]

<u>Figure 4.5 Supply/Demand Balances in Midwest</u>



The supply situation contains a large quantity of so-called "low hanging fruit", amounting to about 35 MMTPA of mostly ethanol fermentation emissions (lower left corner of supply curve), another ~20 MMTPA of intermediate cost supply in the $40-50/MT area, and a very large quantity of supply in the $60/MT area. Those $60/MT industries are primarily coal power plants, steel furnace blast furnace combustion vent stacks, and oil refinery Fluidized Catalytic Cracking Units (FCCUs).

Because some possible EOR producing areas of this "region" have traditionally had little access to *plentiful* and reliable supplies of CO_2 (especially Oklahoma and Kansas) there appears to be some strong demand even at relatively high prices. However, the vast bulk of demand in the $40/bbl oil case occurs in a zone where EOR producers are paying (oilfield CO_2 value only) in the $20-35/MT range for CO_2.

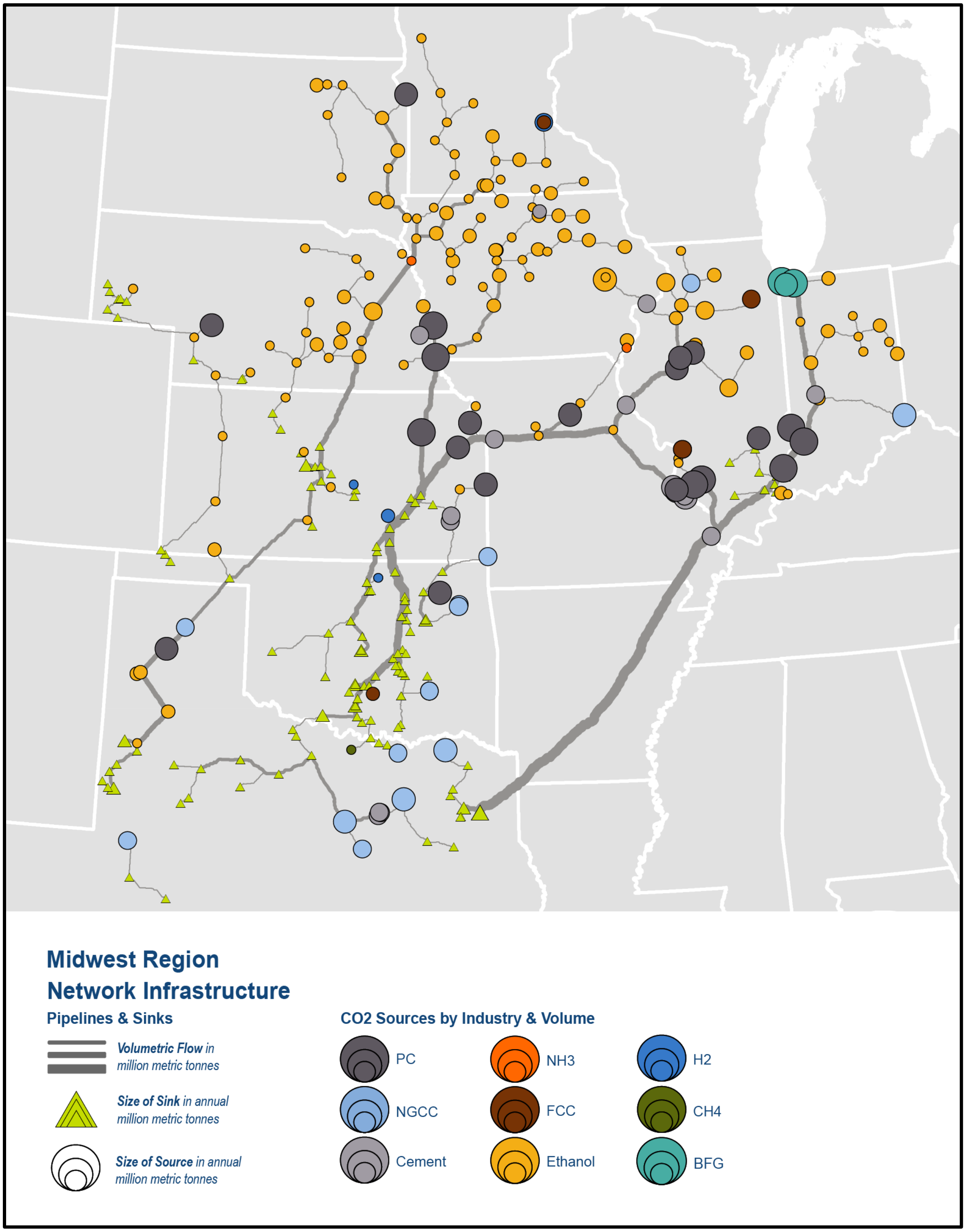
The table below categories the four equilibrium points where the two pairs of supply curves and two pairs of demand curves intersect in the graph above.

Table 4.3 Midwest Region Four Scenarios Results

<table>
<tr><td colspan="2" rowspan="2">Midwest Scenarios</td><td colspan="2">Demand Curve Scenarios</td></tr>
<tr><td>Low-Demand ($40/bbl)</td><td>High-Demand ($60/bbl)</td></tr>
<tr><td rowspan="2">Supply Curve Scenarios</td><td>High-Cost (40% contingency & 13% CRF)</td><td>45 MMTPA
CO_2 price = $63/MT</td><td>103 MMTPA
CO_2 price = $75/MT</td></tr>
<tr><td>Low-Cost (20% contingency and 10% CRF)</td><td>90 MMTPA
CO_2 price = $55/MT</td><td>135 MMTPA
CO_2 price = $60/MT</td></tr>
</table>

The map following shows the pipeline routing that LANL's models developed for the Midwest. The network-wide tariff per MT delivered over this routing was ~$10/MT. [Note: LANL's model cannot easily solve for a cost-of-service based allocation to each particular customer. Hence, for now, we must use what is referred to as a "postage stamp" charge, meaning everyone using the system pays the same price.]

<u>**Figure 4.6 Midwest Region Network Infrastructure**</u>

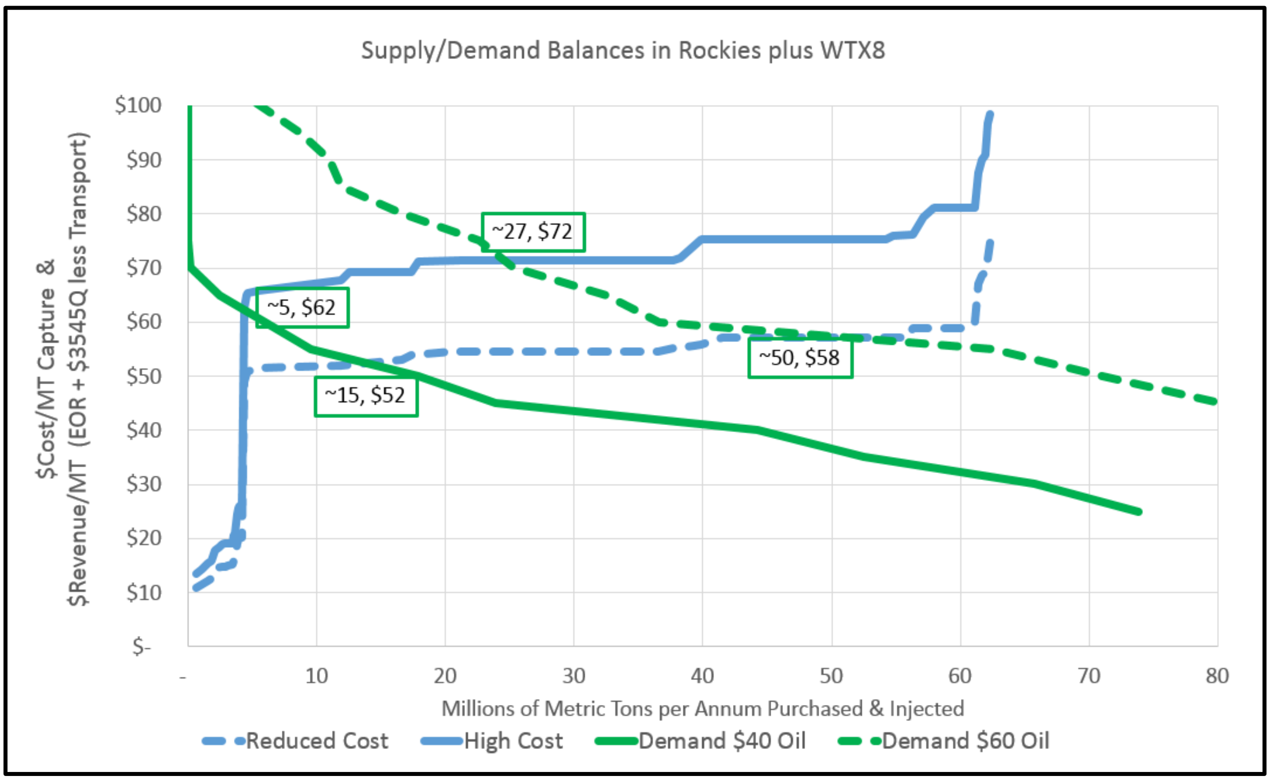


e. Region 3: Rockies Region Supply and Demand

The following graph depicts our estimate of supply and demand in the Rockies. The boxed numbers are "x, y" coordinates for tonnage and price. Thus, the far right box labelled $\boxed{50, \$58}$ means an equilibrium at 50 million MTPA volume with a clearing price of $58/MT.

For the supply curves (the blue lines) the "y" axis values represent purely the cost of capture and compression. For the demand curves (the green lines) the "y" axis values represent the sum of three items: a $35 §45Q tax credit, *plus* the value of the CO_2 to the CO_2-EOR operator at his receipt point, *minus* the pipeline tariff. Thus the $58/MT shown in the far right box does not mean CO_2-EOR producers by themselves paid $58/MT. Rather the $58/MT represents $35/MT §45Q, *plus* $33/MT from CO_2-EOR @ $60/bbl oil, *minus* $10/MT transport tariff. [Note that this is a much smaller region than the Gulf or Midwest, so the "x" axis scale runs from zero to 80 MMTPA, whereas Gulf graph and Midwest "x" axes' maximum values are 160MMTPA and 120 MMTPA, respectively.]

<u>Figure 4.7 Supply/Demand Balances in Rockies</u>



The supply situation contains a small amount of the "low hanging fruit", amounting to about 5 MMTPA of ethanol and natural gas processing emissions.[53] This particular region has few large oil refineries, hydrogen plants, cement plants, or steel mills. Thus after exhausting the low-cost capture possibilities, the supply curve jumps up sharply to reach a large possible capture supply from coal power plants supply with costs in the $50-60/MT area (reduced cost scenario). This situation, with some very low-cost tonnes and then many more high-cost tonnes gives rise to the pronounced "S" shape of the supply curves.

Though oil and gas are large economic presences in the Rockies, the incremental demand from EOR (except for "TX8" which we included to top up demand) is modest in total volume, and relatively price-sensitive in comparison with oilfields accessible in our Midwest and Gulf regions. Oil demand also drops off relatively quickly in terms of price that producers can pay and absolute volumes demanded. The unique characteristics of the "S" shaped supply curve and thinner demand for oil cause all four of the possible equilibrium points to occur before inclusion of most of the higher cost capture opportunities from the areas very large and relatively new coal plants. *Given the small quantities involved and the large cost curve jump between the 5MMTPA and 10MMTPA the less favorable cases had to be interpolated.* [Note: The coal plants make up the horizontal portions on the right sides of blue supply curves.][54]

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[53] Wyoming, a part of this region, does have some very notable supply from natural gas processing from gas fields that are very heavily contaminated with CO_2 (i.e., in the 60% molar concentration range for gas processed at Exxon-Mobil's Shute Creek facility). But those tonnes are already captured and being sold to EOR producers, so the actual incremental supplies are small, often from gas reserves that have quite low (~2-4%) CO_2 fractions in field gas.

[54] There are two idiosyncratic reasons that the right side of the supply curves is so flat: first, the entire supply curve in the particular region is made up of pulverized coal plants in the absence of major refineries, steel mills, and efficient NGCC power plants; second, we assumed uniformly sized maximum coal carbon capture installations. Based upon discussions with technology providers and EPC contractors we formed the view that the likely maximum capture units (or "trains" as chemical engineers term them) would be at the ~1,600 MTPA size executed by MHI for NRG at its W. A. Parish retrofit. If a coal plant wanted to capture more, we assumed it would do so in large, efficient increments.

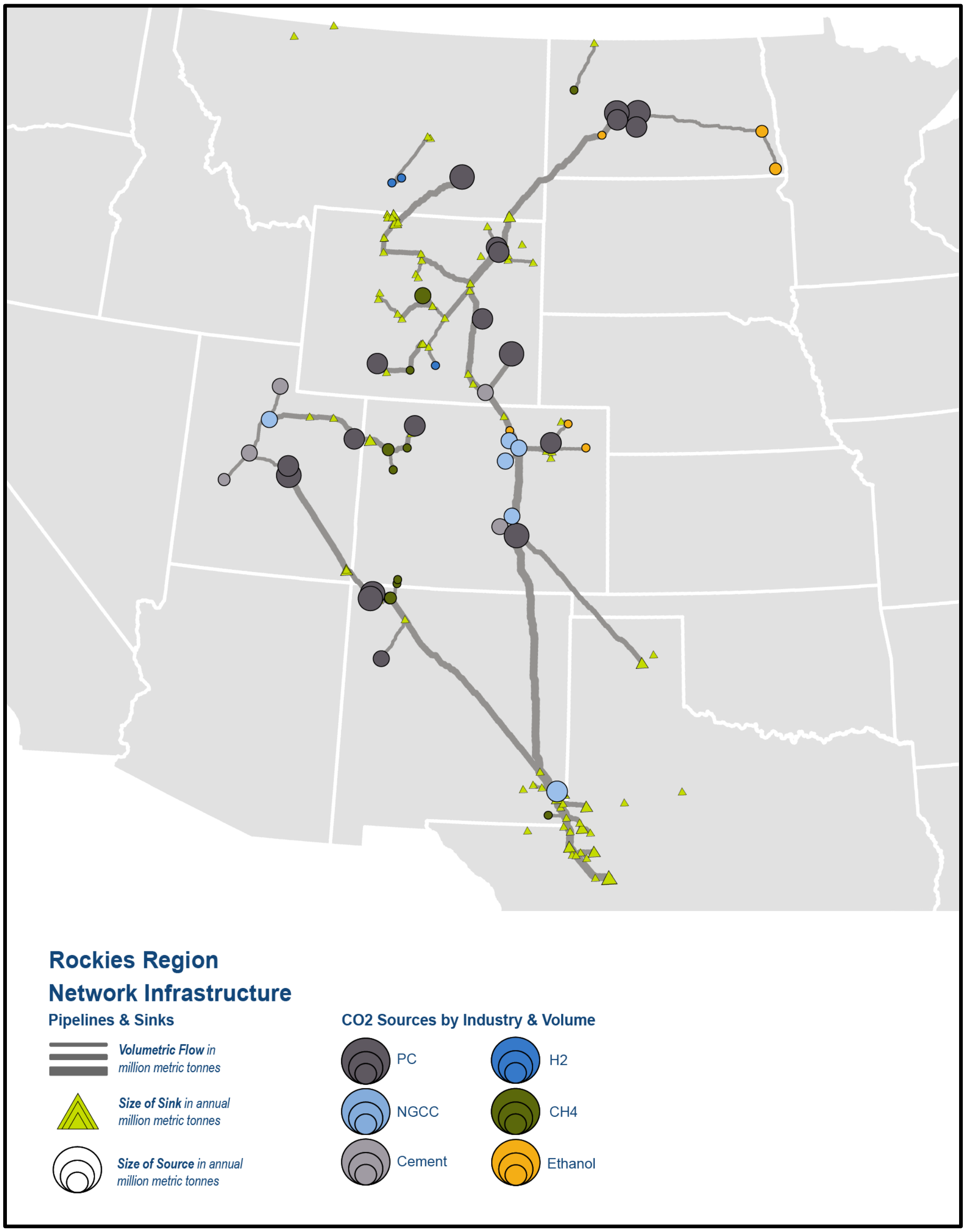
The table below categories the four equilibrium points where the two pairs of supply curves and two pairs of demand curves intersect in the graph above.

Table 4.4 Rockies Region Four Scenarios Results

Rockies Scenarios		Demand Curve Scenarios	
		Low-Demand ($40/bbl)	High-Demand ($60/bbl)
Supply Curve Scenarios	High-Cost (40% contingency & 13% CRF)	5MMTPA CO_2 price = $62/MT	27MMTPA CO_2 price = $72/MT
	Low-Cost (20% contingency and 10% CRF)	15MMTPA CO_2 price = $52/MT	50MMTPA CO_2 price = $58/MT

The map on the next page shows the pipeline routing that LANL's models developed for the Rockies area. The network-wide tariff per MT delivered over this routing was ~$10/MT. [Note: LANL's model cannot easily solve for a cost-of-service based allocation to each particular customer. Hence, for now, we must use what is referred to as a "postage stamp" charge, meaning everyone using the system pays the same price.]

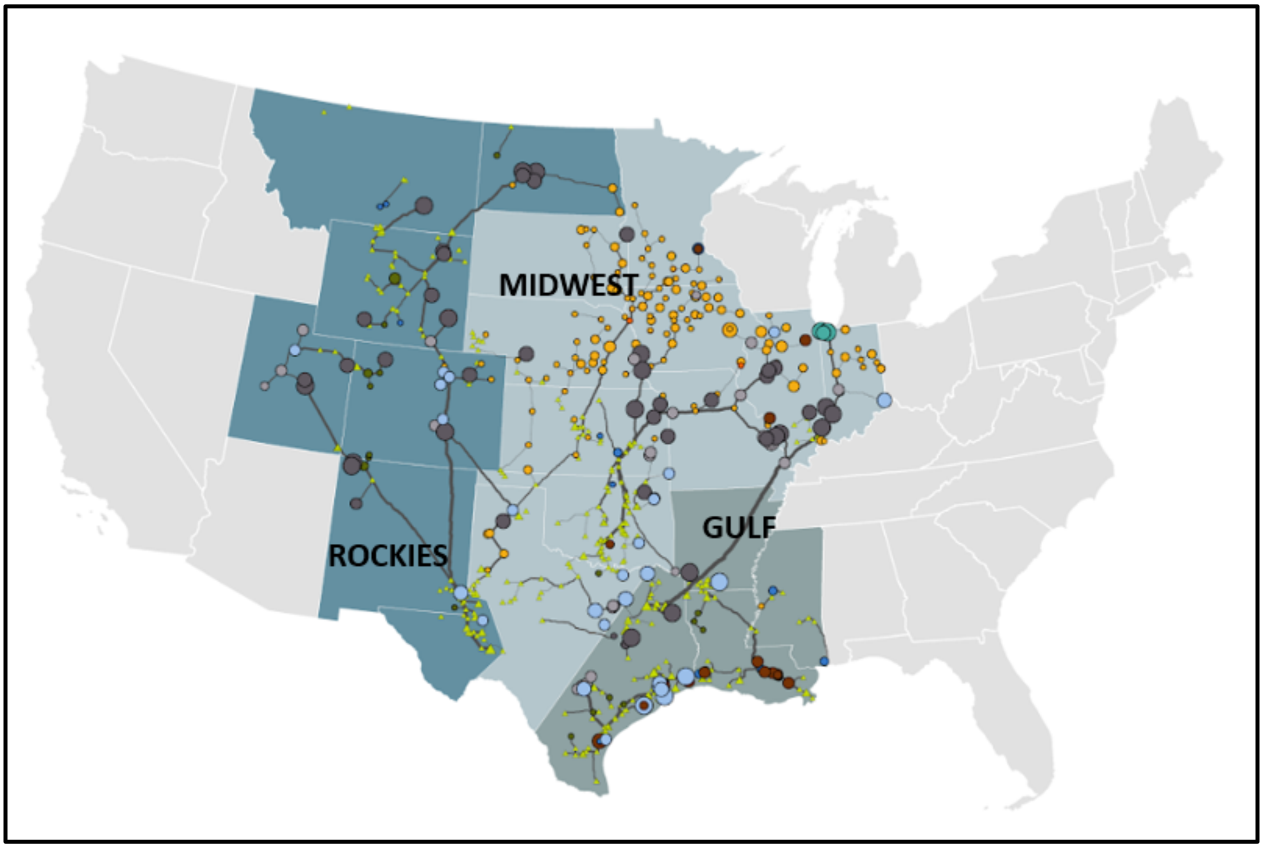
Figure 4.8 Rockies Region Network Infrastructure



f. Indicative U.S. Pipeline Routing under "Best Case" Scenario for all Three Regions

The map below shows the combination of all three regions.

Figure 4.9 Three Regional Network Infrastructure



Section (5) Carbon Capture Costs

This section discusses the various capture cost elements in general and then shows the industry-by-industry estimates we developed in order to create the "supply curves" discussed in Section 3. We conclude this section with a short discussion of why and how capture costs have often been seriously over-estimated.

a. Summary of Major Cost Items for Carbon Capture Projects

The three major cost categories for a CCUS project are (i) annual cost of repaying lenders/investors who put up funds for the original plant construction, (ii) fixed and variable operating costs (ex-energy), and (iii) energy costs, comprised of electricity, plus fuel combusted for steam production.

<u>Cost of repaying original capital expenditures for equipment.</u> In general, repayment of upfront capital costs represents the bulk of total cost per tonne captured for carbon capture projects. As with an individual buying a home, there are two determinants of the size of the mortgage payment: the price tag of the house, and the terms of the mortgage (years to pay back, interest rate, and down payment). As with home mortgage, the last three factors boil down into a payment factor (the mortgage constant). And the "mortgage constant" is always bigger than the interest rate because the mortgage constant include two components: one for interest and one for principal. [55]

For a project financing, instead of just a mortgage constant, our percentage financing payment is a little more complex. It is called a "capital recovery factor" (CRF) and includes five separate items all rolled up into a single percentage number. These items are (i) interest payments, (ii) principal payments, (iii) federal tax, (iv) dividends on equity investment, and (v) return of capital for equity investment.

To figure out annual cost per tonne captured we have to take the original cost of the capture facility, *times* the CRF %, and then *divide* by annual throughput of CO_2 captured. Take an example of a carbon capture plant that costs $300 million upfront, with the project having a 10% CRF, and an annual throughput of 1 million tonnes per year of CO_2 (at normal operating rates). The cost per MT captured for financing and tax is [($300 million x 10%/yr) ÷ 1 million MT/yr] = $30/MT captured. [56]

[55] Example: Take a $100,000 home mortgage, paid off over 30 years at a 5% annual interest rate. The actual annual payment would be $6,195.37, or ~6.2% of the house value.

[56] Note to readers: It is very easy to confuse the two "$ per tonne" metrics that appear in CO_2 capture studies. One is a measure of the upfront expenditure to build each unit of annual throughput capacity ($ per MTPA *capacity*), i.e. $300 million divided by $1 million tonnes per year = $300/MTPA capacity construction cost. The second is the actual product cost ($ per MT *captured*). The $/MTPA capacity figure is the most important data point for calculating $ per MT captured, which adds to the confusion for the unwary.

