Near-Term Electricity Requirement and Emission Implications for Sustainable Aviation Fuel Production with CO_2-to-Fuels Technologies

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[1] *National Renewable Energy Laboratory*
[2] *Argonne National Laboratory*

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List of Acronyms

ADM	Archer-Daniels-Midland Company
ANL	Argonne National Laboratory
CAISO	California Independent System Operator
CO_2	carbon dioxide
CO2U	carbon dioxide utilization
COVID-19	Coronavirus Disease 2019
CPP	Critical Pricing Period
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies
GW	gigawatt
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kg	kilogram
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LS	large electric service
LST	Large Electric Time-of-Use Service
MISO	Midcontinent Independent System Operator
MMT	million metric tons per year
MVA	megavolt ampere
MVar	megavolt ampere of reactive power
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
PEM	polymer electrolyte membrane
PPA	power purchase agreement
PTC	Production Tax Credit
RTP	real-time pricing
SAF	sustainable aviation fuel
TOU	time-of-use
USDA	U.S. Department of Agriculture

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Executive Summary

Aviation contributed approximately 10% of the U.S. transportation sector's greenhouse gas (GHG) emissions and about 3% of the nation's total GHG production before the coronavirus disease (COVID-19) pandemic (EPA 2022). Unlike the ground transportation sector, which can be decarbonized by using batteries and hydrogen fuel cell powertrain technologies, the technical and economic challenges of aviation electrification open the opportunity for CO_2 utilization (CO2U) using clean power sources. The U.S. government set a goal to produce 3 billion gallons per year of sustainable aviation fuels (SAF) by 2030 and scale up the production to 35 billion gallons per year by 2050 (Bioenergy Technologies Office 2022).

In this report, we examine three potential locations, in California, Iowa, and Louisiana, for SAF production using two production pathways that are expected to be available by 2030. We analyze the electricity cost to satisfy 10% of the SAF production potential for the select locations. Specifically, we consider (1) retail electricity cost from the default local utility in each location under the industrial customer retail rate schedule and tariff structure, effective volumetric rates that include volumetric energy charge (for all kilowatt-hours [kWh] of energy use), demand charge (for maximum monthly kW needs), and utility monthly fixed cost; (2) physical power purchase agreement (PPA) for renewable power and battery storage hybrid systems with preset prices; (3) financial PPA from a dedicated renewable plant; and (4) estimated real-time pricing (RTP) from the wholesale power market with utility delivery adders.

Retail rates are available for the three potential locations; however, the developer should negotiate with the local utility in Iowa for new tariff riders, because the load of the proposed SAF plant (1.4 GW) is significantly higher than the current industrial tariff structure requirement (200 kW). The developers are not able to claim federal credits (i.e., the Inflation Reduction Act of 2022) when sourcing electricity from local utilities. Developers could consider prioritizing physical and financial PPAs as purchase options. While physical PPAs can be imported out of state, this structure imposes availability issues as developers must locate in the same electricity grid regions. Financial PPAs do not have the same location restrictions and provide the same cost savings as physical PPAs, but financial PPAs impose financial risks in the event of system curtailment and grid interruption. RTPs are available for customers in California with flexible load and hourly load management capability; however, utilities in our studied regions in Louisiana and Iowa only offer time-of-use and curtailment programs to incentivize lower energy usage in peak hours. These utilities do not currently offer RTP programs, and the developer may need to have further negotiations with the local utilities to access RTP programs.

Table 1 below shows a summary of purchasing options and respective estimated electricity cost ranges. The results show that purchased electricity prices may range from 2.6¢/kWh to 7.1¢/kWh for the three studied plants. For the p10 plant in California, retail electricity, physical PPAs with subsidies, and financial PPAs have the most potential to provide low-cost electricity to the SAF production plant. For the p58 plant in Louisiana, physical PPAs with subsidies and financial PPAs are competitive. For the p45 plant in Iowa, the retail rate is less attractive, while financial PPA could be considered by the developer.

Table 1. Purchase Options and Electricity Cost Ranges

State	Town	Modeled Balancing Area	Retail Rate (¢/kWh)	Physical PPA (¢/kWh)	Financial PPA (¢/kWh)	RTP (annual average ¢/kWh)
California	El Segundo	p10	3.5	3.4–5.9	3.5–4.8	4.5
Louisiana	Sulphur	p58	4.9–5.1	3.4–3.6	3.3–4.5	4.2
Iowa	Arthur	p45	7.1	3.4–3.6	2.6–3.6	3.3

In this report, we also examine the long-run marginal carbon dioxide (CO_2) emission rate and average CO_2 emissions of the three potential locations. The results show that Region p10 in California has the most diverse non-fossil energy generation mix, but adding electric load to this region may be challenging with such significant electric demand in place. Region p58 in Louisiana has nuclear generation capacity, which provides an opportunity for low-carbon and low-cost electricity. For Region p45 in Iowa, onshore wind generation dominates the grid system; however, because of the variability of wind resources, higher carbon emission fossil generation is needed for meeting summer and winter demand.

The next phase of this project will examine the long-term SAF market demand and size, CO_2 and hydrogen sources, and transportation requirements. In the 2050 scenarios, the CO2U industry is assumed to be a price maker and will shape the buildout of the power system. We will also investigate the energy and environmental justice aspects of such developments.

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1 Introduction

This report identifies locations for sustainable aviation fuel (SAF) production through identified CO_2-to-Fuels pathways and quantifies electricity purchase costs, marginal emission rates, and carbon intensity in the 2030 timeframe. This introduction includes the study background and CO_2 conversion pathways and provides an overview of this effort. Section 2 describes the methods to quantify region-specific electricity cost for SAF production and lists the major assumptions, as well as caveats, in this study. Section 3 introduces the selected locations for SAF production as well as the market size and energy requirements for the plants. In Section 4, electricity purchase options and respective cost analyses are detailed. Section 5 discusses the generation mix, long-run marginal emission rate, and average emissions for the three selected locations. Section 6 provides a conclusion and outlines a future work plan for subsequent analysis that focuses on the long-term effects of CO_2 utilization (CO2U) load.

1.1 Background

CO2U technologies that convert carbon dioxide (CO_2) from relatively pure CO_2 emission sources to hydrocarbon fuel products have gained significant traction in recent years for economy-wide decarbonization. These technologies help address concerns in the hard-to-decarbonize industries by extending the usefulness of carbon from biogenic and other sources. If CO2U facilities can utilize relatively low-emission electricity, such as electric resources generated using solar, wind, hydro, and nuclear power, the carbon impact of those CO2U products will be lowered. In addition, while many existing techno-economic analyses apply generic electricity costs, our study presents locationally varied electricity options and costs to inform the CO2U carbon emission impacts and product values.

One CO2U product with potential to substitute current fossil-based jet fuel with a significantly lower carbon impact is SAF. SAF refers to fuels that are produced from biomass or waste resources, such as the CO_2 waste stream that is otherwise emitted into the atmosphere. The physical and chemical composition of SAF is similar to traditional jet fuel (The International Air Transport Association, n.d.), so SAF can mix with jet fuel to a certain degree; such fuel is thus an important solution for decarbonizing the aviation sector without needing modification or adaptation of the aircraft engines and delivery and storage infrastructure.

Recognizing the critical role of SAF in mitigating carbon emissions in the aviation sector, a government-wide SAF Grand Challenge launched by the U.S. Department of Energy (DOE), the U.S. Department of Transportation (DOT), and the U.S. Department of Agriculture (USDA) has set a target for SAF production to reach 3 billion gallons per year by 2030 and meet 100% of the 35 billion gallon per year aviation fuel demand by 2050 (House 2021). CO2U can meet a portion of the target, but its extract role will depend on the technological advancements, as well as costs and emission implications, of CO2U.

1.1.1 SAF Production Pathways

Multiple pathways exist to achieve SAF as CO2U end products. For this study, we collaborated with the CO2U Techno-Economic Analysis and Life Cycle Analysis project team (WBS#2.1.0.506-7) within DOE's CO2-to-Fuels Consortium. Specifically, Pathways 1 and 3 from the project were used for subsequent analysis.

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Figure 1 shows Pathway 1: Electrochemical CO_2-to-CO + Syngas Fermentation + Ethanol-to-Jet. Step 1 of Pathway 1 is electrochemical reduction of a CO_2 source into a carbon monoxide (CO) mixture. This step is achieved by a low-temperature electrolyzer, such as an alkaline and polymer electrolyte membrane (PEM) electrolyzer, and the catalyst material is typically silver (Ag), gold (Au), palladium (Pd), or zinc (Zu). The cathode end of the electrolyzer absorbs the CO_2 and reduces it to CO with the electrons oxide from water in the anode end of the electrolyzer. The CO/CO_2 mixture is then combined with hydrogen (H_2) to go through syngas fermentation, which uses acetogenic microorganisms such as C. ljungdahlii and C. autoethanogenum (Sun et al. 2019) to produce ethanol and other byproducts with appropriate operating conditions such as temperature and pH. The ethanol from Step 2 can be further dehydrated to form ethylene over catalysts such as silica-alumina, followed by oligomerization to form higher and more complex olefins using various catalysts, such as the commercial Ziegler–Natta catalyst and sulfonic resins, as well as hydrogenation to form hydrocarbon complex that is in jet fuel products (Díaz-Pérez and Serrano-Ruiz 2020). The energy inputs to the pathways are electricity needed for CO_2-to-CO electrolysis, CO2U plant electricity, and electricity needed for hydrogen production, as well as heat for ethanol and jet fuel purification.

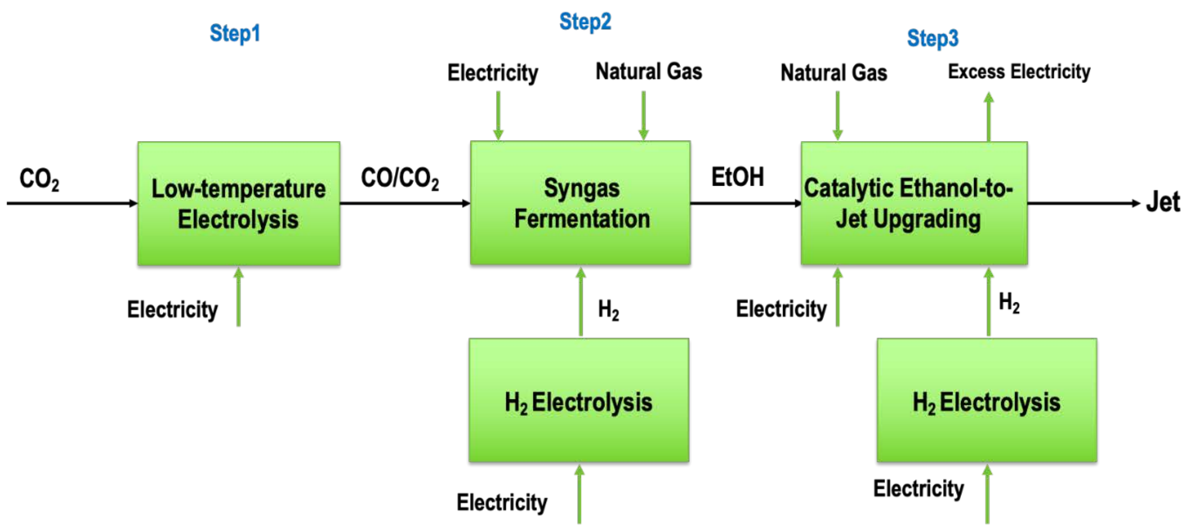

Figure 1. SAF production Pathway 1

Figure 2 shows Pathway 2: Electrochemical CO_2-to-CO + Syngas Fischer-Tropsch-to-Jet. This second pathway consists of electrochemical CO_2-to-CO conversion and syngas Fischer-Tropsch (FT) synthesis. The electrochemical step is the same as Step 1 in Pathway 1. The FT synthesis uses the clean syngas mixture from low-temperature electrolysis to produce the primary form of wax, hydrocarbon complex, tail gas, and water. The wax is further upgraded and hydrocracked with H_2 into smaller hydrocarbon liquids ("10.2. Fischer-Tropsch Synthesis" n.d.). The reaction products from the FT synthesis and wax upgrading are mixed into the desired fuel product. The energy inputs to the process are electricity needed for syngas low-temperature electrolysis, the electricity requirement for hydrogen electrolysis, the CO2U plant electricity, and heat for jet fuel purification.

