Supporting Information

The role of lignin in reducing life-cycle carbon emissions, water use, and cost for US cellulosic biofuels

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Summary

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Figures

Tables

Equations

County-level datasets are too large to display. They are available by request from the corresponding author.

Methods

Combined heat and power system energy and steam pressures

Combined heat and power (CHP) systems for each biorefinery configuration shown in Table 1 of the main text are simulated using a set of proprietary Aspen Plus models. These models provide net power output for given steam, gas, and combined-cycle configurations. The basic parameters not included in Table 1 of the main text are as follows:

- Case 1:
  Steam pressure(s) = 65 bar
  Lignin drying heat requirement = 0 MJ/hour

- Case 2:
  Steam pressure(s) = 65 bar
  Lignin drying heat requirement = 0 MJ/hour

- Case 3a:
  Steam pressure(s) = 13 bar and 9.5 bar
  Lignin drying heat requirement = 17040.28 MJ/hour

- Case 3b:
  Steam pressure(s) = 13 bar
  Lignin drying heat requirement = 17040.28 MJ/hour

- Case 4:
  Steam pressure(s) = 65 bar
  Lignin drying heat requirement = 17040.28 MJ/hour

Combined heat and power system capital costs

Capital costs for CHP system include turbines, boilers, and a lignin dryer where applicable. The lignin dryer costs an estimated 12 million USD and the original lignin solids boiler and steam turbine cost an estimated 157 million USD. Equation 1 is used to calculate the approximate capital costs associated with natural gas combined cycle (NGCC) systems, and is based on the size of the main gas turbine. Lignin dryers are added to the total cost only when lignin is exported.

Equation S1: Capital expenditures for NGCC system (million USD) where c = gas turbine capacity (MW)

$$CAPEX = 21 \times (\frac{c}{14})^{0.65}$$

Cellulosic ethanol production scenario

The ability to process multiple feedstocks facilitates successful scale-up of cellulosic biofuels. Increased flexibility allows biorefinery operators to reduce transportation costs by drawing from locally available biomass resources, avoid the need for long-term biomass storage by taking advantage of different harvest seasons, and protect themselves against the risk of significant supply disruption owing to crop failure.[1] However, because the composition of each feedstock differs, processing multiple feedstocks is technical more challenging and potentially more expensive than relying on a single biomass type. We have limited this scenario to herbaceous feedstocks only, with the assumption that biorefineries will be capable of processing combinations of the three when necessary.

Biomass production in each county is assumed to have sufficient access to transportation infrastructure if its centroid is located within 25 km of a rail line, the more affordable transportation option on a Mg-km basis.[2] We calculate that, on average, a unit of biomass travels 75 km by rail between farm and biorefinery. Although rail is the focus of the analysis, truck transportation may be more attractive for some biorefineries, which will increase the transportation-related GHG emissions but have a minimal impact on the final results.[3, 4]

Biomass loss factors associated with harvesting, baling, bale transport, and storage are adapted from Shastri et al. [5] According to Shastri, Hansen, Rodriguez and Ting [5], storing Miscanthus for a year results in dry matter losses ranging from 1% to 25% depending on the type of storage facility. Each on-farm handling process typically has a biomass loss rate of 5%.[5] For the biomass production scenario presented in this paper, the total field-to-refinery loss rate is estimated by Scown et al.[8] to be 20%.

The minimum commercial cellulosic biorefinery size is set to 136 million liters of ethanol/year, which corresponds to the size of Verenium's first commercial scale cellulosic biorefinery, previously planned for construction in Highlands County, FL. [6] The minimum biorefinery size is smaller than the 231 million liter/year hypothetical plant modeled in Humbird, et al. [7] A location is considered a viable biorefinery candidate for further analysis if it is within 100 km of sufficient biomass production to satisfy 100% of its annual needs, or if it lies in a county with one or more existing corn ethanol facilities and is within 25 km of a rail line. Of the 3,141 counties considered as biorefinery sites, 1,491 counties are within 100 km of sufficient biomass production, and 1,446 of those counties have sufficient access to rail infrastructure.

Accounting for regional and seasonal variations in the E85 blend wall, which varies between an annual average of 77 and 81% by region, [8] fuel blending terminals in the United States could be prepared to receive up to 3.0 trillion MJ (130 billion liters) of ethanol annually in 2050, assuming that all gasoline vehicles are flex-fuel.

