Jumpstarting commercial-scale CO2 capture and storage with ethylene production and enhanced oil recovery in the U.S. Gulf

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Title: Jumpstarting commercial-scale CO_2 capture and storage with ethylene production and enhanced oil recovery in the U.S. Gulf

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Abstract

CO_2 capture, utilization, and storage (CCUS) technology has yet to be widely deployed at a commercial scale despite multiple high-profile demonstration projects. We suggest that developing a large-scale, visible, and financially viable CCUS network could potentially overcome many barriers to deployment and jumpstart commercial-scale CCUS. To date, substantial effort has focused on technology development to reduce the costs of CO_2 capture from coal-fired power plants. Here, we propose that near-term investment could focus on implementing CO_2 capture on facilities that produce high-value chemicals/products. These facilities can absorb the expected impact of the marginal increase in the cost of production on the price of their product, due to the addition of CO_2 capture, more than coal-fired power plants. A financially viable demonstration of a large-scale CCUS network requires offsetting the costs of CO_2 capture by using the CO_2 as an input to the production of market-viable products. We demonstrate this alternative development path with the example of an integrated CCUS system where CO_2 is captured from ethylene producers and used for enhanced oil recovery in the U.S. Gulf Coast region.

Introduction

> *"CCS is caught in a vicious cycle… Firms will not invest in CCS because it is financially risky; it is financially risky because public acceptance is low and there are big hurdles to large-scale deployment; and public acceptance is low because there is so little experience with CCS at a large scale." – William Nordhaus*[1]

CO_2 capture, utilization, and storage (CCUS) is a climate mitigation technology that can reduce industrial greenhouse gas (GHG) emissions by thousands of megatonnes of CO_2 annually (1000s $MtCO_2$/yr).[2] CCUS involves capturing and compressing CO_2 from stationary sources (e.g., coal-fired power plants), transporting the CO_2 in dedicated pipelines, and injecting and storing the CO_2 in geologic reservoirs (e.g., deep saline aquifers) and perhaps using that CO_2 to produce marketable products.[3, 4] CCUS is an essential component of the portfolio of approaches needed to reduce CO_2 emissions and stabilize the concentration of CO_2 in the atmosphere.[5, 6] At present, 68% of the electricity generated in the United States results from burning fossil fuels, more than half of which uses coal—the most CO_2 intensive source—as the primary energy resource.[7, 8] Implementing CCUS could enable a gradual transition to energy sources that emit less CO_2 per unit of energy while continuing to leverage the useful lifetime of existing energy infrastructure. CCUS is also pertinent for developing countries, such as China and India, that have or plan to rapidly expand their fleet of coal-fired power plants that will continue to emit CO_2 for many decades.[9] Ultimately, CCUS must be deployed at a "commercial scale," where many CO_2 sources (including hundreds of power plants) and geologic reservoirs are connected by an extensive network of dedicated pipelines.[10] (Several examples of individual power plants connected to geologic reservoirs already exist, including the Boundary Dam[11, 12] and W.A. Parish[13, 14] generating stations, but not multiple large power plants in a single network.)

Technologies for each step in the CCUS supply chain—CO_2 capture, transport, and injection/storage—have been implemented at commercial scale for several decades,[15] and multiple large (≥1 $MtCO_2$/yr) CCUS projects around the world are successfully demonstrating the performance of these technologies. Present projects include CO_2 capture from a range of industrial sources, including natural gas processing or stripping (e.g., Shute Creek, Wyoming;[16] Sleipner Vest, Norway;[17] Gorgon, Australia[18]), coal gasification (e.g., Beulah, North Dakota[19]), and biorefineries/ethanol production (e.g., Decatur, Illinois[20]). Five of the nine large operational integrated CCUS systems in the world are in the United States[21] (Figure 1), as well as the capture (Beulah, ND) for the Canadian storage project. But despite the importance and potential of CCUS, and the safe demonstration of individual CCUS projects, commercial-scale deployment of CCUS has not yet occurred.

