Electronic Supplementary Material (ESI) for Energy & Environmental Science.

Supplementary Information for

Electrifying the Production of Sustainable Aviation Fuel: The Risks, Economics, and Environmental Benefits of Emerging Pathways Including CO_2

R. Gary Grim[1*], Dwarak Ravikumar[1], Eric Tan[1], Zhe Huang[1], Jack Ferrell[1], Michael Resch[1], Zhenglong Li[2], Chirag Mevawala[3], Steven D. Phillips[3], Lesley Snowden-Swan[3], Ling Tao[1], and Joshua A. Schaidle[1*]

[1] *National Renewable Energy Laboratory, 15013 Denver W Pkwy, Golden, CO 80401.*

[2] *Oakridge National Laboratory, 1 Bethel Valley Rd, Oak Ridge, TN 37830.*

[3] *Pacific Northwest National Laboratory, 902 Battelle Blvd, Richland, WA 99354.*

*Corresponding Authors: josh.schaidle@nrel.gov, gary.grim@nrel.gov

Table of Contents

1. Thermocatalytic Ethanol Conversion Process Flow Diagram 2
2. Standard Techno-economic Assumptions 3
3. Life cycle Analysis Assumptions.............. 4
4. Energy Efficiency Assumptions...7
5. Installed Wind Capacity in the United States..8
6. CO_2 Sources and Pipelines in West Texas 8
7. Regional Case Asumptions..9
8. Credit Calculations...10
9. Risk Register...11
10. References..13

Thermocatalytic Ethanol Conversion Process Flow Diagram

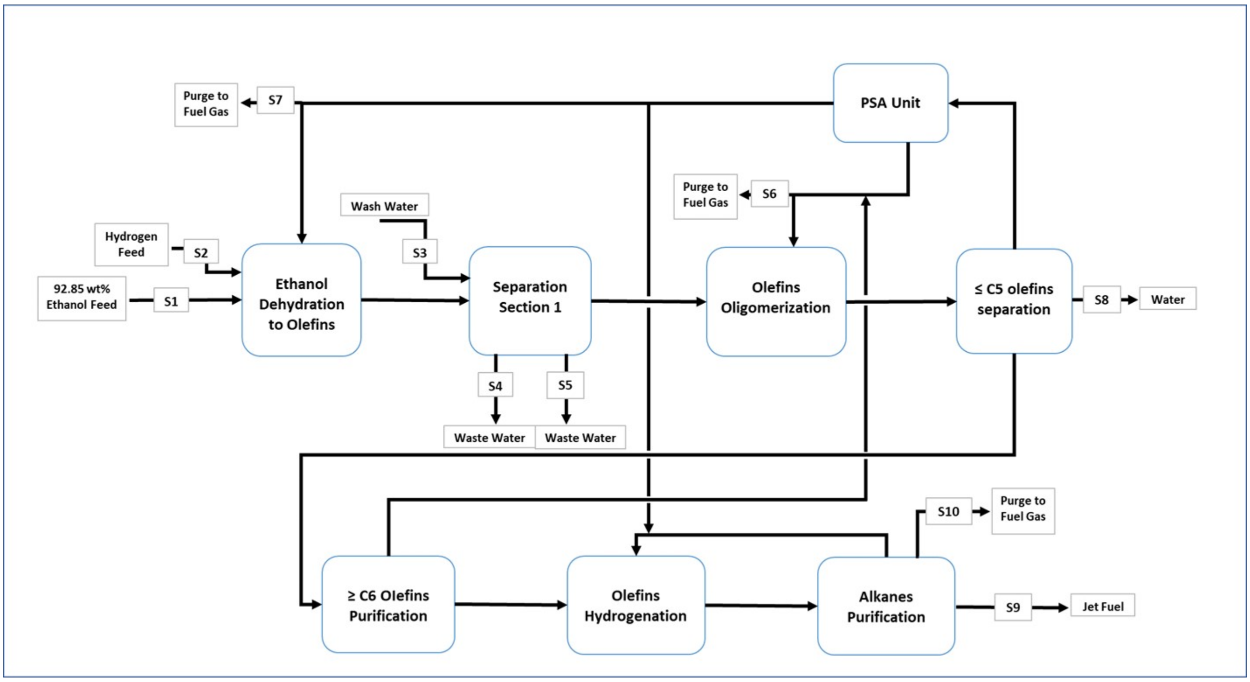


Figure S1: Block flow diagram of the modelled thermocatalytic ethanol catalytic conversion technology.

