Comparative Economics of Carbon Sequestration for Iowa Ethanol Plants

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Prepared For:

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Table 1. Acronyms

Acronym	Description
CI	Carbon Intensity
CO2	Carbon dioxide
CCS	Carbon Capture and Storage
CCSvP	Carbon Capture and Storage via Pipeline
CCUS	Carbon Capture, Utilization, and Storage
DAC	Direct Air Capture
EOR	Enhanced Oil Recovery
GHG	Greenhouse gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Technologies
gCO2e/MJ	Grams of CO2 equivalent per megajoule of energy
LCFS	Low Carbon Fuel Standard
LUC	Land use change
45Q	Section 45Q of the U.S. Internal Revenue Code
45Z	Section 45Z of the U.S. Internal Revenue Code

1 Executive Summary

Iowa currently has 42 ethanol plants with listed annual capacity of 4.669 billion gallons per year. Iowa's ethanol plants produced an estimated 4.5 billion gallons of ethanol in 2022. There are several wet mill plants, but most of them are dry mill plants. Iowa's ethanol production currently is very competitive with ethanol production in other states and even in other countries. Iowa's ethanol plants have great access to corn as a feedstock for ethanol production and relatively good access to truck and rail distribution of ethanol to end markets. In addition, Iowa has significant feed demand for the dried and wet distiller's grains that are co-products of ethanol production and has good demand for the corn oil and distiller's corn oil co-products of its ethanol plants. Iowa currently has four ethanol plants that capture CO2 for utilization (beverage, dry ice, refrigeration, etc.). Iowa has 34 ethanol plants representing 3.892 billion gallons per year of ethanol production that are on the announced CO2 pipeline projects that are expected to service Iowa.

The recently enacted Inflation Reduction Act contains provisions in Section 45Z that create tax credits for clean fuel production. These credits apply to clean fuels produced after 2024 and generally sold before 2028. It is a new general business credit for clean transportation fuel that is produced at a qualifying facility and sells for qualifying purposes. These fuels must meet certain emissions standards. For ethanol, the credit-per-gallon amount can be up to $1.00 if wage and apprenticeship requirements are met. The credits are based on the fuel's carbon intensity score with a CI score of 50 (based on the GREET model) being the trigger point, and the credit potential increasing as the CI score declines toward zero. So, essentially, each reduction in the CI score of the fuel below 50 generates a 2 cents per gallon production tax credit with the tax credit being maximized at $1.00 per gallon if the CI score is zero. The estimated average CI score for Iowa's dry mill ethanol plants is in the mid-50s and it is widely believed that the CI score for Iowa's ethanol plants can be reduced by 30 CI points through carbon capture and sequestration via a pipeline to secure underground storage facilities. Two of the proposed CO2 pipelines that would service Iowa transport the CO2 to storage facilities in Illinois. The other CO2 pipeline would transport the CO2 from Iowa ethanol facilities (and some other facilities such as nitrogen fertilizer production) to a storage facility in North Dakota.

The production tax credit for clean fuels production referred to as the 45Z credit has the potential to be a "game-changer" for the location of ethanol production. The incentive to capture up to 60 cents per gallon of tax credit incentive ($60 million per year for a 100 million gallon per year production facility) by implementing CCUS strategies could stimulate new plant development at locations that enable implementation of CCUS strategies but could also stimulate expansion of ethanol capacity at existing plants that would have access to CCUS capability.

Over the past 13-plus years, gross operating margins for Iowa's ethanol plants have varied from a high of $1.35 per gallon to a low of -$0.06 per gallon. The average gross operating margin over the past 13.5 years has been $0.31 per gallon. Operating margins have declined over the full 15-year period of 2007-2022 but have shown a flat trend since the middle of 2014 with quite a bit of variability during that period. The most recent calculated gross operating margin based on data from January 2023 indicates a gross operating margin of $0.147 per gallon.

The producer tax credits created by section 45Z can be earned by ethanol producers who produce ethanol with a CI score less than 50. While the exact manner in which the credit will be allocated has yet to be determined by the regulating agency, it is assumed for this analysis that it will be calculated based on a sliding scale as the CI score of the ethanol plant declines below the threshold level of 50 CI. For a 100 million gallon per year ethanol plant that can achieve a CI score of 26 via a combination of enhancements of plant operations, carbon capture and sequestration, the value of the 45Z tax credit could be $48 million per year ((50-26)*$0.02/gallons produced), assuming that all gallons of ethanol produced at the facility qualify for the bonus credit. If extended to all 4.5 billion gallons of ethanol production in the state of Iowa through broad access to carbon capture and storage via pipeline, the credits would be worth up to $2.16 billion at a CI score of 26 and $2.7 billion if the ethanol plants can reach an average CI score of 20.

Value of the 45Z Tax Credit at Various CI Scores
100 Million Gallon Per Year Ethanol Plant
and for all of Iowa's Ethanol Plants

CI Score	100 mgy Plant	Iowa's Ethanol Plants
50	$0	$0
47	$6,000,000	$270,000,000
44	$12,000,000	$540,000,000
41	$18,000,000	$810,000,000
38	$24,000,000	$1,080,000,000
35	$30,000,000	$1,350,000,000
32	$36,000,000	$1,620,000,000
29	$42,000,000	$1,890,000,000
26	$48,000,000	$2,160,000,000
23	$54,000,000	$2,430,000,000
20	$60,000,000	$2,700,000,000
17	$66,000,000	$2,970,000,000
14	$72,000,000	$3,240,000,000
11	$78,000,000	$3,510,000,000
8	$84,000,000	$3,780,000,000
5	$90,000,000	$4,050,000,000
2	$96,000,000	$4,320,000,000

Assumes that implementation of the 45Z credit is incremental below 50 CI and producers qualify for bonus credit.
CI 26 highlighted as feasible target for drymill plants with sequestration.

But there is a downside to the 45Z tax credits. The credits are available to clean fuel production anywhere in the United States. As many as 65 ethanol plants in the U.S. have access to carbon capture and sequestration through direct injection at the ethanol plant site and need no pipeline for transportation. A number of ethanol plants are already doing this, such as the ADM ethanol plant in Decatur, Illinois. In addition, there are 38 ethanol plants outside of Iowa representing 3.3 billion gallons of ethanol per year that are on the CO2 pipelines that have been announced.

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The 45Z tax credits create a tremendous incentive for ethanol plants to capture and sequester CO2. It is estimated that the additional gross margin that can be generated by accessing the full value of 45Z tax credits through CO2 sequestration via pipeline will enable existing ethanol plants that will have pipeline access to expand production by 30% with a payback period of 1.5 to 2.5 years and new construction of ethanol plants to have a full payback within 5 to 7 years. If Iowa's ethanol plants are not able to get access to CO2 capture and sequestration via pipeline, then the scenario in which 75 percent of Iowa's ethanol production is displaced by ethanol production in states outside of Iowa that have access to carbon capture and sequestration via pipeline could occur within 5 to 10 years.

Iowa ethanol plants are competitive within the current market structure of energy and ethanol markets and are well positioned to provide feed byproducts of ethanol to local livestock and poultry feeders. But long periods of potentially negative operating margins due to competitors having access to the 45Z tax credits and Iowa's ethanol producers not having access would eventually "right-size" the ethanol market by forcing producers with negative margins to shutter their plants and reduce the supply of ethanol produced in Iowa.

Loss of 75% of the Iowa ethanol industry would result in an eventual decline in revenues from ethanol plants (ethanol, DDGs, and DCO) of more than $10.3 billion per year. These losses would reverberate throughout the Iowa economy as corn prices would adjust downward, costs to get DDGs delivered to Iowa feeders would increase and DCO would be less available (or more costly) to Iowa-produced biodiesel and renewable diesel production facilities and for feed use.

Relocation of Economic Activity - Ethanol Plants
Change in Annual Sales Value of Ethanol Plants
Million $ Per Year

	Iowa	Illinois	Minnesota	Nebraska	South Dakota
Iowa Down 15%	-$1,957	$0	$505	$535	$915
Iowa Down 25%	-$3,436	$304	$743	$1,156	$1,220
Iowa Down 50%	-$6,873	$911	$1,485	$2,167	$2,287
Iowa Down 75%	-$10,309	$911	$2,228	$3,612	$3,506

Includes sales value of ethanol, DDGs, and DCO
Projected using January 2023 prices

Margins matter. And the 45Z tax credits are a game changer. Clean fuels such as ethanol which are produced with CO2 capture and sequestration via pipeline are the future for the renewable fuels industry. Iowa's ethanol industry is at a crossroads – will it be positioned to be the leader in ethanol and other clean fuels or watch that future move over the horizon?

2 Introduction

2.1 Background

First introduced in 2008, Section 45Q of the Unites States Internal Revenue Code provides a tax credit for CO2 storage. The policy is intended to incentivize deployment of carbon capture, utilization and storage (CCUS), and a variety of project types are eligible. In 2022, the US introduced a significant stimulus for CCUS investment with the passage of legislation (the Inflation Reduction Act) to expand and extend the 45Q tax credit. 45Q is a section of the tax code that provides incentives, in the form of tax credits, to encourage companies to invest in carbon capture and storage solutions that reduce carbon emissions to the atmosphere. Captured carbon dioxide must be either stored underground in secure geologic formations, used for carbon dioxide-enhanced oil recovery (EOR) or utilized in other projects that permanently sequester carbon dioxide.

Table 2. Summary of 45Q Tax Credits

Summary of 45Q Tax Credits				
Category	Base Credit $ Per Metric Ton of CO2e	Base Credit $ Per Gallon of Ethanol Equivalent	Bonus Credit $ Per Metric Ton of CO2e	Bonus Credit $ Per Gallon of Ethanol Equivalent
Carbon captured and used for enhanced oil recovery (EOR) or utilization	$12	$.0.0342	$60	$0.1710
Carbon captured and sequestered	$17	$0.0485	$85	$0.2423
Direct air captured and used for EOR or utilization	$26	$0.0741	$130	$0.3705
Direct air captured and sequestered	$36	$0.1026	$180	$0.5130
This credit will be available for direct pay for the first 5 years under broad conditions and the credits are transferable. The annual thresholds of carbon a facility must capture to qualify are:				
• **18,750 tons of CO2 for power plants**				
• **12,500 tons of CO2 for industrial facilities (like ethanol plants)**				
• **1,000 tons of CO2 for direct air capture (DAC) facilities**				

The 2022 changes to 45Q provide up to $85 per metric ton of CO2 permanently stored and $60 per metric ton of CO2 used for enhanced oil recovery (EOR) or other industrial uses of CO2, provided emissions reductions can be clearly demonstrated[1]. The credit amount significantly increases for direct

[1] In GREET 2021 the carbon balance approach was replaced with a stoichiometry approach: one mole ethanol will yield one mole CO2 (2.85 kg CO2/gallon of ethanol) for fermentation CO2 estimation.

air capture (DAC) projects to $180 per metric ton of CO_2 permanently stored and $130 per metric ton for used CO_2. In addition, the 2022 changes reduce the capacity requirements for eligible projects: 18,750 metric tons per year for power plants (provided at least 75% of the CO_2 is captured), 12,000 metric tons per year for other facilities, and 1,000 metric tons per year for Direct Air Capture (DAC) facilities. Finally, the 2022 changes include a seven-year extension to qualify for the tax credit, meaning that projects have until January 2033 to begin construction.

In Part 2 of Subtitle D of the Inflation Reduction Act, tax credits for clean fuel production are contained in section 45Z. This credit applies to clean fuels produced after 2024 and generally sold before 2028. It is a new general business credit for clean transportation fuel that is produced at a qualifying facility and sells for qualifying purposes. These fuels must meet certain emissions standards. For ethanol the credit-per-gallon base amount is $0.20 (non-aviation fuel) and the credit amount increases to $1.00 per gallon (non-aviation fuel) if wage and apprenticeship requirements are met and are based on the fuel's carbon intensity score with a CI score of 50 (based on the GREET model) being the trigger point, and the credit potential increasing as the CI score declines toward zero. So, essentially, each reduction in the CI score of the fuel below 50 generates a 2 cents per gallon production tax credit with the tax credit being maximized at $1.00 per gallon if the CI score is zero.

Table 3. Summary of 45Z Tax Credits - Clean Fuel Production Credit

Summary of 45Z Tax Credits – Clean Fuel Production Credit		
Category	Base Credit ($ Per Gallon)	Bonus Credit Base Credit Multiplied by 5 ($ Per Gallon)
Base Credit Transportation Fuel	$0.20	Up to $1.00
Base Credit Sustainable Aviation Fuel (SAF)	$0.35	Up to $1.75
Beginning on Dec 31, 2024, existing fuel credits will transition to the Clean Fuel Production Credit. The credit is set to expire on Dec 31, 2027. In order to receive the full credit the fuel must have a life-cycle emission level of less than 50 The base credit is adjusted downward based on the emission factor of the fuel. The bonus credit is available (base credit multiplied by five) if production meets prevailing wage and apprenticeship requirements.		

No credit under the 45Z tax credit can be claimed at a facility that includes property for which a credit is claimed under sections 45Q, 45X, or section 48 ITC for clean hydrogen production facilities during the taxable year. Producers do, however, have the choice of which credit to claim as long as they qualify for the tax credit.

Currently, most of the corn-starch-based ethanol production in Iowa has published CI scores between 59 – 82 based on the lowest published corn starch score under the California version of the GREET model (Figure 1).

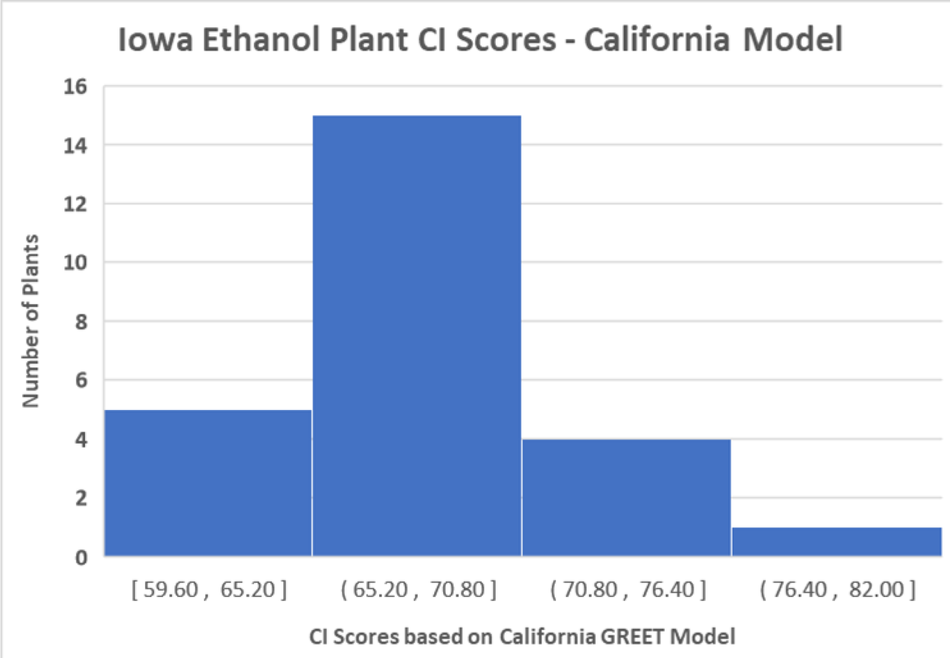


Figure 1. Iowa Ethanol Plant CI Scores - California Model

While there are numerous production techniques and methodologies that can be implemented to incrementally reduce the carbon emissions of ethanol production, the use of CCUS is the most effective means of dramatically reducing the carbon emissions of ethanol production from corn with the implementation of CCUS estimated to typically reduce the CI score of an ethanol facility by approximately 30 CI points.

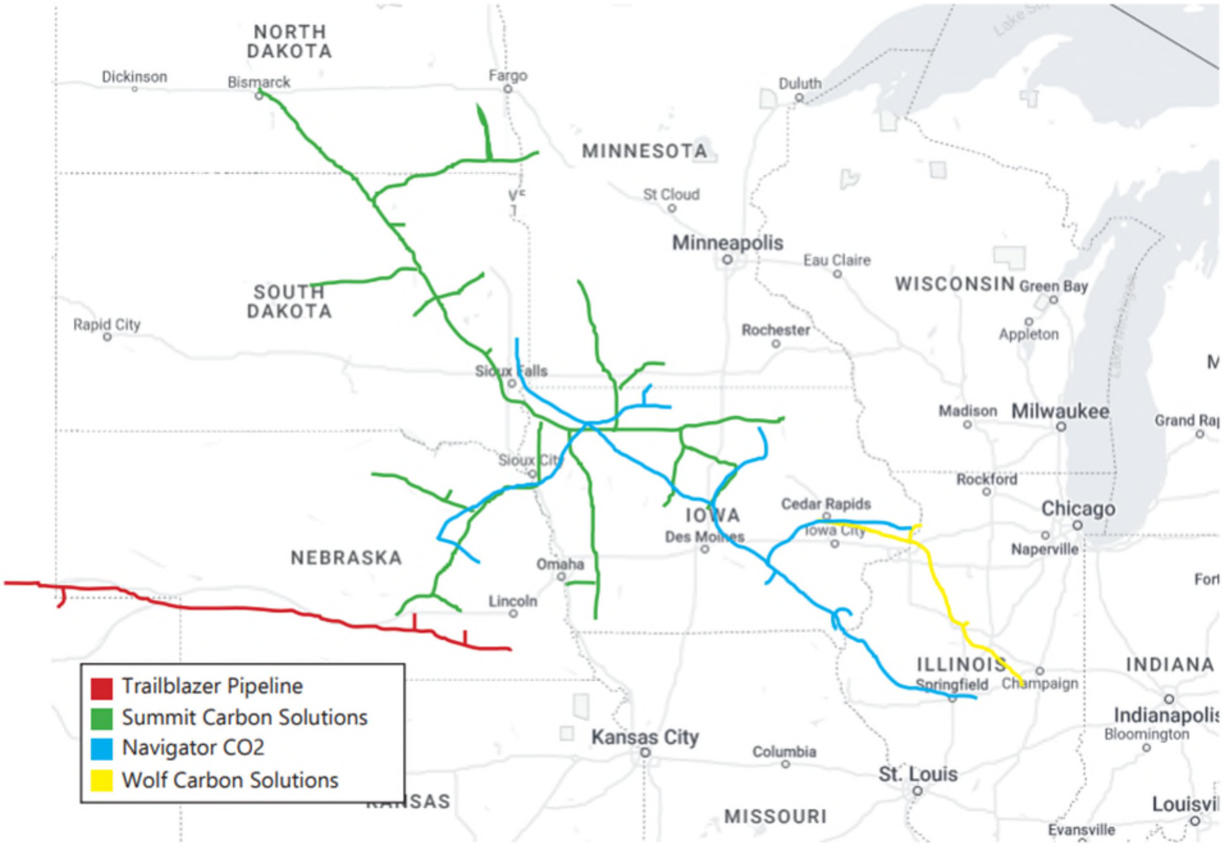
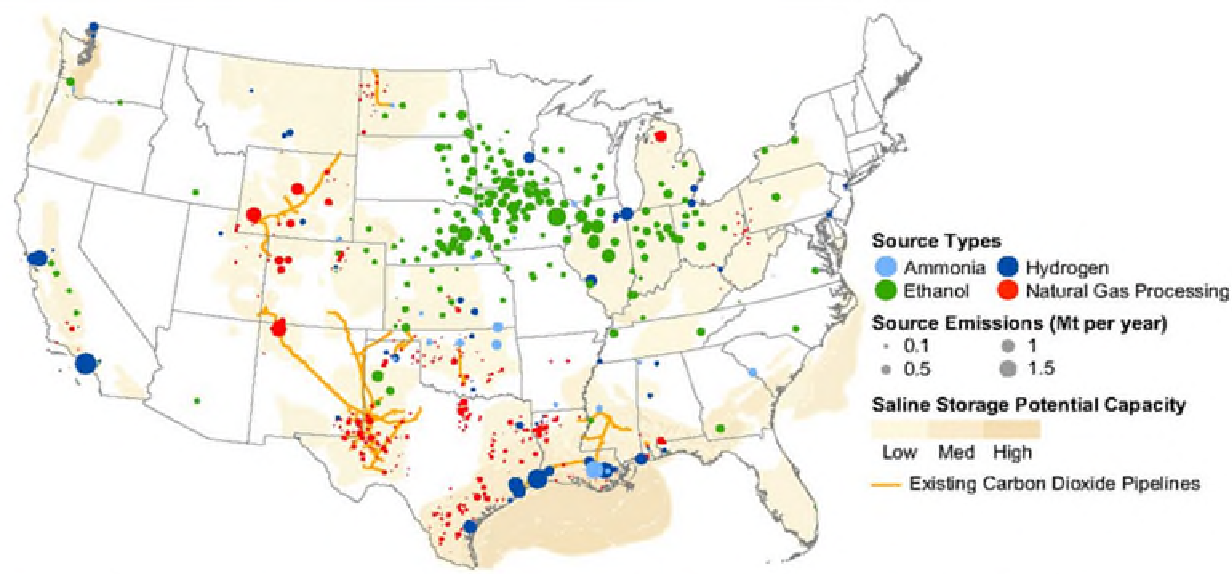


Figure 2. Map of Proposed Carbon Capture Pipelines

Figure 2 shows the carbon pipelines that have been proposed which would transport CO2 from ethanol plants. The Navigator CO2 pipeline collects CO2 from plants in Iowa, Illinois, Minnesota, Nebraska, and South Dakota and transports that CO2 to a storage site in Illinois. The Summit Carbon Solutions pipeline captures CO2 from ethanol plants in Iowa, Minnesota, Nebraska, South Dakota, and North Dakota and transports that CO2 to a storage site in North Dakota. The Wolf Carbon Solutions pipeline collects CO2 from plants in Iowa and transports that CO2 to a storage site in Illinois.

