A Strategic Roadmap for Decarbonizing the U.S. Ethanol Industry

Appendices

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Appendix A: Ethanol Policy Landscape in the United States

Long-standing, proactive policy has promoted ethanol production, consumption, and exports in the United States since the late 1970s. Four laws have built and sustained the policy landscape for the U.S. ethanol industry: the Energy Tax Act of 1978, the 2005 Renewable Fuel Standard (RFS), the Energy Independence and Security Act of 2007, and the Inflation Reduction Act (IRA) of 2022.[1,2,3,4] State-level low-carbon fuel standards have supported ethanol development. Ethanol also indirectly benefits from incentives for corn production.

Energy Tax Act of 1978

In response to the oil crisis of the 1970s, Congress passed the first ethanol tax credit with the Energy Tax Act of 1978, promoting domestic energy production and laying the groundwork for subsequent pro-ethanol legislation.**Error! Bookmark not defined.** The Energy Tax Act exempted E10 (an ethanol-gasoline blend containing 10% ethanol and 90% gasoline) from the federal excise tax on motor fuels.[1] Twenty-five states followed suit, exempting E10 from state gasoline-excise taxes.[5]

2005 Renewable Fuel Standard (RFS) and the Energy Independence and Security Act of 2007

To further reduce U.S. dependence on foreign oil and curb greenhouse gas emissions from transportation, Congress passed the Renewable Fuel Standard (RFS) in 2005. Enacted as part of the Energy Policy Act of 2005 and expanded under the Energy Independence and Security Act of 2007, the RFS mandated blending ethanol with gasoline sold in the United States.[6] The RFS specifically required that transportation fuels contain an increasing portion of renewable fuels (primarily met by biofuels) each year, up to 7.5 billion gallons per year by 2012 and 36 billion gallons by 2022.[6]

The RFS became the primary driver behind increasing ethanol use, creating a guaranteed market for ethanol producers and stimulating investment in production capacity.[5] Starting in 2010, E10 was sold in all 50 states to satisfy the RFS.[5] From 2005 to 2023, ethanol production and consumption in the United States more than doubled. Domestic production and consumption increased from around 4 billion gallons in 2005 to around 11 billion gallons in 2023. Production peaked in 2018 with over 18 billion gallons, and consumption peaked at over 14.5 billion gallons in 2019 due to the RFS requirements.[7]

Low-carbon Fuel Standards

Several states, including Oregon, New Mexico, and California, have introduced Low-carbon Fuel Standards (LCFS), further incentivizing ethanol use and carbon intensity reductions within the ethanol supply chain.[8] California's LCFS was designed to reduce the carbon intensity of transportation fuels by 20 percent by 2030, galvanizing the production and use of low-carbon ethanol.[9]

Under the LCFS, ethanol with a lower carbon intensity than gasoline earns credits based on reduced emissions compared to an annual baseline. These credits can be sold to fuel producers with higher carbon intensity fuels to help them meet compliance requirements.[8] Every kilogram of carbon dioxide reduced from the annual baseline increases the credit value. This creates a market incentive for ethanol producers to invest in technologies and practices that reduce carbon emissions throughout the production process, such as using renewable energy sources, optimizing feedstock selection, and improving production efficiency.[8]

The Inflation Reduction Act (IRA) of 2022

In addition to the 40B and 45Z tax credits already discussed above, the 2022 Inflation Reduction Act contains several tax incentives for ethanol producers, including adding carbon capture to production facilities and developing SAF.

Ethanol plants that utilize CCUS can qualify for the modified 45Q tax credit.[a, 10] Previously, ethanol plants were required to have a minimum annual carbon capture rate of 100,000 Mt. The IRA decreased the minimum capture rate to 12,500 Mt annually.[11] The 45Q credit for ethanol producers ranges from $12 to $85/tCO$_2$ captured, depending on whether the captured carbon is used or sequestered and if prevailing wage and apprenticeship requirements are met. Entities that begin construction before the end of 2032 can claim 45Q but are not eligible for the 45Z Clean Fuel Production Tax Credit, which is discussed below.[b]

Cellulosic ethanol can qualify for the Second-Generation Biofuel production tax credit (PTC), which expired and was extended under the IRA until the end of 2024. The credit is worth $1.01 per gallon of fuel produced, or $0.46 for ethanol that also qualifies for the ethanol blending tax credit. To be eligible, second-generation biofuels must meet EPA fuel and fuel additive registration requirements.[12]

[a] The 45Q tax credit was created under the Energy Improvement and Extension Act of 2008. It was modified in 2018 and, most recently, 2022 under the IRA. Source: Congressional Research Service, The Section 45Q Tax Credit for Carbon Sequestration, 25 August 2023, https://crsreports.congress.gov/product/pdf/IF/IF11455

[b] In addition to the 45Z tax credit, the 45Q tax credit cannot be combined with the 45V clean hydrogen credit, the 45Y or 48E clean electricity credits, or the 48C advanced energy project credit.