The initial ethanol to olefins (ETO) step is conducted at 325 °C, 9.8 bar and WHSV of 1.5 hr^{-1} over Ag-ZrO2/SBA-16 catalyst that achieves 97% conversion of ethanol (with 7 %w/w water) to a mixture of olefins rich in 1-butene. The carbon selectivity to olefins is 81%, 14% oxygenated hydrocarbons and 5% light paraffins of carbon number less than 5. The process stream is washed to remove some oxygenates and dried with a molecular sieve to remove water prior to feeding to the oligomerization reactor. The oligomerization reactor uses HZSM-5 zeolite catalyst to convert light olefins from the ETO reactor, plus light olefins recycled from a downstream separation step, into a mixture of olefins with carbon numbers between 6 and 16. The operating conditions for this reactor are 225 °C. 23.4 bar and a WHSV of 0.46 hr^{-1}. The single-pass light olefins conversion is 65% with 100% selectivity to olefins with increased carbon chain length. The oligomerization reactor effluent is distilled to remove a light fraction that is recycled and heavier olefins with carbon numbers in the range of 8 to 16, inclusive, that are sent on to a hydrotreater. The recycled light fraction of C_{6-} exiting the overhead stream from distillation is further processed to recover H_2, using pressure-swing adsorption, for use throughout the plant. A 5% purge from the recycle stream is required to prevent excessive build-up of light paraffins; the purge stream is burned for process heat. C_{8+} olefins are hydrogenated over a Pd on alumina hydrotreating catalyst at 21 bar and 300 °C and a WHSV of 5 hr^{-1} to produce the final SAF product. The yield of jet blendstock is sensitive to the split between light and heavy olefins leaving the distillation column after the oligomerization step. For this analysis only C_{6-} compounds were recycled. Recycling the C_8 olefins improves the jet fuel yield and reduces the naphtha yield with higher costs associated with recycling (e.g., reactor size and energy penalties for heating/cooling cycles and pumping).

Table S1. Standard Financial Assumptions

Economic parameters	**Assumed basis**
Basis year for analysis	2016
Debt/equity for plant financing	60%/40%
Interest rate and term for debt financing	8%/10 years
Internal rate of return for equity financing	10%
Total income tax rate	21%
Plant life (dry mill facilities)	20 years
Plant life (thermochemical)	30 years
Construction period	3 year
Fixed capital expenditure schedule (Ys 1-3)	32% in year 1
	60% in year 2
	8% in year 3
Start-up time	0.5 year
Revenues during startup	50%
Variable costs during startup	75%
Fixed costs during startup	100%
Site development cost	9% of ISBL*, total installed cost
Warehouse	1.5% of ISBL*

Indirect costs	**% of total direct costs**
Prorated expenses	10%
Home office and construction fees	25%
Field expenses	10%
Project contingency	10%
Other costs (start-up and permitting)	10%

Fixed operating cost	**Assumed basis**
Maintenance	3.0% of ISBL*
Property Insurance and local tax	0.7% of fixed capital investment

***ISBL = Inside battery limits**

CO_2 Capture Emissions Assumptions

Table S2: Environmental Impact Assumptions for Energy Supply (reproduced from von der Assen et al., [1])

Energy Source	Emissions Intensity (kg CO2e/GJ)
Electricity generation	133
Heat generation	75
Natural gas combustion	68
Coal combustion	105
Biomass combustion	5

Table S3: Actual Energy Demands for CO_2 Capture from Direct Air Capture (reproduced from von der Assen et al., [1])

	Actual Energy Demand (GJ/tonne CO2)						
CO_2 source	**Electricity**	**Heat**	**Natural Gas**	**Coal**	**Biomass**	**Total Energy Demand (GJ/tonne CO2)**	**kg CO2e/kg CO2***
Wet air capture	0.43	0	7.67	0	0	8.10	0.58
Wet air capture	0.37	0	7.67	0	0	8.04	0.57
Wet air capture	0.98	0	5.78	0	0	6.76	0.52
Wet air capture	1.96	0	0	3.65	0	5.61	0.64
Wet air capture	1.26	0	4.19	0	0	5.45	0.45
Wet air capture	1.84	0	4.19	0	0	6.03	0.53
Wet air capture	1.04	0	4.19	0	0	5.23	0.42
Wet air capture	1.58	0	4.19	0	0	5.77	0.50
Wet air capture	1.02	0	4.19	0	0	5.21	0.42
Wet air capture	1.28	0	4.19	0	0	5.47	0.46
Wet air capture	1	0	4.19	0	0	5.19	0.42

*Calculated from environmental impact factors in Table S2

Table S4: Actual Energy Demands for CO_2 Capture from Point Source Capture from a Cement Plant (reproduced from von der Assen et al., [1])

	Actual Energy Demand (GJ/tonne CO2)						
CO_2 source	Electricity	Heat	Natural Gas	Coal	Biomass	Total Energy Demand (GJ/tonne CO2)	kg CO2e/kg CO2*
Cement	0.73	3.7	0	0	0	4.43	0.37
Cement	0.13	0	3.6	0	0	3.73	0.26
Cement	-0.35	0	0	5.5	0	5.15	0.53
Cement	-0.38	0	0	4	0	3.62	0.37
Cement	0.54	2.7	0	0	0	3.24	0.27
Cement	0.73	0	0	0.06	0	0.79	0.10
Cement	0.99	0	0	0.86	0	1.85	0.22
Cement	0.54	0	0	1.6	0	2.14	0.24
Cement	-0.39	0	0	6.12	0	5.73	0.59

Cement	0.8	0	0	0.07	0	0.87	0.11
Cement	-0.49	0	0	4.82	0	4.33	0.44
Cement	0	0	0	4.82	0	4.82	0.51
Cement	-0.44	0	0	4.49	0	4.05	0.41
Cement	0	0	0	4.49	0	4.49	0.47

*Calculated from environmental impact factors in Table S2

Table S5: Actual Energy Demands for CO_2 Capture from Point Source Capture from a NGCC Power Plant (reproduced from von der Assen et al., [1])