Calculating biorefinery-to-terminal distances is a large optimization problem that connects all 1254 terminals with 107 biorefineries to minimize system-wide mass distances transported, similar to the analysis completed by Parker, et al. [9] for the western United States. After being produced at biorefineries, the typical liter of ethanol travels 470 km by rail before reaching a blending terminal. Strogen, Horvath and McKone [4] use a distance more than twice as large (1080 km), but their scenario is based on a 10% blend wall and current corn ethanol production only. If all fuel terminals are ethanol-equipped, the average liter of ethanol is estimated to travel 45 km by highway between terminals and fueling stations.

Most freight transportation also involves a fraction of km traveled during which the train or truck is empty, known as backhaul. For fuel transportation and distribution, the backhaul distance can be approximated as 100% of the original distance; this contribution is accounted for in the emission factors taken from Strogen, et al. [10]

Although the E85 label seems to imply a blend of 85% ethanol and 15% gasoline, the true blend varies regionally and seasonally, with lower ethanol content in colder climates and higher ethanol content in warmer climates. Annual average E85 blends are calculated to vary between 77 and 81%. County-level annual average blend data are used to determine the fraction of liquid fuel demand that can be satisfied with ethanol.

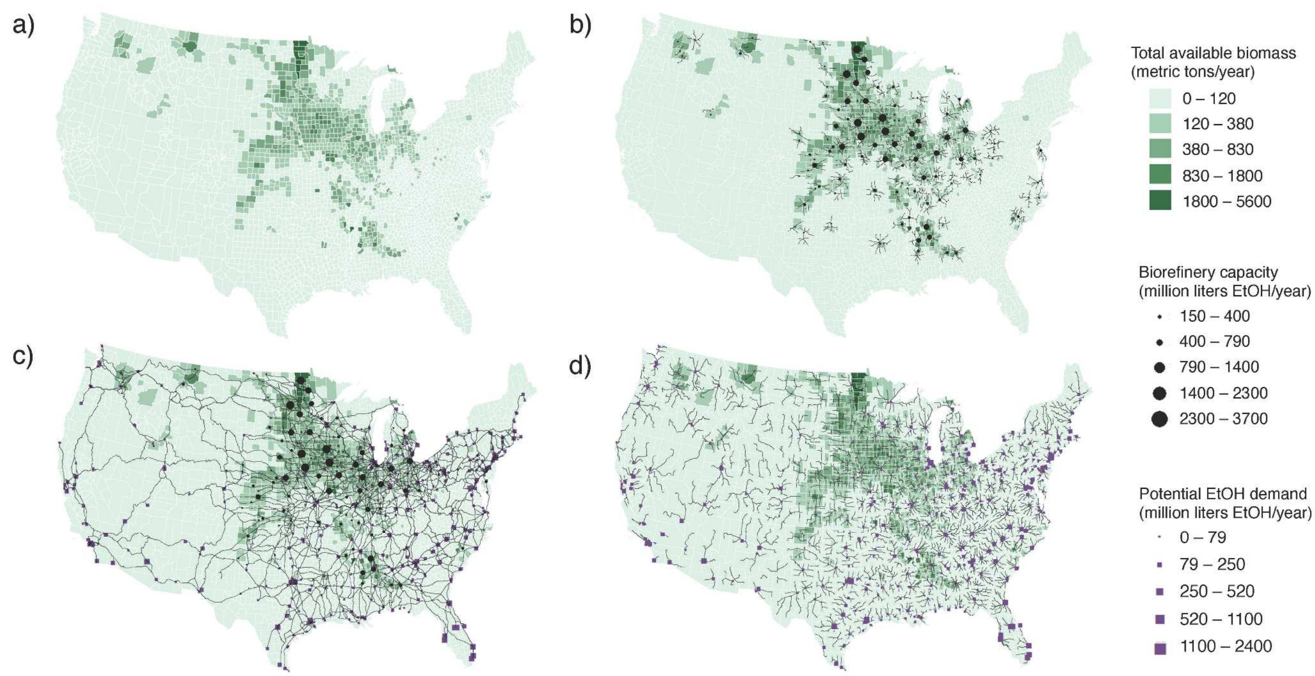

Figure S1: a) Total available Miscanthus, corn stover, and wheat straw at 20% moisture; b) Optimal biorefinery locations and capacities with rail paths for biomass delivery; c) Rail paths connecting the biorefineries to fuel terminals; d) Fuel terminals sized by demand, where 100% of each county demand is allocated to nearest fuel terminal, and highway paths to county centroids

The closest facility analysis including coal-fired power plants connects the biorefineries modeled in our national scenario with coal-fired power plants online in both 2014 and 2050. Coal power plant locations, heat rates, and estimated retirement years are taken from Ventyx datasets, which are purchased and cannot be shared here. The results of our lignin co-firing capacity analysis are shown in Figure S2.

