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Supplementary Information for

Infrastructure to enable deployment of carbon capture, utilization, and storage in the United States

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Emissions Estimation

Estimated emissions from all sources are included in Dataset S1 Source Emissions. Estimation of emissions for each source type is detailed in the following sections.

Ethanol

Ethanol fermentation generates a gas stream that is greater than 99% CO_2 once moisture is removed (1, 2). CO_2 emissions from ethanol fermentation are not reported to the EPA Greenhouse Gas Reporting Program (GHGRP) because they come from a biogenic source. The Renewable Fuels Association and Nebraska Government Energy Office report facility-level ethanol production capacity (3, 4) and aggregated ethanol production data (5). The data show that aggregated ethanol production in 2016 and 2017 was approximately 95% of total nameplate production capacity. We therefore estimated output for each facility as 95% of its nameplate capacity. The data of facility locations and capacity were updated as of January 2018.

The associated CO_2 emissions were calculated from ethanol production volumes using the stoichiometry of the fermentation process, consistent with the EPA emissions estimation methodology for ethanol fermentation (6). The ethanol fermentation chemical reaction is:

$$C_6H_{12}O_6 \rightarrow 2\ C_2H_5OH + 2\ CO_2$$

One mole of CO_2 is produced for each mole of ethanol. The mass of CO_2 produced can be calculated by a straightforward conversion from the reported ethanol production volumes. Final reported ethanol production volume includes the volume of the denaturant that is added to the ethanol, which contributes approximately 2% of the volume, so an adjustment was required to determine the fermented ethanol production volume. The final equation used to estimate CO_2 emissions from each ethanol biorefinery facility was:

$$E_{CO2}\ (tonnes) = CF \times V_E \times \frac{100 - Den\%}{100} \times 3875 \frac{m^3}{10^6 gal} \times \rho_E \times \frac{MW_{CO2}}{MW_E} \times \frac{1}{1000} \frac{tonne}{kg}$$

where:
E_{CO2} = CO_2 emissions (tonnes per year)
CF = Plant capacity factor (assumed 95%)
V_E = Plant ethanol production capacity (millions of gallons per year)
$Den\%$ = Percentage of denaturant in final ethanol volume (assumed 2%)
ρ_E = Ethanol liquid density (789 kg/m^3)
MW_{CO2} = Molecular weight of CO_2 (44 g/mol)
MW_E = Molecular weight of ethanol (46 g/mol)

Hydrogen

Hydrogen produced in the United States is dominantly (~95%) by the steam methane reforming (SMR) process (7-9). CO_2 emissions arise from two parts of the SMR process. One stream is from the process chemical reactions (the syngas), while a second stream is from gas combusted to provide heat to the process reactor and to generate steam for the process. There are three possible capture locations in the process: two points within the process stream, and one at the flue gas stack where the process and combustion emissions are combined (see Figure S1 below). The flue gas stack (point 3) offers the ability to capture all CO_2 from the process, but the CO_2 concentration and partial pressure is much higher at the two possible capture points in the process stream and therefore cheaper. Capture of a smaller proportion of total emissions from the process stream has been favored in hydrogen projects to date. Both literature (8-10) and deployed hydrogen carbon capture projects indicate that point 1 is the lowest-cost capture point. The Port Arthur (11, 12) and Quest (13, 14) hydrogen projects capture at point 1, between the water-gas shift and hydrogen pressure swing adsorption, which has the highest CO_2 partial pressure in the process stream. The proportion of CO_2 emissions from the SMR system in the process stream at point 1 depends on the exact design of the system (particularly the steam-to-carbon ratio), but is around 40-70% for typical designs (9). The plant design of Meerman*, et al.* (8) captured 66% of total system emissions by capturing the process stream, while an IEAGHG (10) techno-economic evaluation included 56% capture. A basic estimate of the Port Arthur facility capture rate gives 56% capture (total capture amount divided by reported total production emissions for the facility to GHGRP) (11, 15).

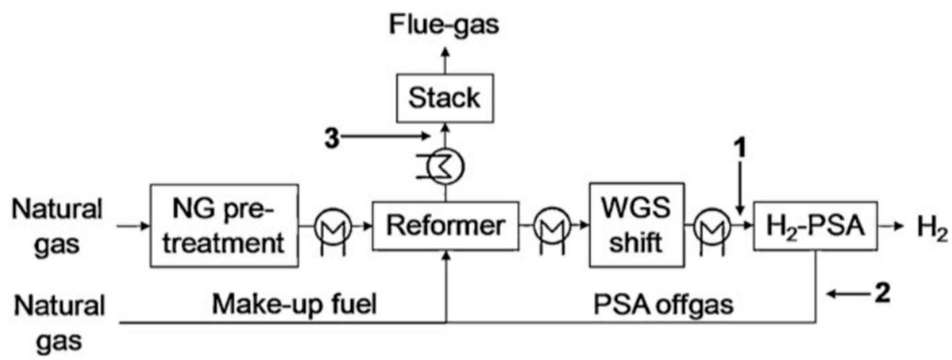

Figure S1. The hydrogen steam methane reforming process showing potential CO_2 capture points (Fig. 2 from Meerman*, et al.* (8)).

The EPA GHGRP reports emissions from hydrogen production for individual facilities (15). The GHGRP regulation 40 CFR Part 98 Subpart P requires reporting of CO_2 emissions from each hydrogen unit, described in §98.163. The reported emissions include both the process and combustion emissions associated with each hydrogen production unit. Therefore, we need to modify the reported emissions to reflect only the low-cost-capture process stream. As a simple estimate, we assume CO_2 available for lowest-cost capture at each hydrogen production facility as 50% of the reported hydrogen production emissions. We used 2016 reported hydrogen emissions (the most recent available).

The CO_2 capture process requires additional energy/heat. This leads to increased electricity and gas consumption and therefore increased CO_2 emissions when carbon capture is added to hydrogen production. However, the increase is relatively small (~14% in Meerman*, et al.* (8)), and not relevant for this study because we are only interested in the proportion of reported emissions that can be captured to determine a capture CO_2 quantity.

Ammonia

Most ammonia in the United States is produced from natural gas feedstock, with SMR used to produce hydrogen, and then the Haber-Bosch process to produce ammonia (16). CO_2 emissions from ammonia production are therefore essentially hydrogen production emissions, described in the preceding section. However, unlike hydrogen production, ammonia production has another factor to consider in determining the additional low-cost CO_2 capture opportunity. The dominant use of ammonia is to make fertilizers (around 90% of total production), and the most common direct use is for urea synthesis (55% of ammonia production) (16, 17). Urea is synthesized by combining ammonia with CO_2, where the CO_2 is sourced by capture from the hydrogen production process stream. Assuming 50% of ammonia production from a particular plant is used for urea production, the stoichiometry of the hydrogen, ammonia, and urea synthesis reactions dictates that 38% of the hydrogen process stream CO_2 production would be consumed in urea synthesis. This is consistent with the reported industry average of 36% CO_2 capture from the ammonia synthesis hydrogen production process stream (18).

There is likely to be heterogeneity between capture opportunities at different facilities depending on their particular production focus (i.e. urea versus other fertilizer types). However, since the major ammonia production facilities within the region of interest in Kansas and Oklahoma already capture CO_2 to supply CO_2-EOR and therefore are excluded from the analysis, and since there are only small, insignificant ammonia plants within the upper Midwest region, we simply assume the industry average 35% of CO_2 emissions from the hydrogen process stream are used for urea synthesis, and that 65% remains available for other uses.