Incentives for corn production

While no direct tax incentives exist for corn used in ethanol, various programs that support ethanol production—many of which vary by state—indirectly incentivize corn for ethanol.[13]

Federal farm subsidy programs further support corn farming and ethanol production by stabilizing farm incomes, promoting rural development, and providing payments based on historical production or acreage. They also provide crop insurance premium subsidies to mitigate risks related to weather and market fluctuations.[14] The Value-Added Producer Grants (VAPG) instituted under the 2018 Farm Bill help independent agricultural producers enter or expand value-added activities, including biofuel production.[15]

Appendix B: GREET Modeling Methods

Argonne National Laboratory's R&D GREET model provides life cycle GHG intensity modeling for an exhaustive variety of energy, material, and fuel products on a wells-to-wheels or cradle-to-grave basis. R&D GREET 2023rev1, released by Argonne on April 30, 2024, was used to estimate carbon intensity reduction of the ethanol decarbonization strategies identified in this study.[16]

By default, R&D GREET models ethanol blended into gasoline for common vehicle uses, such as 10% ethanol by liquid volume for E10, 15% for E15, and 85% for E85. In each of these blends, the ethanol component has also been denatured with a 2% blend of gasoline at the ethanol biorefinery. This denaturing occurs at the plant before the ethanol product is transported to fuel terminals for blending into the final retail gasoline product.

To isolate life cycle GHG intensity results to ethanol, rather than the default E10 or E85 blends (with 90% or 15% gasoline content by volume, respectively), user inputs on R&D GREET's *Inputs* worksheet section 12.1 are modified to adjust fuel blend assumptions. Cell F871, the share of ethanol in a dedicated ethanol fuel vehicle, is changed from its default 85% to 100%. The assumption for gasoline use as a denaturant at the ethanol biorefinery is kept unchanged at a default of 2% by volume. As a result, the model is set to provide well-to-wheel results for ethanol as it is produced at the biorefinery in its denatured state, consisting of 98% ethanol and 2% gasoline by volume.

Table B1
R&D GREET 2023rev1 default shares of corn ethanol biorefining process

Biorefinery type	Share of ethanol production
Dry milling plant w/o corn oil extraction	4.5%
Dry milling plant w/ corn oil extraction	85.5%
Wet milling plant	10.0%

R&D GREET has many options for ethanol biorefinery type and configuration. Section 8.7.c.ii on the R&D GREET *Inputs* worksheet reports default assumptions for the share of corn ethanol produced at wet milling plants, dry milling plants, dry milling plants with corn oil extraction, and dry milling plants without corn oil extraction. The largest share of production, 85%, is by dry milling plants with corn oil extraction (Table B1), which is relatively consistent with grain consumption figures published by the ethanol industry.[17]

To isolate and assess the impact of various decarbonization strategies available to a typical U.S. ethanol biorefinery, dry milling plants with corn oil extraction were used as the mode of operation. Section 8.7.c.ii of R&D GREET's *Inputs* worksheet was modified to set 100% corn ethanol production at dry milling plants with corn oil extraction. Therefore, this section's proceeding figures and results correspond to a denatured blend of 98% ethanol and 2% gasoline produced at dry milling ethanol biorefineries that engage in byproduct corn oil extraction.

Life cycle GHG results are provided on R&D GREET's *Results* worksheet. The energy functional unit is set to megajoule (MJ) to view results in grams of CO_2-equivalent per megajoule (gCO_2e/MJ), consistent with multiple state and federal policy frameworks. In the dedicated ethanol vehicle section near row 363 of the *Results* worksheet, R&D GREET reports a life cycle GHG intensity of 53.6 gCO_2e/MJ for ethanol from dry milling plants with corn oil extraction.

For vehicle operation, R&D GREET reports a GHG intensity of 71.4 gCO_2e/MJ from fuel combustion in the vehicle. Of this, an estimated 68.9 gCO_2e/MJ is due to the combustion of ethanol and is thus considered biogenic. To account for the biogenic nature of these emissions, an offset for CO_2 uptake from corn plant growth is added to the feedstock phase of the ethanol life cycle, resulting in a net negative (-44.0 gCO_2e/MJ) GHG intensity. These biogenic emissions and offsets, as well as each of the primary emitting steps of the ethanol production and use life cycle, are illustrated in Figure B1. Fermentation emissions, estimated for this analysis to be about 33.5 gCO_2e/MJ, are also considered biogenic by R&D GREET and, by default, do not contribute to the total GHG intensity of ethanol.[18, 19]

Decarbonization measures available to typical corn ethanol biorefineries were identified as discussed in the body of this report. Table B2 outlines the primary scenarios for ethanol decarbonization pathways modeled using the R&D GREET model. These include a *Net-zero by 2050 measures* pathway with adoption rates for 2035 and 2050 and a *Deeper-decarbonization measures pathway*, inclusive of the Net-zero by 2050 measures, for 2035 and 2050. The Net-zero by 2050 measures pathway effectively achieves a net-zero carbon intensity for ethanol by 2050, while the Deeper-decarbonization measures pathway achieves deep decarbonization by 2050 with a more deeply negative carbon intensity.