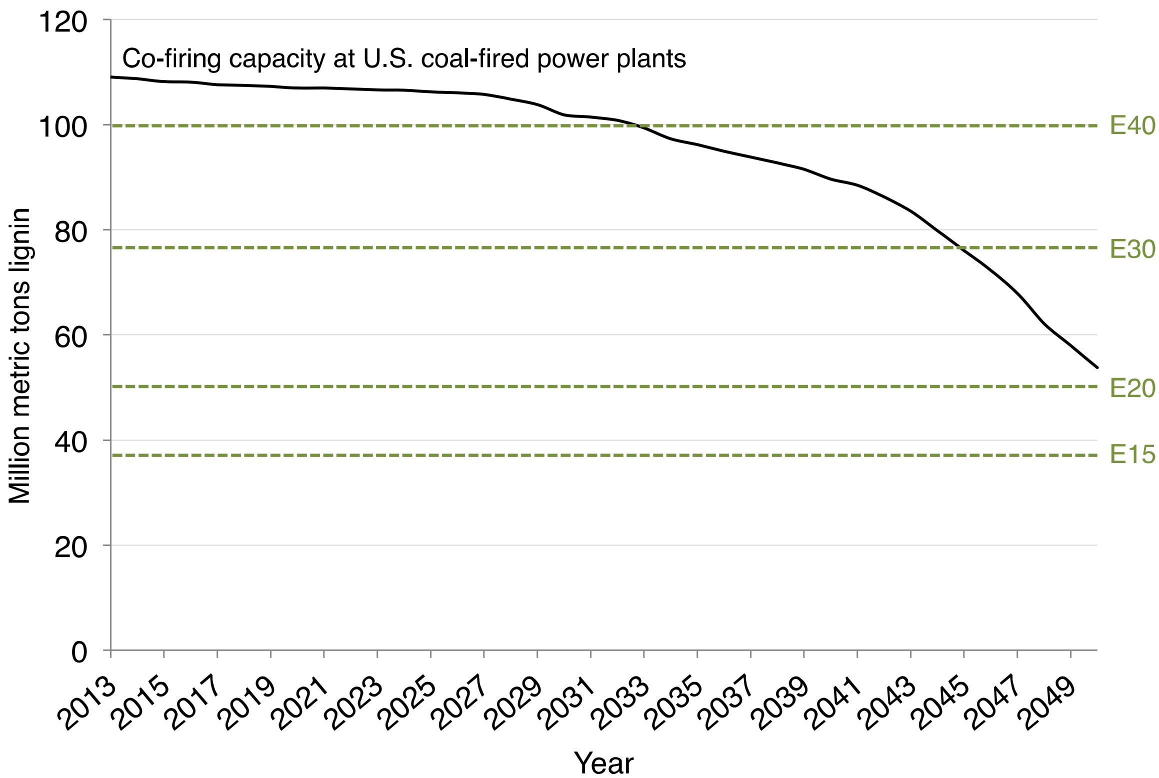

Figure S2: Coal-fired power plant capacity to accept lignin for co-firing

Life-cycle inventory

The greenhouse gas inventory is calculated using a custom input-output vector that is constructed based on physical units, and then converted to dollars input per dollar output based on approximate costs. The life-cycle inputs are converted back to physical units using the original USD/physical unit cost estimates. This method allows us to easily keep track of input data in a clean, computationally efficient manner, eliminate, and eliminate truncation error. The input-output method was originally introduced for life-cycle assessment by Hendrickson et al. [11] Rather than using the Economic Input-Output Life-cycle Assessment (EIOLCA) tool (eiolca.net), we choose to construct our own, more limited input-output vector to avoid the uncertainties associated with sector aggregation.