The GHGRP regulation 40 CFR §98.72 indicates that emissions reported in the GHGRP under ammonia production are essentially the SMR process emissions for hydrogen production, but are not reported in the hydrogen production category whenever integrated with ammonia production. Using the same assumptions described in the preceding hydrogen section, we assume that 50% of the total reported ammonia production emissions are low-cost capture process emissions, and based on the information above we assume that 65% of the process CO_2 is available for additional capture. Therefore, we assume 33% of total reported CO_2 emissions associated with ammonia production are available for capture. The United States ammonia production industry reports that 33% of total CO_2 emissions associated with ammonia production are currently captured (19)

Natural gas processing

CO_2 emissions reported under the "Petroleum and Natural Gas Systems Onshore Natural Gas Processing" industry segment of the GHGRP represent CO_2 separated from natural gas, which are highly concentrated CO_2 streams (20). Correspondingly, natural gas processing sources were the earliest, and remain the dominant, existing anthropogenic CO_2 source captured for use in EOR. Available CO_2 for capture is assumed to be the total reported to the GHGRP. However, the Midwest region of interest for our analysis does not contain any significant natural gas processing CO_2 sources, so these sources are irrelevant and we do not estimate capture costs.

Other sources

Other source categories: Significant amounts of relatively concentrated CO_2 may be emitted by petrochemical production (for example, ethylene or methanol production (21)), petroleum refining, pulp and paper production, and lime production, but the reported emissions in the GHGRP from these source categories include multiple processes and combustion sources. Therefore, it is not possible to resolve and determine reasonable estimates of concentrated low-cost-capture CO_2 emissions at the facility level for these sources. There are also few of these sources in the study region compared with ethanol fermentation emissions. The highest concentration of these sources is along the Gulf Coast, where there are existing CO_2 pipelines. Therefore, we excluded these sources from our analysis.

Capture Cost Estimation

Ethanol

Ethanol fermentation produces a 99% pure CO_2 stream once moisture is removed (the fermenter outlet stream contains up to 3% water by weight) (22). The fermentation gas outlet stream only needs to be collected, dehydrated, and compressed for pipeline transport (22-24). Three ethanol biorefineries currently capture CO_2 at large scale for EOR or dedicated storage (2).

We used the ethanol capture cost model developed by the State CO_2-EOR Deployment Workgroup (2). The model estimates capital and operating costs based on public information from two Department of Energy-funded demonstration projects and with input from sources with direct project experience (2, 25). They developed a linear model for ethanol capture project capital costs:

$$\text{Capital cost (\$ million)} = 0.15 \times \text{Plant capacity (million gallons ethanol per year)} + 9$$

We compared the capital cost model with costs for the ADM Decatur phase 1 project reported by McKaskle (25) and a techno-economic analysis of a reference facility by NETL (20). The comparisons are shown below in Table S1. The model over-estimates costs in both comparisons. We consider the as-built costs from McKaskle, for which the over-estimation is smaller, to be more indicative than the NETL desktop analysis, and we consider the model performance acceptable for our analysis.

Table S1. Published ethanol capture capital cost data compared with the model estimates.

Cost source	Facility size (tonnes CO_2 per year)	Cost (*year*) ($ million)	Cost (2018 $ with 2% inflation rate)	Model cost estimate (2018 $)
McKaskle (25)	143,000	20.3 *(2010)*	23.8	29.6 (+24%)
NETL (20)	365,000	10.0 *(2011)*	11.5	17.1 (+49%)

The State CO_2-EOR Deployment Workgroup model operational cost was a constant $8.58 per tonne of CO_2 for all facilities. McKaskle reported operational cost of $11.11 per tonne averaged over the first three years of operation of the Decatur project, with the dominant cost component the electricity for compressors (25). During the early project life there are likely to be additional startup costs and learning improvements; therefore, we did not consider this data point sufficient to use directly as our model operational cost, but we slightly increased the model operational cost. We adopted the following operational cost model, assumed to be constant for all facilities:

Operational cost = $9.00 per tonne CO_2 captured

Hydrogen and ammonia

Information on hydrogen capture costs is available from existing demonstration projects, including the Shell Quest project and Air Products Port Arthur project, and from desktop techno-economic studies of carbon capture from hydrogen production. We developed our hydrogen capture cost model based on the existing demonstration projects, while considering the desktop analyses for context. Carbon capture from ammonia production captures CO_2 from the SMR hydrogen production and therefore is technically the same as hydrogen capture. However, ammonia facilities may already capture CO_2 for use in subsequent urea synthesis, which may make additional carbon capture capacity less expensive because a capture facility would be built regardless. Correspondingly, several ammonia production facilities already supply CO_2 commercially to EOR projects. We could not find any specific information on ammonia capture costs, however, so we conservatively assumed that ammonia capture costs are equivalent to hydrogen capture costs. This decision has negligible impact on our analysis because there are very few CO_2 emissions associated with ammonia in the study area.

The Shell Quest project is a carbon capture retrofit project that uses amine chemical absorption to capture CO_2 from hydrogen production. Shell reports detailed cost information as a condition of its public funding in Canada (13). Shell data give capital costs for each year in the 6-year capital expenditure period, with detailed breakdown of costs by category and component of the project (capture, storage, pipeline, and tie-in to the existing facility). Since our case applies only to the capture facility and retrofit/tie-in with the existing facility, we remove the storage and transport component costs. We include the overhead Shell labor and commissioning costs, which are substantial (~18% of total capital costs) and apply to all components of the project, but we scale those costs by the capture facility proportion of total capital costs. Shell does not include the front-end engineering design (FEED) costs in their total project capital sum. Since other companies may not operate this way, we have included the FEED costs in our total cost sum. The costs are presented in Canadian Dollars, and Shell state that almost all of their costs were incurred in Canadian Dollars. We converted the costs to US Dollars by applying the average exchange rate for each year of the capital expenditure as published by the IRS (26). Shell stated that the same project could be completed for 20-30% lower cost today due to a variety of improvements (27). Therefore, we have assumed the lower-end estimate of a 20% cost saving for a subsequent project. We apply this discount only to the capital cost, since the operational costs are dominated by labor and energy costs that will likely not be reduced as significantly. We divide our total estimated capital cost for a subsequent project by the capture capacity (tonnes of CO_2 per year) of the Quest project to determine a capital cost per tonne of capture capacity. We used this cost per tonne of capacity as our hydrogen capture cost model. At 1.2 million tonnes of CO_2 per year, the Quest project is relatively large scale compared to the hydrogen capture opportunities in the area of analysis and likely has economy of scale cost advantages over smaller projects. However, given we do not have any data with which to quantify the economy of scale, we have not explicitly considered project scale in our cost model.

Detailed operational costs are also reported for the Quest project. Similarly to capital costs, we removed the costs associated with the pipeline and storage components of the project and converted the capture-related costs to US Dollars. The total annual operational cost was divided by the quantity of CO_2 captured to determine an operational cost per tonne of CO_2 captured. Operational costs were available for 2015 and 2016, but we adopted the cost for 2016 since it was the first full year of operation.

Air Products' Port Arthur hydrogen plant project uses vacuum pressure swing adsorption. Only the capital cost of the project is publicly available (12, 28). The capital cost is almost identical to our estimated "next project" cost based on the Quest project cost data. We therefore employed a capture cost model based on the Shell Quest project data:

Capital cost = $368 per tonne-per-year capture capacity

Operational cost = $13.70 per tonne CO_2 captured

A simple levelized cost calculation assuming 15% rate of return and a 20-year project life gives $72 per tonne capture cost (or $56 per tonne at 10% rate of return). Hydrogen capture is therefore too expensive to be sufficiently compensated by the tax credits and EOR sales, and hydrogen and ammonia sources are eliminated in the first network iteration.