	Actual Energy Demand (GJ/tonne CO2)						
CO_2 source	Electricity	Heat	Natural Gas	Coal	Biomass	Total Energy Demand (GJ/tonne CO2)	kg CO2e/kg CO2*
Post Combustion Capture	2.38	0	0	0	0	2.38	0.32
Post Combustion Capture	1.59	0	0	0	0	1.59	0.21
Post Combustion Capture	1.66	0	0	0	0	1.66	0.22
Post Combustion Capture	1.22	0	0	0	0	1.22	0.16
Post Combustion Capture	1.9	0	0	0	0	1.9	0.25
Post Combustion Capture	1.61	0	0	0	0	1.61	0.21
Post Combustion Capture	0.79	0	0	0	0	0.79	0.11

**Calculated from environmental impact factors in Table S2

Listed capture emission factors (kg CO_2e/kg CO_2 captured) in Table 3 of the main text reflect the average values from Tables S3-S5. Unless otherwise stated, the data include compression of at least 10 MPa which contributes ~0.05 kg CO_2e/kg CO_2 to the emissions factor.

Life Cycle Calculation Details

Table S6: Life cycle inventory data and emissions factors for modelled CO_2 to SAF process (SimaPro + Literature)

Material	Value	Units	Emissions Factor	Emission Units	Calculated Emissions	Emissions Factor Reference
SAF	15,874	kg/hr	-	-	-	-
CO_2	52,233	kg/hr	1.0	kg CO_2/kg	52,233	-
Process Water	1,000	kg/hr	0.001	kg CO_2/kg	1.0	[2]
H_2 (Syngas Fermentation)	6,168	kg/hr	1.63	kg CO_2/kg	10,054	[3]
H_2 (Hydrotreating)	242	kg/hr	1.63	kg CO_2/kg	395	[3]
Ammonia	172	kg/hr	1.86	kg CO_2/kg	321	[2]
Wind Electricity (CO_2 Electrolysis)	117,070	kWh	0.027	kg	3,161	[2]
Wind Electricity (BOP)	5,949	kWh	0.027	kg	161	[2]
Natural Gas (reboilers)	178.8	MMBTU/hr	6.21	kg/MMBTU	1,110	[4]
KH_2PO_4	40.4	kg/hr	1.72	kg CO_2/kg	70	[5]
NaCl	404.2	kg/hr	0.29	kg CO_2/kg	117	[2]
$CaCl_2$	8.1	kg/hr	1.06	kg CO_2/kg	9	[2]
$MgSO_4$	46.9	kg/hr	0.48	kg CO_2/kg	23	[2]
NH_4Cl	684.8	kg/hr	1.48	kg CO_2/kg	1,014	[2]
Yeast Extract	60.6	kg/hr	0.41	kg CO_2/kg	25	[2]
CO_2 Process Emissions	-	kg/hr	1	kg CO_2/kg	-	-
Waste Water Sludge	5,073	kg/hr	0.036	kg CO_2/kg	184	[5]
Total CO2e Emissions (SimaPro)					**16,643**	

Table S7: Life cycle inventory data and emissions factors for modelled CO_2 to SAF process (GREET + Literature)

Material	Value	Units	Emissions Factor	Emission Units	Calculated Emissions	Emissions Factor Reference
SAF	15,874	kg/hr	-	-	-	-
CO_2	52,233	kg/hr	1.0	kg CO_2/kg	52,233	-
Process Water	1,000	kg/hr	0.001	kg CO_2/kg	1.0	[2]
H_2 (Syngas Fermentation)	6,168	kg/hr	1.63	kg CO_2/kg	0	[3]
H_2 (Hydrotreating)	242	kg/hr	1.63	kg CO_2/kg	0	[3]
Ammonia	172	kg/hr	1.86	kg CO_2/kg	321	[2]
Wind Electricity (CO_2 Electrolysis)	117,070	kWh	0.027	kg	0	[2]
Wind Electricity (BOP)	5,949	kWh	0.027	kg	0	[2]
Natural Gas (reboilers)	178.8	MMBTU/hr	6.21	kg/MMBTU	1,110	[4]
KH_2PO_4	40.4	kg/hr	1.72	kg CO_2/kg	70	[5]
NaCl	404.2	kg/hr	0.29	kg CO_2/kg	117	[2]
$CaCl_2$	8.1	kg/hr	1.06	kg CO_2/kg	9	[2]
$MgSO_4$	46.9	kg/hr	0.48	kg CO_2/kg	23	[2]

NH_4Cl	684.8	kg/hr	1.48	kg CO_2/kg	1,014	[2]
Yeast Extract	60.6	kg/hr	0.41	kg CO_2/kg	25	[2]
CO_2 Process Emissions	-	kg/hr	1	kg CO_2/kg	-	-
Waste Water Sludge	5,073	kg/hr	0.036	kg CO_2/kg	184	[5]
Total CO2e Emissions (GREET)					**2,872**	

Table S8: CO_2-to-SAF carbon intensity calculations (LTE electrolyzer, Baseline Economic Scenario)

