Electricity Costs and Carbon Implications for CO_2-to-Fuels in Selected Locations in 2030

Yijin Li, Bethany Frew, Mark Ruth, and Ella Zhou

National Renewable Energy Laboratory

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National Renewable Energy Laboratory
15013 Denver West Parkway
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Preface

Concern is growing about global warming and greenhouse gas emissions from human activities, and carbon capture and recycling offer one of the viable solutions. The Markets, Resources, and Environmental and Energy Justice of CO_2-to-Fuels Technologies project supports the development of carbon capture and utilization (CO2U) technologies and a CO2U industry, in addition to evaluating the implications on environmental and energy justice metrics for a CO2U industry.

The economics of CO2U are often favorable and positive when a carbon dioxide (CO_2) resource can access low-cost and low-carbon electricity, as well as when the CO_2 source is relatively pure. This project quantifies the location-specific costs for electricity purchasing and time-dependent hourly electricity costs, as well as the marginal emission rates for the mid-term (~2030) and long-term (~2050). The results are expected to inform other projects within the U.S. Department of Energy's CO2-to-Fuels Consortium, especially the Economics and Sustainability of CO2 Utilization Technologies with Techno-Economic Analysis and Life Cycle Analysis (TEA/LCA) project, led by Michael Wang of Argonne National Laboratory and Ling Tao of the National Renewable Energy Laboratory. The project results are also expected to inform the investment and technology communities and policymakers at the U.S. Department of Energy, state, and regional levels and guide investment by government and industry in research and development portfolios.

This report provides information on electricity purchase options, costs, along with their respective marginal emissions for CO2U technologies in the 2030 time frame. The methodology assumes that a CO2U plant would have similar electricity options to today and that the grid impacts would also be similar to what would occur today. An analysis of greater impacts, such as the potential increased load and additional generation deployment required by a large CO2U industry, is planned for subsequent work, which will focus on the 2050 time frame. That future analysis will include electricity system capacity expansion and production cost modeling for scenarios with significant CO2U loads. Likewise, an analysis of CO_2 sources and potential markets for CO2U products is being performed in other tasks within this project and is not reported here.

This analysis extends the industry's understanding of electricity factors important for facility siting. The overall project's outcomes, in conjunction with the TEA/LCA project's outcomes, will provide an understanding of the market potential of a CO2U industry, the associated costs and environmental implications, and the potential technical and market barriers to informing future research and development decisions. These factors provide essential information necessary to determining the priority for future CO2U research, development, and demonstration projects and facilitating the evolution of a CO2U industry over the next 30 years.

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Alex Badgett, Researcher III, National Renewable Energy Laboratory
Thomas Bowen, Researcher, National Renewable Energy Laboratory
Pieter Gagnon, Senior Energy Systems Researcher, National Renewable Energy Laboratory
Jenny Heeter, Senior Energy Analyst, National Renewable Energy Laboratory
Jeffrey Logan, Chief Analyst, National Renewable Energy Laboratory
Ling Tao, Senior Chemical Engineering Researcher, National Renewable Energy Laboratory
Kwang Hoon Baek, Postdoctoral Appointee, Argonne National Laboratory
Amgad A. Elgowainy, Senior Scientist and Group Manager, Argonne National Laboratory
Uisung Lee, Energy Systems Analyst, Argonne National Laboratory
Pingping Sun, Principal Energy Systems Analyst, Argonne National Laboratory
Michael Wang, Senior Scientist and Director, Argonne National Laboratory

List of Acronyms

ATB	Annual Technology Baseline
CO2U	carbon capture and utilization
EEJ	environmental and energy justice
LCOE	levelized cost of energy
NREL	National Renewable Energy Laboratory
PPA	power purchase agreement
PTC	production tax credit
ReEDS	Regional Energy Deployment System
RTP	real-time pricing
TEA/LCA	Techno-Economic Analysis and Life Cycle Analysis

Executive Summary

With the growing interest in converting carbon dioxide (CO_2) to fuels and products to reduce overall greenhouse gas emissions and extend carbon from biogenic and other sources, the development of carbon capture and utilization (CO2U) technologies and industry is crucial. The Markets, Resources, and Environmental and Energy Justice of CO_2-to-Fuels Technologies (short title: MarkeRs & EEJ) project supports this goal by assessing the resource and market potential and infrastructure requirements for mid-term (~2030) and long-term (~2050) deployment of CO2U technologies. The overall project analyzes CO2U economic and resource requirements as well as sustainability and environmental and energy justice (EEJ) metrics.