The CO_2 capture requires additional energy/heat. The Port Arthur capture installed a new 28 MW cogeneration plant for 1 Mt p/a capture. However, hydrogen is often produced at petroleum refineries and other integrated industrial facilities where there may be waste heat available. In these cases, the energy penalty and therefore cost of CO_2 capture may be reduced (8). The heat and steam production and therefore natural gas consumption costs play a key role in the capture costs (50-80% at ~$8.5/GJ) (8). Costs are therefore likely to be heterogeneous between locations. We assumed a conservative case for a standalone SMR unit, but it is possible that some hydrogen facilities may have cheaper capture opportunities.

IEAGHG (10) performs a techno-economic analysis on carbon capture from SMR hydrogen production for a hypothetical new build plant in Europe. Costs with and without carbon capture are compared and options for carbon capture at various points in the system are considered. Consistent with other studies, it finds that the lowest-cost capture option is from the process syngas stream after the water-gas shift and before the hydrogen pressure-swing adsorption. CO_2 avoidance cost under European reference case conditions was found to be €47.1 per tonne of CO_2 avoided. (Avoidance cost is not the directly relevant comparison, since there is no price on positive emissions, but the difference is small—Meerman*, et al.* (8) found a 14% cheaper capture versus avoidance cost). However, key parameters for the analysis are significantly different for the US compared to Europe, including natural gas price and electricity prices. Also, the cost includes a €10/tonne storage cost, which is not applicable in the case of EOR. The study presents sensitivity analysis graphs that allow adjustment according to the relevant key cost parameters for the US. Adjusting natural gas price from the assumed €6 per GJ to the U.S. 2017 average around $3 per GJ (€2.75 based on IRS published average exchange rate for 2017 of 1 USD = 0.923 Euro (26)) decreases cost by €3.3 per tonne. Adjusting industrial electricity price from the assumed €80 per MWh to the average north central U.S. industrial price of $70 per MWh (from EIA November 2017 published industrial electricity price, equivalent to €65 based on 1USD = 0.923 euro) decreases cost by €3.3 per tonne. Removing the CO_2 storage component decreases cost by €10 per tonne. The adjusted avoidance cost is therefore €47.1 – €16.6 = €30.5 per tonne. This is equal to US $33 per tonne based on the average 2017 exchange rate. This cost may indicate cheaper carbon capture opportunities for new build hydrogen plants compared with the example demonstration retrofit projects, but since our analysis applies to retrofit cases and since the examples are actual as-built costs, we use the cost model based on the Quest project.

Natural gas processing

We did not estimate capture cost for natural gas processing, since there are minimal emissions from this source type within the study area. Natural gas processing emissions were ignored.

Carbon Dioxide Pipeline Transport Model

We used the US Department of Energy FE/NETL CO_2 transport cost model (29-31). The model is a dual engineering and cost model that calculates the required CO_2 pipeline design (pipeline diameter, number of pump stations, energy requirement) based on engineering input parameters including the pipeline length, flow rate, and required inlet and outlet pressures. The model also estimates the cost of the pipelines using a choice of three different pipeline cost sub-models and calculates required pipeline tariffs using a discounted cash flow financial model. The model is intended to provide screening-level costs that are accurate to +50/-30%. We selected the sub-model options that produced the most similar output costs compared with two reported as-built projects and industry rule-of-thumb costs.

Pipeline costs for all network iterations and pipeline financing scenarios are summarized in the Dataset S4 Pipeline Cost Summary spreadsheet.

Cost sub-model selection and validation

The model gives three choices for the underlying cost equations (cost sub-models). These include the pipeline cost equations developed by Parker (32), McCoy and Rubin (33), and Rui. The model user guide provides comparison with published data for capital costs of two recently completed CO_2 pipelines, which show that the cost equations of Parker and McCoy and Rubin are closest to actual costs (31). Parker (32) tends to somewhat overestimate costs, while McCoy and Rubin (33) tend to underestimate costs (34). We conducted further comparison of the models with the published cost data, shown in Table S2 below. These comparisons confirm that the Parker model gives more accurate costs, with modeled cost consistent with one project, but around 40% higher than another.

Table S2. Published CO_2 pipeline data compared with different cost sub-model options in the FE/NETL transport cost model. The model project contingency factor was set at 0%

Green pipeline, Gulf Coast, 314 miles length, 24-inch diameter, 12.6 Mt CO_2 per year				
	2010 (completion year)		2018 (escalated at 2% in model)	
	Capital cost	Specific cost per inch-mile	Capital cost	Specific cost per inch-mile
Reported actual	\$660m - \$884m	\$88,000 - \$117,000		
Model (Parker)	\$653m	\$87,000	\$765m	\$101,000
Model (McCoy Southwest)	\$241m	\$32,000	\$283m	\$38,000
Model (McCoy Midwest)	\$347m	\$46,000	\$406m	\$54,000
Greencore pipeline, Wyoming, 232 miles length, 20-inch diameter, 11.2 Mt CO_2 per year				
	2013 (completion year)		2018 (escalated at 2% in model)	
Reported actual	\$270m - \$285m	\$61,000		
Model (Parker)	\$400m	\$86,000	\$441m	\$95,000
Model (McCoy Central)	\$155m	\$34,000	\$172m	\$37,000
Model (McCoy Midwest)	\$228m	\$49,000	\$252m	\$54,000

The model user guide also includes a table of rule-of-thumb costs from Kinder-Morgan for CO_2 pipelines in different terrains, which were sourced from a 2009 presentation (31): \$50,000 per inch-mile for flat, dry terrain, and \$85,000 per inch-mile for mountainous terrain. Escalated to 2018 dollars by general inflation, these would be around \$60,000 and \$100,000, respectively. Kinder Morgan's proposed long-distance Lobos pipeline was estimated to cost \$88,000 per inch-mile in 2014 (35). A recent CCUS-focused publication stated that the CO_2-EOR industry rule-of thumb for pipelines is \$100,000 per inch-mile (2). This rule-of thumb cost is 15% lower than the \$118,000 per inch-mile median cost of all pipeline segments in our network modeled using the Parker model. An important factor to consider in this comparison is that the pipeline cost per inch-mile is lower for larger-capacity trunk pipelines (which the project cost data relate to), and higher for smaller-capacity feeder pipelines. We should therefore expect a higher median cost per inch-mile for our full network of large and small-capacity pipelines compared with specific large pipeline costs (like the Lobos example above). General conclusions are difficult to make with only two as-built project cost comparisons. However, considered together, the cost information supports the conclusion that the Parker (2004) model is closest to real-world costs, and that it may overestimate pipeline capital costs by around 10-20%.

Another key difference between the cost model of Parker compared with McCoy and Rubin is that the McCoy and Rubin model shows strong economies of scale for pipeline cost per unit *length* as pipeline length increases, while the Parker model does not (different from the fundamental pipeline economy of scale with diameter.) Knoope, Ramírez and Faaij (36) rev iewed CO_2 pipeline cost models and found that raw cost data from FERC for oil and gas pipelines in the United States show that economies of length scale are important for pipeline lengths less than around 50 km, but there are minimal economies of length scale above 50km. The McCoy and Rubin model gives strong economies of scale at all length scales, which appears to be a major departure from real-world observations. The Parker model has minimal economies of scale with length beyond 50km.