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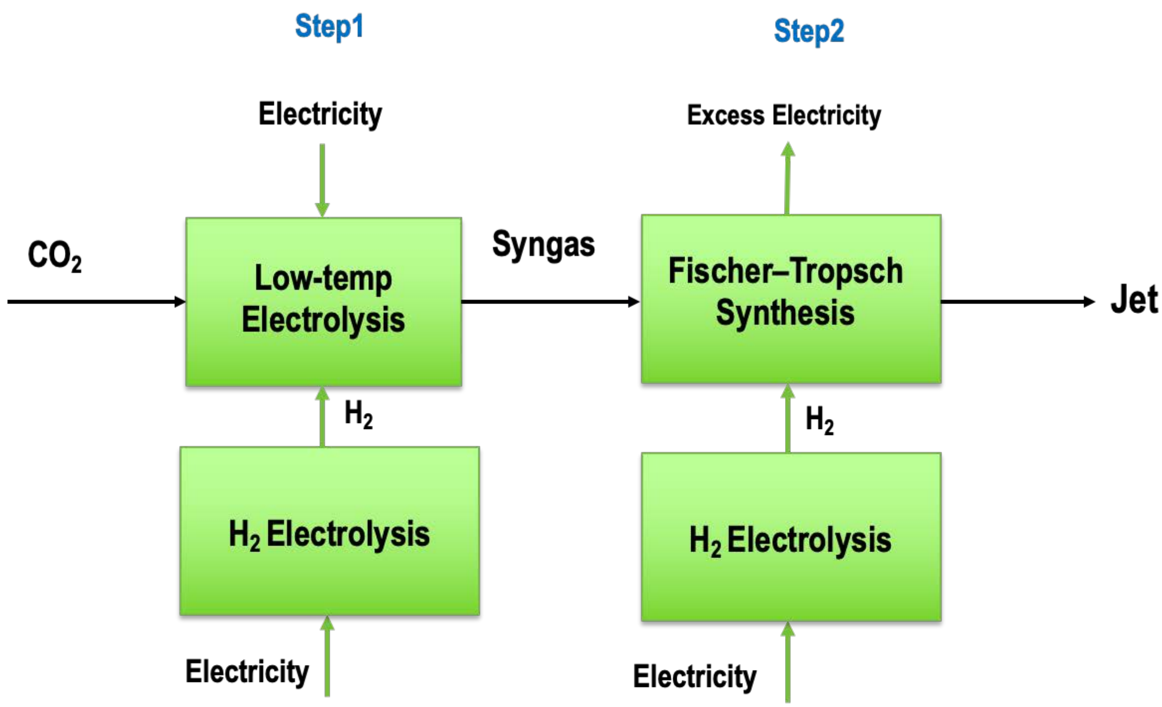

Figure 2. SAF production Pathway 2

Figure 3 shows Pathway 3: CO_2-to-CO (reverse water-gas shift) + Syngas Fischer-Tropsch-to-Jet. Pathway 3 starts with a reverse water gas shift, and CO_2 reduces to a synthesis gas mixture of CO, H_2, and steam at a high temperature (above 700°C) with a catalyst. The composition of the syngas mixture can be adjusted before FT synthesis. For the reverse water-gas shift reaction, several precious metals have been proven reliable, such as platinum (Pt), Pd, ruthenium (Ru), and Au; however, other alternative metal catalysts and heterogeneous formulations have also been shown to support the reactions in catalytical behavior to break down CO_2 molecules (González-Castaño, Dorneanu, and Arellano-García 2021). Step 2 in this pathway is assumed to be the same as the second step in Pathway 2. The energy needs for this pathway are the heat demand for the reverse water-gas shift reaction, as well as the hydrogen electricity demand for the FT synthesis.

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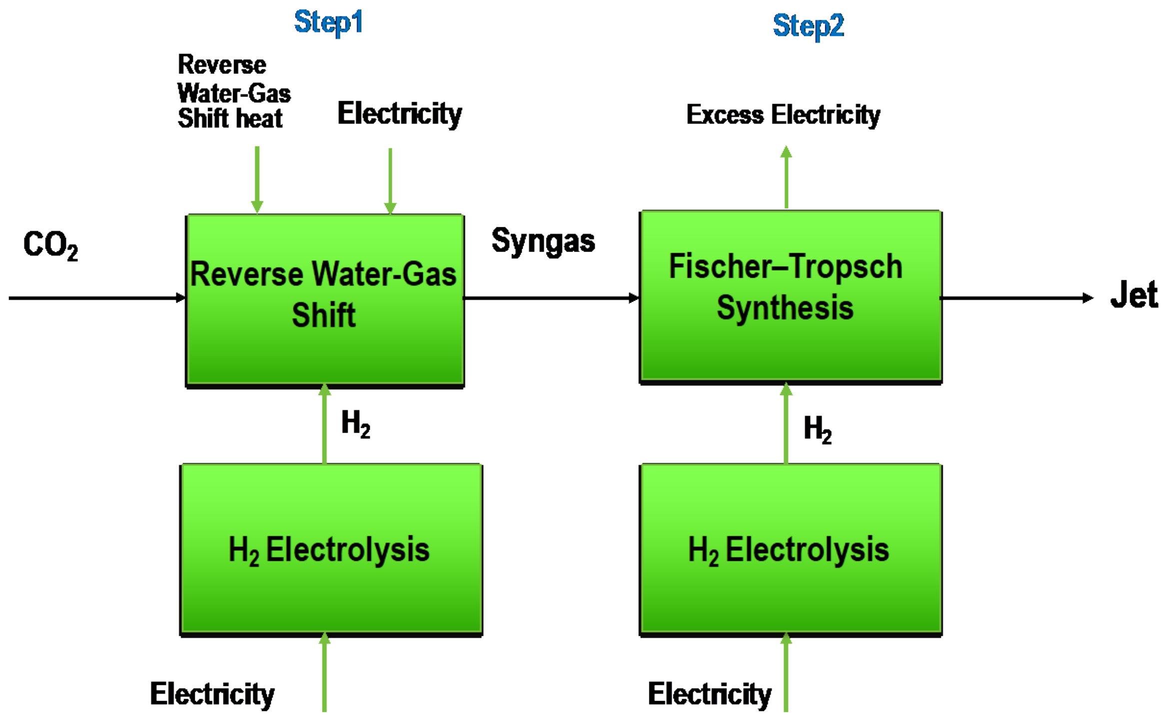

Figure 3. SAF production Pathway 3

When accounting for electricity demand for hydrogen productions via water electrolysis, we assume clean hydrogen production using PEM technology. Per a recent DOE Program Record (Peterson, Vickers, and DeSantis 2020), the electricity requirement for PEM electrolysis is approximately 55.5 kilowatt-hours per kilogram hydrogen (kWh/kg-hydrogen). The energy demand for each pathway is listed below in Figure 4. Pathway 3 shows the least process electricity demand, but it requires the greatest PEM electrolyzer demand when included in the analysis. The energy demands of Pathways 1 and 3 are similar, while Pathway 2 requires the highest energy demand. In addition, natural gas input is required in Pathway 1, while Pathways 2 and 3 require electricity only.

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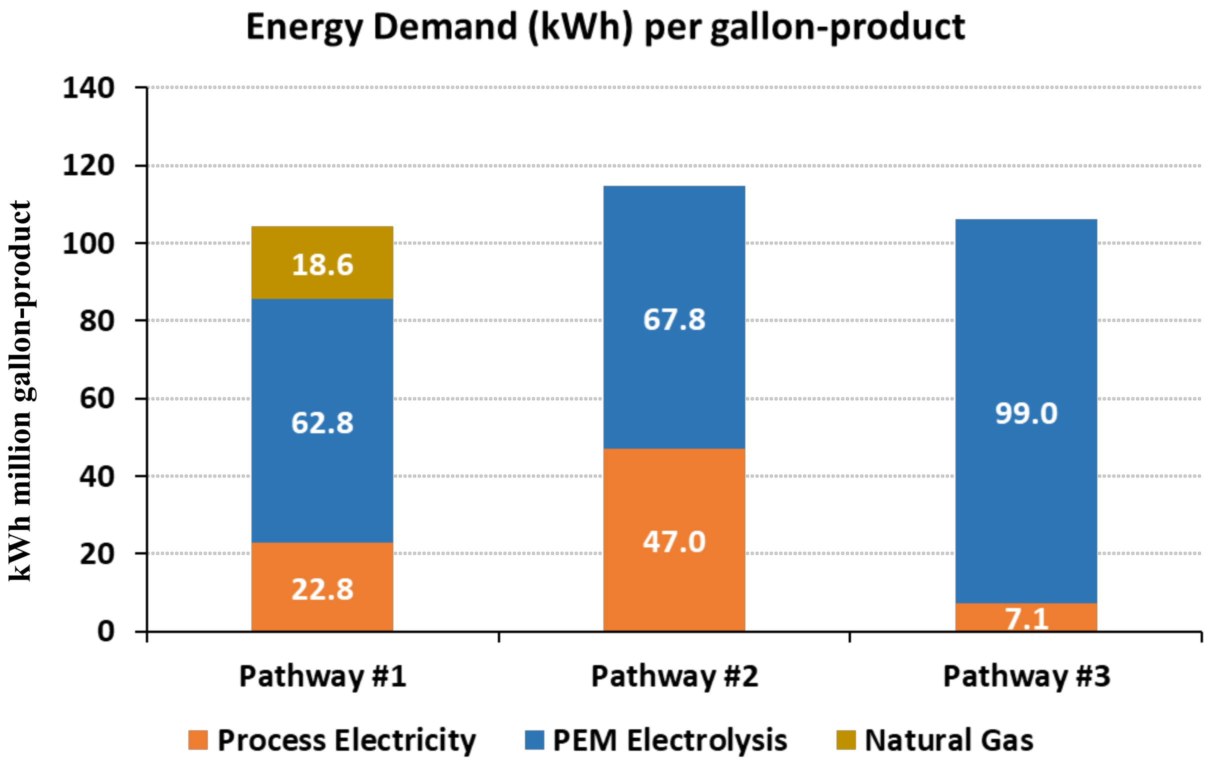

Figure 4. Energy demand for each pathway

1.2 Objective

This report discusses three regions for potential CO2U facilities for SAF production in 2030. We quantify the locational-specific electricity costs with different purchase options; CO_2 sources that support SAF products; and SAF product market sizes from the plants that could be built in 2030. We also investigate the power system for each region and estimate the marginal generation mix and carbon intensity of the electricity using the Regional Energy Deployment System (ReEDS) model (Ho et al. 2021). This report is a part of a larger project to assess the cost and availability of CO_2 resources, CO2U product market sizes, values, and the cost to deliver the infrastructure of resources and final products to their respective markets. A subsequent analysis will focus on long-term (~2050) electricity and CO_2 resources as well as market potential. In addition, this project plans to evaluate implications on energy and environmental justice factors, such as air quality, gross domestic product, and jobs. Addressing both topics will enable the project to provide context that can be used across a large portfolio of CO2U technologies, so stakeholders can make decisions informed by both economic and societal factors.

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2 Approach

For this study, we select potential CO2U locations for SAF production and estimate SAF market sizes using the potential nearby CO_2 sources from industrial and power sectors. We then analyze four different electricity purchase options, and the respective costs of electricity, for three potential CO2U production sites in 2030. We also calculate the total annual cost ($/year [yr]), average electricity cost ($/kWh), and average electricity cost for SAF ($/gallon SAF) to purchase electricity for each site and purchase option. Lastly, we show the CO_2 impact (long-run marginal impact) and CO_2 intensity (average CO_2 emission) in the 2030 power system for the three selected regions.

2.1 Method Explanation

We explore the following four potential future purchase options to power the SAF system in 2030.

Retail Rate

The retail rate refers to electricity purchased from the default local utility under the industrial customer retail rate schedule and tariff structure. The retail electricity rate typically includes (1) a volumetric energy charge that applies to the total electricity usage in kilowatt-hours (kWh), (2) a demand charge on the maximum electricity demand in kilowatts (kW) within the billing period, (3) utility fixed charges, such as a basic consumer service charge billed for each meter regardless of the electricity consumed and use profile, and (4) a fuel adjustment charge that reflects the actual cost for the utility to generate electricity when it is not recovered by a preset tariff rate; we assume that the current existing tariff rates and fuel adjustment rates will remain unchanged in 2030.

Physical Power Purchase Agreement (PPA) With Storage

Electricity from a renewable power and battery storage hybrid plant is purchased and physically delivered through a long-term contract with a preset price for energy. The contract price is based on the seller's project cost for generation and storage, expected wholesale market revenues, and subsidy offsets, as well as the utility cost for managing the PPA. We provide two methods for cost estimation for 2030, as shown in Table 2. Method 1 uses the capacity weight average cost for existing PV-plus-battery PPA prices for all available data across the United States. We are not able to develop region-specific estimates, because the sample size of existing PPAs for PV-plus-battery is small; therefore, we provide another estimate with regional granularity for comparison. Method 2 uses historical wind PPA contract costs for different regions with a storage cost adder.

