Cost Analysis of Carbon Capture and Sequestration of Process Emissions from the U.S. Industrial Sector

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ABSTRACT: The industrial sector represents roughly 22% of U.S. emissions. Unlike emissions from fossil-fueled power plants, the carbon footprint of the industrial sector represents a complex mixture of stationary combustion and process emissions produced as a reaction byproduct of cement, iron and steel, glass, and oil production. This study quantifies the potential opportunities for low-cost carbon capture and storage (CCS) scenarios with process emissions from the U.S. industrial sector by analyzing the variabilities in point-source capture and geographic proximity to relevant sinks, specifically enhanced oil recovery (EOR) and geologic sequestration opportunities. Using a technology-agnostic cost model developed from mature CO2 capture technologies, costs of CCS are calculated for each of the 656 facilities considered, with application of the U.S. federal tax credit 45Q to qualifying facilities. Capture of these targeted industrial process emission streams may lead to the avoidance of roughly 195 MtCO2/yr (188 MtCO2/yr qualifying for 45Q). A total of 123 facilities have the potential to avoid roughly 68.5 MtCO2/yr at costs below $40/tCO2 delivered. This could be competitive for using CO2 for EOR depending on the price of oil. At regional CO2 collection hubs, emissions of 40 MtCO2/yr can be avoided within 100 miles of the existing Louisiana–Mississippi and Texas–New Mexico pipelines.

INTRODUCTION

In 2007, the Intergovernmental Panel on Climate Change (IPCC) released their 4th Assessment Report on global emissions and their recommendation for policymakers around the world. A significant conclusion of the report was that to avoid an average of 2.0 °C increase in global surface temperature, greenhouse gas (GHGs) emissions must be reduced by 60–80%. To reach these climate goals, a combination of technological advances and policy incentives will be required. In the United States, the FUTURE Act of 2017 provides a federal tax credit to companies for capturing CO2 from industrial processes, provided they capture ≥100,000 tCO2/yr and subsequently sequester it in the earth either through CO2-enhanced oil recovery (EOR) or dedicated reliable storage projects. This federal tax credit is commonly known as 45Q.

To determine the adequacy of 45Q in bridging the cost gap of delivered CO2 to EOR or dedicated reliable sequestration projects, it is necessary to first determine the costs of capture from each type of industrial facility. Roughly, 22% of U.S. greenhouse gas emissions in 2017 came from the industrial sector. The industrial sector covers a wide variety of products, some of which include cement, steel, hydrogen, ammonia, ethanol, and glass. To make these products, a carbon-containing feedstock is often used in addition to heat and power for fueling the product manufacture. Hence, the collective carbon footprint of a given industry is a combination of stationary combustion emissions and the production of CO2 through the reaction pathway of making the product itself, called process emissions. For example, in making lime (CaO), calcium carbonate (CaCO3) is mined and then heated in a kiln roughly at 900 °C to liberate CO2, thereby producing CaO, as shown among other similar examples in Table S1. If the kiln is fired with natural gas, the exhaust stream of the kiln will be a mixture of combustion exhaust combined with “process” CO2 generated by carbonate calcination.

The current study is focused solely on the industrial emissions for which carbon capture technology may be applied as a solution for avoiding CO2 emissions. For this reason, industrial emissions from petroleum and natural gas production, coal mining, and other industrial processes that are not suitable for carbon capture retrofits are not considered further in this analysis. The systems not included represent roughly half (i.e., ~650 MtCO2-eq/yr) of all U.S. industrial emissions, with those allowing for carbon capture retrofit technology accounting for the other half. Of those facilities that would allow for carbon capture retrofit, roughly half of those emissions are associated with stationary combustion. The remaining 25% (i.e., ~320 MtCO2-eq/yr) of total...
AMMUNITION: are process emissions to which a given facility may use carbon capture technology as a method of reducing their on-site emissions.