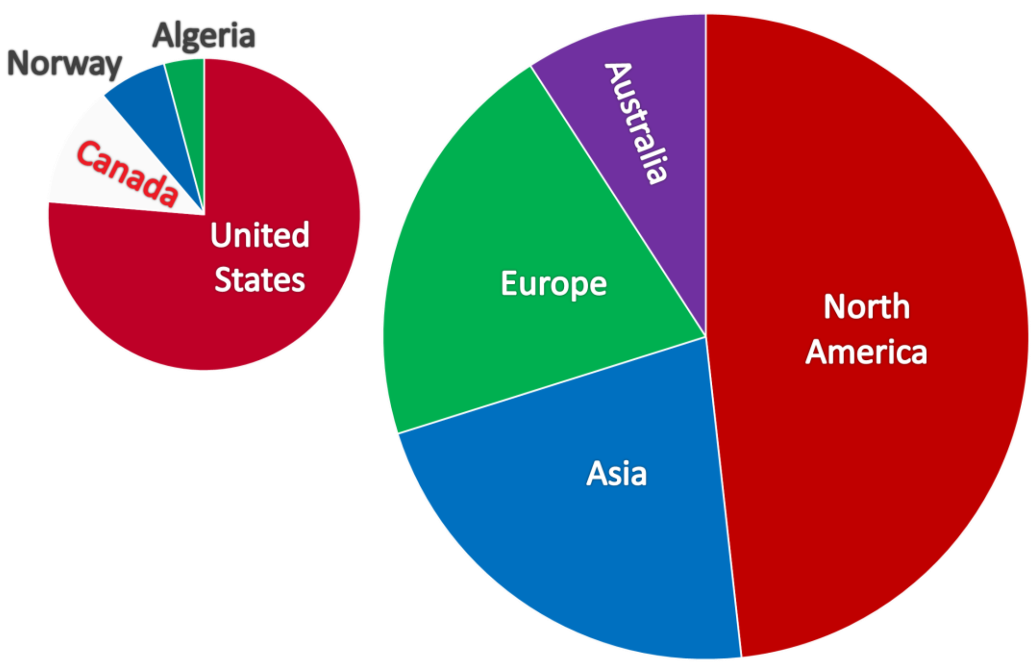

Figure 1: Distribution of currently operational (left, 24.08 $MtCO_2$/yr) and planned (right, 99.54 $MtCO_2$/yr) integrated CCS projects as of June 2013. Projects only include large coal (≥ 0.8 $MtCO_2$/yr) and large industrial (≥ 0.4 $MtCO_2$/yr) projects. The operational project in Algeria—In Salah—is now inactive.

Numerous barriers to CCUS deployment exist, including interlinked issues such as costs, public awareness and acceptance,[22] regulation and permitting,[15] and operational experience with large integrated CCUS systems.[15] To initiate near-term commercial-scale deployment of CCUS, a development path for an integrated system that handles 50-100 $MtCO_2$/yr is perhaps needed—roughly an order of magnitude larger than the 10 $MtCO_2$/yr emitted from a large coal-fired power plant. Accelerating CCUS deployment could be achieved by developing a highly visible and economically viable demonstration of a commercial-scale CCUS system that integrates multiple CO_2 sources and reservoirs. Implementing CO_2 capture increases general production costs; for coal-fired power plants this could result in a doubling of electricity prices for consumers. We suggest that systems that use CO_2 captured from facilities that produce high-value chemicals/products (HVCPs), such as ethanol or iron/steel production, can better absorb the expected impact on the price of their products.[23] Using this HVCP CO_2 to produce a marketable commodity further adds economic viability. Near-term pathways that focus on the development of such an integrated system would complement present investment approaches, which have focused on developing and demonstrating *new* technologies for two of the three stages in the CCUS supply chain: CO_2 capture and CO_2 storage. Our proposed pathway focuses on market-viable CO_2 capture from HCVP facilities—some of which are in industries that already provide CO_2 for use elsewhere—and the implementation of pipeline transportation like that which already exists for CO_2-based enhanced oil recovery (CO_2-EOR). We demonstrate our approach in a case study using *existing* technology to capture CO_2 from ethylene producers as well as for CO_2-EOR in the U.S. Gulf Coast region. Our perspective is to provide an overview of near-term market-viable opportunities to establish the operation of CCUS, as an integrated system, while other pathways for technology development are being pursued.