The primary adjustments made to inputs and assumptions in the R&D GREET model to measure the impact of these decarbonization pathways are described below.

Figure B1. Steps of the dry mill ethanol production and use life cycle

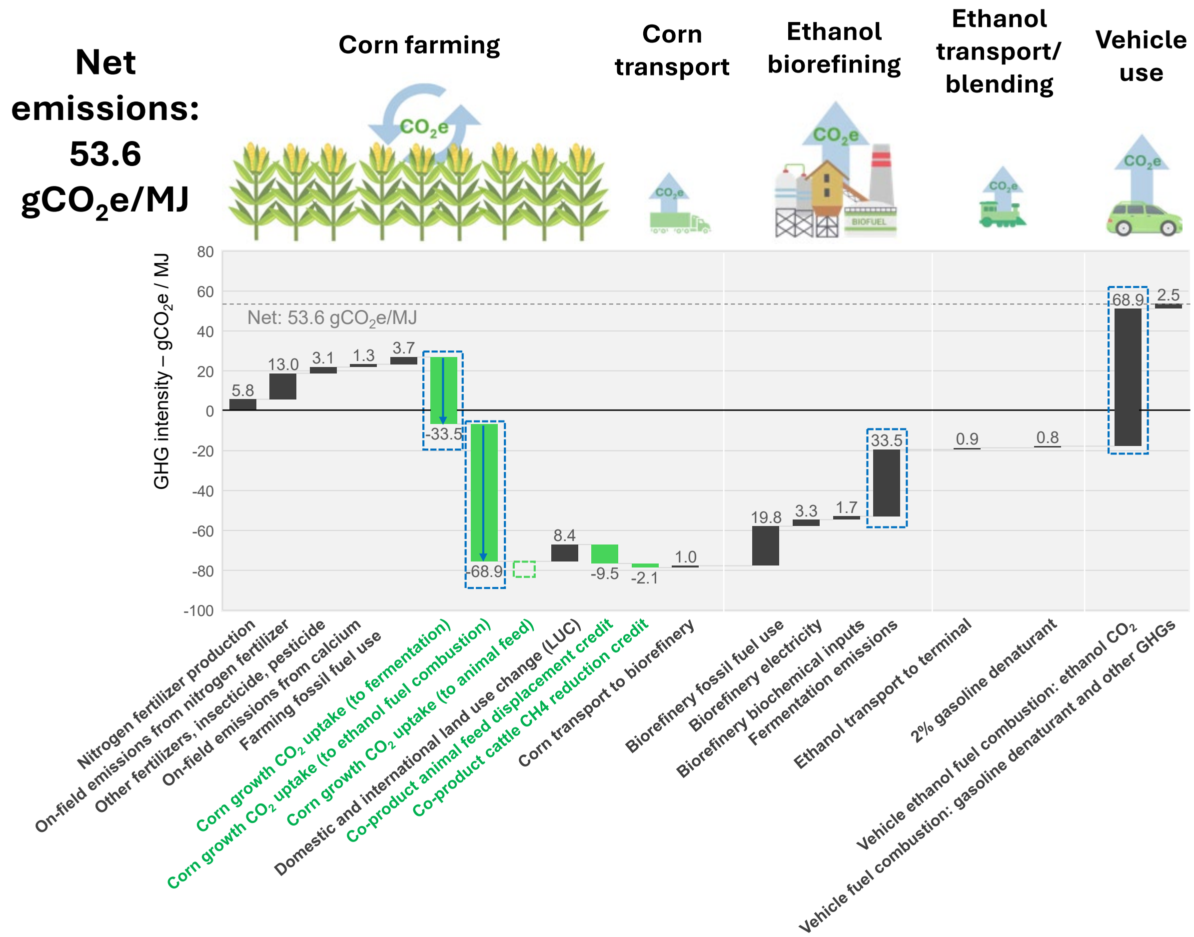


Table B2
Assumptions for decarbonization pathways

		Assumptions by 2035	Assumptions by 2050
Net Zero by 2050 measures	No-till farming	50%	100%
	4R nitrogen management	50%	100%
	Carbon-free electricity in biorefinery	100%	100%
	Ethanol yield improvement	5% improvement	10% improvement
	Corn yield improvement	12% improvement	18% improvement
	Enhanced efficiency fertilizers (EEFs)	30%	50%
	Fermentation CCUS	Adopted	Adopted
	Cover crops	30%	50%
	CHP boiler/steam turbine with a mix of fuels	Replace 20% of natural gas with biomass	Replace 50% of natural gas with biomass
Deeper-decarbonization measures	Blue ammonia	25%	0%
	Green ammonia	25%	100%
	Renewable diesel in farm machinery	5%	10%
	CHP boiler/steam turbine with a mix of fuels	Replace 40% of natural gas with a mix of low-carbon fuels (biomass, RNG, blue hydrogen)	Replace 100% of natural gas with a mix of low-carbon fuels (biomass, RNG, blue hydrogen)
	Renewable diesel vehicles for ethanol transport	5%	10%
	Renewable diesel vehicles for corn transport Renewable diesel vehicles for corn transport	5%	10%

Net-Zero by 2050 measures

Corn yield improvement

On the R&D GREET model *EtOH*[c] worksheet, corn yield is reported in cell C24, with a default value of 176.7 bushels per acre for the model's default year. Improvements to corn yield can be made in this cell or changed on the Fuel_Prod_TS worksheet. The value is increased by 12% or 18% according to the pathways in Table B2.