Table S1 lists the major products in our input-output table and the corresponding data sources used to calculate their inputs per physical unit of product. The full input-output vector, although too large to be displayed here, can be obtained by contacting the corresponding author. Table S2 lists the resulting emission factors for both combustion and non-combustion processes. Emission from steel production vary by origin due to differences in the electricity mix. Chinese electricity is assumed to be 70% coal, 30% hydro and Canadian electricity is assumed to be 77% renewables (primarily hydro), with the remainder made up of 66% coal and 33% natural gas.

Table S1: Data sources for major life-cycle inventory inputs

Input	Data source(s)
Atrazine	GREET[12]
Lime	EPA GHG Inventory[13]
$CaCO_3$	GREET[12]
H_2SO_4	GREET[12]
NaOH	GREET[12]
K_2O	GREET[12]
Ammonia	EPA[14]
Nitrogenous fertilizer	GREET[12]
P_2O_5	GREET[12]
Coal	Jaramillo et al.[15]
Diesel	Wang et al.[16]; Sheehan et al.[17]
Residual fuel oil	Wang et al.[16]
Crude oil	Sheehan et al.[17]
Natural gas	Jiang et al.[18]; Spath & Mann[19]
Uranium	Lenzen et al.[20]; Scown et al.[21]
Electricity - US avg	eGRID[22]
Electricity - natural gas simple	eGRID[22]
Electricity - NGCC	eGRID[22]
Electricity - Coal	eGRID[22]
Electricity - Renewables	eGRID[22]
Miscanthus	Scown et al.[3]
Corn stover	GREET[12]
Wheat straw	GREET[12]
Farm equipment	GREET[12]
Domestic steel	MECS[23]; EIOLCA[24]
Canadian steel	Calculated
Chinese steel	Calculated
Concrete	Santero & Horvath[25]
Cement	Santero & Horvath[25]
Lignin pellets	Wilson & Wilson[26]
Flatbed truck	Strogen et al.[10]
Tanker truck	Strogen et al.[10]
Liquid pipeline	Strogen et al.[10]
Rail	Strogen et al.[10]
Barge	Strogen et al.[10]
Marine tanker	Strogen et al.[10]

Table S2: Emission factors for major life-cycle inventory inputs

		Combustion			Non-combustion			
Input	Input unit	CO_2 emissions (kg)	CH_4 emissions (kg)	N_2O emissions (kg)	CO_2 emissions (kg)	CH_4 emissions (kg)	N_2O emissions (kg)	Data source(s)