2.2 Overview

The production tax credit for clean fuels production referred to as the 45Z credit has the potential to be a “game-changer” for the location of ethanol production. The incentive to capture up to 60 cents per gallon of tax credit incentive ($60 million per year for a 100 million gallon per year production facility) by implementing CCUS strategies could stimulate new plant development at locations that enable implementation of CCUS strategies but could also stimulate expansion of ethanol capacity at existing plants that would have access to CCUS capability. The Trailblazer pipeline connects with an abandoned natural gas pipeline and proposes to transport CO2 from Nebraska and Colorado ethanol plants to a storage site in Wyoming.



Low-capture-cost carbon dioxide emissions in the United States, existing carbon dioxide pipelines, and potential saline storage formations. Colocated sources are summed so that the total emissions are observable. Total emissions are 87 Mt per year, including 43 Mt from ethanol fermentation at biorefineries, 22 Mt from hydrogen production, 5 Mt from ammonia production, and 17 Mt from natural gas processing.

Figure 3. Low-Capture-Cost CO2 Emissions in the U.S., Existing CO2 Pipelines and Saline Storage Potential Capacity Source: https://www.pnas.org/doi/10.1073/pnas.1806504115

Figure 3 shows the existing CO2 pipelines in the U.S., locations of saline storage potential (with a capacity estimate), and major sources of industrial CO2 such as ammonia plants, ethanol plants, hydrogen production facilities, and natural gas processing facilities.

One of the barriers to implementation of CCUS strategies may be the ability of pipelines to be constructed that connect ethanol facilities with the identified carbon sequestration injection sites and storage. There is a concentration of ethanol production facilities in Iowa and surrounding states, but most of these plants do not have direct access to the areas with good CO2 storage capacity. It will require a transportation system to transport the CO2 that can be collected at these plants to the storage areas. The most likely vehicles for such transport are dedicated CO2 pipelines. Such pipelines exist in some of the most prominent natural gas processing areas. Several pipelines have been proposed in the major ethanol production areas, but state and local laws and regulations can create barriers to the construction of such pipelines. If states neighboring Iowa facilitate the construction of CO2 pipelines, but Iowa regulations are considered sufficiently burdensome that CO2 pipelines are not built in Iowa, the incentives created by 45Z and 45Q tax credits could result in expansion of ethanol production in locations with pipeline access through new construction or expansion of existing ethanol plants with access and abandonment of plants without access. If that occurs, then it is likely that production of ethanol at some existing plants that do not achieve CCUS capabilities may operate at a disadvantage and may ultimately become uncompetitive.

Phase 1 of this project is to conduct a comparative economic analysis of ethanol plant operations with and without access to CCUS with the existence of the 45Q and 45Z tax credits. This analysis will compare ethanol plant operational economics in Iowa *without* access to CCUS with ethanol plant operations in Nebraska, South Dakota, Minnesota and Illinois *with* CCUS access.

Phase 2 of the project will examine the impacts of potential movement of ethanol production from areas without access to CCUS technology to areas with CCUS technology on corn commodity flows in the states within the study area and the estimated impacts on corn basis levels in Iowa and will be released in a forthcoming report.

3 Comparative Economic Analysis of Ethanol Production with and without CCUS in the Presence of 45Q and 45Z Tax Credits Methodology

3.1 Primary Set of Assumptions

- All the corn, sorghum and wheat-based ethanol produced in the U.S. meets the qualifying standards for participation in the Clean Fuels Production Credit (45Z) program[2].
- For the purposes of this study, it is assumed that the ethanol plants and pipeline operators will figure out the legal criteria in a manner that allows the pipelines and ethanol plants to utilize the 45Q and 45Z tax credits in the most advantageous manner.
- The structure of 45Z tax credit implementation is likely to be a simple 0.4 cents per point of reduction in CI score under base credit and 2 cents per point of reduction in CI score with the bonus credit. This assumes that the 20 cents referenced in 45Z(a)(2) covers emission reductions from 50 kgCO2e/CI to zero and that the alternative amount ($1.00) referenced in 45Z(a)(2)(B) is a simple 5-times multiplier of the base amount for production that meets the Prevailing Wage requirements.
- For the purposes of this study, rounding of CI scores was to the nearest 1 kg of CO2e per mmBTU, although the statute would allow Secretarial discretion to round to the nearest 5 kg CO2e/mmBTU.
- The current national average CI score for ethanol produced in the U.S. (at the refueling station) using the defaults in the GREET 3.0 model is calculated as 55.333 based on the GHG-100 grouping. This calculation uses CO2 from Land Use Change (LUC) of 7.382 which is 12.62 g CO2/MJ of ethanol lower than that used in the California GREET scores.

3.2 CI Scores

Like corn and ethanol production, refineries with LCFS approved ethanol fuel pathways are spread out around the country but are generally concentrated in the Midwest. Currently, Iowa has the highest number of registered ethanol fuel pathways from corn, corn fiber, corn stover, grain sorghum, and/or wheat and wheat residues with 81; these pathways have an average CI of 60.09. After Iowa, the States with the most approved pathways are Nebraska (61 pathways; average CI of 66.60), South Dakota (50 pathways; average CI of 62.04), Kansas (43 pathways; average CI of 69.17), California (33 pathways; average CI of 62.51), and Minnesota (25 pathways; average CI of 62.5). All other States have fewer than 20 ethanol fuel pathways (Table 4).

[2] This assumes that the production facilities in the U.S. meet the requirements of a qualified facility as defined in section 45Z and that the ethanol produced at the facilities meet the ASTM standards delineated in section 45Z and that the fuel is not derived from palm fatty acid distillates or petroleum.

Table 4. Number of Certified LCFS Corn, Sorghum, and Wheat ethanol Pathways and Average CI Scores

Number of Certified LCFS Corn, Sorghum, and Wheat Ethanol Pathways and Average CI Scores		
State	**Number of Pathways**	**Average CI All Pathways**
Arizona	**3**	**62.82**
California	**33**	**62.51**
Colorado	**3**	**64.32**
Idaho	**1**	**66.44**
Illinois	**1**	**76.27**
Indiana	**15**	**56.63**
Iowa	**81**	**60.09**
Kansas	**43**	**69.17**
Michigan	**3**	**55.67**
Minnesota	**25**	**62.50**
Missouri	**7**	**57.26**
Nebraska	**61**	**66.60**
North Dakota	**7**	**66.57**
Ohio	**9**	**56.35**
South Dakota	**50**	**62.04**
Texas	**19**	**70.65**
Wisconsin	**1**	**72.25**
Grand Total	**362**	**63.32**
Source: LCFS Pathway Certified Carbon Intensities, California Air Resource Board		

Table 5 shows the state average CI scores for lowest published corn starch ethanol CI score from all plants with published scores. Currently, Iowa has the lowest state-average corn-starch California carbon intensity (CA-CI) score at 68.25 followed by Nebraska with 68.59, South Dakota at 69.15, Minnesota at 70.58, and Illinois at 76.27. When the CA-CI scores are adjusted for the difference in the CA-Greet LUC amount versus the LUC amount in the GREET 3.0 default model, the adjusted scores are IA: 55.83; NE: 55.97; SD: 56.53; MN: 57.96; and IL: 63.65. The distribution of these state averages compared to the simple average of all plants with published CA-CI scores is: Iowa 1.2% below the average, Nebraska 0.9% below the average, South Dakota 0.1% above the average, Minnesota 2.6% above the average, and Illinois 12.7% above the average.

Table 5. Comparison of State Average CA-CI Scores

Comparison of State Average CA-CI Scores			
State	CA-CI Score	CA-CI Score Adj for LUC	CA-CI Score Adjusted for LUC Pct Difference from Avg
IA	68.25	55.83	-1.2%
IL	76.27	63.65	12.7%
MN	70.58	57.96	2.6%
NE	68.59	55.97	-0.9%
SD	69.15	56.53	0.1%
Average	69.04	56.50	
Based on lowest published CI score for a corn starch ethanol pathway Source: LCFS Pathway Certified Carbon Intensities, California Air Resources Board			Decision Innovation Solutions

The CI score for corn ethanol has significantly decreased between 2005 and the current time. Figure 4 shows the reductions for the total ethanol CI scores from 58 to 45 gCO2e/MJ of corn ethanol (a 23% reduction) since 2005. This is due to several factors. Corn grain yield has increased continuously, reaching 190 bushels/acre in the five Midwestern major ethanol producing states (a 17.8% increase in the 3-year weighted average yield since 2005-08) while fertilizer inputs per acre have remained relatively constant, resulting in decreased intensities of fertilizer inputs (e.g., 7% and 18% reduction in nitrogen and potash use per bushel of corn grain harvested, respectively). A 6.7% increase in ethanol yield, from 2.70 to 2.88 gal/bushel corn, and a 24% reduction in ethanol plant energy use, from 32,000 to 25,000 Btu/gal ethanol (9.0 to 6.9 MJ L−1 ethanol) also helped reduce the CI score.

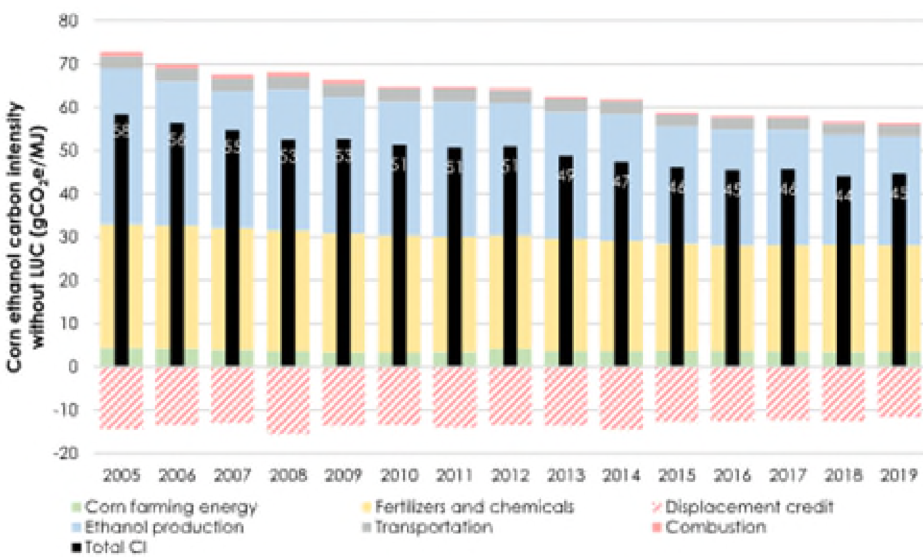


Figure 4. Carbon Intensity (gCO2e/MJ undenatured ethanol) of Corn Ethanol Without LUC for 2005-2019 [3]

[3] Source: Modeling and Analysis -- Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005-2019: Implications for Greenhouse Gas Emission Reductions

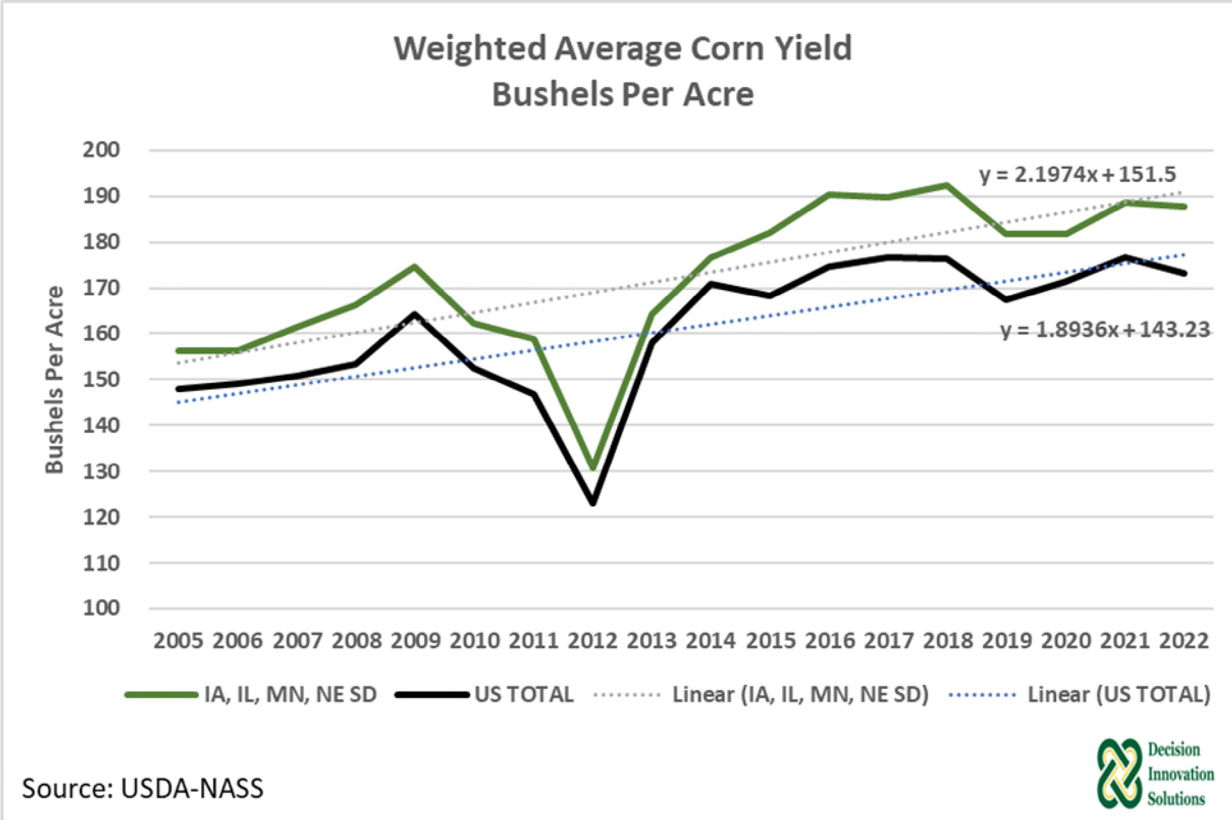


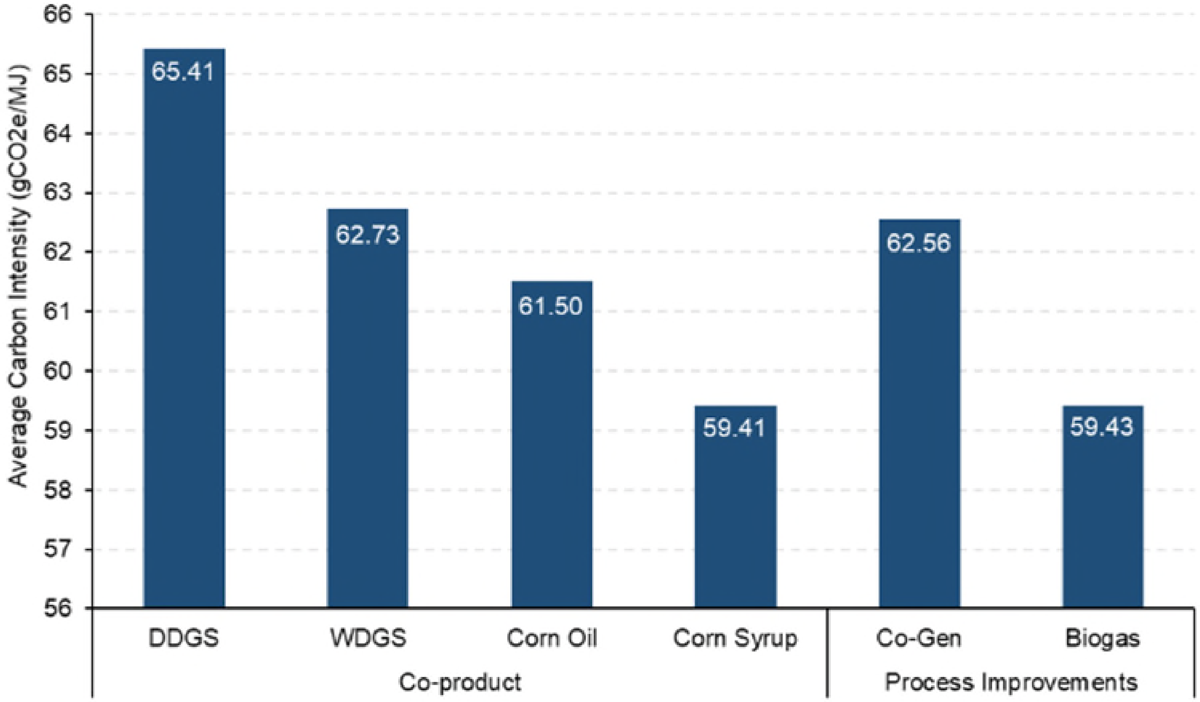
Figure 5. Weighted Average Corn Yield

The total GHG emission reduction benefits through the reduction in the CI and increased ethanol production volume are estimated at 140 million metric tons (MMT) from 2005 to 2019 in the ethanol industry. Displacement of petroleum gasoline by corn ethanol in the transportation fuel market resulted in a total GHG emission reduction benefit of 544 MMT CO2e during the period 2005 to 2019.

The national average CI score for ethanol production (at the refueling station) is estimated by Argonne National Laboratory to be 55.333 gCO2e/MJ of ethanol using factors that represent 100-year global warming potential[4].

Further reductions in CI scores for ethanol plants can be achieved through modifications of the ethanol plant and/or changes in operations of the plants and the co-products produced. For example, changing from dried distiller's grains to wet distiller's grains can reduced the CI score by 2.68 points, on average, and removing corn oil from the corn before processing can reduce the score another 1.23 CI points, and producing corn syrup can reduce the CI score 2.09 CI points.

[4] GREET 2022



Note: DDGS = Distiller's Dried Grains with Solubles; WDGS = Wet Distillers Grains with Solubles

Figure 6. Average CI Score Associated with Facility Modifications[5]

Net lifecycle emissions reductions from the capture of biogenic CO2 from ethanol fermentation can be significant. The application of carbon capture to corn ethanol plants in the U.S. has the potential to reduce the carbon intensity of resulting biofuels production by upwards of 55 percent if the captured CO2 is stored in saline geologic formations[6]. In the case of storing captured CO2 in oilfields through EOR, large net emissions reductions still result, even after accounting for the additional oil produced. Analysis from the International Energy Agency (IEA) shows that, after accounting for the additional oil produced and global market effects, every ton of anthropogenic CO2 delivered for CO2-EOR results in a 63 percent emissions reduction[7].

Carbon capture, compression and dehydration systems were installed at the Arkalon and Bonanza ethanol plants in Kansas in 2009 and 2012, respectively, together with the construction of pipelines to transport the CO2 to Texas and Kansas for use in EOR. These commercial operations continue successfully today. However, a combination of conditions made these projects feasible in the market place—close proximity to suitable oilfields and higher oil prices—that cannot be replicated elsewhere today. For production of biogenic CO2 from the fermentation of ethanol to expand and become a major

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[5] The California Low Carbon Fuel Standard: Incentivizing Greenhouse Gas Mitigation in the Ethanol Industry, USDA, Office of the Chief Economist, November 2020.