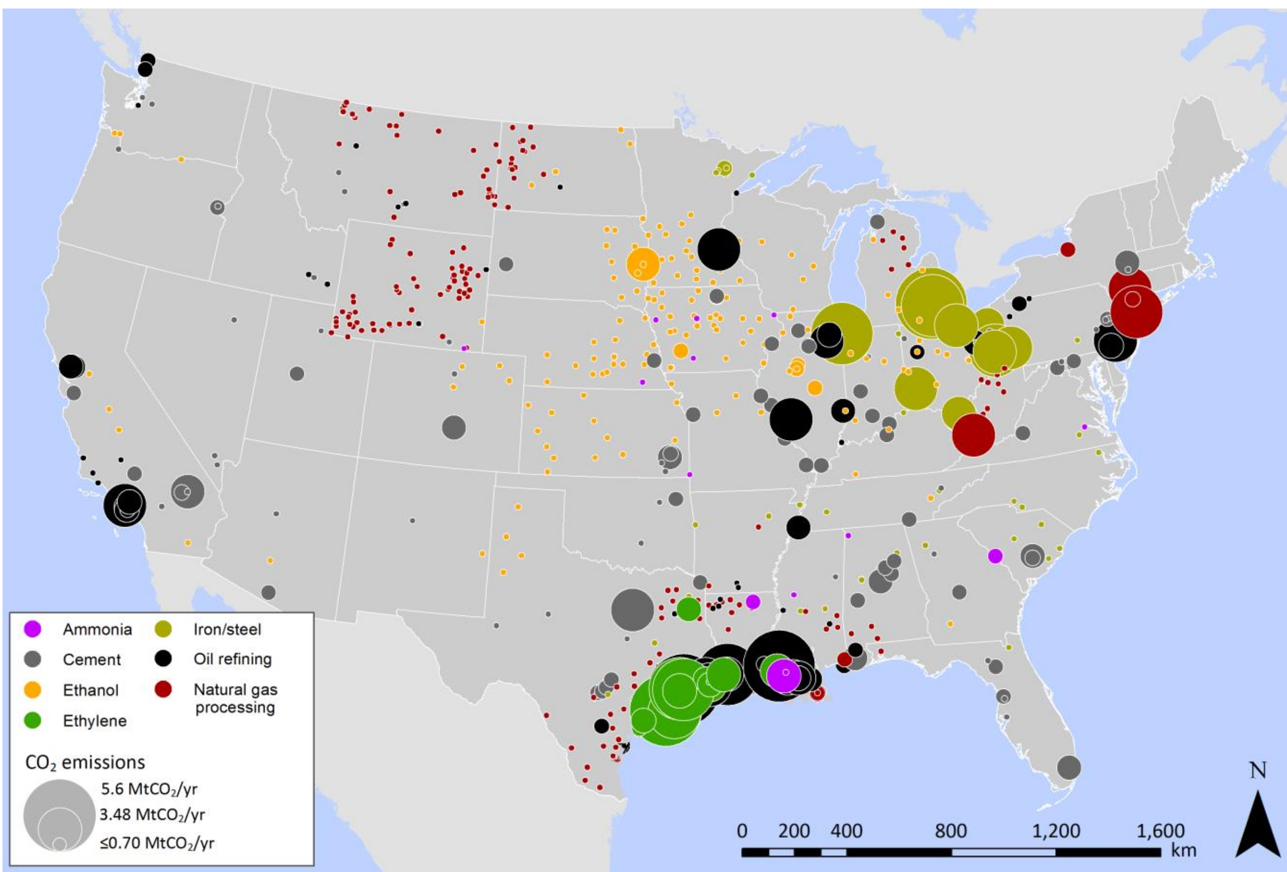

Figure 2: Spatial distribution of HVCPs in the United States.[24]

Table 1: Major sources of CO_2 in the US including production amounts, costs, CO_2 emissions, and impact of CO_2 capture. The table is based on major products highlighted in the NATCARB database.[24] Entries without a clear distinction in the NATCARB database (e.g., mining, general manufacturing, and agriculture)—a total of 30 $MtCO_2$*/yr emissions—are omitted from the table. Missing entries in the table denotes values that do not exist in the public domain.*

Product	Annual U.S. production	Representative cost (electricity) or price	Emissions ($MtCO_2$/yr)	Number of sources		Clustering (km from centroid[a])	Capture cost ($/$tCO_2$)	Cost/price increase (%)
				Total	>1Mt CO_2/yr			
Electricity (fossil/biomass)[b]	2783.3 TWh[25]	-	2394.4[25]	3314[25]	473[25]	-	-	-
Coal	1784 TWh[25]	$62-141/MWh[26]	1912.2[25]	560[25]	308[25]	835	29-51[27]	61-76[28]
Natural Gas	907 TWh[25]	$61-89/MWh[26]	431.7[25]	1416[25]	157[25]	1113	37-74[27]	37-57[29]
Biomass	68 TWh[25]	$87-116/MWh[26]	26.7[25]	560[25]	2[25]	635	-	42[30]
Oil & Petroleum Coke	25 TWh[25]	$68/MWh[30] [c]	23.9[25]	778[25]	6[25]	704	-	66[30]
Oil Refining[d]	15 MMbbl/d[31]	$92.02-104.67/bbl[e]	172.5[24]	308[24]	62[24]	1346	19-96[2]	1-6[28]
Cement	67.9 Mt[32]	$90/t[32]	85.7[24]	111[24]	30[24]	1258	46-80[2, 28]	39-52[28]
Iron/Steel	113.5 Mt[32]	$126/t[32] [f]	76.3[24]	88[24]	16[24]	434	>54[28]	10-14[28]
Ethylene	27.6 Mt[33]	$1040/t[34]	50.1[24]	25[24]	20[24]	124[g]	35-55	3-11
Ethanol	13.9 Bgal[35]	$1.95-2.55/gal[36]	49.3[24]	173[24]	3[24]	662	6-12[28]	1-2[h]
Pulp/Paper/Wood	75.3 Mt[32] [i]	-	22.4[24]	78[24]	6[24]	490	6-12[28]	-
Natural Gas Processing	16.3 Tcf[37]	$3.35/MCF[38] [j]	18.4[24]	144[24]	1[24]	350	16-21[28]	1[28]
Ammonia/Fertilizer	9.4 Mt[32] [k]	$585/t[32]	10.1[24]	21[24]	2[24]	381	10-20[28]	3[28]
Soda	10.7 Mt[32]	$147/t[32]	4.2[24]	5[24]	2[24]	7	-	-
Lime	19.1 Mt[32]	$112/t[32]	3.8[24]	10[24]	1[24]	621	-	-

[a] Clustering is calculated as the average distance between each CO_2 source and the centroid of all those sources from NATCARB.
[b] Includes "other" fossil fuels such as coke oven gas and tire-derived fuel.
[c] Inflated from 2006 to 2012 using CPI calculator but not changes due to oil price.
[d] Refining to gasoline/diesel.
[e] WTI monthly spot price range between January and July 2013 - http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm.
[f] Price for steel.
[g] Excludes one ethylene source in Pennsylvania.
[h] Assumes capturable CO_2 of 2.8 kg per gallon and $12/tco2 capture cost.
[i] Paper and board.
[j] Wellhead price.
[k] Tonnes of nitrogen content.

CO_2 capture from High Value Chemicals and Products (HVCPs) Production

Much of the effort for developing CO_2 capture technology has focused on fossil-fueled power plants, in part because of the size of the installed base. The CO_2 emissions from power plants form the majority of stationary CO_2 emissions in the United States.[24] In addition, CO_2 capture costs are estimated to comprise up to 90% of the CCUS supply chain costs, and CO_2 capture on fossil fuel power plants can increase the cost of production 50-100%, from $31-51/MWh to $43-72/MWh for natural gas power plants and $43-52/MWh to $62-86/MWh for coal-fired plants[27] (Table 1). The potential doubling of electricity prices has led public utilities commissions to reject CCUS plans due to unacceptable increases in the rate that consumers would have to pay.[39, 40]