Atrazine	kg	8.4E+00	3.9E-05	3.2E-05	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Lime	kg	2.6E-01	0.0E+00	6.0E-07	5.2E-01	0.0E+00	0.0E+00	EPA GHG Inventory[13]
$CaCO_3$	kg	1.5E-01	0.0E+00	1.1E-06	0.0E+00	0.0E+00	0.0E+00	EPA GHG Inventory[13]
H_2SO_4	kg	2.5E-03	0.0E+00	4.5E-08	0.0E+00	0.0E+00	0.0E+00	GREET[12]
NaOH	kg	1.2E+00	2.0E-05	1.5E-05	0.0E+00	0.0E+00	0.0E+00	Wicke et al.[27]
K_2O	kg	2.9E-01	0.0E+00	2.3E-06	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Ammonia	kg	8.5E-01	0.0E+00	0.0E+00	9.3E-01	0.0E+00	0.0E+00	EPA[14]
Nitrogenous fertilizer	kg	1.5E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	1.5E-02	GREET[12]
P_2O_5	kg	3.3E-01	0.0E+00	1.3E-06	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Coal	MJ	1.9E-04	2.0E-10	5.1E-11	0.0E+00	0.0E+00	0.0E+00	Jaramillo et al.[15]
Diesel	MJ	8.0E-03	6.9E-06	1.6E-07	0.0E+00	0.0E+00	0.0E+00	Wang et al.[16]; Sheehan et al.[17]
Residual fuel oil	MJ	1.7E-03	0.0E+00	1.4E-08	0.0E+00	0.0E+00	0.0E+00	Wang et al.[16];
Crude oil	MJ	7.7E-04	0.0E+00	1.4E-08	0.0E+00	0.0E+00	0.0E+00	Sheehan et al.[17]
Natural gas	MJ	1.2E-03	0.0E+00	1.7E-08	0.0E+00	1.2E-04	0.0E+00	Jiang et al.[18]; Spath & Mann[19]
Uranium	kg	6.6E+01	0.0E+00	1.2E-03	0.0E+00	0.0E+00	0.0E+00	Lenzen[20]; Scown et al.[21]
Electricity - US avg	kWh	5.5E-01	1.1E-05	8.2E-06	0.0E+00	0.0E+00	0.0E+00	eGRID[22]
Electricity - natural gas simple	kWh	4.2E-01	8.4E-06	9.1E-07	0.0E+00	0.0E+00	0.0E+00	eGRID[22]
Electricity - NGCC	kWh	3.4E-01	6.7E-06	7.2E-07	0.0E+00	0.0E+00	0.0E+00	eGRID[22]
Electricity - Coal	kWh	9.7E-01	1.1E-05	1.6E-05	0.0E+00	0.0E+00	0.0E+00	eGRID[22]
Electricity - Renewables	kWh	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	eGRID[22]
Miscanthus	kg	1.3E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Scown et al.[3]
Corn stover	kg	1.6E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Wheat straw	kg	1.6E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Farm equipment	N/A	2.5E-04	0.0E+00	3.5E-09	0.0E+00	0.0E+00	0.0E+00	GREET[12]
Domestic steel	kg	4.1E-01	0.0E+00	5.9E-06	0.0E+00	0.0E+00	0.0E+00	MECS[23]; EIOLCA[24]
Canadian steel	kg	4.1E-01	0.0E+00	5.9E-06	0.0E+00	0.0E+00	0.0E+00	Calculated
Chinese steel	kg	4.1E-01	0.0E+00	5.9E-06	0.0E+00	0.0E+00	0.0E+00	Calculated
Concrete	m^3	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Santero & Horvath[25]
Cement	kg	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Santero & Horvath[25]
Lignin pellets	MJ	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Wilson & Wilson[26]
Flatbed truck	tonne-km	1.2E-01	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]
Tanker truck	tonne-km	8.5E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]
Liquid pipeline	tonne-km	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]
Rail	tonne-km	1.9E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]

Barge	tonne-km	2.2E-02	0.0E+00	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]
Marine tanker	tonne-km	6.9E-03	8.0E-08	0.0E+00	0.0E+00	0.0E+00	0.0E+00	Strogen et al.[10]

The sensitivity analysis is meant to capture both aleatory uncertainty (referred to as variability) and epistemic uncertainty (resulting from data availability limitations and modeling limitations). The input parameters for the sensitivity analysis are provided in Table S3. The largest sources of aleatory uncertainty are biomass yield and N_2O fluxes from soil, both of which depend on climate conditions that are impossible to predict, particularly for a scenario that extends to the year 2050. We assume that national average Miscanthus yields vary by 20%, and with that, their fertilizer and chemical inputs also vary. We vary N_2O emissions, which are generally quantified as a fraction of total nitrogen applied as fertilizer, by 50% because the relationship of N_2O fluxes to regular weather events such as rainfall are not well understood.[28] Another contributor to aleatory uncertainty is the energy and GHG-intensity of the marginal unit of petroleum. Although the general trend indicates that crude oil will become more resource-intensive to extract as reserves are depleted, new exploration methods can also temporarily halt or reverse this trend as new reserves are uncovered.[29] Fugitive emissions of methane are a major contributor to epistemic uncertainty, particularly in this analysis where we vary the natural gas requirements substantially between biorefinery test cases. Although there is still much to learn about the nature of fugitive emissions, recent studies indicate that these emissions may have been systematically underestimated by the scientific community.[30] We vary fugitive emissions from natural gas distribution systems by 20%.

Cooling water needs also contribute large uncertainty to our results, particularly in the case of water withdrawals. This is because, particularly in water-stressed regions, industries that have previously relied heavily on open-loop cooling may be shifting to closed-loop cooling, which can result in total withdrawals being reduced by an order of magnitude or more. Although we separate out closed and open-loop cooling systems for power plants in our analysis, we must characterize that distinction for chemical manufacturing facilities using the sensitivity analysis. Existing data shows a reliance on primarily open-loop cooling systems, so we have varied the water withdrawals and consumption to match closed-loop systems to capture a potential scenario where the marginal unit of chemicals such as H_2SO_4 and fertilizers are supplied by newer, more water-efficient facilities.