This report focuses on short-term (~2030) aspects of the project. It identifies three CO2U locations in the Midwestern United States and quantifies the costs for potential electricity resources and marginal emissions for each site in the near term (e.g., 2030). We focus on four electricity purchase options, including retail rate, physical power purchase agreement (PPA), financial PPA, and real-time pricing (RTP), for each of the three sites and consider potential policies such as production tax credits (PTCs). We also assess time-dependent hourly marginal electricity costs and the marginal emission rates using modeled scenarios from Cambium (Gagnon et al. 2021).

The retail rate refers to electricity purchased from the local utility under industrial retail tariff structures. Physical PPA refers to electricity purchased and physically delivered from a renewable energy plant through a long-term contract with a preset price for energy. Financial PPA refers to the financial arrangement between a renewable electricity generator and the buyer to hedge against electricity market price volatility at an agreed strike price. RTP refers to electricity purchased that matches either the wholesale electricity market or the utility's cost of production with contractual adders.

This analysis suggests that electricity purchase prices can range from 0.3 to 8.3 cents per kilowatt-hour (¢/kWh), depending on the purchase options. Retail rates are higher than other rate options for two of the three locations, so sites are likely to consider other options. Physical PPAs have the potential to provide the lowest electricity costs, especially if the PTC is available as an additional revenue stream to the project developer, thereby offsetting the cost to the electricity buyer (e.g., “with PTC”). Financial PPAs have fewer restrictions than physical PPAs and retain much of the cost savings when compared to retail rates. RTP has the potential for lower costs if the load can be flexible (i.e., turn off when prices are high), although we do not quantify the benefit of such flexibility in this analysis.

Table ES-1. Electricity Cost for Four Purchase Options

Plant location	Retail Rate (¢/kWh)	Physical PPA (¢/kWh)	Financial PPA (¢/kWh)	RTP (¢/kWh)
Liberal, Kansas Plant	8.3	0.3–4.3	2.7–3.6	3.3
Rochelle, Illinois Plant	5.6		3.3–4.4	4.1
Decatur, Illinois Plant	3.4		3.3–4.4	4.1

The retail rate is estimated based on the average historical rates in 2019–2021 published by the local utilities; physical PPA is estimated based on historic wind PPA prices in Kansas and Illinois; and modeled data of levelized cost of energy (LCOE) for land-based wind comes from the Regional Energy Deployment System (ReEDS) model (Ho et al. 2021) and the National Renewable Energy Laboratory's 2021 Annual Technology Baseline model (NREL 2022). Financial PPA price is estimated based on projected wholesale electricity price +/- an uncertainty range. RTP price is cross-checked with a real-world RTP program and estimated based on the average of hourly marginal electricity costs from the Cambium Mid-Case scenario (Cole et al. 2021).

While we provide a range of values to reflect various potential future outcomes with price and policy considerations, our results are sensitive to a number of uncertainties, including future cost projections and the impact of adding the CO2U load. Furthermore, our price and emission estimates are based on modeled scenarios that cannot accurately predict the future, and these modeled projections do not account for the impact of the CO2U unit on the rest of the system, both for operation and investment considerations. Results from this report can be used in a baseline scenario to understand the impacts of adding a CO2U industry on electricity prices and generation mix. Additional production cost modeling is needed to better estimate hourly electricity costs, emissions, and operational metrics. In such future work, we plan to perform additional analysis using new data sets for 2030 and 2050.

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1 Introduction

This report describes an analysis of electricity purchase options for three ethanol production sites in the Midwestern United States in the relatively near future (2030). It also includes a discussion of time-dependent electricity prices of the three areas studied and their respective marginal emission estimates. This section of the report introduces the background and overall objectives of the Markets, Resources, and Environmental and Energy Justice of CO_2-to-Fuels Technologies (MarkeRs & EEJ) project and provides an overview of this effort. Section 2 describes our approach to estimating the electricity purchase prices. Section 3 describes the selection mechanism for the carbon capture and utilization (CO2U) plants and provides details for these locations. Section 4 includes the detailed calculations for electricity price estimates for each location and discusses the caveats. In Section 5, the approach, results, and caveats of the time-dependent electricity prices and long-run marginal emission analysis are described. Section 6 outlines future work and next steps for this task.

1.1 Background

The environmental impact of greenhouse gas emissions is a key global issue. Because the carbon emissions from burning fossil fuels are the largest source of emissions (EPA 2022a), in addition to direct fossil burn reduction, other decarbonization options are likely needed to address the issue. There is a growing interest in CO2U, which involves converting carbon dioxide (CO_2) to fuel products. CO2U technology possesses tremendous potential to convert carbon from biogenic and other sources into synthetic fuels, chemicals, and products, which serves as additional revenue for the CO2U process.