Figure 1 shows the distribution of process emissions associated with the various industrial sectors that are considered in this study. Table S1 lists the process emissions associated with each of the sectors represented in Figure 1, along with the corresponding chemical reaction that displays the carbon source of the process emissions.

In some cases, alternate pathways exist to lower process emissions but are hindered for technical or economic reasons. An example, consider H2 production. Globally, 78% of H2 is produced using steam-methane reforming (SMR), while 18% is produced from coal gasification and 4% from water electrolysis. Of these routes, electrolysis can lower the carbon intensity of hydrogen production significantly when paired with renewable energy. However, because of the high costs of this route, which has a reported low-end cost of $2.8/kg H2 compared to the low-end cost of SMR at $1/kg H2, the process is mostly carried out through the more cost-effective yet carbon-intensive SMR path, which relies on natural gas as a feedstock. More recently, there has been development toward the production of H2 through SMR coupled to carbon capture, which may be cost-competitive with the conventional approach if the H2 production facility can qualify for the federal tax credit 45Q.

In addition, many process emissions are “committed” because of the existing infrastructure associated with the industrial sector. In the United States, committed emissions associated with industrial processes amount to 5800 MtCO2. This value was determined using country-level emissions data from 2018, obtained from the IEA for all reported industrial facilities. This further assumes a plant lifetime of 40 years, corresponding to a lower number of facilities half of the industrial sector does not qualify for the federal tax credit 45Q. This policy applies to a lower number of facilities.

When considering all emissions from the industrial sector (e.g., stationary combustion, process emissions, and emissions from waste treatment), roughly 860 facilities out of 1529 could qualify for 45Q, while only 555 facilities qualify when only process emissions are considered (Figure 2). Hence, when considering emissions that the facilities can control today, over half of the industrial sector does not qualify for the federal tax credit 45Q. This policy applies to a lower number of facilities when considering that, in the case of facilities with multiple streams (i.e., refineries, cement production, hydrogen, ammonia, and iron & steel industries), it is often uneconomical to apply carbon capture retrofit to each individual stream. Rather, the facility will likely prioritize higher purity and higher volume streams, which may represent only a fraction of the total facility emissions. This study quantifies the amount of CO2 that can be captured for the major streams sourced from each of the sectors of the industry where carbon capture retrofit is feasible.

The primary focus of this study is to determine the cumulative costs of CO2 capture, compression, and transport from a given industrial facility to (1) geologic utilization via EOR or (2) dedicated geologic sequestration. The cost of capturing CO2 from a variety of industrial sources based on previous economic studies. This includes studies of iron and steel, refineries, cement production, hydrogen production, and ammonia production. In the iron and steel industry, the authors noted that the cost of postcombustion amine capture on the blast furnace (with a composition of 20–25% CO2) ranged from $65.1 to $119.2/tCO2 avoided. Similarly, for refineries, the cost ranged from $68.2 to $83.9/tCO2 avoided for the fluid catalytic cracking (FCC) unit with assumed CO2 concentrations ranging from 10 to 20%. Higher costs were reported for capture from combined stacks. For cement production, the authors reported costs ranging from $17.0 to $40.6/tCO2 avoided for oxy-combustion with calcium looping, with an average cost of $39.4/tCO2 avoided. The calcium looping systems proved more advantageous than traditional amine scrubbing technology, which was noted to have costs from $66.0 to $164.6/tCO2 avoided. Additional cost comparisons from Leeson et al. were provided for hydrogen production and other high-purity industrial streams. In hydrogen production, the reported costs ranged from $6.0 to $74.0/tCO2 avoided. This can vary widely, depending on the inlet CO2 concentration and the hydrogen purification process. For these economic analyses, the percent of captured CO2 ranged from roughly 50% up to 94% capture (specific to oxycombustion capture with chemical looping for CO2 capture from the cement industry). With the exception of the aforementioned process, most analyses exhibited capture percentages between 50 and 65%