The changing cost with pipeline length is an important element of our analysis for determining the feasibility of the feeder pipelines connecting facilities to the trunk pipeline. We compare the Parker model and McCoy and Rubin models for a test case feeder pipeline transporting 0.5 million tonnes of CO_2 per year for several pipeline lengths below 200km in Table S3 below. The Parker model shows decreasing capital cost per inch-mile for pipelines up to 50km, but negligible decrease beyond. The McCoy and Rubin model shows continuing economies of scale. The Parker model therefore appears to better match the observed behavior. The costs in Table S3 also support the prior conclusion that the Parker model gives costs that are slightly high, while the McCoy and Rubin model underestimates costs.

Table S3. Comparison of modeled pipeline capital costs using the Parker (32) and McCoy and Rubin (33) cost models for a pipeline with a capacity of 0.5 million tonnes of CO_2 per year, for varying pipeline lengths.

Pipeline Length (km)	Parker		McCoy and Rubin	
	Capital cost	Specific cost per inch-mile	Capital cost	Specific cost per inch-mile
5	\$5.6m	\$220,000	\$3.5m	\$140,000
10	\$8.5m	\$172,000	\$4.8m	\$96,000
25	\$17.2m	\$139,000	\$8.1m	\$66,000
50	\$31.9m	\$128,000	\$13.3m	\$53,000
100	\$60.9m	\$122,000	\$22.3m	\$45,000
200	\$120.0m	\$121,000	\$39.0m	\$39,000

We therefore used the Parker cost sub-model. We set the capital cost contingency parameter in the FE/NETL model to zero (reduced from the default 15%) for two reasons: 1) The Parker model was developed using as-built pipeline costs, and 2) the Parker model appears to over-estimate project capital costs based on comparisons with the limited number of available as-built CO_2 pipeline costs and industry rule-of-thumb costs.

Engineering parameters

The required engineering input parameters for the model are pipeline lengths, flow rates, and required inlet and outlet pressures for each pipeline segment. The model calculates the cost and required tariff for each individual segment of the pipeline network. Segments are defined by sections of the network with constant flow rate (i.e. segments are separated at junctions of pipelines and where capture facilities feed CO_2 in to the network). Pipeline segment lengths were calculated directly from the ArcGIS network output, and flow in each section was calculated based on the sources contributing to each pipeline segment. More details on these calculations are provided in the Network Analysis Methodology section.

The main trunk pipeline sections were calculated separately to the remaining pipelines in the network. The methods for trunk pipelines and the remaining pipelines are explained below.

Trunk pipeline segments:

1. Determine the main trunk (highest flow) sections and observe the flow rates in each segment of the trunk. Pick out significant breaks in flow rate between segments, and group segments between the breaks as single trunk sections.
2. Calculate the pipeline design, cost, and tariffs for each trunk section using the FE/NETL transport cost model (Dataset S2 Pipeline cost model spreadsheet). Each trunk section is modeled with uniform trunk flow rate equal to the maximum flow in each section. A linear pressure gradient was assumed across the entire main trunk pipeline from 1,400 psi at the Permian Basin destination (a typical oilfield delivery pressure) to 2,100 psi at the most upstream trunk end in Illinois (a typical compressor outflow pressure). Each section within the trunk has inlet and outlet pressure calculated based on its length and position (chainage) in the full trunk pipeline.
3. Distribute the full cost and tariff for each trunk section amongst the constituent segments, based on the proportional lengths and flow rates in each trunk segment compared with the whole trunk section. These calculations are shown in Dataset S4 Pipeline Cost Summary.
4. Check that the sum of the tariff revenue for each trunk segment is equal the tariff revenue needed for the full trunk section.

All other pipeline segments:

1. Calculate all segment costs and tariffs individually using the network version of the FE/NETL model (Dataset S3 Pipeline cost model_network spreadsheet). A standard pressure loss is calculated for each segment, based on segment length and flow rate. (Absolute pressures could be calculated based on the pressure at the trunk connection point, but this is less important than the change in pressure for pipeline segment design.) The implemented equation to determine the design pressure loss for each segment was:

   Pressure loss (psi) = 6 × length of pipeline (miles) × pipeline capacity (millions of tonnes CO_2 per year)

   Note that this is not a hydraulic pressure loss equation; it gives the amount of pressure loss that the pipeline will be designed for (using hydraulic equations) in each segment.

Treatment of the trunk segments was differentiated from the other pipeline network segments for a few reasons: 1) By designing the trunk pipelines as a whole, we can implement a more realistic engineering design with consistent pressure profile through the entire trunk pipeline, consistent pipe diameter through large sections, and with appropriate pump station design considering the entire trunk as a hydraulically connected system. This would not occur if trunk segments were considered individually. 2) This approach results in most trunk segments being slightly over-sized, so the network is designed with some additional capacity expansion potential. This is also a slightly conservative cost assumption. 3) Trunk segment pipeline design (diameter and number of pump stations) is sensitive to whether the trunks are considered as a whole or as individual segments, while the design of the smaller feeder pipeline segments that constitute the rest of the network is insensitive to pressure loss. The smaller pipelines were insensitive because they have little flow or pressure loss and therefore mostly do not need pumps, and because most have calculated required diameters well below the minimum pipe diameter that can be assigned in the model, so a large change in flow rate or pressure loss is needed to change the design diameter.

Other model parameter selections

We set the pipeline capacity factor at 100% since the capacity factor parameter scales the design flow rate capacity of the pipeline (a lower capacity factor leads to a higher design peak flow rate so that the specified total quantity of CO_2 can be transported each year within the operational time). We are interested in pipeline total flow capacities and not on a fixed amount of CO_2 to be transported in a given year, so we set the capacity factor to 100%

The required pipeline tariffs are only slightly sensitive to the length of the capital expenditure/construction period due to the influence of cash flow discounting. We adopted 4 years capital expenditure period for all pipelines. Costs are shown in Table S4 for different pipeline engineering parameters and capital expenditure periods using the Parker (2004) model.

Table S4. Sensitivity of required pipeline tariffs to capital expenditure period, for three different sets of pipeline engineering parameters.

(\$ per tonne CO_2)	Capital expenditure period		
Pipeline parameters	2 years	3 years	4 years
10km, 0.5 Mt/year	\$1.37	\$1.40	\$1.43
100km, 2 Mt/year	\$2.95	\$3.01	\$3.09
500km, 20 Mt/year	\$4.26	\$4.35	\$4.45

The pipeline financial analysis is more sensitive to the capital payback period/project financial lifetime. Our full commercial financing scenario assumed 12-year payback period, consistent with the tax credit duration, while we assumed that the government would take the post-tax credit policy risk and enable 20-year payback period for the commercial-government and full government financing scenarios. The impact of changes in payback period is shown in Table S5.

Table S5. Sensitivity of required pipeline tariffs to capital payback period, for three different sets of pipeline engineering parameters.