Database	CO_2 Source	CO_2 Converted (kg/hr)	CO_2 Capture Emissions Factor (kg/kg)	Direct CO_2 Emissions (Capture Step, kg/h)[a]	Direct CO_2 Emissions (SAF Production, kg/h)[b]	Net CO2 Emissions (kg/h)[c]	WTP Emissions (g/MJ)[d]	WTWa Emissions (g/MJ)[e]
SimaPro	Bioethanol	(52,233)	0.00	-	16,643	(35,590)	(51.5)	21.3
SimaPro	NGCC	(52,233)	0.16	8,190	16,643	(27,400)	(39.7)	33.2
SimaPro	Cement	(52,233)	0.29	15,307	16,643	(20,283)	(29.4)	43.5
SimaPro	DAC (avg)	(52,233)	0.48	24,910	16,643	(10,680)	(15.5)	57.4
SimaPro	DAC (OH)	(52,233)	0.08	4,179	16,643	(31,411)	(45.5)	27.4
SimaPro	DAC (VTS)	(52,233)	0.06	3,134	16,643	(32,456)	(47.0)	25.9
GREET	Bioethanol	(52,233)	0.00	-	2,872	(49,361)	(71.5)	1.4
GREET	NGCC	(52,233)	0.16	8,190	2,872	(41,171)	(59.6)	13.3
GREET	Cement	(52,233)	0.29	15,307	2,872	(34,054)	(49.3)	23.6
GREET	DAC (avg)	(52,233)	0.48	24,910	2,872	(24,451)	(35.4)	37.5
GREET	DAC (OH)	(52,233)	0.08	4,179	2,872	(45,182)	(65.4)	7.4
GREET	DAC (VTS)	(52,233)	0.06	3,134	2,872	(46,227)	(66.9)	5.9

a: Calculated by multiplying CO_2 converted by CO_2 capture emissions factor
b: from Table S6
c: Sum of CO_2 converted, capture emissions, and SAF production emissions
d: “well to pump” emissions. Assumes SAF production rate of 15,540 kg/hr and SAF energy density of 43.5 MJ/kg, yielding hourly energy outflow of 690,502 MJ SAF/hr
e: WTP + PTWa emissions (no compression). PTWa emissions fixed at 72.88 g/MJ based on GREET model.

Table S9: CO_2-to-SAF Energy Efficiency calculations (LTE electrolyzer, Baseline Economic Scenario)

CO_2 Source	CO_2 Converted (tonne/hr)	CO_2 Capture Energy Intensity (GJ/tonne)[a]	Energy Req. CO_2 Capture (GJ/hr)	Energy Req. H2 Production (GJ/hr)	Energy Req. Other Electricity (GJ/hr)	Energy Req. Heat (GJ/hr)	Total Energy Req. (GJ/hr)	Total Energy Out (GJ/hr)[b]	Energy Efficiency (%)
Bioethanol	52.23	0	0	1,246	443	189	1,878	691	36.8
NGCC	52.23	1.59	83	1,246	443	189	1,961	691	35.2
Cement	52.23	3.52	184	1,246	443	189	2,062	691	33.5
DAC (avg)	52.23	6.08	318	1,246	443	189	2,195	691	31.5
DAC (OH)	52.23	6.61	346	1,246	443	189	2,223	691	31.1
DAC (VTS)	52.23	10.62	555	1,246	443	189	2,432	691	28.4

a: Refs [[1], [6], [7]]
b: Assumes SAF production rate of 15,874 kg/hr and SAF energy density of 43.5 MJ/kg, yielding hourly energy outflow of 690,502 MJ SAF/hr

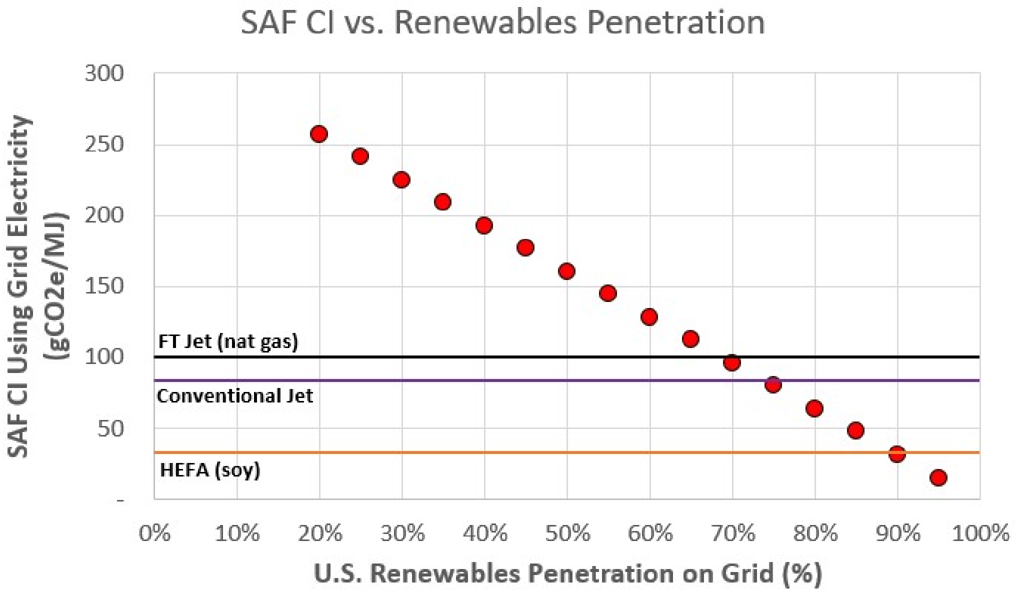
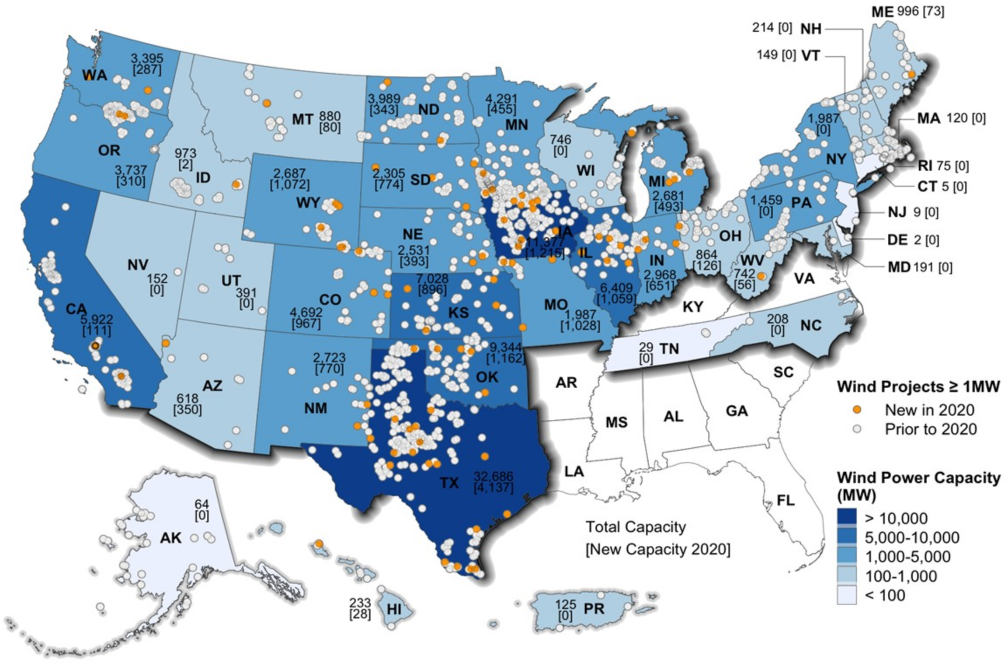