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The primary focus of this study is to determine the cumulative costs of CO2 capture, compression, and transport from a given industrial facility to (1) geologic utilization via EOR or (2) dedicated geologic sequestration of CO2, in the contiguous United States, in light of the existing federal tax credit 45Q. In order to determine these costs, a technology-agnostic cost model has been developed for CO2 capture across gas streams of varying CO2 purity and flow rates. Careful mapping of each of the U.S. industrial facilities responsible for emitting CO2 along with the potential corresponding CO2 sink is carried out, which is required for accurate costing of CO2 transport. Transportation costs are determined through the lower cost route among options of pipeline or trucking. Ultimately, low-end and average cumulative costs are estimated to determine the remaining gap after application of the 45Q federal tax credit for qualifying streams to provide insight into what may be required for
reducing further emissions from the industrial sector. Opportunities below $40/t CO₂ are outlined for EOR end uses as the price range of CO₂ may be favorable for EOR depending on the current price of oil.30−33

■ METHODS

Data were analyzed for major industrial emission sources to determine the amount of overall process emissions that can be captured and ultimately reliably sequestered in the earth. Data were collected from the EPA Greenhouse Gas Reporting Program.4 Here, the major industry emitters include petroleum refining, bioethanol production, hydrogen production, iron and steel making, cement and lime production. For bioethanol, additional data were collected from the Nebraska Energy Office (NEO), the U.S. Energy Information Administration (EIA), the Ethanol Producer Magazine (EPM), and the Renewable Fuel Association (RFA).5−9

In this analysis, only emissions from industrial processes making up >1 wt % of the total U.S. CO₂ emissions were considered. Additional industrial emissions making up >1 wt % of U.S. emissions were neglected if the emissions were primarily composed of a greenhouse gas other than CO₂, as they cannot be captured with the technology we consider. This reduces the number of facilities considered in this analysis to 656 capture point sources. Further details on the distribution of CO₂ emissions considered in this analysis among the various industrial sectors are given in Table S2. In addition, the units considered for capture along with their CO₂ emission share at the facility level and the CO₂ purity of their exhaust stream are given in Table S3. On the processing units where point-source capture is implemented, 90% capture of CO₂ is assumed. The collected data were used to develop cost estimates for capturing CO₂ from the major process units and evaluate the ability for these industrial emitters to qualify for the federal tax credit 45Q. A technology-agnostic cost model is used in the current work for estimating the costs of CO₂ capture for single-stream systems and is based on a previous model that was developed by the authors.34 More details regarding this cost model are given in the Supporting Information. Additionally, these point sources were mapped with the software ArcGIS (ArcMap 10.6) to determine the proximity to EOR operations and opportunities for dedicated geological sequestration projects. Distances between all sources and the nearest sink were determined using straight lines for pipelines and the Network Analyst toolbox for trucking and are used in the cost model. The overlay and proximity toolboxes were used to

Table 1. Breakdown of the Number of Facilities and Their Emissions by Industrial Sector, Type of Emissions, and CO₂ Capture Potential for all Industrial Facilities in the Contiguous U.S. (Nonsupplier of CO₂), Industrial Facilities Considered for Capture in This Study, and Facilities Qualifying for the 45Q Tax Credit

<table>
<thead>
<tr>
<th>refining a</th>
<th>chemicals</th>
<th>bioethanol</th>
<th>metals</th>
<th>minerals</th>
<th>pulp &amp; paper</th>
<th>total</th>
</tr>
</thead>
<tbody>
<tr>
<td>number of facilities</td>
<td>123</td>
<td>360</td>
<td>174</td>
<td>289</td>
<td>369</td>
<td>214</td>
</tr>
<tr>
<td>total emissions [Mt CO₂-eq/yr]</td>
<td>163</td>
<td>138</td>
<td>60</td>
<td>93</td>
<td>114</td>
<td>38</td>
</tr>
<tr>
<td>SC b [Mt CO₂-eq/yr]</td>
<td>101</td>
<td>70</td>
<td>19</td>
<td>55</td>
<td>30</td>
<td>28</td>
</tr>
<tr>
<td>PE c [Mt CO₂-eq/yr]</td>
<td>57</td>
<td>68</td>
<td>41</td>
<td>37</td>
<td>84</td>
<td>10</td>
</tr>
</tbody>
</table>