(\$ per tonne CO_2)	Capital payback period		
Pipeline parameters	12 years	20 years	25 years
100km, 2 Mt/year	\$4.74	\$3.60	\$3.32
1000km, 20 Mt/year	\$14.34	\$10.95	\$10.09

Pipeline financial analysis modifications

We modified the discounted cash flow financial analysis in the FE/NETL model to reflect recent changes in tax law as part of the Tax Cuts and Jobs Act of 2017. The taxation calculation was modified to prevent negative tax and to enable carry forward of losses. We added explicit debt calculation and payback schedule, rather than the integrated weighted average cost of capital (WACC) structure that the default FE/NETL model uses. With the explicit debt calculation, we also added explicit interest deduction in the taxation calculation and included the new limits on interest deductions introduced by the Tax Cuts and Jobs Act of 2017. Interest deductions will be limited to 30% of earnings before interest and tax (EBIT) from 2022 onward, compared to previous law where all interest was deductible (there will be a less stringent transition arrangement from 2018 to 2021, but we used the post-2022 rules since any pipeline project lifetime will be mostly or completely after 2022). Associated with our explicit debt calculation modification, we modified the free cash flow calculation to reflect the cash flow to equity only. All modifications are indicated in the Dataset S2 Pipeline cost model spreadsheet (our modified version of the FE/NETL model).

The overall result of our modification was to modestly increase the tariff required for CO_2 transport, mainly because interest tax deductions are limited in the modified model but implicitly 100% deducted in the original model. Table S6 shows the difference for two example pipelines.

Table S6. Comparison of required tariffs to achieve the same rate of return using the original FE/NETL model financial analysis and our modified financial analysis.

Pipeline parameters	Pipeline tariff ($ per tonne CO2)	
	Original FE/NETL model	Modified financial analysis
100km, 2 Mt/year	$3.05	$3.32
1000km, 20 Mt/year	$9.30	$10.09

Pipeline financing scenarios

The financial parameter assumptions for each financing scenario are listed in Table S7. The three pipeline financing scenarios are:

Full commercial – Assumes a fully commercial project developed by a corporate pipeline developer. Assumes 50/50 debt/equity finance partition and that debt is procured on typical commercial debt market terms. The financial parameters were chosen so that the weighted average cost of capital was 8.3%, a typical rate for major oil and gas pipeline companies (37).

Commercial-government – Assumes a project developed by a corporate pipeline developer with 50/50 debt/equity finance partition, but with the entire debt portion financed by a government entity. We modeled the debt interest rate on the DOE Loan Program, which offers debt at an interest rate around 1% above the US Treasury bond rate. We assumed the government entity provides 20-year finance and accepts all risk of post-tax credit policy, so the pipeline developer sets tariffs with certainty that it will continue to receive income after the tax credits expire (e.g. the developer receives a government guarantee, or extended tax credits or new policies give sufficient support for capture projects to continue).

Full government – Assumes the project is developed by a government-financed entity with 100% government debt finance at the 20-year US Treasury bond interest rate.

Table S7. Financial parameter assumptions for each of the pipeline financing scenarios.

Parameter	Full commercial	Commercial-government	Full government
Debt and equity percentage	50% / 50%	50% / 50%	100% / 0%
Equity target IRR	12%		3.5% (debt rate)
Debt interest rate	6%	4.5% (US Treasury 20-year bond 5-year max. plus 1% - similar to DOE Loan Program rate)	3.5% (US Treasury 20-year bond 5-year maximum. For context, current rate ~3%)
Corporate tax rate	24% (including federal, state, local)		
Inflation rate	2% for all inputs		
Depreciation schedule	MACRS 150% declining balance, 15-year recovery period		
Project start year	2020		
Capital spending duration	4 years		
Financial lifetime / capital payback period	12 years (duration of tax credits)	20 years	20 years

The impact of the different financing scenarios on required tariffs for different sets of pipeline design parameters is shown in Table S8. The ratios of tariff differences for each financing case are very similar for all pipeline design parameters. The average full commercial to commercial-government tariff ratio is 0.724. The average full commercial to full government tariff ratio is 0.459. In implementing the different financing scenarios, we use the full FE/NETL model to calculate tariffs for the full commercial scenario, and then use these average conversion factors to convert tariffs to both of the other financing scenarios. This saves considerable time that would be involved in repeatedly calculating tariffs for each financing scenario using the full model.

Table S8. Comparison of pipeline tariffs for different sets of pipeline design parameters under each pipeline financing scenario.

($ per tonne CO_2)	Pipeline financing scenario		
Pipeline parameters	Full commercial	Commercial-government *(proportion of full commercial case cost)*	Full government *(proportion of full commercial case cost)*
10km, 0.5 Mt/year	$2.18	$1.59 *(0.729)*	$1.03 *(0.472)*
100km, 0.5 Mt/year	$15.30	$11.07 *(0.724)*	$6.97 *(0.456)*
100km, 2 Mt/year	$4.74	$3.41 *(0.719)*	$2.12 *(0.447)*
200km, 5 Mt/year	$5.24	$3.80 *(0.725)*	$2.41 *(0.460)*
1000km, 20 Mt/year	$14.34	$10.38 *(0.724)*	$6.56 *(0.457)*

Capture Facility Financial Analysis

The capture facility financial analysis model used a discounted cash flow analysis based on the FE/NETL CO_2 Transport Cost Model financial analysis (31). The financial analysis model is the Dataset S5 spreadsheet. The model calculates the required CO_2 sales price for a capture facility to achieve a specified rate of return, given the capture facility capital and operating costs and the pipeline tariff the capture facility must pay to transport its CO_2 to its destination. The capture facility capital and operating cost models described in the Capture Cost Estimation section were implemented in the financial analysis model. We automated the financial analysis to read in the pipeline tariff (which was calculated by the pipeline cost model) for each capture facility, and we created a macro to solve for the required CO_2 sales price.

Carbon capture facilities are treated as chemical manufacturing facilities for tax purposes and use 5-year MACRS depreciation (38). We used the corporate tax rate from the Tax Cuts and Jobs Act of 2017. An important tax assumption was that the asset depreciation and net operating losses can offset other taxable income for the project owners. This tax offset value is relatively small for most plants (see main text Figure 5), but it is larger for marginal sources that have higher net cash operating losses. For these plants, the tax offset value is up to \$7.90, or around 15% of total effective revenue. This value is significant for the viability of marginal plants.

We assume that ethanol capture facility construction begins in 2022 with 2 years construction/capital expenditure period, and that hydrogen capture facility construction begins in 2020 with 4 years construction/capital expenditure period. These start dates were chosen to allow maximum time for the pipeline, capture, and EOR network to be coordinated, planned, designed, and constructed before the eligibility period for tax credits ends. While the projects could begin operation later than 2024 and still receive tax credits (the legislated deadline to begin construction is January 1, 2024), we chose to assume the projects become operational in 2024. The impact of this choice on our analysis is negligible.

One exception in the analysis was consideration of ADM's Decatur biorefinery: a capture facility already exists, so it may be ineligible for the new tax credits (depending on whether it claimed the previous Section 45Q credits, which is not public information). We assumed no new tax credits were received by this facility, which resulted in its financial unviability.

Capture facility costs for all network iterations and pipeline financing scenarios are summarized in the Dataset S6 Capture Facility Cost Summary spreadsheet.