Multiple routes exist to convert CO_2 into commercial products: direct electrochemical, direct bioelectrochemical, plasma and indirect bioelectrochemical (fermentation), and indirect thermochemical. Among these technologies, indirect thermochemical, fermentation, and direct electrochemical have the highest technology readiness level (Grim et al. 2020). Additionally, CO2U products are dependent on conversion pathways and accessible C_1–C_3 species; based on conversion pathways investigated by Grim et al. (2020), the top CO2U products are CO, ethylene, formate, methane, acetate, and methanol. Figure 1 shows more details on these chemical species. For the direct bioelectrochemical pathway, acetate is a potentially viable product. For the indirect pathways, methanol and methane are competitive products because of their high technology readiness levels and high rates of formation.

Species	Rate of Formation[a]	Selectivity[b]	Energy Efficiency[c]	Current TRL[d]
Carbon Monoxide	High	High	High	High
Ethylene	High	Medium	Low	Low
Formate	Medium	High	Medium	Low
Methane	High	High	Medium	High
Acetate	Low	High	Medium	Low
Methanol	High	High	High	High

[a] High: >200 mA/cm^2 (or commercial TC), Medium: 200 >/>100 mA/cm^2, Low: <100 mA/m^2

[b] High: >80%, Medium 80% > FE > 60%, Low: < 60%

[c] High: >60%, Medium 60% > EE > 40%, Low: < 40%

[d] High: Operated at TRL > 6, Medium: Operated TRL 4-6, Low: Operated TRL 1-3

Figure 1. Top CO2U products

Source: (Grim et al. 2020)

In locations with low carbon renewable electricity resource availability and access to high-purity, CO_2-containing waste streams, CO2U technologies could be profitable in producing low-carbon-intensity products. The cost of electricity that CO2U facilities can access is the largest cost fraction for many of these technologies, whether the electricity is grid-connected or directly connected to generation resources (e.g., wind generation, solar photovoltaics). If the CO2U facilities can use low- or zero-carbon emission resources, such as solar, wind, hydro, nuclear and others, carbon emissions induced by the CO2U process are lower than fossil alternatives. Thus, the location, market size, resource availability, delivery infrastructure, and existing infrastructure are key considerations.

Other key considerations for sustainability include environmental and energy justice (EEJ) and reducing air pollutant emissions. As CO2U technologies are developed, it is imperative to discuss social equity and benefits to disadvantaged communities, in addition to economic and sustainability aspects. The benefits discussed should range from reducing pollution-related illness to increasing the availability of jobs.

1.2 Analysis Objectives

This analysis supports the development of CO2U technologies and a CO2U industry by accessing electricity costs and marginal generation mixes to provide electricity for a CO2U industry based on the evolution of the grid. It includes potential electricity prices and tariff structures (including the retail rate, physical power purchase agreement [PPA], financial PPA, and real-time pricing [RTP] mechanism) for three possible CO2U sites. Electricity prices and tariff structures for CO2U sites in 2030 are assumed to be similar to those today and are dependent on the current utility service territories. We use a combination of historical rates, modeled results, and extrapolation of historical costs to estimate the costs. We also consider the potential for policy incentives, such as production tax credits (PTCs).

This analysis is a part of a larger project to assess cost and availability of CO_2 resources, product market sizes, values, and the cost to deliver the infrastructure of resources and final products to their respective markets. We are planning a subsequent analysis of long-term (~2050) electricity and CO_2 resources, as well as market potential. In addition, this project plans to evaluate implications on EEJ factors such as air quality, gross domestic product, and jobs. Addressing both the CO2U economic and EEJ enables 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.

2 Approach

For this mid-term analysis, we calculate the cost to power a CO2U system in 2030 at three possible CO2U sites in Liberal, Kansas; Rochelle, Illinois; and Decatur, Illinois; which are all ethanol production plants in the Midwestern United States. We estimate unit-level electricity prices in 2030 at these plants under a range of potential future purchase options. We then calculate the total annual energy cost (dollars per year [$/yr]) and average cost (dollars per kilowatt-hour [$/kWh]) to purchase electricity for each site and purchase option. Lastly, we estimate time-dependent electricity prices and marginal emissions in 2030 at each site.