Figure S2: LTE CO2-to-SAF Carbon Intensity using Grid Electricity

Regional Case Supporting Data



Note: Numbers within states represent megawatts of cumulative installed wind capacity and, in brackets, annual additions in 2020.

Figure S3: Wind energy sites within the United States (2020). Reproduced from [8]

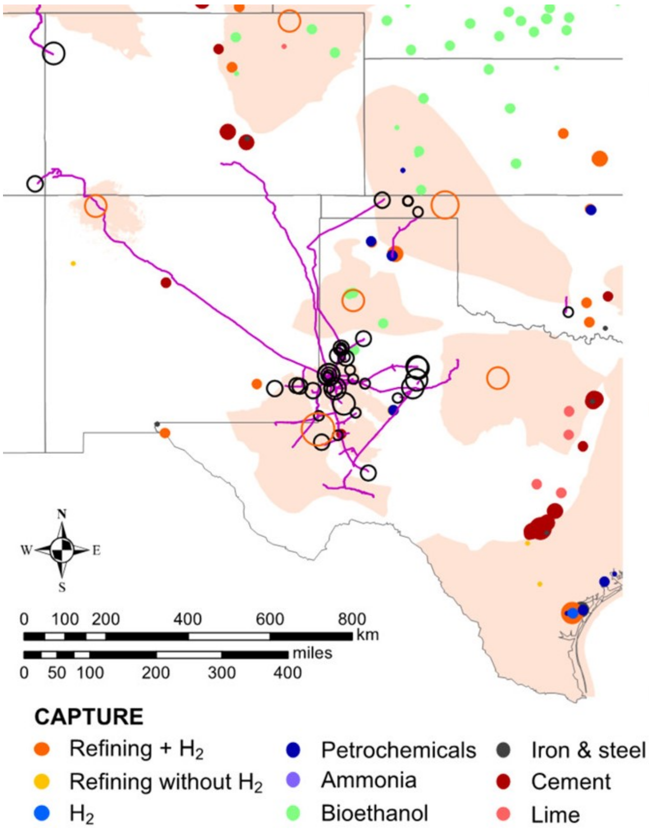


Figure S4: Carbon point sources and transportation infrastructure in the west Texas Permian Basin region. Reproduced from [9].