In the current state of industry development, the vast majority of carbon capture projects generally use similar components.[57] The main operating portions, and generally the most expensive portions, of these carbon capture systems are (i) equipment that separates the CO_2 from other gases in a mixed inlet gas stream, and (ii) equipment that removes any water and compresses the CO_2 to pipeline pressures so it can be transported. If the CO_2 is already at 100% concentration (on a dry basis) then only the second step is needed. In this section we are primarily going to describe capital requirements for amine solvent-based Acid Gas Removal (AGR) systems, since the literature contains no generalized examples showing alternative technologies to have a lower cost at present.[58]

Operating and Maintenance Costs. O&M costs include annual fixed operating costs (such as taxes, insurance, overhead, and general plant salaries), semi-fixed operating costs (such as major and minor repairs, maintenance, and overhauls), non-energy variable operating costs (such as replacement of process chemicals, water, water treatment, etc.) The fixed and semi-fixed costs vary more-or-less directly with original capital cost. I.e., more expensive plants have more expensive parts, more employees, and pay more property tax and insurance. For practical purposes, the truly variable costs (ex-energy) are so small that we can simply estimate O&M costs by multiplying original capital cost times a sector-specific percentage rate without losing much accuracy. As described below those percentages ranged from 4% to 7%, depending on the industry.

Energy Costs. Energy costs per tonne captured vary widely among studies mostly because the studies use widely different price assumptions. The actual per-tonne-captured unit quantities of electric and fuel energy needed are relatively predictable (i.e., the MWh of electricity needed to compress 1 MT of CO_2), as opposed to the highly variable price (the price per MWh). In our cost investigations we ferreted out the unit quantities so that for modeling purposes we could then allow electric and fuel commodity prices to be a sensitivity variable.

[57] As a special case, for very high concentrations of CO_2, such as would be found downstream of coal gasification equipment (e.g., the Coffeyville, Kansas pet-coke gasification plant) or in a natural gas processing plant whose field gas is highly CO_2-contaminated (e.g., field gas from Exxon-Mobil's LaBarge field in Wyoming) different systems that use cold methanol or propylene glycol as solvents, brand named Rectisol and Selexol, respectively, are used. It would be unusual to utilize Rectisol or Selexol for concentrations below 25%, especially at ambient pressures.

[58] It is true that some plant sites cannot support either the space requirements or energy requirements of an amine solvent based AGR system, in which case other equipment has to be used. This was apparently the case for plant-specific reasons at the Air Products & Chemicals, Inc. project at a steam methane reformer at Pt. Arthur, TX, causing the company to use a surface chemistry-based Vacuum Swing Adsorber. (Personal conversation of author's with company personnel.)

b. Capital Equipment Cost Detail

Compressors: Pure streams of CO_2 from ethanol[59], natural gas processing, and ammonia/urea nitrogen fertilizer plants in general only require dewatering and compressor systems to "capture" CO_2. In the aggregate, however, the amounts of pure CO_2 now emitted to the atmosphere from ethanol, gas processing, and ammonia plants—i.e., amounts not already being used or being sold by these emitters—are small in the context of U.S. emissions, about 78 MMTPA maximum, but considerable less (32 MMTPA once eliminating uneconomically small emitters, those already selling for EOR, and those that use apparently "captured CO_2" [60] in industrial processes. The table below is our best estimate, on a national basis, of available CO_2 from sources that only require compression, as opposed to CO_2 separation.

Table 5.1 Incremental CO_2 Volumes Not Requiring New Separation Equipment

Industry	High Purity Emissions Location	Gross Emissions MMTPA	Adjustments Reason	Adjustment Amount MMTPA	Net MMTPA
Ethanol	Fermentation	43	Below 0.25 MMTPA, too small for economic pipeline, or already selling to EOR	(19)	24
Gas Processing	Vent from Amine (or Rectisol) Unit	18		(13)	5
Fertilizer Plants	Vent from Amine Unit pre- or post-PSA	17* 78	67% capturable, but ~8-9 MMTPA captured & used for urea	(14)	3 32

*less Coffeyville, Great Plains, and Koch Enid already selling to EOR

[59] In the course of this study it was determined that some, but not all ethanol plants additionally require deoxygenation, which could cost as much as $15-20/MT. We did not factor this cost into our supply cost because we had no idea which particular ethanol plants did or didn't need deoxygenation. Additionally, even with $15-20/MT extra cost, ethanol is on the low-cost end of the supply curve; and this adjustment wouldn't have made a material difference to the results of the paper. We recommend further study, since virtually all discussions of cheaply available CO_2 from ethanol fermentation ignore this deoxygenation factor.

[60] Ammonia plants capture CO_2 in conjunction with operation of steam methane reformers (SMRs) in the normal course of operations. However, most of that CO_2 is typically reserved for reincorporation into the final product at a later production stage: only surplus CO_2, if any, is cheaply available. Oversimplifying, SMRs plus downstream gas-water shift reactors, use inputs of heat, water, and natural gas to produce a mixed gas stream *primarily* consisting of hydrogen gas and CO_2, which are separated. (There are also remaining amounts of unreacted CH4 and CO.) The hydrogen (H2) is combined with nitrogen to make ammonia gas (NH3). In most such plants virtually 100% of CO_2 captured from the SMR process is subsequently combined with ammonia ($2NH_3$+CO_2 -> H_2N-CO-NH_2 + H20) to make solid granular urea, a much easier, safer fertilizer to transport and use. Thus, even though lots of CO_2 is captured, most of it is used to make urea and very little CO_2 is unused and vented.

There are a host of studies that show the relationship between size and compressor cost, not all easily accessible to the layman because they focus on horsepower vs. cost, as opposed to volume of CO_2 that can be compressed versus cost. There are two types of compressors: reciprocating and centrifugal. The smaller reciprocating compressors are mechanically similar to pumps, whereas the large centrifugal machines are more like turbines.

- NETL's study of industrial capture concluded that for plants capturing 100,000-600,000 MTPA reciprocating compressors would be used with bare erected costs[61] of ~$43/MTPA capacity and no real scale economies.
- Above 600,000 MTPA NETL suggests that centrifugal machines would be used, with bare erected costs of ~$20-25/MT capacity dropping into the ~$15/MTPA capacity area for 1-2 million MTPA volumes.[62]

The reciprocating compressors are relatively cheap and can be ordered in standard sizes and are relatively cheap in absolute dollar terms, often assembled in series or with multiple trains of compressors in series to handle large volumes; but this means that scale economies are limited (since the buyer is buying many small units). Creating multiple trains of the smaller reciprocating compressors allows for redundancy and increases reliability.[63]

Like natural gas combustion turbines, the large centrifugal compressors have multiple stages of blades, all turning on a common shaft. This gives rise to scale efficiency possibilities for larger units. Conversations with experts raise the possibility that large CO_2 compressors that boost CO_2 from near ambient pressure (15psi) to pipeline pressures (2200 psi) are not a commodity industrial product, as opposed to the large compressors used in great quantities along gas pipelines that boost falling pressures back from ~1,500 psi to 2,200 psi. If those comments are correct, that would add to the attractiveness of the off-the-shelf commoditized reciprocating compressors.

From a practical point of view, we concluded:

- In the scheme of total costs of carbon capture, variations in the costs of compressors translate into relatively small changes in $/MT compressed. I.e., the difference between $25/MTPA capacity and $15/MTPA capacity, using a 13% CRF is $1.30/MT captured.

[61] "BEC" is a relatively commonly used term in studies we reviewed and generally means the cost of purchased components, materials to install (cement, steel, piping, wiring), and construction labor. We find the most useful number is the "EPCC" or Engineer, Procure, Construct cost, which adds in roughly 10% estimate of engineering and contractor construction supervision. Neither figure includes contractor or owner contingencies, interest during construction, development costs, or working capital. In this study when we refer to costs before contingencies, etc. we are using EPCC.

[62] Cite to Booz Allen/NETL Industrial Study

[63] Interview with Scott MacDonald of ADM. ADM uses banks of reciprocating compressors in its ~1 million MTPA Decatur Illinois project.

- Also, small projects with expensive compressors, projects dealing with 100-600,000 MTPA, are quite often in the ethanol or natural gas processing industries. Thus, despite a slightly higher cost for compressors, they are the lowest cost overall producers of CO_2 since they do not have to acquire the expensive CO_2 scrubbing systems described in the next subsection. This factor argues against excessive preoccupation on the part of policy makers with the exact cost of the smaller compressor systems.

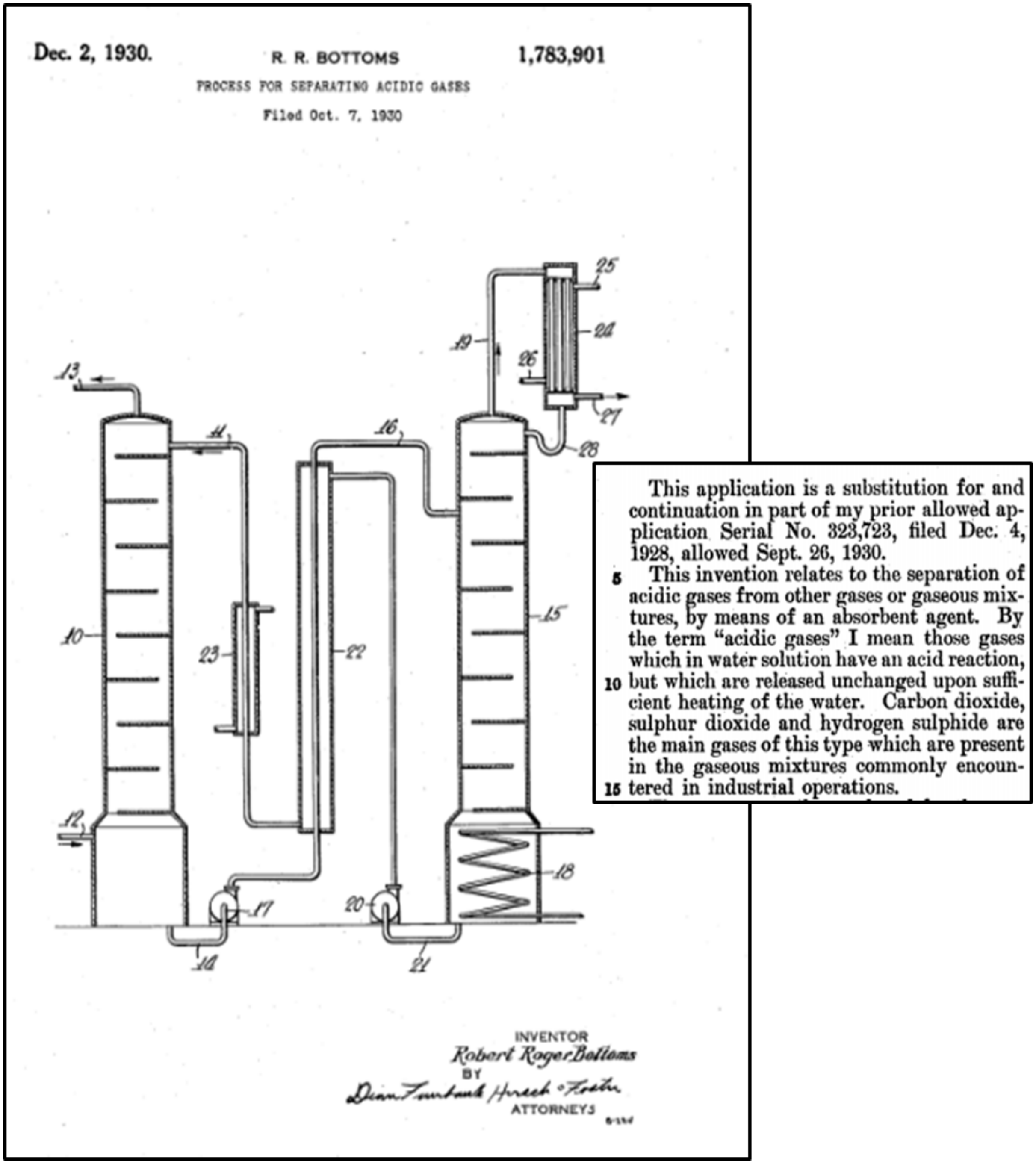
CO_2 Separation/Scrubbing Systems: Outside the 100% CO_2 concentrations seen in ethanol and gas processing, CO_2 in industrial and power plant vent stacks is more usually found at molar concentrations of 25% or less, mostly at atmospheric pressure.[64] Thus, keeping that CO_2 from being emitted, and making that CO_2 clean enough to allow pipeline transport, requires installation of special equipment that will separate the CO_2 from other gases in a mixed gas waste stream. The most common, and the oldest and best-tested system, involves use of chemicals (a family of "amine solvents" of various types) that have a strong affinity for CO_2 at low temperatures but that will release the CO_2 if boiled. The CO_2 scrubbing process involves spraying an aqueous solution containing the solvent into the top of an exhaust stack (absorber tower) so as to come in contact with the waste gas stream rising up the stack in counter-flow. Then the CO_2-laden solution is routed to a steam-heated pressure vessel (stripper tower or solvent regenerator) where the CO_2 is released, after which the solvent solution is recirculated back to the absorber tower.

Simply to make to the point that, notwithstanding a vast amount of misinformation calling carbon capture "a new technology" use of amines to remove acid gases is nearly a century old. This technology is used in the vast bulk of every natural gas processing or fertilizer plant in the world that is processing medium- to low-concentration CO_2.[65] This system was patented by Louisville inventor R. Roger Bottoms on October 30, 1930 and is shown below:

[64] The key cost driver is carbon-dioxide molecules as percent of total gas molecules in a volume of gas treated, which is called the "molar concentration." Since CO_2 is quite heavy compared to the other gas molecules in ambient air, CO_2 concentrations measured by weight are typically much higher than molar concentrations. In this Topic Paper when referring to concentration we mean molar concentration, and not concentration by weight.

[65] When processing very high CO_2 concentrations, such as "sour gas" that is >50% CO_2, or when using coal or petroleum coke feedstock in gasification units, a 1950's liquid methanol solvent system is used.

Figure 5.1 1930s Patent Drawing for Amine Solvent Separation



This application is a substitution for and continuation in part of my prior allowed application Serial No. 323,723, filed Dec. 4, 1928, allowed Sept. 26, 1930.

This invention relates to the separation of acidic gases from other gases or gaseous mixtures, by means of an absorbent agent. By the term "acidic gases" I mean those gases which in water solution have an acid reaction, but which are released unchanged upon sufficient heating of the water. Carbon dioxide, sulphur dioxide and hydrogen sulphide are the main gases of this type which are present in the gaseous mixtures commonly encountered in industrial operations.

Source: US Patent Office https://patents.google.com/patent/US1783901A/en

Amine solvent systems (e.g., amine acid gas scrubbing system) are often used in industries such as natural gas processing and fertilizer manufacture.[66] They are now being increasingly applied for emissions control purposes in industries where they have not been used historically. For instance, amine solvent systems are used in both examples of North American coal plant retrofits for carbon capture, the Petra Nova/W.A. Parish power plant in Texas and Boundary Dam coal power plant in Saskatchewan. The installed costs of the amine systems themselves are typically in the range of $80-$100/MTPA. Cost per tonne of annual capacity falls with larger size and also falls with higher molar concentrations/pressures of CO_2 in treated waste gases.

Empirical evidence gathered from a cross section of studies validates the concept that higher CO_2 concentrations in the treated gas stream drive unit capital costs downward.[67] The scatterplot below depicts the equipment cost for solely the amine solvent-based Acid Gas Removal ("AGR") system portion of various carbon capture projects at industrial and power plant sites.[68] The "y" axis shows the dollar upfront capital expenditure divided by the MTPA of CO_2 that flow into the AGR system. The "x" axis reflects the molar, or molecular concentration of CO_2 in that inlet gas on a dry basis.[69] There is a strong, but not perfect trend (blue line) showing that unit costs ($/tonne throughput capacity) go down as concentrations rise from the 5% range to the 25% range. If the data for the chart below had reflected work by a single engineering firm using at a single date, using identical equipment assumptions and currency, we would have expected the correlation to have been stronger. However, the data here reflects 9 projects, in 6 industries, 3 currencies, and 5 different years. Additionally, even these relatively good studies often did a poor job in specifying what ancillary equipment or costs may have been lumped in with the AGR system line items. [N.B.: This chart does not show the capital cost for the entire carbon capture project—just the capital cost for the single most critical and expense component, the AGR system.]

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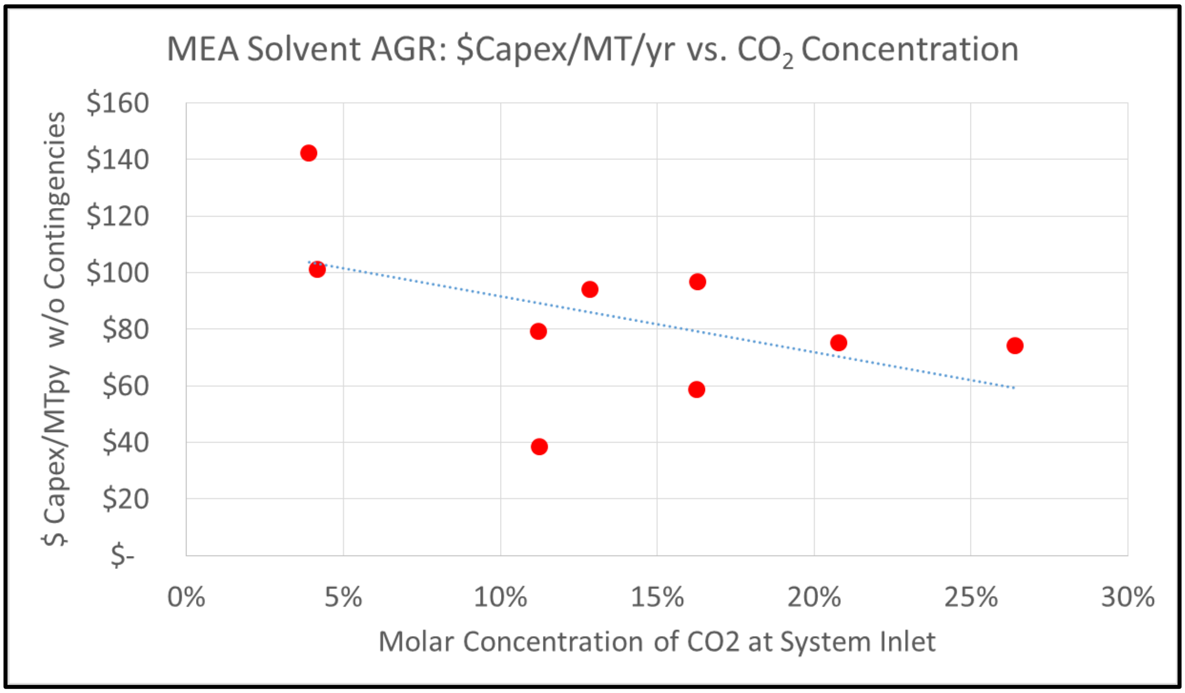
[66] The most common "amine" compound used is MEA or monoethanoloamine. Others include 2-amino-2-methyl-1- propanol (AMP) and methyl-diethanolamine (MDEA).

[67] There is also a theoretical rationale for capital and operating costs to decrease with concentration. See discussion of "Sherwood Analysis" in "CO_2 capture from the industry sector" by Bains, Psarras, and Wilcox, 2017, sections 3.1 and 3.2.

[68] For this chart we attempted, where possible to isolate the costs estimated by engineers for the AGR comprised of purchased equipment, materials to erect the AGR system, construction labor, engineering, and construction supervision, while eliminating any project contingencies, owners' costs, and interest during construction, etc. Where information allowed we removed items such as water infrastructure, duct work to connect to the original emitting vent stack, etc.

[69] Note: For readers who are not gas chemists, the key concentration measure is not the weight of CO_2 in a mixed gas stream, but rather the number of molecules of CO_2 compared to the number of other type of gas molecules (the molar concentration, sometimes referred to as "mol/mol%"). That is because a molecule of one kind of gas takes up the same amount of volume as a molecule of any other type of gas (at same temperature and pressure). Since amine AGR systems depend on amine solvent droplets physically contacting a CO_2 molecule, the higher the molar concentration of CO_2 in the flowing mixed gas stream, the more probable it is that solvent will contact a CO_2 molecule in the absorber tower. Thus, if the CO_2 concentration is high, the CO_2 can be removed quite quickly in a smaller absorber tower, saving money.

Figure 5.2 Installed Equipment Cost for MEA Solvent Sub-systems at Various CO_2 Concentrations[70]



Other capital costs. Other large capital expenditure components typically include:

- ducts to move exhaust gases to the inlet of the capture system from the vent stacks where they were formerly emitted;
- cooling systems if the AGR inlet gas is too hot;
- pre-treatment systems if the inlet gas contains undesirable contaminants (for example, unless virtually all SO2 has been removed from inlet gas, additional "polishing" of inlet gas is required);
- water systems to circulate, clean, and provide make up water for the solvent system; and
- storage bins and tanks for materials, including reserves of solvent.

Sector-specific capital costs used in this study. We detail the industry-by-industry central capture project capital cost estimates we used for modeling regional supply curves in the table below, later providing deeper details on *how* we made these estimates based on existing studies and our own industry research.

- For the non-pure CO_2 situations it is easy to see how total capacity costs could reach the $200/MTPA capacity range. As a simple example, assume "bare

[70] The red data points each represent information on the "Bare Erected Cost" (Equipment, Materials, and Labor) for the MEA Solvent separation sub-system. The costs were extracted from nine different studies covering six industries. These same nine studies were part of the group of studies analyzed to develop industry cost estimates later in this Section. Not all studies clearly broke out the needed figures, or we would have had more data points.

erected costs" plus engineering/construction supervision of \$25/MTPA for compressors, \$100/MTPA for an amine system, and another \$25/MTPA for associated water, electrical, and waste systems, for a total of \$150/MTPA. Multiplying that \$150/MTPA figure times 1.20x for contingencies and times 1.10x again to allow for cost of funds during construction puts us at the \$200/MTPA capacity cost mark.

- The most significant cost items in addition are (i) cost of ducting, to the extent stack gases need to be routed a significant distance from the old vent stack to the new carbon capture system, and (ii) cost of providing for electricity and steam to run the carbon capture system itself.
- Note that the figures in the table below represent our lower cost analytical range, using a 20% contingency factor and CRF of 10%.[71]
- The high end of our range used 40% contingency and a CRF of 13%.

Table 5.2 Capital Investment Cost Multiplied x CRF in Various Industries

Capacity, Investment Cost per Unit Capacity, and Cost per Tonne Captured				
Category	Sector	Reference Plant Size (MTPA)	\$ Capital Investment /MTPA of *Capacity*	\$/MT *Captured* w/ CRF at @ 10% x Capex
Pure Streams [No AGR Needed]	Natural Gas Processing	600,000	\$39	\$4
	Ethanol	500,000	\$49	\$5
	Ammonia	400,000	\$68	\$7
Hydrogen Plants	Industrial Hydrogen Plants (Refinery and Stand-alone)	350,000	\$168	\$17
Large Concentrated Sources	Cement Plants	1,000,000	\$187	\$19
	Refinery Fluidized Catalytic Cracking (FCC)	1,000,000	\$225	\$22
	Steel Blast Furnace Gas (BFG) Combustion	3,000,000	\$281	\$28
	Coal Power Plant	1,600,000	\$299	\$30
Large Dilute Sources	Natural Gas Power Plants	500,000	\$382	\$38

[71] Note: The CRF is not an exogenous variable, but rather the CRF is the solution to a multi-year, multi-factor model that will meet multiple constraints, with the most important being to provide a specified life-of-project equity return (IRR) to equity. See table on following page for CRF inputs for the 10% and 13% CRF cases. Note also that we are using cost of debt and cost of equity assumptions that are "nominal", thus accounting for the impact of future inflation. Nominal funding costs are higher than "real" or constant-dollar funding costs. US DOE sometimes uses real/constant dollar funding costs and zero inflation assumption in order to obtain real/constant dollar capture costs.