2.1 Explanation and Mechanism

As Figure 2 shows, we explored the following four potential future purchase options to power the CO2U system in 2030:

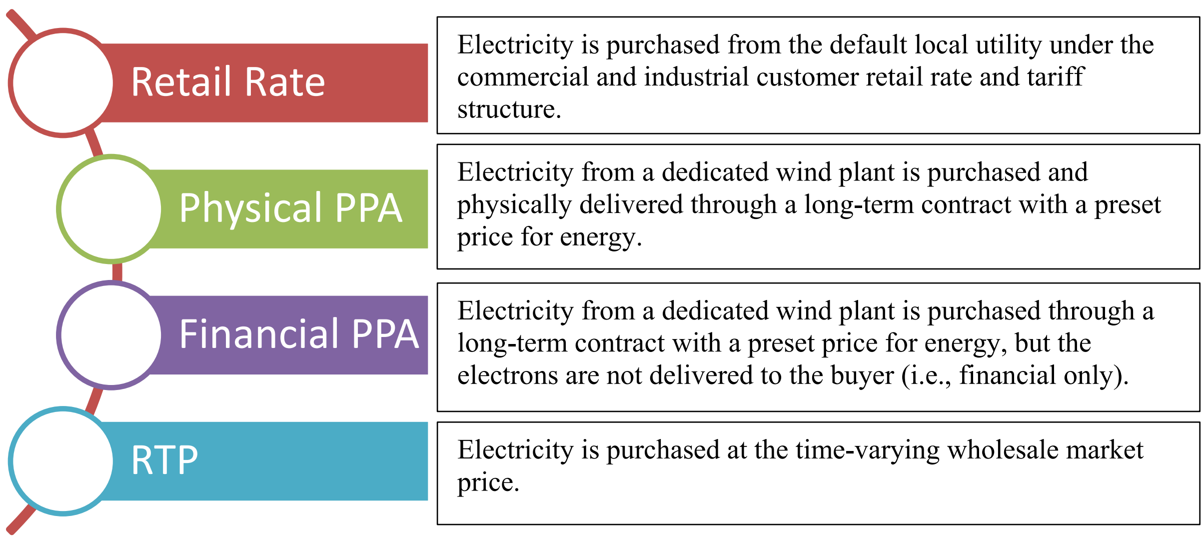

Figure 2. Electricity purchase option definitions

Figure 3 shows the estimation methods for each 2030 purchase option with available data collected and modeled for the regions near the three plants.

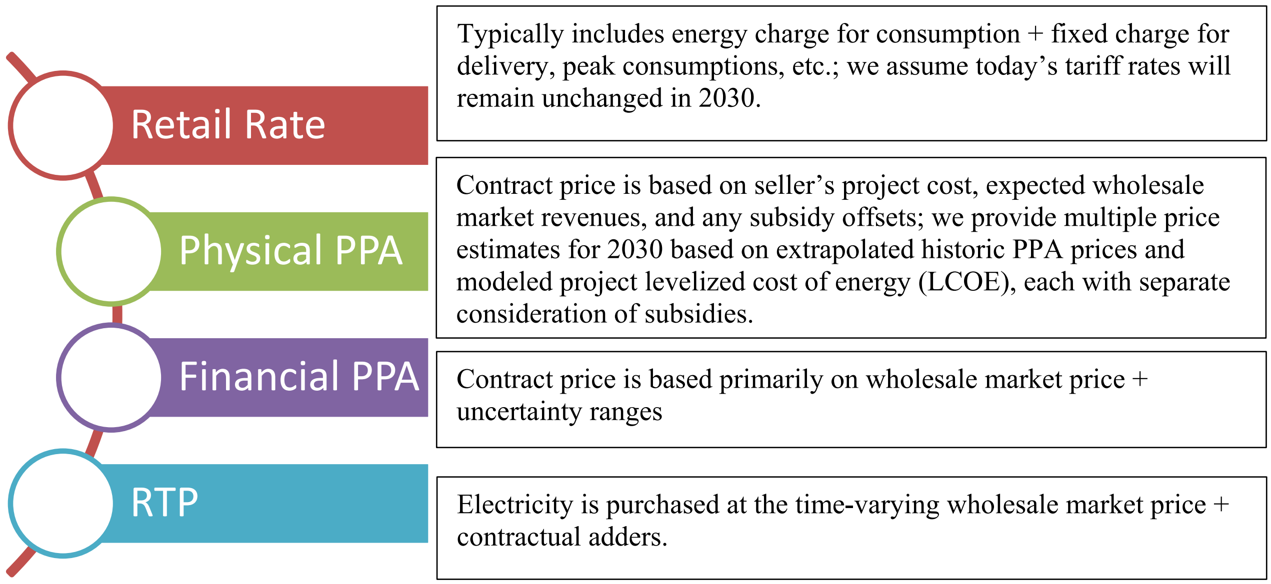

Figure 3. Electricity purchase option estimation methods

2.2 Key Data Sources and Analysis Tools

We use a range of power system modeling tools, technology cost projections, and industry data to estimate electricity prices in 2030 across our four options. For models, we use Cambium outputs (Gagnon et al. 2021), which synthesize hourly emission and cost values from the Regional Energy Deployment System (ReEDS) capacity expansion model (Ho et al. 2021) and the PLEXOS production cost model (Energy Exemplar 2022). For industry data, we use existing utility retail tariffs in the location of our three illustrative plants, and Bloomberg New Energy Finance data (BloombergNEF 2020) on existing wind PPAs.