Facilities Considered for Carbon Capture Retrofit

| number of facilities | 97 | 104 | 174 | 118 | 163 | 0 |
| total emissions [Mt CO₂-eq/yr] | 163 | 82 | 60 | 73 | 96 | 0 |
| SC b [Mt CO₂-eq/yr] | 107 | 39 | 19 | 45 | 15 | 0 |
| PE c [Mt CO₂-eq/yr] | 56 | 39 | 39 | 27 | 81 | 0 |
| captured emissions [Mt CO₂/yr] | 40 | 26 | 37 | 19 | 72 | 0 |

Facilities Qualifying for the 45Q Tax Credit

| number of facilities | 75 | 62 | 155 | 37 | 129 | 0 |
| captured emissions [Mt CO₂/yr] | 39 | 24 | 36 | 17 | 71 | 0 |

aRefining category includes the emissions from the refining process and the hydrogen production at refineries. bSC = emissions from stationary combustion; PE = process emissions. cProcess emissions from the ethanol industry are not reported by the EPA, the total process emissions reported by the EPA would thus equal to 256 Mt CO₂/yr. In addition, this number excludes emissions from wastewater treatment and landfills that are not studied for point-source carbon capture in this work. Details are available in the Supporting Information.
perform a sensitivity analysis around pipelines and sedimentary basins.

## RESULTS

### Areas of Opportunity Associated with Top Emitting Industries

Emissions from refining (16.6%), bioethanol (14.4%), and cement manufacturing (22.5%) comprise just over half of the U.S. industrial process emissions of CO2 considered in this study. In particular, cement production and bioethanol represent unique opportunities because their process emissions are associated with a single reactor exhaust stream. Others, such as refining, or iron and steel production, are significantly more complex, having multiple exhaust streams, each with varying levels of CO2 concentration.

The total U.S. industrial emissions (including stationary combustion units) analyzed in the current study is approximately 606 MtCO2-eq/yr. Of these emissions, about half occur from the chemical processes themselves, whereas the remaining half occur in stationary combustion units. Facilities considered for CO2 capture retrofit emit 473 MtCO2-eq/yr, of which 242 MtCO2-eq/yr are process emissions. Each process has a unique potential for capture based on the flow rate and concentration of CO2 emitted. Capturing 90% of the emissions from the major process unit(s) only has the potential to reduce emissions by 195 MtCO2/yr (Table 1 and Figure S8). The major process units associated with each of the primary industrial emitters (i.e., cement manufacturing, bioethanol, refining, hydrogen production, ammonia production, and iron and steel production) are described in detail in the Supporting Information.

### Technology-Agnostic Cost Model for CO2 Capture from Streams of Varying Concentration and Flow Rates

The cost of CO2 avoided, measured in dollars per tonne of CO2 separated, compressed, and transported considers all fixed, variable, and capacity-related costs, in addition to discount rates and the effect of corporate income taxes that must be incurred in order to deliver one tonne of purified CO2. In general, the cost of separation represents 60–80% of the cost of CO2 avoided, with the transportation cost having the greatest variability because of the varying distances between source and sink. It is well-known that as the CO2 concentration increases in a given gas mixture and that the concentration of CO2 emitted. Capturing 90% of the emissions from the major process unit(s) only has the potential to reduce emissions by 195 MtCO2/yr (Table 1 and Figure S8). The major process units associated with each of the primary industrial emitters (i.e., cement manufacturing, bioethanol, refining, hydrogen production, ammonia production, and iron and steel production) are described in detail in the Supporting Information.