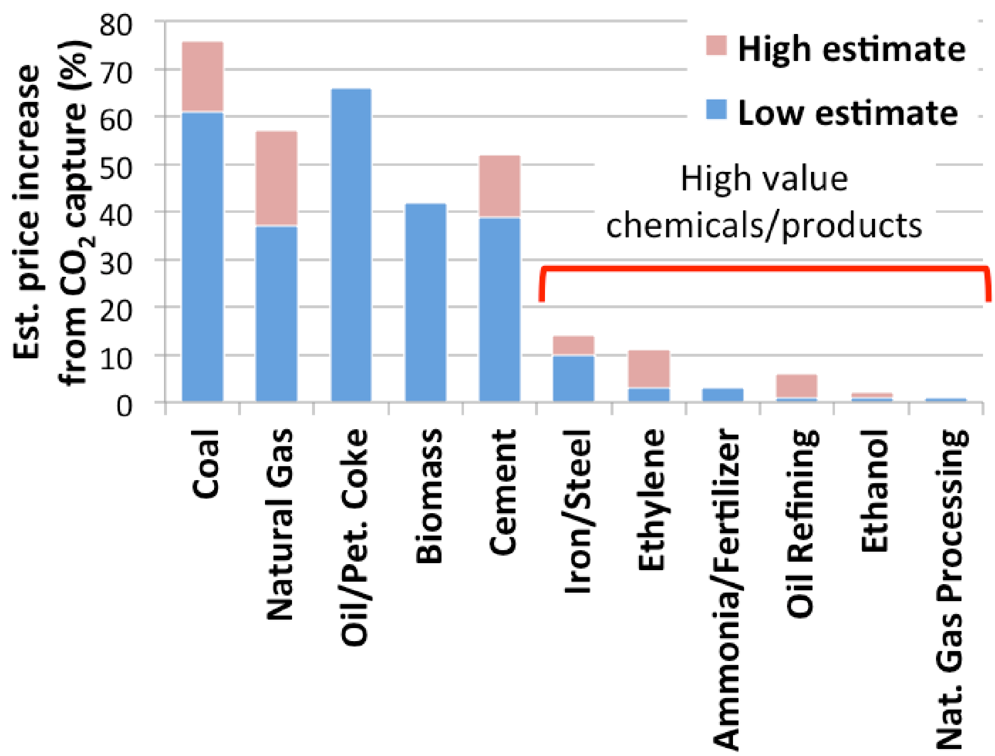

Figure 3: Estimated relative price increases due to CO_2 capture (last column in Table 1) are much lower for high value chemicals and products relative to fossil-fuel power plants.

As an alternative, CO_2 that is emitted from facilities that produce HVCPs could be attractive candidates for CO_2 capture. Four of these industries—oil refining, iron/steel production, ethylene manufacture, and ethanol production—each emit at least 50 $MtCO_2/yr$ (Table 1).[24] Collectively HVCP industries emit 360 $MtCO_2/yr$, which is roughly the same amount of CO_2 emitted by natural gas power plants. These HVCP facilities are located broadly throughout much of the non-mountainous portions of the United States (Figure 2). Most importantly, the estimated marginal increase in the cost of production is much lower for HVCPs than for power plants. In a competitive industry, where profit-maximizing firms should seek to set price equal to marginal cost, the estimated proportional increases in price for HCVP facilities range between 1-15%, which is substantially less than the estimated increases in the price of fossil-based electricity (Table 1, Figure 3).

HVCPs also enable targeted CO_2 capture to stimulate large-scale CCS. For example, as Figure 2 shows, ethanol facilities are distributed over the U.S. Midwest. These facilities currently emit around 50 $MtCO_2$/yr in aggregate, which is an amount sufficient enough to be the basis for a large-scale CCUS network without oversupplying CO_2. As a consequence, there would likely be a minimal impact on marginal price of CO_2 supplied for EOR. Facilities in other HVCP industries, such as ethylene manufacturing, are larger in size and more clustered in location, which provides logistical advantages for the establishment of an integrated CCUS system. For the remainder of this paper we use CO_2 capture from ethylene production facilities as one example of how an integrated network using CO_2 captured from HCVPs could stimulate commercial-scale CCUS.

Ethylene manufacture and CO_2 capture

Ethylene is used throughout the petrochemical industry. Almost 60% of the supply devoted to producing polyethylene for products such as packaging and plastic bags.[41] Ethylene is manufactured by steam cracking hydrocarbons including ethane, naphtha, propane, and butane.[42] The energy necessary for this cracking is provided by burning natural gas and other residual gases from the cracking process.[43] Worldwide ethylene production is greater than 140 Mt/yr, with production concentrated in three countries: the United States (27.6 Mt/yr)[44], Saudi Arabia (13.2 Mt/yr), and China (13.0 Mt/yr)[33] (Figure 4). In the United States, ethylene facilities are clustered in the Texas and Louisiana Gulf Coast region (Figure 5), largely due to feedstock availability. These U.S. facilities emit approximately 50 $MtCO_2$/yr.[24]

We are not aware of literature that estimates CO_2 capture costs specifically for ethylene facilities. Since a detailed facility-level systems analysis is outside the scope of this paper, we approximate these costs by the similarity of the flue gas CO_2 concentration and pressure to that of coal-fired power plants (12% vs. 12-15% by volume, 1 bar[2, 45]). As a result, CO_2 capture costs for ethylene facilities are broadly similar to those for coal-fired power plants, approximately \$35-\$55/tCO_2.[27] Manufacturing one tonne of ethylene produces between 1 tCO_2 (ethane feedstock) to 2 tCO_2 (naphtha feedstock)[46], and each tonne of CO_2 costs \$35-\$55/tCO_2 to capture. Ethylene prices reached \$1500-\$1800/t between 2008 and 2012, and typically are around \$1000/t.[47] At a lower price of \$1000/t, these increases in costs translate into an additional \$35-\$110/t of ethylene. Assuming that ethylene markets are competitive and therefore priced at their marginal cost, CO_2 capture would add 3.5 to 11% to the price of ethylene. Consequently, CO_2 capture from ethylene production results in a much lower increase in price than for fossil fueled electricity generation. For example, electricity prices from natural gas and coal are expected to increase prices by 55-70% (Table 1).