2.2.1 ReEDS

ReEDS is the National Renewable Energy Laboratory's (NREL) capacity expansion model. It simulates the least-cost expansion of generation, transmission, and storage to satisfy the load under different possible futures (e.g., different projections of load, fuel prices, technology costs and performance, and policies/regulations) using linear optimization programming. Details on the ReEDS formulation can be found in the most recent documentation (Ho et al. 2021).

ReEDS simulates134 balancing areas and 356 renewable regions (Figure 4). ReEDS represents seasonal and diurnal variations in load and resources using 17 time slices for each year. In addition to its high-resolution spatial modeling capabilities, ReEDS has detailed representations of challenges associated with the integration of variable resource renewables, such as curtailment and capacity value. The key outputs from the model are annual generation and transmission capacity builds/retirements, dispatch, emissions, fuel consumption, electricity prices, and credit prices.

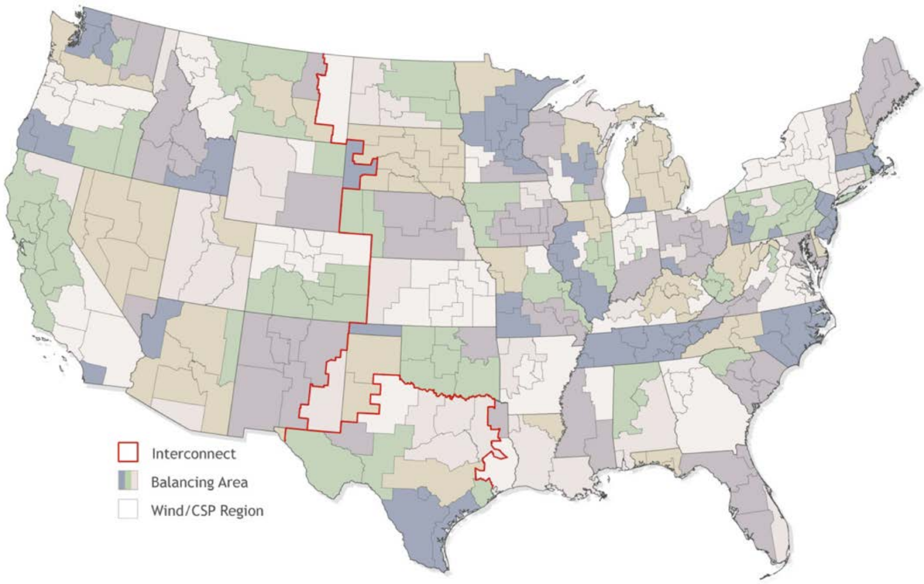

Figure 4. ReEDS spatial resolution

Source: (Ho et al. 2021)

2.2.2 PLEXOS

PLEXOS is commercial production cost software model that performs hourly chronological optimization and system-wide cost minimization using mixed integer programming. The model commits and dispatches generating units based on: (1) electricity demand, (2) operating parameters of generators (e.g., ramp rates, minimum generation level, outages), (3) transmission grid parameters (flow limits, contingencies), and (4) operating reserve requirements. PLEXOS is used to simulate the hourly economic dispatch of the future electric systems projected by ReEDS.

2.2.3 Cambium

Cambium is a tool that assembles structured data sets of simulated hourly emission, cost, and operational data for modeled futures of the U.S. electricity sector. It uses the outputs produced by ReEDS and PLEXOS. Cambium is used for the analysis of both electricity cost and carbon emissions. As Figure 5 shows, there are 134 balancing areas, which are used as the nodes for supply and demand balancing in both the ReEDS and PLEXOS models that Cambium draws from.