Financial PPA

Electricity from a dedicated renewable plant is purchased through a long-term contract with a fixed price for the output, where the purchaser retains the renewable energy attributes (such as the renewable energy credits). The contract is financial only, and the electricity from the plant is not directly delivered to the buyer. Such contracts are typically set up as a contract for differences, with prices based primarily on wholesale market prices with uncertainty ranges. We use the averages of hourly marginal electricity costs from Cambium (Gagnon et al. 2021) results for the Standard Scenarios 2021 (Cole et al. 2021) for the wholesale cost estimation.

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Real-Time Pricing (RTP)
RTP electricity is purchased at the wholesale power market. We use the averages of hourly marginal electricity costs from the Cambium Mid-Case for Year 2030 as estimates. The price is time-varying with adders for delivery.

Table 2. Physical PPA Cost Estimation Methods Summary

Method	Data Set
Existing PV-plus-battery PPA price	Lawrence Berkeley National Laboratory (LBNL) on existing PPA and storage adder prices with execution date after December 2021 (Bolinger et al. 2021)
Historical PPA price plus storage adder	Historical PPA prices: Bloomberg New Energy Finance (BloombergNEF) renewable standalone contract price signed after Year 2016 (BloombergNEF 2020) Historical levelized price for storage adder: the National Renewable Energy Laboratory's (NREL's) *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks* (Ramasamy et al. 2021)

2.2 Key Assumptions and Caveats

2.2.1 Project Scope

This study has limited scope. We focused on the emission and cost implications for three selected locations and the 2030 timeframe. The results from this study will inform subsequent analysis for the CO2U Techno-Economic Analysis and Life Cycle Analysis projects within DOE's CO_2-to-Fuels Consortium, as well as a study focusing on the greater impact of SAF production on grid structural change.

We assume two specific conversion pathways from CO_2 to SAF, and we assume each plant can satisfy 10% of the total SAF technical production potential in the respective region. These pathways provide adequate boundaries for electricity requirements for SAF and associated hydrogen production. However, uncertainty still exists regarding the actual electricity requirement for the SAF production plant.

We assume the SAF plant operates with a flat load profile with a 90% capacity factor. In this study, we do not incorporate the load flexibility when the plant follows closely with electricity prices, such as turning down the energy demand when prices are high.

2.2.2 Electricity Cost Assumption

The retail cost is based on the current tariff structure and rates. We also assume that the fuel adjustment utility adders that exist in the retail tariff structure today will remain the same in 2030.

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PPA cost prediction included the Production Tax Credit (PTC) that could potentially be claimed with the Inflation Reduction Act (IRA) of 2022. However, the potential Investment Tax Credit (ITC), and the vintaging analysis of such credits, is not included. PTC values may vary in a real-world scenario.

The SAF plant analyzed in this report is assumed to operate with a 90% capacity factor, electricity delivered by physical PPA providers may not be able to maintain such capacity factor at all times, even with battery units to balance the variability. The cost incurred for the developer to source electricity from the grid and maintain the assumed capacity factor is not included.

2.2.3 Grid

We use the 2030 power system buildout from the Standard Scenarios 2021 Mid-Case and Low Renewable (RE) cost scenarios, and assume that fulfilling 10% of the SAF production potential in each location does not induce structural impact on the grid.

The Mid-Case scenario reflects federal and state electricity policies enacted as of June 2021; however, the federal, state, and local taxes are not included in the electricity cost calculation.

2.2.4 Future Projection

Many events in recent years (e.g., the COVID-19 pandemic and the Russia-Ukraine war) have caused significant changes in the energy sector landscape. This report does not attempt to estimate the lasting impacts of these events, nor does it consider other unexpected future events.

3 CO2U Location and Market Sizes

We analyze the potential of the regional SAF production capacity based on CO_2 source availability, with mid-high CO_2-purity sources from the industrial sector (ethanol, natural gas processing, ammonia, H_2, iron/steel, and cement plants) and low CO_2 purity from natural gas and coal power plants. The identified three potential regions with ample CO_2 supply were the Midwest, West Coast, and Gulf Coast of the United States. We then further narrowed down the SAF facility locations in the identified ReEDS balancing areas. For the three locations of SAF production facilities, we primarily consider the following:

- Wholesale electricity cost estimates in 2030 (Mid-Case simulation results from the Standard Scenarios 2021 (Cole et al. 2021), Figure 5)
- Grid greenhouse gas (GHG) emissions in 2030 (Mid-Case simulation results from the Standard Scenarios 2021, Figure 6 and Figure 7)
- Proximity to CO_2 sources, both high purity and medium-low purity
- Proximity to existing petroleum refineries (to utilize the infrastructure for SAF distribution)
- Potential renewable supply amount to meet the electric load associated with SAF e-fuel production (further discussed in Section 5)
- Policy incentives (e.g., Low Carbon Fuel Standard)

Electricity cost is among the most impactful factors in calculating the cost of SAF production as well as the potential renewable generation capability of the selected regions. Long-run marginal carbon emissions reflect the changes in carbon emissions induced by a sustained marginal e-fuel demand increase, including the changes in power system operation and structural buildout (Hawkes 2014). In comparison, the carbon intensity reflects the grid's average carbon emission at a given hour of operation. We examine both metrics in the analysis.

In the Midwest region, high-purity CO_2 is available from ethanol plants and ammonia plants. In the Gulf Coast region, high-purity CO_2 sources are available in natural gas processing and ammonia plants. In the West Coast region, medium-purity sources come from cement plants. Since the CO_2 delivery cost increases with distance, we practically consider the available CO_2 within a 200-mile radius of the selected CO2U production location.

The exact location of each SAF facility is assumed to be near a current jet production facility (i.e., a petroleum refinery). This is to allow potential blending, if needed, and to utilize the existing jet fuel infrastructure (such as pipelines) for distribution to jet fuel markets. If no jet fuel refinery is present[1] in the selected region (e.g., Iowa), we set the new SAF facility next to an ethanol plant that could collect the largest CO_2 amount within a 200-mile radius.

[1] Not all petroleum refineries produce jet fuel.

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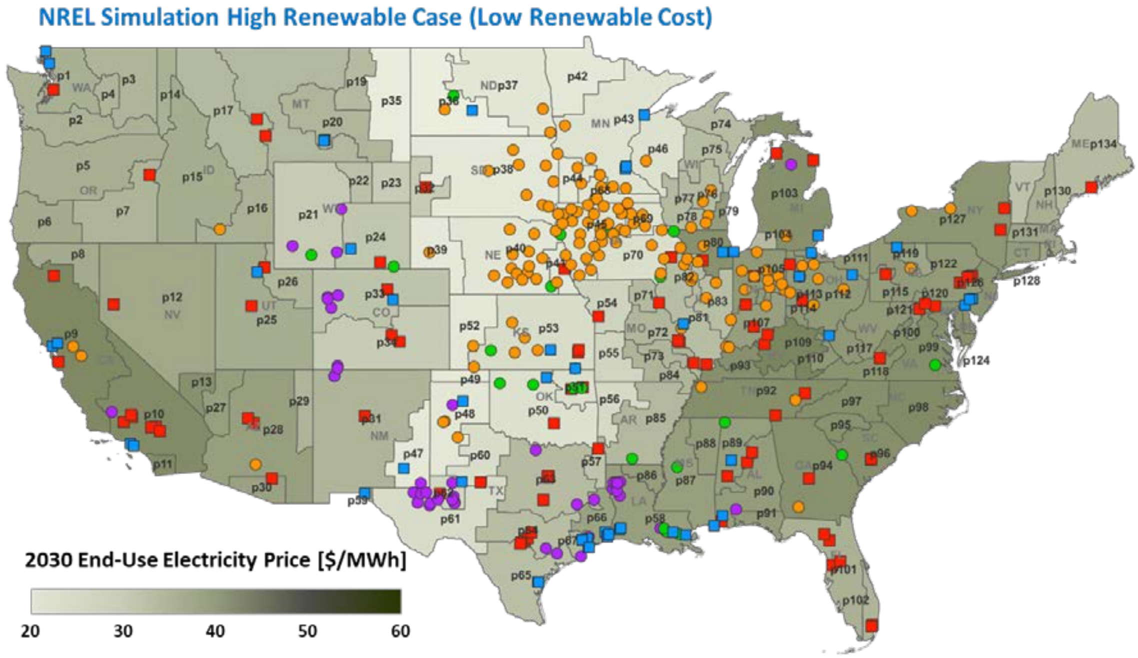

Figure 5. 2030 end-use electricity prices ($/MWh) near CO_2 sources

MWh = dollars per megawatt-hour

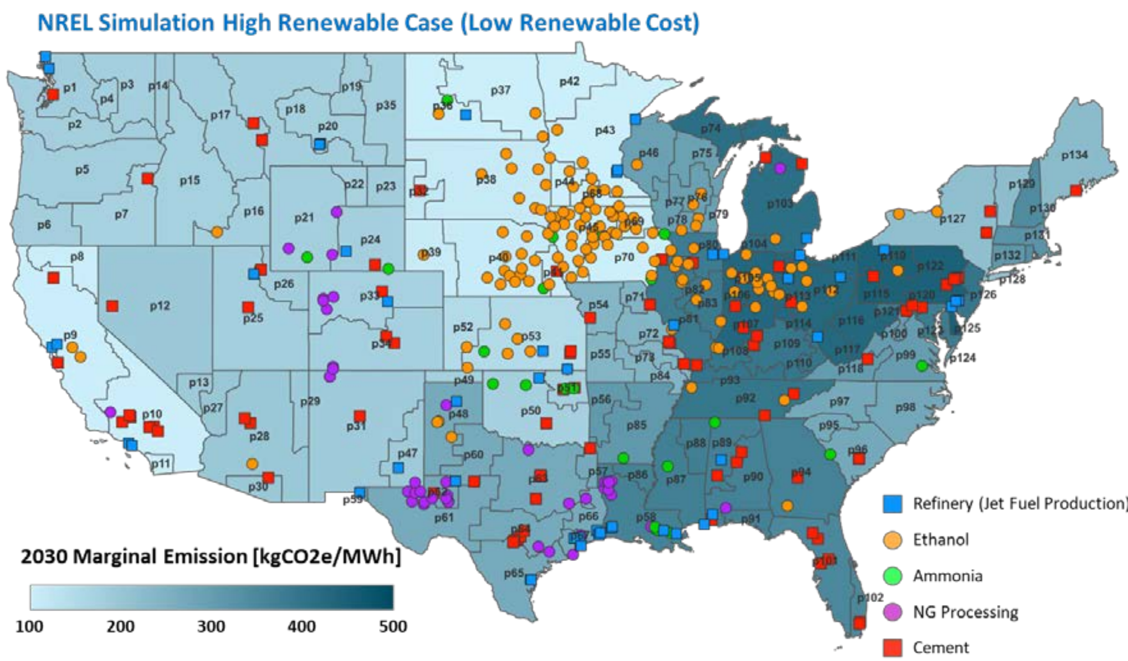

Figure 6. 2030 marginal emissions (kg CO_2e/MWh) near CO_2 sources

kg CO_2e/MWh = kilograms carbon dioxide equivalent per megawatt-hour

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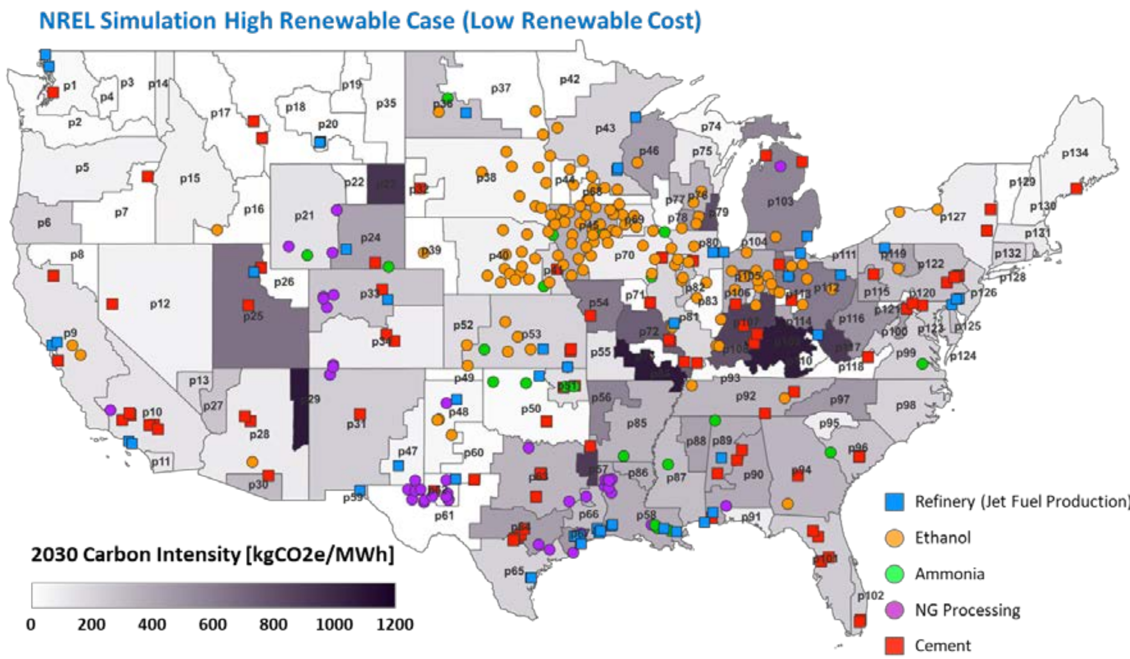

Figure 7. 2030 carbon intensities (kg CO_2e/MWh) near CO_2 sources

After considering the factors listed above, we selected the following three locations, as illustrated in Figure 8.