[6] Reduction from 55.3 CI score to 25.3 CI score through capture and sequestration.

[7] International Energy Agency, "Storing CO 2 through Enhanced Oil Recovery, combining EOR with CO 2 storage (EOR+) for profit," 2015.

source of supply for oil production with geologic storage, that CO_2 must be delivered to the oilfields at a market price compatible with the economics of EOR projects[8].

Similarly, ADM's current efforts at its Decatur ethanol facility in Illinois to capture CO2 and store it in a saline formation depends on federal funding provided by the U.S. Department of Energy (DOE) for the purposes of first-time commercial-scale demonstration. Red Trail Energy in Richardton, ND, also is underway with its plans to store 180,000 MT of CO2 annually from ethanol fermentation in the Broom Creek saline formation. They have been actively sequestering CO2 since the middle of 2022. Further commercial-scale deployment of saline storage of CO2 from ethanol production will be greatly enhanced and accelerated by the enactment of the 45Z tax credits whereas prior to such enactment, additional CO2 sequestration from ethanol plants into saline formations would have been challenging without financial incentives.

Ethanol plants constitute the largest single-sector source of CO2 for U.S. merchant gas markets, and the CO2 produced enters a wide variety of markets, including food, beverage and dry ice applications. A valuable commodity, it averages $95 per ton with a large number of applications led by food and beverages and dry ice applications. Light industrial users in the merchant market include metal welding, chemicals, pH reduction, and CO2 fracking applications in oil and gas[9].

Nearly 43 percent of domestic CO2 by-product for refinement and liquefaction is derived from 48 ethanol plants, mostly in the Midwest. While several regions in the U.S. are saturated, more ethanol plants will be tapped for carbon dioxide feedstock in the future as the U.S food industry continues to expand. For example, Continental Carbonic opened a new CO2 plant in 2017 that is co-located with ethanol producer Pennsylvania Grain Processing in Clearfield, Pennsylvania. The Pennsylvania project is an example of a strategically located CO2 source that cannot be replaced by other sources in an affordable and clean manner.

The 2016 U.S. CO2 merchant market was estimated at 9.63 million short tons, the largest in the global 22 million-tons-per-year market. Domestic prices average $95 per delivered ton, sold in a wide range of containers from 105-ton rail cars to 24-ton, over-the-road tankers, as well as smaller 500-pound microbulk tanks and 20-pound cylinders.

The captive market is led by enhanced oil recovery (EOR) with White Energy, Russell, Kansas, the only dedicated source. Captive supply of CO2 has been evaluated for other projects such as delivery into the EOR pipeline infrastructures owned by Denbury Resources in the mid-South, and Kinder Morgan in the Southwest. Other captive markets include enhanced coal bed methane, sodium bicarbonate, methanol and, potentially, urea.

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[8] Capturing And Utilizing CO2 from Ethanol: Adding Economic Value and Jobs to Rural Communities While Reducing Emissions, White paper prepared by the Wyoming State CO2-EOR Deployment Work Group, December 2017.

[9] https://ethanolproducer.com/articles/14122/ethanol-industry-provides-critical-co2-supply

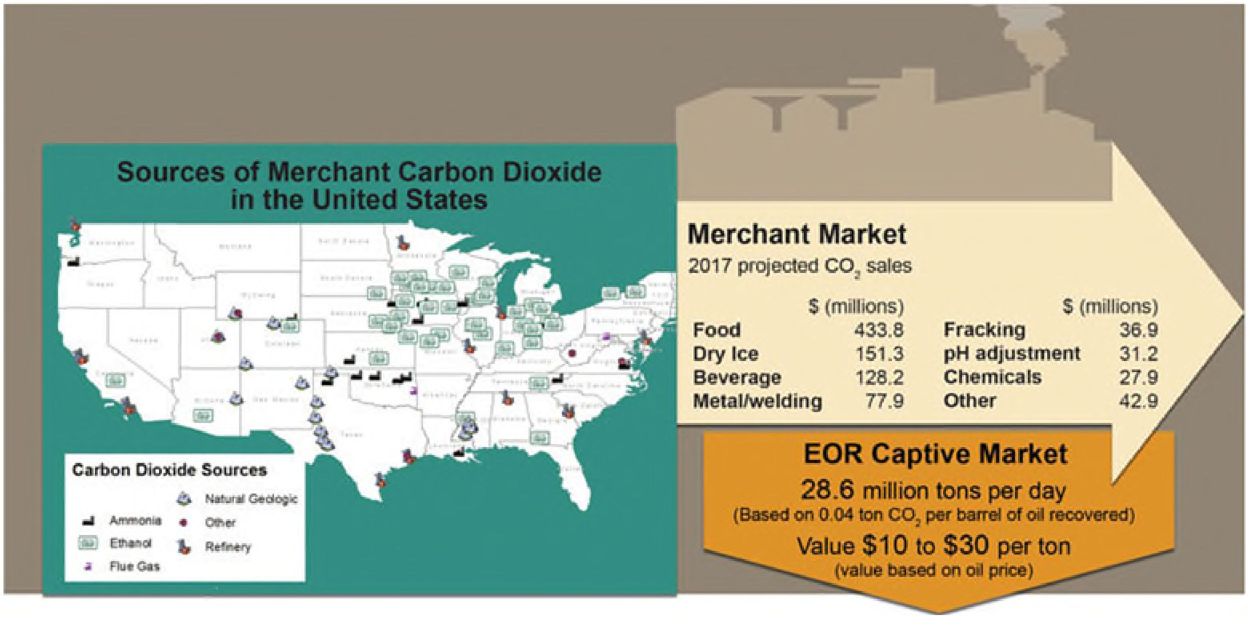


Figure 7. Sources of Merchant Carbon Dioxide in the United States (2016)[10].

3.3 Ethanol Plant Economics

The profitability of ethanol plants is a function of the price of the outputs (ethanol and the combination of byproducts (wet distiller's grains (WDG), distillers dried grains (DDG), distillers grains with solubles (DDGS), corn oil, condensed distiller's solubles (CDS), de-oiled distiller's grains (DODG), and carbon dioxide (CO2)) minus the cost of the inputs, which are primarily corn, electricity, and natural gas.

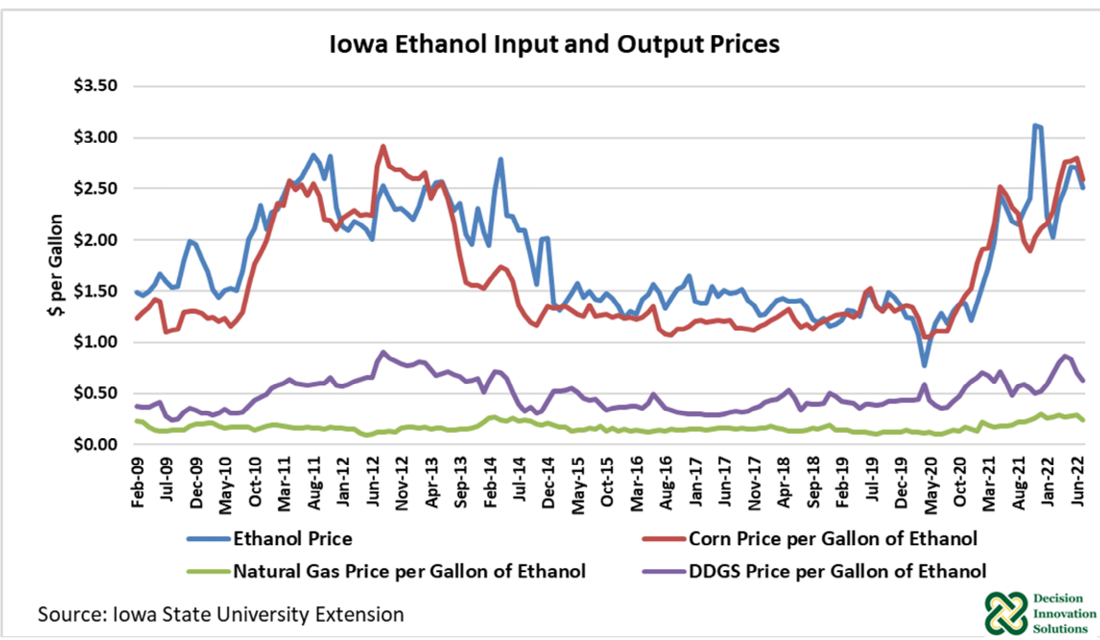


Figure 8. Iowa Ethanol Input and Output Prices

[10] https://ethanolproducer.com/articles/14122/ethanol-industry-provides-critical-co2-supply

Both ethanol prices and corn prices have been quite variable over the past 15 years and occasionally do not move together, although the correlation coefficient between the price of ethanol and the price of corn is 0.81. Natural gas prices vary month to month but are not as volatile as either ethanol prices or corn prices. In Figure 8, the corn and natural gas values are shown on a 'per gallon of ethanol" production basis.

3.3.1 Operating Margins

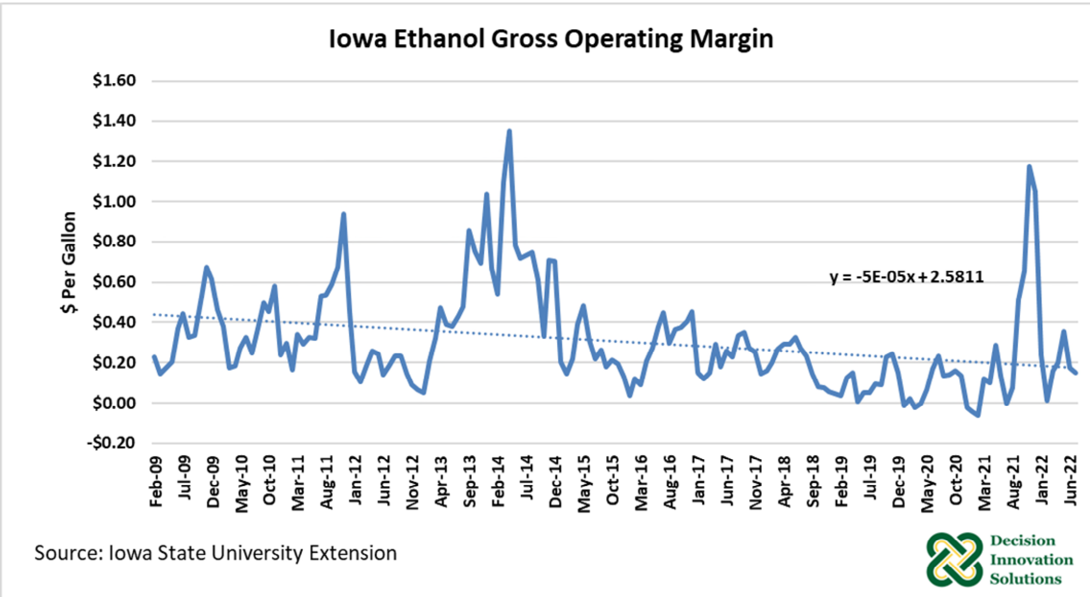


Figure 9. Iowa Ethanol Gross Operating Margin

Gross operating margins in Iowa as shown in Figure 9 have varied from a high of $1.35 per gallon to a low of -$0.06 per gallon. The average gross operation margin over the past 13.5 years has been $0.31

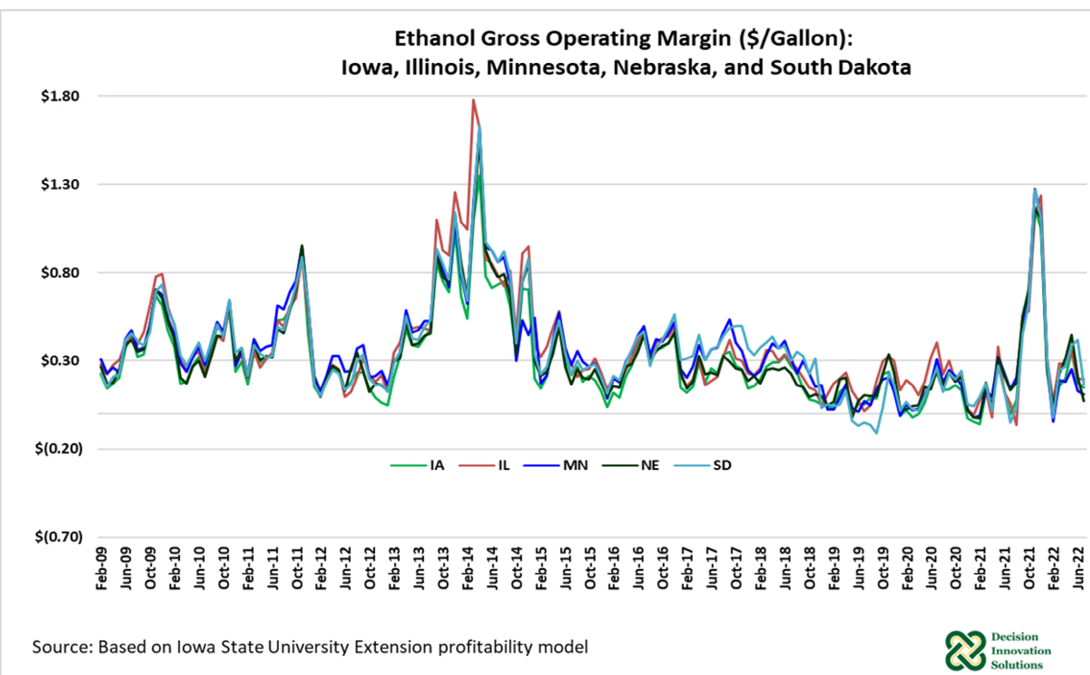


Figure 10. Ethanol Gross Operating Margin ($/Gallon): Iowa, Illinois, Minnesota, Nebraska, and South Dakota

per gallon. Operating margins have declined over the full 15-year period of 2007-2022 but have shown a flat trend since the middle of 2014 with quite a bit of variability during that period. The most recent gross operating margin based on data from January 2023 indicates a gross operating margin of $0.147 per gallon. Graphs similar to Figure 9 for Illinois, Minnesota, Nebraska and South Dakota are in the appendix.

Based on 13.5 years of data (February 2009-July 2022), operating margins in the five states (Figure 10) included in the study have averaged from $0.31/gallon in Iowa, to $0.38 in Illinois. The lowest operating margin among these states was registered in South Dakota at $-0.11/gallon, whereas the highest operating margin was experienced in Illinois at $1.78/gallon (see Figure 10 and Table 6).

Table 6. Summary of Operating Margins (Feb 2009-Jul 2022, $/Gallon): Iowa, Illinois, Minnesota, Nebraska, South Dakota

Gross Operating Margins (Feb 2009- Jul 2022, $/Gallon)					
Statistic	**IA**	**IL**	**MN**	**NE**	**SD**
Minimum value	**-$0.06**	**-$0.06**	**-$0.04**	**-$0.03**	**-$0.11**
Maximum value	**$1.35**	**$1.78**	**$1.62**	**$1.57**	**$1.64**
Average value	**$0.31**	**$0.38**	**$0.37**	**$0.34**	**$0.37**
Source: Based on Iowa State University Extension profitability model					Decision Innovation Solutions

3.3.2 Impacts of 45Z Tax credits

The producer tax credits created by section 45Z can be earned by ethanol producers who produce ethanol with a CI score less than 50. While the exact manner in which the credit will be allocated has yet to be determined by the regulating agency, it is assumed for this analysis that it will be calculated based on a sliding scale as the CI score of the ethanol plant declines below the threshold level of 50 CI. For a 100 million gallon per year ethanol plant that can achieve a CI score of 26 via a combination of enhancements of plant operations, carbon capture and sequestration, the value of the 45Z tax credit could be $48 million per year ((50-26)*$0.02/gallons produced), assuming that all gallons of ethanol produced at the facility qualify for the bonus credit.

Table 7. Value of 45Z Tax Credit at Various CI Scores

Value of the 45Z Tax Credit at Various CI Scores 100 Million Gallon Per Year Ethanol Plant					
	Pct CO2 Captured & Sequestered				
CI Score	20%	40%	60%	80%	100%
50	$ -	$ -	$ -	$ -	$ -
47	$ 1,200,000	$ 2,400,000	$ 3,600,000	$ 4,800,000	$ 6,000,000
44	$ 2,400,000	$ 4,800,000	$ 7,200,000	$ 9,600,000	$ 12,000,000
41	$ 3,600,000	$ 7,200,000	$ 10,800,000	$ 14,400,000	$ 18,000,000
38	$ 4,800,000	$ 9,600,000	$ 14,400,000	$ 19,200,000	$ 24,000,000
35	$ 6,000,000	$ 12,000,000	$ 18,000,000	$ 24,000,000	$ 30,000,000
32	$ 7,200,000	$ 14,400,000	$ 21,600,000	$ 28,800,000	$ 36,000,000
29	$ 8,400,000	$ 16,800,000	$ 25,200,000	$ 33,600,000	$ 42,000,000
26	$ 9,600,000	$ 19,200,000	$ 28,800,000	$ 38,400,000	$ 48,000,000
23	$ 10,800,000	$ 21,600,000	$ 32,400,000	$ 43,200,000	$ 54,000,000
20	$ 12,000,000	$ 24,000,000	$ 36,000,000	$ 48,000,000	$ 60,000,000
17	$ 13,200,000	$ 26,400,000	$ 39,600,000	$ 52,800,000	$ 66,000,000
14	$ 14,400,000	$ 28,800,000	$ 43,200,000	$ 57,600,000	$ 72,000,000
11	$ 15,600,000	$ 31,200,000	$ 46,800,000	$ 62,400,000	$ 78,000,000
8	$ 16,800,000	$ 33,600,000	$ 50,400,000	$ 67,200,000	$ 84,000,000
5	$ 18,000,000	$ 36,000,000	$ 54,000,000	$ 72,000,000	$ 90,000,000
2	$ 19,200,000	$ 38,400,000	$ 57,600,000	$ 76,800,000	$ 96,000,000

Assumes that implementation of the 45Z credit is incremental belo
and producers qualify for bonus credit
CI 26 highlighted as feasible target for drymill plants with sequestra

The values in Table 7 represent the potential differential in gross revenues that ethanol plants which have the ability to capture carbon and sequester it through means such as a pipeline may have over plants which cannot access such opportunities. Given that the gross operating margin for 100 mgy ethanol plant has averaged $28 million per year, competing with an ethanol plant that can boost its revenues by $48 million per year (271%) by accessing carbon capture and sequestration technology creates a substantial disadvantage for an ethanol plant which cannot access the technology.

Continuing to assume a CI reduction to 26 and a gross margin of $48 million per year, if the cost to build an ethanol plant on a location that has the capability to access carbon capture and sequestration technology is between $2 to $2.50 per gallon of capacity, it would only take 4 to 5 years for a new plant to fully recover the cost of building a plant in a location that enables access to carbon capture and sequestration.

Expansion of ethanol production capacity is estimated to cost $0.50 to $1.00 per gallon of additional capacity. Continuing to assume a CI reduction to 26, ethanol plants with access to carbon capture and sequestration, and thus the 45Z tax credit will have significant incentives to expand capacity since the cost of expansion may be fully recovered in 1 to 2 years.

Ethanol plants that do not have access to either direct injection of CO2 or carbon capture and sequestration via a pipeline may have an opportunity to participate in the 45Q tax credits for carbon capture and utilization. In this case, there are two variables that affect the overall value of the carbon captured and used. One is the percentage of the carbon produced that is captured and utilized. The second variable is the value of the carbon dioxide that is being used in the merchant markets or for Enhanced Oil Recovery (EOR). If the captured carbon has no commercial value (for example when sequestered), then the 45Q tax credit for a 100 mgy ethanol plant could be $17.1 million per year just for the capture and sequestration.