Table S10: Business Case Specific Parameters for West Texas ERCOT Region

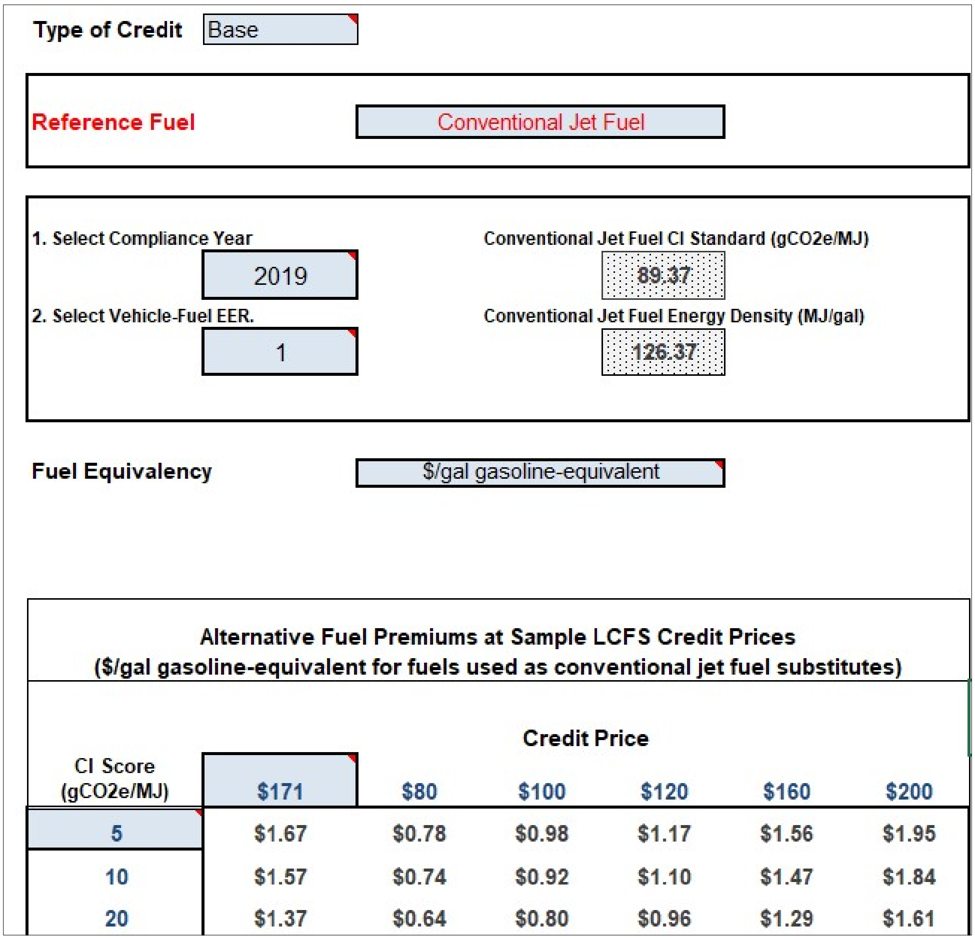
Parameter	Value	Notes
Electricity Price (\$/kWh)	0.016	1/3 Solar PPA + 2/3 Wind PPA [10]
H_2 Price (\$/kg)	1.51	[11]
Capacity Factor (%)	87.5	[12]
CO_2 Input Cost (\$/tonne)	25	-
Combined Corporate Income Tax Rate (%)	21	[13]
LCFS Incentives (\$/GGE)	(1.67)	LCFS Credit Calculator at CI of 5 [14]
Inflation Reduction Act (\$/GGE)	(1.59)	Estimated Credit at 94% reduction in CI [15]
Property Tax + Insurance (%)	2.53	[16]

Credit Calculations

Under the regional case assumptions shown in Table S9, our calculations suggest that SAF could be produced via the three-step LTE method at a price point of $6.27/GGE. Assuming the CO_2 is sourced from bioethanol and yields a carbon intensity of 5 gCO2e/MJ, the SAF product could qualify for at least two credits if sold in the state of California. Specifically, the low carbon fuel standard LCFS (credit) and the new Inflation Reduction Act (IRA) credit of $1.25 – $1.75/gal. Below we show how these credits may be calculated.

Low Carbon Fuel Standard

Using the credit calculator available from the LCFS website [14], users can determine the dollar per gallon credit based on the tradeable value of the LCFS credit [17] which varies on the open market. At the time of our calculations, LCFS credits were trading at a value of $171/ea and for a CI score of 5 gCO2e/MJ SAF would qualify for a incentive of $1.67/GGE as shown in Figure S5.



Type of Credit Base

Reference Fuel Conventional Jet Fuel

1. Select Compliance Year: 2019

Conventional Jet Fuel CI Standard (gCO2e/MJ): 89.37

2. Select Vehicle-Fuel EER.: 1

Conventional Jet Fuel Energy Density (MJ/gal): 126.37

Fuel Equivalency $/gal gasoline-equivalent

Alternative Fuel Premiums at Sample LCFS Credit Prices
($/gal gasoline-equivalent for fuels used as conventional jet fuel substitutes)

CI Score (gCO2e/MJ)	Credit Price $171	$80	$100	$120	$160	$200
5	$1.67	$0.78	$0.98	$1.17	$1.56	$1.95
10	$1.57	$0.74	$0.92	$1.10	$1.47	$1.84
20	$1.37	$0.64	$0.80	$0.96	$1.29	$1.61

Figure S5: LCFS Calculator Example

Inflation Reduction Act

In newly passed legislation in the United States, sustainable aviation fuel with a ≥ 50% reduction in carbon intensity relatively to conventional jet fuel would qualify for a $1.25/gallon credit. For every % above 50% CI reduction, an additional $0.01/gal credit is applied, reaching a maximum of $1.75/gal [15]. At our calculated CI of 5 gCO2e/MJ, it represents a 94% reduction relative to conventional jet fuel at 84 gCO2e/MJ. Thus, based on the language in the IRA, our SAF could qualify for up to \$1.25 + \$0.44 or \$1.69/gal total credit. Converting \$1.69/gal to a gallon-of-gasoline equivalent energy basis yields \$1.52/GGE credit.

In combing these two credits, the LCFS and IRA, we get a total possible credit of \$3.19/GGE (1.67 + 1.52). Applying this combined credit to our regional LTE case MJSP of \$6.27/GGE suggests that with credits our net SAF production costs could reach values as low as \$3.08/GGE.