Region p10 (California): California is the largest jet fuel consumption state in the country (EIA 2022) with relatively high electricity costs. However, the 2030 grid system has diverse renewable energy in the generation mix, providing an opportunity for using low-CO_2-emission grid electricity for SAF production. This region is expected to have a growing market demand for hydrogen under the policy incentives of the Low Carbon Fuel Standard, which provides an additional opportunity for SAF production via CO2U. The main CO_2 source is from the nearby cement plants in this region, and refineries also exist to provide infrastructure utilization for SAF production.

Region p58 (Louisiana): The U.S. Gulf Coast is considered another potential CO2U location because of its abundant CO_2 sources and ample clean power resources, including wind, solar, and nuclear. Also, this region has the nation's largest refinery and chemical production capacity, with infrastructure and conversion technology availability for fuels and chemical production and delivery. The Gulf Coast is currently a main jet fuel supply hub with a vast pipeline connection to the rest of the country. Texas, which is adjacent to Louisiana, is the second largest jet fuel consumption state (EIA 2022). Also, this selected region has nuclear generation capacity and abundant CO_2 sources from natural gas processing plants and ammonia plants, which can be used as feedstocks for SAF production. A potential new SAF facility in this location could also leverage the Gulf Coast harbor facilities for shipping and delivery.

Region p45 (Iowa): This region is nested in the pipeline network connected to major airports in Chicago, Illinois; St. Louis, Missouri; Minneapolis, Minnesota; and other cities. It has high-purity CO_2 resources from ethanol plants and abundant onshore wind resources. The recently announced Archer-Daniels-Midland Company pipeline (ADM 2022) to collect and transport

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biogenic CO_2 from a cluster of ethanol plants in this area could be an attractive development for low-cost SAF production via CO2U. No refinery is near to this region, but the availability of low-cost, low-emission electricity and a convenient transportation pipeline network makes this region attractive for near-term CO2U facility development.

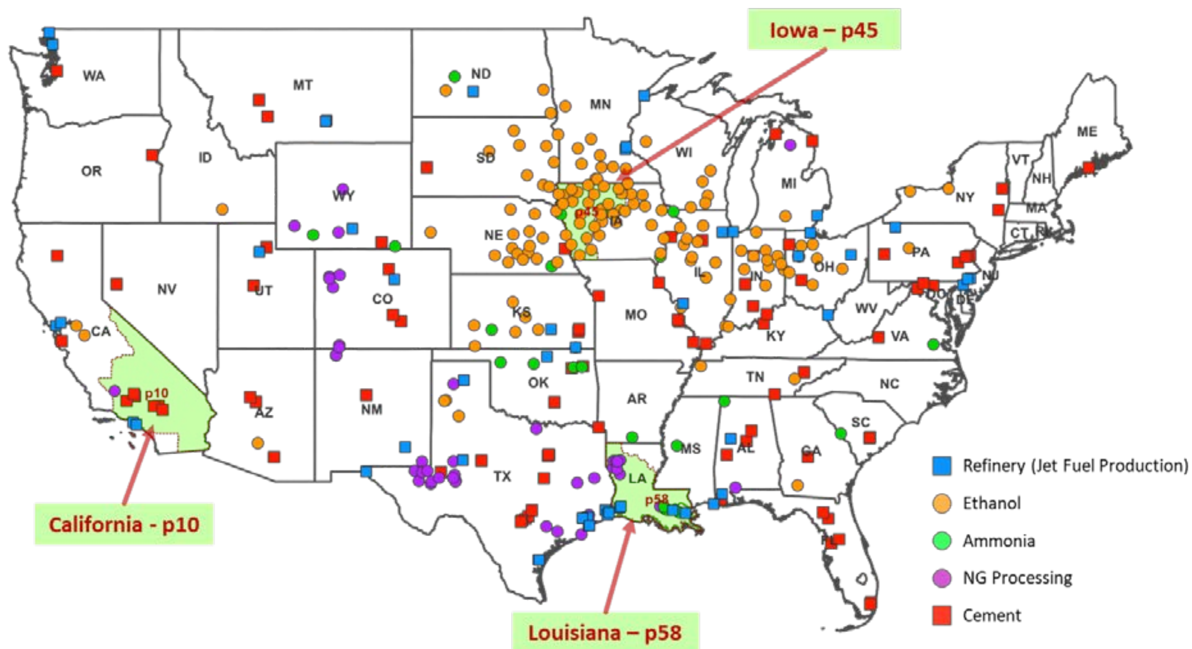

Figure 8. Three potential SAF facility locations (p-regions)

A summary of CO_2 sources, supply scales, hydrogen demands for SAF production, and estimated electricity and natural gas demands is provided in . The scale of available CO_2 sources was estimated using the U.S. Environmental Protection Agency's (EPA's) Greenhouse Gas Reporting Program 2020 (EPA 2020) and Argonne National Laboratory's GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies) model (Argonne National Laboratory 2022). The CO_2 sources include a relatively pure supply from nearby cement, ammonia, ethanol, and natural gas processing plants within 200 miles of the proposed CO2U facility location. The CO_2 captured for other uses, such as urea production, is discounted from the available CO_2 supply calculations.

The estimation of maximum electricity demand is calculated for each CO2U technology pathway, assuming maximum SAF production with all available CO_2 sources (within a 200-mile radius of the selected CO2U location). We also accounted for electricity demand for hydrogen production via water electrolysis, assuming clean hydrogen production polymer electrolyte membrane (PEM) technology. Per a recent DOE Program Record (Peterson, Vickers, and DeSantis 2020), the electricity requirement for PEM electrolysis is approximately 55.5 kWh/kg-hydrogen.

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Table 3. Energy Requirements for SAF Production in Each Region

SAF Production Pathway	State	Region	Max. CO_2 Source (MMT/yr)	Max. Hydrogen Input (MMT/yr)	Max. SAF Production (Billion Gallons/yr)	Max. Electricity Demand (TWh/yr)			Natural Gas Input (TWh/yr)
						Process	Hydrogen (for PEM Electrolysis)	Total Demand	
1	CA	p10	6.7	0.76	0.67	15.3	42.2	57.5	12.5
	LA	p58	5.2	0.59	0.52	11.9	32.9	44.8	9.7
	IA	p45	13.1	1.49	1.31	30.0	82.5	112.5	24.5
2	CA	p10	6.7	0.64	0.21	24.8	35.7	60.5	n/a
	LA	p58	5.2	0.50	0.16	19.3	27.8	47.1	
	IA	p45	13.1	1.26	0.41	48.4	69.8	118.3	
3	CA	p10	6.7	0.97	0.22	3.9	53.7	57.6	n/a
	LA	p58	5.2	0.75	0.17	3.0	41.8	44.8	
	IA	p45	13.1	1.89	0.42	7.6	105.0	112.5	

MMT/yr = million metric tons per year

TWh/yr = terawatt hours per year.

For 2030, we assumed that the new CO2U facilities could meet 10% of the maximum technical production potential in each region, and we focused Pathways 1 and 3 on the subsequent analysis. Table 4 below reports the annual energy demand, respective percentage of annual load, and annual generation in each region.

Table 4. Energy Demand Analyzed for Each Region

SAF Production Pathway	State	Region	Energy Demand (TWh/yr)	Percentage of Annual Regional Load	Percentage of Annual Regional Generation
1	CA	p10	5.75	3.6%	4.2%
	LA	p58	4.48	5.2%	5.6%
	IA	p45	11.25	84.7%	29.9%
3	CA	p10	5.75	3.6%	4.2%
	LA	p58	4.48	5.2%	5.6%
	IA	p45	11.25	84.7%	29.9%

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4 Electricity Costs

In this section, we calculate the electricity costs for four electricity-sourcing options: retail purchase rate, physical PPA, financial PPA, and real-time market price. Note that our analysis is for one facility in each location, assuming that the facility is able to satisfy up to 10% of the location's total technical SAF production potential. All reported costs are in 2020 U.S. dollars.

4.1 Retail Rate

4.1.1 Retail Electricity Cost for p10 CA Plant

Balancing Area p10 is in southeastern California, excluding San Diego County (). The potential SAF production location is near a Chevron USA refinery in El Segundo, California, and the CO_2 sources are from cement plants within a 200-mile radius. We assume the potential SAF production is located in Southern California Edison's (SoCal Edison's) service territory, as is the Chevron refinery ("Service Directory | El Segundo" n.d.). Table 5 below shows the electric information regarding the plant.

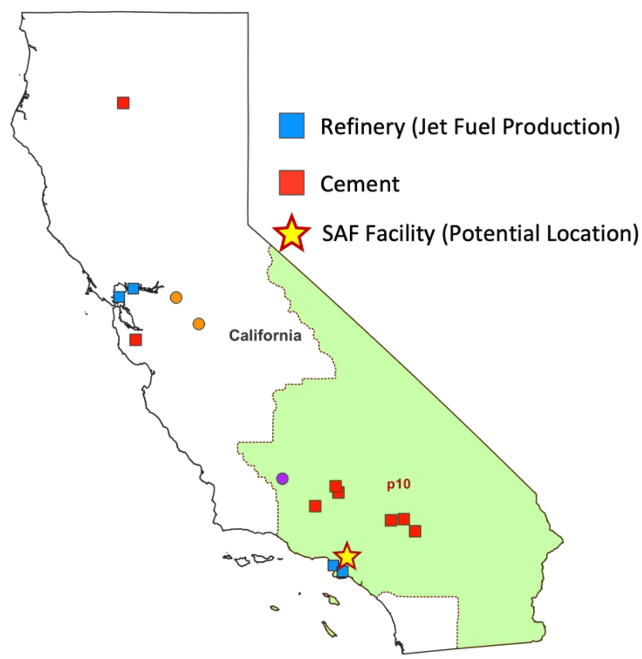

Figure 9. Balancing Area p10 in California

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Table 5. Calculation Assumptions and Energy Requirements for p10 CA plant

	Unit	Pathway 1	Pathway 3
Facility electric demand	TWh/yr	5.75	5.76
Capacity factor	%	90	90
Average demand	MW	730	730
Power factor	%	95	95
Apparent power	MVA	768	768
Reactive power	MVar	240	240

MVA = megavolt ampere

MVar = megavolt ampere of reactive power

Based on the load level, SoCal Edison's rate schedule applicable to the SAF production facility is Schedule D - Critical Pricing Period (CPP) of Schedule - Time of Use (TOU) - 8 for large industrial customers ("Rates & Pricing Choices" n.d.). We assume the service meter is delivered above 50 kilovolts (kV) since the electric load is 730 MW ("Terminology – an Introduction" n.d.). We also assume the CPP event charges and CPP non-event credits are not applicable because this study assumes a flat production profile for the SAF plant. Should the SAF plant be able to operate in a more flexible manner—turning down the demand when the prices are high—it will be able to lower its electricity cost at the expense of its SAF production. This issue is outside the scope of the current study; other works, such as that by Huang et al. (Huang et al. 2021), have investigated the economics of CO2U under different electricity prices and average capacity factors. Table 6 below documents the average electricity rates for 2020–2022, and all rates are adjusted to 2020 dollars. The annual electricity cost under this rate schedule is $203 million per year in 2030 for Pathways 1 and 3, and the average cost is around 3.5¢/kWh.