Table 8. Value of the 45Q Tax Credit at Various Pct of CO2 Capture & Use Values

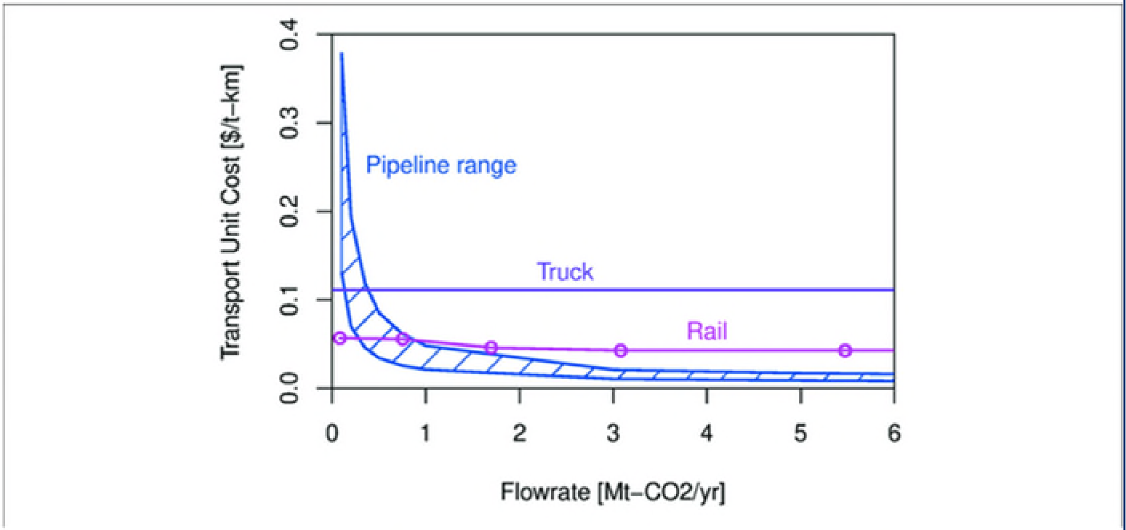
Value of the 45Q Tax Credit at Various Pct of CO2 Capture & Use Values 100 Million Gallon Per Year Ethanol Plant					
	Pct CO2 Captured & Utilized				
CO2 Market Value	**20%**	**40%**	**60%**	**80%**	**100%**
$0.00	$ 3,420,000	$ 6,840,000	$ 10,260,000	$ 13,680,000	$ 17,100,000
$10.00	$ 3,990,000	$ 7,980,000	$ 11,970,000	$ 15,960,000	$ 19,950,000
$20.00	$ 4,560,000	$ 9,120,000	$ 13,680,000	$ 18,240,000	$ 22,800,000
$30.00	$ 5,130,000	$ 10,260,000	$ 15,390,000	$ 20,520,000	$ 25,650,000
$40.00	$ 5,700,000	$ 11,400,000	$ 17,100,000	$ 22,800,000	$ 28,500,000
$50.00	$ 6,270,000	$ 12,540,000	$ 18,810,000	$ 25,080,000	$ 31,350,000
$60.00	$ 6,840,000	$ 13,680,000	$ 20,520,000	$ 27,360,000	$ 34,200,000
$70.00	$ 7,410,000	$ 14,820,000	$ 22,230,000	$ 29,640,000	$ 37,050,000
$80.00	$ 7,980,000	$ 15,960,000	$ 23,940,000	$ 31,920,000	$ 39,900,000
$90.00	$ 8,550,000	$ 17,100,000	$ 25,650,000	$ 34,200,000	$ 42,750,000
$100.00	$ 9,120,000	$ 18,240,000	$ 27,360,000	$ 36,480,000	$ 45,600,000
Assumes that plants can access 100% of the bonus credit level for 45Q for Capture and Use for the percentages of capture modeled					Decision Innovation Solutions

As the value of the captured and utilized carbon increases, the combined value of the 45Q tax credit and the CO2 sold into merchant markets (industrial use or EOR) increases. At a market value of $30/ton for CO2, the ethanol plant gross revenues could be increased by $25.65 million per year. If the value of merchant carbon rises to $100 per metric ton of CO2, then the combined value of the 45Q tax credit and the sale of the CO2 becomes equivalent to an ethanol plant with a CI score of 27 to 28.

3.3.3 Transport Costs for CO2

The cost of capturing carbon dioxide at the ethanol plant should be similar whether the carbon is being sent to a pipeline or being captured in an on-site storage facility for transfer to commercial use by either truck or rail. The cost of transportation, regardless of its end use, is likely to be much higher for non-pipeline transport methods.

CO2 resulting from ethanol production can be captured and either compressed for transport via pipeline or liquified for transport by truck or rail. Pipeline CO2 can then be injected directly underground when it reaches the storage site. Liquified CO2, which is kept at about –40°C and 20 bar of pressure, must be warmed and compressed before injection into a pipeline (90-145 bar and ambient temperature). The cost of CO2 transport via pipeline declines rapidly as flow rate of the pipeline increases (Figure 11).



| Comparison of transport costs of CO 2 by truck, rail, and pipeline as a function of flowrate. Costs are calculated for a distance of 200 km.

Figure 11. Comparison of Transport Cost for CO2 by Truck, Rail, and Pipeline as a function of Flowrate, Calculated for a Distance of 200 km[11].

CO2 pipelines are a mature technology and have been widely used globally for decades, with over 5,000 miles of CO2 pipelines in the United States in 2017 (Righetti, 2017). CO2 pipelines in the United States are used primarily to transport CO2 to oil fields for use in enhanced oil recovery. As mentioned, data for the cost of transporting different quantities of CO2 are limited, but natural gas pipelines are a useful analog by which to understand the cost components and variability underpinning CO2 pipelines. Both depend largely on pipeline diameter and distance and differ little in land construction costs, though CO2 pipelines may cost slightly more due to greater pipe thickness needed to transport CO2 at higher pressure (Heddle, 2003). The feasibility of repurposing natural gas pipelines for CO2 transport is not practical for transporting large quantities of CO2 (e.g., 20 Mtpa) over long distances (100 miles or more). This is because CO2 requires a higher pressure than natural gas to be kept in a liquid state for pipeline transport, and thus thicker pipelines are generally needed (NPC, 2019)[12].

(Erin E Smith 2021) Many integrated assessment modeling studies assume a combined cost for CO2 transport and storage that is uniform in all regions of the world, commonly estimated at $10/tCO2. Realistically, the cost of CO2 transport and storage is not fixed at $10/tCO2 and varies across geographic, geologic, and institutional settings. A survey of the literature to identify key sources of variability in transport and storage costs was done and a method to quantify and incorporate these elements into a cost range was developed. Onshore pipeline transport and storage costs vary from $4 to $45/tCO2 depending on key sources of variability including transport distance, scale (i.e., quantity of CO2 transported and stored), monitoring assumptions, reservoir geology, and transport cost variability such as pipeline capital costs.

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[11] Transport Cost for Carbon Removal Projects With Biomass and CO2 Storage, Frontiers in Energy Research, May 12, 2021. Sec. Carbon Capture, Utilization and Storage Volume 9 - 2021

[12] https://globalchange.mit.edu/sites/default/files/Smith-TPP-2021.pdf

Liquified CO_2 can be transported in insulated tanker railcars (assumed to carry 105 tons per car) that are similar between truck and rail. It is assumed the near-full capacity of 22 tons is retained for trucks, however, costs are somewhat higher because the trailers are more expensive and the trucks are slightly more expensive to operate and maintain.

Two studies have used techno-economic models to estimate the cost of CO_2 by rail for CO_2 storage case studies. Gao et al. (2011) calculated \$13/ton in 2018 US dollars to transport 1.5 Mt/yr over 600 km for a project in China[13]. This included \$0.88/t for staging and loading facilities. Roussanaly et al. (2017) estimated \$5/ton and \$13/ton to transport CO_2 for 50 km and 200 km, respectively, for a project in the Czech Republic. That includes slightly more than \$1/ton for loading and unloading facilities[14]. The staging operation thus appears to be a minor part of transport costs. Overall, it is estimated that the staging and loading operation adds \$2/ton-CO_2 to the cost of transport by rail. Thus, the unit costs for CO_2 transport by truck are estimated to be \$0.176/ton-mile and \$0.0704/ton-mile plus \$2 per ton for rail. So, a 200-mile truck shipment to commercial use is estimated to cost \$35.20 per ton and a 400-mile rail shipment to commercial use is estimated to cost \$30.16 per ton (including staging at both ends).

The cost of CO_2 transport by pipeline is more variable than for other modes since it depends on local construction costs and securing rights of way. Even with these challenges, pipelines are strongly preferred for large volumes of CO_2. There are over 7,000 km of CO_2 pipelines in the U.S. as well as a vastly larger network of natural gas pipelines that also informs the cost of pipeline construction.[15]

A spreadsheet-based model was developed by the National Energy Technology Laboratory[16] to estimate CO_2 transport costs via pipeline which in turn implements several earlier models from the literature.[17] [18] When validating the model against recent CO_2 pipeline projects, the authors found that the variant based on Parker tended to overestimate costs, while the variant based on McCoy and Rubin underestimated it. We thus take these to be the upper and lower bounds of the pipeline costs in further analysis. In Figure 12, "Parker" represents the model with the Parker (2004) variant, and the other lines show results for the McCoy and Rubin (2008)[19] variant for the respective regions of the U.S.

[13] Cost Analysis of CO_2 Transportation: Case Study in China, Lanyu Gao, Mengxiang Fang, Hailong Li, and Jens Hetland, Energy Procedia Volume 4, 2011. Pages 5974-5981.

[14] Roussanaly, S., Skaugen, G., Aasen, A., Jakobsen, J., and Vesely, L. (2017). Techno-economic evaluation of CO_2 transport from a lignite-fired IGCC plant in the Czech Republic. *Int. J. Greenh. Gas Control* 65, 235–250. doi: 10.1016/j.ijggc.2017.08.022.

[15] Wallace, M., Goudarzi, L., and Wallace, R. (2015). *A Review of the CO_2 Pipeline Infrastructure in the U.S." DOE/NETL-2014/1681.* Pittsburgh, PA: National Energy Technology Laboratory.

[16] NETL (2018). *FE/NETL CO_2 Transport Cost Model: Description and User's Manual DOE/NETL-2018/1877.* Pittsburgh, PA: National Energy Technology Laboratory.

[17] Parker, N. (2004). *Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs. UCD-ITS-RR-04-35.* Davis, CA: Institute of transportation Studies.

[18] McCoy, S. T., and Rubin, E. S. (2008). An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage. *Int. J. Greenh. Gas Control* 2, 219–229. doi: 10.1016/S1750-5836(07)00119-3

[19] McCoy, S. T., and Rubin, E. S. (2008). An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage. *Int. J. Greenh. Gas Control* 2, 219–229. doi: 10.1016/S1750-5836(07)00119-3

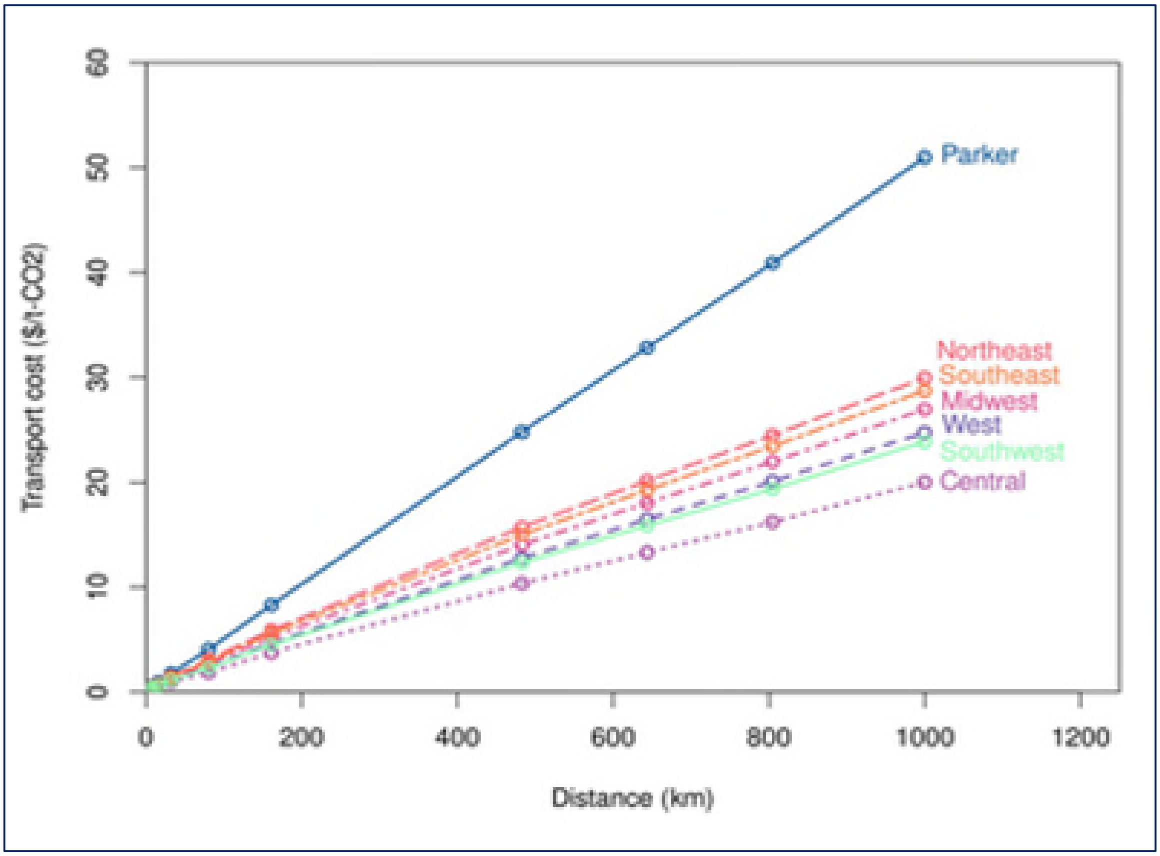

Figure 12. Cost of CO2 Transport by Pipeline in the U.S. by Model and Region with a Flow of 1 Million tons/year in 2014 dollars.

(Erin E Smith 2021) calculated the combined costs of CO2 transport and storage for various combinations of scale, transport distance, monitoring requirements, and cost assumptions. Table 9 summarizes the "mean cost" and the "high cost with monitoring" for three different pipeline capacities and for 100-mile and 500-mile transport distances. Smith notes that the "high cost with monitoring" scenario is more apt to be representative of storage and transport costs in the United States. For transport of CO2 for 500 miles in the U.S. Midwest, the estimated cost would be about $20 per ton.

Table 9. Combined Pipeline and Storage Costs

Combined Pipeline and Storage Costs				
	Mean Cost		High Cost with Monitoring	
Pipeline Capacity	100 Miles	500 Miles	100 Miles	500 Miles
3.2 Mtpa	$11.20	$24.10	$23.10	$43.80
6 Mtpa,	$9.00	$17.90	$18.60	$33.00
15 Mtpa	$7.40	$12.20	$15.60	$23.40
Source: The Cost of CO2 Transport and Storage in Global Integrated Assessment High cost with monitoring is more representative of the U.S.				

3.3.4 Impact of Various Carbon Capture Scenarios on Gross Margins of Ethanol Plants

The potential for capturing CO2 at ethanol plants and sequestering that CO2 with transport by pipeline greatly enhances the gross margins of an ethanol plant. Table 10 shows the gross margins as calculated using the ISU Extension Ethanol Margin Calculator for a 100 million gallon per year (mgy) Iowa ethanol plant under five scenarios. The first scenario is an ethanol plant that is operating with no CO2 capture. Using the latest data (January 2023) in the ISU calculator and state-average efficiency factors from Christianson Benchmarking LLC, it is estimated that the gross margin for a 100 mgy ethanol plant is 14.87 cents per gallon which translates to $14.87 million per year if the plant is running at capacity. That margin does not change with a change in the value of carbon and with an estimated CI score near 55 without capture and sequestration, there is no direct benefit for either the 45Q or the 45Z tax credits.

Table 10. Iowa Annual Gross Margins - 100 mgy Plant ($Million)

Iowa Annual Gross Margins - 100 mgy Plant ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Tax Credit Rate/gal	$0.00	$48.00	$24.20	$17.10	$17.10
Pct Participation	100%	100%	100%	75%	75%
$0.00	$14.87	$57.17	$33.40	$21.29	$20.22
$10.00	$14.87	$57.17	$33.40	$23.42	$22.35
$20.00	$14.87	$57.17	$33.40	$25.56	$24.49
$30.00	$14.87	$57.17	$33.40	$27.70	$26.63
$40.00	$14.87	$57.17	$33.40	$29.84	$28.77
$50.00	$14.87	$57.17	$33.40	$31.97	$30.90
$60.00	$14.87	$57.17	$33.40	$34.11	$33.04
$70.00	$14.87	$57.17	$33.40	$36.25	$35.18
$80.00	$14.87	$57.17	$33.40	$38.39	$37.32
$90.00	$14.87	$57.17	$33.40	$40.52	$39.45
$100.00	$14.87	$57.17	$33.40	$42.66	$41.59
$110.00	$14.87	$57.17	$33.40	$44.80	$43.73
$120.00	$14.87	$57.17	$33.40	$46.94	$45.87
$130.00	$14.87	$57.17	$33.40	$49.07	$48.00
$140.00	$14.87	$57.17	$33.40	$51.21	$50.14
$150.00	$14.87	$57.17	$33.40	$53.35	$52.28
$160.00	$14.87	$57.17	$33.40	$55.49	$54.42
$170.00	$14.87	$57.17	$33.40	$57.62	$56.55
$180.00	$14.87	$57.17	$33.40	$59.76	$58.69
Gross Margin calculated using ISU Extension Ethanol Margin Calculator Carbon tax credit and costs calculated by DIS					Decision Innovation Solutions

The second scenario (shown in the highlighted line in Table 10) is a 100 mgy ethanol plant that can capture its CO2 and achieves a CI score of 26 due to full access to carbon capture and sequestration via connection to a saline-formation storage facility via a CO2 pipeline. In this case, the gross margin rises to 57.17 cents per gallon which is equal to $57.17 million per year at capacity. That is a 284% increase in the gross operating margin of the ethanol plant. Since the Section 45Z tax credits are a function of the volume of ethanol produced and the CI score of that ethanol production, the value does not change with the price of carbon, but the gross margin would change based on the percentage of production capacity at which the plant operates and the CI score of the ethanol produced. For each 1-point change in the CI score, the gross margin would change by $2 million. Thus, there is a significant incentive for an ethanol plant to adopt processes and methodologies which would result in lowered CI scores. In a similar light, the enhanced margins that will be seen with section 45Z tax credits not only will greatly incentivize the adoption of processes and methodologies that result in lowered CI scores, but it creates incentives for production migration through construction of new production with access to 45Z tax credits and eventual abandonment of production at plants that do not qualify for 45Z tax credits.

Scenario 3, also reflected in Table 10, reflects the gross margin that is estimated for an ethanol plant that has the capability to capture carbon and transport it to sequestration via pipeline but is doing so under the conditions of Section 45Q tax credits. In this scenario, the tax credit is based on the number of tons of CO2 sequestered with the tax credit (assuming the bonus level is achieved) being $85 per metric ton of CO2 which translates to 24.2 cents per gallon of ethanol produced.

The value of the credit does not change with changes in the price of CO2 and it is assumed that since the carbon is being sequestered that the carbon itself generates no direct value to the ethanol plant. In this scenario, the gross operating margin is 33.4 cents per gallon which equates to $33.40 million per year for a 100 mgy plant. The difference between sequestering carbon via pipeline using either the 45Q or 45Z tax credits is estimated to be 23.77 cents per gallon or $23.8 million per year.

The 4th scenario in Table 10 is a 100 mgy ethanol plant that captures 75% of its carbon and needs to use rail to transport that carbon to either industrial end users or for use in Enhanced Oil Recovery (EOR)[20]. In this case, the 45Q tax credit is paid on the tons of CO2 captured and used at a rate of $60 per metric ton (bonus credit rate). In this case the operating margin is dependent on the price of carbon and is 21.29 cents per gallon if the carbon has no value and could be as high as 59.76 cents per gallon if CO2 can be sold at $180 per metric ton. If CO2 can be sold near the prices reported by Ethanol Producer magazine in 2017 (around $90 per ton) then the operating margin would be 40.52 cents per gallon. The ability to monetize the CO2 partially offsets the lowered tax credit rates of 45Q versus 45Z tax credits.