Summary of inputs to Capital Recovery Factors (CRFs). The table below shows the inputs from which we derived 10% and 13% CRFs for a 12-year investment horizon.

Table 5.3 Inputs Used in Deriving Nominal Capital Recovery Factors

Inputs Used in Deriving Capital Recovery Factors		
CRF	**10%**	**13%**
Asset Life	12 years	12 years
Debt Term	12 years	12 years
Debt Rate	4.5%	5%
Debt as % of Total Capitalization	60%	50%
Total Debt Service Coverage Ratio	1.5x	2.3x
After Tax Internal Rate of Return on Equity Investment	10%	15%
Corporate Tax rate	21%	21%
CO_2 Equipment Depreciation	5-year MACRS	5-year MACRS

Note that because the life of Section 45Q tax credits is only 12 years we used also used a 12-year investment horizon (implying the full investment cost is recovered over 12 years). In truth, we could have also chosen to use the 20-year horizon more appropriate for long-lasting major capital projects, but that would have raised concerns that the capture units could cease operations once the tax incentives ceased at the beginning of Year 13. Moreover, parties have raised the question of how to verify the useful life of the host industrial facilities onto which the capture equipment is being added. *If we had been able to extend the investment horizon to 20 years, the 10% CRF would have dropped to 8.5% (1.5% less); and the 13% CRF would have dropped to 11.7% (1.3% less).*

Cost of providing for electricity and steam: This is a complex subject that has serious implications for cost of carbon capture, having also led to great confusion among readers of carbon capture techno-economic analyses.

In general, the combination of a compressor and an amine system create a need for ~0.15 MWh of electricity and ~2.5-3.5 MMBtu of fuel, that fuel being combusted to create steam for solvent regeneration.[72] The question is how to provide for the electricity and steam. Further, not all steam is appropriate for heating the CO_2-rich amine solvent solution in the stripper vessel. The amine system needs relatively low pressure/low temperature steam, whereas most steam generation systems, including power plant boilers, are designed to create very high pressure/high temperature steam.

Different analysts have taken very different approaches; and rarely have they taken the least risky, least complex, cheapest route. Thus, this issue has tended to create significant lack of comparability among studies, and it has generally tended to inflate the "cost of capture."

- Build your own power plant: One very expensive method is to build one's own little power plant to make electricity and steam. It is hard to understand why this would be a good idea in nations like the U.S. where electricity is easily available and competitively priced. That is especially true in grids that have relatively low average carbon intensity (MT CO_2 per avg. MWh sold on the grid), since electricity self-generated at a fossil fuel consuming host plant is likely to be more carbon intensive than grid electricity.[73] Some studies seem to choose this option for analytical reasons, to be able to keep careful track of all heat, electricity and carbon balances within the plant boundary; but that convenient analytical approach comes at a high price in terms of capital expenditures.
    - Highly efficient generators: Taking this approach, a project can use very efficient power generation equipment (such as a natural gas combustion turbine combined with a heat recovery steam generator). However, the power generation is generally in the wrong proportion to steam needs, so the project needs to sell more fossil electricity to the grid. In one NETL example, this approach led to more than doubling the electrical output of the old host coal plant.[74]
    - Combined Heat and Power: One can use a traditional industrial "combined heat and power" (CHP) approach that uses boilers rather than turbines, getting a correct power/steam ratio but at a much higher capital cost. This approach was taken in two IEA studies, one on cement and another on steel. In the

[72] Discussed further under operating costs. These are rough figures and vary by small, but not economically significant amounts for our purposes, depending on compressor efficiencies and the particular heat requirements of each solvent or solvent mixture.
[73] As an example, using coal to self-generate incremental electricity in order to run carbon capture devices seems environmentally counterproductive, as well as expensive. Further, as the grid gradually decarbonizes, so too would the electricity used to power the carbon capture equipment. Using coal to run the capture equipment today typically creates emissions of ~0.9 MT per MWh when the U.S. grid average is half that figure at 0.45 MT per MWh. See Table 3 at https://www.epa.gov/sites/production/files/2018-02/documents/egrid2016_summarytables.pdf
[74] NETL's Case 2 in "Eliminating the De-rate of Carbon Capture Retrofits", DOE/NETL-2016-1796.

cement study so doing doubled capital costs to build a 45MW coal power plant at an astounding price of $4,000 per kW.[75]

- Cannibalize existing power plant: Another approach, primarily considered in the power sector, is to cannibalize the original/host power plant (technically called "de-rating") in order to get electricity and steam. Taking electricity from the host power plant is easy, and just reduces the amount of electricity for sale to the grid. If the host plant is a relatively old coal generating unit, and if without addition of capture the host coal plant is likely to be shut down, some amount of "derating" doesn't have a high real-world cost. This "cannibalization" or "de-rating" approach at a coal plant is also very attractive if the cost of coal quite low, as is the case at some plants in Wyoming that report coal cost below $/MMBtu.
    - However taking steam, depending upon the exact spot from which the steam is taken, as in a coal power plant, may cause the need for modifications to the heart of the host power plant—the steam turbine—as was done at considerable expense at SaskPower's Boundary Dam project.[76]
    - An alternative sometimes suggested is taking the highest-pressure steam direct from a coal plant boiler and using a "letdown turbine" or "backpressure turbine" to capture some energy as the steam pressure is reduced to the low temperature/pressure needed for solvent regeneration. This was the approach suggested by Duke Energy in a joint analysis with Lawrence Livermore National Labs.[77] This does not require modifications to the host plant steam turbine.
    - Close linking of the host power plant steam system to the capture project removes flexibility to operate the power plant without the capture system (e.g., in case of a forced outage of the capture system), and it also means that the host power plant may suffer lengthy outages during the construction of the carbon capture plant.
- Low capex approach: The approach used by developers of carbon capture projects who are seeking to minimize risk and capital cost, with an accompanying modest probability of higher electric and fuel bills is to simply (i) buy electricity from the grid or at internal cost from the host plant, and (ii) buy an off-the-shelf gas "package boiler" to make steam. A "package boiler" earns its name by virtue of being factory made, deliverable on site ready to run.[78]

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[75] The 45MW power plant, represented 50% of the Euro 294 million capital cost, or Eur 147 million, which is $184 million after currency and inflation adjustment. $184 million/45,000 kW= $4,089/kW. Typical cost for an efficient new natural gas combined cycle power plant is in the range of $800 per kW, or about 1/5 the cost.

[76] The difficulty is that the usual site to withdraw steam from the host plant is at the crossover point between the intermediate- and low-pressure sections of the steam turbine. Unless the turbine blade configuration at the low-pressure end is adjusted there will be too little torque on the low-pressure end of the turbine shaft, which will then go out of balance.

[77] "Technoeconomic Evaluation of MEA versus Mixed Amines for CO_2 Removal at Near-Commercial Scale at Duke Energy Gibson 3 Plant" LLNL-TR-642494

[78] https://en.wikipedia.org/wiki/Package_boiler

In the context of carbon capture projects that are perceived as risky and for which raising capital is difficult, eking out modest fuel/thermal efficiency gains by adding an expensive power plant to a project seems counter-intuitive, and the numbers seem to bear out that intuition. The "benefits" of using a capital intensive method to supply steam and electricity could be either (i) savings in power cost if self-generation is significantly cheaper than buying from the grid or (ii) higher fuel efficiency in generating steam, since high pressure steam has first been used to generate electricity before low pressure steam has been used to re-boil solvent. Having analyzed these benefits, our conclusions are that: (i) attempting to make a profit by small scale electric self-generation vs. buying power from the grid is a separate business proposition from carbon capture, and mixing the two up creates confusion; and (ii) the thermal efficiencies created by combining power generation and steam generation in the context of carbon capture are small when compared to the capex required to do so. On this last point, we have calculated that in round terms, there could be fuel savings of ~1 MMBtu/MT CO_2 if steam is manufactured as a co-product of electricity generation, which is worth only~$3.00-3.50 in today's U.S. natural gas market. It is hard to rationalize increasing capital expenditures on a capture project by 25% to 50% to obtain such paltry savings.

The table below summarizes some examples of how this problem has been approached in terms of comparative capital expenditures, without making a comprehensive effort to value incremental electricity generation, etc. The point is to show the great variation in capital expenditures and associated "cost of capture" engendered by differing approaches to this seemingly minor issue of supplying electricity and steam to a capture project.

Table 5.4 Various Approaches to Providing Electricity and Steam Supplies for Carbon Capture Equipment

Capital Expenditure Impacts of Different Approaches to Generating Electricity and Steam to Supply Carbon Capture Project Energy Needs			
Approach to generating additional electricity and steam	Example	Incremental capital expenditure per MTPA capacity	Impact per MT captured @ (10% CRF + 5% O&M factor)
Build efficient gas power plant	NETL study on coal power plant retrofit[79]	\$63-\$150/MT	\$9-23/MT captured[80]
Small coal boiler CHP	Mott MacDonald IEA cement	\$158/MT	\$25/MT captured
Taking steam and power from host power plant (assuming no de-rating allowed)	Implied from NETL new-build Case B11A vs. B11B	\$50/MT including extra generation cost and incremental boiler	\$8/MT captured
Gas package boiler for steam	Various developer studies (private)	\$7/MTPA	\$1/MT captured

c. Capture Operating & Maintenance Costs

Major operating and energy costs include:

- Annual fixed operating costs (such as taxes, insurance, overhead, and general plant salaries);
- Semi-variable operating costs (such as major and minor repairs, maintenance, and overhauls)
- Non-energy variable operating costs (such as replacement of process chemicals, water, water treatment, etc.), and
- Energy variable costs (electricity to drive compressors, motors, pumps and fans; plus fuel used to make steam to boil CO_2-laden solvent).
- Because unit quantities of electric and fuel energy loads are relatively predictable (i.e., the amount of electricity needed to run a compressor), as opposed to the highly variable price (the price per MWh to make or buy that electricity), we kept energy variable costs separate from other variable costs.

[79] Eliminating the De-rate of Carbon Capture Retrofits, DOE/NETL-2016-1796.

[80] Extra electric generation from natural was created, at a reasonable incremental cost of ~\$600-700/kW. But the project total cost, complexity, and CO_2 emissions also rose, as did the business risk of selling electricity to the grid.

Ultimately, we determined that for projects in each particular industry sector, a percentage rate applied to project original capital cost would be a satisfactory estimate of non-energy fixed, semi-variable and variable costs. We were seeking, as far as possible to derive a representative figure or methodology that could be easily applied across many dozens of capture projects of each type. Further, we sought an operating cost methodology that would scale up and down reasonably accurately for carbon capture plants that were bigger or smaller than prototypes for which we had engineering detail.

It makes sense that operating costs would be strongly correlated with original plant cost. We surveyed multiple detailed studies of particular plant types and obtained expected maintenance costs in absolute dollars, dollars per MT processed, and as a percentage of carbon capture plant construction cost. Authors of the studies we reviewed often estimated operating costs based on percentages of plant cost[81]: a bigger plant has more parts to break than a small plant, and a big plant costs more than a small plant, so it makes sense that O&M should rise with absolute capital cost. Further, if two plants are of the same size, but one was much more expensive to build, it seems likely that its labor rates may be more expensive and its spare parts will be more expensive. Finally, there are some scale economies both in building a large plant, and in operating a large plant, and those economics appear to move roughly in tandem.

- Two large fixed cost items are certainly a fixed percentage of plant cost. For local/state property taxes and property/casualty insurance we used standard percentage figures of 1% and 1/2% respectively. When annual supervisory and labor positions were detailed, they appeared to be correlated with plant cost, and also comparatively small.
- Typical semi-variable costs include maintenance, need for which is partly triggered by passage of time and partly triggered by usage. However, since in virtually all cases we were planning for carbon capture operations that would run at 85-90% capacity factors, these items could be treated as fixed costs. Maintenance materials typically made up 3/5ths or more of maintenance costs, and cost of maintenance materials vary directly with original plant cost (i.e., replacement costs for expensive machines cost more than replacement parts for cheap machines).
- The main non-energy variable cost in the plants we examined was replacement of amine solvents, especially when those were proprietary formulations. Often prices for solvents are carefully guarded. Nonetheless, big plants that capture large amounts of CO_2 use up more solvent that small plants—so again there is a logical reason for the annual solvent replacement bill to be strongly correlated with plant cost.

[81] Duke/LLNL Gibson study (see p. 47/69) used 3% of Battery Limits Investment (roughly corresponding to 1.8% of total investment) to estimate each of maintenance materials and maintenance investment. Of course, their property tax and insurance figures were also based on investment cost. Ultimately approximately half of non-energy O&M costs were directly calculated as a percent of investment.

The particular factors we used in the report are set forth in the table below, both as percent and in dollars per tonne. The only major outlier data point we observed in the cross-study comparison was that USDOE NETL studies for industrial carbon capture for amine units had used 11.77% of capture plant cost for annual cost of maintenance materials. However, USDOE NETL studies for power plant amine capture systems were less than 1%, and those power plant systems had perplexingly been cited as the source for the 11.77% figure. Thus, we disregarded that particular data point, especially as it did not correspond to any other studies, most of which put the maintenance material cost in the 1-3% of capex range.

Table 5.5 Non-Energy O&M Costs

Operating and Maintenance Costs				
Category	Sector	Reference Plant Size (MTPA)	Non-energy O&M as % of Capex	$/MT*
Pure Streams [No AGR Needed]	Natural Gas Processing	600,000	6%	$2.35
	Ethanol	500,000	7%	3.42
	Ammonia	400,000	5%	3.40
Hydrogen Plants	Industrial Hydrogen Plants (Refinery and Stand-alone)	350,000	5%	8.39
Large Concentrated Sources	Cement Plants	1,000,000	7%	13.11
	Refinery Fluidized Catalytic Cracking (FCC)	1,000,000	4%	9.88
	Steel Blast Furnace Gas (BFG) Combustion	3,000,000	5%	14.03
	Coal Power Plant	1,600,000	4%	12.43
Large Dilute Sources	Natural Gas Power Plants	500,000	5%	19.08

*$/MT obtained by multiplying % figure in column to left x capital cost figures from Table 5.2.

d. Energy Costs

Overall, and throughout our review of various studies, there was little difference from industry to industry in the electricity and fuel consumption of running compressors alone, or in running compressors and an amine CO_2 scrubbing system. Variations in exact consumption and prices are relatively small impact items in terms of overall cost of capture.

- Electricity:
  - Running only compressors (plus dehydrators) generally consumed on the order of 0.1 MWh per MT.
  - Running both amine systems and compressors typically consumed on the order of 0.15 MWh per MT.

- For our study we used a \$50/MWh electricity price, which corresponds to typical tariffs for large manufacturing facilities. We also cross-checked that figure with several managers from NPC study participants whose job it is to acquire electricity and who agreed with the assumption. For reference the USEIA figures for February 2019 were \$51.80 per MWh for "West South Central" (AR, LA, OK and TX) average price to electricity to "Industrial" customers.
- At \$50/MWh the 0.1MWh costs \$5/MT and 0.15MWh costs \$7.50. Note that if the host emitter has very low cash operating costs and the capture facility can get power at the "inside the fence" cost then these figures would be much lower.

- Fuel: Other than for cases where fuel and steam were self-generated in a combined process, fuel needs were in the 2.5-3.5 MMBtu per MT CO_2 range. When the analysts had direct information from manufactures known to have solvent with low heat requirements for regeneration (i.e., Mitsubishi Heavy Industries' K-1 Solvent) requirements were on the low end. For generic estimates, requirements were on the high end.
  - For our study we used natural gas prices of \$3.50/MMBtu, which again was in line with costs actually incurred by study participants, most of whom have access wholesale gas prices and purchase firm transmission for fuel requirements on pipelines. Note that though USEIA reports prices paid by industrial consumers for natural gas, USEIA shows only a small portion of industrial users as having reported. That said, average annual TX industrial prices for the last six years were \$3.70, with \$3.39/MMBtu for 2018. At \$3.50/MMBtu, 2.5MMBtu costs \$8.75/MT CO_2; and 3.5 MMBtu costs \$12.25/MT CO_2.
  - In some places, such as southern Illinois or Wyoming, coal is very cheap compared to natural gas, and capture projects may make an economic decision to use that cheap fuel to operate capture projects. For example some Wyoming coal plants pay coal prices less than \$1/MMBtu, and USEIA shows February 2019 coal delivered to Illinois power plants at \$1.86/MMBtu.[82]

e. Our Total Capture Cost Estimates Compared to Other Industry Figures

In the table below we compare the high and low capture cost estimates we derived by analyzing the available sources. As stated in the previous subsection, our approach was to carefully examine the engineering details, equipment lists, operating cost details, and mechanisms to provide for capture unit needs for electricity and steam. We then sought to use common assumptions as to contingencies, financing costs, tax and insurance, natural gas costs, and electricity to create comparability. In the table below the footnotes summarize major adjustments we performed in the "Other Studies" column. Note that

[82] https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_4_10_a

Table 5.6 Comparisons vs. Selected Other Studies

Our Total Capture Costs per Tonne[83] vs. Selected Other Studies					
Category	Sector	Reference Plant Size (MTPA)	Capture Details	This Paper (low-high)	Other Studies[84]
Pure Streams [No AGR Needed]	Natural Gas Processing	600,000	100%	$11-14	~$15 NETL[85]
	Ethanol	500,000	100%	$14-18	~$17 NETL[86]
	Ammonia	400,000	N.A. Unused SMR CO_2	$15-20	~$21 NETL[87]
Hydrogen Plants	Industrial Hydrogen Plants (Refinery and Stand-alone)	350,000	~56% of total, 67% of pre-PSA carbon	$43-54	$30 IEA[88]
Large Concentrated Sources	Cement Plants	1,000,000	90% at vent	$49-62	$58 Kuramochi[89] $51 IEA[90] $64 NETL[91]
	Refinery Fluidized Catalytic Cracking (FCC)	1,000,000	90% at vent	49-63	$73 Kuramochi
	Steel Blast Furnace Gas (BFG) Combustion	3,000,000	90% at vent	$59-77	$32 Kuramochi

[83] NB: This table is showing “capture cost” and not “avoided cost.” Avoided cost subtracts any CO_2 emissions imputed to the operation of capture cost equipment. Thus, if a unit captures 1 tonne of CO_2 at a cost of $50, its capture cost is $50/MT. If the operation of the capture unit itself emits 0.2 tonnes of CO_2 the avoided cost would be $50 ÷ (1.0-0.2) = $62.5.

[84] For all other studies, where no CRF was available or disclosed, we used the 13% high end of our 10-13% CRF range for sake of conservatism.

[85] NETL/Booz Allen table 7-25 shows $17.38/MT, and we made $2/MT adjustment for mistake in maintenance material cost discussed in subsection “f” below. Plant was sized at 551,818 MTPA.

[86] NETL/Booz Allen graph Exhibit 7-9 (p. 43/144) shows ~$21 per MT for ~500,000 MTPA, however needed to subtract ~$4/MT for mistake in maintenance material cost discussed in subsection “f” below.

[87] NETL/Booz Allen table 7-16, shows $26.26/MT, and we made $5/MT adjustment for mistake in maintenance material cost discussed in subsection “f” below. Plant was sized at 389,639 MTPA.

[88] IEA Levelized Cost of Hydrogen report with key assumptions converted to USA values consistent with this Topic Paper: Euro USD @1.22 as of 2014 Q4, 10% CRF, $50/MWh power, & $3.50/MMBtu gas. Also corrected for improper consultant calculation of cost of funds during construction. Our assumptions and IEA’s were amine capture at ~300psi and ~16pct molar concentration. Other studies have higher costs but use a less cost-effective configuration, so comparability is difficult. Post-PSA tail gas is disadvantaged by low pressure which requires an intermediate compressor in IEA analysis. Vent stack capture treats a far more dilute CO_2 stream which raises costs.

[89] Kuramochi (2012) in tables 7, 8, 9, and 11, gave energy quantities in GJ, capital cost in 2012 Euro/tonne, and O&M as % capital cost. From those we calculated capture cost using 1.05 GJ/MMBTU, 0.28 MWh/GJ, $3.50/MMBtu gas, $50/MWh power, 1.28 USD/EUR in 2012, and 3% change in the CEPCI Index from 2012 to 2018. Few details in Kuramochi’s study.

[90] Adjusted to remove capital expenditure on SOx NOx equipment that should not have been charged against CCS, and to remove a coal-fired Combined Heat and Power plant, using boilers and grid power instead.

[91] Adjusted to remove SOx NOx equipment, and for mistake in maintenance material cost.

Our Total Capture Costs per Tonne[83] vs. Selected Other Studies					
Category	Sector	Reference Plant Size (MTPA)	Capture Details	This Paper (low-high)	Other Studies[84]
	Coal Power Plant	1,600,000	90% of stack gases bypassed to CCUS[92]	\$60-77	\$50(avg.) Rubin/Herzog[93] \$54 CURC[94] \$63-\$68 LANL/Duke[95] \$42-\$65 Linde/ICKan[96] \$85 Bechtel[97]
Large Dilute Sources	Natural Gas Power Plants	500,000	90% of stack gases bypassed to CCUS	\$65-90	\$69 CURC[98] \$74(avg.) Rubin/Herzog[99]

[92] Similar to successful NRG W. A. Parish Unit#8 retrofit, our approach was to size capture unit at a level that could capture 90% of stack gases when generator(s) are running at approximately minimum turndown levels or on approximately 50% of stack gases on 2x1 combined cycle natural gas turbine plants. In general—but highly dependent upon unit operating patterns-this approach will allow 50-60% overall capture rate, with the capture rate going up as unit capacity factor declines.

[93] Our estimates are based on retrofits of subcritical coal plants, and subcritical plants might be modestly more expensive than supercritical coal plants if the both subcritical and supercritical plants studied used self-generated electricity and steam to meet electric and thermal parasitic loads. Herzog/Rubin (2015) cite six supercritical coal studies, with capture costs in \$/tonne (low to high) at \$36, \$45, \$46, \$46, \$47, and \$53, with a mean of \$46. We inflated the \$46 by 8% reflecting change in the CEPCI Index from 2015 to 2018.

[94] CURC (2018) figures for capex, O&M, and heat rate changes. Capture cost calculation above used our 13% CRF, \$2/MMBtu coal, 85% plant capacity factor, and 90% capture. Tables B-6 & B-7 using Year 2020 values.

[95] "Technoeconomic Evaluation of MEA versus Mixed Amines for CO_2 Removal at Near-Commercial Scale at Duke Energy Gibson 3 Plant", Jones, McVey, and Friedman (2013), LLNL-TR-642494, Table 3.2, p. 21/69. The figures in the report are \$60-\$64, which we inflated by 6% reflecting change in CEPCI Index from 2013 to 2018.

[96] Integrated CCS for Kansas (ICKan) study "Final Report Appendices" (2018). Study principal investigators were Eugene Holubnyak and Marin Dubois. Award Number: DE-FE0029474. Cited material reflects Jeffrey Energy Center, with calculations having been performed by Linde based on Linde/BASF amine system. See table 5.4 and text below table at p. 77/237. Numbers at low end of range reflect more efficient approaches to capture of waste heat for use in solvent regeneration. Analysis for smaller Holcomb power plant showed \$46-\$71/MT (Table 5.8 p. 83/277).