Technological Agnostic Cost Model for CO2 Capture from Streams of Varying Concentration and Flow Rates. The cost of CO2 avoided, measured in dollars per tonne of CO2 separated, compressed, and transported considers all fixed, variable, and capacity-related costs, in addition to discount rates and the effect of corporate income taxes that must be incurred in order to deliver one tonne of purified CO2. In general, the cost of separation represents 60–80% of the cost of CO2 avoided, with the transportation cost having the greatest variability because of the varying distances between source and sink. It is well-known that as the CO2 concentration increases in a given gas mixture and that the concentration and flow rates. Importantly, this approach allows for the adjustment of expected capture costs for the smaller scale emissions encountered in industrial facilities. As shown in Figure 3, the cost of CO2 capture is estimated for various industries, assuming 90% capture.

### Mapping Industrial Emission Sources and Potential Sequestration Opportunities

Figure 4 shows the geographical distribution and the magnitude of the 656 capture point sources and the underground injection opportunities, either for EOR or dedicated geologic sequestration. Sequestration opportunities in limestone and sandstone formations have capacities in the range of 740–1,800,000 MtCO2, adding up to 2,740,000 MtCO2 in the contiguous United States. The feasibility of CO2 sequestration in appropriate sedimentary formations, however, relies on the injectivity, which has been noted in prior work to be greater than 0.25 MtCO2/yr to avoid risks associated with low-injectivity reservoirs.37 For the opportunities presented in the current work to be realized, the levels associated with industrial emission sources must align with the rates of injectivity of the sequestration reservoirs. The injectivity has been calculated considering a single injection point at the centroid of each basin.38 However, the reality likely is different from this, the edges of the basin being on average 80 miles from the centroid and up to 500 miles for the largest basins (U.S. Gulf Coast). Injection project locations rely on multiple parameters including geology, surrounding sources of CO2, ownership of the land, regulatory constraints, and public acceptance.

In the contiguous United States, 656 facilities have the potential to capture 195 MtCO2/yr. Within these facilities, 458 facilities qualify for the 45Q federal tax credit, accounting for 188 MtCO2/yr (Figures 4 and S9). A majority of industrial facilities that have the ability to capture their process emissions are located above or close to sedimentary basins suitable for CO2 injection. In particular, 276 industrial facilities with the potential to capture 83.2 MtCO2/yr are co-located with sedimentary basins suitable for injection, of which 176 facilities (with a capture potential of 80.2 MtCO2/yr) are eligible for the 45Q federal tax credit. In addition, 281 facilities with a capture potential of 77.6 MtCO2/yr are less than 100 miles from a sedimentary basin, of which 172 facilities (with a capture potential of 74.4 MtCO2/yr) are eligible for the 45Q federal tax credit. In addition, 67 facilities with a capture potential of 17.0 MtCO2/yr are between 100 and 200 miles from a sedimentary basin, of which 57 facilities (with a capture potential of 16.5 MtCO2/yr) are eligible for the 45Q federal tax credit. The breakdown of the facilities and the corresponding capture potential by distance from the sedimentary basins are given in Table S4 along with the facilities qualifying for the 45Q federal tax credit.

Delivered Costs of High-Purity CO2 for EOR and Geological Sequestration Opportunities. Costs of delivered CO2 to EOR and dedicated geologic sequestration sites
have been considered with the inclusion of the federal tax credit 45Q for flows $\geq 100,000$ tCO$_2$/yr. An additional driver in the case of EOR is that operators today may pay between $27$ and $40/tCO_2$, which can help in deploying more capture projects. To determine the economic potential of carbon capture applied to the industry sector, separation, compression, and transport costs are included, which requires georeferencing industrial emission sources to the potential sinks, that is, EOR or geologic sequestration.