Even with no value for the CO2, the 4th scenario still generates a gross operating margin that is 6.4 cents per gallon better than the base case with no carbon capture, but it is 63 percent less than the operating margin that can be obtained through full participation in carbon capture and sequestration via pipeline and the 45Z tax credit. However, at $90 per metric ton for CO2, the gross operating margin is still 29% less than the 45Z case, but 172% better than the base case with no carbon capture.

It should be noted that if railroads are to be used for the movement of captured CO2, it will take an estimated 1,357 railcars per year (which is 26 railcars per week) to move the CO2 away from one 100 mgy plant and to its end use. If all the ethanol plants in Iowa had to try to use this method to capture CO2 and move it, an additional 61,071 railcars of CO2 would need to be moved year in Iowa, and would require an additional 2,350 CO2 railcars assuming they could complete a round trip once every two weeks and 4,700 new CO2 railcars if it took a month for each railcar to make the round trip with the CO2. It should be noted that enough railcars to move CO2 from Iowa's ethanol plants currently do not exist and the lead time to develop a fleet of these cars is likely to extend years into the future.

Another issue with the assumption that railcars can provide the transportation of the CO2 from Iowa's ethanol plants is that rail service is already stretched to provide sufficient and timely transportation for

[20] In the cases of rail or truck transport of CO2, we have only calculated the impacts of the 45Q tax credits, and not the 45Z tax credits because the CI scores for sequestration via rail or truck transport of CO2 from an ethanol plant has not been determined. The 45Q tax credit is based on the tonnage of CO2 sequestered or used, not on the CI score.

the ethanol that moves from Iowa's plants via rail tankers. Expecting railroads to be able to meet this new demand may be a significant stretch of the assumptions. Another issue with this scenario is that there may not be rail lines or rail services to the end users of CO2, either merchant use of CO2 or CO2 used for EOR. In this case, many of the issues with permitting and construction of pipelines may be manifest if new rail lines are needed which will permanently affect surface road transportation, land easements and environmental considerations. To be perfectly clear, reliance on rail and truck movements to transport all of Iowa's CO2 to sequestration points is just not feasible. There is already a shortage of rail engineers, the lead time to build all the trackage, tank cars, and/or tank trucks would mean plants are doomed before the system could reasonably build out that infrastructure and adjust to the idea of moving all that CO2 via surface transportation.

The 5th scenario in Table 10 is a 100 mgy ethanol plant that captures 75% of its carbon and needs to use trucks to transport that carbon to either industrial end users or for use in EOR. In this case, the captured CO2 is eligible for the 45Q tax credit and the captured CO2 is assumed to have positive value since it is being used for constructive purposes and not just sequestered. In this case, the higher costs of transportation of CO2 via truck versus either rail or pipeline, lowers the operating margin to 20.22 cents per gallon if CO2 has no value and to 39.45 cents per gallon at $90 per metric ton.

It should be noted that if trucks are to be used for the movement of captured CO2, it will take an estimated 6,477 trucks per year (which is 25 trucks per day in a 5-day shipping week) to move the CO2 away from one 100 mgy plant and to its end use. If all the ethanol plants in Iowa had to try to use this method to capture CO2 and move it, it would put an additional 291,500 trucks on the road per year in Iowa and would require an additional 1,121 CO2 trailers assuming they could complete a round trip per day with the CO2. Each trailer is likely to cost between $150,000 to $250,000.

It is possible that the plants represented by scenarios 4 and 5 could capture and monetize all of their CO2, but according to data from Christianson Benchmarking, LLC about 30% of ethanol plants capture some level of CO2 and the range for those that capture CO2 is between 22% of total emissions to 100% of total emissions. The average is 65% of total CO2 emissions available are being captured by plants that capture CO2.

According to the Global CCS Institute, "Pipelines are – and are likely to continue to be – the most common method of transporting the very large quantities of CO2 involved in CCS. There are already millions of kilometers of pipelines around the world that transport various gases, including CO2. Transport of CO2 by truck and rail is possible for small quantities. Trucks are used at some project sites, moving the CO2 from where it is captured to a nearby storage location. Given the large quantities of CO2 that would be captured via CCS in the long-term, it is unlikely that truck and rail transport will be significant[21]."

With regards to geographic distribution of CO2 capture at ethanol plants, there are a few plants within the primary corn belt states (Iowa, Illinois, Nebraska, Minnesota, South Dakota, and Nebraska) that capture CO2 for sale into the merchant carbon market (industrial uses and EOR). The majority of ethanol plants that currently capture CO2 are in states outside that region (tending toward the eastern area of the U.S.) and there does not seem to be an observable geographic pattern beyond this. It is likely that the facilities that currently capture CO2 for sale are located relatively near a consumer of CO2.

[21] https://www.globalccsinstitute.com/wp-content/uploads/2018/12/Global-CCS-Institute-Fact-Sheet_Transporting-CO2-1.pdf

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3.3.5 Potential State-level Impacts of the 45Z and 45Q Tax Credits

For the state of Iowa, the estimated gross margin of the ethanol industry which produced 4.5 billion gallons of ethanol in 2022 is $669 million. If all of the ethanol plants in Iowa were able to access pipelines and capture 100% of their CO2 emissions thus dropping their CI scores to a state-wide average of 26, then the operating margin would increase to $2.57 billion, a gain of $1.904 billion. In the case in which rail or trucks would be used to transport captured CO2 into the merchant CO2 market, the gross operating margin could still be greater than the base case with no CCS, ranging from $910 million (trucking with $0 price on CO2) to $1.82 billion (rail transport at $90/mt CO2 price).

Table 11. Annual Gross Margins - Iowa 4,500 mgy Production ($Million)

Annual Gross Margins - Iowa 4,500 mgy Production ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	75%	75%	75%
$0.00	$669	$2,573	$1,503	$958	$910
$10.00	$669	$2,573	$1,503	$1,054	$1,006
$20.00	$669	$2,573	$1,503	$1,150	$1,102
$30.00	$669	$2,573	$1,503	$1,246	$1,198
$40.00	$669	$2,573	$1,503	$1,343	$1,295
$50.00	$669	$2,573	$1,503	$1,439	$1,391
$60.00	$669	$2,573	$1,503	$1,535	$1,487
$70.00	$669	$2,573	$1,503	$1,631	$1,583
$80.00	$669	$2,573	$1,503	$1,727	$1,679
$90.00	$669	$2,573	$1,503	$1,824	$1,775
$100.00	$669	$2,573	$1,503	$1,920	$1,872
$110.00	$669	$2,573	$1,503	$2,016	$1,968
$120.00	$669	$2,573	$1,503	$2,112	$2,064
$130.00	$669	$2,573	$1,503	$2,208	$2,160
$140.00	$669	$2,573	$1,503	$2,304	$2,256
$150.00	$669	$2,573	$1,503	$2,401	$2,353
$160.00	$669	$2,573	$1,503	$2,497	$2,449
$170.00	$669	$2,573	$1,503	$2,593	$2,545
$180.00	$669	$2,573	$1,503	$2,689	$2,641
Gross Margin calculated using ISU Extension Ethanol Margin Calculator Carbon tax credit and costs calculated by DIS					Decision Innovation Solutions

Developing a merchant CO2 market for CO2 captured from Iowa ethanol plants is not as straightforward as planning for CO2 capture and delivery to a pipeline. There is substantially more uncertainty involved with development of merchant carbon markets that would require creating relationships and marketing channels with hundreds if not thousands of disparate, relatively small users of CO2 compared to planning for a single point-of-service hook-up to a pipeline. In addition, there would need to be construction of storage and loading, unloading facilities as well as CO2 injection facilities capable of handling hundreds of trucks and/or groups of rail cars as juxtaposed to a single point of injection access from a pipeline at the injection point.

3.3.6 Competitive Ethanol Production

Comparing ethanol production with CO2 capture and sequestration via pipeline (CCSvP) versus ethanol production with no carbon capture sets up a competitive advantage for producers who can do the CCSvP. With 40+ cents per gallon of enhanced gross margins (See Table 10 columns 2 and 3), there is a substantial incentive to expand production in locations that will facilitate the conditions in which that enhanced margin can be garnered. Based on news releases and data regarding expansion of ethanol production capacity at existing plants, the range of capital expenditure needed on a cost per gallon basis for expanded production is $0.50 to $1.00 per gallon. This range of capital costs appears to hold for recent expansions of production capacity in the range of 10-25% of existing plant capacity and may be applicable to up to 50% expansion of plant production capacity. For new construction, current capital expenditures needed to build dry mill plants sized at 100 mgy or greater range is $2.00 to $2.50 per gallon of production capacity.

As noted in Table 12 South Dakota and Iowa tentatively have the greatest shares of their ethanol production that is likely to have access to CCSvP. If in a state such as Iowa, ethanol plants are unable to access CO2 transport via pipeline, then there will be incentives for expansion of production in areas where such access is feasible. Many ethanol plants in Illinois will have access to carbon capture and direct injection at or near the plant site (such as is currently done by ADM in Decatur, IL) and thus there is less need for pipeline transport of CO2 in Illinois. Similar conditions (capability for direct injection) exist for many, if not most, of the ethanol plants in Indiana, Ohio, Michigan, and Kansas (see the map in Figure 3.

Table 12. Summary of CO2 Pipeline Volumes

Summary of CO2 Pipeline Volumes

	Pipeline Name					
State	Navigator	Summit	Wolf	Pipeline Total	State Total	Pipeline Share of State Total
IA	6,329,850	3,773,400.0	2,214,450	12,317,700	13,329,450	92.4%
IL	370,500	-	-	370,500	5,449,200	6.8%
MN	929,100	1,319,550.0	-	2,248,650	3,975,750	56.6%
ND	-	498,750.0	-	498,750	1,539,000	32.4%
NE	997,500	1,427,850.0	-	2,425,350	6,697,500	36.2%
SD	2,166,000	1,710,000.0	-	3,876,000	3,876,000	100.0%
Grand Total	10,792,950	8,729,550	2,214,450	21,736,950	34,866,900	62.3%

Source: DIS Estimates of CO2 production capacity per ethanol plant
Pipeline match-up with ethanol plants based on publicly available maps

Using the midpoint of the costs for expansion of capacity, existing ethanol plants in areas where CO2 pipelines are enabled, the margin differential is sufficient to cover the capital expenditures associated with expansion in 1.5 to 2.5 years. At this payback rate, it is estimated that a 30% expansion of ethanol production at existing plants with CCSvP capacity would occur, assuming the plants in Iowa did not have CCSvP access. This would result in an estimated 690 million gallons of additional ethanol production just from the expansion of existing plants and could eventually result in an offsetting reduction in production at ethanol plants based in Iowa.

Table 13. Potential Expansion of Ethanol Production at Plants with CCSvP Capability

Potential Expansion of Ethanol Production at Plants with CCSvP Capability			
State	Navigator	Summit	Total
MN	70,815	100,575	171,389
ND	-	38,014	38,014
NE	76,028	108,829	184,857
SD	165,090	130,334	295,424
Grand Total	311,933	377,752	689,685

In addition to expansion of ethanol production at existing plants, a 40+ cent per gallon differential in the gross operating margin of plants with CCSvP and plants that do not have it, there will be incentives to build more capacity with such access. The payback time for these plants if they use all the enhanced gross margin difference is 4.25 to 5.7 years. This is a long enough timeframe that immediate new construction is not likely given the level of uncertainty that exists for potential construction of CO2 pipelines in Iowa and uncertainty about the extension of 45Z tax credits beyond the initial authorization period[22], but the longer that uncertainty with regards to construction of CO2 pipelines in Iowa persists, the greater the incentives for new construction that can capture the higher gross operating margins and that would lead to the reduction in production in areas where the margins are lower. Inasmuch as there is more than 3.67 billion gallons of ethanol production in Iowa that is proposed to be on the CO2 pipelines, it is not out of the realm of possibility that all that production could be displaced by production just beyond the borders of Iowa where access to a CO2 pipeline is achievable or could be achievable with rerouting of planned pipelines.

Some may question how much migration of production might occur since the 45Z tax credit is currently only authorized for 3 years (through the end of 2027). While the 45Z tax credit is only authorized through 2027 and likely to be extended, it should be noted that the 45Q tax credit already extends to 2030 in current law. At $85/ton of CO2, which equates to about 24 - 25 cents per gallon of ethanol. Plants that initially qualify for and elect to take the 45Z tax credit could then switch to 45Q tax credits if the 45Z tax credits were allowed to expire . But even so, there would still be nearly 25 cents of value per gallon to those that had access to a pipeline. The rapid payback for new construction with access to CCSvP and the certainty of significant tax credits for sequestration that extend to at least 2030 increases the likelihood of migration of production, and the quicker that migration begins the more certainty those new plants would have of benefitting from the 45Z and/or the 45Q tax credits.

Table 14 summarizes the comparison of annual gross margins (using annualized January 2023 data) for production of ethanol with no CCS and with CCSvP for Iowa, Illinois, Minnesota, Nebraska, and South Dakota. It also includes a summary of the comparative advantage Illinois, Minnesota, Nebraska, and South Dakota would have over Iowa if they can access CCSvP and Iowa cannot. Table 14 also shows just

[22] It is widely expected that the 45Z tax credits will be extended beyond the initial authorization period, but there is no certainty that an extension will be forthcoming.

how quickly the capital costs of new construction of ethanol production in those states could be paid back using just the additional margin that those plants would have because of access to the 45Z tax credits and access to CCSvP.

Table 14. Comparison of annual Gross Margins - 100 mgy Plants ($Million)

Comparison of Annual Gross Margins - 100 mgy Plants ($Million)					
	Iowa	Illinois	Minnesota	Nebraska	South Dakota
No CCS	$14.87	$11.97	$15.86	$19.05	$25.86
CCS45Z Pipeline	$57.17	$54.27	$58.16	$61.35	$68.16
Comparative Advantage CCSvP vs No CCS		$39.40	$43.29	$46.48	$53.29
Payback Time New Plant with CCSvP from	Years	5.71	5.20	4.84	4.22
Assumes $2.25 per gal construction cost					

3.3.7 Projected Impacts on Iowa Ethanol Production

Four scenarios are presented here with regard to construction of new production of ethanol in areas where CCSvP is facilitated versus areas that are not facilitative of CCSvP (Table 15). The quickest relocation of ethanol production would come from expansion of existing plants that have greater certainty that they can access a CO2 pipeline. The first scenario is the production that could come from expansion of production at existing plants in four state that adjoin Iowa (IL, MN, NE and SD) that have relative certainty about CCSvP. The second scenario is the level of relocation of production that could come in 3-4 years as companies build new ethanol facilities on CO2 pipelines. The third scenario could happen in as few as 4-6 years as the certainty over carbon emissions policy (tax incentives) becomes more certain that it would last beyond the current termination date in the Inflation Reduction Act. And the fourth scenario is what may be feasible if the CO2 pipelines are built with excess capacity and the ability to absorb even more new development.

Table 15. Scenarios of Relocation of Ethanol Production (Million Gallons Per Year)

Scenarios of Relocation of Ethanol Production						
Million Gallons Per Year						
	Iowa	Illinois	Minnesota	Nebraska	South Dakota	Feasibility Period
Iowa Down 15%	(655)		170	185	300	Expansion 1-3 yrs
Iowa Down 25%	(1,150)	100	250	400	400	3-4 yrs
Iowa Down 50%	(2,300)	300	500	750	750	4-6 yrs
Iowa Down 75%	(3,450)	300	750	1250	1150	5-10 yrs

While there is some room for expansion of ethanol capacity over the next few years without crashing operating margins for all ethanol plants, the ability to collect the 45Z tax credit by plants that are sequestering CO2 via pipeline will create huge incentives for those plants to expand and for investors to build capacity that is on a pipeline. It is that expansion that will push ethanol margins down overall which will result in ethanol plants without access to the 45Z credits to have their operating margins turn negative while the plants with the credits will still have very positive operating margins. This pressure will build until nearly all ethanol plants that are operating are those with access to the tax credits. There is historical evidence of ethanol plants with negative operating margins shutting down.

High corn prices that resulted in negative margins were cited as a reason that Southwest Georgia Ethanol shut down in 2012. Flint Hills acquired the 120 mgy plant in 2015 and after shutting the plant down during COVID-19, determined that it would not re-open the plant.

Iowa ethanol plants are competitive within the current market structure of energy and ethanol markets and are well positioned to provide feed byproducts of ethanol to local livestock feeders. But long periods of potentially negative operating margins would eventually “right-size” the ethanol market by forcing producers with negative margins to shutter their plants and reduce the supply of ethanol.

Loss of 75% of the Iowa ethanol industry would result in an eventual decline in revenues from ethanol plants (ethanol, DDGs, and DCO) of more than $10 .3 billion per year (Table 16). These losses would reverberate throughout the Iowa economy as corn prices would adjust downward, costs to get DDGs delivered to Iowa feeders would increase and DCO would be less available (or more costly) to biodiesel and renewable diesel production facilities and for feed use.

Table 16. Relocation of Economic Activity - Ethanol Plants

Relocation of Economic Activity - Ethanol Plants					
Change in Annual Sales Value of Ethanol Plants					
Million $ Per Year					
	Iowa	Illinois	Minnesota	Nebraska	South Dakota
Iowa Down 15%	-$1,957	$0	$505	$535	$915
Iowa Down 25%	-$3,436	$304	$743	$1,156	$1,220
Iowa Down 50%	-$6,873	$911	$1,485	$2,167	$2,287
Iowa Down 75%	-$10,309	$911	$2,228	$3,612	$3,506
Includes sales value of ethanol, DDGs, and DCO Projected using January 2023 prices					

3.3.8 Summary of the Impacts of No Carbon Pipelines in Iowa

Margins matter. And with even a moderate time horizon, margin advantages of 40+ cents per gallon will stimulate movement of ethanol production to locales that enable capturing those margins. Not facilitating access to CCSvP in Iowa could lead to a significant reduction in ethanol production within Iowa. Under the scenario in which Iowa ethanol production contracts by 75% (within 5-10 years) the loss in direct revenue from ethanol production is more than $10.3 billion per year. The 45Z tax credits significantly change the operating environment for all ethanol production. Iowa's ethanol plants cannot afford to miss out on $2.16 billion in tax credits that would be available to plants that have access to CCSvP.

The difference in margins for plants with access to CCSvP will create incentives for rapid and significant expansion of production in those areas and corresponding reductions in ethanol production in areas without such access. Currently, Iowa processes 1.58 billion bushels of corn for ethanol. If Iowa loses 75% of its ethanol production over the next 5-10 years due to non-competitive margins with ethanol plants that can successfully capture carbon and transport it economically to storage facilities, Iowa farms stand to lose local markets for 1.18 billion bushels of corn. That corn may still have a market, either ethanol in a neighboring state or export markets, but the value of that corn will be less as the transportation differentials for local demand versus demand that may be a hundred or a thousand miles away will reduce local basis by that transportation differential.

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5 Appendices

5.1 Feedstock Carbon Intensity Calculator (FD-CIC)[23]

The carbon intensities (CIs) of biofuels are determined with the life cycle analysis (LCA) technique, which accounts for the energy/material uses and emissions during the complete supply chain of a biofuel including feedstock production and fuel conversion stages.

Besides biofuel conversion stage, different farming practices for feedstock growth can result in significant CI variations for feedstocks, thus for biofuels. To provide evidence-based research findings, the U.S. Department of Energy's Advanced Research Projects Agency–Energy (ARPA-E) has supported the Systems Assessment Center of the Energy Systems Division at Argonne National Laboratory to examine CI variations of different farming practices to grow agricultural crops for biofuel production. Meanwhile, the ARPA-E has launched the Systems for Monitoring and Analytics for Renewable Transportation Fuels from Agricultural Resources and Management (SMARTFARM) program to develop technologies and data platforms that enable an accurate measurement of key farming parameters that can help robust accounting of the GHG benefits of sustainable, low-carbon agronomic practices at farm level.