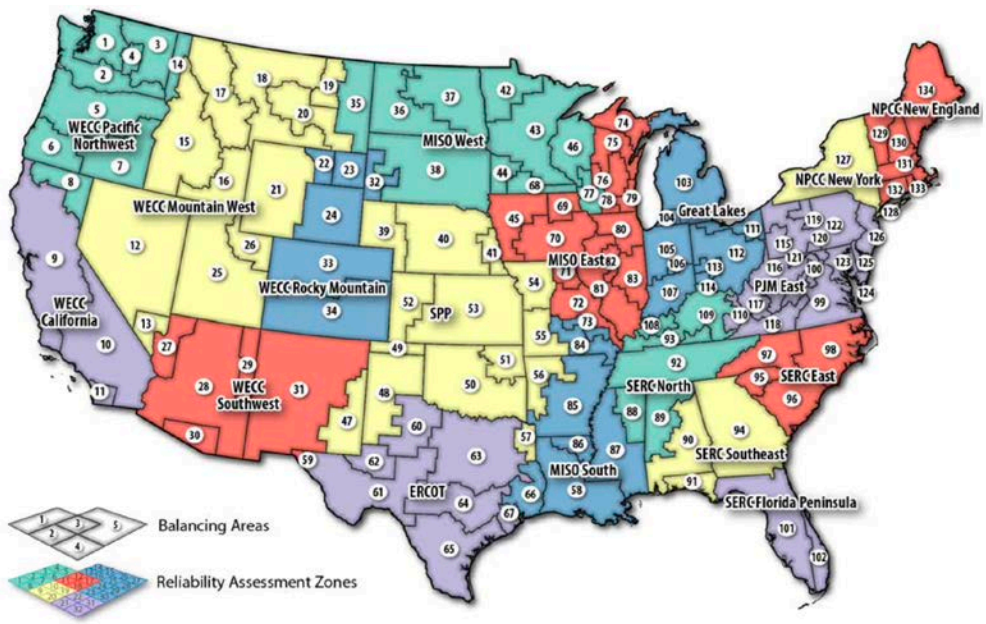

Figure 5. Balancing areas from Cambium

Source: (Gagnon et al. 2021)

2.2.4 Standard Scenarios

NREL produces a set of Standard Scenarios with ReEDS each year to capture a diverse set of potential futures (Cole et al. 2021). We use the *2021 Standard Scenario* “Mid-Case” for our four electricity purchase options analyses, and both the “Mid-Case” and “Low Renewable Energy (RE) Cost” for our marginal mixes analyses. Figure 6 shows the generation mix from the Mid-Case scenario, which uses the reference, mid-level, or default assumptions for demand growth, resource, system cost, fuel price, and technology input. In Figure 7, the Low RE Cost case shows the advanced renewable energy cost-reduction projection for all renewable energy technologies.

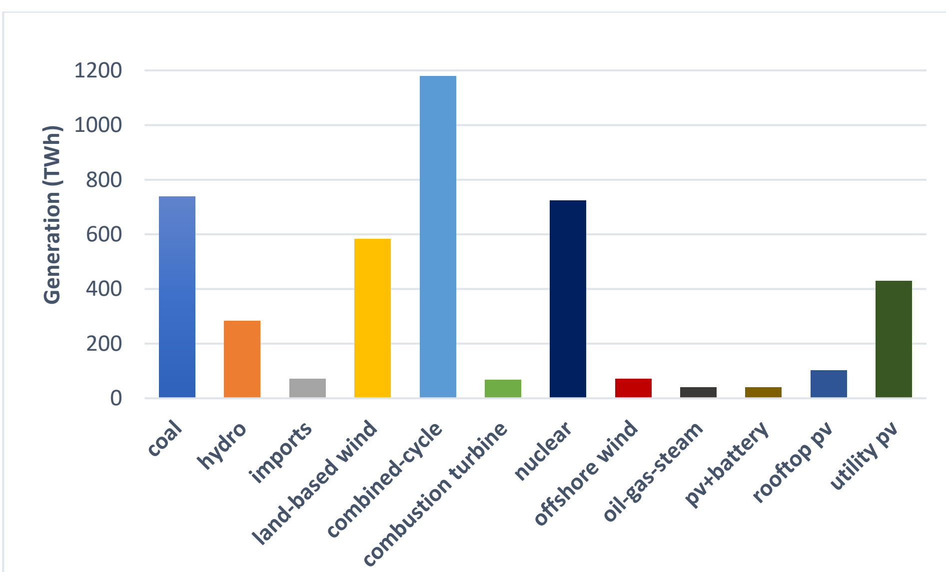

Figure 6. Year 2030 Mid-Case total annual generation from ReEDS 2021 Standard Scenarios

Source: Adapted from (Cole et al. 2021)