Average costs for delivery to EOR and dedicated geologic sequestration sites are displayed as deconstructed costs of compression, capture, and transport by mode in Figure 5. With the exception of bioethanol capture for which the cost of separation is assumed to approach zero (excluding compression and dehydration), the cost of capture does not vary significantly among these industries, with an average cost of $32/tCO_2$ avoided and a range from $24/tCO_2$ avoided (for capture from ammonia) to $47/tCO_2$ avoided (for capture from ethylene processing). The cost for compression is even less variable, typically falling within $\pm 1/tCO_2$ of the average cost of $10$ and $13/tCO_2$ avoided for compression to trucking and pipeline, respectively. Certainly, the cost incurred by transport is the largest variable and, in most cases, dominates the cost structure. With the exception of ammonia, the average cost for transport to EOR is higher than the cost for transport to dedicated sequestration. This is due to the isolated nature of viable EOR opportunities relative to more geographically distributed sequestration sites. However, it is important to consider that transport to sedimentary basins is currently modeled to a single injection point placed at the centroid of each injection basin; thus, it is crucial to further examine regional suitability for injection so that additional, viable

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**Figure 4.** Geographical distribution of the CO$_2$ capture opportunities from industrial point sources (closed circles) in the United States along with EOR and dedicated geological sequestration opportunities (open circles).

**Figure 5.** Abatement supply curve for CO$_2$ capture from the industrial sectors investigated in this study (a). Breakdown of the total costs and tax credit from the capture of CO$_2$ to its injection in the subsurface, for (b) EOR or (c) geologic sequestration. The total weighted average cost is given for the cheapest transportation option (truck or pipeline), along with the lowest calculated cost scenario for each type of industry.
injection points may be determined. This could have significant impacts on the cost of transportation associated with geologic sequestration.

**DISCUSSION**

**Ethanol: an Opportunity for Low-Cost Carbon Capture.** Ethanol manufacturing has the highest proportion of facilities situated far away from sedimentary reservoirs (Figure 4). For instance, roughly 75% of these facilities (i.e., 131 plants) do not lie above a sedimentary reservoir. More specifically, 43, 47, and 41 plants are located from 0 to 100 miles, from 100 to 200 miles, and over 200 miles from a sedimentary reservoir, respectively. Despite the fact that many of the ethanol plants are not located near EOR or geologic sequestration sites, their high-purity CO₂ byproduct stream makes this industry attractive because of the low cost of CO₂ capture. Understanding the costs of transport as described later in the study will provide insight into the true potential impact this industry may have in CO₂ capture and avoided emissions potential.

Because of the high-purity CO₂ stream, there are a number of ethanol plants that produce and sell CO₂ as a marketable product. Some of the CO₂ utilization opportunities outside of EOR include food, dry ice, beverage, metal welding, pH adjustment, and chemicals. The prices of CO₂ supply associated with EOR are normally indexed to West Texas Intermediate (WTI) crude oil prices. The EOR market uses roughly 68 MtCO₂/yr, with prices ranging from $27 to $40/tCO₂ at an oil price of $70/bbl. The EPA lists 28 ethanol plants as suppliers of CO₂ that have the ability to capture 6.30 MtCO₂/yr. Several projects exist to leverage the high-purity CO₂ stream from fermentation either for dedicated sequestration in sedimentary basins or for EOR. The largest producer of ethanol is located in Decatur, Illinois, and captures roughly 1.07 MtCO₂/yr. The CO₂ is subsequently stored in the Illinois Basin through the Illinois Basin Decatur Project, which has a total injection capacity of approximately 1 MtCO₂/yr. The State CO₂-EOR Deployment Work Group proposed two possibilities for a new pipeline from ethanol plants to EOR locations in the states of Kansas, Nebraska, and Iowa. Both projects’ costs have been calculated for a 22-year period including 2 years of construction and 20 years of operation. The first project involves 15 plants in Kansas and Nebraska that have the potential to capture 4.30 MtCO₂/yr. It is also reported that the project would have a CAPEX of $1.06B and an annual OPEX of $53M including the cost of capture and transportation via pipelines. The second project is more ambitious and involves 34 plants in Kansas, Nebraska, and Iowa, including 7 plants from the top 10 emitters from ethanol plants in the U.S. These plants have the potential to capture 9.85 MtCO₂/yr, and the CAPEX and annual OPEX estimates for this project are $2.67B and $131M, respectively. The Midwest region of the United States has the potential to be considered a “hub” for CO₂ capture and sequestration, similar to operations taking place in the Permian Basin and Gulf Coast regions.