Network Economic Analysis Methodology

Trunk route selection

Trunk routes (shown in the main text Figure 2) were determined by finding least-distance routes along the potential pipeline corridors between key points. The method for least-distance optimization in ArcGIS is described in steps a.-f. in the following ArcGIS network methodology. A common point for the paths of the northern and southern ethanol collection trunks and the

Wyoming and Permian delivery trunks was identified in southern Nebraska. The Permian and Wyoming trunks were calculated between the common point and the nearest connection points to existing high-capacity CO_2 pipelines in the respective regions. For Wyoming, this was straightforward since there is one main CO_2 pipeline corridor in the state. For the Permian Basin, the selected point was the hub at the confluence of several major CO_2 pipelines. There are closer potential connection points to existing Permian Basin CO_2 pipelines than the selected point, but those closer pipelines (from Sheep Mountain and Bravo Dome to the Permian Basin) are already in use, have smaller diameter (and therefore flow capacity) than would be required for the additional flow from the new trunk pipeline (35), and, as shown by the Wyoming versus Permian trunk analysis on page 20, the additional trunk pipeline distance has minimal impact on the total network cost. The southern ethanol collection trunk option was determined as the least-distance path from a point on the Iowa-Illinois border near a group of large ethanol biorefineries to the common point. The northern ethanol collection trunk option was determined by the least-distance path from the Iowa-Illinois border point, through two other points in northern Iowa at the center of biorefinery spatial density, and then to the common point in Nebraska.

ArcGIS network methodology

We initially considered all of the low-capture-cost sources in the study area with emissions exceeding the 100,000 tonnes per year minimum for tax credit eligibility, shown in the main text Figure 7. The study area included Indiana, Illinois, Wisconsin, Minnesota, Iowa, Nebraska, eastern North and South Dakota, Kansas, north-eastern Colorado, and Texas. These sources are almost all ethanol biorefineries. The ArcGIS network analysis methodology to develop the initial network design is described below. ArcGIS *function names* are included in italics.

a. In ArcGIS, *merge* the potential pipeline corridor shapefiles (natural gas, ammonia, and carbon dioxide pipelines, railways, interstate highways, and electricity transmission lines greater than 220kV).
b. *Clip* the merged potential corridor feature class to the study area.
c. *Integrate* the merged potential corridor feature class so that there are vertices at all network intersections.
d. Create a *feature dataset* and import the merged potential corridor feature class.
e. Create a *network dataset* from the merged potential corridors within the *feature dataset*.
f. Use the ArcGIS Network Analyst *closest facility* function to calculate the shortest route from each emissions source point (facility) to the Permian Basin destination point. Manually edit the merged potential corridors to place constraints on the available corridors so that sources aggregate efficiently and follow the trunk pipeline routes. Iterate step f. until a satisfactory network is calculated.
g. Use the *dissolve* function to combine the overlapping routes from each individual facility into a single line for each network segment. Add a segment number field to give each network segment a unique number.
h. Perform *identity* analysis with the individual routes feature class as the input feature and the dissolved network feature class as the identity feature. The *identity* output table identifies the facilities that overlap each network segment, i.e. the sources that contribute flow to each pipeline segment.

Financial analysis and network iteration methodology

After determining the initial network design, we performed the financial analysis and network iteration process to find the stable, viable networks for each financing scenario. The network analysis methodology from the main text is repeated below with more detail for each step:

1. Determine the carbon dioxide flow rate for each segment of the pipeline network.
    a. Run the Matlab script "segment_flow_calc.m" (included in the Matlab Script section on page 25) to calculate the flow rate in each segment of the network, using the table of sources contributing to each segment from the ArcGIS step h.
2. Calculate the pipeline size, costs, and required carbon dioxide transport tariffs using the modified NETL CO_2 Transport Cost Model (29, 30, 39). Calculate the tariff that each source must pay based on the pipeline segments it uses.
    a. Calculate the costs and required tariffs for each individual pipeline segment using the differentiated methodologies for trunk segments and the remaining network segments described in the Carbon Dioxide Transport Model Engineering parameters section on pages 11-12.
    b. Create a .csv table including each unique pipeline segment number and the required tariff for each segment.
    c. Run the Matlab script "facility_tariff_calc.m" (included in the Matlab Script section on page 26) to calculate the total transport tariff for each source (facility), using the input of the pipeline segment tariffs from the previous step and the table of sources contributing to each segment from the ArcGIS step h.
3. Calculate the required carbon dioxide sales price for each source using the capture facility financial analysis model, with the pipeline tariff input from the previous step.
    a. Import the table of pipeline tariffs for each source from step 2.c. into the capture facility financial analysis model (Dataset S5 Capture facility financial model).
    b. Use the capture facility financial analysis model to calculate the carbon dioxide sales price required for each facility to achieve the target rate of return.
4. Eliminate all sources with a required carbon dioxide sales price above the \$23 per tonne threshold. A threshold requiring 15% rate of return at \$23 per tonne was used in the first iteration. Subsequent iterations allowed a 10% minimum rate of return for marginal facilities, as explained in the Results section.
    a. Create a price curve from the table of required carbon dioxide sales prices for each facility calculated from step 3.b. above by sorting facilities in order from lowest to highest price and calculating the running cumulative carbon dioxide captured by facilities. The price curves are included in Dataset S7 Price Curves.
    b. Eliminate facilities above the price threshold. Create a new list of viable facilities.
5. Update the pipeline network design (if required).
    a. In ArcGIS, select only the viable sources from step 4.b. and create a new feature class of those sources.
    b. Repeat steps f.-h. above to calculate new network. Modify the network if appropriate given the sources removed (e.g. the optimal route from a remaining source to the trunk may take a more direct route if the previous route passed via a nearby source that was eliminated).
6. Repeat steps 1 to 5 until stable a stable system is found with all sources economically viable.

Parameter sensitivity analysis additional information

Table S9. Parameter sensitivity cases and reasons for their selection.

Parameter	Case	Value	Reasoning
Capture capital cost	Optimistic	-20%	The single available ethanol capture project as-built cost is 20% lower than the modeled cost for the same size capture facility. See Table S1
Pipeline capital cost	Optimistic	-15%	The industry rule-of-thumb cost is around 15% lower than the median modeled cost. See discussion on SI page 10
	Pessimistic	+10%	A smaller cost change compared with the optimistic case, since it is more likely that the model over-estimates cost
Oil price	Optimistic	\$80 per barrel	Approximately the price range for WTI oil over the past 4 years, and also +/- \$20 per barrel compared with the April 2018 price around \$60 per barrel
	Pessimistic	\$40 per barrel	
Pipeline financing	All	See Table S7	See main text and SI page 14

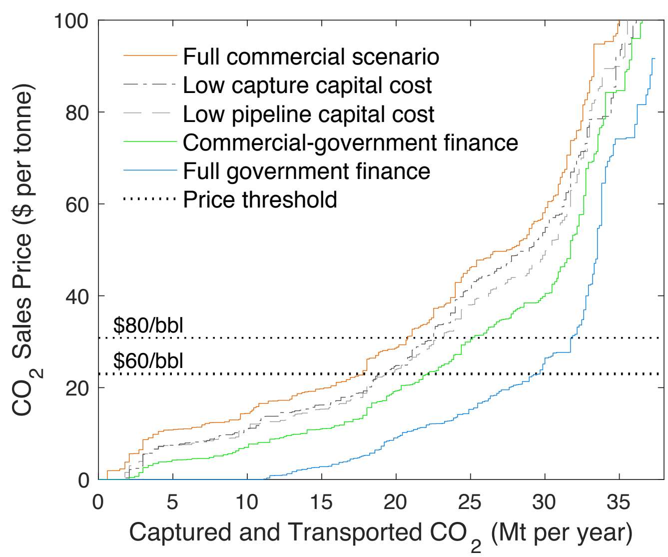

Figure S2. Full commercial scenario initial network price curve with sensitivity cases. The sensitivity cases are described in Table S9 above.