From the market perspective, individual facilities and their owners should be concerned about the competitiveness of their products. The modest estimated increase in costs when CO_2 is captured is only a small portion of the price of the ethylene from facilities that do not capture CO_2. As a result, CO_2-capturing ethylene facilities should not be at a competitive disadvantage. In addition, ethylene is typically used as an input to other processes and products within complex supply chains. The price elasticity of demand for ethylene is low because there are no feasible substitutes, and as a result the marginal increase in cost is unlikely to affect the margins of other producers and suppliers. Further, cost increases for inputs will pass through these supply chains, but demand elasticities and efficiencies throughout the supply chain between the ethylene manufacturer and the public will mitigate this increase to the public. As a result, the public is unlikely to directly experience increased costs, which is in sharp contrast to electric utilities that will visibly pass on costs to consumers in their electricity bills.

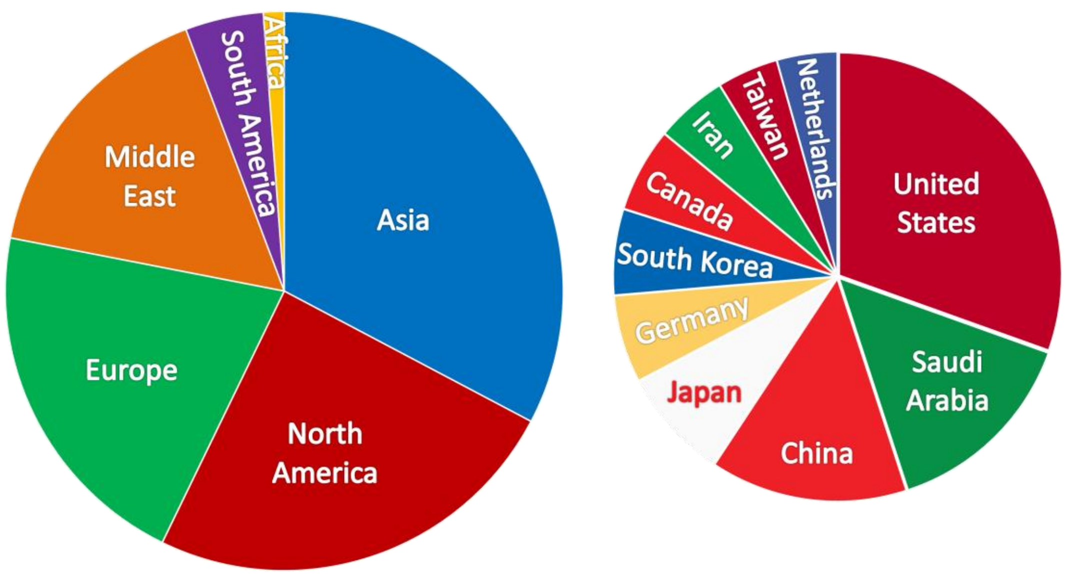

Figure 4: Distribution of ethylene manufacturing by continent (left, 141 Mt/yr) and top ten producing countries (right, 91 Mt/yr).

In addition to the modest increase in costs and expected prices due to CO_2 capture, ethylene manufacturing facilities are more clustered than any other major CO_2-emitting industry, and 20 out of 25 sources in the region emit >1 $MtCO_2$/yr, a higher proportion than any other major CO_2 emitting industry (Table 1). Assuming that fixed and operating costs do not exhibit increasing marginal costs with increased facility size, these economies of scale suggest that larger sources are more attractive candidates for CO_2 capture than are smaller sources. The combination of substantial CO_2 emissions (50 $MtCO_2$/yr), a small increase in price, and sources that are clustered together, make CO_2 capture from the U.S. ethylene industry a promising avenue for stimulating regional-scale CO_2 capture.

CO_2-Enhanced oil recovery (CO_2-EOR)

CO_2-EOR produces oil by injecting large volumes of CO_2 and water into depleted oil reservoirs. This tertiary production technique typically produces an additional 4-15% of the original oil in place (OOIP) on top of primary and secondary techniques that produce about 30-35% of the OOIP.[48] CO_2-EOR in the United States accounts for 46% of the oil produced by EOR processes.[49] Next generation CO_2-EOR technologies could recover 22% or more of the OOIP, resulting in production of up to 60% of the OOIP by primary, secondary, and tertiary means.[48] At present, about 4% of domestic U.S. oil production is by CO_2-EOR.[48] In 2012, there were 120 active CO_2-EOR projects in the United States that produced more than 352,000 bbl/d of oil[49] and purchased about 60 $MtCO_2$/yr.[50] Some of the CO_2 that is injected for CO_2-EOR will be produced with the oil, but most of this produced CO_2 is recycled and re-injected. As a consequence, the amount of CO_2 that is purchased ends up being stored in the reservoir, even if it is re-used multiple times.