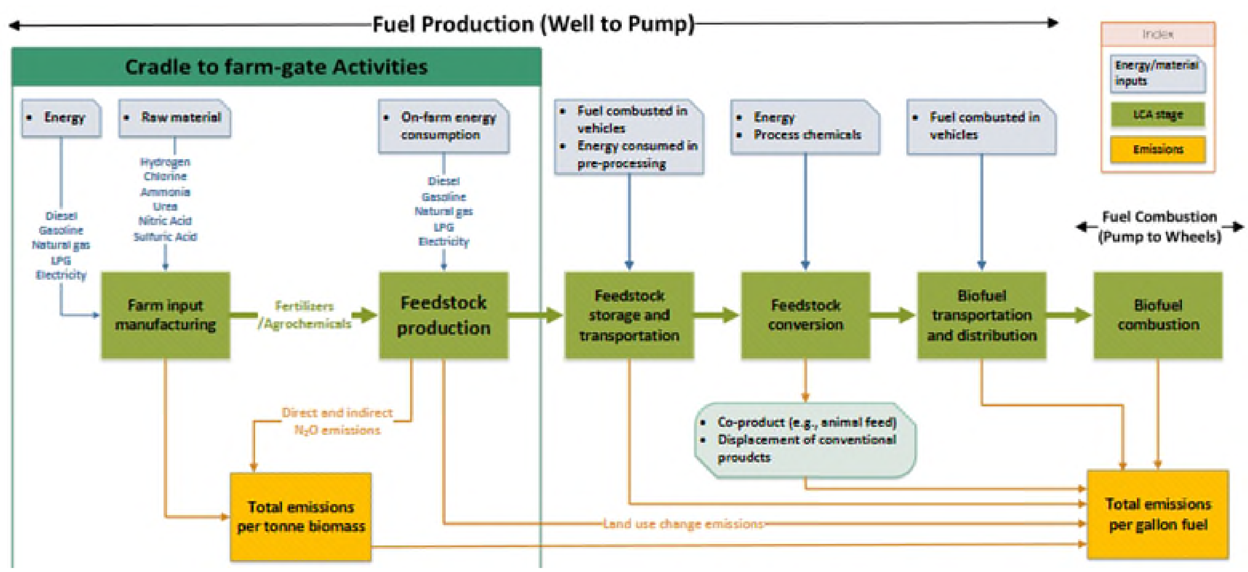

Figure 13. The System Boundary of FD-CIC (i.e. cradle-to-farm-gate activities) compared to a complete supply chain of a biofuel

A transparent and easy-to-use tool for feedstock-specific, farm-level CI calculation of feedstocks is especially helpful. With the ARPA-E support, the Systems Assessment Center has developed a tool - the Feedstock Carbon Intensity Calculator (FD-CIC). The first version of the FD-CIC with the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model 2020 release accounts for user-specific, farm-level input data for corn production, coupled with the life-cycle inventory (LCI) data

[23] Argonne National Laboratory, https://greet.es.anl.gov>files>fd-cic-tool-2020

of key farming inputs from the GREET model (Wang et al 2020). The FD-CIC tool helps stakeholders to assess the effects of changing farm-level input parameters on corn CI scores in the biofuel LCA context.

Key parameters affecting biofuel feedstock CI include corn yield, fertilizers/chemicals application rates, and agronomic practices. Corn yield is related to the total volume of ethanol produced per area of land by coupling with the corn-grain-to-ethanol conversion rate (2.88 gallon of ethanol per bushel of corn). The corn yield also determines the amount of corn residue left on the farm field, which affects N2O emission and soil organic carbon (SOC) sequestration potentials.

Inclusion of agronomic practice as a key parameter in FD-CIC reflects the current interest in evaluating the CI of the biofuel feedstock produced by various sustainable land management practices such as: i) nitrification inhibitor use to reduce fertilizer-induced N2O emissions, ii) conservation tillage adoption to increase SOC and reduce on-farm energy uses in tilling, iii)manure application to improve soil quality by adding organic carbon and nutrients, and iv) cover cropping to increase residue carbon and nutrients in soils and reduce soil erosion.

As an important component in biofuel LCA, land use change (LUC) -induced emissions have been incorporated into biofuel CI calculation to account for SOC sequestration/GHG emissions associated with the shift in land-use and land-cover for large-scale biofuel feedstock production. However, since the FD-CIC focuses on the cradle-to-farm-gate activities, it does not include LUC emissions in CI calculation but has a lookup table for SOC sequestration potentials of diverse farming practices to address great opportunities for CI reductions.

Currently, two versions of FD-CIC are available, namely the dynamic version and the standalone version. The dynamic version interacts with the GREET model (in particular, GREET1, the fuel cycle model of GREET) by directly reading the LCI data of key farming inputs from the model. The dynamic version suits well when users want to change the default settings of the GREET model as related to farming inputs. For example, if the users want to assess the impact of using regional electricity grid mix, instead of the U.S. average grid mix, they can modify the grid mix in the GREET model and utilize the interacting feature in the FD-CIC to re-read the updated CI values for key farming inputs. The interacting feature also enables the CI values to be updated with annual GREET release. The standalone version suits well for users who are not familiar with the GREET model and contains the default LCI data for key farming inputs from the GREET model. It is worth mentioning that the interacting feature will only work if users have GREET version 2020 or later and keep the GREET1 excel file in the same folder as with the FD-CIC tool.

The structure of the FD-CIC tool is presented in Figure 14 and defines the color schemes of cells for different types of parameters used in the FD-CIC tool.

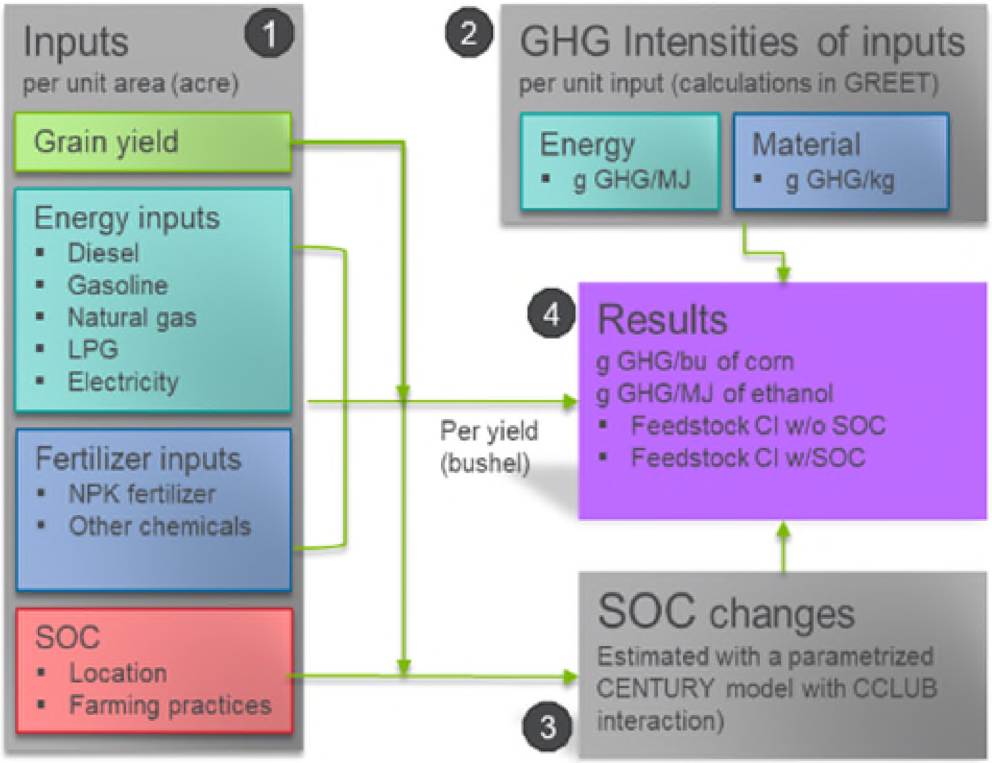

Figure 14. Structure of FD-CIC Calculator Model

In the Inputs worksheet, users need to provide key information on corn yield, energy consumption, and fertilizer/chemical uses Table 17. In particular, the energy use from all on-farm operations, including field preparation, tilling, fertilizer/chemical application, grain drying, and corn irrigation, should be included. If farms have not used a specific energy/fertilizer type, as defined in FD-CIC, the value for the specific type should be set to zero.

The FD-CIC tool uses U.S. customary units by default (e.g. pound per acre or bushel per acre), followed by intermediate calculations to translate them into the GREET customary units for CI calculation (i.e. grams of GHG emitted per short ton of fertilizer or per British Thermal Unit of energy), so that the CI coefficients obtained from the GREET model can be utilized. It is noteworthy that herbicide and insecticide types are not differentiated because of their small contribution to the overall feedstock CI (< 2%).

As shown in Table 17, GREET default values reflecting US average corn farming are provided as the baseline scenario. Users can modify the blue cells to build their specific case and compare the results with the GREET default scenario. Please note that in the GREET model, the amount of fertilizers applied is measured by the amount of nutrients in fertilizer; but in FD-CIC, the amount of fertilizers applied is the actual compound application rates.

Table 17. Farm-Level Inventory Required by FD-CIC Calculator

1) Farming input parameters			
1.0) Farm size	User Specific Value	GREET Default Value	Unit
1.0.1) Farm size	1000	1000	acre
1.1) Yield	User Specific Value	GREET Default Value	Unit
1.1.1) Corn yield	166	166	Bushels/acre
1.2) Energy	User Specific Value	GREET Default Value	Unit
1.2.1) Diesel	4.4	4.4	Gallons/acre
1.2.2) Gasoline	1.5	1.5	Gallons/acre
1.2.3) Natural gas	158.4	158.4	ft3/acre
1.2.4) Liquefied petroleum gas	2.4	2.4	Gallons/acre
1.2.5) Electricity	15.5	15.5	kWh/acre
1.3) Nitrogen Fertilizer	User Specific Value	GREET Default Value	Unit
1.3.1) Ammonia	52.7	52.7	lbs/acre
1.3.2) Urea	69.0	69.0	lbs/acre
1.3.3) Ammonium Nitrate	8.0	8.0	lbs/acre
1.3.4) Ammonium Sulfate	13.2	13.2	lbs/acre
1.3.5) Urea-ammonium nitrate solution	44.8	44.8	lbs/acre
1.4) Phosphorus Fertilizer	User Specific Value	GREET Default Value	Unit
1.3.6)/1.4.1) Monoammonium Phosphate	51.0	51.0	lbs/acre
1.3.7)/1.4.2) Diammonium Phosphate	52.6	52.6	lbs/acre
1.5) Potash Fertilizer	User Specific Value	GREET Default Value	Unit
1.5.1) K2O	53.6	53.6	lbs/acre
1.6) Lime	User Specific Value	GREET Default Value	Unit
1.6.1) CaCO3	472.2	472.2	lbs/acre
1.7) Herbicide	User Specific Value	GREET Default Value	Unit
1.7.1) Herbicide	971.6	971.6	g/acre
1.8) Insecticide	User Specific Value	GREET Default Value	Unit
1.8.1) Insecticide	2.1	2.1	g/acre

Soil organic carbon lookup

Currently, the corn ethanol CI calculated for regulations does not account for SOC changes in corn farms due to different land management practices, which is either sequestrated as SOC (i.e., increase in SOC) or emitted as CO2 (i.e., decrease in SOC). The change in SOC due to the change in practices in corn farms can be significant and consideration of SOC in CI scoring can incentivize conservation practices that are tied to carbon sequestration and abatement. For example, growing of cover crops and application of manure in corn farms contribute positively to SOC stock increase, leading to net carbon sequestration compared to cases where cover crops and manure are not applied. On the other hand, the growth of cover crops and manure applications are associated with additional herbicide/energy use and associated emissions due to herbicide/energy manufacturing. These emission burdens also need to be accounted for (Liu et al 2020).

The FD-CIC provides a lookup table for the SOC sequestration potentials corresponding to different farming practices based on default simulation results using county-level corn yield record, soil, and climate information (Liu et al 2020). Therefore, the farm-level yields of cover crop and major crops (e.g., corn and soybean) provided by users would not affect the SOC change per hectare but the SOC change per bushel of corn. That is, SOC estimates in the FD-CIC are developed at the U.S. county level, not at the farm level. As indicated by the SOC lookup table (Figure 15), the users can look up the potential SOC changes. It should be noted that positive SOC values represent CO2 emissions while negative values represent SOC sequestration.

3) Soil organic carbon lookup		CCLUB Default Value	
2.0.) Location - State		SD	
2.0.1) Location - County		Aurora	
2.0.2) Location - FIPS		46003	
2.1.) Cover crop		Cover crop	
		Cover crop	
		No cover crop	
2.2.) Manure		Manure	
		Manure	
		No manure	
2.2.) Tillage		Conventional tillage	
		Conventional tillage	
		Reduced tillage	
	User Specific Value	No tillage	
2.4.) SOC	-48.2	-48.2	kg C/ha/yr

Figure 15. Soil Organic Carbon Look-up Table

The FD-CIC tool estimates the emissions of CO2, CH4, and N2O combined with their 100-year global warming potentials (GWP) of 1, 30, and 265, respectively. N2O emissions from soils and biomass are calculated mainly on the basis of the emission factors approach developed by the Systems Assessment Center (Wang et al 2012, Xu et al 2019) and Intergovernmental Panel on Climate Change (Dong et al 2006), using emission factors from various nitrogen sources defined by the GREET model. As an example, to calculate the N2O emission due to ammonia fertilizer application, the application rate of ammonia is multiplied by the ratio of nitrogen in ammonia to calculate the application rate of ammonia-nitrogen. The emission factor of 1.325% is then applied, which is the percentage of nitrogen in nitrogen fertilizer and biomass that is converted to nitrogen in N2O (N2O-N), which can be further converted to N2O (Xu et al 2019). For those who are familiar with GREET N2O calculations for biofuels, nitrogen fertilizer usage there in GREET is presented in the mass of nutrients, not the mass in compounds as in FD-CIC. The latter was done intentionally so that farming inputs can be entered into the FD-CIC by users without any conversion outside of it. For Monoammonium Phosphate (MAP) and Diammonium Phosphate (DAP), which serve as both nitrogen and phosphorus sources, the tool employs more complex calculations (Figure 16).

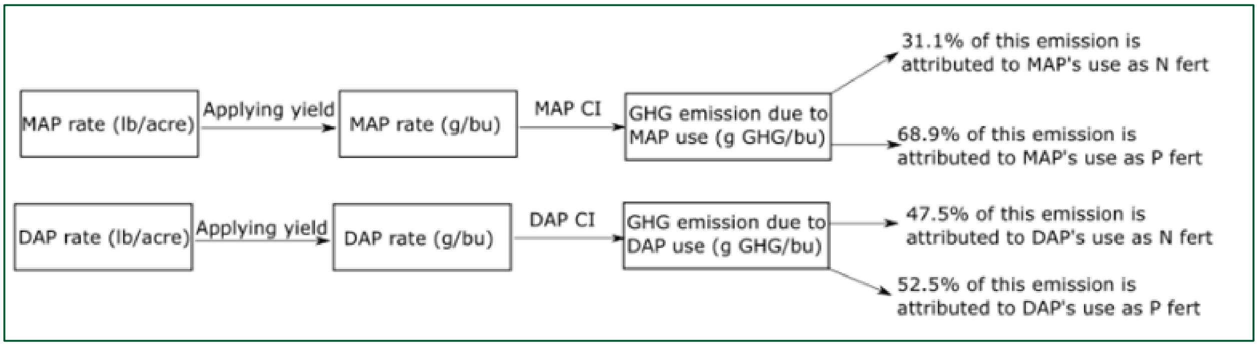

Figure 16. Calculations Associated with MAP and DAP

In the Results worksheet, the FD-CIC tool reports both GREET default and user-specific CI for corn for comparison. The tool provides figures for comparison as well. The contribution from each emission source is also calculated and depicted in a pie chart. The FD-CIC tool also translated the feedstock CI into ethanol CI based on per MJ of corn ethanol produced by applying the corn-grain-to-ethanol conversion rate (2.88 gallon of ethanol per bushel of corn) and the lower heating value of ethanol (80.5 MJ per gallon, lower heating value based) as the volume-to-energy unit conversion factor. This feature helps users to understand how the variations in feedstock-level CI can propagate through the bioethanol supply chain.

5.2 Operating Margins: IL, MN, NE, SD

Consistent with Iowa's ethanol industry, prices for both corn and ethanol have fluctuated during the last 14 years in the states of Illinois, Minnesota, Nebraska, and South Dakota. Correlation coefficients between these price series have varied from 0.809 for Illinois to 0.841 for Nebraska from February 2009 to July 2022. The correlation for Iowa was estimated at 0.840 during the same period. For all states, natural gas price per gallon of ethanol shows variations during the last 13.5 years, but not as much as the prices of ethanol, corn, or DDGS (see Figure 17, Figure 19, Figure 21, and Figure 23).

Similarly to the trend in Iowa, operating margins have dropped over the full 13.5-year period of 2007-2022, with substantial decline since middle of 2014, but continued variability during that period (see Figure 18, Figure 20, Figure 22, Figure 24).