Risk Register Details

Table S11: Technical Risks for LTE

Technical Risk	Severity	Description
Variable CO_2 feedstock characteristics (e.g., impurities, variable flowrate)	High	There is limited understanding and/or testing around the performance and stability of CO_2 electrolyzers using real gas mixtures containing species other than CO_2. Adverse reactions with diluents and/or species found in process recycle loops could degrade conversion metrics and negatively impact electrolyzer stability. To mitigate the risk of premature failure, systems should be tested with the real samples of process gas at each scale to understand the stability and interactions of different processes.
Unknown stability profile of electrolyzer and balance of plant equipment	High	Studies to date have investigated electrolyzer stabilities on the order of hundreds of hours to a few thousand at most. The performance trends and equipment replacement rates over longer durations are largely unknown, especially using real process gases. Current analyses suggest electrolyzer CAPEX and replacement rates are dominant contributors to process economics and thus uncertainty around stability and required replacement intervals introduces significant risk to overall process economics.
Membrane Irreproducibility	Moderate	Membranes (specifically anion exchange membranes) are not yet produced at a large scale and experience batch-to-batch variability, leading to differences in performance and stability for each stack. Membrane quality issues in the form of pinholes, nonuniformities, and other defects can contribute to rapid degradation and/or process upsets. Mitigation of this risk will involve identifying commercial partners and/or developing the in-house capabilities to scale up production of membranes such that the process is repeatable and of high quality.
Accumulation of electrolyte contaminants, change in pH	Moderate	At-scale processes will involve recycle of electrolytes to save on cost. Unlike lab-scale studies, commercial electrolyzer units will include recycle streams throughout the process which may harbor trace amounts of compounds not studied at the lab-scale. It is unknown how accumulation of contaminants over time will affect the electrolyte and/or the pH which plays a vital role in conversion efficiency.
Scale up of thermal management	Moderate	Maintaining a constant stack temperature and preventing overheating from resistive heating is a key element to preserving electrolyzer performance and stability. While demonstrated at the lab-level for small systems on the order of a few square centimeters, it has not yet been proven in larger systems and those with many combined stacks. Failure to provide adequate and uniform cooling opens the risk to degraded performance, premature failure, and consequently higher replacements rates.
Poor performance metrics	Moderate	The current state of the art and technical performance of CO_2 electrolyzers falls short of the comparatively higher TRL H_2O electrolysis systems. To approach commercial viability, performance metrics such as conversion, voltage efficiency, and current density need to be increased across the board. While this has been achieved in other similar systems (e.g., PEM H_2O electrolyzers) providing a precedent for possible improvement, it is unclear if the same performance increase can be achieved in CO_2R systems, and until demonstrated, poses a risk to achieving commercial success.
Corrosion of Carbon Supports	Moderate	The relatively high operating voltage of current electrolyzers can corrode and promote degradation of electrocatalyst supports and/or stack housing materials leading to accelerated degradation. This issue has the potential to become

		exacerbated as current densities are pushed higher. This increased degradation poses a risk in the form of increased replacement rates, introduction of possible failure modes, and higher OPEX/CAPEX charges.
Poorly understood durability under intermittent operation	Low / Moderate	Electrolysis needs access to the lowest cost electricity to be competitive economically which is likely to be available only intermittently. It is not well understood how CO_2 electrolysis systems will adapt to frequent cycling and poses a risk to durability / increased replacement rates and process economics.

Table S12. Technical Risks for Ethanol to SAF Conversion

Risk	Severity	Description
Limited knowledge of catalyst stability	High	Similar commercial catalysts are often run with intervals of 1 to 2 years between replacement. Current experimental catalysts have only been tested for a small fraction of that time and it is largely unknown how the presence of metals, organics, and other possible contaminants will impact the stability and performance. Longer testing with real process streams is needed.
Too low olefin selectivity	Moderate	The final SAF fuel yield and more broadly the process economics will be governed by the selectivity of the initial ethanol to olefins steps. Further optimization of the catalyst is likely needed to increase SAF yields and enhance economic viability
Product not yet qualified by ASTM	Moderate	Although comprising elements found in a typical jet fuel product, the ORNL process has not yet produced enough fuel to undergo formal ASTM certification and thus until the process is complete poses a risk to achieving market acceptance.

Table S13. General Market and Scaling Risks for Ethanol to SAF Conversion

Risk	Severity	Description
Competing Markets for Intermediates	High	CO is available as a waste gas (e.g., steel mills) or can be produced at high volumes from other mature conventional methods (e.g., RWGS). Similarly, ethanol is available for low cost from first generation corn grain sources. Creating these intermediates from lower TRL processes (e.g., electrolysis) and high-cost feedstocks (e.g., electrolytic hydrogen) can create a challenging economic environment versus alternatively simply purchasing the materials from incumbent methods. Without a strong economic driving force, there is risk for competition from other lower cost providers and/or more intensified processes.
Competition from other processes	High	Sustainable jet products can be produced from a variety of technologies and feedstocks, some of which are higher TRL and can involve less stages. For example purchasing ethanol directly from a corn dry-mill source and performing ETJ.
Scaling too early before identifying market fit	High	Lab-scale/pilot-scale processes not yet perfected nor have most shown a clear pathway to economic viability. A clear path to economic viability with minimal technical risks should be demonstrated before scale up.
Sourcing raw materials	High	A significant fraction of the LTE electrolyzer cost (and total process cost) is attributed to the metal electrocatalysts due to the use of rare earth metals (e.g., iridium, platinum, yttrium). The price of the raw materials is both high and, in the past, has seen dramatic price movement from geopolitical affects. The sourcing of sufficient quantities of the required metal at a viable price point poses a significant economic risk.
High upfront capital costs	High	The infrastructure required for electricity supply and CO_2R conversion come with higher upfront capital costs relative to conventional methods. These higher costs can make securing financing more risky, leading to higher rates and/or a lower appetite for investment.
Resource allocation	Moderate	As research continues to evaluate the life-cycle impacts of deep electrification and