The sensitivity analysis was performed by updating parameters in the pipeline cost model or capture facility financial model as required for each case in Table S9. The required carbon dioxide prices for each source were then re-calculated (step 3 on page 18). This was performed for the full initial network for the analysis in main text Table 1, and for the final stable commercial-government and full government networks for the analysis in main text Figure 4. The sensitivity analyses therefore show changes in required prices due to changes in parameters assuming static systems; they are not iterated solutions showing the final stable impact.

Permian versus Wyoming trunk additional information

From the divergence point of the two pipeline options in Nebraska (see main text Figure 2), the Wyoming trunk is 793km, and the Permian trunk is 1019km long. The tariffs required for each trunk were calculated assuming the initial full potential Midwest capture network (main text Figure 7 with varying destination trunk) and for the fully commercial financial assumptions. The estimated capital cost for the Wyoming trunk is $1.74 billion, and for the Permian trunk is $2.23 billion. The difference in capital cost, $0.49 billion, represents 5% of the total cost of the initial full network capital cost of $9.43 billion. The Permian Basin option was therefore selected since the increased transport cost is minor compared to the substantial additional potential demand.

The costs for each trunk option were again calculated for the final full government scenario network (the larger network and total CO_2 flow of the two final cases) to confirm that the difference is not significantly different from the initial network. The capital cost of the final full government pipeline network is $6.69 billion. The $0.49 billion difference between the Wyoming and Permian trunks represent a 7.3% difference in total cost. The total average cost of the Permian system including capture is 3.3% higher, which is a minor difference for the overall economics of the networks compared to the demand advantage of the Permian Basin option.

Northern versus southern trunk additional information

The CO_2 sales price curves for the initial networks and first iterations of the northern and southern trunk networks are shown in Figure S3. The price curves are generally similar across the full range for the initial networks (the northern trunk is favorable at the threshold price), but the northern trunk option has 17.8 Mt of captured carbon dioxide below the price threshold compared to 16 Mt for the southern trunk. The price advantage of the northern trunk over the southern trunk for the full price curve is more evident after the first iteration, where the northern trunk option has 9.5 Mt below the price threshold compared to 7.1 Mt for the southern trunk.

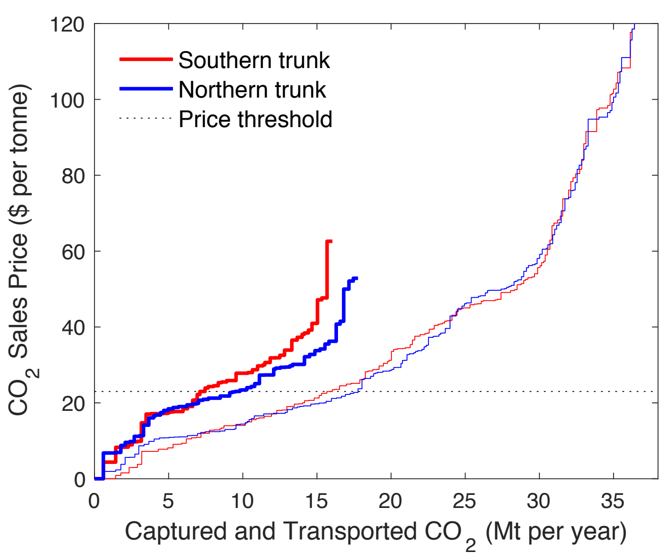

Figure S3. Northern versus southern trunk initial network (thin lines) and first iteration (thicker lines) price curves.

Section 45Q Tax Credit

The Section 45Q Credit for Carbon Oxide Sequestration was enacted on February 9, 2018, in the Bipartisan Budget Act of 2018, which directly included the FUTURE Act text (40). The value of the credit is differentiated into two categories: 1) dedicated secure geological storage, or 2) use as an injectant in enhanced oil recovery or natural gas recovery which results in secure geological storage, or other utilization methods that either permanently isolate CO_2 from or displace CO_2 from being emitted to the atmosphere. The credit values are included in the main text.

Credits are earned for a 12-year period beginning on the date the carbon capture equipment was originally placed in service. Construction of the carbon capture equipment must begin before January 1, 2024, or if a part of a larger facility, the overall facility must begin construction by that date and have original plans that included the carbon capture equipment.

The credits are attributable to the owner of the capture equipment who physically or contractually ensures its disposal or utilization, but the owner can also elect to have the credits transferred to the company that disposes or utilizes the CO_2 (the EOR or storage operator).

Electricity generation facilities must capture at least 500,000 tonnes per year to be eligible, while other industrial facilities must capture at least 100,000 tonnes per year. There are lower quantity limits for CO_2 that is captured and utilized by other methods, but these are not applicable to the EOR or saline storage case.

Calculations

<u>Levelized costs and revenues</u>

Levelized costs are presented in main text Table 1 and levelized costs and revenues in Figure 5.

Costs:

The full commercial case costs in main text Figure 5 apply the full commercial financial parameters to the stable full government network, since there is no stable full commercial network. The cost excluding finance case also applies to the stable full government network.

Levelized costs are the net present value (discounted to the project start date) of total project costs including capital and operating costs, divided by net present value of the total CO_2 tonnes captured in the project financial lifetime. The levelized costs are reported in 2018 dollars, adjusted by the assumed 2% inflation rate. The project start date years were 2020 for pipelines and 2022 for ethanol biorefinery capture facilities. All projects begin operation in 2024.

The discount rates for determining net present value were the project owner (equity) target rates of return: 15% for capture facilities, 12% for the full commercial and commercial-government pipeline financing scenarios, and 3.5% for the full government pipeline financing scenario.

The levelized cost for the pipeline network is equivalent to the required tariffs for the pipeline owner (equity) to achieve their target rate of return. The system-wide average levelized transport cost is therefore the average pipeline tariff paid by each capture facility.

The costs excluding finance are the sum of total project costs in 2018 dollars, including capital and operating costs, divided by the total tonnes of CO_2 captured in the financial lifetime of each capture facility (for the capture component) or the pipeline network (for the transport component).

The average levelized costs for the whole system were calculated as a weighted average of the costs for each facility and pipeline segment, weighted by total tonnes of CO_2 captured or transported by each facility or segment. This is equivalent to the total system levelized costs divided by total system tonnes captured and transported.

The average system-wide levelized costs that are shown graphically in main text Figure 5 are shown below in Table S10. The source of costs for the table can be found in the Dataset S4 Pipeline Cost Summary and Dataset S6 Capture Facility Cost Summary spreadsheets.

Table S10. Average system levelized costs for the capture and transport project components for each financing scenario.

Scenario	Transport Levelized Cost (2018 $/tonne)	Capture Levelized Cost (2018 $/tonne)
Full commercial (applied to stable full government network)	39.81	23.13
Government-commercial	27.13	22.48
Full government	18.28	23.13
Costs excluding finance (applied to stable full government network)	16.45	16.52

Revenues:

The effective tax credit revenue is the present value of the per-tonne tax credit over 12 years beginning in 2024, according to the legislated tax credit value schedule and assuming 2% inflation per year after 2026 when the credit value reaches $35 per tonne, divided by net present value of one tonne of CO_2 captured per year over the 12-year financial lifetime of each capture facility.

The effective tax offset revenue is the net present value of the per-tonne offset value assuming the capture projects receive the typical $23 per tonne CO_2 price, divided by net present value of one tonne of CO_2 captured per year over the 12-year financial lifetime of each capture facility. The tax offset value includes net operating losses (since the capture facilities have net cash operating losses each year) and depreciation of the capture facility asset. The displayed tax offset value is a weighted average for all capture facilities in the full government network. The offset value could be higher if facilities receive a lower CO_2 price and therefore have greater net cash operating losses, and vice-versa.