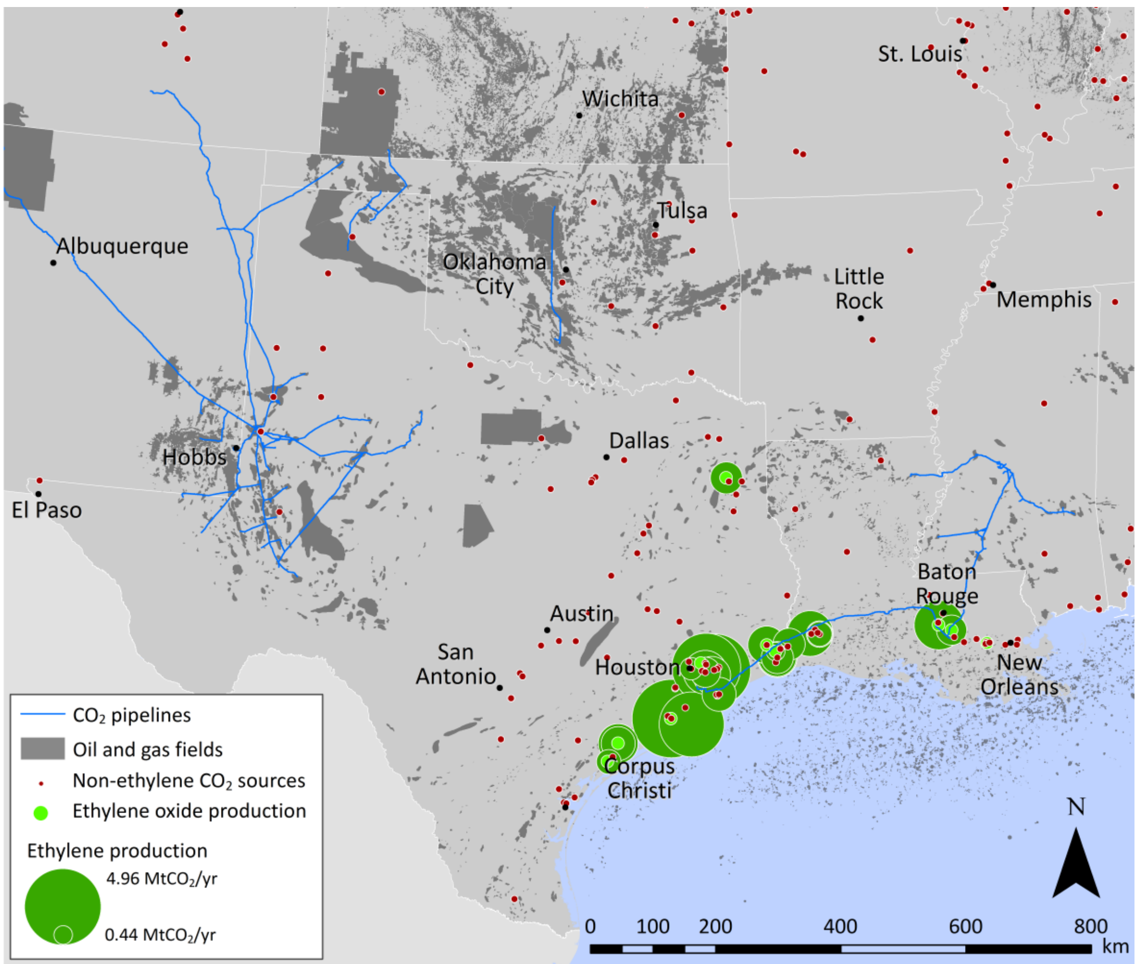

Figure 5: Ethylene and ethylene oxide production, major non-ethylene sources of CO_2, existing CO_2 pipeline transportation network, and oil & gas fields in the western U.S. Gulf Coast region and surrounding areas.[51]

The key goal of CCUS is to reduce the amount of CO_2 emitted to the atmosphere. However, about three quarters of the CO_2 used for CO_2-EOR is extracted from natural geologic deposits[50] in a process that relocates naturally occurring CO_2 from one subsurface location—where it would have remained isolated from the atmosphere indefinitely—to another. Only one quarter of the CO_2 that is used for EOR is captured from industrial sources. Using this "byproduct" CO_2, which is normally vented to the atmosphere, instead of "extracted" CO_2, is the only way that EOR can reduce net CO_2 emissions to the atmosphere on a life cycle basis.[50] The majority of the byproduct CO_2 used for EOR is sourced from natural gas processing facilities where CO_2 is be stripped from produced gas in order to meet pipeline specifications. Using byproduct CO_2 can reduce the net amount of CO_2 emitted to the atmosphere.[52] For example, byproduct CO_2-EOR can reduce the wells-to-wheels emissions compared with conventional oil production by 25-60%.[53]

Purchase prices for EOR-ready CO_2 (i.e., including CO_2 capture, purification, compression, and delivery/transportation costs) are \$28 to \$52/tCO_2 for oil prices of \$60 to \$110/bbl.[54] Oil prices below \$60/bbl will likely have a commensurate drop in CO_2 prices, though long-term crude prices are likely to substantially rebound. One common CO_2 price relationship suggests EOR operators are prepared to pay 2.5% (in \$/Mcf) of the Western Texas Intermediate (WTI) oil price (\$/bbl);[55] at an oil price of \$100/bbl this is equivalent to \$47/tCO_2. At this price, CO_2-EOR offers a substantial incentive for high-purity CO_2 sources to capture their emissions (e.g., ethylene oxide, ammonia, and biorefineries with capture and compression costs of less than \$20/tCO_2) as well as significantly offsetting costs for more expensive capture technologies (e.g., fossil fuel power plants and oil refineries). And because EOR operators can sign up to 20 year CO_2 supply contracts,[55] CO_2-EOR has the potential to reduce CO_2 emissions over the medium to long term.