Illinois Operating Margins

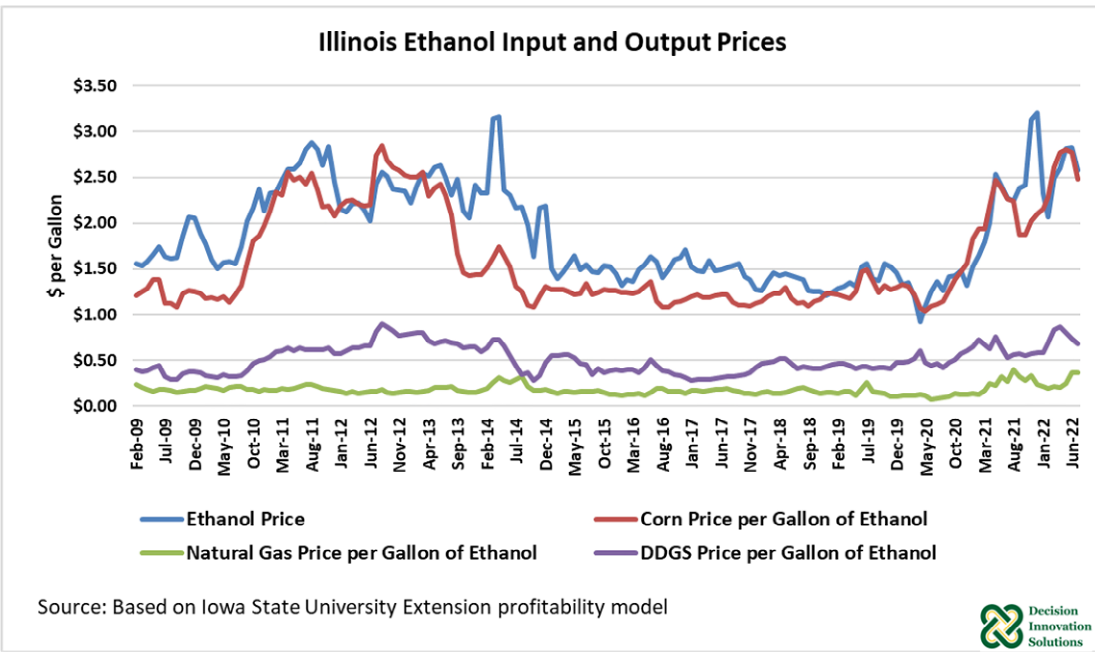

Figure 17. Illinois Ethanol Input and Output Prices

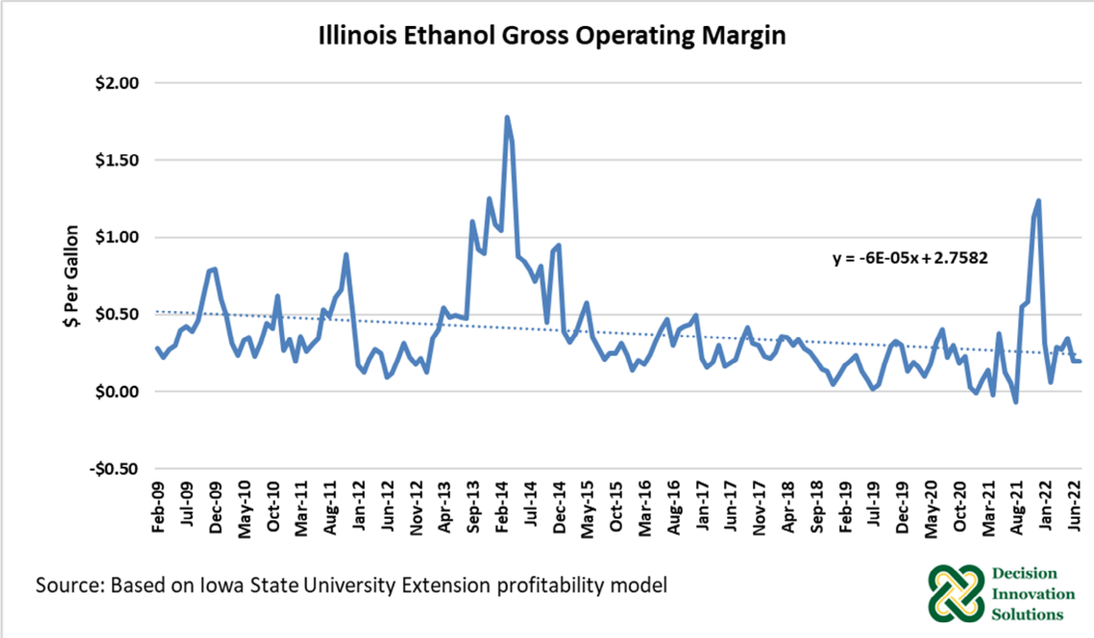

Figure 18. Illinois Ethanol Gross Operating Margin

Minnesota Operating Margins

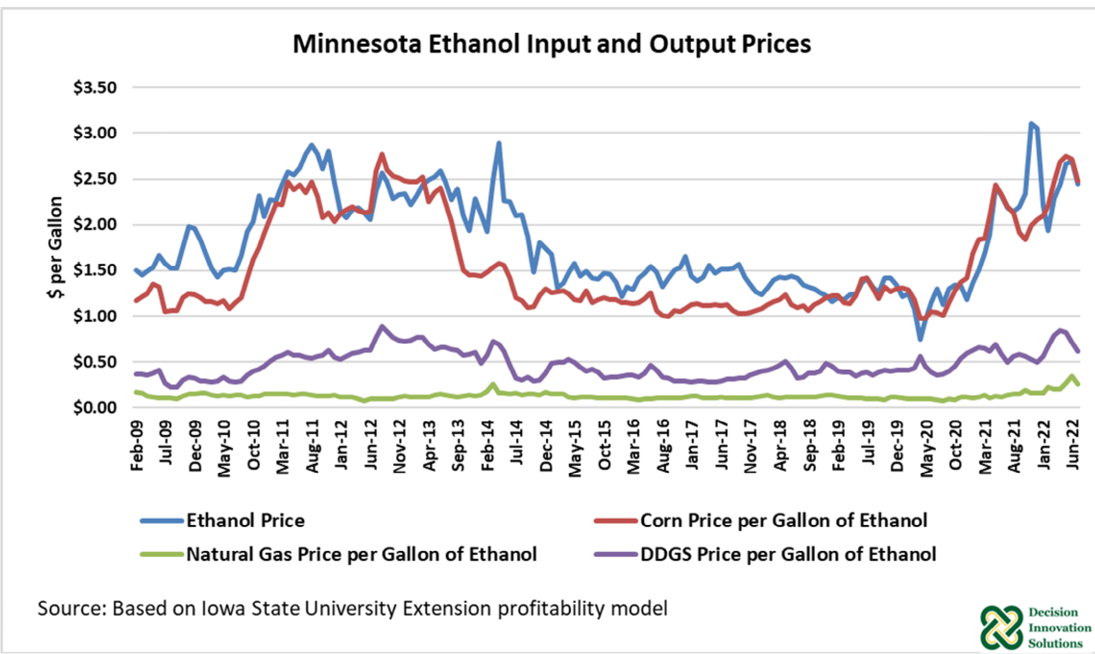

Figure 19. Minnesota Ethanol Input and Output Prices

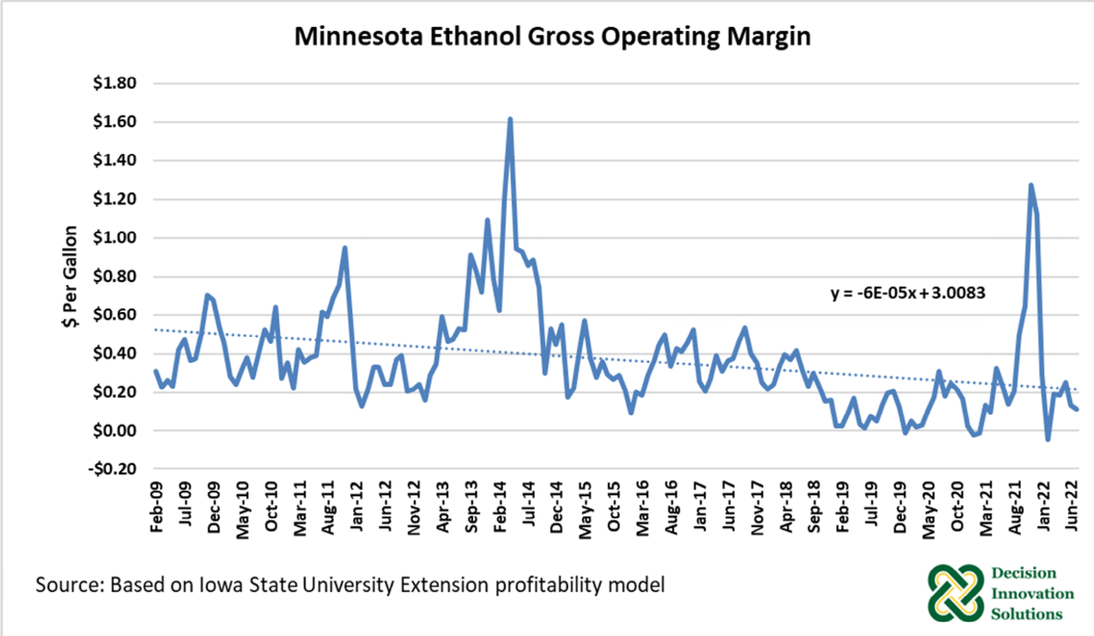

Figure 20. Minnesota Ethanol Gross Operating Margin

Nebraska Operating Margins

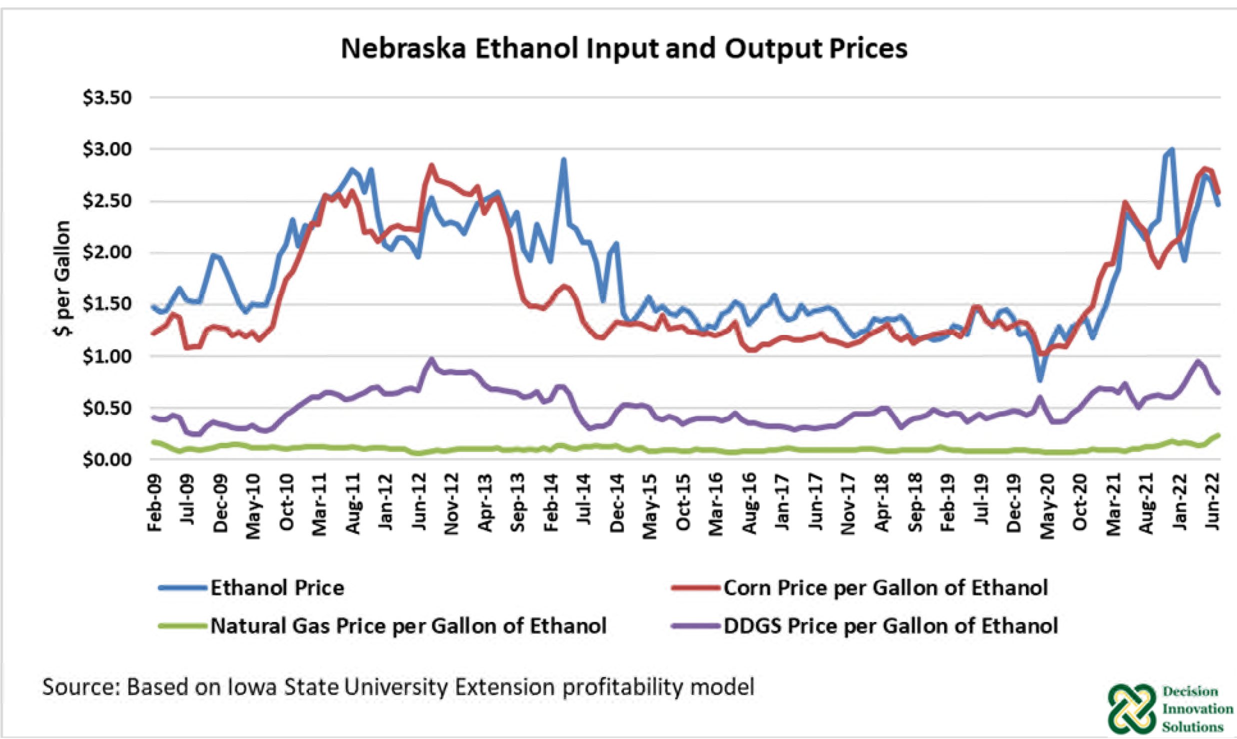

Figure 21. Nebraska Ethanol Input and Output Prices

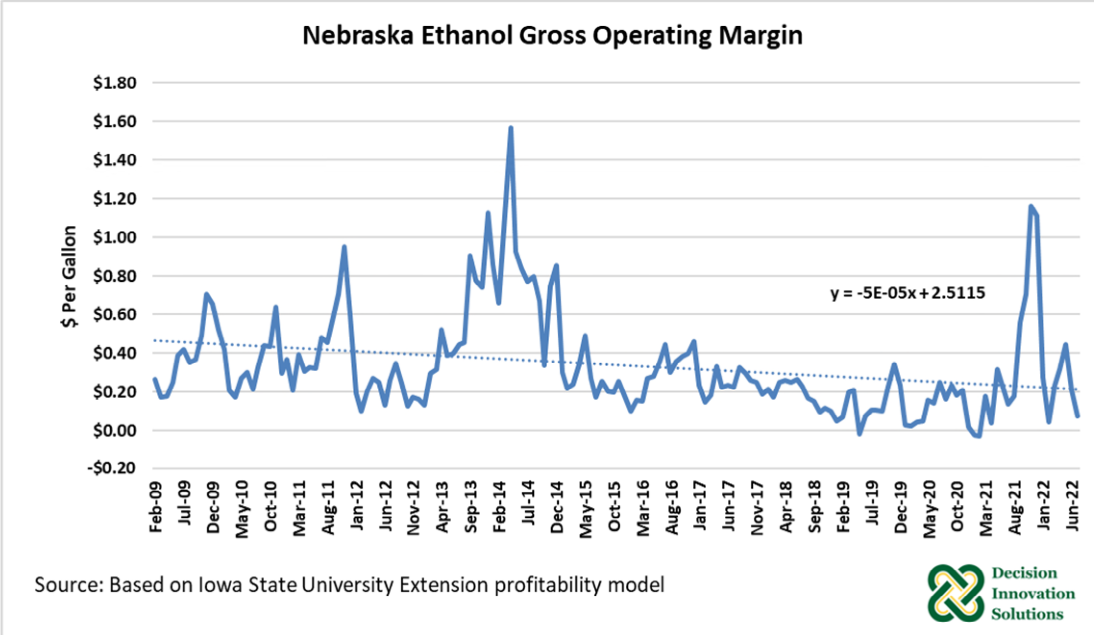

Figure 22. Nebraska Ethanol Gross Operating Margin

South Dakota Operating Margins

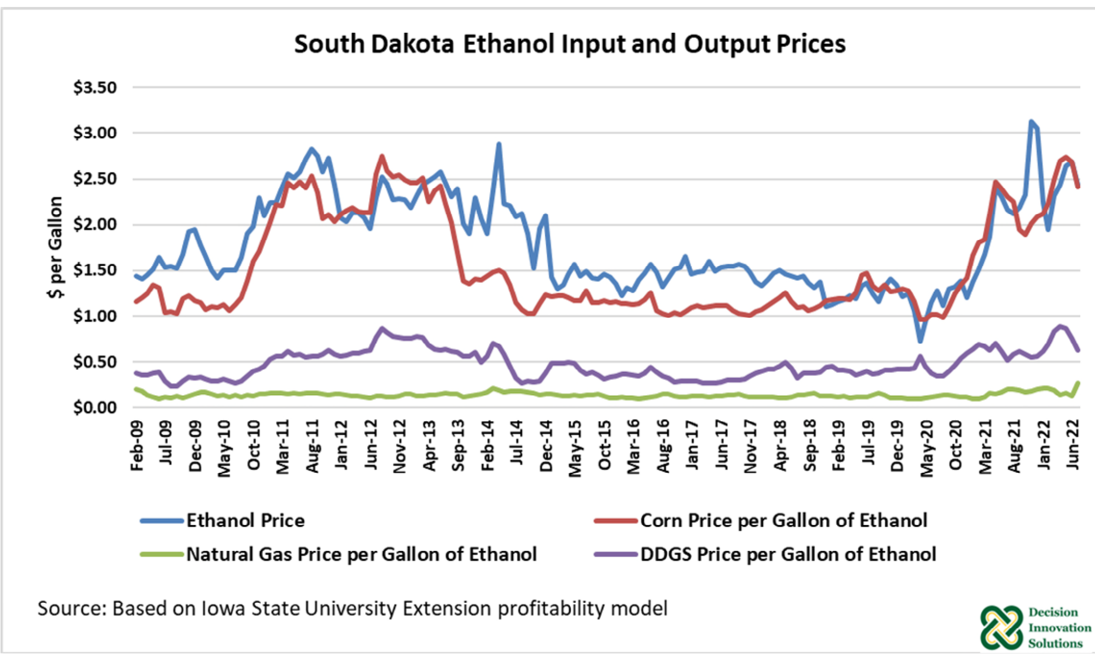

Figure 23. South Dakota Ethanol Input and Output Prices

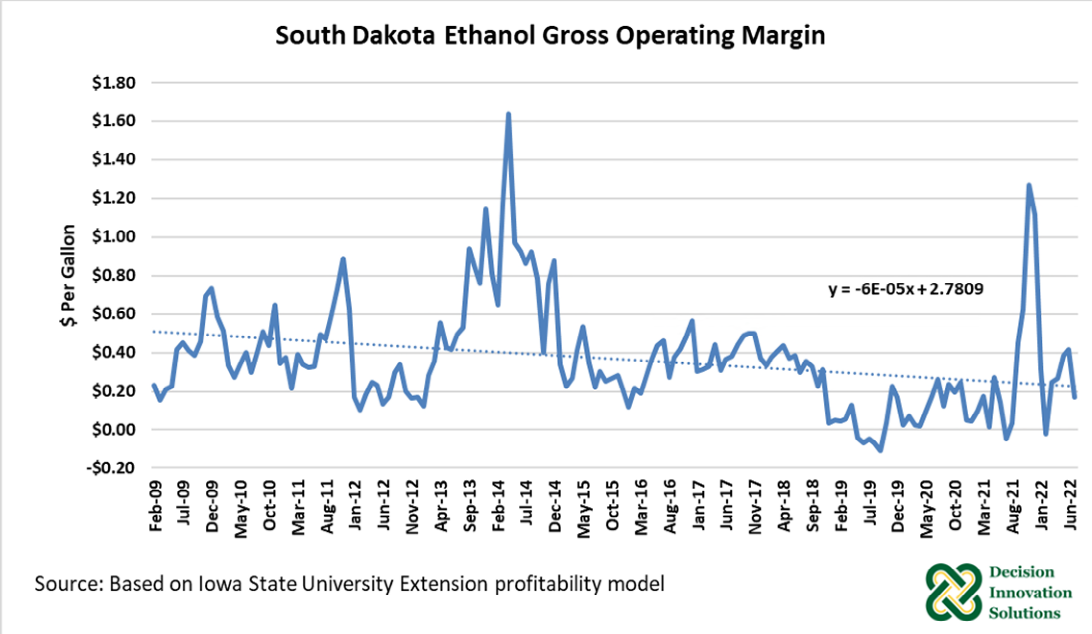

Figure 24. South Dakota Ethanol Gross Operating Margin

5.2.1 Summary of Annual Gross Margins for Ethanol Plants in IL, MN, NE, and SC

Table 18. Illinois Gross Margins - 100 mgy Plant ($Million)

Illinois Annual Gross Margins - 100 mgy Plant ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	100%	75%	75%
$0.00	$11.97	$54.27	$30.49	$18.38	$17.31
$10.00	$11.97	$54.27	$30.49	$20.52	$19.45
$20.00	$11.97	$54.27	$30.49	$22.65	$21.59
$30.00	$11.97	$54.27	$30.49	$24.79	$23.72
$40.00	$11.97	$54.27	$30.49	$26.93	$25.86
$50.00	$11.97	$54.27	$30.49	$29.07	$28.00
$60.00	$11.97	$54.27	$30.49	$31.20	$30.14
$70.00	$11.97	$54.27	$30.49	$33.34	$32.27
$80.00	$11.97	$54.27	$30.49	$35.48	$34.41
$90.00	$11.97	$54.27	$30.49	$37.62	$36.55
$100.00	$11.97	$54.27	$30.49	$39.75	$38.69
$110.00	$11.97	$54.27	$30.49	$41.89	$40.82
$120.00	$11.97	$54.27	$30.49	$44.03	$42.96
$130.00	$11.97	$54.27	$30.49	$46.17	$45.10
$140.00	$11.97	$54.27	$30.49	$48.30	$47.24
$150.00	$11.97	$54.27	$30.49	$50.44	$49.37
$160.00	$11.97	$54.27	$30.49	$52.58	$51.51
$170.00	$11.97	$54.27	$30.49	$54.72	$53.65
$180.00	$11.97	$54.27	$30.49	$56.85	$55.79
Gross Margin calculated using ISU Extension Ethanol Margin Calculator Carbon tax credit and costs calculated by DIS					Decision Innovation Solutions

Table 19. Annual Gross Margins - Illinois 1,661 mgy Production ($Million)

Annual Gross Margins - Illinois 1,661 mgy Production ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	75%	75%	75%
$0.00	$539	$2,442	$1,372	$827	$779
$10.00	$539	$2,442	$1,372	$923	$875
$20.00	$539	$2,442	$1,372	$1,019	$971
$30.00	$539	$2,442	$1,372	$1,116	$1,068
$40.00	$539	$2,442	$1,372	$1,212	$1,164
$50.00	$539	$2,442	$1,372	$1,308	$1,260
$60.00	$539	$2,442	$1,372	$1,404	$1,356
$70.00	$539	$2,442	$1,372	$1,500	$1,452
$80.00	$539	$2,442	$1,372	$1,597	$1,548
$90.00	$539	$2,442	$1,372	$1,693	$1,645
$100.00	$539	$2,442	$1,372	$1,789	$1,741
$110.00	$539	$2,442	$1,372	$1,885	$1,837
$120.00	$539	$2,442	$1,372	$1,981	$1,933
$130.00	$539	$2,442	$1,372	$2,078	$2,029
$140.00	$539	$2,442	$1,372	$2,174	$2,126
$150.00	$539	$2,442	$1,372	$2,270	$2,222
$160.00	$539	$2,442	$1,372	$2,366	$2,318
$170.00	$539	$2,442	$1,372	$2,462	$2,414
$180.00	$539	$2,442	$1,372	$2,558	$2,510
Gross Margin calculated using ISU Extension Ethanol Margin Calculator Carbon tax credit and costs calculated by DIS					Decision Innovation Solutions

Table 20. Minnesota Annual Gross Margins - 100mgy Plant ($Million)

Minnesota Annual Gross Margins - 100 mgy Plant ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	100%	75%	75%
$0.00	$15.86	$58.16	$34.39	$22.27	$21.21
$10.00	$15.86	$58.16	$34.39	$24.41	$23.34
$20.00	$15.86	$58.16	$34.39	$26.55	$25.48
$30.00	$15.86	$58.16	$34.39	$28.69	$27.62
$40.00	$15.86	$58.16	$34.39	$30.82	$29.76
$50.00	$15.86	$58.16	$34.39	$32.96	$31.89
$60.00	$15.86	$58.16	$34.39	$35.10	$34.03
$70.00	$15.86	$58.16	$34.39	$37.24	$36.17
$80.00	$15.86	$58.16	$34.39	$39.37	$38.31
$90.00	$15.86	$58.16	$34.39	$41.51	$40.44
$100.00	$15.86	$58.16	$34.39	$43.65	$42.58
$110.00	$15.86	$58.16	$34.39	$45.79	$44.72
$120.00	$15.86	$58.16	$34.39	$47.92	$46.86
$130.00	$15.86	$58.16	$34.39	$50.06	$48.99
$140.00	$15.86	$58.16	$34.39	$52.20	$51.13
$150.00	$15.86	$58.16	$34.39	$54.34	$53.27
$160.00	$15.86	$58.16	$34.39	$56.47	$55.41
$170.00	$15.86	$58.16	$34.39	$58.61	$57.54
$180.00	$15.86	$58.16	$34.39	$60.75	$59.68