No-till farming

Cell F416 on R&D GREET's *Inputs* worksheet allows the user to set the tilling practice to the following options: Conventional Tillage, Reduced Tillage, No-Tillage, and U.S. Average. The "No-Tillage" option was selected. Changes to agricultural practices may not impact life cycle GHG results depending on the allocation method chosen for corn grain and corn stover.

For processes in R&D GREET that produce multiple products, such as corn and corn stover or ethanol and distillers' grains, an allocation method is required to assign the appropriate fuel use and emissions shares to each product's life cycle GHG intensity. This can be done based on factors like mass, energy content, or the market value of each product. For this work, Cell E336 on the *Inputs* worksheet was set to "3. Mass allocation" to allocate agricultural emissions based on the harvested mass of corn grain versus the harvested mass of corn stover. To model a 50% adoption rate, two pathways must be produced: one with the default option and another with No-Tillage selected. The affected life cycle GHG results are then averaged to account for a 50% adoption rate.

4R nitrogen management

Cell C17 on the *EtOH* worksheet allows the user to select corn agricultural nitrous oxide (N_2O) emissions management practices between the following options: BAU (business-as-usual), 4R, or EEF. Using this input toggle, R&D GREET treats 4R and EEF as mutually exclusive. However, reduced nitrogen application from the 4R practice can be manually adjusted in the ethanol pathway on cell D471 on the *EtOH* worksheet.

GREET assumes that the 4R practice results in a 14% reduction in nitrogen application. A 50% adoption rate of 4R across suppliers of corn to ethanol biorefineries would effectively achieve a total 7% reduction in nitrogen. Therefore, to model 4R simultaneously with EEF, the equation in D471 is adjusted from its default '=D41*IF (N_Management_Corn="4R", 1-N_Reduction_Rate_Under_4R, 1)' to '=D41*.93' in the

[c] EtOH is the chemical abbreviation for ethanol.

2035 scenarios. For an adoption rate of 100% in the 2050 scenarios, this cell is adjusted to ‘‘=D41*.86’ to reflect the full 14% reduction from the 4R practice.

Enhanced efficiency fertilizers (EEFs)

As mentioned above, Cell C17 on the *EtOH* worksheet allows the user to toggle on the adoption of EEFs. In R&D GREET, this results in a 30% reduction in field N_2O emissions. A 50% adoption rate would result in a total 15% reduction in field N_2O emissions, while a 30% adoption rate would result in a 9% reduction. To scale the N_2O emission reduction from EEFs to reflect a 30% or 50% adoption rate, cell D539 on *EtOH* is adjusted from the default “IF(N_Management_Corn="EEF", D471*(0.01*0.7+0.00374) + B12*B15, 0))” to “IF(N_Management_Corn="EEF", D471*(0.01*0.85+0.00374) + B12*B15, 0))” or “IF(N_Management_Corn="EEF", D471*(0.01*0.91+0.00374) + B12*B15, 0))”, respectively.

Cover crops

The Land Management Scenario input toggle in cell F413 on the *Inputs* worksheet provides the option “1: Rye Cover Crop.” To model a 30% or 50% adoption rate, a pathway without cover crops and a pathway with cover crops must be modeled separately. Then, the affected life cycle GHG results must be averaged between the two (at a rate of 30% or 50% according to the adoption rate).

Cover crops also significantly impact soil organic carbon (SOC). SOC impact was modeled separately using Argonne National Laboratory’s Feedstock Carbon Intensity Calculator (FD-CIC).[20] The FD-CIC was used to model the above agricultural practices for tillage, cover crops, and fertilizer type and application and produce a SOC impact result for adopting cover crops. FD-CIC provides county-level results. An average result across all United States counties was calculated and applied at a rate of 30% or 50% to this report’s scenario pathway results.

Carbon-free electricity in biorefinery

Section 10.2 of R&D GREET’s *Inputs* worksheet provides a selection of electricity mixes for U.S. regions. Section 10.2.a allows the user to select “13 User Defined Mix”, which will use shares of electricity generation sources reported by the user in GREET’s Table 10.2.b. For this study, the share of each fossil fuel electricity generation source was reduced to keep a consistent ratio with the default values while the share of carbon-free electricity (‘Others’ in R&D GREET) increased.[d] Table values for the default mix, 50% renewable mix, and 100% renewable mix are as follows:

- Default US average electricity mix:

[d] For simplicity, biomass was not considered a source of carbon-free electricity in the modeling because the biomass source and combustion technology used impact emissions from biomass electricity generation.