[97] "Retrofitting an Australian Brown Coal Power Station with Post Combustion Capture, a Conceptual Study", Bechtel Infrastructure, 2018. Cited AUD 935MM for capex and AUD 60MM/yr for non-fuel operating expenses on 2.4 MM MTPA capture module (Table 1.2-1 page 9/131). Converted to USD at 0.77 exchange rate used in study, used 13% CRF, and used same fuel and electricity quantities and prices as our own calculations. The study itself did not give capture or avoided costs.

[98] CURC (2018) figures for capex, O&M, and heat rate changes. Capture cost calculation above used our 13% CRF, \$3.5/MMBtu natural gas, 85% plant capacity factor, and 90% capture. Tables B-8 & B-9 using Year 2020 values.

[99] Rubin/Herzog cite six NGCC studies, with capture costs in \$/tonne (low to high) at \$48, \$58, \$65, \$80, \$88, and "\$104", with a mean of \$74. The "\$104" figure is the mid-range from EPRI which actually had a range of \$86-\$130 without supporting engineering information. Removing that \$104 figure reduces the mean to \$68.

f. Capture Cost Discrepancies

"Capture costs" estimates (on a dollar per tonne basis) reported in the literature can be quite dissimilar, even for studies of the same type of equipment, with identical capacity, installed in the same industry. Some studies are meant to be generic or representative (especially true of studies of "greenfield" new-built facilities with carbon capture installed at inception), while other studies may be of retrofits at particular sites. If a particular site or existing emitter has major *non-carbon capture investments* that must be made simultaneously with installation of carbon capture equipment, the total costs may be astonishingly high, but not "wrong." Though not wrong, blithely quoting cost metrics from these very particular instances is bad practice.

As an example, it is reported that the Boundary Dam amine retrofit of a small, and outdated coal plant was on the order of $800 million per MTPA captured. However, the "capture costs" included revamping the entire plant site's water systems, rebuilding the 50-year old boiler, rebalancing the steam turbine, etc.: effectively, Saskatchewan Power chose to experiment on a moribund old coal plant that was going to be closed down anyway, a perfect low-risk subject for a science experiment, but not a representative data point for future project developers who would seek to deploy carbon capture at big, new, efficient coal plants that required virtually no additional investments beyond the capture system itself.

<u>Mistakes and poor assumptions:</u> Below are a few of the causes for the often misleadingly wide variations in results across studies in the same industry.

- **Poor assumptions**: assumptions are not transparent and poor/bad assumptions get applied and go unnoticed
- **Errors**: Errors that go unnoticed
- **Inefficient allocation of capital:** some studies have estimated costs that attempt to capture all or the majority of emissions from diverse flue stacks. This approach fails to deploy capital efficiently by not focusing on "cheap" tonnes to capture
- **Inflated contingency factors:** studies occasionally inflate cost estimates with unrealistic contingency factors, even though cost components are well-known or off-the-shelf.

The table below lists a few of the issues we found with prior studies.

Table 5.7 Why Similar Projects Report Widely Different "Capture Costs"

Issue	Author/Industry	Detail of Concern	Impact Cost/MT Captured
"Maintenance Materials" 11.77% x Capital Cost	NETL and Booz Allen for Industrial Capture (2014)	The justification for the 11.77% came from a study that used 0.6%-1.5% for the same items. Appears to be simple transcription error.	Extra \$33/MT captured (for industries w/ \$300/MTPA capacity cost.). I.e., the mistake would approximately negate the 45Q credit.
Building sub-scale coal power plant instead of buying grid power	IEA and Mott MacDonald for Cement study (2008)	Why build a coal plant at \$3,250/kW instead of buying from grid?	Doubled the capital cost and maintenance, adding about \$25/MT to capture cost.
Over-estimate cost of basic unabated plant	AMEC Foster Wheeler re NGCC (2014)	Assumed NGCC would cost \$2,180/kW instead of normal \$800-900/kW	Tripled the capital cost attributable to de-rating the NGCC to provide steam and power: ~\$8/MT
Multiple layers of contingency factors for 100-year old technology	NETL and Booz Allen for Industrial Capture (2014)	20% for EPC contractor contingency compounded with 10% owner contingency	On the order of \$2/MT

Overall, these issues have created confusion about the costs of capture. As a notable example, in the Mott MacDonald cement study highlighted in the second row above, capital expenditures "on a carbon capture project" in the cement industry totaled €133 million. However only 30% of the capex related to carbon capture as such. The other 70% of capex represented (i) a silly solution to meeting steam and electric needs plus (ii) an odd decision about normal pollution control equipment. An analyst who applied the bottom line "carbon capture cost" from this study to a U.S. situation unwittingly would have made a big mistake.

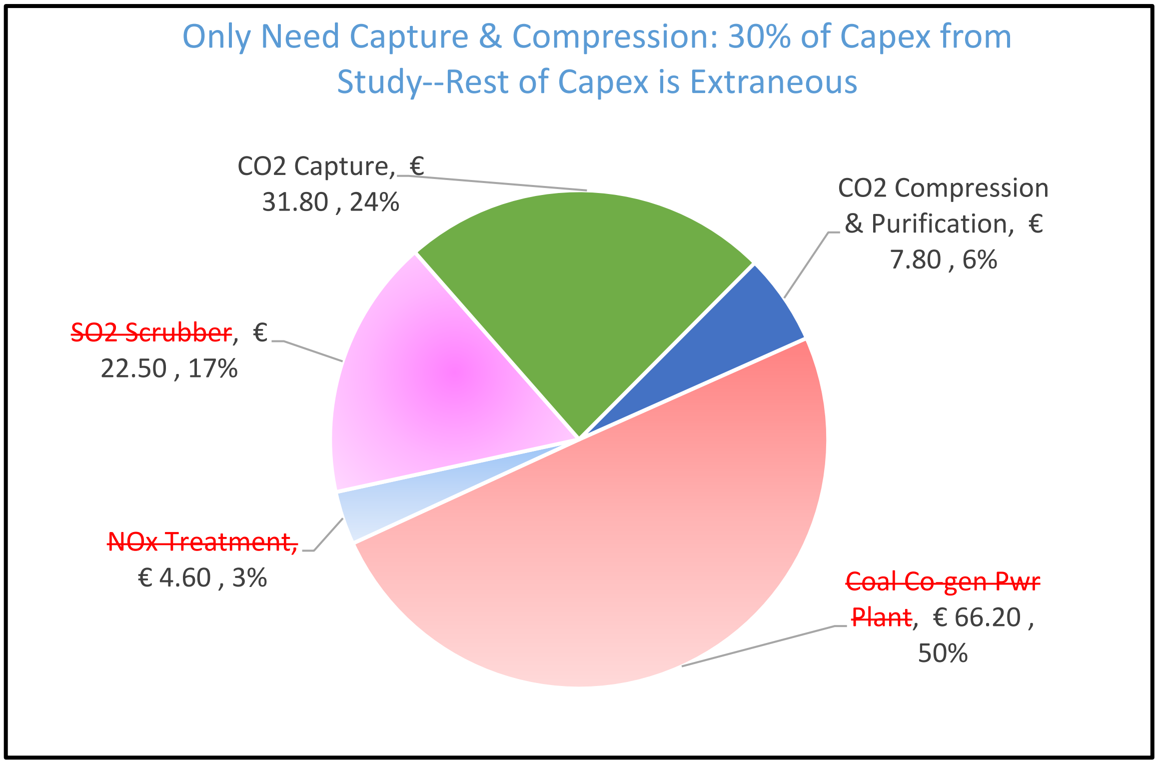
- In figure 5.3 below, 50% of the capital expenditures EUR 66.20 million, were for a small coal power plant intended to provide steam and electricity for the cement plant in order to operate the carbon capture equipment. The authors noted "An alternative to installing a [Combined Heat and Power] plant would be to import the electricity and provide the steam using an auxiliary boiler. This would reduce the amount of coal required and reduce the capital cost of the plant as a steam turbine would not be required. However, the benefits of producing power would not be realized."[100] Why

[100] Mott MacDonald IEA p. 4-21 (PDF page 93/221)

it is a good idea for a cement plant seeking to reduce emissions to build a miniature coal power plant on premises?

- Another 20% of the capital expenditures (EUR 22.50 and EUR 4.60 million) were on pollution control for sulfur oxides and nitrogen oxides. The authors concluded that an ordinary cement plant required would *not* have required SOx or NOx pollution control devices, whereas the authors concluded that a plant with carbon capture *would* require these expensive devices. In most advanced countries, of course, cement plants that burn coal for process heat do indeed require normal pollution controls for what are called "criteria pollutants" in the U.S. Normal pollution control devices do not constitute an incremental cost relating solely to carbon capture.

Figure 5.3 Example of Extraneous Equipment in Cement Carbon Capture Study



Avoided vs. capture costs: Another issue is confusing/conflating "capture costs" and "avoided costs": occasionally studies do not provide sufficient detail on how "costs" were derived and are cited inappropriately by different readers. The terms capture costs and avoided costs are very different. [Please see footnotes 15 and 82.]

The table below shows an example of the calculations of capture cost vs. avoided cost. The capture cost is $50/MT captured and does not take account of emissions by the fuel or electricity needed to run the capture equipment. Capture cost is the relevant figure for project feasibility in a situation, as in the U.S., when there are no explicit limits on CO_2 emissions for existing plants, whereas revenues and tax credits are based on capture volumes. An environmental economist is of course concerned about the net tonnes captured, which would lead one to focus on "avoided cost"; however, the problem with avoided cost is that it is not a static number, for instance if a capture plant buys power from the grid, that grid power is likely to have unpredictable, but decreasing carbon intensity as the grid decarbonizes. The identical basic capture plant could be correctly reported as "costing" $50/MT, $62.5/MT or $83/MT unless the readers are careful and study authors are very explicit.

Table 5.8 Capture vs. Avoided Costs

	Capture Cost	**Avoided Cost & Capture Equipment run by Gas**	**Avoided Cost & Capture Equipment run by Coal**
Cost of Capture $/MT	$50	$50	$50
Tons Captured	1.0	1.0	1.0
Less Tons Emitted by Capture Equipment	NA	(0.20)	(0.40)
Net Tons	1.0	0.80	0.60
"Cost" per Ton	$50/1.0 = **$50** Per MT Captured	$50/0.80= **$62.5** Per MT "Avoided"	$50/0.60= **$83** Per MT "Avoided"

Section (6) Selection of Emitters for Carbon Capture Retrofit and Quantification of Target Capture Volumes

a. Overall Approach to Selection of Emissions Sources for Carbon Capture

This subsection discusses the emissions data and selection process used to identify and select the relevant facilities within the three Regions discussed in Section 4. As described below, our selection process can be summarized as follows:

- We sorted the entire EPA FLIGHT (Facility Level Information on Greenhouse Gases Tool)[101] to eliminate facilities that emit less than 100,000 MT/year, since that is the cutoff capture volume for Section 45Q.[102]
- We then created three "regions" as described above by sorting the FLIGHT data for the larger emitters by State. No states were subdivided into different regions other than Texas. Texas was divided as shown on Figure 4.1, with emitters being divided along a diagonal NE-to-SW line into "Gulf" (SE corner) and "Midwest" (NW corner). Oilfield basins were assigned the same way other than the farthest west Texas basin assigned to receive CO_2 from the "Rockies" region.
- Within each region we then examined each of the emitters of size > 100,000 MTPA of emissions for suitability for capture. To do so we had to categorize the industry of the emitters in different ways than EPA typically would. We had to identify the emitters within a particular industry that were of interest. Among the interesting emitters we also had to identify the emissions generated by processes at those emitting sites that had the best potential for carbon capture.

b. Emissions Data: EPA FLIGHT Database[103]

The United States Environmental Protection Agency (EPA) tracks US greenhouse gas emissions from large emitting facilities (> 25,000 tonnes) and covers over 8,000 facilities. We rely on the FLIGHT database to identify and select potential facilities that might be relevant for our analysis.[104] In particular, we examined the emissions details for each significant emitter in each region belonging to the industries described in Section 5 to determine whether the particular facilities and their emissions profile might be viable candidates for CO_2 capture equipment.

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[101] https://ghgdata.epa.gov/ghgp/main.do#

[102] Simplifying somewhat, the minimum capture project cutoffs are 500,000 MTPA for power projects, 100,000 for general industrial, and a smaller 25,000 threshold for carbon "utilization projects." Since we were not analyzing such utilization projects, 100,000 was a safe minimum.

[103] We want to extend a special thanks to Mark DeFigueirido, PhD., of the EPA for help understanding the database and how to extract key information for this Topic Paper.

[104] The FLIGHT data only covers anthropogenic sources. We supplement data for ethanol plants using Edwards (September 4, 2018 published online) as ethanol fermentations are not reported to EPA because they are from a biogenic source. http://www.pnas.org/lookup/suppl/doi:10.1073/pnas.1806504115/-/DCSupplemental

Many emitters were quickly ruled out. For example, several large emitters such as coal power plants that are scheduled for retirement or that are rarely used would not be good candidates. In addition, we did not consider natural gas power plants that are rarely used, very small emitters that would not qualify for the 45Q tax credit (given limited emissions), and some emitters that appeared to be older and/or of very small size for their particular industries.

c. Identification of CO_2 Emissions from Industries, Sites, and Processes that are Susceptible to Carbon Capture at Reasonable Cost

- First, we had to categorize the industry of the particular emitters in a way more helpful than either the EPA's GHGRP subparts or the NAICS Codes. As described earlier in this Topic Paper, we focused on the following industries: Ethanol, Natural Gas Processing, Ammonia, Hydrogen, Steel, Cement (and Lime), Oil Refining, Coal Power, and Natural Gas Power. We re-sorted to eliminate emitters that did not fall into any of these industries. Certainly, there is the potential to capture CO_2 from other industries such as the pulp and paper industry; however, we did not have the time or industry knowledge to examine very industry.
- Second, among some emitters that fit into particular industries, we needed to search the actual reports filed with U.S. EPA[105] to identify the emissions for the manufacturers of interest and industrial processes of interest.
    - The "Iron and Steel" industry reports under Subpart Q. However, that category includes a wide variety of emitters such as standalone coke batteries, electric-arc furnace mini-mills, specialized alloy foundries, etc. that do not emit large volumes of concentrated CO_2. We had to carefully review all the Subpart Q emissions to extract the easiest-to-capture blast furnace gas emissions. Hence, for a steel mill such as Arcelor Mittal's Burns Harbor, Indiana plant (GHGRP Id. #1003962), overall reported emissions are 10.1 MMTPA; but blast furnace gas combustion contributes 4.5 MMTPA out of the total.[106]
    - With the "Electricity Generation" sector that reports under Subpart D, there are many emitters that are of limited interest for our purposes, such as banks of simple cycle gas combustion turbines that operate only rarely and thus are uneconomic for carbon capture retrofit. Sometimes a single "emitter" is a mix of coal plants, combined cycle gas plants, and simple cycle gas combustion turbines. Some of these generators run all the time, others intermittently. We used ABB's "Energy Velocity" database to get

[105] To find these specific emissions sources within a reporting emitter site, once has to first access the specific site on the FLIGHT data base, with the easiest method often being to using the EPA GHGRP "Facility ID". Once there, an investigator needs to click onto "As Reported Data" to see the actual reports filed. Finally, the investigator needs to scroll through the reports to see "Unit Details" for the various vent stacks.

[106] 3 furnaces, with the biggest single blast furnace gas combustor "CP-03-BFG-Mix" being 3.0 MMTPA alone.

detailed information on each of the generating units at a multi-power plant "emitter" site.

  - Continuing with "Electric Generation", only power plants that actually serve the general grid report under Subpart D. There are some very large power plants that operate solely "inside-the-fence", for instance at oil refineries and petrochemical plants. Even though the emissions result from making power, the emissions are reported under Subpart C "Stationary Combustion."[107]
  - Petroleum refineries, depending on configuration report under many different subparts. Beyond internal power plants, sub-systems of interest include hydrogen production and catalyst regeneration at Fluidized Catalytic Cracking Units or FCCUs. Hydrogen is reported under subpart P and the emissions from FCCUs is typically reported under subpart MM-Ref. For a larger oil refinery such as the Wood River Refinery in Roxanna, IL, total emissions are 4.2 million MT/year of which FCCU emissions represent 0.9 million MT/year and hydrogen manufacture another 1.0 million MT/year.

- Third, once having identified emitters of interest and the manufacturing processes of interest, we had to be quite careful about the idiosyncrasies of the way in which the same physical process might be reported in two different industries. As an example, emissions from hydrogen plants—i.e., Steam Methane Reformer units—can be parsed into "combustion emissions" and "process emissions". Combustion of purchased natural gas in stoves beneath the reformer vessels creates "combustion emissions", whereas emissions from any elemental carbon originally injected into the reformer vessels create "process emissions". The low-cost capture opportunities are found in a portion of the *process* emissions.
  - However, if the SMR is used to make hydrogen as a final product, either when owned by an oil refinery (known as a "captive hydrogen plant") or owned by an industrial gases company, both the *process* emissions and *combustion* emissions are listed under subpart P.
  - The opposite is true when an SMR is used to make hydrogen as an intermediate feedstock in an ammonia plant. In that case the ammonia producer is supposed to parse the SMR emissions, putting the process emissions under subpart G (ammonia) and the combustion emissions from the SMR under subpart C (stationary combustion).
- Fourth, for the ethanol industry (which is not an identified GHGRP subpart), which often focused upon because it is such a low-cost source of CO_2, it was necessary to rely upon non-EPA estimates of biogenic fermentation emissions.

[107] As an example, review the Marathon Petroleum Corp.'s Los Angeles Refinery (GHGRP Id. #10066267), which reports 6.4 MMTPA total CO_2eq., with 4.5 MMTPA being "General Stationary Fuel Combustion". It turns out that 2.6 MMTPA of those stationary combustion emissions come from six different combined cycle gas turbine inside-the-fence power plants (LARW Turbine A & B, and the four LARC Watson Co-gen Turbines CEMS91-94). That is, 40% of the "refinery" is really a power plant.

At an ethanol plant, emissions that are created by combusting fuel beneath a fermentation vat are reported as Stationary Emissions under Subpart C, but the fermentation emissions themselves are not reported. Additionally, ethanol biofuels plants are not easily identified as such, typically being reported under "Industry Type" as "Other" or "Other, Waste." Ethanol also presented a problem because the reported emissions, which do not include fermentation emissions, caused good candidate plants to be screened out. That is, an ethanol plant that had large enough fermentation emissions to be of economic interest, i.e., >100,000 MTPA had non-biogenic emissions that feel below 100,000 MTPA. Where possible, we identified those plants and reversed our earlier screening process to include them.

d. Fine-tuning Capture Equipment to Reflect Power Plants Ramping Up and Down

Special problems arise in deciding the capacity of capture equipment that would be economic to install on a fossil power plant whose output levels vary significantly day-to-day and season-to-season. In areas of the country that operate in "organized power markets", usually involving regional exchanges organized either as Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), the System Operator, not the owner of the generator, effectively decides when and at what level the generator should operate. *In organized power markets with high levels of renewable penetration, System Operators typically treat certain zero-carbon or low-carbon resources (such as nuclear, large hydro, or fossil units with CCS) identically to unabated fossil plants.* In such systems, fossil units with carbon capture may be curtailed whenever intermittent resources increase output. If fossil units with capture ramp up and down to accommodate other generators, the expensive carbon capture equipment may operate at low capacity factors, harming feasibility.

To illustrate, think of a single 600 nameplate MW coal generating unit in a deregulated/organized market (Texas, operating under ERCOT) where considerable intermittent wind energy is present. How big should the carbon capture equipment be? Should the carbon capture equipment be large enough to capture ~90% of emissions when the plant is running at the full 600 MW capacity? The problem with sizing the capture equipment for 600 MW of emissions is that the coal plant doesn't often run flat-out at the full 600 MW level. The alternative is to capture ~90% of emissions from the amount of stack gases produced when the plant is operating at its most typical minimum output level—for instance at 200-250 MW if the plant is frequently turned down to minimum operating levels during off-peak hours.

We will use as an example data from the 615MW nameplate W. A. Parish Unit #7 (located at same site as Unit #8 that was retrofitted with an amine scrubbing system deployed in 2016). In 2017, Unit 7's maximum output was 577MW, maximum CO_2

emissions per hour were 581 s-tons/hour, and the *average* emissions rate was 0.94 s-tons/MWh. [The available raw data is in short tons and we did not convert to metric.]

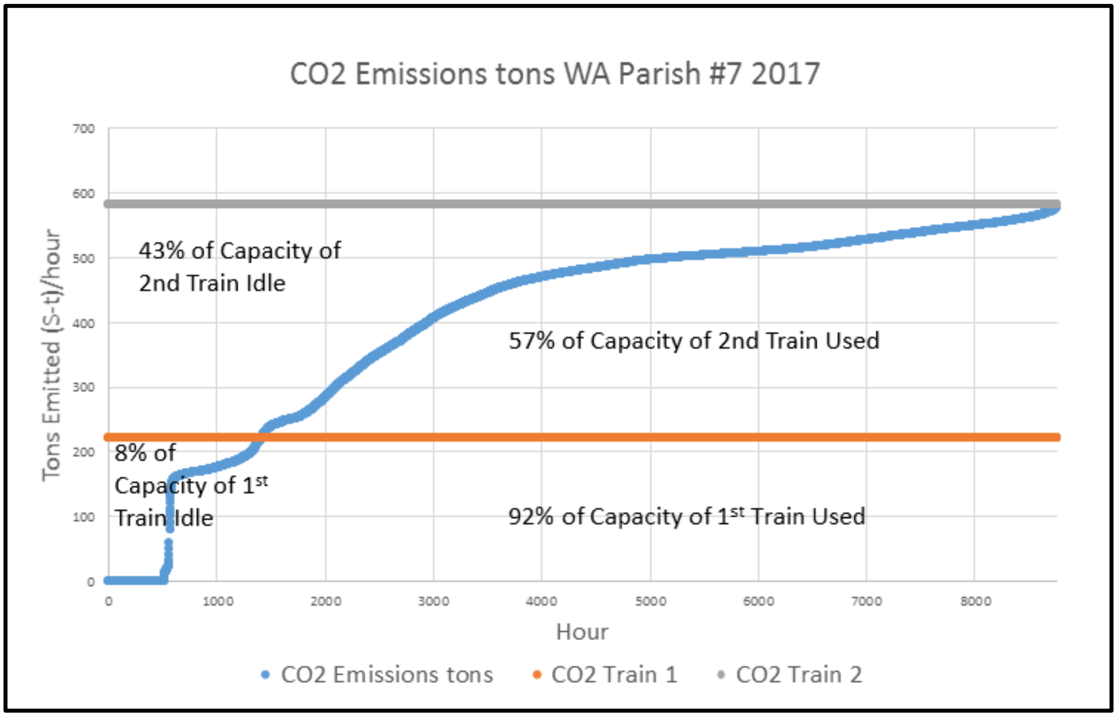
Figure 6.1 below shows a graph of emissions ranked from low-to-high for each hour of the year (blue line), with two possible CO_2 control configurations superimposed (the orange and grey straight lines). The "y" axis is s-tons of CO_2/hour emitted, ranked from low-to-high over 8760 hours ("x" axis). *[Note: Figure 6.1 is not showing hours in the year in chronological sequence. Instead the chronological data has been sorted from lowest to highest emissions hours in the year.]*

- The blue line shows that for about 500 hours/yr the plant was off line, another ~1,000 hours per year were spent ramping up the plant in an emissions band of 180- 220 s-tons/hour, and that the remaining ~7,500 hours were in the emissions range of 220-581 s-tons/hr. So how big should the capture equipment be?
- If the plant is warmed up and running, it is certain to emit at least 220 s-tons/hour. If a treatment system module (or "train") that handles 220 s-tons/hour were installed, that train will run at a 92% capacity factor. Said another way, the cumulative idle capacity over the entire year for the 220 s-tons/hour train would only be 8%. This is a very capital efficient investment—the capture system will run almost all the time.
- One could install a second, incremental 361 s-tons/hour train to allow treatment of total maximum emissions of 581 s-t/hr. However, the second train would only run at 57% capacity factor—this is pretty poor utilization of expensive capital equipment.