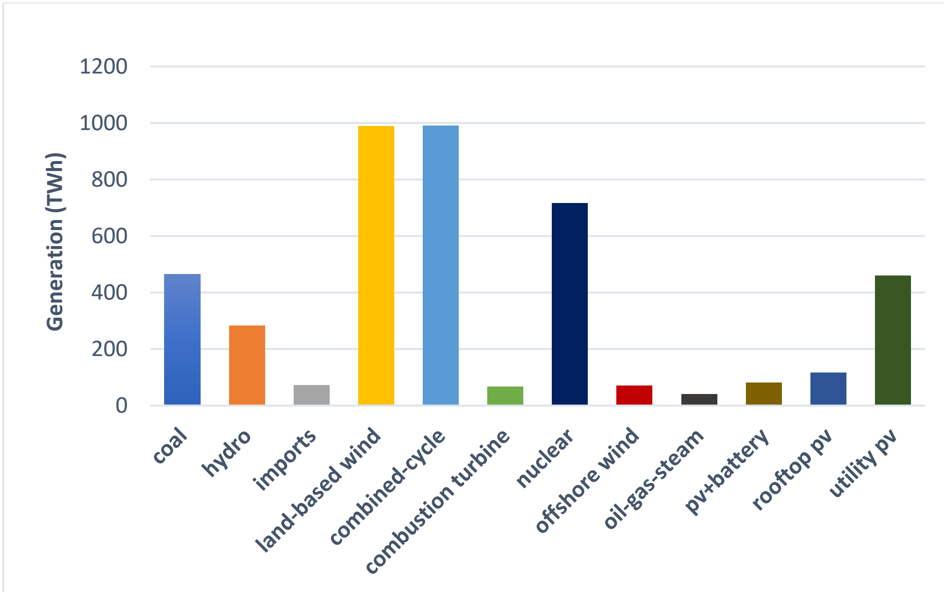

Figure 7. Year 2030 Low RE Cost case total annual generation from ReEDS 2021 Standard Scenarios

Source: Adapted from (Cole et al. 2021)

3 Selected CO2U Sites

We selected the three ethanol production plants shown in Figure 8 for the CO2U system analysis because: (1) they represent different wholesale market regions; (2) they are among the largest ethanol plants; and (3) they correspond roughly to plants identified by Argonne National Laboratory as potential CO_2 supply sources for carbon capture and utilization applications (Elgowainy et al. 2022). More detailed information for each plant is displayed in Table 1.

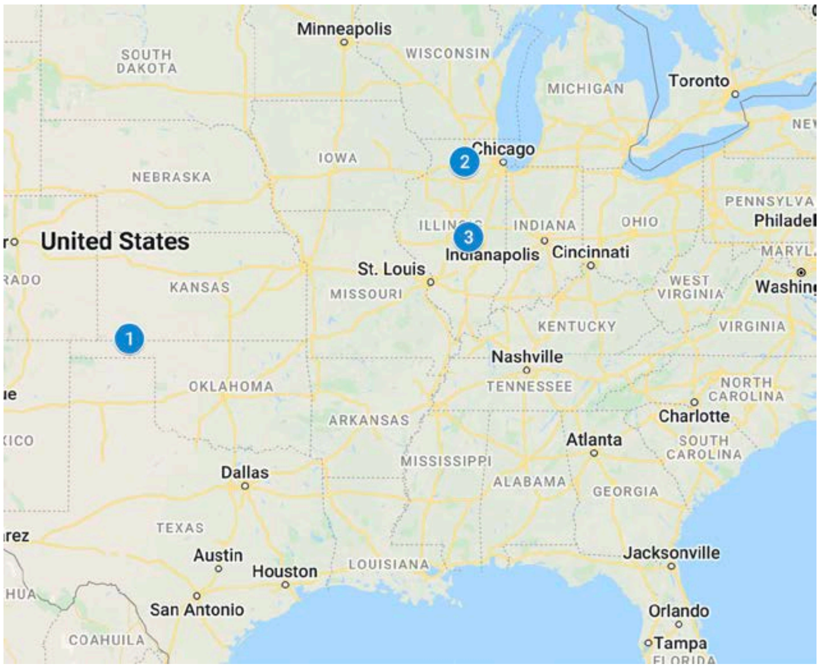

Figure 8. Locations of ethanol plants

Table 1. Three Illustrative Ethanol Plants

	1. Liberal Plant	2. Rochelle Plant	3. Decatur Plant
Ethanol Plants	Arkalon Ethanol	CHS Inc.	Archer Daniels Midland Co.
Location	Liberal, KS	Rochelle, IL	Decatur, IL
Capacity (million gallons/year) (RFA 2022)	115	133	300
Technology	Dry mill	Dry mill	Wet mill
Electricity Wholesale Market Region	SPP South Hub	PJM ComEd Zone	MISO Illinois Hub
Load-Serving Entity	Southern Pioneer Electric	Rochelle, IL	Ameren, IL
CO_2 Supply by Process (MMT/yr) (Baek 2022)	0.19	0.15	0.63