Table 6. Retail Rate at SoCal Edison

Charge Type	Unit	Rate	Annual Costs (Million $)
Customer charge	$/Month	2223	150
Energy charge	$/kWh	0.026	0.186
Fixed recovery charge	$/kWh	3.2E-05	0.027
Demand charge	$/kW	7.1	61.7
Voltage discount, demand, 220 kV – facilities-related	$/kW	-1.2	1.52
Power factor adjustment	$/kVar	0.53	-10.4

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4.1.2 Retail Electricity Cost for p58 LA plant

Region p58 covers the majority of Louisiana (Figure 10). The new SAF facility is assumed to be next to the existing Phillips 66 refinery in Sulphur, Louisiana. The CO_2 sources are from natural gas processing and ammonia plants within a 200-mile radius. Based on the location of the SAF facility, the utility could be Entergy Louisiana ("Utility Companies - Sulphur, LA (Billing, Payments & Services)" n.d.). The electric load information for the SAF facility is included in Table 7. Based on the production load level, Rate Schedule LA and Rate Schedule GS for large load and high load factor power service are both applicable to our system. We calculate volumetric energy cost for both riders to provide a range for our estimates.

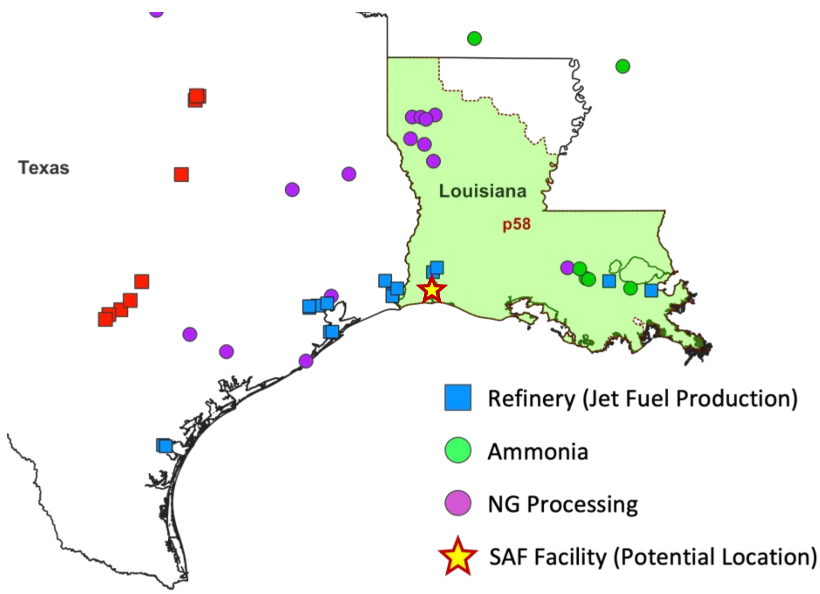

Figure 10. Balancing Area p58 in Louisiana

Table 7. Calculation Assumptions and Energy Requirements for p58 LA plant

	Unit	Pathway 1	Pathway 3
Facility electric demand	TWh/yr	4.48	4.48
Capacity factor	%	90	90
Average demand	MW	569	569
Power factor	%	95	95
Apparent power	MVA	599	599
Reactive power	MVar	187	187

For Rate Schedule LA, Table 8 below shows the average rate from December 2020 to November 2022. Firm demand charges are based on demand block. The first demand block is the greater of 41,000 kW or 50% of the assumed average electric demand for this analysis. The second demand block is 15,000 kW. The third demand block is the difference between (a) the lesser of the current monthly average demand and (b) the first demand block plus the second demand block, but not less than zero. The fourth demand block is the remainder of monthly average demand,

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but not less than zero ("Commercial and Industrial Rate and Rider Schedules" n.d.). The fuel adjustment cost is the standard cost prescribed by the Louisiana Public Service Commission ("Commercial and Industrial Energy Price" n.d.). The annual electricity cost under this rate schedule is $221 million per year in 2030 for Pathways 1 and 3, and the average cost is around 4.9¢/kWh.

Table 8. Retail Rate Schedule LA (Adapted from Entergy Louisiana)

Charge Type	Demand Block	Unit	Rate	Annual Costs (Million $)
Demand Charge	First	$/kW	10.6	36
	Second		7.3	1.32
	Third		4.4	14.1
	Fourth		3.4	0
Energy Charge	All blocks	$/kWh	0.0032	14.3
Fuel Adjustment	All blocks		0.034	156

Rate Schedule GS has a fixed demand charge for the first 200,000 kW per month, as defined below in Table 9 ("Commercial and Industrial Rate and Rider Schedules" n.d.). The annual electricity cost under this rate schedule is $230 million per year in 2030 for Pathways 1 and 3, and the average cost is around 5.1¢/kWh.

Table 9. Retail Rate GS Schedule (Adapted from Entergy Louisiana)

Charge Type	Demand Block	Unit	Value	Annual Costs (Million $)
Demand Charge	First 200,000 kW	$	1,665,947	20
	Additional kW	$/kW	8.3	36.8
Energy Charge	All blocks	$/kWh	0.0042	18.9
Fuel Adjustment	All blocks		0.034	154

4.1.3 Retail Electricity Cost for p45 IA Plant

Balancing area p45 includes western Iowa (Figure 11). The new SAF facility is assumed to be next to the existing ethanol plant, Flint Hills Arthur, in Arthur, Iowa. The CO_2 sources are from ethanol and ammonia plants within a 200-mile radius. Table 10 below shows the electric information regarding the plant.

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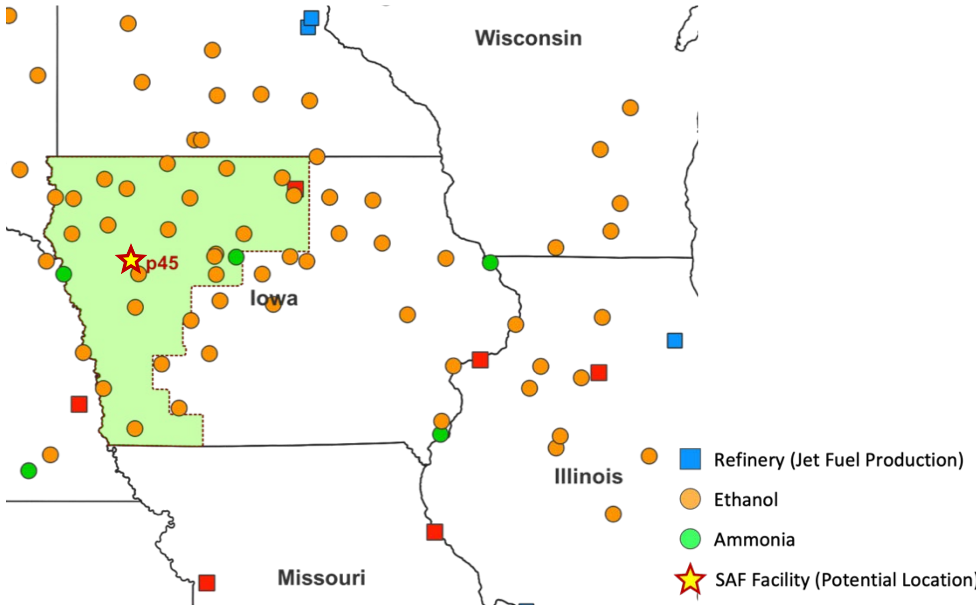

Figure 11. Balancing Area p45 in Iowa

Table 10. Calculation Assumptions and Energy Requirements for p45 IA plant

	Unit	Pathway 1	Pathway 3
Assumed electric demand for this analysis	TWh/yr	11.25	11.25
Capacity factor	%	90	90
Average demand	MW	1,427	1,427
Power factor	%	95	95
Apparent power	MVA	1502	1502
Reactive power	MVar	469	469

MidAmerican Energy Company is the local utility for this SAF production site ("Tools" n.d.). Based on the load level of the proposed plant, two rate schedules are applicable to this analysis: Rate Large Electric Service (LS) and Rate Large Electric Time-of-Use Service (LST) ("Rates and Tariffs" n.d.). We calculate volumetric electricity costs for both tariff structures to serve as a cost estimate range.

For Rate LS, the detailed monthly rate is listed in Table 11 below. Summer is defined as the four monthly billing periods of June through September. Winter is during the eight monthly billing periods of October through May. The Transmission Cost Adjustment fee includes additional operating costs from the Midcontinent Independent System Operator (MISO) allocated among all kW sales within its service territory under the Rate LS schedule. The Energy and Energy Efficiency Cost Recovery Adjustment covers Iowa jurisdictional costs of energy allocated among all generation in kWh; these jurisdictional costs recover the cost differences between the expenses of nuclear, natural gas electricity, emission allowances, and the revenue from sales of

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the Renewable Energy Credit and Production Tax Credit (PTC). This adjustment also covers the cost recovery for energy efficiency program expenditures under the MidAmerican Energy service. The annual electricity cost under this rate schedule is $798 million per year in 2030 for Pathways 1 and 3, and the average cost is around 7.1¢/kWh.

Table 11. Retail Rate LS Schedule (Adapted from MidAmerican Energy Company)

Season	Charge Type	Unit	Rate	Annual Costs (Million $)
All Year	Basic Service Charge	$/Month	175	0.0021
Summer	Energy Charge	$/First 200 hours × kW of Demand	0.071	72.7
		$/Next 200 hours × kW of Demand	0.061	62.3
		$/Over 200 hours × kW of Demand	0.053	91.2
	Demand Charge	$/kW	4.8	27.4
Winter	Energy Charge	$/First 200 hours × kW of Demand	0.036	74.3
		$/Next 200 hours × kW of Demand	0.035	72.2
		$/Over 200 hours × kW of Demand	0.034	116
	Demand Charge	$/kW	4.5	52
All Year	Transmission Cost Adjustment	$/kW	0.99	16.9
All Year	Energy and Energy Efficiency Cost Recovery Adjustment	$/kWh	0.019	212

For Rate Schedule LST, Table 12 below shows the rate details. On-peak hours refer to hours between 1 p.m. and 6 p.m. Monday through Friday, excluding U.S. legal holidays. Off-peak hours refer to hours between 10 p.m. and 8 a.m. every day. All-other hours are hours not included in the definition of on-peak or off-peak hours. The annual electricity cost under this rate schedule is $800 million per year in 2030 for Pathways 1 and 3, and the average cost is around 7.1¢/kWh.

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Table 12. Retail Rate LST Schedule (Adapted from MidAmerican Energy Company)

<table>
<tr><th>Season</th><th>Time of Use</th><th>Charge Type</th><th>Unit</th><th>Rate</th><th>Annual Costs (Million $)</th></tr>
<tr><td>All Year</td><td>All hours</td><td>Basic Service Charge</td><td>$/Month</td><td>175</td><td>0.0021</td></tr>
<tr><td rowspan="4">Summer</td><td>On-peak</td><td rowspan="3">Energy Charge</td><td rowspan="3">$/kWh</td><td>0.16</td><td>84.9</td></tr>
<tr><td>All-other</td><td>0.054</td><td>89.4</td></tr>
<tr><td>Off-peak</td><td>0.033</td><td>51.4</td></tr>
<tr><td>All hours</td><td>Demand Charge</td><td>$/kW</td><td>4.8</td><td>27.4</td></tr>
<tr><td rowspan="4">Winter</td><td>On-peak</td><td rowspan="3">Energy Charge</td><td rowspan="3">$/kWh</td><td>0.037</td><td>39.9</td></tr>
<tr><td>All-other</td><td>0.037</td><td>120.7</td></tr>
<tr><td>Off-peak</td><td>0.033</td><td>104.3</td></tr>
<tr><td>All hours</td><td>Demand Charge</td><td>$/kW</td><td>4.6</td><td>52</td></tr>
<tr><td>All Year</td><td>All hours</td><td>Transmission Cost Adjustment</td><td>$/kW</td><td>0.99</td><td>17</td></tr>
<tr><td>All Year</td><td>All hours</td><td>Energy and Energy Efficiency cost Recovery Adjustment</td><td>$/kWh</td><td>0.019</td><td>212</td></tr>
</table>

4.2 Physical PPA

Physical PPA, and the associated electricity sold by the renewable project developer, is physically delivered to the customer. However, the renewable production profile is variable and often temporally mismatched with the demand shape. If this mismatch occurs, the PPA offtaker will source electricity from the respective local grid for their energy needs. For this study, we investigate the additional costs of demand-supply matching by studying the hybrid systems that pair battery storage with renewable technologies. The co-located configuration has gained commercial interest in many regions in the United States. According to the interconnection queue data summarized by LBNL (Gorman et al. 2022), 34% of solar and 6% of wind projects, by capacity, are coupled with battery storage units. For the California Independent System Operator (CAISO), where p10 is located, 89% of solar and 37% of wind, by capacity, are hybrid. For MISO, where p58 and p45 are located, 18% of solar and 5% of wind are coupled with battery storage.