Since the 2nd train has similar capital expense per installed ton of capture capacity, but operates less frequently, its effective capture cost rises. If the 1st train had a capture cost of $60/MT, the 2nd train would have capture cost of $84/MT.[108] With a $35/MT tax credit, if CO_2 could garner a sales price from EOR of $30/MT, for a total of $65/MT, the 1st train may be economic. The 2nd train has virtually no chance of being economic under that incentive and revenue picture. This example helps demonstrate why our Topic Paper did not by any means treat all technically capturable emissions as being economically capturable.

[108] Assumptions: $60/MT includes $21/MT for fuel, electricity and solvent, with remaining $39/MT for O&M and financing expenses that vary directly with original capex. The 2nd train's capacity factor is only 62% of the 1st train's capacity factor (0.57/0.92). Thus the capex related cost per tonne would rise to $39/MT ÷ 0.62 = $63/MT, which plus $21/MT for the other costs equals $84/MT.

Figure 6.1 Treatment System Size needs to be Fine-Tuned to Plant Operating Patterns



e. **Fine-tuning Location of Capture within Multi-Stage Processes**

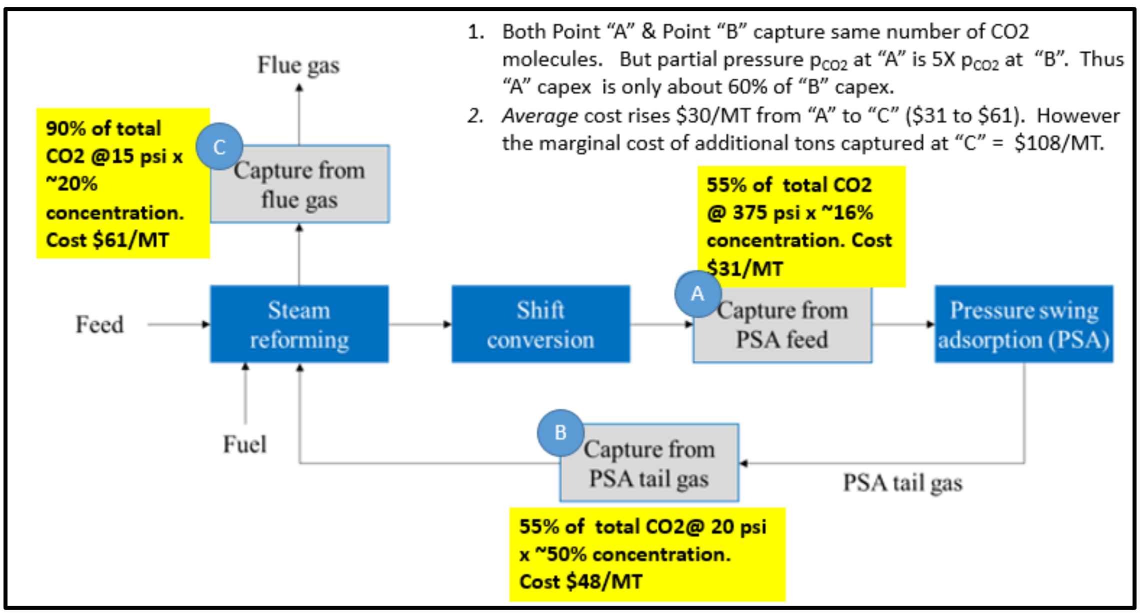
Finally, unlike a power plant, some multi-stage industrial processes may afford an owner multiple possible points at which to install capture equipment. In a strict compliance environment or with high carbon taxes, the owner might try to maximize total tonnes captured. But in an environment where carbon capture is strictly opportunistic, meaning that the owner will only capture if revenues exceed cost, the owner may choose to capture whatever tons are reasonably available at the profit-maximizing capture point.

This is illustrated in Figure 6.2 below, which summarizes information from an International Energy Agency study that examined an unabated Steam Methane Reformer (hydrogen plant using natural gas feedstock) and five different possible capture configurations/technologies.[109]

[109] See IEAGHG Technical Report 2017-02, February 2017, "Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS. We are focusing on the cheapest three of five configurations analyzed. Authors recomputed IEA results using US dollar currency instead of Euro, updating electricity and natural gas prices to U.S. levels, and removing IEA cost of geologic sequestration, since we are concerned only with capture/compression in this section.

- Point "A" and Point "B" each afford the chance to capture 55% of total CO_2, but the "partial pressure"[110] of CO_2 at Point "A" is roughly five times higher than at Point "B". Thus the IEA calculated that the capture cost was only $31/MT at "A" compared to $48/MT at "B". *[Note: The author did considerable adjustment to convert currencies, and make energy costs correspond to U.S. conditions for this diagram, but the relative costs differentials were similar in the original study.]*
- Most studies of carbon capture at SMRs have focused on Point "C", the point where the carbon present in "feed" natural gas combines with carbon present in "fuel" natural gas. If one adds CCUS at this point, 100% of CO_2 can be treated, and 90% captured. However the partial pressure of CO_2 at Point "C" is 1/70th of the partial pressure of CO_2 at Point "A". Correspondingly the cost of capture rises to $61/MT at Point "C".
- Far more interesting, the key economic decision criterion, the incremental cost of the extra CO_2 captured by tapping Point "C" is $108/MT. At the margin Point "3" lets us get 1.64 times as much CO_2 (90%/55%); but total capture cost is 3.2 times larger at Point "C" vs. between Point "A."[111] In a situation where no SMR owner is compelled to capture at Point "C", and where maximum revenues are in the $50-60/MT range [see Figure 2.2], installing capture equipment at Point "C" is a bad decision.

<u>Figure 6.2 Cost of Capture for Various SMR Configurations</u>



Source: IEAGHG report with currencies and energy prices adjusted to U.S. values. See footnote 108.

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[110] Earlier we said that the molar concentration of CO_2 is the key driver of cost, which is true if all systems are at ambient pressure. However, if different points in manufacturing have different pressures, the critical factor is pressure x concentration, or "partial pressure".

[111] The reader may not be able to figure this out by inspecting the diagram. Point "A" captures 365,000 MTPA @ $31/MT or total cost of $11.3 million/year. Point "C" captures 600,000 MTPA @ $61/MT or total cost of $36.6 million a year. Total cost at Point "C" is 3.2 times larger than at Point "A" ($36.6/$11.3).

f. **Quantities of Emissions Analyzed in the Three Regions**

In the section above, we discussed the general process use to identify the relevant facilities, subsets of those facilities and corresponding emissions. Ultimately, we created a list of reviewed, edited emissions sources in a region, ranked from lowest cost to highest cost. *[Note: please recall that US EPA adds up the emissions at a single emitter site and reports those under a single common seven digit "Facility ID". But under that common ID may be six to eight emitting power plants, only a few of which are good CCS candidates. Or the ID may aggregate a complex industrial site with many products lines and dozens of vent stacks for each product line, only a few of which are of interest.]*

As is clear from the table below we were highly selective, since we were seeking to find lower cost emissions in industries in which capture techniques have been well-researched. Table 6.1 on the next page gives the details of this selection process, by numbers of emitter sites and by tonnage emitted or "capturable."

- We had a minimum size threshold, but some emitter sites above the minimum size are in industries where there are not good estimates of capture cost or with production units too small to allow cost-efficient retrofit. We selected as emitter sites that could contribute to regional supply curves only 326 of the 879 emitter sites that had over 100,000 MTPA in the particular regions. Those 326 selected emitter sites represented 60% of total emissions from emitter sites > 100k MTPA.
- The two largest sources of emissions that were *not* included in our regional supply curves were miscellaneous uncategorized stationary combustion sources and coal power plants that were screened out on grounds of age, lack of pollution control, or inefficiency.
- Of the total emissions of 738 MMTPA from the selected emitter sites in the supply curves we only considered 309 MMTPA to be "capturable". By "capturable" we mean that we had gone through the selection process outlined in this chapter and found the subset of emissions at individual vent stacks at these selected emitter sites that seemed likely to have total capture costs not higher than \$70/MT.
- So of 100% of total tonnage from large emitters in the regions, 60% of the total were promising sites, and 25% of the total tonnage appeared "capturable."

Table 6.1: All Emitters, Supply Curve Candidate Emitters, and "Capturable" Emissions

Emitters and Feasible Capturable Tonnage (2017) by Region (millions of MTPA) [112]				
	Gulf	Midwest	Rockies	Total of 3 Regions
# of All Emitter Sites in Region > 100k MTPA in FLIGHT	373 facilities	365 facilities	141 facilities	879 facilities
# of Select Emitter Sites Contributing to Supply Curve	112 facilities	162 facilities	52 facilities	326 facilities
% of All Emitter Sites in Supply Curve	*30%*	*44%*	*37%*	*37%*
Total CO_2/yr Emissions of All Emitter Sites>100k MTPA in FLIGHT	497 MMTPA	530 MMTPA	213 MMTPA	1,240 MMTPA
Total CO_2/yr Emissions from Select Emitter Sites Contributing to Supply Curve	293 MMTPA	294 MMTPA	151 MMTPA	738 MMTPA
% of Emissions of All Emitter Sites Contributing to Supply Curve	*59%*	*55%*	*71%*	*60%*
CO_2/yr Capturable from Select Emitter Sites in Supply Curve	107 MMTPA	140 MMTPA	62 MMTPA	309 MMTPA
% Emissions Capturable of All Emitter Sites >100k MTPA	*22%*	*26%*	*29%*	*25%*

[112] Includes biogenic fermentation from ethanol plants not reported in FLIGHT, as do the other tonnages in this column. Therefore these totals do not exactly correspond to FLIGHT.

Section (7) CO_2-EOR Sales Revenue

Currently, absent a price on carbon, carbon capture provides two sources of revenue streams: CO_2 sales for enhanced oil recovery activities (market price) and tax credits ($35/MT for EOR, $50/MT for saline storage). This section will discuss possible revenues from the CO_2-EOR industry.

In terms of demand for CO_2, EOR is the main near-term focus, since EOR has a proven track record and business model (along with 45Q tax credit incentives). In terms of passive storage, some opportunities exist primarily in saline formations close to capture locations, where transport costs are minimal; but as mentioned earlier, since the fundamental assumption of this Topic Paper is that efficient pipeline transport has been made available by private, or more likely, government action, the economic models never "chose" saline storage over cash sales to EOR. Similarly, we did not look at "utilization" options since our mission was to examine scale-up to hundreds of millions of MTPA, whereas most of the promising utilization options are still at the scale of hundreds or thousands of MTPA.

a. CO_2-EOR Data Source

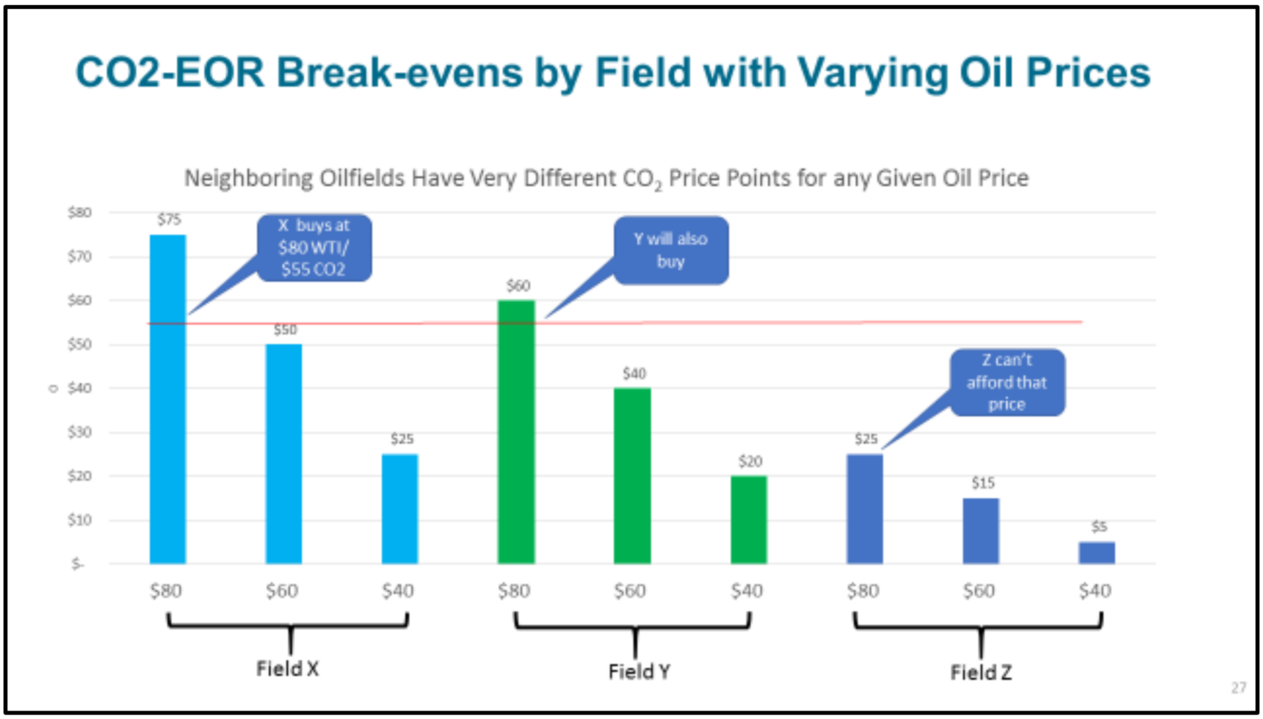
For this analysis we relied heavily upon a database supplied by Advanced Resources International (ARI). The database modeled over 1,000 oilfields spread over 16 states.

- ARI provided analyses of oil field's ability to pay various prices for CO_2 in three different oil price environments for West Texas Intermediate crude: $40/bbl, $60/bbl, and $80/bbl.
- In any particular oil price environment, ARI showed for each oilfield the maximum price the field could theoretically pay for CO_2 while still being able to pay for all other operating expenses and while still earning a satisfactory return on financial capital invested in the flood.
- Even within a small geographic area, two adjacent CO_2-EOR fields are likely to have very different economics simply because of size, complexity of subsurface conditions, past development history, and variable oil production response to CO_2 injection. Thus the universe of oil fields is quite heterogeneous. That heterogeneity is quite useful to our analysis, since it means that CO_2-EOR industry demand for CO_2 is not a binary, all-or-none proposition, where all producers are happy to buy CO_2 at $20/MT but no producer will pay $25/tonne. Instead, higher and higher CO_2 prices gradually discourage more and more producers from undertaking floods—creating a conventional-looking long-term demand curve for CO_2 by the CO_2-EOR industry.

Figure 7.1 below shows in simple terms how demand curves for CO_2 could be constructed from the data supplied by ARI. Figure 7.1 portrays potential EOR fields X, Y, and Z. The three bars for each field represent break-even demand for CO_2 (in price per MT) that the field can pay in a WTI price environment of $80/bbl, $60/bbl, and $40/bbl.

- If the market-derived price for CO_2 is $55/MT (red horizontal line), Fields X and Y will still buy CO_2 as long as oil is at $80/bbl. Field X is delighted to pay $55/MT market price since it could possibly have broken even paying $75/MT. So is Field Y, since it could have paid $60/MT in a pinch but only has to pay the market price of $55/M%.
- However, at oil prices of $60/bbl, no field has interest at $55/MT CO_2. The reader can see that to bring all three fields in as purchasers when oil prices are $60/bbl the market clearing price would have to be $15/MT.

<u>Figure 7.1 Using Oil Field CO_2 Price Break-even Information to Create Regional EOR Demand Curves</u>



Since the information provided by ARI was detailed, down to inclusion of latitude, longitude, state, and particular oil basin within a state, that information could be used to create geographically-based regional demand curves. If we wished to analyze CO_2-EOR demand for states A and B, plus the northern half of state C, we could pull the information for the specific relevant fields from the database.

b. Limitations to the Analysis

It is important to note that the ARI-sourced information a consistent set of data, across all the states we studied, that is likely to be predictive of long-term demand for CO_2 for use in EOR fields, in the aggregate. The data is directionally consistent with energy economics: oil operators could afford to pay more for CO_2 in a high oil price environment than they can in a low oil price environment. And operators whose fields are more responsive to CO_2 injection, have more residual oil, etc., can afford to pay more than their less geologically fortunate neighbors.

However, ARI make no claims that their data base can possibly predict an individual oil operator's behavior in the short-run. No such database, founded upon geologic and production cost factors could make such dispositive predictions, since an individual operator's behavior depends on views as to future oil prices, constraints on capital availability, constraints on availability of workers and equipment, ability to unitize and lease oil-bearing formations, the regulatory environment for tracking injected CO_2, etc. Similarly, ARI's data base is not configured to answers about how fast operators can respond to particular stimuli.

Oil price volatility creates a problem in blindly relying on the information from ARI. The ARI data can predict that if an operator knew that a particular oil price would prevail forever, it could pay a particular price for CO_2 and break even financially. However, oil prices are volatile, and thus even if oil prices are at $80/bbl, an individual operator may only be willing to use $40/bbl as a planning parameter. As discussed in Section 3 of this Chapter, we did not at all utilize the set of oilfield demand data for ARI's $80/bbl WTI price case. We used ARI's $40/bbl cases for our low price case CO_2-EOR demand curve, and used their $60/bbl cases as our "upside."

Market practice of linking CO_2 price to WTI price creates yet another issue. ARI's data set is geared toward determining a maximum fixed $/MT CO_2 price that a CO_2-EOR operator would pay in a certain oil price environment, i.e., $40-$60-$80/bbl. In reality, based on general industry knowledge, re-confirmed in private conversations with experienced operators, CO_2 prices are often pegged to WTI prices. For instance in the Permian—the biggest market with the broadest number of pipelines and sellers—the arm's length price per 1,000 standard cubic feet (mcf or mscf) is typically 2% to 3% of the WTI/NYMEX price.[113] Using a 2.5% mid-range formula at a $60 WTI price the price per MT of CO_2 would be:

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[113] Note that there are many different variants of customized formulas, often involving a certain fixed price per MCF plus an oil-price-sensitive percentage. Other variants include caps or floors with CO_2 floating in a band between the cap and floor. In the less competitive areas, it is believed that if CO_2 may be priced in a lower band such as ~1% of WTI/NYMEX per mcf in the Gulf and ~1.3-1.5% in Rockies. This information is anecdotal, but believed to be representative.

- 2.5% of WTI price (floating up and down) per mcf
- equals \$1.50/mcf @ \$60/bbl
- times 19.2 mcf per MT CO_2
- equals \$29/MT

A further limitation is lack of transparency in CO_2 pricing and that markets for anthropogenic CO_2 in ten or twenty years may be more competitive than today's CO_2 markets. At present the market both for supply of, and consumption of, CO_2 is highly concentrated. Occidental Petroleum, Kinder-Morgan, and Denbury operate[114] natural domes that represent > 80% of US CO_2 supply including Bravo Dome (NM), Sheep Mountain (CO), McElmo Dome (CO), Doe Canyon Deep (CO), and Jackson Dome (MS). However, the same three companies also represent ~55% of annual barrels of oil produced by CO_2-EOR U.S.[115] Thus, more than half of CO_2 "trading" is effectively an internal transfer not observable by outsiders, though the transfer price may be eagerly watched by lessors or their attorneys, since royalty payments are price-dependent. The situation is further obscured because some dominant regional pipelines are not common carrier: in such cases, a capturer's only choice may be to sell CO_2 outright to the non-common carrier pipeline owner, even if capturer would prefer to keep ownership of the CO_2 and use the pipeline to carry CO_2 to a different buyer. Finally, even if it is true that today's prices are low either absolutely or because of the particular formulas in extant contracts, one cannot conclude that such a situation would continue if there were a broad universe of supplier/capturers offering CO_2 to a broad universe of EOR buyers, with all parties interconnected by means of open-access common carrier pipelines. The past may not predict the future if the CO_2 industry were to become more transparent and more competitive.

[114] Operating a CO_2 dome is not the same thing as owning the resource, but it is one of the few available data points to indicate industry concentration. Typically a number of lessors own the actual resource, and a number of lessees may operate the natural CO_2 dome. The largest and/or most capable lessee will typically operate the CO_2 dome on behalf of the multiple lessees, while also managing royalty payments to lessors. Companies such as Occidental, Kinder-Morgan, and Denbury will typically state whether they operate a dome but do not state their percentage of the leasehold interests.

[115] These figures are assembled from multiple consulting reports, U.S. government reports, company investor presentations, and SEC filings dating from a variety of years. They are believed to be approximately accurate, but we have not made an attempt to confirm figures directly with the specific companies since the figures are inherently proprietary and confidential.

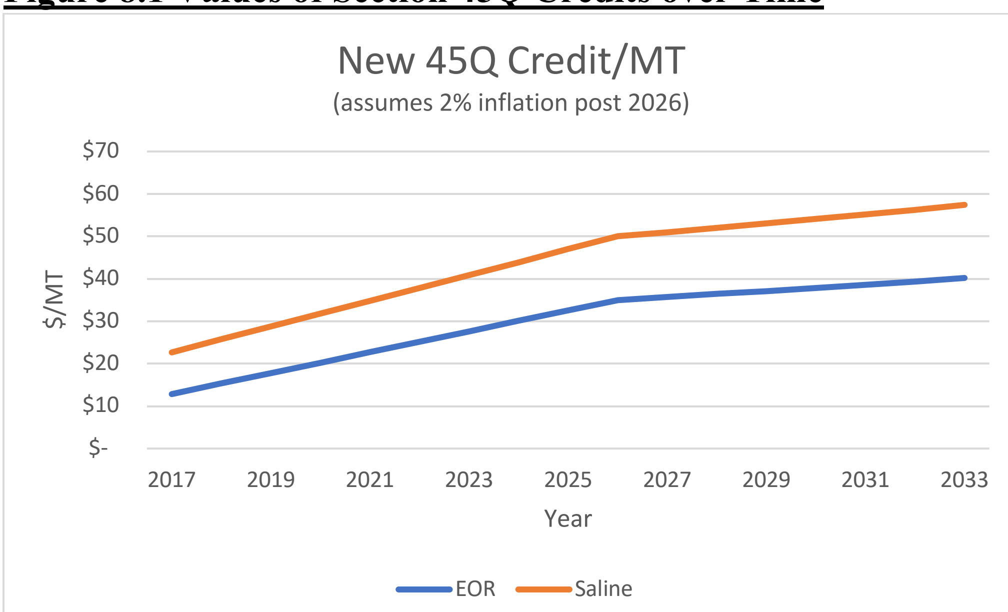
Section (8) Section 45Q Tax Credit for CO_2-EOR and for Passive Sequestration

We note here that the §45Q credit value for EOR rises in statutorily prescribed increments to \$35/MT in 2026 and is then adjusted by inflation after. For simplicity, we assume a value of \$35/MT in the analysis. In addition, we also treat these credits as revenue equivalents and assume a dollar-for-dollar value. In reality, the credits are likely to be discounted *to some extent* for transaction purposes.