challenges		electrofuels, there is a risk that in the future it may be favored to allocate resources away from fuels into other sectors with more favorable GHG reduction potential.
Availability of components/suppliers at scale	Moderate / Low	Many of the major components of the LTE system and BOP as well as the next-generation catalysts have yet to be produced at scale nor are there currently any commercial partners presently with the capability to scale the production of the required components posing a risk to process development.

Table S14. Systems Integration Risk for CO_2-to-SAF Conversion

Risk	Severity	Description
Challenging siting requirements	High	Breaking in the established field of fuels production using sustainable feedstocks is anticipated to be challenging economically. Current analyses suggest that the deployment of CO_2-to-SAF technologies are likely to be constrained with specific siting requirements, needing access to cheap land, the cheapest yet abundant feedstocks, and favorable incentives to approach viability. This poses a risk around the availability of such locations that meet all requirements while also co-locating with consumers and other required infrastructure (e.g., transportation and storage)
Integration of multiple process steps	High	Managing the throughput of multiple complex processing stages and their respective turndowns (e.g., if supply of feedstocks to any respective stages are not constant).
CO_2/electricity supply stopped unexpectedly or delivered intermittently	Low	Electrolyzers will typically have at least two feed streams consisting of electricity and CO_2. The supply of either stream could be disrupted for example under a load following scheme or due to unanticipated outage. Frequent on/off cycling may negatively impact electrolyzer stability and catalyst activity.

References:

1. von der Assen, N., et al., *Selecting CO2 Sources for CO2 Utilization by Environmental-Merit-Order Curves.* Environ Sci Technol, 2016. **50**(3): p. 1093-101.
2. *SimaPro EcoInvent Database*.
3. Burkhardt, J., et al., *Hydrogen mobility from wind energy – A life cycle assessment focusing on the fuel supply.* Applied Energy, 2016. **181**: p. 54-64.
4. EIA. 2022 [cited 2022 6/1/2022]; Available from: https://www.eia.gov/environment/emissions/co2_vol_mass.php.
5. Argonne National Laboratory *GREET.Net: A fresh design for GREET life cycle analysis tool*. 2021 [cited 2022 1/03]; Available from: https://greet.es.anl.gov/index.php?content=greetdotnet.
6. de Jonge, M.M.J., et al., *Life cycle carbon efficiency of Direct Air Capture systems with strong hydroxide sorbents.* International Journal of Greenhouse Gas Control, 2019. **80**: p. 25-31.
7. Deutz, S. and A. Bardow, *Life-cycle assessment of an industrial direct air capture process based on temperature–vacuum swing adsorption.* Nature Energy, 2021. **6**(2): p. 203-213.
8. Lawrence Berkeley National Laboratory; Available from: http://windreport.lbl.gov.
9. Pilorgé, H., et al., *Cost Analysis of Carbon Capture and Sequestration of Process Emissions from the U.S. Industrial Sector.* Environmental Science & Technology, 2020. **54**(12): p. 7524-7532.
10. Level Ten Energy, *North American Q1 2019 PPA Price Index*. 2019 [cited 2021 9/29]; Available from: https://www.leveltenenergy.com/post/q1-2019.
11. NREL. *H2A: Hydrogen Analysis Production Models*. 2021 [cited 2021 03/19]; Available from: https://www.nrel.gov/hydrogen/h2a-production-models.html.

12. Slusarewicz, J.H. and D.S. Cohan, *Assessing solar and wind complementarity in Texas.* Renewables: Wind, Water, and Solar, 2018. **5**(1).
13. Square, T.C. *Texas posts a combined corporate tax rate of 21 percent, tied for lowest in U.S.* . 2020 [cited 2021 9/29]; Available from: https://www.thecentersquare.com/texas/texas-posts-a-combined-corporate-tax-rate-of-21-percent-tied-for-lowest-in-u/article_af587072-6924-11ea-b333-43cb23d40dae.html.
14. California Air Resource Board, *The LCFS Credit Price Calculator*. 2019 [cited 2022 10/04]; Available from: https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/creditvaluecalculator.xlsx.
15. 117th Congress, R.J.A.Y. *H.R.5376 - Inflation Reduction Act of 2022*. 2022 [cited 2022 09/30]; Available from: https://www.congress.gov/bill/117th-congress/house-bill/5376.
16. Texas Taxpayers Association. *Property Taxation of Business Personal Property*. 2018 [cited 2021 9/29]; Available from: https://ttara.org/wp-content/uploads/2018/09/TTARATestimonyonBusinessPersonalProperty_2_20_18.pdf.
17. California Air Resource Board, *Weekly LCFS Credit Transfer Activity Reports*. 2021 [cited 2021 12/15]; Available from: https://www.arb.ca.gov/fuels/lcfs/credit/lrtweeklycreditreports.htm.