  - Residual oil: 0.3%
  - Natural gas: 38.5%
  - Coal: 20.6%
  - Nuclear power: 18.9%
  - Biomass: 0.3%
  - Others: 21.5%
- 50% renewable mix:
  - Residual oil: 0.2%
  - Natural gas: 24.5%
  - Coal: 13.1%
  - Nuclear power: 12.0%
  - Biomass: 0.2%
  - Others: 50.0%
- User-defined mix at the table at Inputs 10.2.b is set to:
  - Residual oil: 0%
  - Natural gas: 0%
  - Coal: 0%
  - Nuclear power: 0%
  - Biomass: 0%
  - Others: 100.0%

Ethanol yield improvement

Cell F523 on the *Inputs* worksheet reports a default ethanol yield of 2.86 gallons of ethanol per bushel of corn. This is increased by 5% or 10% according to the scenarios outlined in Table B2.

Fermentation CCUS

Ethanol biorefinery CCUS is toggled in cell C196 on the *EtOH* worksheet to value '2 – with CCS'. By default, R&D GREET uses a 97.5% capture rate for fermentation CO_2 and applies an electric use of 180 kWh/t for carbon capture equipment.

Deeper-Decarbonization measures

Blue ammonia and green ammonia

Section 1.1 of the *Ag_Inputs* worksheet allows users to allocate ammonia production between conventional, green, and blue ammonia. For the 2035 additional measures scenario, this table is set to 50% conventional, 25% green, and 25% blue ammonia. For the 2050 additional measures scenario, this table is set to 100% green ammonia.

CHP boiler/steam turbine with a mix of fuels

Adopting combined heat and power at the ethanol biorefinery may be modeled in many ways. For simplicity, this analysis assumed that the adoption of CHP with a share of net-zero carbon alternative fuels such as biomass, clean hydrogen, or renewable natural gas would deliver the same amount of heat and electricity used at the default biorefinery while reducing emissions according to the share of net-zero fuels being used. In practical terms, net emissions from biorefinery energy use were lowered by the share provided by CHP, which was considered emission-free.

For dry mill ethanol biorefining with corn oil extraction, cell P471 on the *EtOH* worksheet sets the total energy used by the biorefinery at 25,034 Btu/gallon. Rows 474 to 484 in column P set the energy use share between fossil fuels, electricity, and other energy sources. The share of energy from renewable sources can be increased in rows 481 to 484, or the overall amount of fossil energy can be reduced in P471 to reflect the benefits of a CHP system powered by alternative fuels.

Renewable diesel in farm machinery, ethanol transport, and corn transport

Section 1.8.1 of R&D GREET's *SAF Interface* worksheet allows the user to set the share of diesel vehicle fuel between conventional diesel, biodiesel, and renewable diesel for agricultural machinery.

For corn and ethanol transport, primary delivery modes can be adjusted on the *T&D Flowcharts* worksheet. To set fuel-specific mixes for transportation modes, namely diesel trucks that deliver corn from farms to biorefineries and ethanol from biorefineries to fuel terminals, R&D GREET's cell formulas must be adjusted on the *T&D* worksheet. Delivery modes and fuel shares for corn transport can be found in the table from cell GD109 to GG157 on the *T&D* worksheet, while ethanol transport is found at Hz109 to ID158. Fuel shares for diesel and renewable diesel must be adjusted on rows 114 and 122, respectively, and the emissions calculations in rows 138 to 148 must be adjusted to use R&D GREET emissions factors for renewable diesel from the *EF* and *BioOil* worksheets.