With present technology, CO_2-EOR may reduce the CO_2 footprint of U.S. transportation fuel in the short and medium term, assuming that CO_2-EOR gasoline is displacing conventional gasoline. For example, the one-third reduction in life cycle CO_2 emissions through CO_2-EOR relative to conventional gasoline[53] is approximately the same as that from compressed natural gas (CNG) vehicles (~6-30% reduction[56-58]) and first-generation biofuels (~3-20% reduction,[59, 60]). Similarly, the CO_2-EOR gasoline footprint compares well with the one-third reduction in CO_2 emissions by hybrid electric vehicles (HEVs)[61] and plug-in hybrid electric vehicles (PHEVs) using a typical balance of electricity sources in the United States.[61]

With larger quantities of cost-effective CO_2 from HVCPs and the appropriate market incentives, greater quantities of CO_2 could be used in the EOR process. At present, CO_2 is an input to EOR operations that optimize for oil production, but it is possible to co-optimize CO_2 storage and oil production if the incentives are in place to value sequestering CO_2 from the atmosphere.[62] A typical CO_2-EOR operation uses roughly equal amounts of CO_2 and water whereas a pure CO_2 flood can increase production use and store larger quantities of CO_2.[62-64] Furthermore, primary and secondary oil production techniques can reduce ultimate recovery rates (e.g., formation of gas caps, trapped water). With appropriate sequestration incentives and cost-effective supplies of CO_2, primary and secondary production techniques could be skipped entirely, potentially enhancing total oil production while sequestering large volumes of byproduct CO_2.

Regional-scale CO_2 transportation

A large and integrated pipeline network is necessary to demonstrate an integrated CCUS system, connecting spatially dispersed, reliable, and market-viable supplies and demands of byproduct CO_2. Integrated pipeline networks minimize construction and operation costs for CO_2 transportation because economies of scale and utilization are be significant. [65] 7[51] Existing pipelines carry large volumes of extracted CO_2, such as the approximately 1000 km Cortez pipeline running from Colorado to West Texas for EOR; these pipelines are already at capacity. Industry has planned or established several basic CO_2 pipeline networks, including those that allow byproduct CO_2 suppliers to join the network.[66-68] Multiple efforts have developed detailed models to optimize integrated CCUS systems,[69-74] including examining an hypothetical pipeline network that links byproduct CO_2 from ethylene manufacturers with EOR reservoirs; CO_2 transport costs were estimated to be \$5-6/tCO_2.[51] Such a pipeline system could be constructed with a combination of public (federal and/or state government) and private investment.[75] Obtaining right of ways (ROWs) can be barrier to constructing extensive pipeline systems, but policy and regulatory agencies could accelerate permitting processes, as has been done for renewable energy generation projects,[76, 77] and a combination of public and private investment,[75] could focus investment on ROWs that are robust to *a priori* uncertainties in where byproduct CO_2 may be captured and where it may be used.[77]

Ethylene:CO_2-EOR

The challenge is to develop a large, commercially viable, and fully integrated system to build awareness and acceptance, reduce the cost of CO_2 capture through technological learning, and gain familiarity with byproduct CO_2 capture in business models. Byproduct CO_2 from ethylene manufacture is not presently used for CO_2-EOR, but the availability of large and clustered sources and the demand for CO_2 for EOR suggests that a commercially viable, large-scale integrated CCUS system could be deployed in the U.S. Gulf Coast and neighboring regions (Texas, Louisiana, Mississippi, New Mexico, Oklahoma, and Kansas). Specifically, ethylene manufacturing could be an appropriate case study because the facilities are much more geographically co-located than any other major CO_2 source (see the clustering column in Table 1; this would likely enable a lower-cost pipeline network to be constructed as well as potential collaboration among ethylene facilities). The region has experience with large-scale oil and gas operations, a history of ROW development, pipeline safety, and public acceptance, pipeline transportation and use of CO_2. Several oil fields in the region already use byproduct CO_2 from the chemical industry. These and other projects indicate the capacity to handle complex siting, liability, investment, and permitting issues. The preferred development pathway would be for ethylene byproduct CO_2 to initially complement the reliance on extracted CO_2 for EOR. The system would grow from individual ethylene facilities connected to individual EOR reservoirs to large-scale integrated clusters of multiple facilities. The CCUS pipeline network initiated with ethylene:CO_2-EOR could then be the backbone for a network that evolves to incorporate byproduct CO_2 from other industries and ultimately coal-fired and natural gas power plants. Our previous research has shown that it can be cost-effective to overbuild pipeline capacities and underutilize CO_2 transportation for a decade or more to enable the seamless integration of future CO_2 sources.[78] The experience with byproduct CO_2 capture could stimulate CO_2 capture investment on the numerous other byproduct CO_2 sources in the region—including fossil fuel power plants and oil refineries (Figure 5)—to eventually entirely displace extracted CO_2 for EOR.