However, the exact extent of the discounting depends on a host of factors such as: (i) competing supply of other types of tax credits in the market for tax-motivated transactions, (ii) extent to which legislation allowing use of MLPs broadens the market for clean energy partnerships, (iii) extent to which, as recommended in the main NPC-CCUS Report, individual taxpayer unit holders in such MLPs are permitted to apply Section 45Q credits against taxes owed on their individual federal tax bills, (iv) level of corporate tax rates, since lower tax rates diminish total taxpayer demand for tax credits, (v) and the degree of certainty and flexibility contained in the to-be-released IRS regulations and/or guidance regarding implementation of §45Q.

Figure 8.1 below shows the statutory credit value per MT for CO_2 used in EOR (blue) and for CO_2 delivered sequestration in saline formations (orange). After 2026 the credit values graphed increase with CPI inflation, here assumed to be 2% annually.

<u>Figure 8.1 Values of Section 45Q Credits over Time</u>



For practical timing reasons it made sense to assume values of the credits commencing 2026. Our rationale was that capturers can earn the credit as long as construction of capture facilities, or construction of an industrial emitter whose original plans include carbon capture equipment, is commenced by the last day of 2023.[116] If past is prologue, many facilities will be rushing to meet the end-2023 deadline and will be fortunate to go into service by 2026, thus being quite likely to be earning $35/MT or $50/MT plus inflation.

There are some positive factors based upon the substantial improvements made in Section 45Q that have the effect of making the credit easier to use and/or transfer, as well as overall changes in the tax credit market. The factors make it likelier that any discounts to the face value of 45Q credits will be smaller than they would have been previously:

- It is easier to "monetize" tax credits if the party claiming the tax credit doesn't actually have to run the capture facility. That is because in many cases the party that needs the tax credits to reduce its corporate tax liability is a profitable financial, insurance, or even high-tech company that has little desire to actually be in the carbon capture business. The 2018 revisions permit a structure where the party that owns the capture equipment can claim the credit but doesn't have to actually operate the facility or inject the CO_2 underground.[117] This situation appears to open the door to the low-cost equipment leasing transactions such as those often used to finance solar projects.[118]
- In general tax credits cannot, of course, be simply bought and sold like securities, but the improved Section 45Q opened some options for tax-owners of capture facilities. The credit can also be assigned to the party that "disposes of the qualified carbon oxide, utilizes the qualified carbon oxide, or uses the qualified carbon oxide as a tertiary injectant", so a tax-owner of the capture facility that cannot use the credit to shield its own tax liabilities has an opportunity to easily shift the credit to other parties in the value chain without resorting to a lease or tax equity partnership (see footnote).
- Finally, the 45Q credit is stepping up as the now well-established wind and solar industries become less reliant on tax credits. Under provisions of the Consolidated Appropriations Act of 2016 the Investment Tax Credit for commercial solar projects will drop to 10% by 2022, while the wind Production Tax Credit drops to 0% by 2024. Thus, it is possible that taxpayers looking for credits may more aggressively search for carbon capture projects than they have in the past.

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[116] Section 45Q(d)(1)(A)&(B).

[117] Section 45Q(f)(3)(A)(ii) under heading "Credit Attributable to Taxpayer".

[118] The alternative, when the tax-credit claimant has to both own the facility and operate the facility is true for wind Production Tax Credit claimants. Oddly, under the old 45Q provisions, it didn't matter who owned the capture equipment. The credit went to the party that owned the polluting facility if it also operated the capture facility and injected or provided for injection of the CO_2. When ownership and operations cannot be separated, the only reasonable means of "monetizing" the tax credit is to engage in a special partnership transaction often known simply as a "tax equity partnership" or more confusingly as an "equity flip transaction" (so called because the partners' allocations change, or flip, through time).

Section (9) Transporting CO_2

As discussed in the Chapter 6 ("CO_2 Transport") of the NPC CCUS Report, there are a number of means to transport CO_2 including using pipelines, ships, barges or trucks. Currently, CO_2 is mainly transported via pipelines over a network of 5,000 miles of CO_2 pipelines. Pipeline costs benefit from scale and fall very rapidly with volume transported: the cost tying together a single 1MMTPA CO_2 capture source and a single EOR flood with 200 miles of pipeline might destroy project feasibility (~$25/MT), whereas the cost of transportation on a 35MMTPA CO_2 network stretching 600 miles could be quite reasonable ($13/MT), i.e., triple the distance for half the cost.[119]

Finding equilibrium supply/demand solutions requires inclusion of transportation costs to connect CO_2 sources and sinks (EOR and/or saline storage). In the early stages of analysis, we used FE/NETL's CO_2 Transport Cost Model[120] to roughly estimate transport costs. Ultimately, a realistic analysis requires taking account of actual terrain along a proposed pipeline route, while including the high costs of feeder lines that join outlying sources and sinks to a main trunk line. This is obviously a very difficult exercise, but we obtained help from Los Alamos National Laboratory, whose *SimCCS$^{2.0}$* pipeline routing software is designed to solve such problems (see more below).

a. NETL Pipeline Cost Model

For initial analysis (i.e., for first drafts of supply and demand curves such as those shown in this Topic Paper, Section 3), we estimated costs from NETL's Pipeline Cost Model. This model was derived by NETL primarily by reviewing academic work by multiple engineers who had attempted to base prices of new CO_2 pipelines upon engineering principles and costs used in the analogous long-distance natural gas pipeline industry. As a first estimate, for main regional and intra-regional trunk lines, we simply assumed the largest known pipe diameter (a 36" line that can transport 35MMTPA) and input the appropriate distance, elevation changes, and financing cost factors into the NETL model. This, of course is not adequate for actually optimizing routing to connect many dozens of sources and sinks but the approximation helped narrow down the scope of projects.

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[119] Calculations obtained from the well-documented and organized FE/NETL CO_2 Transport Cost Model maintained by Tim Grant and David Morgan of NETL. The version we downloaded was NETL document number "DOE/NETL-2018-1876". The document is periodically updated and improved. The cost settings are not hardwired: users can choose among several sets of pipeline costing methodologies sourced from prior studies (primarily from natural gas pipelines). Financial inputs are also adjustable. The cost examples above both assumed a 1,000 foot rise in elevation; 2020 project start; Parker's cost methodology (Main Tab cell E77); 20 year project horizon; 2% escalation; and a financial structure with 50% debt-to-capital, 12% pre-tax cost of equity, 6% debt, & 24% tax rate. https://www.netl.doe.gov/energy-analysis/details?id=543

[120] A description of the model can be found at https://www.netl.doe.gov/projects/files/FENETLCO2TransportCostModel2018ModelOverview_050818.pdf.

b. SimCCS$^{2.0}$

SimCCS$^{2.0}$, developed by Los Alamos National Laboratory (LANL), is designed for simultaneously optimizing capture of CO_2 emissions, building of realistic pipeline networks and storing of the emissions. The software's novel optimization engine combined with high-performance computing speed has been critical for evaluating the simultaneous selection of sources of captured CO_2, injection points in EOR or saline formations, and the pipeline interconnections among them. In particular, *SimCCS$^{2.0}$*'s ability to construct a candidate network of routes (based on lowest cost routes) where realistic pipelines could be built has been key for evaluating the three Regions detailed in Section 4.

In a conventional industry analysis in which transportation issues were not critical—for example in the granular urea fertilizer industry where barges, rails, truck, bulk ocean carriers are all easily used—future supply and demand can be projected based on existing known capacity, announced additions to capacity, past demand, and known transport costs. The emerging CCUS industry is far more difficult because in most cases the supply, the demand, and the transport each constitute a new project. The benefit of using *SimCCS$^{2.0}$* was that we could input all the possible capture projects in a region, specify EOR and saline sites in the region, and then let *SimCCS$^{2.0}$* perform thousands of iterations to find an equilibrium price and quantity of CO_2 captured, transported, and injected. At the equilibrium price any capture or injection site connected to the cost-optimized network is covering, or more than covering, its capture costs and transport costs through a combination of tax credits and/or revenues. In economic jargon, the model continues to add or subtract nodes to the network until the sum of consumer surplus and producer surplus has been maximized.

c. Limitations to the Analysis

<u>Postage stamp rates</u>: We would note that *SimCCS$^{2.0}$* cannot specify exactly which source connects to which use, and thus it can't say precisely the *cost* of moving a particular tonne of CO_2 for a discrete source/sink pair. Since *SimCCS$^{2.0}$* is solving for a system-wide equilibrium there is no particular order in which individual sources and sinks are added. Thus we can obtain from *SimCCS$^{2.0}$* only an *average price* sufficient to cover *total costs* for the entire pipeline system. This is not a major concern since many infrastructure systems work on a "postage stamp rate" basis whereby any user of the system pays the same charge regardless of distance travelled.[121] In a large system containing vast quantities of indistinguishable molecules, it is in fact impossible to say exactly who supplied which molecule to whom. We do not make a recommendation that actual rates of a CO_2 transmission system should work this way—we are just observing

[121] An interesting discussion on "postage stamp rates" and "license plate rates" is at https://www.nttg.biz/site/index.php?option=com_docman&view=download&alias=829-nrri-postage-stamp-coursebook&category_slug=cost-allocation-meeting-material-10-05-2009&Itemid=31. Postage stamp rates are also sometimes called "peanut butter rates" because the cost is smooshed evenly across the system.

that the fact that the *SimCCS$^{2.0}$* model's rate output is on a postage stamp basis doesn't meaningfully detract from its usefulness for our purposes.

<u>Chickens and eggs</u>: A further limitation is that while we can account for the cost of a transportation network once developed, supply and demand curves can't predict how such a transportation network would spring into existence in the first place. Successful deployment of CCUS at significant industrial scale requires full-scale CO_2 pipelines. The trouble is that while interstate natural gas pipeline engineering precedents may apply to CO_2 pipelines, interstate natural gas pipeline finance precedents probably don't apply.

Traditional natural gas pipelines are financed in reliance upon a number of long-term contracts with existing, creditworthy "shippers", customers who agree to pay their share of fixed costs whether or not they actually transport natural gas.[122] The developer of a proposed new natural gas line obtains regulatory approval for routing and then conducts an "open season", a process by which shippers express their interest in obtaining firm point-to-point capacity on the proposed line. If enough customers express interest to fill, or mostly fill, the line, the developer goes ahead with the project.[123] Even a modest-sized natural gas pipeline requires many dozens of potential customers: for example the Alliance Pipeline, financed in the early 2000s, transports a natural gas volume equivalent to approximately 25 MMTPA of CO_2; and fully subscribing the line required 35 shippers.[124]

However, in the case of carbon capture, those shippers may not currently exist at all, much less be sufficiently creditworthy to subscribe for a portion of a billion dollar pipeline. Potential capturers aren't operating because they have no way to get their CO_2 to oilfields, and CO_2-EOR operators aren't starting new floods because they have no assurance of being able to get CO_2 from a pipeline.

Determining feasibility for an interstate natural gas pipeline is far simpler than for a CO_2 pipeline because gas producers and gas consumers are already up and running when the new natural gas pipeline is being considered. A proposed new segment of natural gas

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[122] A "shipper" in the pipeline context could either be the producer or consumer of a gas. So "shippers" in a long-distance natural gas pipeline could either be gas producers who want a guaranteed way to reach customers, or could be gas-consuming customers who want a reliable way to ensure access to supply of natural gas. The typical contract is called a "ship-or-pay" contract that requires the shipper to pay agreed amounts whether or not it actually uses its contracted portion of the pipeline. Thus, the pipeline does not bear the risk of low utilization creating a revenue shortfall. Risk of utilization has been contractually shifted to the shippers.
[123] https://www.sempra.com/newsroom/press-releases/rockies-express-pipeline-completes-successful-open-season-northeast. This is a press release announcing successful open season for an expansion of the Rockies Express Pipeline in 2007.
[124] Author's personal notes from original financing documents for Alliance. Of these shippers, the largest 10 only made up 62% of the volume. Seventy-three percent of shippers had investment grade ratings, and payments by these shippers were sufficient to pay debt service even if the other 27% of sub-investment grade shippers defaulted.

pipeline typically is designed to relieve *existing* bottlenecks by connecting *existing* natural gas producers to *existing* natural gas users. There is a firm expectation that the cost of the pipeline will be more than outweighed by higher prices received by producers, lower prices paid by consumers, or both. Before the first shovelful of dirt is moved, gas is already in production, and facilities that will buy the natural gas are already consuming natural gas from other sources: the natural gas pipeline is a low-risk bet that improves everyone's lot, both producers and consumers.

To conclude, the commercial challenge of financing the pipeline infrastructure for a brand-new *non-existent* carbon capture and storage industry is tough problem—vastly tougher than simply adding a new natural gas pipeline segment to an *already existing*, vast, interconnected, nationwide natural gas transportation system. An objection to federal assistance for new CO_2 pipelines, based on the observation that today's 2.4 million mile[125] US natural gas pipeline network no longer needs such assistance, is not well-grounded.

[125] According to "Pipeline 101" site, apparently maintained by the Association of Oil Pipelines and the American Petroleum Institute, there are 300,000 miles of intrastate and interstate main transmission pipelines and another 2.1 million miles of distribution pipelines.   https://pipeline101.com/Why-Do-We-Need-Pipelines/Natural-Gas-Pipelines

Section (10) Conclusions

In this section we state the broad conclusions of the overall analysis. These conclusions highlight certain risks that serve as roadblocks to successful near-term scale up of U.S. CCUS. Possible interventions to mitigate those risks are in the following section.

- Both the public's and industry participants' general impressions of the costs of carbon capture are too pessimistic, especially as to the costs of applying conventional, 60-90 year-old, carbon capture technologies to the industrial sector.[126] As we describe below, serious analysts can have valid disagreements about costs, but widespread fears that carbon capture is speculative and expensive have a different origin:
    - The poor outcomes of speculative projects that sought to deploy untested technology—often technology unrelated to carbon capture—have overshadowed the quiet successes of well-designed projects that used conventional carbon capture technologies. [127]
    - Studies of carbon capture deployment often envision commercially inefficient project configurations, rather than being oriented towards capturing the most CO_2 for the least money.
    - Sometimes otherwise careful carbon capture costs analyses are seriously skewed upwards by outright mistakes, or by puzzling capital expenditures that the analysts themselves have red-flagged as dubious.[128]
- The potential commercial demand from the EOR industry for new supplies of anthropogenic CO_2 may also have been under-estimated. That is, observers may be underestimating both the volumes that would be demanded and the prices that could be paid:
    - Existing CO_2 markets in the Permian, the Gulf, and Wyoming/Montana Rockies are thinly traded and dominated by a few large providers of

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[126] Of the two principal tested CO_2 scrubbing technologies, one was patented in 1930 (amine solvent system) and the other first deployed in the mid-1950's (cold methanol solvent).

[127] A good example is the failed $7 billion Kemper integrated gasification combined cycle plus carbon capture project. A report by the Clean Air Task Force contrasts this project with the successful NRG Parish project. https://www.catf.us/2017/07/two-carbon-capture-projects/ . The main problem for Kemper was a 150x scale-up of the new technology gasifier unit, not with UOP's utterly conventional Selexol propylene glycol solvent system. See Burns & Roe's report to the Mississippi Public Service Commission, footnote 48 on p. 27. https://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=328417

[128] One set of studies appears to have mistakenly increased cost of spare parts by 11% of original capital cost per year, i.e., $33/MT captured if the project costs $300/MT of annual capture capability. Another study doubled the cost and increased the CO_2 emissions of a cement "carbon capture project" by adding in a medium sized coal power plant. The authors noted that capital costs would have been lower if a simple steam boiler had been bought instead, but they never analyzed the cheaper alternative. (Mott MacDonald 2008 p. 137/221).

geologically sourced CO_2[129], which means those markets offer a poor basis from which to forecast the characteristics of a much expanded and competitive CO_2 market based primarily upon captured anthropogenic CO_2.

- Meanwhile, expert analyses show robust potential incremental demand in areas that have never had easy access to *plentiful*, competitive supplies of CO_2, such as Oklahoma, Wyoming, Kansas, or parts of the Gulf. Additionally, the grandfather of EOR regions, the Permian, is also believed to be capable of significant expansion if reliable new sources of CO_2 were available.
- Finally, for conservatism, many assessments of CO_2-EOR volume exclude offshore Gulf of Mexico and the Residual Oil Zone, which could be in the range of 50% of maximum conventional onshore CO_2-EOR.[130]

- Transportation is a modest cost item, assuming pipelines are actually built at scale. That is, long distance pipeline tariffs calculated by the LANL *SimCCS*$^{2.0}$ model for our three regions were in the $5-10/MT range, whereas capture/compression costs from medium concentration CO_2 streams are in the $40-60/MT area.
- Section 45Q, as modified by the FUTURE act, makes a large difference in project feasibility:
  - Under the old, lower, pre-FUTURE act tax credit amounts only a few isolated projects were feasible without some other incentive or assistance.[131] The old tax credit values were $10/MT vs. the current $35/MT for CO_2 captured and used in EOR, and were $20/MT vs. the current $50/MT for passive sequestration. The projects that were feasible solely based upon the old 45Q incentives included compression of 100% pure CO_2 from ethanol, gas processing, or ammonia plants and transportation short distances to the best EOR prospects.
  - The new higher 45Q amounts, together with a number of other major improvements to 45Q, can make more projects feasible: some industrial/power plant projects that are located adjacent to excellent EOR fields are now feasible as well. The incremental $25/MT related to EOR (i.e., from the old $10/MT to the new $35/MT) makes a difference. The extra $30/MT for passive sequestration (i.e., from the old $20/MT to the new $50/MT) will likely also trigger deployment of more low cost capture for local injection into saline formations.
  - Very important aspects relating to 45Q are yet to be ruled upon by the IRS. The effort to obtain the needed guidance and regulations has been a major industry and government effort. If this effort does not result in practical and

[129] Natural domes in the case of the Gulf (Jackson Dome, MS) and the Permian (McElmo Dome), and the largest producer of CO_2 separated from CO_2-rich natural gas in the Rockies (Shute Creek).
[130] https://www.netl.doe.gov/projects/files/FY14_NextGenerationCO2EOR_030114.pdf. See slide 38.
[131] I.e., cheap projects were feasible, but more expensive projects were not feasible unless they received some additional federal assistance from cost-sharing grants or investment tax credits to supplement the old, low 45Q credit amount.

certain standards for using Section 45Q, even the newly increased 45Q tax credit levels will elicit few extra CCUS tons.

- Still, the higher 45Q credit values *alone*, even with appropriate IRS rules, are probably insufficient—close, but not quite enough—to spark 100-200 MMTPA. We reach that conclusion by looking at the small total deployment we estimate in the "worst case" scenario of low oil prices and high capture costs: We identify three major risks pertaining to supply, demand, and transportation, respectively:
  - First mover risk: Cost contingency and financing rate uncertainty for building capture projects
  - Commodity price risk: Oil price uncertainty for EOR projects that spills over into financing difficulties for capture projects as well
  - Transport risk: Daunting logistical/organizational problems for assembling enough credit-worthy shippers to finance a pipeline at scale.
- First-mover risk is a supply side problem. It is triggered by the existence of widely divergent views among experts as to the ultimate construction and financing costs of carbon capture facilities. The issue is thorny since there are relatively few actual projects in the relevant industries to prove one side or the other wrong.[132] Serious engineering studies we reviewed show surprisingly small variations in the basic cost of buying carbon capture equipment and installing it on-site in industrial and power plant situations. This is not surprising, since the main technologies involved, amine solvent CO_2 scrubbing systems and CO_2 compressors, are in widespread use worldwide in industries such as natural gas processing and fertilizer manufacturing. By far the largest factor in the cost of capturing a tonne of CO_2 is the annual financing burden of repaying the original investors and lenders, i.e., the original total cost of the project times the annual financing rate, pro-rated over the tonnes captured. That annual financing fixed cost to cover a project's equipment can vary widely because of factors unrelated to the expected basic installed cost of the key equipment:
  - Some analysts have high confidence in the technology, thus budgeting relatively low amounts of money for untoward "contingencies" and demanding relatively conventional rates of return, such as would be appropriate for utility or pollution control projects.

[132] Note to readers: This statement may appear to conflict with the idea that carbon capture technologies are old and well-proven. The explanation is that these capture technologies are widely used in any industry where a carbon capture system is indispensable for the purposes of manufacturing the commercial product, but without explicit intention to reduce environmental impact of CO_2 emissions. Thus, virtually all North American fertilizer plants that make urea from natural gas feedstock have carbon capture systems in place, because carbon captured at an early stage in the manufacturing process must be reintroduced later in the process to synthesize the final urea product. Similarly, raw natural gas, or "field gas", almost always contains too much CO_2 to pass natural gas pipeline quality standards; and thus virtually all natural gas is "scrubbed" of its CO_2 content in gas treatment plants. The technology used in both the urea and gas processing industry is identical to the technology used in the successful coal power plant carbon capture deployment at NRG's W.A. Parish Unit #8 in Texas; but no one had previously used amine scrubbers at such a scale, in a coal plant, for pollution control purposes.

- Other analysts have low confidence either in the technology itself or are fearful of major complexities when the technology is retrofit into an existing plant—i.e., they are worried about the remodeling risk as well as the capture process itself. They advocate the necessity of budgeting large amounts for contingencies and would foresee the need for projects to earn very high rates of return.
- Taken together, the combined uncertainties for these two factors—contingencies and cost of funds—could cause the financing cost per captured tonne to fall into a wide band. As an example, for a 1MMTPA capture project estimated to cost +/- $200 million[133] the financing cost per tonne captured could be as low as $24/MT or as high as $60/MT.[134]
- In the regional supply curve analysis we provided in this Topic Paper we showed two supply curves in each region, one based on the relatively sanguine view of costs, one based on the more pessimistic view. The differences are large, and the argument cannot be resolved without more industry experience.