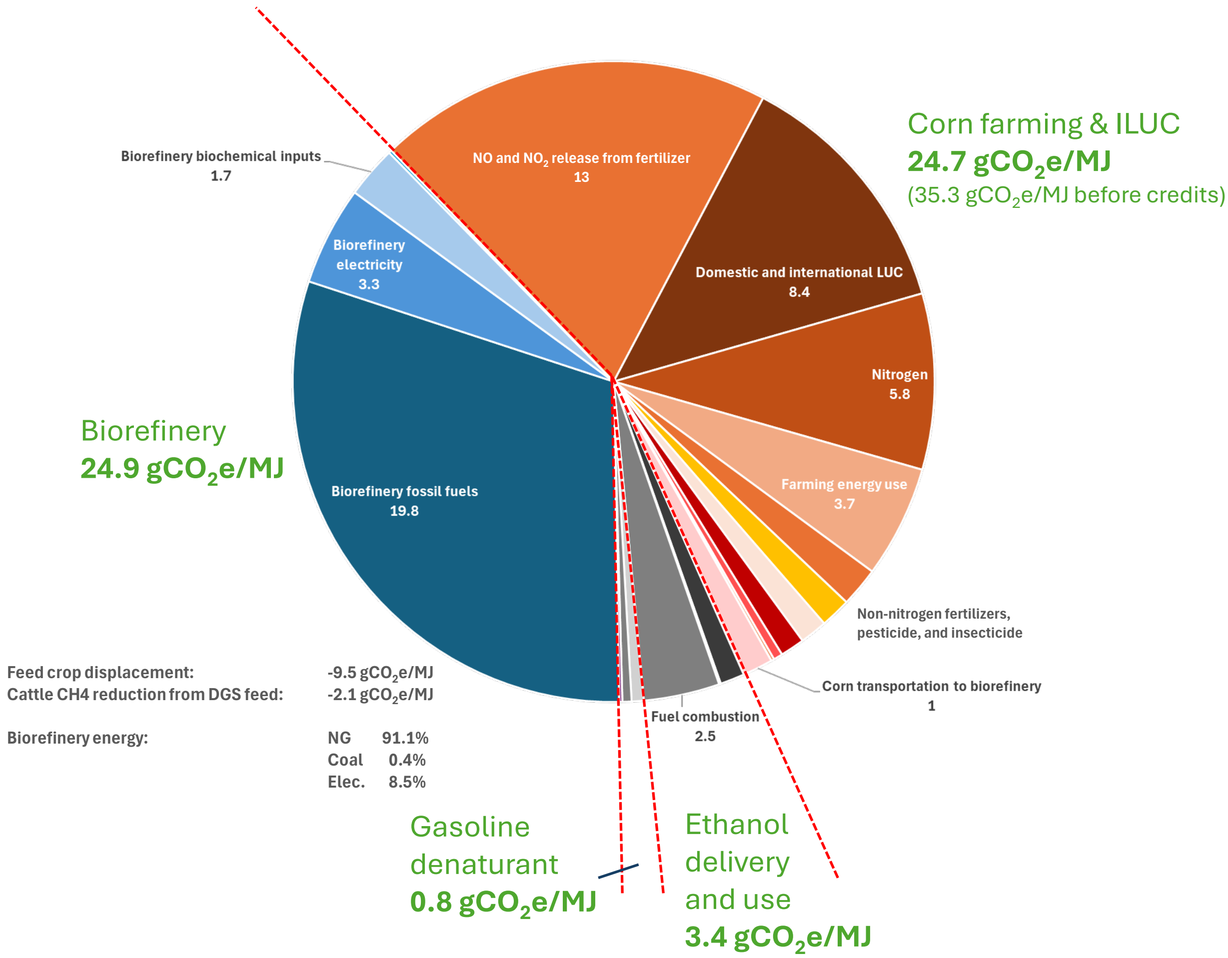
Final results

The R&D GREET model calculated life cycle GHG results for the default baseline pathway and the four decarbonization pathways outlined in Table B2. R&D GREET cell formulas were investigated to further break down emissions results into primary components for each life cycle phase. These detailed results are provided for each pathway in Table B3 and Figure B2 below.

Table B3
Life cycle GHG intensity components for dry mill ethanol with corn oil extraction

	Default Baseline	Net Zero by 2050		Deeper-Decarbonization	
		2035	2050	2035	2050
Corn Farming	**24.7**	**14.9**	**8.2**	**13.2**	**4.3**
Energy use	3.7	3.5	3.4	3.4	3.2
Fertilizer					
Nitrogen	5.8	5.0	4.4	3.5	1.0
P_2O_5	0.9	0.9	0.8	0.8	0.6
K_2O	0.3	0.3	0.3	0.3	0.3
$CaCO_3$	0.1	0.1	0.1	0.1	0.1
Urea use	1.0	0.9	0.8	0.9	0.8
NO from nitrogen fertilizer and above/below ground biomass	13.0	11.0	9.6	11.0	9.6
CO_2 from $CaCO_3$ use	1.3	1.3	1.2	1.3	1.2
Herbicide	0.8	0.9	1.0	0.9	1.0
Insecticide	0.003	0.0	0.003	0.0	0.003
Domestic and international land use change (LUC)	8.4	8.4	8.4	8.4	8.4
Displacement: Corn, soybean meal, urea, soybean oil	-9.5	-9.5	-9.5	-9.5	-9.5
Cattle CH_4 reduction from DGS feed	-2.1	-2.1	-2.1	-2.1	-2.1
SOC change	0.0	-6.5	-10.9	-6.5	-10.9
Corn transportation to biorefinery	1.0	0.9	0.9	0.9	0.8
Ethanol biorefining	**24.9**	**-12.9**	**-18.9**	**-16.9**	**-28.8**
Chemical inputs	1.7	1.7	1.7	1.7	1.7
Electricity	3.3	0.0	0.0	0.0	0.0
Fossil fuels	19.8	15.8	9.9	11.9	0.0
Non-combustion emissions	0.1	0.1	0.1	0.1	0.1
Carbon capture	0.0	-30.5	-30.5	-30.5	-30.5
Chemical inputs	1.7	1.7	1.7	1.7	1.7
Electricity	3.3	0.0	0.0	0.0	0.0
Ethanol transport to terminal	**0.9**	**0.9**	**0.9**	**0.8**	**0.8**
Ethanol transport and distribution	0.9	0.9	0.9	0.9	0.9
Bulk terminal volatile organic compounds (VOCs)	0.02	0.02	0.02	0.0	0.02
Refueling station VOCs	0.04	0.04	0.04	0.0	0.04
Distribution credit	-0.1	-0.1	-0.1	-0.1	-0.1
2% gasoline denaturant	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Petroleum production	0.3	0.3	0.3	0.3	0.3
Gasoline refining (excludes distribution)	0.4	0.4	0.4	0.4	0.4
Gasoline transport and storage	0.1	0.1	0.1	0.1	0.1
Vehicle	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**
Fuel combustion	71.4	71.4	71.4	71.4	71.4
CO_2 uptake combustion credit	-68.9	-68.9	-68.9	-68.9	-68.9
Total well-to-wheels LCA	**53.6**	**6.2**	**-6.5**	**0.4**	**-20.3**