Method 1: LBNL reported the most recent PPA and storage adder pricing data for hybrid projects (Bolinger et al. 2021), as Figure 12 shows. We use the capacity-weighted PPA price for the PV-plus-storage system, $31.8/MWh, plus a utility adder of 7%, to estimate the contractual markups collected by the local utility for managing the transmission and distribution (Quackenbush 2020; Quilici et al. 2019) as one possible hybrid PPA value for subsequent analysis. Because the sample size of the reported PPAs for the select location is small, we present an additional set of results using Method 2 as a comparison.

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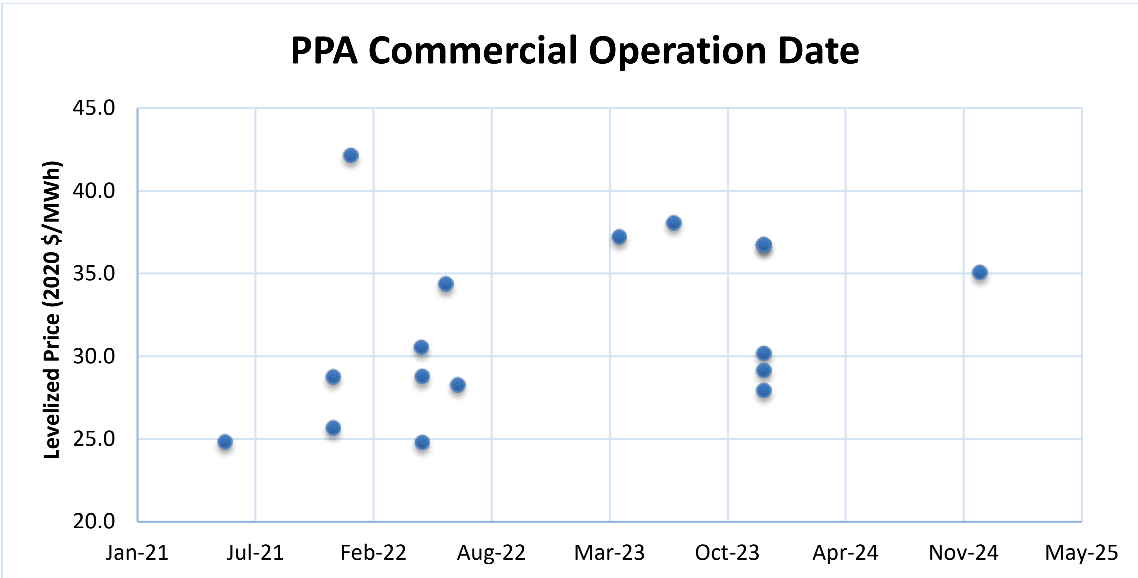

Figure 1212. PPA prices and commercial operation dates

Source: (Bolinger et al. 2021)

Method 2: The passage of the IRA of 2022 makes the PTC and ITC available for renewable and renewable-plus-storage project developers to accelerate deployment. PPA prices will benefit from the energy supply diversification and the improved price certainty by 2030. With the PTC and ITC, cost reductions for developers will provide competitive PPA pricing options for offtakers. For this study, we analyzed the impact of the IRA by assuming the PTC received by the developer directly reduces the cost of PPA. Aligning with NREL's ReEDS modeling team (Gagnon 2022), we assume the projects meet the prevailing wage requirements in the IRA, and additional bonus credits are available for domestic content and being located in energy communities. The PTC is assumed to be $28.6/MWh for a 10-year duration.

Since 2020, however, PPA prices have jumped as a result of growing demand, renewable construction delays, interruptions to the global supply chain, transmission and interconnection constraints, and cost increases in the wholesale electricity market ("PPA Prices Jump 9.6% in Q3 as Growing Demand Hits Supply Chain, Transmission Roadblocks: LevelTen" n.d.). PPA prices are now 34% higher compared to 2021, which results in a lengthy PPA contracting process and even price renegotiations. For this study, the best available recent PPA prices from BloombergNEF (up to May 2020) and LBNL (up to September 2021) are analyzed. We do not include further PPA price disruptions in our calculations for Year 2030.

We use historical PPA contracts for CAISO for Region p10 (Figure 13), and for MISO for Regions p58 and p45 (Figure 14), with signing dates from 2016 to 2019 (BloombergNEF 2020). PPA price estimates are the capacity-weighted averages of the historical contracted prices. The capacity-weighted averages are $47.7/MWh and $25.8/MWh for the CAISO and MISO regions, respectively. As shows, the storage adder price for the hybrid system is estimated using the benchmark levelized cost of energy between a utility-scale PV-plus-storage system and a utility-scale standalone PV system; the levelized storage adder is $36/MWh (Ramasamy et al. 2021). We estimate by wholesale market region because of the limited state- and site-specific data. We

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also include the PTC consideration; when the PTC applies, it is assumed to serve as a separate revenue source for the PPA seller, thereby reducing the PPA price to the buyer. The equation below shows how we estimate the cost for physical PPA.

$$\text{Physical PPA Cost} = (\text{PPA Contract Price} + \text{Storage Adder} - \text{PTC}) \times (1 + \text{Utility Adder})$$

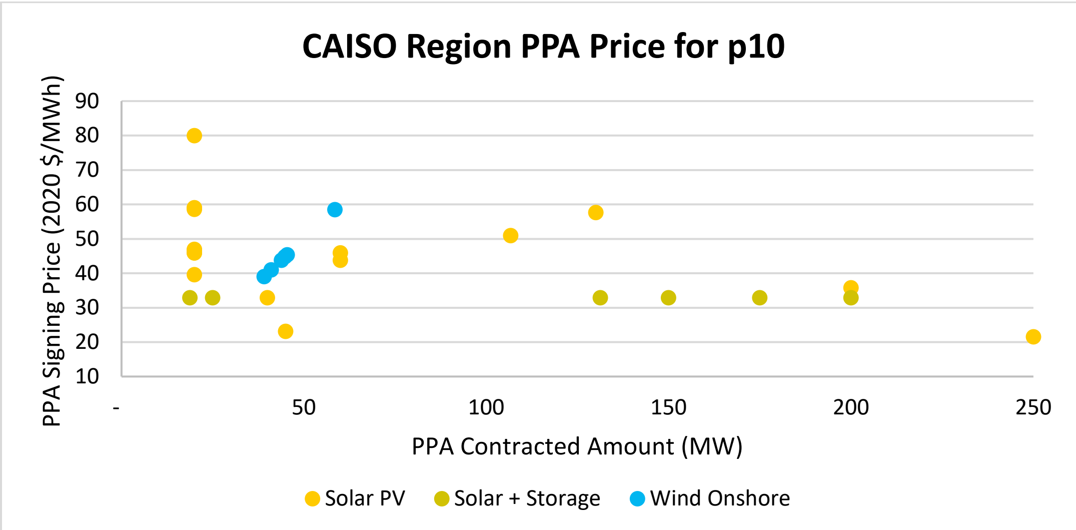

Figure 13. CAISO region PPA price

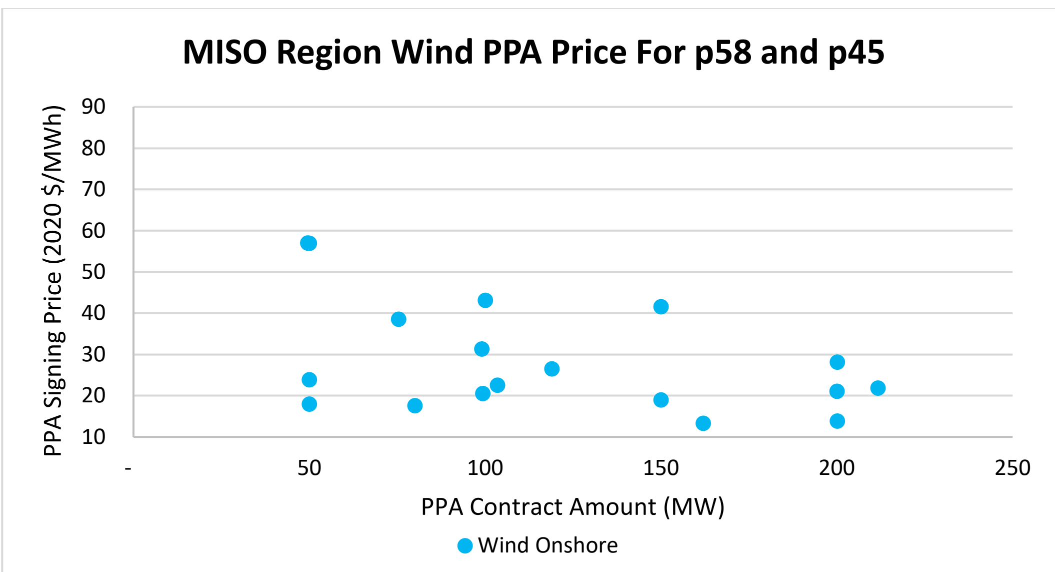

Figure 14. MISO region PPA price

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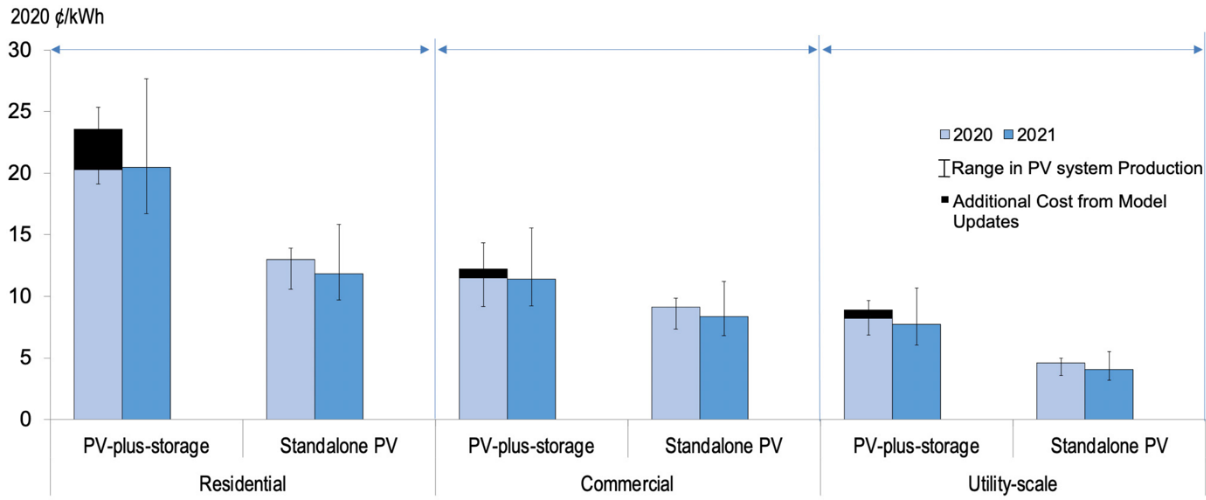

Figure 15. Levelized cost of energy comparison

Source: (Ramasamy et al. 2021)

For Pathways 1 and 3, when PTC applies, the average electricity is between 3.4¢/kWh (Method 1) and 5.9¢/kWh (Method 2) for the p10 CA plant and between 3.4¢/kWh (Method 1) and 3.5¢/kWh (Method 2) for the p45 IA and p58 LA plants. The annual electricity cost with physical PPA contracts for the p10 CA plant is between $195 million and $338 million per year with PTC; the annual cost is between $152 million and $159 million per year for the p58 LA plant, and $382 million and $399 million per year for the p45 IA plant.

4.3 Financial PPA

Similar to a previous study (Li et al. 2022), we estimate the financial PPA price in 2030 as the projected wholesale electricity price +/- an uncertainty range. For the wholesale electricity price, we use the average of the hourly marginal electricity costs (total bus cost metric) from the 2021 Cambium Mid-Case for Year 2030 for the three locations (from the ReEDS Standard Scenarios); the 2021 Standard Scenarios dollar values are in 2020 dollars. We choose +/-15% as the uncertainty range and assume the project developer does not receive additional revenue, such as renewable energy certificates. Table 13 shows the financial PPA rates with lower and upper bounds for each location.

Table 13. Financial PPA Rates (Adapted from Gagnon et al. 2021)

Region (plant)	Lower Bound	Upper Bound
p10 (El Segundo, CA)	¢3.5/kWh	¢4.8/kWh
p58 (Sulphur, LA)	¢3.3/kWh	¢4.5/kWh
p45 (Arthur, IA)	¢2.6/kWh	¢3.6/kWh

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If the plant is under a financial PPA agreement, the annual electricity cost is between $203 million and $274 million per year for the p10 CA plant; $149 million and $202 million per year for the p58 LA plant; and $296 million and $401 million per year for the p45 IA plant, for Pathways 1 and 3.