Table S3: Sensitivity analysis inputs

Factor	Variation (%)
Ammonia input	20%
Atrazine input	10%
$CaCO_3$ input	20%
Coal extraction GHG emissions	20%
Crude oil extraction GHG emissions	20%
Diesel production GHG emissions	20%
Biorefinery fossil energy requirements	10%
Coal-fired power plant efficiency	20%
NGCC power plant efficiency	20%
US and NERC region grid electricity GHG-intensity	20%
Miscanthus farm fossil fuel inputs	10%
Stover collection fossil fuel inputs	10%
Wheat straw collection fossil fuel inputs	10%
Farm equipment lifetime	20%
Flatbed truck transportation distance	20%
Gas pipeline GHG emissions	20%
H_2SO_4 biorefinery pretreatment input	10%
K_2O fertilizer input	20%
Lime fertilizer input	20%
N_2O fluxes from soil	50%
NaOH for H_2SO_4 netralization at biorefinery	10%
Natural gas extraction GHG emissions	20%
P_2O_5 fertilizer input	20%
Rail transportation distance	20%
Steel production fossil fuel inputs	10%
Tanker truck transportation distance	20%
Power plant cooling needs	20%
Chemical manufacturing cooling needs	Vary between open loop and closed loop withdrawals

Results

Table S4: Life-cycle greenhouse gas emissions expected value results ($g\ CO_2e/MJ$ ethanol output)

Power source/offset	Scenario	Farm direct	Transportation direct	Biorefinery direct	Chemicals & materials	Fossil fuels upstream	Electricity
Grid electricity: NGCC	1	6.6E+00	3.4E+00	0.0E+00	1.0E+01	6.6E-01	-3.1E+00
	2	6.6E+00	5.1E+00	4.3E+01	1.7E+01	5.0E+00	-1.6E+01
	3a	6.6E+00	4.1E+00	5.1E+00	1.2E+01	4.2E+00	-1.5E+01
	3b	6.6E+00	2.5E+00	5.1E+00	1.2E+01	4.0E+00	-1.5E+01
	4	6.6E+00	3.0E+00	2.3E+01	1.5E+01	6.4E+00	-1.8E+01
Grid electricity: Coal	1	6.6E+00	2.9E+00	0.0E+00	1.0E+01	1.8E+00	-1.7E+01
	2	6.6E+00	3.1E+00	4.3E+01	1.7E+01	9.7E+00	-7.2E+01
	3a	6.6E+00	4.5E+00	5.1E+00	1.2E+01	3.2E+00	-3.7E+00
	3b	6.6E+00	2.9E+00	5.1E+00	1.2E+01	3.1E+00	-5.3E+00
	4	6.6E+00	3.0E+00	2.3E+01	1.5E+01	6.4E+00	-1.8E+01
Grid demand: NGCC	1	6.6E+00	2.9E+00	0.0E+00	1.0E+01	1.8E+00	-1.7E+01
	2	6.6E+00	3.1E+00	4.3E+01	1.7E+01	9.7E+00	-7.2E+01
	3a	6.6E+00	4.1E+00	5.1E+00	1.2E+01	4.2E+00	-1.5E+01
	3b	6.6E+00	2.5E+00	5.1E+00	1.2E+01	4.0E+00	-1.5E+01
	4	6.6E+00	3.0E+00	2.3E+01	1.5E+01	6.4E+00	-1.8E+01

Table S5: Life-cycle greenhouse gas emissions sensitivity analysis results ($g\ CO_2e/MJ$ ethanol output)

Power source/offset	Scenario	Low case	Expected value	High case
Grid electricity: NGCC	1	1.2E+01	1.8E+01	2.4E+01
	2	4.7E+01	6.1E+01	7.5E+01
	3a	8.2E+00	1.8E+01	2.7E+01
	3b	6.2E+00	1.5E+01	2.5E+01
	4	2.4E+01	3.6E+01	4.8E+01
Grid electricity: Coal	1	-3.8E+00	4.7E+00	1.3E+01
	2	-1.8E+01	8.3E+00	3.4E+01
	3a	2.1E+01	2.8E+01	3.5E+01
	3b	1.8E+01	2.5E+01	3.2E+01
	4	2.4E+01	3.6E+01	4.8E+01
Grid demand: NGCC	1	-3.8E+00	4.7E+00	1.3E+01
	2	-1.8E+01	8.3E+00	3.4E+01
	3a	8.2E+00	1.8E+01	2.7E+01
	3b	6.2E+00	1.5E+01	2.5E+01
	4	2.4E+01	3.6E+01	4.8E+01