**Carbon Hubs: Permian Basin and Gulf Coast.** Today, roughly 80% of the CO₂ used for EOR is naturally sourced from geologic reservoirs. Sourcing CO₂ from anthropogenic sources such as the industrial sector would improve the carbon footprint of oil production in the U.S. today. When CO₂ is injected for enhancing oil production, although it is recovered at the surface for reinjection, ultimately the original CO₂ is permanently stored in the earth. The way that EOR is carried out today results in net-positive CO₂ emissions. If EOR is carried out using avoided CO₂ rather than naturally sourced CO₂, the CO₂ footprint of the oil may be reduced. The utilization of CO₂ for EOR may be viewed as an opportunity to jump-start carbon capture and storage (CCS), but not as part of a long-term solution for achieving carbon neutrality.

The capture potential from industrial process emissions that qualifies for the 45Q tax credit is roughly 188 MtCO₂/yr (Table S4), which is significantly higher than the 68 MtCO₂/yr currently required for EOR in the United States or even the total CO₂ needs associated with all U.S. CO₂ utilization opportunities, that is, 80 MtCO₂/yr. Using solely anthropogenic sources to meet EOR needs in the United
States is thus technically feasible and would decrease significantly the carbon footprint of the oil refining industry. Figure 6 displays two regions in the United States (i.e., Permian Basin and Gulf Coast) where CO₂ pipeline infrastructure exists today, for the original purpose of transporting CO₂ from natural sources to EOR opportunities. The cost of trucking per tonne of CO₂ increases with increasing distance, it being roughly $5/tCO₂ for 20 miles, $9/tCO₂ for 50 miles, and $15/tCO₂ for 100 miles. Facilities closest to the pipeline would thus serve as attractive opportunities. The two hubs pictured in Figure 6 include 67 facilities within 20 miles of pipelines that are able to capture 26.2 MtCO₂/yr or 13.5% of the capture potential in the United States, 50 being eligible for 45Q with a capture potential of 25.7 MtCO₂/yr. An additional 32 and 17 facilities are located between 20 and 50 miles and between 50 and 100 miles from the pipelines, respectively. The breakdown of facilities and corresponding capture potential by distance from the nearest pipeline is provided in Table S4 for both Louisiana–Mississippi and Texas–New Mexico pipelines, along with the facilities eligible for the 45Q tax credit. Collectively, the two regions include opportunities for achieving roughly 40 MtCO₂/yr from industry-sourced anthropogenic emissions.

An optimal transportation network might look like a fleet of refrigerated trucks that gather high-purity CO₂ from regional clusters of low-volume capture operations (i.e., <0.25–0.30 MtCO₂/yr) and deliver them to central collection hubs and recompression stations. There, CO₂ would be stored in buffer vessels and recompressed from trucking conditions (low temperature and pressure) to that suitable for pipeline transport (high pressure). Because truck-delivered CO₂ must be recompressed prior to injection at some point in the supply chain, this regional hub would serve that step while boosting the transport volume and lowering the pipeline economics through economies of scale. Though there are incremental costs associated with buffer storage, it is likely that a collection-hub network complete with recompression would achieve lower overall costs of transport than any of the individual standalone source-to-sink pathways. However, further economic analysis is necessary to validate this cost mitigation potential.

Low-Cost Opportunities for a Fast Development of CCS in the Industrial Sector. Inspection of transport costs calculated for pipeline delivery reveals that, as expected, the cost of delivery is lower on average than that calculated for trucking. This is especially true for higher volume capture operations. However, in roughly two-thirds of the cases examined, trucking transport was the more economic option. This is due to the economies of scale associated with pipeline transport at volumes lower than 500 kt/yr. Unfortunately, at this scale, trucking—while more economical than pipeline—is still extremely cost-prohibitive (at ca. $0.15/tCO₂/mile, transportation costs alone often exceed $100/tCO₂ avoided). This result would suggest a need for local gathering or collection hubs that could be placed strategically to concentrate captured CO₂ before long-distance pipeline transport.