4.4 Real-Time Pricing

We applied the same RTP calculation methodology as presented in a previous study (Li et al. 2022). We cross-checked the formula to confirm the calculations are aligned closely with several real-world RTP programs (Nezamoddini and Wang 2017). The RTP calculation methodology is as follows:

$$\text{Real-Time Pricing Cost} = \text{Simulated Wholesale Energy Cost} \times (1 + \text{Utility Adder})$$

As shown in Table 14, we used the averages of hourly marginal electricity costs (total bus cost metric) from the Cambium Mid-Case for Year 2030 as estimates. Then, we applied an adder of 7% to estimate the markups collected by RTP providers.

Table 14. RTP Rates (Adapted from Gagnon et al. 2021)

Region (plant)	Average RTP Cost With Markup
p10 (El Segundo, CA)	¢4.4/kWh
p58 (Sulphur, LA)	¢4.2/kWh
p45 (Arthur, IA)	¢3.3/kWh

If the plant is under an RTP schedule, the annual electricity cost is $255 million per year for the p10 CA plant; $188 million per year for the p58 LA plant; and $373 million per year for the p45 IA plant. The average electricity costs are 4.4¢/kWh, 4.2¢/kWh, and 3.3¢/kWh, respectively, for Pathways 1 and 3.

4.5 Summary Table of Total Annual Cost of Purchase Electricity ($/yr and $/MWh)

Table 15 below suggests that the purchased electricity prices may range from $26/MWh to $71/MWh for the three plants. The retail rate and financial PPAs have the potential to provide the lowest electricity costs relative to other electricity supply options in the p10 CA location. The retail rates are higher in the p58 LA and p45 IA locations, so the SAF project developer may consider other electricity purchase options. The physical PPA is competitive, especially when the PTC is available to the renewable energy project developer. Financial PPAs also provide cost benefits to the SAF locations but need to source electricity from the grid. RTP has the potential for lower costs if the load in the CO2U facility can be turned down/off to avoid paying high-demand charges at times of system stress.

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Table 15. Summary of Cost to Purchase Electricity and Electric Cost of SAF Production

<table>
<tr><th rowspan="3">SAF Production Pathway</th><th rowspan="3">Plant</th><th colspan="2">Retail Rate</th><th colspan="4">Physical PPA</th><th colspan="4">Financial PPA</th><th colspan="2">RTP</th></tr>
<tr><th rowspan="2">Avg. $/MWh</th><th rowspan="2">Avg. $/Gallon SAF</th><th colspan="2">Method 1</th><th colspan="2">Method 2</th><th colspan="2">Lower Bound</th><th colspan="2">Upper Bound</th><th rowspan="2">Avg. $/MWh</th><th rowspan="2">Avg. $/Gallon SAF</th></tr>
<tr><th>Avg. $/MWh</th><th>Avg. $/Gallon SAF</th><th>Avg. $/MWh</th><th>Avg. $/Gallon SAF</th><th>Avg. $/MWh</th><th>Avg. $/Gallon SAF</th><th>Avg. $/MWh</th><th>Avg. $/Gallon SAF</th></tr>
<tr><td rowspan="3">1</td><td>p10</td><td>35.4</td><td>3</td><td rowspan="6">34</td><td rowspan="3">2.9</td><td>59</td><td>5</td><td>35.3</td><td>3.0</td><td>47.8</td><td>4.1</td><td>44.5</td><td>3.8</td></tr>
<tr><td>p58</td><td>49.4-51.3</td><td>4.2-4.4</td><td rowspan="2">35.5</td><td rowspan="2">2.9</td><td>33.4</td><td>2.9</td><td>45.1</td><td>3.9</td><td>42.0</td><td>3.6</td></tr>
<tr><td>p45</td><td>70.9</td><td>6.1</td><td>26.4</td><td>2.3</td><td>35.7</td><td>3.1</td><td>33.2</td><td>2.8</td></tr>
<tr><td rowspan="3">3</td><td>p10</td><td>35.4</td><td>9.4</td><td rowspan="3">9.1</td><td>59</td><td>15.7</td><td>35.3</td><td>9.4</td><td>47.8</td><td>12.7</td><td>44.5</td><td>11.8</td></tr>
<tr><td>p58</td><td>49.4-51.3</td><td>13.2-13.6</td><td rowspan="2">35.5</td><td rowspan="2">9.1</td><td>33.4</td><td>8.9</td><td>45.1</td><td>12.0</td><td>42.0</td><td>11.2</td></tr>
<tr><td>p45</td><td>70.9</td><td>18.9</td><td>26.4</td><td>7.0</td><td>35.7</td><td>9.5</td><td>33.2</td><td>8.8</td></tr>
</table>

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5 2030 Power System

5.1 Capacity and Generation Mix

NREL produces a set of Standard Scenarios with ReEDS to capture a diverse set of potential futures (Cole et al. 2021). We use the 2021 Standard Scenario Mid-Case and Low Renewable Energy (RE) costs for the power system analysis. Figure 16 and Figure 17 show the capacity and generation mixes from the Mid-Case and Low RE cost scenarios, respectively. The Mid-Case scenario uses the reference assumptions for future grid evolvement, while the Low RE cost case shows a high renewable penetration case with an advanced level of renewable energy cost reduction.

Table 16 shows the percentage of non-fossil generation divided by load in the three selected locations for this study. Region p10 in California has the most diverse non-fossil energy generation resources, and the largest electric load among the three locations. The grid system in Region p10 has the potential to provide low-emission electricity; however, adding electric load for SAF production may be challenging with such significant electric demand in place. Region p58 in Louisiana has decent nuclear generation capacity, which provides the opportunity for low-carbon and low-cost electricity. Onshore wind generation dominates the Region p45 system. The system is using coal generation to compensate for the variability of onshore wind and balance the grid. Onshore wind also has the potential to provide low-emission electricity to the SAF plant; however, the proposed p45 plant has very large electricity needs, and with the current grid load level, adding load to fulfill those needs may be challenging.

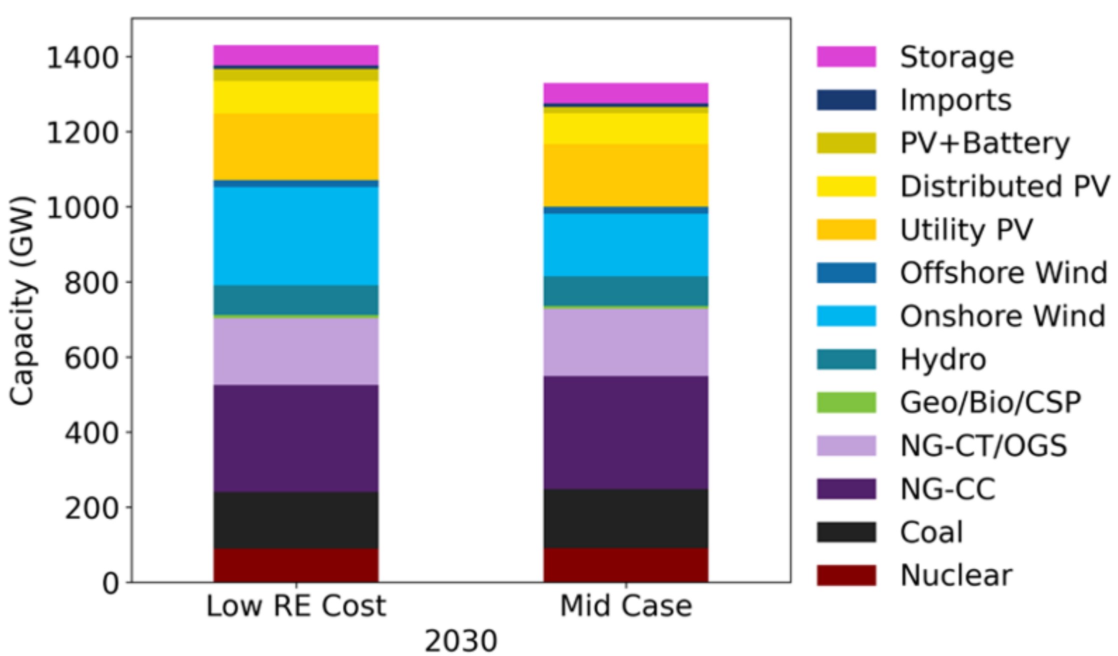

Figure 16. National capacity mix in 2030

Source: (Gagnon et al. 2021)

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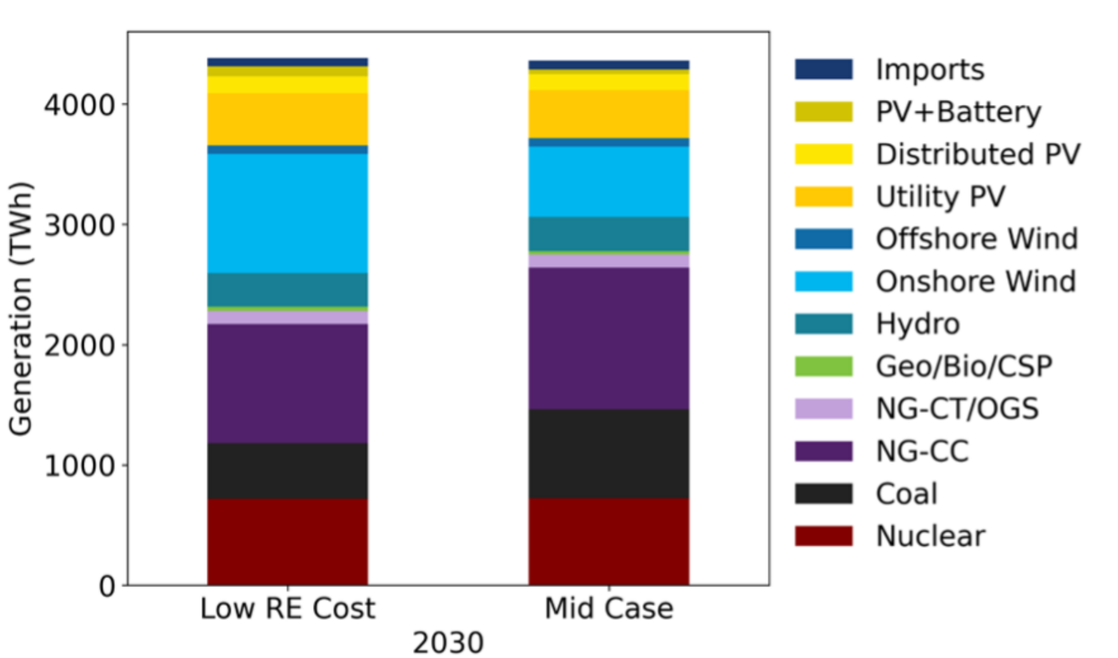

Figure 17. National generation mix in 2030

Source: (Gagnon et al. 2021)

Table 16. Non-Fossil Generation Percentage in 2030 for Each Region (Adapted from Gagnon et al. 2021)

State	Region	Mid-Case in 2030	Low RE Case in 2030
CA	p10	59%	53%
LA	p58	22%	23%
IA	p45	165%	141%

5.2 CO_2 Impact (Long-Run Marginal Emission)

To estimate the carbon impact of the studied SAF production plant, we created the diagram of Figures 18 through 23. We calculated the load weighted cumulative average for each hour, moving from the lowest-cost hour to the highest-cost hour, for long-run marginal emission rates. Figures 18 through 23 demonstrate the cumulative emissions under different capacity factors in the modeled 2030 systems. As we assume 90% capacity for the three proposed SAF production plants, the figures show the cumulative emissions are between 80 kg CO_2_eq/MWh and 159 kg CO_2_eq /MWh for the p10 CA plant; 328 kg CO_2_eq /MWh and 395 kg CO_2_eq /MWh for the p58 LA plant, and 74 kg CO_2_eq /MWh and 357 kg CO_2_eq /MWh for the p45 IA plant.