- On the demand side, the biggest issue is commodity price risk. Even if plenty of CO_2 is theoretically available to start new EOR floods, the instability in oil prices plays a huge role in whether or not those floods are actually undertaken. If, by some miracle, oil prices were to stay exactly at today's level for 20 years, investing in a particular new EOR flood and spending hundreds of millions of dollars on the associated surface and sub-surface equipment might be a lucrative business proposition. However, oil prices are ferociously volatile. In just the last five years oil monthly average WTI reached a high of $105.79 during June 2014, had dropped to $30.32 during February 2016, ground back up to $70.23 for September 2018, and is now back in the $50s. Not only does oil price uncertainty justifiably engender caution as to beginning new CO_2 floods. That oil price uncertainty also prompts oilfields to seek to transfer oil price risk to CO_2 capturers, via contractual CO_2 pricing that varies directly with WTI prices. With oil price risk then shifted onto the shoulders of CO_2 capturers, would-be lenders to carbon capture projects become flustered: instead of the steady revenues lenders wanted, the borrowers will have volatile CO_2 sales revenues linked to gyrating oil prices.
  - In the demand curve analysis in this Topic Paper, we bound this uncertainty by showing two demand projections in each region: one projection of EOR operators' demand for CO_2 assuming a steady $40/bbl WTI and another at a steady $60/bbl WTI.[135]

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[133] The "$200 million" is for engineering, equipment, materials, labor, and construction management, before provision for funding of construction contingency accounts.
[134] The low example uses a 20% combined contractor and owner contingency amount with a 10% financing cost, while the high example uses a combined 50% contingency and a 20% financing cost. These figures are broadly representative of the high and low end of the ranges involved in expert discussions.
[135] We do not have access to information about how CO_2-EOR operators react to oil price uncertainty in the aggregate—instead we only possess break-even CO_2 purchase prices for each field in three different oil price

- Information provided by ARI, nationally recognized experts in CO_2-EOR economics, allowed us to contrast scenarios, one with CO_2 priced at a fixed $30/MT and oil fixed at $60/bbl, the other still with CO_2 at $30/MT but with oil fixed at $40/bbl. Forecast CO_2 demand for the first $60/bbl oil case was 2.4 times higher than the CO_2 demanded at the lower $40/bbl oil case. Many more EOR floods are feasible at $60/bbl oil than at $40/bbl oil. *[Note that there is no available data base that lets us test variable CO2 prices and variable oil prices together.]*
- Given that oil (monthly average WTI) has averaged below $50/bbl for 16 months in the last three years, we'd expect EOR operators in today's ~$55/60/bbl environment to conservatively plan and make capex decisions based on $40/bbl oil.

- The <u>transportation risk</u> is a daunting logistical and timing problem, a cat herding problem in layman's language. Financing a billion dollar CO_2 pipeline in accordance with conventional financial market precedents requires assembling at one fixed time point dozens of would-be capturers and dozens of would-be CO_2 injectors, all with solid commercial creditworthiness, all willing to sign binding long-term contracts to use the to-be-constructed pipeline.
- We conclude that, in the near-term, CCUS deployment *at significant industrial scale* is unlikely to rely upon injection of captured CO_2 into passive saline formations. In the near-term some individual path breaking projects of great industry and political significance may rely on capture plus short pipelines to convenient saline formations. Those projects just don't add up to serious volumes:
  - If a solution to the long distance transportation conundrum outlined above *is* found, then any capturer with access to EOR customers is likely to contract with EOR customers, receiving cash for the captured CO_2, instead of being required to pay cash to the owner of a passive disposal site.[136]
  - If a solution *is not* found to that long distance transportation puzzle, then of course some emitters of pure CO_2 (such as ethanol, gas processing, ammonia, or perhaps a coal gasification project) would inject in local saline formations, if available. However, such limited capture tonnage from the relatively few "pure CO_2 sources" would be a small consolation prize, in the context of having generally failed to deploy capture at scale in the many industries that

environments as modeled by industry experts. Thus, to take account of risk mitigation behavior by oil producers, we assumed oil producers are likely, in a $60/bbl spot oil price environment, to base their decisions on a more conservative long-term $40/bbl assumption. Though according to market participants most CO_2 sales contracts are indexed to oil prices, there is no CO_2-EOR data base that forecasts CO_2 demand by oilfields on that basis.

[136] Other things being equal, for a capturer to select saline injection, notwithstanding availability of pipeline access to EOR fields, the price paid by the oilfield would have to be quite low. I.e., (EOR price, less transport cost to EOR field) < ($15/MT incremental §45Q tax credit, less transport cost to saline formation, less storage charge at saline formation). If transport to EOR field = $10/MT, transport to saline formation = $5/MT, and saline storage = $12/MT, then that equation becomes "(EOR price - $10) < ($15 - $5 - $12)" or EOR price < $8/MT. Even at $40/bbl oil prices, CO_2 has typically sold at $15-$23/MT (i.e., 2% to 3% of WTI per mcf of CO_2).

have far larger volumes available for capture and that require technological progress to be made.

- We also conclude that, in the near-term, CCUS deployment at significant industrial scale could be accomplished with existing technologies, albeit using the best current materials such as new amine solvent formulations that require less heat input to boil off dissolved/entrained CO_2. We do not need to wait for major scientific advances in capture technology to make a quantum leap in terms of captured tonnage. That said, there are a number of promising non-amine technologies that use surface chemistry (e.g., solid adsorber systems such as Air Product's Vacuum Swing Adsorbers) or membrane-based CO_2 separation systems. In general, techno-economic studies show these VSA and membrane technologies as having higher upfront capital costs but lower parasitic energy operating costs. Given today's low natural gas and electricity prices, incurring higher capital cost to save energy is unattractive. In the longer term this tradeoff could reverse with more experience with these new technologies, higher energy prices, and/or carbon taxes imposed on CO_2 emissions from the parasitic energy loads. Oxy-combustion technologies are also promising, but they incur front-end parasitic loads of Air Separation Units to avoid the back-end parasitic loads of amine systems.
- Because of the very small volumes involved, we did not find new CO_2 "utilization" initiatives to be relevant *for the purposes of this Topic Paper*. In the longer-term, it may be that meaningful volumes of CO_2 can be captured and utilized in ways that avoid ultimate emission to the atmosphere. To date, however, proposed technologies to permanently bind CO_2 in construction materials such as concrete have not been demonstrated at relevant scale. Captured CO_2 is now used in foods, soft drinks, beer, and urea manufacturing; but re-emissions of CO_2 to the atmosphere occur in short order when the beer is consumed, or when urea contacts moisture in the soil. Arguments have been made that drilling for oil and gas could be reduced if, instead, fossil fuels were resynthesized using captured CO_2. Besides captured CO_2, however, the other key ingredient in this fossil fuel re-synthesis would be free or low-cost surplus renewable electricity, which can power electrolysis systems that turn water into H_2 and O_2 gas. Given the current absence of the hypothesized costless electricity, the lack of large-scale hydrolysis plants, and the unproven scalability of the proposed fossil fuel re-synthesis processes, we did not count upon this emerging industry as a meaningful consumer of captured CO_2, at least for our limited analytical purposes. That is an analytical simplification solely for the purposes of this Topic Paper, however, and should not be taken as a criticism of the very important scientific work proceeding in the utilization field.

Section (11) Recommendations

The analysis and conclusions described above in this Topic Paper motivate certain specific policy assessments and recommendations. The framework we used to analyze the economics of CCUS for a "First Big Step" of ~100-200MMTPA highlights the idea that even when meticulous examination of capture costs vs. revenues shows that a certain amount of capture/injection is "feasible", there may be hard-to-quantify roadblocks—such as first mover risk and commodity price risk[137]—that counteract feasibility. In these recommendations we consider what relatively low-cost policy instruments may be available to overcome those roadblocks, short of requiring wholesale boosting of per-tonne incentives like Section 45Q credit levels.

There are two major schools of thought as to incentivizing reduction of CO_2 emissions. One school of thought, whose proponents might be called the "economic purists", informed by economic theory and impeccable logic, would favor use of CO_2 emissions taxes[138] as the clearly predominant policy instrument. Members of the second school, the "empiricists", include businesspeople who have experienced the great difficulties of actually completing decarbonization projects. The empiricists hold that CO_2 emissions taxes should be a cornerstone of policy, but that some highly targeted "complementary measures" may be useful to address specific intractable roadblocks that impede the efficacy of carbon taxes. Said more simply, the purists might favor a $100/MT carbon tax whereas the empiricists would say, "a $50/MT tax may be enough for now, as long as some low-cost rifle-shot policy measures are taken to deal with certain issues." This is a hotly debated topic, especially because those who inherently distrust market-based solutions want to start with command-and-control measures that they deem complementary, leaving little scope of action for market-based carbon tax measures. There is an extensive discussion of this topic in the report of the IPCC's "Working Group 3" for AR5. In rather technical language, the IPCC group says that carbon taxes may not be the best policy tool to address certain kinds of problems: for instance if businesses are afraid that unfamiliar technologies won't work, or developers fear that the needed infrastructure may not materialize, or deals can't get financing because lenders are put off by a novel-seeming project.

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[137] As a reminder, past commodity price can easily be *measured* in terms of historical volatility of WTI oil, or ERCOT spot electricity prices. What is difficult to forecast is how individual actors such as oil companies and lenders will make future decisions based upon those actors' perceptions of commodity risk.

[138] Or cap-and-trade regimes, as an alternative to taxes. Economists seem rather more ready to say that carbon taxes and cap-and-trade are quite similar. Business people tend to gravitate toward the certainty of prescribed levels of carbon taxes, shying away from cap-and-trade regimes where prices depend upon periodic adjustments of carbon emission reduction targets.

Quoting from the IPCC report:

> A theme that runs through many of the sectoral deployment policy discussions is the importance of information, and the relationship between incomplete information and risk. Uncertainty about the physical and economic performance of new technologies is a major factor limiting their diffusion, so policies that address information issues maybe complementary with economic incentives or regulatory approaches.[139]
>
> Although most economic theory suggests that economy-wide policies for the singular objective of mitigation would be more cost-effective than sector-specific policies, since AR4 a growing number of studies has demonstrated that administrative and political barriers may make economy-wide policies harder to design and implement than sector-specific policies. The latter may be better suited to address barriers or market failures specific to certain sectors, and may be bundled in packages of complementary policies.[140]
>
> There are numerous market failures, such as research and adoption spillovers, limited foresight, limited information, and imperfect capital markets, which can cause underinvestment in mitigation technologies. . .[141]

In light of this theoretical framework, we discuss below some targeted solutions that could address key risks we have highlighted throughout the paper:

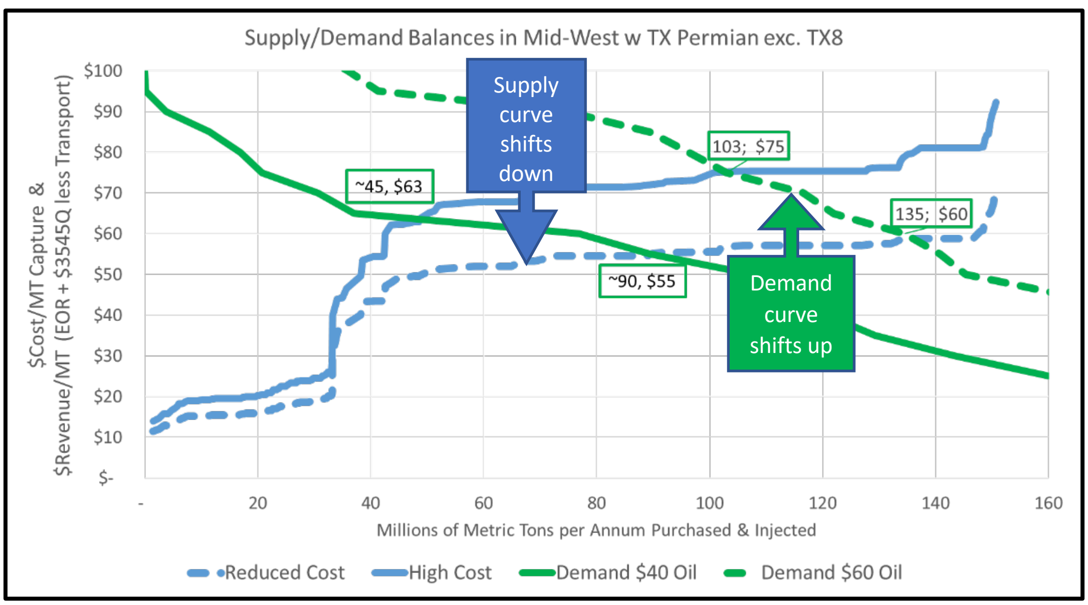
Table 11.1: CCUS Project Risks and Possible Mitigants	
Risks	**Mitigants**
First mover risk: High cost contingencies and financing rate uncertainty for the first 1-5 companies building capture projects in their industry.	• Government support for initial engineering work • Cost sharing grants from government • Changing certain limitations for DOE loan program • Making technical details from government-supported projects widely available.
Commodity price risk: Oil price uncertainty for EOR projects that spills over into financing difficulties for capture projects as well.	• Contracts for differences (create a contractual equivalent of fixed price contract for seller of oil or CO_2 linked to oil prices). • Floor prices on commodities (similar to agricultural commodity price supports).
Transport risk: Daunting logistical/organizational problems for assembling enough credit-worthy shippers to finance a pipeline at scale.	• Direct government ownership or part ownership of initial CO_2 pipelines (subject to later privatization) • Government subscription to unsubscribed "ship-or-pay" volume during pipeline open season proceedings. • Financing cost reduction tools such as access to Private Activity Bond financing or direct loans from US DOE's Loan Program Office.

139 See WG3 of AR5 at Section 15.6.3 (p. 1177)
140 Same source in Summary for Policy Makers, SPM.5.1 (p.26)
141 Same source Section 6.3.6.5 (p. 456)

Table 10.1 above particularly highlights the specific risks that were obvious from the supply/demand curve analysis carried out in the Topic Paper, as opposed to other issues that have been widely raised elsewhere, including in the NPC-CCUS Report. Returning to Figure 4.5 (repeated below), there is a clear reason why solutions to first-mover risk and commodity price risk could be so powerful: the "flatness" of the supply and demand curves.

- The "Demand Curves" (green lines) are quite flat, so a small reduction in supply costs could elicit a big change in amount of CO_2 demanded. The technical term for this is that the demand for CO_2 is highly elastic with respect to changes in price. On the solid green line at $63/MT, demand is only 45 MMTPA. An $8/MT drop in price to $55/MT would double volume to 90 MMTPA. Hence, if we can obtain a relatively modest improvement in cost (corresponding to the shift downwards between the solid blue "high cost" supply curve and the dashed blue "reduced cost" supply curve). Reducing contingencies and financing costs could create such a downward movement in the supply curves (blue box with arrow).
- The "Supply Curves" (blue lines) are quite flat, at least in the $50-60/MT area, so a small increase in demand costs could elicit a big change in amount of CO_2 supplied. The technical term for this is that the supply for CO_2 is also highly elastic with respect to changes in price. On the solid blue line at $63/MT demand is only 45 MMTPA. A ~$12/MT increase in price to $75/MT would more than double volume to 103 MMTPA. Hence, if we can obtain a relatively modest improvement in demand (corresponding to the shift upwards between the solid green "Demand $40 Oil" supply curve and the dashed green "Demand $60 Oil" supply curve). Reducing risk of severe periodic oil price crashes could create such an upward movement in the demand curves (green box with arrow).

<u>Figure 11.1 Supply and Demand Curve Shifts</u>



a. First Mover Risk & Solutions

The first mover risk lies in the existence of widely divergent views among experts as to the ultimate construction and financing costs when existing technologies such as amine solvent systems are applied in a new industrial context, as described above in Section 10. In short, we noted that contractors and financiers might be concerned about the first few amine solvent retrofits in cement, or steel, standalone hydrogen plants, or oil refinery FCCUs, even though amine units are ubiquitous in natural gas processing and urea plants.

Solutions to first mover risk: A straightforward solution to overcome industrialists' concerns about the potential high capital and financing costs of first efforts to implement carbon capture projects in their power plants and factories would be to significantly raise Section 45Q tax credits overall: a problem with doing so is that taxpayers would be paying big additional subsidies to projects that are already feasible and demonstrated (such as ethanol projects) in order to reassure the less-demonstrated project types. To avoid that issue, some parties have considered creating a difficulty-graded sliding tax credit scale that pays more tax credit per MT for more costly projects.

On the other hand, it may prove to be more cost-effective to directly address project risks for the less-demonstrated projects in a more targeted way.

- In an innovative and welcome initiative, US DOE is already addressing project risks by providing funding opportunities [see DE-FOA-0002058][142] that would cover Front-End Engineering Design studies for carbon capture projects. By doing so, US DOE is addressing one of the biggest roadblocks to projects, namely a developer's fear that after spending tens of millions of dollars on a first-rate engineering analysis, the quoted construction price could be vastly above the original optimistic vendor quotation, causing the project to be infeasible and rendering the development investment worthless. Alternatively, if a well-funded FEED study is done by an independent engineer, such a study can give the developer considerable contract negotiating leverage. The project proponent can use the DOE-assisted FEED study to obtain competitive quotes from multiple technology providers and construction contractor. In contrast a frequent problem is that the FEED study is done by a single would-be EPC contractor designed to use a single proprietary capture technology: in such a case the FEED work is not likely to be useful to any other vendor or EPC contractor and the developer has no credible competitive leverage. [143] This US DOE FEED study initiative should be continued and expanded.

[142] https://www.energy.gov/fe/articles/doe-issues-notice-intent-funding-opportunity-front-end-engineering-and-design-studies

[143] Source: Author's personal experience on the former Texas Clean Energy Project, an IGCC with CCS slated to be built in West Texas.

- A natural follow-up to providing FEED study support would be for the US DOE to continue on with a modified version of its previous cost-sharing efforts for carbon capture projects in the industrial and power sectors. Past successes include the Clean Coal Power Initiative cost-sharing agreement with the Petra Nova coal plant retrofit[144] and the Industrial Carbon Capture and Storage program's cost-sharing agreement for the Air Products & Chemicals Port Arthur Steam Methane Reformer project.[145] In the past, US DOE's cost-sharing program appears to have had a strong focus on demonstration of technology. Going forward, we would suggest a stronger focus on deploying multiple, replicable instances of the most proven technologies available. Only when there are 3-5 working instances of a particular technology type in a particular industrial setting will industry participants, contractors, and financiers begin to reduce the construction cost and financing cost premiums they now put on "undemonstrated technologies." The value of a single demonstration project is vastly over-estimated. If a developer seeks to interest investors/lenders in a coal plant post-combustion capture project that is essentially a twin of the successful Petra Nova project, the typical response is, "OK, but that's just one. Are there others?"[146]
- In order to maximize replicability of federally-supported projects, it would be highly beneficial to fully publicize costs, deal terms, full heat & material balances (or "stream tables"), names of subcontractors or vendors of subassemblies, etc. in cost-sharing agreement-supported projects. This would address the problem that the IPCC calls "incomplete information." Federal dollars are much more impactful if the sponsored projects provide a detailed roadmap to assist follow-on projects. Of course safeguards to intellectual property, patents, etc. must be in place; but current levels of secrecy on government-supported carbon capture projects are counterproductive.
- A critical change to existing federal policy would be to legislatively change the existing prohibition of issuance of direct federal loans or loan guarantees to innovative fossil fuel projects that have received government funding such as cost-sharing. [147] If DOE is willing to help bear some of the construction risk incurred by first movers, that invaluable assistance should not make the project ineligible for a federal loan guarantee. A DOE cost-sharing grant addresses the difficulty of raising equity, and the loan guarantee addresses the difficulty of getting loans: they are two distinctly different portions of a project's capitalization, and 1st-3rd of a kind projects have major problems raising both equity and debt. Moreover, there is no "double" dip in terms of federal expenditures when a project gets both grants and DOE loans.

[144] https://www.netl.doe.gov/project-information?p=FE0003311
[145] https://www.energy.gov/fe/articles/breakthrough-large-scale-industrial-project-begins-carbon
[146] Source: Author's personal experience.
[147] As stated in the US DOE's solicitation for Federal Loan Guarantees for Advanced Fossil Energy Projects, "Subject to limited exceptions that are set forth in the 2009 Appropriations Act, DOE will not be able to issue loan guarantees to projects that will benefit directly or indirectly from certain other forms of federal support, such as grants or other loan guarantees from federal agencies or entities. . ." See Solicitation Number: DE-SOL-0006303 at page 5/46.

A grant does in fact consume appropriated funds; however the current DOE loan program for Advanced Fossil Energy projects charges borrowers an upfront amount, calculated by an interagency federal committee advised by external rating agencies, deemed sufficient to reimburse the U.S. government for the expected value of default of the particular loan.

b. Commodity Price Risk & Solutions

The most commodity price risk we see is oil price volatility. The issue is not precisely the spot oil price, nor is it the expectation of long-term average oil price: rather the issue is the possibility of several years in a row of terrible oil prices even in the context of long-term prosperity. Hence, even when oil prices were above \$100/bbl, bond rating agencies were asking project developers to show that their projects could withstand \$40/bbl prices without defaulting.

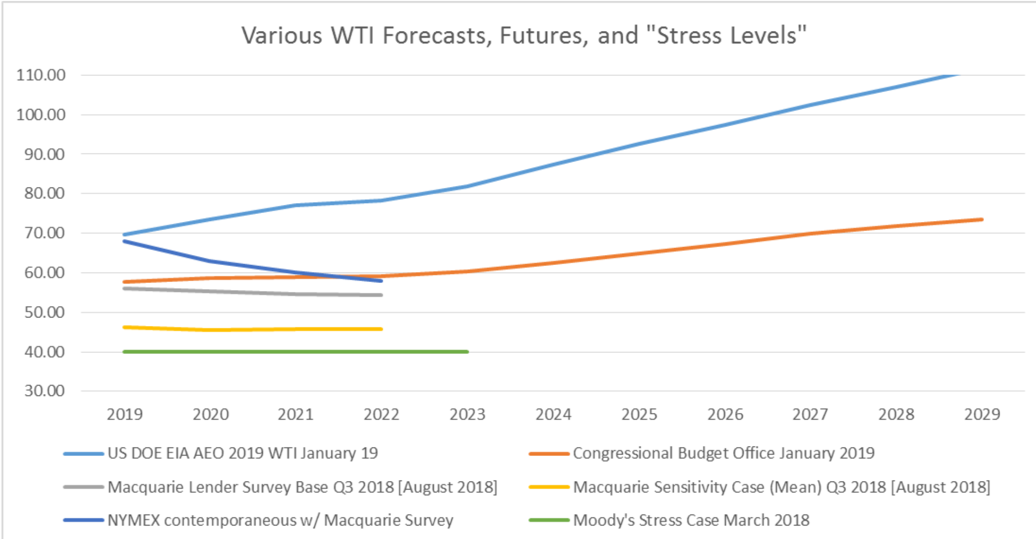
Even if plenty of CO_2 is theoretically available to start new EOR floods, the instability in oil prices plays a huge role in whether or not those floods are actually undertaken. If, by some miracle, oil prices were to stay exactly at today's level for 20 years, investing in a particular new EOR flood and spending hundreds of millions of dollars on the associated surface and sub-surface equipment might be a lucrative business proposition. However, oil prices are notoriously volatile. In just the last five years oil monthly average WTI reached a high of \$105.79 during June 2014, had dropped to \$30.32 during February 2016, ground back up to \$70.23 for September 2018, and was back below \$50 again by December 2018. Not only does oil price uncertainty justifiably engender caution as to beginning new CO_2 floods. That oil price uncertainty also prompts oilfields to seek to transfer oil price risk to CO_2 capturers, via contractual CO_2 pricing that varies directly with WTI prices. With oil price risk then shifted onto the shoulders of CO_2 capturers, would-be lenders to carbon capture projects become flustered: instead of the steady revenues lenders wanted, the borrowers will have volatile CO_2 sales revenues linked to gyrating oil prices.

The issue with lenders is shown in the chart immediately below. Even if official forecasters show oil prices rising, prospective lenders and bond rating agencies demand that borrowers show ability to repay debt at "stress oil price levels" are far below those official forecasts:

- As of January 2019, the U.S. government's forecasts (AEO and CBO) were both rising, and the U.S. government forecasts run for a decade or more.
- Futures quotations were falling out to 2022 [Note: Futures are not a forecast because they include a cost of storage for the physical commodity.]
- Macquarie's Lender Base survey was \$5-10/bbl lower than futures (base case projection upon which banks would lend)
- Macquarie's Lender Stress Case was approximately \$15 lower than futures (borrowers must be able to show they can repay debt at that level.