Figure B2. R&D GREET 2023rev1 default life cycle contributors to dry mill corn ethanol greenhouse gas intensity



Appendix C: Levelized Cost of Carbon Abatement Assumptions

Levelized cost of carbon abatement (LCCA) calculates the cost per ton of emissions reduced by an investment or policy measure. It is determined by taking the difference in annualized costs between the current and new measures and dividing it by the reduction in annual CO_2 emissions:

L = C / (E0- E1)

where C is the annualized cost associated with the change of measure, E0 is the GHG emissions of the existing measure, and E1 is the GHG emissions in the new measure. [21]

This report calculated the LCCA for each decarbonization measure using publicly available data on the latest costs, prices, and existing policy incentives. Targets or commitments not yet shaped as policy incentives or long-term projections were excluded from consideration.

Corn yield improvement / Ethanol yield improvement

The LCCAs of corn and ethanol yield improvements were estimated as zero. Both measures should cost less than zero because they reduce input to produce the same output. However, the actual cost of each measure is difficult to estimate because both measures result from adopting multiple technologies or practices.

Applying enhanced efficiency fertilizers (EEFs)

The upper bound of the LCCA (-$105/t$CO_2$) was estimated under the assumptions that EEFs cost 15% more compared with the average conventional fertilizer ($179/acre from 2006 to 2023) and 15% improvement in fertilizer use efficiency.[22, 23, 24] The lower bound (-$314/t$CO_2$) was estimated assuming EEFs cost 5% more than conventional fertilizers, with the same efficiency improvement assumption.[25] The change in GHG emissions was measured using the GREET model.

No-till farming

The upper bound of the LCCA for no-till farming (-$63/t$CO_2$) was estimated based on anticipated fuel savings of $8/acre, while the lower bound (-294/tCO_2) was estimated using projected long-term net changes in on-farm economic returns of $37.12/acre.[26, 27] The change in GHG emissions was measured using the GREET model.

4R nitrogen management

The LCCA for 4R nitrogen management was estimated to be zero. While existing data consistently demonstrate cost savings from implementing 4R practices, the data vary widely and are difficult to generalize due to their case-specific nature.

Planting cover crops

Estimated costs of planting cover crops range from $58.56/ha to $155/ha.[28, 29, 30, 31, 32] The costs include seeds, planting, and termination expenses. The LCCA upper bound ($64/t$CO_2$) was estimated based on the $155/ha estimate, and the lower bound ($24/t$CO_2$) was based on $58.56/ha. The change in GHG emissions was measured using the GREET model and Argonne National Laboratory's Feedstock Carbon Intensity Calculator (FD-CIC).

Blue ammonia-based fertilizers

The LCCA of blue ammonia was estimated by comparing the cost of gray ammonia with blue ammonia in the United States. In 2023, the U.S. average cost of gray ammonia was $250/metric ton (t).[33] The levelized cost of blue ammonia was assumed to be $300/t and $420/t with and without 45Q tax credits, respectively.[34] The change in GHG emissions was calculated based on the difference in carbon intensity between gray ammonia (1.9 tCO_2/tNH_3) and blue ammonia (0.2 tCO_2/tNH_3).[35] The upper bound of LCCA ($100/t$CO_2$) reflects the blue ammonia cost without 45Q tax credits, while the lower bound ($29/t$CO_2$) reflects the cost with 45Q tax credits.

Green ammonia-based fertilizers

The LCCA of green ammonia was estimated by comparing the cost of gray ammonia with green ammonia in the United States. The levelized cost of green ammonia was assumed to be $250/t with the 45V, 48E, and 45Y tax credits and $1,250/t without any tax credits.[36] The change in GHG emissions was estimated based on the difference in carbon intensity between gray ammonia (1.9 tCO_2/tNH_3) and green ammonia (0 tCO_2/tNH_3).[37] The upper bound of LCCA ($526/t$CO_2$) reflects the green ammonia cost without any tax credits, while the lower bound ($ 0/tCO_2) reflects the cost with the 45V, 48E, and 45Y tax credits.