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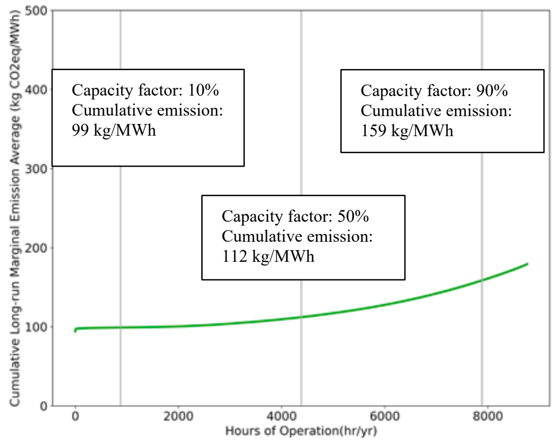

Figure 18. 2030 Mid-Case for p10 CA region

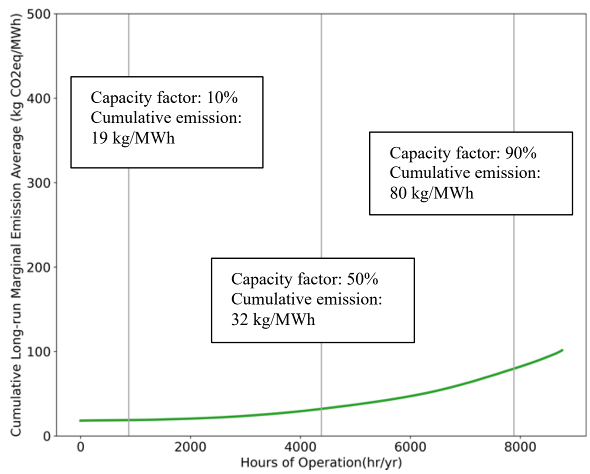

Figure 19. 2030 Low RE Case for p10 CA region

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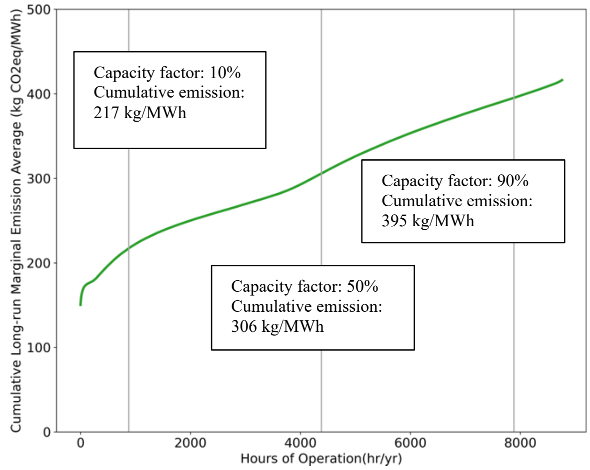

Figure 20**. 2030 Mid-Case for p58 LA region**

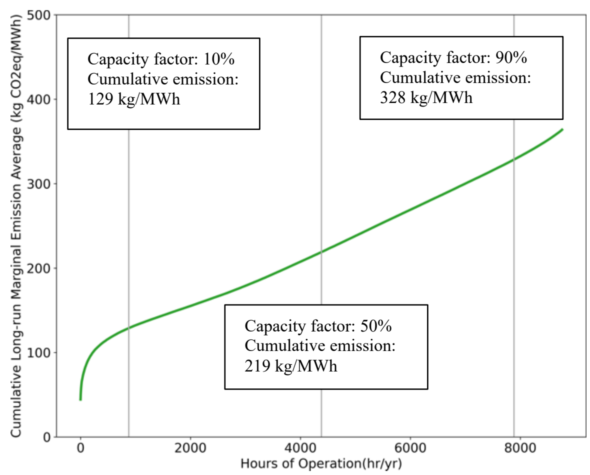

Figure 21**. 2030 Low RE Case for p58 LA region**

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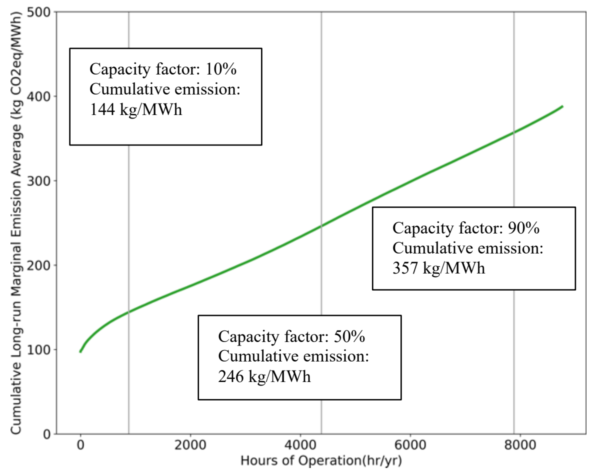

Figure 22. 2030 Mid-Case for p45 IA region

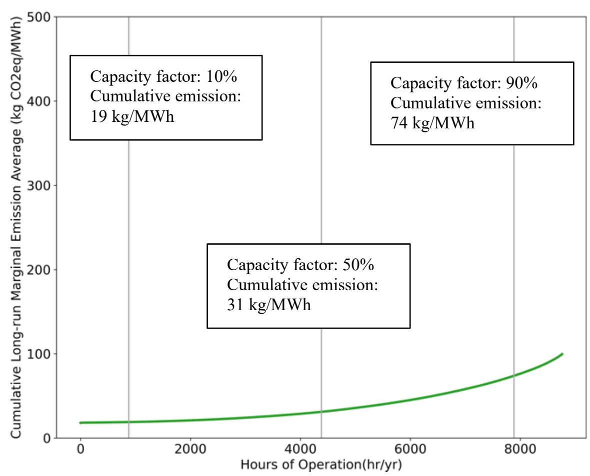

Figure 23. 2030 Low RE Case for p45 IA region

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5.3 CO_2 Intensity (Average Emission)

CO_2 intensity is the average emission rate of all generation within a region for a specified duration of time. We used average emission rates that combined combustion and precombustion rates from Cambium. Cambium does not adjust the emission rate for imported or exported electricity. Start-up and shut-down emissions are also not included. The emission intensities are very similar between the Mid-Case and Low RE costs in 2030, so we only show the simulated results from the Mid-Case below. As Figure 24 shows, Region p10 has the lowest average emission rate in 2030; solar generation provides emission benefits in midday and summertime. As Figure 25 shows, for p58, nuclear dominates the generation mix, so overall grid emission is consistent with coal generation ramping up for summer peaking hours. As Figure 26 shows, P45 shows the variability in onshore wind generation, higher emission is generation needed for electric demand in winter and summer times.

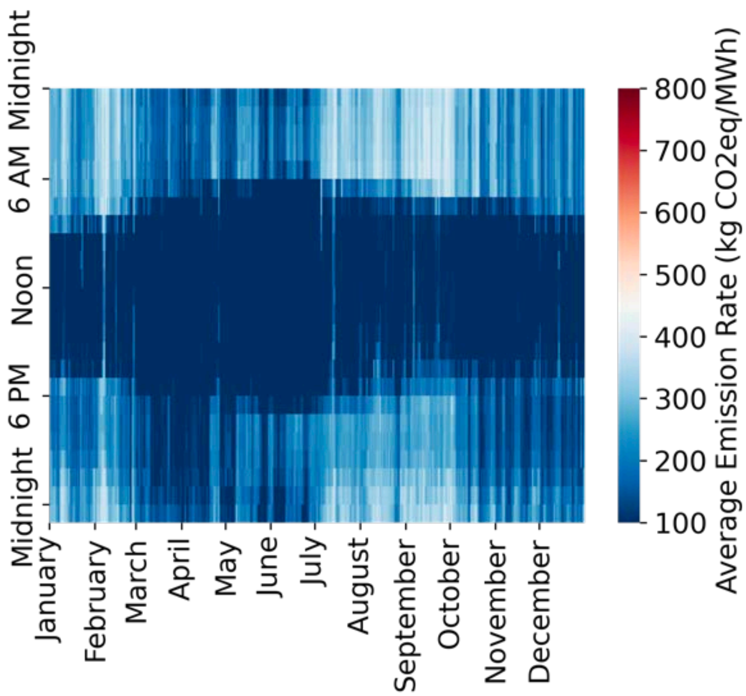

Figure 24. 2030 Mid Case for p10 CA region

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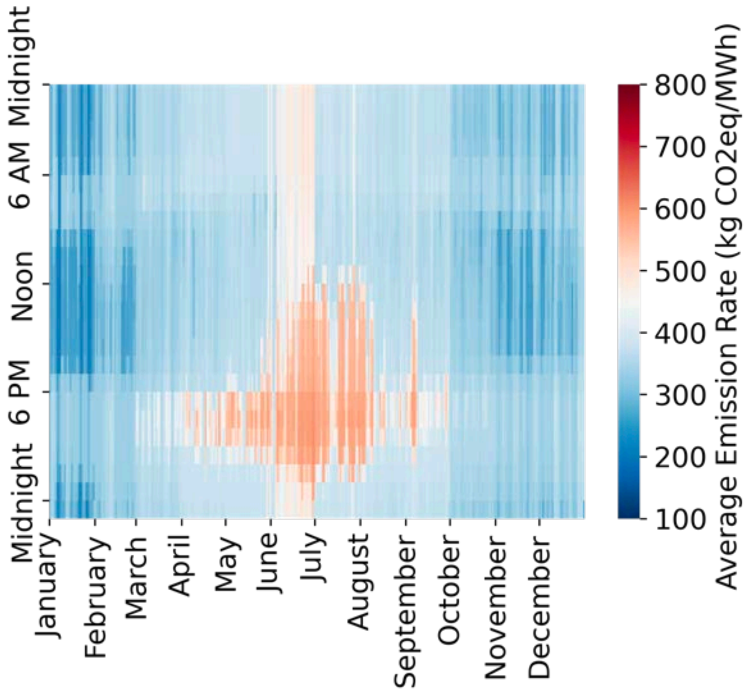

Figure 25. 2030 Mid Case for p58 LA region

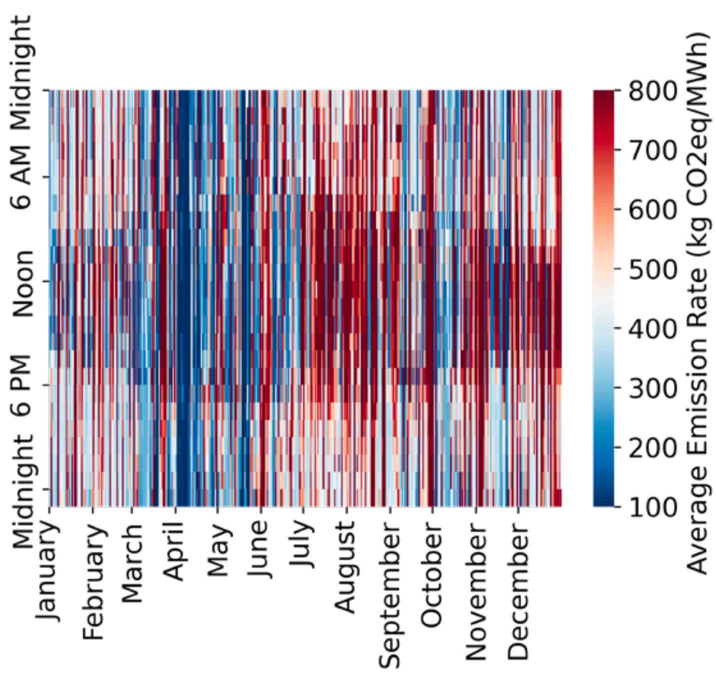

Figure 26. 2030 Mid Case for p45 IA region

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6 Conclusions

This analysis work selects three potential regions for CO2U facilities to produce SAF in 2030. The maximum production potentials of the SAF plants are estimated based on nearby CO_2 sources from industrial and power sectors. We quantify the locational-specific electricity costs for retail rate, physical and financial PPA, and RTP market mechanisms; we then analyze the carbon impact and emission intensity for the three regions in 2030.

Our analysis has shown that to meet 10% of the technical potential for SAF production in the three selected locations in El Segundo, California; Sulphur, Louisiana; and Arthur, Iowa, through CO2U conversation Pathway 1 (Electrochemical CO_2-to-CO + Syngas Fermentation + Ethanol-to-Jet) and Pathway 3 (Reverse Water-Gas Shift + Syngas Fischer-Tropsch-to-Jet), would require roughly 5.75 TWh/yr, 4.48 TWh/yr, and 11.2 TWh/yr of electricity, respectively.

To meet the required electricity needs, developers are likely to consider physical PPAs with subsidies and financial PPAs. For the p10 plant in California and the p58 plant in Louisiana, retail rates may be considered by developers if the industrial load for the proposed SAF production can be accommodated. Overall energy costs to Pathways 1 and 3 are similar, but the average cost per gallon for the SAF produced is different; the cost of natural gas heat input to Pathway 1 is not included, while both Pathways 1 and 3 have the energy required for hydrogen electrolysis included. The other major cost driver is the PTC. The PTC cost impact on the average cost of SAF production is around $5/gallon for Pathway 1 and $15/gallon for Pathway 3, based on our estimates.

For the next phase of this study, we will investigate the overall grid impact from SAF production via CO2U and evaluate the associated energy and environmental justice impacts.

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