Table S6: Life-cycle water consumption and withdrawals expected value results (liters/MJ ethanol output)

Power source/offset	Scenario	C or W	Biorefinery direct	Primary fuels	Chemicals	Construction & materials	Supply-chain agriculture	Supply-chain services	Grid electricity
Grid electricity: NGCC (cooling tower)	1	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-1.4E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-1.8E-02
	2	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-5.5E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-7.0E-02
	3a	C	1.1E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	1.1E-02
		W	1.1E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	1.4E-02
	3b	C	1.2E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	9.8E-03
		W	1.2E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	1.3E-02
	4	C	1.5E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	0.0E+00
		W	1.5E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	0.0E+00
Grid electricity: Coal (open-loop)	1	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-2.3E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-2.7E+00
	2	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-9.1E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-1.1E+01
	3a	C	1.1E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	1.8E-02
		W	1.1E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	2.1E+00
	3b	C	1.2E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	1.6E-02
		W	1.2E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	1.9E+00
	4	C	1.5E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	0.0E+00
		W	1.5E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	0.0E+00
Grid demand: NGCC (cooling tower) Grid offsets: Coal (open loop)	1	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-2.3E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-2.7E+00
	2	C	3.3E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	-9.1E-02
		W	3.3E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	-1.1E+01
	3a	C	1.1E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	1.1E-02
		W	1.1E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	1.4E-02
	3b	C	1.2E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	9.8E-03
		W	1.2E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	1.3E-02
	4	C	1.5E-01	1.0E-02	5.6E-02	3.2E-03	4.8E-02	3.9E-03	0.0E+00
		W	1.5E-01	1.0E-02	5.1E-01	8.3E-03	4.8E-02	3.9E-03	0.0E+00

Table S7: Life-cycle water consumption and withdrawals sensitivity analysis results (liters/MJ ethanol output)

Power source/offset	Scenario	C or W	Low case	Expected value	High case
Grid electricity: NGCC (cooling tower)	1	C	4.2E-01	4.3E-01	4.8E-01
		W	4.3E-01	8.9E-01	1.0E+00
	2	C	3.7E-01	3.9E-01	4.5E-01
		W	3.7E-01	8.4E-01	9.8E-01
	3a	C	2.3E-01	2.5E-01	2.7E-01
		W	2.5E-01	7.0E-01	8.2E-01
	3b	C	2.4E-01	2.5E-01	2.7E-01
		W	2.6E-01	7.1E-01	8.2E-01
	4	C	2.6E-01	2.7E-01	2.9E-01
		W	2.7E-01	7.2E-01	8.4E-01
Grid electricity: Coal (open-loop)	1	C	4.1E-01	4.2E-01	4.7E-01
		W	-2.8E+00	-1.8E+00	-1.1E+00
	2	C	3.3E-01	3.6E-01	4.2E-01
		W	-1.4E+01	-9.7E+00	-7.4E+00
	3a	C	2.4E-01	2.5E-01	2.8E-01
		W	1.9E+00	2.8E+00	3.3E+00
	3b	C	2.4E-01	2.6E-01	2.8E-01
		W	1.8E+00	2.6E+00	3.1E+00
	4	C	2.6E-01	2.7E-01	2.9E-01
		W	2.7E-01	7.2E-01	8.4E-01
Grid demand: NGCC (cooling tower) Grid offsets: Coal (open loop)	1	C	4.1E-01	4.2E-01	4.7E-01
		W	-2.8E+00	-1.8E+00	-1.1E+00
	2	C	3.3E-01	3.6E-01	4.2E-01
		W	-1.4E+01	-9.7E+00	-7.4E+00
	3a	C	2.3E-01	2.5E-01	2.7E-01
		W	2.5E-01	7.0E-01	8.2E-01
	3b	C	2.4E-01	2.5E-01	2.7E-01
		W	2.6E-01	7.1E-01	8.2E-01
	4	C	2.6E-01	2.7E-01	2.9E-01
		W	2.7E-01	7.2E-01	8.4E-01

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