Using renewable diesel in farm machinery/corn transport /ethanol transport

The LCCA of switching from diesel to renewable diesel was estimated based on the price difference between these fuels. The price of renewable diesel was assumed to be $5.36/gallon, which reflects the average price in California as of April 2024, the only U.S. state with a market price for renewable diesel.[38] The higher bound of LCCA ($138/t$CO_2$) is based on the difference between diesel and renewable diesel prices in the Midwest in April 2024 ($3.95/gallon).[39] The lower bound ($126/t$CO_2$) is based on the difference between the national average diesel price ($4.07/gallon) and the price of renewable diesel.[40] The change in GHG emissions was estimated based on the difference in carbon intensity between diesel and renewable diesel.[41]

Fermentation CCUS/CCUS in thermal energy generation

The LCCAs of adopting CCUS in the fermentation process and thermal energy generation in a biorefinery were estimated using cost data for CCUS applications in the ethanol industry and combined cycle gas turbines, as outlined in the EFI Foundation's study, *Turning CCS Projects in Heavy Industry and Power into Blue Chip Financial Investments.*[42] The upper bound of LCCAs ($37/t$CO_2$ for fermentation CCUS and $106/t$CO_2$ for CCUS in thermal energy generation) does not account for 45Q tax credits. The lower bound of LCCAs (-$48/t$CO_2$ for fermentation CCUS and $106/t$CO_2$ for CCUS in thermal energy generation) reflects the impact of 45Q tax credits.

Carbon-free electricity

The upper bound of LCCA ($18/t$CO_2$) was estimated based on the biorefinery purchasing voluntary renewable energy certificates (RECs), with the REC price assumed at $7/MWh, the highest in the past decade.[43] The lower bound (-$48/t$CO_2$) was estimated assuming the biorefinery entered a wind power purchase agreement (PPA). The PPA price was estimated as the difference between the MISO wholesale electricity price in 2023 ($45/MWh) and the average wind PPA price in the Central region (MISO, SPP, ERCOT) in 2022 ($26/MWh).[44,45] The change in GHG emissions was estimated based on the CO_2 emissions from the U.S. electric power industry in 2022, which was 0.39 tCO_2/MWh.[46]

Fuel switching to RNG

The LCCA was estimated by comparing the price of natural gas with that of RNG. The price of natural gas was assumed to be $4.35/MMBtu, the U.S. average natural gas industrial price in 2023.[47] The LCCA's upper bound was estimated assuming an RNG cost of $45/MMBtu, the highest projected production cost in the United States, according to the American Gas Foundation. The lower bound was based on an RNG cost of $18.4/MMBtu, reflecting the lowest RNG cost from animal manure. [48] The change in GHG emissions was estimated based on the difference in carbon intensity between natural gas (100 gCO_2e/MJ) and the average carbon intensity of RNG from different sources (-75 gCO_2e/MJ).[49]

Fuel switching to blue hydrogen

The LCCA was estimated by comparing natural gas's cost with blue hydrogen. The cost of natural gas was based on the same assumptions used for fuel switching to RNG. The upper bound of LCCA was estimated using a green hydrogen cost of $2/kg, without accounting for 45Q tax credits. The lower bound was estimated assuming $1.7/kg after 45Q tax credits.[50] The change in GHG emissions was estimated based on the difference in carbon intensity between natural gas (100 gCO_2e/MJ) and the average carbon intensity of blue hydrogen (5.15$kgCO_2e/kgH_2$).[51]

Fuel switching to green hydrogen

The LCCA was estimated by comparing natural gas's cost with green hydrogen. The cost of natural gas was based on the same assumptions used for fuel switching to RNG. The upper bound of LCCA was estimated using a blue hydrogen cost of $6/kg without accounting for 45V tax credits. The lower bound was estimated assuming a cost of $3/kg after 45V tax credits.[52] The change in GHG emissions was estimated based on the difference in carbon intensity between natural gas (100 gCO_2e/MJ) and the average carbon intensity of green hydrogen (1$kgCO_2e/kgH_2$).[53]

Biomass CHP

The capacity of biomass CHP was assumed to be 27.7 MW, sufficient to provide 100% of the heat required for a median-sized biorefinery producing 83 million gallons of ethanol per year. CHP's capital and operating expenditures were estimated using DOE's Combined Heat and Power Technology Fact Sheet Series data.[54] Fuel costs were estimated using corn stover cost data from Iowa.[55] The electricity produced in CHP was assumed to be sent to the grid to generate additional revenue. The 2023 average MISO wholesale electricity price of $45/MWh was used to calculate this revenue.[44] The upper bound LCCA (-$1/$tCO_2$) was calculated assuming the upper bound cost of corn stover, while the lower bound LCCA (-\$38/tCO_2) was based on the lower bound cost of corn stover.

Blue hydrogen CHP/green hydrogen CHP

Capacity, capital expenditure, operating expenditure, and electricity production were estimated using the same assumptions applied to biomass CHP. Fuel costs were calculated based on the assumptions from “fuel switching to blue hydrogen” and “fuel switching to green hydrogen.”

RNG CHP

Capacity, capital expenditure, operating expenditure, and electricity production were estimated using the same assumptions applied to biomass CHP. Fuel costs were calculated based on the assumptions from “fuel switching to RNG.”

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