In light of proximity and volume (scaling) considerations, certain industrial capture opportunities surface as least-cost options. The least expensive transportation option for EOR and dedicated geologic sequestration are outlined in Figure 5b,c, respectively, for the weighted average cost and for the lowest calculated cost scenario of each type of industry. These figures also show the breakdown of the cost of CCS including capture, compression, transportation, and injection and MRV (monitoring, reporting, and verification), with the inclusion of the federal tax credit 45Q for qualifying streams. A flat $11/tCO₂ injection fee is included in these estimates to reflect additional capital and operating expenses associated with CO₂ injection and MRV. Importantly, all qualifying facilities receive the 45Q federal tax credit (2018 rate). While inclusion of injection fees allows for a more complete cost estimate, it is helpful to remove the flat injection fee for direct comparison of industrially sourced CO₂ to incumbent economics. The impact of 45Q together with large-scale, short-distance delivery to EOR is evidenced by 7 of 10 minimum cost scenarios falling at or below $40/tCO₂ delivered (when injection costs are excluded). This places several opportunities at or near the price range of CO₂ for EOR today.

Cost scenarios for dedicated sequestration are even lower, on account of the aforementioned lower costs of transport due to proximity relationships between targeted industrial facilities and geological sequestration sites, and the higher 45Q tax credit associated with dedicated sequestration. Here, 5 of 10 minimum-cost scenarios fall at or below $20/tCO₂ delivered, with one (ethanol) falling below zero (when injection and MRV costs are excluded) once the tax credit is applied. Overall, 123 facilities had a cost scenario that fell below the $40/tCO₂ threshold, with the majority of facilities classified under bioethanol (60), cement (28), and H₂ production (23). This corresponds to ca. 68.5 MtCO₂/yr of potential low-cost CO₂ emission abatement, with the majority coming from cement (28.6 MtCO₂/yr), hydrogen (12.9 MtCO₂/yr), and bioethanol production (12.4 MtCO₂/yr). It is important to note that the 45Q tax credit will continue to escalate through 2026, adding ca. $20 and $25 per tonne avoided on top of existing credits for EOR and sequestration opportunities, respectively. Further efforts to reduce transportation costs together with this increased tax credit could leave even more facilities in a position to profit from the strategic capture of process CO₂ emissions from the industrial sector.

**ASSOCIATED CONTENT**

*Supporting Information*

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.9b07930.

Carbon capture retrofit opportunities for the industrial sector; emissions considered from the industrial sector; cost model; industrial processes: chemical reactions; emissions of industrial sectors considered; descriptions of the industrial processes (cement manufacturing, bioethanol, refining, hydrogen production, ammonia production, and iron and steel production); emission reduction potential by the industrial sector; enhanced oil recovery and reliable geologic sequestration; and cost breakdown for truck and pipeline delivery (PDF)

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ABBREVIATIONS

CAPEX capital expense  
CCS carbon capture and storage  
EIA U.S. Energy Information Administration  
EOR enhanced oil recovery using CO₂  
EPA Energy Protection Agency  
EPM Ethanol Producer Magazine  
FCC fluid catalytic cracking  
GHG greenhouse gas  
IECM Integrated Environmental Control Module  
IGCC integrated gasification combined cycle  
IPCC Intergovernmental Panel on Climate Change  
MRV monitoring, reporting, and verification  
MtCO₂ million metric tonne of CO₂  
NEO Nebraska Energy Office  
NGCC natural gas combined cycle  
OPEX operating expense  
PC pulverized coal combustion  
RFA Renewable Fuel Association  
SMR steam-methane reforming  
tCO₂ metric tonne of CO₂  
WP1 West Texas Intermediate

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