The CO_2 sales revenue value assumes the typical CO_2 sales price of 38.6% of the per-barrel WTI oil price per tonne of CO_2 (converted from the typical benchmark of 2% of per-barrel WTI oil price per thousand standard cubic feet of CO_2). Since the project revenue and project tonnes are discounted at the same rate, the levelized sales value per tonne is the starting CO_2 sales price.

Equivalent wind and solar abatement

The IEA estimated CO_2 emissions abatement per tonne of CO_2 delivered for CO_2-EOR (41). They calculate abatement for a case where 3.33 barrels of oil are produced for each tonne of CO_2 injected, and a case where 1.66 barrels of oil are produced for each tonne of CO_2 injected. The typical ratio for existing CO_2-EOR projects is around 2.5 barrels for each tonne injected (41-45), which is the average of the two IEA cases. Therefore, we averaged the two IEA abatement cases to find the typical abatement for existing CO_2-EOR projects. The IEA values are 0.63 and 0.73 tonnes abated per tonne delivered, the average of which is 0.68 tonnes abated per tonne delivered.

Therefore, estimated CO_2 emissions abatement for the full government case is:
CO_2 delivered for CO_2-EOR = 28.7 Mt per year
CO_2 abated = 19.5 Mt per year

Estimated CO_2 emissions abatement for the commercial-government case is:
CO_2 delivered for CO_2-EOR = 19.0 Mt per year
CO_2 abated = 12.9 Mt per year

In order to calculate the amount of wind and solar capacity that abates equivalent CO_2 emissions, we need to know the average emissions intensity of electricity displaced by wind and solar and the quantity of wind and solar electricity generation per unit of generation capacity (the capacity factor). Marginal electricity emission rates are around 0.5 to 0.8 tonnes of CO_2 per MWh (46, 47) in different regions, with the US-wide average around 0.6 tonnes per MWh. These rates are similar to the emissions rates of open-cycle and combined-cycle natural gas generators that are often the marginal units in electricity grids. The average capacity factor for wind generators in the United States was 34% over the past five years, and for solar it was 26% (48). The following equation was used to calculated abated emissions equivalent:

$$Abated\ emissions\ \left(\frac{tonne}{year}\right) = x\ MW \times capacity\ factor \times 8760\,\frac{h}{year} \times 0.6\,\frac{tonnes}{MWh}$$

The equation is solved for x, the equivalent generating capacity of wind and solar, using the capacity factors above. The equivalent wind capacity for the full government case is 11 GW, and equivalent solar capacity is 14 GW.

Total installed wind capacity in Texas at the end of 2017 was 22.6 GW (49). Total installed solar capacity in California at the end of 2017 was 21.0 GW (50).

Equivalent per-gallon tax credit and LCFS value

Using the ethanol fermentation CO_2 emissions equation in the Ethanol Emissions Estimation section on page 3, we calculate that 1 gallon of ethanol produces 0.00266 tonnes of CO_2.

The Section 45Q tax credit is earned for each tonne stored through EOR, which is essentially equal to the quantity delivered since there is minimal CO_2 lost in the process. We therefore calculate the value of the tax credit per gallon of ethanol directly as the tax credit value of CO_2 produced by each gallon fermented. Multiplying the $35 final tax credit value by the quantity of CO_2 per gallon gives $0.09 per gallon CCS tax credit value.

The draft accounting protocol for CCS under the California LCFS proposes to give credit for the net project emissions abatement by CO_2-EOR, not accounting for the downstream combustion of the oil or market impacts (51). The net project emissions abatement accounts for CO_2 losses and associated energy-use emissions in the capture, transport and injection of the CO_2. The IEA estimated net CO_2-EOR project emissions factor is -0.795 tonnes per tonne injected (41). Multiplying the quantity of CO_2 per gallon by the project emissions factor and the $100 per tonne LCFS credit value gives $0.21 per gallon CCS value under the LCFS.

GIS Data

Table S11. Sources of GIS data.

Data type	Source
Locations and emissions of low-capture-cost sources	RFA & NEO (for ethanol, as described on page 3) (3-5); EPA GHGRP (15)
Saline storage formations and other stationary CO_2 sources	NETL NATCARB Carbon Storage Atlas (52)
Interstate highways	Natural Earth (53)
Pipelines	EIA (54)
Railways	ORNL Center for Transportation Analysis (55)
Electricity transmission lines	Homeland Infrastructure Foundation-Level Data (56)

Supplementary Datasets

We include the following supplementary datasets:

Dataset S1 Source Emissions.xlsx
Dataset S2 Pipeline cost model.xlsm
Dataset S3 Pipeline cost model_network.xlsm
Dataset S4 Pipeline Cost Summary.xlsx
Dataset S5 Capture facility financial model.xlsm
Dataset S6 Capture Facility Cost Summary.xlsx
Dataset S7 Price Curves.xlsx

Matlab Scripts

The following Matlab scripts were used in the network analysis:

segment_flow_calc.m

```
%%% Script for determining the flow through each pipe segment in the network
% based on input of the sources/facilities contributing to each segment
% Ryan Edwards, 18/2/2018

%%% Instructions:
% facility_emissions.csv must have two columns: the first column contains all
facility numbers, the second column contains the emissions for each
facility/source
% segment_facility_PNX_Y.csv must have two columns: the first column contains
facility numbers, the second column contains pipeline segment numbers

% Read in csv files
facility_emissions = csvread('facility_emissions.csv'); % file with emissions
from each facility
segment_facility = csvread('segment_facility_PN3_3.csv'); % file with
facilities contributing to each segment

segment_flow = zeros(max(segment_facility(:,2)),2);
segment_flow(:,1) = [1:1:max(segment_facility(:,2))]';

for i=1:size(segment_facility,1)

    segment_flow(segment_facility(i,2),2) =
segment_flow(segment_facility(i,2),2)+facility_emissions(segment_facility(i,1
),2);

end

csvwrite('segment_flow_PN3_3.csv',segment_flow); % output flow rate in each
pipeline segment
```

facility_tariff_calc.m

```
%%% Script for calculating the pipeline transport tariff for each facility
% based on input of all the facilities, the facilities contributing to
% each segment, and the tariffs for each segment
% Ryan Edwards, 18/2/2018

%%% Instructions:
% facility_list_PNX_Y.csv must have one column listing facility numbers for
the network.
% segment_facility_PNX_Y.csv must have two columns: the first column contains
facility numbers, the second column contains pipeline segment numbers.
% segment_tariffs_PNX_Y.csv must have two columns: the first column contains
pipeline segment numbers, the second column contains the tariff for that
segment.

% Read in csv files
facilities = csvread('facility_list_PN3_3.csv'); % file with list of
facilites
segment_facility = csvread('segment_facility_PN3_3.csv'); % file with
facilities contributing to each segment
segment_tariffs = csvread('segment_tariffs_PN3_3.csv'); % file with the
tariffs for each segment

facility_tariffs = zeros(size(facilities,1),2);
facility_tariffs(:,1) = facilities(:,1);


for i=1:size(facilities,1)

   for j=1:size(segment_facility,1)

       if facilities(i)==segment_facility(j,1)
           facility_tariffs(i,2) =
facility_tariffs(i,2)+segment_tariffs(segment_facility(j,2),2);
       end
   end

end

csvwrite('facility_tariffs_PN3_3.csv',facility_tariffs); % output total
pipeline tariff for each facility
```

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