Developing an ethylene:CO_2-EOR network would have significant challenges, notably the potential difference between a CO_2 capture and transport costs of \$50-60/tCO_2 and a byproduct CO_2-EOR purchase price of \$28-52/tCO_2. This difference could theoretically be profitable (-\$12/tCO_2), though even the most unprofitable difference (+\$32/tCO_2) only increases a \$1,000/t ethylene price by 3.2% (assuming that it is priced at marginal cost). Investment to provide byproduct CO_2 from ethylene facilities could also be a component of an initiative to reduce emissions from the industry, much like the approach in Houston, Texas that has targeted non-CO_2 emissions from a variety of chemical plants including facilities that crack ethane to produce ethylene.[79] A CO_2 tax or a cap-and-trade program that imposes a sufficient cost on emitting CO_2 could also encourage an integrated ethylene:CO_2-EOR system. A targeted CO_2 regulation—similar to the difference in treatment under proposed U.S. Environmental Protection Agency standards for CO_2 emissions from natural gas-fired turbines and coal-fired units[80]—could be implemented. And recently, Petra Nova has demonstrated the economic viability of installing post-combustion CO_2 capture technology at its 240 MW W.A. Parish (Thompsons, Texas) coal-fired generating station, where 1.4 MtCO_2/yr is used to produce approximately 15,000 barrels of oil a day;[13, 14] through a partnership with the EOR operation, the CO_2 capture process is, without further subsidization or incentives, profitable. SaskPower's Boundary Dam carbon capture project has also successfully integrated CO_2 capture retrofit coupled with EOR.[11, 12]

CO_2 prices may fluctuate, and the competitive market price for CO_2 could decrease if the total supply of CO_2 from ethylene of other HVCP manufacturers increased faster than an increase in demand. But the possibility of collapsing the market price for CO_2 is low, in part because the unfulfilled demand for CO_2 for CO_2-EOR is larger than ethylene could ever supply.[28] Further, the market for CO_2 may not be perfectly competitive, in part because of the infrastructure needs to supply CO_2, and the present undersupply of CO_2 in the Permian Basin may be inflating the prices that EOR operators are securing in their contracts.[81] For an asset such as an oilfield to be considered a reserve, oil production must be feasible; the present undersupply of CO_2 for EOR would not be considered an undersupply if the economically viable production of the resource was sensitive to prices that change as a function of changes in CO_2 supply. In addition, CO_2 supply is only likely to exceed demand for EOR when the quantities of byproduct CO_2 from coal-fired and natural gas power plants are in the system. Such widespread CO_2 capture is only likely to occur in the long term and with credible and robust commitments to CO_2 emissions reductions, the regulation of which should also apply to emissions from HVCPs.

Making CCUS a reality in North America and beyond

An ethylene:CO_2-EOR network would leverage favorable cost, engineering, and location factors in order to stimulate commercial-scale CCUS: clustered large CO_2 sources that could be captured at low cost, product prices that can absorb the increased costs with little if any impact on competitiveness, proximity to strong and consistent demand for CO_2, and a favorable business and regulatory environment. Such a network could reduce CO_2 emissions by as much as 50 $MtCO_2$/yr while producing 200 million bbl/yr of lower-carbon oil.[81] A 50 $MtCO_2$/yr system is equivalent to taking 10 million cars off the roads[82] and would be capturing, transporting, and storing more than twice the amount of byproduct CO_2 in CCUS projects worldwide (Figure 1).[21] Other HVCPs also have similarly favorable characteristics, including iron and steel, oil refining, and, although less clustered, ethanol (Table 1). The oil refining industry is particularly attractive because the industry is experienced with CO_2 removal through the oil-sweetening process, and oil refineries and oil fields are already connected by pipelines. Although the CO_2 capture cost at oil refineries (\$19-96/tCO_2) could be higher than the CO_2 purchase price for EOR, recent research suggests that capturing CO_2 from the largest emitting components of the refining process is economically feasible.[83, 84] Principally, an integrated network based on ethylene or other HVCP byproduct CO_2 would provide a visible and economically viable CCUS demonstration that can increase public awareness and acceptance of CCUS as a climate change mitigation technology.

An HCVP:CO_2-EOR system could serve as a point of departure for other projects in North America and beyond. For example, the CO_2 footprint of Alberta oil sands production, which has a wells-to-tank CO_2 intensity 70-110% higher than typical U.S. transportation fuels,[85] could be reduced by using the CO_2 in nearby EOR fields.[86] Shale gas, which has led to a low-cost lower-carbon energy boom in the United States, could also provide a large potential for CO_2 injection/fracturing[87, 88] and storage[88, 89] from commercial-scale CO_2 emission sources. France, whose CO_2 emissions are largely from non-electricity sources, also provides a relevant case study for developing CCUS using HCVPs.[77] China also has substantial opportunities for HCVP byproduct CO_2-EOR systems. China's ethylene production is projected to approximately double to 25.5 Mt/yr by 2015,[90, 91] and China is actively developing and deploying coal-to-liquids technology. The goal of this development is to increase oil production, but the inherent gasification process produces a stream of almost pure CO_2[92] that could be used for CO_2-EOR. A Chinese coal-to-liquids:CO_2-EOR system could stimulate commercial-scale CCUS without external incentives.

Overall, a CCUS network based on byproduct CO_2 from HVCPs could reduce CO_2 emissions in the near term while leveraging the market viability of CO_2 capture when implemented on HVCP facilities and when the captured byproduct CO_2 is used for EOR. Deploying this large-scale system is potentially possible in the U.S. Gulf Coast, where numerous large and clustered sources of CO_2 as a byproduct of ethylene production as well as EOR opportunities are present. Such a visible integrated system can increase public awareness and demonstrate an approach that reduces CO_2 emissions while complementing existing CCUS technology development strategies.

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