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

Table 21. Annual Gross Margins - Minnesota 1,212 mgy Production ($Million)

Annual Gross Margins - Minnesota 1,212 mgy Production ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	75%	75%	75%
$0.00	$714	$2,617	$1,547	$1,002	$954
$10.00	$714	$2,617	$1,547	$1,099	$1,050
$20.00	$714	$2,617	$1,547	$1,195	$1,147
$30.00	$714	$2,617	$1,547	$1,291	$1,243
$40.00	$714	$2,617	$1,547	$1,387	$1,339
$50.00	$714	$2,617	$1,547	$1,483	$1,435
$60.00	$714	$2,617	$1,547	$1,579	$1,531
$70.00	$714	$2,617	$1,547	$1,676	$1,628
$80.00	$714	$2,617	$1,547	$1,772	$1,724
$90.00	$714	$2,617	$1,547	$1,868	$1,820
$100.00	$714	$2,617	$1,547	$1,964	$1,916
$110.00	$714	$2,617	$1,547	$2,060	$2,012
$120.00	$714	$2,617	$1,547	$2,157	$2,109
$130.00	$714	$2,617	$1,547	$2,253	$2,205
$140.00	$714	$2,617	$1,547	$2,349	$2,301
$150.00	$714	$2,617	$1,547	$2,445	$2,397
$160.00	$714	$2,617	$1,547	$2,541	$2,493
$170.00	$714	$2,617	$1,547	$2,638	$2,589
$180.00	$714	$2,617	$1,547	$2,734	$2,686

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

Table 22. Nebraska Annual Gross Margins - 100 mgy Plant ($Million)

Nebraska Annual Gross Margins - 100 mgy Plant ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	100%	75%	75%
$0.00	$19.05	$61.35	$37.57	$25.46	$24.39
$10.00	$19.05	$61.35	$37.57	$27.60	$26.53
$20.00	$19.05	$61.35	$37.57	$29.73	$28.67
$30.00	$19.05	$61.35	$37.57	$31.87	$30.80
$40.00	$19.05	$61.35	$37.57	$34.01	$32.94
$50.00	$19.05	$61.35	$37.57	$36.15	$35.08
$60.00	$19.05	$61.35	$37.57	$38.28	$37.22
$70.00	$19.05	$61.35	$37.57	$40.42	$39.35
$80.00	$19.05	$61.35	$37.57	$42.56	$41.49
$90.00	$19.05	$61.35	$37.57	$44.70	$43.63
$100.00	$19.05	$61.35	$37.57	$46.83	$45.77
$110.00	$19.05	$61.35	$37.57	$48.97	$47.90
$120.00	$19.05	$61.35	$37.57	$51.11	$50.04
$130.00	$19.05	$61.35	$37.57	$53.25	$52.18
$140.00	$19.05	$61.35	$37.57	$55.38	$54.32
$150.00	$19.05	$61.35	$37.57	$57.52	$56.45
$160.00	$19.05	$61.35	$37.57	$59.66	$58.59
$170.00	$19.05	$61.35	$37.57	$61.80	$60.73
$180.00	$19.05	$61.35	$37.57	$63.93	$62.87

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

Decision Innovation Solutions

Table 23. Annual Gross Margins - Nebraska 2,041 mgy Production ($Million)

Annual Gross Margins - Nebraska 2,041 mgy Production ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	75%	75%	75%
$0.00	$857	$2,761	$1,691	$1,146	$1,098
$10.00	$857	$2,761	$1,691	$1,242	$1,194
$20.00	$857	$2,761	$1,691	$1,338	$1,290
$30.00	$857	$2,761	$1,691	$1,434	$1,386
$40.00	$857	$2,761	$1,691	$1,530	$1,482
$50.00	$857	$2,761	$1,691	$1,627	$1,579
$60.00	$857	$2,761	$1,691	$1,723	$1,675
$70.00	$857	$2,761	$1,691	$1,819	$1,771
$80.00	$857	$2,761	$1,691	$1,915	$1,867
$90.00	$857	$2,761	$1,691	$2,011	$1,963
$100.00	$857	$2,761	$1,691	$2,108	$2,059
$110.00	$857	$2,761	$1,691	$2,204	$2,156
$120.00	$857	$2,761	$1,691	$2,300	$2,252
$130.00	$857	$2,761	$1,691	$2,396	$2,348
$140.00	$857	$2,761	$1,691	$2,492	$2,444
$150.00	$857	$2,761	$1,691	$2,588	$2,540
$160.00	$857	$2,761	$1,691	$2,685	$2,637
$170.00	$857	$2,761	$1,691	$2,781	$2,733
$180.00	$857	$2,761	$1,691	$2,877	$2,829

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

Decision Innovation Solutions

Table 24. South Dakota Annual Gross Margins - 100 mgy Plant ($Million)

South Dakota Annual Gross Margins - 100 mgy Plant ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	100%	75%	75%
$0.00	$25.86	$68.16	$44.39	$32.27	$31.21
$10.00	$25.86	$68.16	$44.39	$34.41	$33.34
$20.00	$25.86	$68.16	$44.39	$36.55	$35.48
$30.00	$25.86	$68.16	$44.39	$38.69	$37.62
$40.00	$25.86	$68.16	$44.39	$40.82	$39.76
$50.00	$25.86	$68.16	$44.39	$42.96	$41.89
$60.00	$25.86	$68.16	$44.39	$45.10	$44.03
$70.00	$25.86	$68.16	$44.39	$47.24	$46.17
$80.00	$25.86	$68.16	$44.39	$49.37	$48.31
$90.00	$25.86	$68.16	$44.39	$51.51	$50.44
$100.00	$25.86	$68.16	$44.39	$53.65	$52.58
$110.00	$25.86	$68.16	$44.39	$55.79	$54.72
$120.00	$25.86	$68.16	$44.39	$57.92	$56.86
$130.00	$25.86	$68.16	$44.39	$60.06	$58.99
$140.00	$25.86	$68.16	$44.39	$62.20	$61.13
$150.00	$25.86	$68.16	$44.39	$64.34	$63.27
$160.00	$25.86	$68.16	$44.39	$66.47	$65.41
$170.00	$25.86	$68.16	$44.39	$68.61	$67.54
$180.00	$25.86	$68.16	$44.39	$70.75	$69.68

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

Table 25. Annual Gross Margins - South Dakota 1,181 mgy Production ($Million)

Annual Gross Margins - South Dakota 1,181 mgy Production ($Million)					
Carbon Price	No CCS	CCS45Z Pipeline	CCS45Q Pipeline	CC&U Rail 45Q	CC&U Truck 45Q
Pct Participation	100%	100%	75%	75%	75%
$0.00	$1,164	$3,067	$1,997	$1,452	$1,404
$10.00	$1,164	$3,067	$1,997	$1,549	$1,500
$20.00	$1,164	$3,067	$1,997	$1,645	$1,597
$30.00	$1,164	$3,067	$1,997	$1,741	$1,693
$40.00	$1,164	$3,067	$1,997	$1,837	$1,789
$50.00	$1,164	$3,067	$1,997	$1,933	$1,885
$60.00	$1,164	$3,067	$1,997	$2,029	$1,981
$70.00	$1,164	$3,067	$1,997	$2,126	$2,078
$80.00	$1,164	$3,067	$1,997	$2,222	$2,174
$90.00	$1,164	$3,067	$1,997	$2,318	$2,270
$100.00	$1,164	$3,067	$1,997	$2,414	$2,366
$110.00	$1,164	$3,067	$1,997	$2,510	$2,462
$120.00	$1,164	$3,067	$1,997	$2,607	$2,559
$130.00	$1,164	$3,067	$1,997	$2,703	$2,655
$140.00	$1,164	$3,067	$1,997	$2,799	$2,751
$150.00	$1,164	$3,067	$1,997	$2,895	$2,847
$160.00	$1,164	$3,067	$1,997	$2,991	$2,943
$170.00	$1,164	$3,067	$1,997	$3,088	$3,039
$180.00	$1,164	$3,067	$1,997	$3,184	$3,136

Gross Margin calculated using ISU Extension Ethanol Margin Calculator
Carbon tax credit and costs calculated by DIS

5.3 Transporting CO2

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FACT SHEET

TRANSPORTING CO_2

Safely and reliably transporting CO_2 from where it is captured to a storage site is an important stage in the carbon capture and storage (CCS) process. Transport of CO_2 occurs daily in many parts of the world however, significant investment in transportation infrastructure is required to enable large-scale deployment.

HOW IS CO_2 TRANSPORTED?

Pipelines are – and are likely to continue to be – the most common method of transporting the very large quantities of CO_2 involved in CCS. There are already millions of kilometres of pipelines around the world that transport various gases, including CO_2.

Transport of CO_2 by truck and rail is possible for small quantities. Trucks are used at some project sites, moving the CO_2 from where it is captured to a nearby storage location. Given the large quantities of CO_2 that would be captured via CCS in the long-term, it is unlikely that truck and rail transport will be significant.

Ship transportation can be an alternative option for many regions of the world. Shipment of CO_2 already takes place on a small scale in Europe, where ships transport food-quality CO_2 (around 1,000 tonnes) from large point sources to coastal distribution terminals.

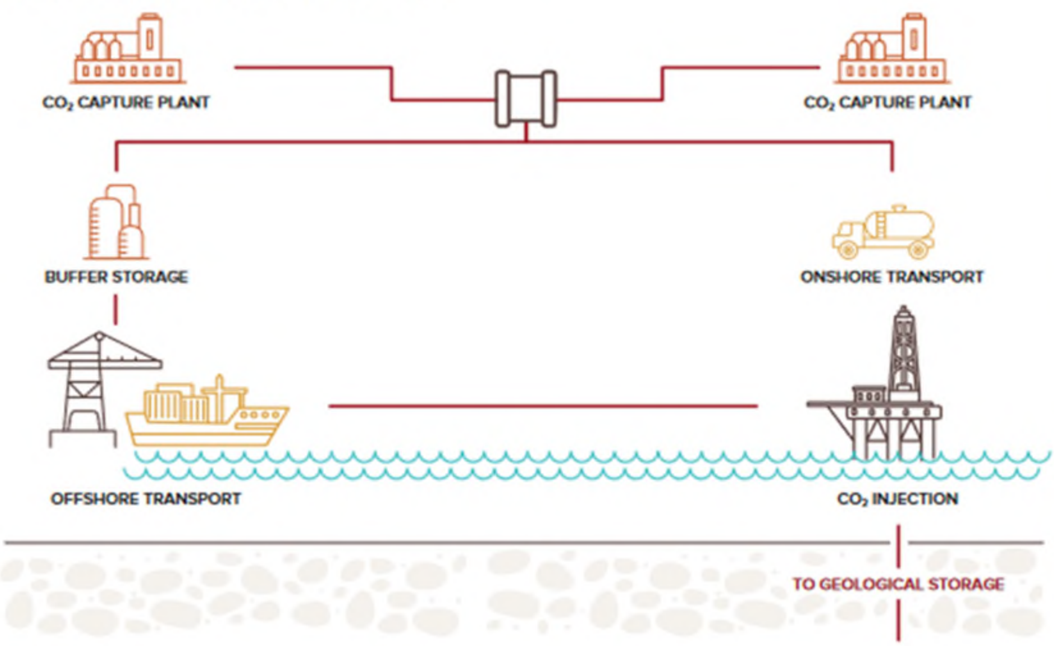
Larger-scale shipment of CO_2, with capacities in the range of 10,000 to 40,000 cubic metres, is likely to have much in common with the shipment of liquefied petroleum gas (LPG). There is already a great deal of expertise in transporting LPG, which has developed into a worldwide industry over a period of 70 years.

IS TRANSPORT OF CO_2 SAFE?

There is significant experience with CO_2 pipeline development and operation on land and under the sea. There are around 50 CO_2 pipelines currently operating in the US, which transport approximately 68 million tonnes per annum of CO_2.

CO_2 pipelines and ships pose no higher risk than is already safely managed for transporting hydrocarbons such as natural gas and oil. International standards are being developed to further promote safe and efficient operation of CO_2 infrastructure.

Figure 1: Transport overview of CCS technologies



GLOBAL CCS INSTITUTE FACT SHEET TRANSPORTING CCS

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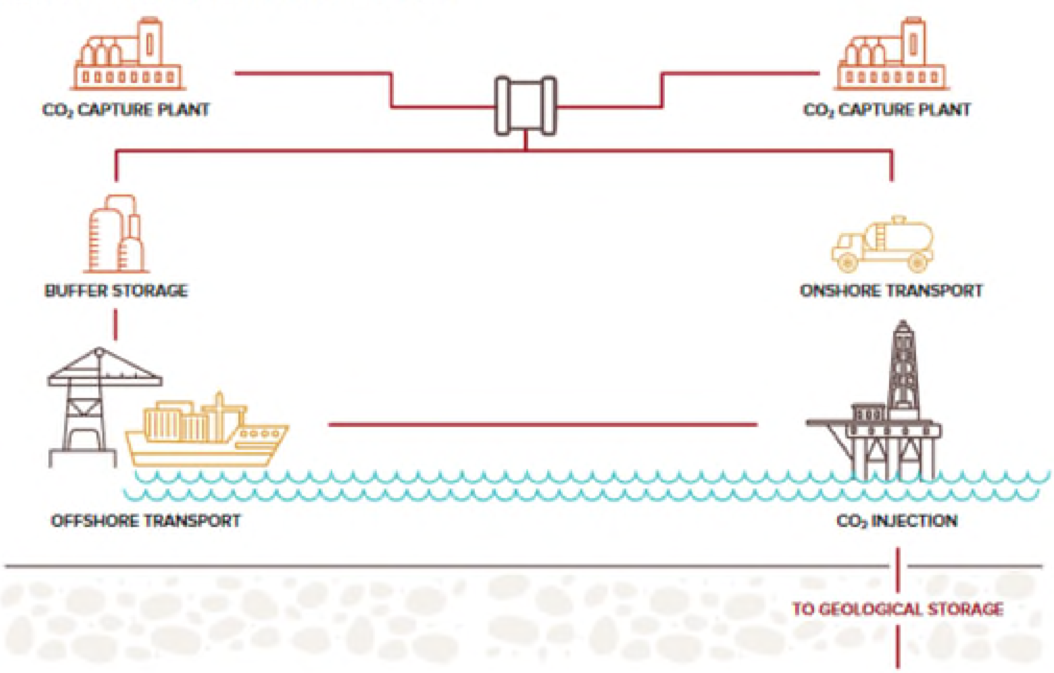

DOES THE INFRASTRUCTURE NEEDED TO SUPPORT CO_2 TRANSPORT EXIST?

Extensive networks of pipelines already exist around the world, both on land and under the sea. In the United States (US) alone, there are about 800,000 km of hazardous liquid and natural gas pipelines, in addition to 3.5 million km of natural gas distribution lines. Some 6,500 km of pipelines actively transport CO_2 today.

That said, the scale of pipeline infrastructure needed to support longer-term CCS deployment around the world is considerable. The estimated CO_2 transportation infrastructure to be built in the coming 30-40 years (consistent with the International Energy Agency's least-cost pathway to halve energy-related CO_2 emissions by 2050) is roughly 100 times larger than currently exists.

CO_2 HUBS, CLUSTERS AND TRANSPORTATION NETWORKS

The initial demand for additional CO_2 transportation capacity will likely unfold in an incremental and geographically dispersed manner as new dedicated capture plants, storage and enhanced oil recovery (EOR) facilities are brought online.

Large-scale deployment of CCS is likely to result in the linking of proximate CO_2 sources, through a hub, to clusters of storage 'sinks', either by ship or so-called 'back bone' pipelines. While hubs, clusters, and networks are terms used somewhat interchangeably, their use to describe projects highlights subtle differences.

A CO_2 cluster may refer to a grouping of individual CO_2 sources, or to storage sites such as multiple fields within a region. The Permian Basin in the US has several clusters of oilfields undergoing CO_2-EOR fed by a network of pipelines.

A CO_2 hub collects CO_2 from various emitters and redistributes it to single or multiple storage locations. For example, the South West Hub project in Western Australia seeks to collect CO_2 from various sources in the Kwinana and Collie industrial areas for storage in the Lesueur formation in the Southern Perth Basin.

A CO_2 network is an expandable collection and transportation infrastructure providing access for multiple emitters.

The incentives for CCS projects to be developed as part of a hub, cluster, or network include economies of scale (lower per unit costs for constructing and operating CO_2 pipelines). The costs per project are lower than can be achieved with stand-alone projects, where each CO_2 point source has its own independent and smaller scale transportation or storage requirement. A coordinated network approach can also lower the barriers of entry for all participating CCS projects, including for emitters, that do not need to develop their own separate transportation and storage solutions.

FOR MORE INFORMATION

Visit globalccsinstitute.com or email info@globalccsinstitute.com

5.3.1 Trailer Requirements for Transporting CO2 by Truck

Trailers used to haul CO2 are regulated by the U.S. Department of Transportation (DOT). To haul cryogenic or industrial gases such as CO2, these are the main types of tankers to use when hauling hazardous and nonhazardous materials.

MC331: For transportation of compressed gases, MC 331 cargo tank is the option. Generally speaking, this trailer must be a DOT specification tank, so it must always have a trailer data plate that displays information on the manufacturer, capacity and construction material. Here's its requirements:

- Must be made of steel or aluminum however, if aluminum is used, the tank can be insulated or non-insulated, and the hazardous material must be compatible (some products are corrosive with certain metals).
- Must have an outer jacket if the tank is insulated and used to transport flammable gas or pressurized gas.
- Vapor pressure inside the vessel ranges between 100-500 psi.
- If insulated, must have a barrier of at least 2-4 inches depending on combustibility and material .
- Every uninsulated cargo tank attached to a motor vehicle, unless covered with an aluminum or stainless steel jacket, must be painted white, aluminum or similar reflective color on the upper two-thirds of the cargo tank.
- All valves, fittings, pressure relief devices, and other accessories on the tank must be protected against crashes and rollovers.
- A single shell carbon steel construction with circular cross-section, and rounded ends.
- The capacity of the tanks ranges from 2,500 gallons and 11,500 gallons, depending on the type of vehicle and trailer.

The MC 331 is only used for gases that are liquefied under extremely high pressures such as: butane, propane (liquified natural gas), chlorine, anhydrous ammonia, and liquid carbon dioxide (CO2).

Figure 25. 10,600-gallon, 265 PSI, MC 331 Liquid Tanker

5.3.2 Rail Requirements for Shipping CO2

Title 49 (Transportation) of the Federal Code of Regulations (FCR) in Part 179 details the specifications for rail tank cars. Section 179.102-1 has the requirements for tank cars that carry CO2 as a refrigerated liquid.

(a) Tank cars used to transport carbon dioxide, refrigerated liquid must comply with the following special requirements: (1) All plates for tank, manway nozzle and anchorage of tanks must be made of carbon steel conforming to ASTM A 516/A 516M (IBR, see § 171.7 of this subchapter), Grades 55, 60, 65, or 70, or AAR Specification TC 128-78, Grade B. The ASTM A 516/A 516M plate must also meet the Charpy V-Notch test requirements of ASTM A 20/A 20M (see table 16) (IBR, see § 171.7 of this subchapter) in the longitudinal direction of rolling. The TC 128 plate must also meet the Charpy V-Notch energy absorption requirements of 15 ft.-lb. minimum average for 3 specimens, and 10 ft.-lb. minimum for one specimen, at minus 50 °F in the longitudinal direction of rolling in accord with ASTM A 370 (IBR, see § 171.7 of this subchapter). Production-welded test plates prepared as required by W4.00 of AAR Specifications for Tank Cars, appendix W (IBR, see § 171.7 of this subchapter), must include impact test specimens of weld metal and heat-affected zone. As an alternate, anchor legs may be fabricated of stainless steel, ASTM A 240/A 240M Types 304, 304L, 316 or 316L, for which impact tests are not required.

Figure 26. 21,964 gallon non-coiled, insulated car designed to operate at a 286,000 lbs. gross rail load for the transportation of carbon dioxide.