- Moody's Stress Case for getting investment grade bond ratings was $20-25/bbl below futures and the CBO projections.

<u>Figure 11.2 Various Forecasts, Futures, and "Stress Levels" of WTI</u>



<u>Commodity price risk solutions</u>: Policy tools exist that, if used by the Federal government, could cut off this downside risk for CO_2 capture projects and their oilfield customers. If liquid, long-term oil price hedges were available to lock in $60/bbl oil for 15-20 years—i.e., at a price below today's spot $63.67—this oil price risk would disappear and the attractive $60/bbl scenario described above would be relevant.

The particular tool most commonly used by governments, notably by the U.K., is a so-called Contract for Differences ("CfD").[148] In such a contract, the Federal Government and the capturer would agree on a long-term, fair, central estimate of 15-20-year oil prices. "Fair" might be based on the U.S. government's own projections of oil prices, such as those by the Congressional Budget Office and/or US Department of Energy as published in the Annual Energy Outlook. In a CfD set at $60/bbl, the capturer would be protected by the U.S. government if oil prices dropped below $60/bbl, and the capturer would give up to the U.S. government any upside above $60/bbl. From the U.S. Government point of view, the bilaterally symmetrical nature of the CfD tool is attractive, especially when compared to the asymmetry of "price floor" programs in which the U.S. Government writes checks when a commodity price goes below the floor, but does not share any upside if commodity prices skyrocket.

A more extensive discussion of the possible use of CfDs in improving feasibility for CCUS projects is contained in a paper published by The State CO_2-EOR Deployment

[148] See https://www.emrsettlement.co.uk/about-emr/contracts-for-difference/

Work Group entitled "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry."[149]

To put such a program in context, it is helpful to know how the size and nature of the hedging need of carbon capturers compares to that of the US government. In the language of commodities traders, carbon capturers are "long oil" and the U.S. government is "short oil."

- Exposure of carbon capturers: First, a typical variable, oil-indexed pricing formula for CO_2 can be simplified as Price of 1 MT CO_2 = ~Price of ½ bbl Crude. Thus, if we wished to hedge the oil price exposure of 100MMTPA, we would need a hedge against prices *falling* on 50 million bbl/year of crude.
- Current exposure of U.S. government: The federal government typically consumes approximately 100 million bbl/year of petroleum.[150] If prices of oil fall, the federal budget benefits, and if oil prices rise, the federal budget is harmed. If we want to protect the budget, we need to hedge against prices *rising* on 100 million bbl/year of crude.
- Thus, an appropriately sized CfD program designed to protect carbon capturers would likely also reduce the federal government's own risk. The two parties have more-or-less opposite risk positions that can cancel out each other's exposures.

An alternative program, simpler to understand, but exposing the government to asymmetrical price risk, would be to create a price floor program similar to price floors used in agricultural price support systems in the U.S.

c. Transportation Roadblock & Solutions

The transportation roadblock is a daunting logistical and timing problem, a cat herding problem in layman's language. Financing a billion dollar CO_2 pipeline in accordance with normal market practice requires assembling, at one fixed time point, many dozens of would-be capturers and many dozens of would-be CO_2 injectors, all with solid commercial creditworthiness, all willing to sign binding long-term contracts to use the to-be-constructed pipeline.[151] The issue is not whether a pipeline would *eventually* be filled with captured CO_2 making its way to CO_2-EOR fields or to passive sequestration sites: rather, the issue is that capturers and injectors will get project permits, approvals, and

[149] See pp. 35-36 of the paper which can be downloaded at https://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf. CfDs were also recommended in the Carbon Capture Coalition's May 2019 "Federal Policy Blueprint" on pp. 16-17. https://www.betterenergy.org/blog/carbon-capture-coalition-federal-policy-blueprint/

[150] See following source, which shows petroleum fuel use at approximately 613 trillion Btu, which is the equivalent of approximately 100 million bbl. The figures are from 2013, and we were unable to find official sources that are more recent. https://www.eia.gov/todayinenergy/detail.php?id=19851

[151] Kinder Morgan Energy Partners' "open season" for capacity subscriptions for the Rockies Express Pipeline is a good example of the normal practice. See https://www.rigzone.com/news/oil_gas/a/26969/encana_inks_deal_for_capacity_on_proposed_rockies_express_pipeline/

commercial contracts at unpredictable times over many years, whereas a pipeline company needs for the line to be fully subscribed by creditworthy customers on a single date to allow financing.

Solutions for transportation: One family of solutions goes directly at the cat herding problem via either direct federal ownership or direct federal subscription for capacity. A second family of solutions addresses cost of debt and/or equity capital.

It may be that some type of federal/industry public/private partnership is required, with the U.S. government initially funding the pipeline and maintaining ownership until the pipeline can be privatized based once enough customers have been contracted to make the pipeline financially viable. After the pipeline is financially viable, the asset could be privatized. A related solution is to have the federal government temporarily stand in for future shippers during the initial pipeline "open season" proceeding described in Section 9.

A number of solutions have been proposed that could cut the financing rates incurred by a pipeline. The author believes these financing-oriented solutions could be very helpful to cutting transportation costs for a well-subscribed pipeline, but that they may not be powerful enough to directly address the vexing cat herding problem. One possibility would be to allow CO_2 pipelines carrying captured CO_2 to utilize tax-exempt bond financing of the type used by airports, seaports, and mass-transit projects. Another possibility would be to allow CO_2 pipelines to tap into the approximately $8 billion of loan funds available through the U.S. Department of Energy's Loan Program Office via the program entitled "Federal Loan Guarantees for Advanced Fossil Fuel Energy Projects." These would be excellent steps forward, but they may not be enough.
The State CO_2-EOR Deployment Work Group has published a major report, "21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks" which contains a number of other interesting policy suggestions.[152]

d. Additional Issues, Findings, and Recommendations

In the previous three subsections we highlighted the most critical roadblocks and possible solutions that are directly observable from the industry analysis in this Topic Paper. There are a number of other issues that also play an important role in discouraging progress in implementation of carbon capture. Some prominent issues and possible solutions are summarized in Table 10.2 below:

[152] https://www.betterenergy.org/blog/21st-century-energy-infrastructure-policy-recommendations-development-american-CO2-pipeline-networks/

Table 11.2: Additional Issues, Impacts, and Recommendations

Additional Issues, Impacts, and Recommendations		
Issue	**Impact**	**Recommendations**
Capacity factors: Electric generators' operating rates make a huge difference in "capture cost" and willingness to capture a high percentage of CO_2.	Unstable capacity factors, tending lower over time especially in ISO-managed "organized markets" make investment in carbon capture equipment risk.	Include CCUS-enabled projects as "policy resources" that can be procured under bilateral contracts by ISOs. Continued serious investigation by Federal Energy Regulatory Commission on policies that permit the capacity attributes of carbon capture enabled fossil power plants to be fairly valued.
Environmental permitting risks: CCUS retrofits relationship to existing air permits.	Not clear whether adding CCUS is a significant modification, leading to reopening air permit. Plant owners don't want to take the risk.	CCUS added inside the fence or over-the-fence should not be treated as significant modification to an existing plant unless the addition of the CCUS facility creates a serious increase in emissions of conventional criteria pollutants in a non-attainment area.
Limited appetite for tax credits among investors, and difficulty in monetizing tax credits through 3rd party investor participation.	CCUS projects and most upstream oil companies don't have much "tax appetite" given high depreciation and interest expense. Tax equity partnerships and leveraged leases can be used, to allow non-industrial companies to benefit from tax credits, but these transactions are expensive, time consuming, and usually result in the 3rd parties taking the lion's share of benefits.	Find some long-term method to make §45Q refundable for cash as renewable PTC/ITCs were under §1603. As an alternative, make taxable attributes of CCUS projects that flow through to individual investors in CCUS partnerships or LLCs not subject to passive activity rules. Those rules limit individual taxpayers' ability to benefit from Congressionally-provided tax credits.
Short duration of Section 45Q credits in light of operating costs and typical industry investment horizons. Without Section 45Q credits projects may contemplate cessation of operations after 12 years.	We had to limit the time horizon of projects, including the period over which all debt and equity needed to be recovered, to 12 years. That is because in many cases, the annual fixed and variable operating costs (other than financing) are too big to be covered by cash revenues from sales to CO_2-EOR operators. I.e., if no more 45Q tax credits are available, operating costs are \$25/MT, but CO_2-EOR sales revenues net of transportation tariffs are only \$18/MT, a project will cease operating.	If the period of payments of tax credits under 45Q were lengthened projects would operate longer, but the secondary benefit would be that more projects would be feasible in the first place. Extending the time frame of debt amortization and equity capital recovery from 12 years to 20 years would typically cut capture costs/MT by ~\$5/MT for projects with initial investment cost of \$300/MTPA. [See discussion below Table 5.3 "Inputs Used in Deriving Capital Recovery Factors.]

e. Future Research Issues, Impacts, and Policy Suggestions

This research project was limited in terms of budget, scope and manpower. During the course of the work, we made some observations on possible future work that could improve knowledge of this emerging anthropogenic CCUS industry.

Table 11.3: Future Research Issues, Impacts, and Recommendations

Future Research Issues, Impacts, and Recommendations		
Issue	**Impact**	**Recommendations**
Federal research results on carbon capture costs in industry and electricity	Existing federally-funded studies seem to generate figures that are inconsistent for different industries using same technology	Peer review of existing NETL studies, especially those done by outside consultants
Federal research detail published	Lack of specificity on main cost items. I.e., no visibility as to subcomponents of CO_2 capture systems	Cost breakdowns similar in detail to those a developer would use in negotiating an EPC contract.
Cross industry cost study	The same CCUS equipment components are used in multiple applications: compressors, boilers, and MDEA systems. Pricing for these units is non-transparent.	Private or public serious study of the supply chain, modularization potential, scalability, etc. of these standard components.
Studies that have a pure engineering focus, as opposed to seeking most least-cost solutions in carbon capture	Many research projects have used unrealistic assumptions about add-on capex (such as power plants buried in industrial CCUS projects) & thus produce alarming headline "cost of CCUS" figures.	Follow on to current capture cost examination in NPC study that is better-resourced, with access to engineering, contractor and "behind pay wall" resources could clear the air.

Appendix A: Passive Sequestration Costs

There are a number of different possible sources for locations, capacity, and cost of injection of CO_2 for sequestration purposes into saline formations. Some public data is at quite a high level, just showing total volumes (e.g., the Carbon Storage Atlas published by NETL). Other data identifies in each state the formations, structures, and general locations where CO_2 could be injected, as well as estimated cost per tonne injected, but without the specific latitude/longitude coordinates needed to run a transportation model (e.g., the FE/NETL CO_2 Saline Storage Cost Model (2017)).[153] Los Alamos National Laboratory's models have used EPA data, and they state this allows them to "directly relate geologic properties (e.g., injection rate, plume dimensions) to the EPA costs using reduced-order model (ROM) versions of a full reservoir simulator." Finally, non-government investigators such as those at the University of Indiana have sought create quite specific cost data for tightly defined injection spots, which is ideal for economic modeling of regional systems.

In this Topic Paper we used the FE/NETL model for purposes of creating approximate regional storage cost curves (since state-level analysis was sufficient), but LANL used more locationally precise EPA data in running their models. In neither case did saline storage matter much to results of the analysis because any significant scale-up of the CO_2 industry (i.e., an increment of ~100-200MMTPA) requires revenues per tonne captured significantly above the value of saline storage tax credits, less sequestration and transportation costs. That is, we made saline storage resources available to our nascent regional markets; but as modeled, no one wanted to use those saline sites.

Again, we did originally include the option of sequestration in saline formations as an important input in construction of demand curves for CO_2. Under that original methodology "demand curves" for CO_2 reflected two different "markets" for CO_2; and each of those markets had different characteristics.

- The CO_2-EOR market in each region is comprised of EOR field data from ARI's models. From the point of view of a CO_2 capture operation the EOR market pays cash revenues for the value of CO_2 to the EOR operator delivered to his oilfield, less transportation costs from the capture site to the oilfield, plus allowing the capturer to claim the Section 45Q tax credit value that reaches $35/MT in 2026.

[153] National Energy Technology Laboratory (2017). FE/NETL CO_2 Saline Storage Cost Model. U.S. Department of Energy. Last Update: Sep 2017 (Version 3) https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2403

- The passive saline aquifer storage charges the capturer for the cost of operating the storage site, charges transportation costs from the capture site to the storage site, and allows the capturer to claim a large Section 45Q tax credit value that reaches \$50/MT in 2026.

As we stated in the summary, the Section 45Q tax credit at \$50/MT for passive storage is *primarily* attractive to a carbon capturer if three things are true:[154]

1. The capturer has costs far below \$50/MT. This would be true for an ethanol producer compressing pure fermentation-derived CO_2, a natural gas processor that already had to separate CO_2 from natural gas to meet pipeline specifications, or an ammonia producer that has captured more CO_2 than is needed for its current urea production. Depending on scale, all three capturer types would have compression/dehydration costs in the ~\$15/MT range.
2. The capturer has access to saline storage sites and the combined cost of transportation—likely on a relatively small-diameter spur pipeline—plus the amount charged by the saline storage site operator are relatively small, i.e., no more than a combined ~\$30/MT. Thus, there would be some margin left after subtracting the compression, transport, and storage cost from the \$50/MT credit. For example: \$50/MT credit - \$15/MT compression expense - \$30/MT transport/storage expense = \$5/MT margin. Such a situation—combined transport and storage to saline aquifer under ~\$30/MT—could be true for many ethanol plants and natural gas processing plants if:
    a. The capturing plant is reasonably large and not too far from the storage site. To put this in context, just the annual financing cost of a 100-mile, 4 inch diameter pipeline that could carry 200,000 MT/year would work out to ~\$30/MT transported. The median U.S. ethanol plant would capture about 160,000 MT/year.
    b. The storage site has relatively low costs. The information we have from the federal source cited below indicates that there is capacity for 12.8MMTPA in Illinois and Indiana with storage cost at or below \$10/MT, which would be adequate for the 8 million tonnes of ethanol fermentation emissions from ethanol plants emitting > 100,000 MTPA in those states. There is also capacity for 89MMTPA at or below \$10/MT in the Onshore Texas and Mississippi Gulf of Mexico area, but there is no ethanol production and relatively little natural gas processing capacity in the area (less than 2MMTPA) to take advantage of that huge storage resource.
3. The low-cost capturer does not have access to a low-cost, large diameter, efficient CO_2 trunk pipeline. If it does have such access, especially in the early scaling up stages of the CO_2 capture industry, the economic proposition of getting money from

[154] Note also that the capturer would have to capture at least 100,000 MT/year, which is not true for many ethanol producers and natural gas processors. As an example, our estimates are that 30 out of 210 reporting U.S. ethanol plants fall below that cutoff, as do 386 of 429 natural gas processors.

customers in EOR fields is likely to be more attractive than paying a storage site to accept the CO_2.

Passive saline storage may also be a key tactical, interim step for capturers who do not now have pipeline access to sales to CO_2-EOR buyers of CO_2, but who may have such pipeline access in the future. If those capturers have local passive saline storage resources, there are two potential benefits:

1. Passive storage forms a basis to finance and operate until transportation infrastructure and CO_2-EOR floods can be arranged. For at least 12 years the capturer can inject locally and receive at least some tax credit compensation for its efforts.
2. Assuming that during this window, access to CO_2-EOR fields and sales contracts can be arranged, the capturer is likely two switch from local injection to pipelining to oilfields. However, the permitted local passive injection opportunity would still serve as an injection backstop if a CO_2-EOR buyer defaulted on its contracts, while the capturer searched for other buyers. This would be especially important, for instance, if the capturer would be forced to pay emissions fees or has a compliance obligation.

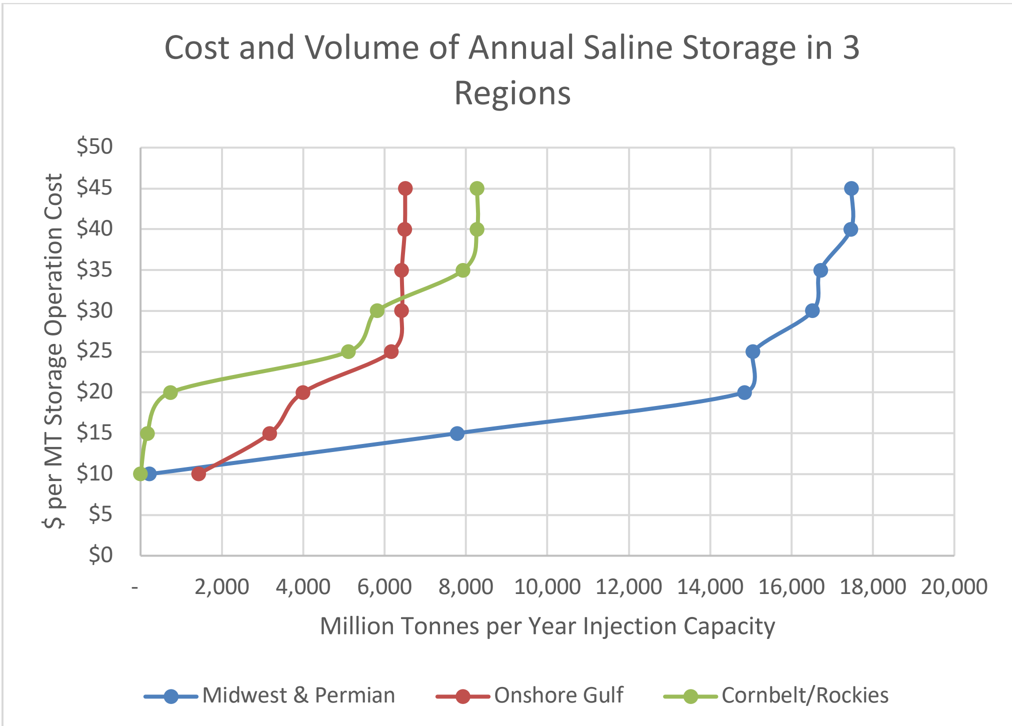
The principal source of information for this Chapter on location, possible storage volumes, and cost of operating sequestration sites was information published by the National Energy Technology Laboratory known as the FE/NETL CO_2 Saline Storage Cost Model (2017). The model's authors describe it as follows:

> *The FE/NETL* CO_2 *Saline Storage Cost Model (Storage Model) estimates costs to store a tonne of* CO_2 *in a saline reservoir. The model estimates costs associated with a project, using simplified geo-engineering equations to calculate reservoir values needed to determine injection well costs, monitoring costs, financial responsibility costs, etc. All of these costs are summed over the life of a* CO_2 *storage project and discounted to a NPV of near zero to determine the first-year break-even cost to store a tonne of* CO_2*. The FE/NETL* CO_2 *Saline Storage Cost Model (2017): User's Manual provides some details on the use of this model.*

The FE/NETL (2017) model shows a nationwide total capacity of passive storage sites of 1.637 trillion MT.

For the regions studied in this Chapter, the graph below shows the storage resources as cost curves. The "x" axis is the amount that must be paid per MT by the capturer to access the storage. The "y" axis values are the amounts that could be stored at or below such price. The "x" axis values are solely fees charged to the capturer by the storage operator, and do not include transportation. As long as capturers can pay a significant price to access these storage resources, total volumes are large in comparison to U.S. total stationary emissions of 2.6 billion MTPA: at $15/tonne the three regions could store over 10 billion MTPA (i.e., 10,000MMTPA on the "x" axis.) Storage basins accessible in each region are:

- "Midwest": IL, IN, KS, OK, Palo Duro Basin of TX, and Permian Basin of TX
- "Gulf ": Onshore basins of MS, LA, and TX
- "Rockies": WY, MT, ND, and very small volumes in SD



The tables immediately below show state-by-state details of these passive storage resources as portrayed in the FE/NETL data. In the tables, storage costs in the first column are shown in red, in parentheses, since they are negative cash flows to capturers. [Note: Please note that the units are in Millions of Metric Tons per Annum (abbreviated MMTPA). So the figure in the upper right hand corner of the table, "8,271" means 8,271 million metric tonnes per annum, or 8.271 billion MPTA, could be injected at a cost less than $45/MT in the particular region.]

Saline Storage Resource Cost Curves in Three Study Regions

(red figures are $ per MT cost of CO_2 stored, & other figures are in cumulative Million Metric Tons Per Annum injected at less than the corresponding cost, MMTPA)

less than	IA	NE	MT	WY	MN	SD	ND	SUM MMTPA
($45.00)	-	-	2,114	2,826	-	2	3,330	8,271
($40.00)	-	-	2,114	2,826	-	-	3,330	8,269
($35.00)	-	-	2,059	2,609	-	-	3,263	7,931
($30.00)	-	-	2,048	672	-	-	3,090	5,810
($25.00)	-	-	1,390	630	-	-	3,090	5,110
($20.00)	-	-	86	403	-	-	240	730
($15.00)	-	-	3	42	-	-	122	166
($10.00)	-	-	-	-	-	-	-	-
($5.00)	-	-	-	-	-	-	-	-
$0.00	-	-	-	-	-	-	-	-

						Palo Duro	Permian	
less than	IL	IN	MO	KS	OK	TX	TX	SUM MMTPA
($45.00)	1,554	1,793	-	1,487	339	3,062	9,235	17,470
($40.00)	1,554	1,780	-	1,487	339	3,062	9,235	17,458
($35.00)	1,551	1,779	-	1,487	339	3,062	8,491	16,710
($30.00)	1,551	1,779	-	1,487	339	2,872	8,491	16,520
($25.00)	1,382	1,779	-	1,433	339	2,867	7,254	15,056
($20.00)	1,382	1,691	-	1,432	339	2,861	7,136	14,842
($15.00)	1,158	1,507	-	1,430	26	794	2,861	7,775
($10.00)	112	102	-	-	-	-	-	214
($5.00)	-	-	-	-	-	-	-	-
$0.00	-	-	-	-	-	-	-	-

					Gulf Coast Onshore			
less than				MS	LA	TX		SUM MMTPA
($45.00)	-	-	-	3,094	344	3,066	-	6,504
($40.00)	-	-	-	3,086	344	3,066	-	6,496
($35.00)	-	-	-	3,086	270	3,066	-	6,422
($30.00)	-	-	-	3,086	268	3,065	-	6,419
($25.00)	-	-	-	3,072	29	3,064	-	6,165
($20.00)	-	-	-	954	26	3,015	-	3,994
($15.00)	-	-	-	266	-	2,915	-	3,181
($10.00)	-	-	-	26	-	1,401	-	1,427
($5.00)	-	-	-	-	-	-	-	-
$0.00	-	-	-	-	-	-	-	-

The principal conclusion we reach by examining these storage resources, is that in terms of a near-term national strategy to scale up the carbon capture industry, storage in passive saline formations may not be as important as many parties believe. There are simply not that many “cheap tonnes” of capturable CO_2 located near low-cost storage, at least according to the only comprehensive data available to us. Of course, this observation is made in the economic context of only the \$50/MT tax credit as a “revenue source”, the relatively small size of typical capturers in the low-cost industries, and the likely high transport cost for such small volumes. That said, passive storage is likely to be of major importance in the long run, even if it is not of immediate importance for the limited purposes of the current analysis. For instance, in the context of a possible high future price for CO_2 emissions, and with capture volumes that outpace amounts of CO_2 that can be productively absorbed by the CO_2-EOR industry, the situation would be completely different.