4 2030 Electricity Price Estimates

This section includes a detailed discussion of the four purchase options and mechanisms. We adapt the electricity requirement from the existing Aspen Model for CO_2-to-Jet Pathway1 (Tao 2022): "CO_2-to-CO electrolysis + Syngas fermentation + ETJ upgrading," with a CO_2 input flow rate of 56,306 kilograms per hour (kg/hr) and jet production of 5,620 gasoline gallon equivalents per hour (GGE/hr). Total energy consumption is 7,658 kilowatt-hours per tonne CO_2 (kWh/tonne CO_2) or 76.7 kWh/GGE Jet. Table 2 shows the load assumption, energy, and power requirements for the CO2U system at each location. The estimate results are shown in Sections 4.6 and 4.7.

Table 2. Calculation Assumptions and CO2U Energy Requirements for Each Site

	Liberal, KS Plant	Rochelle, IL Plant	Decatur, IL Plant
CO2U Capacity Factor	90%	90%	90%
Total Energy Consumption for CO2U (kWh/tonne CO_2)	7,658	7,658	7,658
CO2U Power Factor	95%	95%	95%
CO2U Energy Consumption (kWh/GGE Jet)	76.7	76.7	76.7
CO2 Supply by Ethanol Production (tonne/yr)	193,143	152,835	629,815
Electricity Requirement for CO2U Facilities (TWh/yr)	1.5	1.2	4.8
Load for CO2U Facilities (kW)	187,606	148,454	611,761

4.1 Retail Rate

Retail rate options represent electricity purchased from the default local utility under the commercial and industrial customer retail rate and tariff structure. For these calculations, we assumed the load for each site would be constant for every hour in a year.

4.1.1 Liberal, Kansas, Plant

For the plant in Liberal, Kansas, the local utility Southern Pioneer Electric Company offers two services for large industrial customers: industrial service and interruptible industrial service. The net monthly bill for industrial customers consists of three components: monthly customer charge, delivery charge, and demand charge. We performed calculations for both the interruptible and noninterruptible service to provide a bound for our estimates. We assumed no further adjustments on energy costs, and that the plant does not receive service discounts and is operated to meet all system reliability and power factor requirements. The winter refers to the period from November to June, and the summer refers to months from July to October. The industrial service rates for both noninterruptible and interruptible services (Southern Pioneer Electric Company 2022) are shown in Table 3.

Table 3. Southern Pioneer Retail Rate (adapted from Southern Pioneer Electric Company 2022)

	Noninterruptible		Interruptible
Customer Charge	$102.15/month		$100.62/month
Demand Charge	$11.18/kW (Winter)	$14.18/kW (Summer)	$7/kW
Delivery Charge	$0.08213/kWh		$0.08213/kWh

The annual electricity cost under this rate schedule is from $123 million (interruptible) to $124 million (noninterruptible) per year in 2030, and the average cost is around 8.3¢/kWh.

4.1.2 Rochelle, Illinois, Plant

This plant would likely be under Rochelle Municipal Utilities' Rate Schedule #165 for large industrial customers with a minimum monthly demand of at least 5 MW per month. The net monthly bill for industrial customers consists of three components: a monthly facilities charge, energy charge, and demand charge. The on-peak hours refer to hours starting at 9 a.m. and ending at 10 p.m., except Saturdays, Sundays, and holidays that are generally observed (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas Day), and the off-peak hours refer to all hours that do not fall within the on-peak hours (i.e., nights, weekends, and holidays). We assume the plant does not participate in the Demand Response Program. We also assume no further adjustment on power cost and that the plant maintained the average power factor above 95%, so no further penalty cost is induced by the power factor requirement. We use an on-peak, off-peak hour weighted average energy charge for the calculation. Table 4 shows the rates from Rochelle Municipal Utilities' Rate Schedule #165 (Rochelle Municipal Utilities 2022).

Table 4. Rochelle Municipal Utilities Retail Rates (adapted from Rochelle Municipal Utilities 2022)

	On-Peak	Off-Peak
Monthly Facilities Charge	$250 per month	
Energy Charge	$0.084/kWh	$0.0358/kWh
Demand Charge	$17.2/kW	

The annual electricity cost under this rate schedule is $65 million per year, and the average cost is around 5.6¢/kWh.

4.1.3 Decatur, Illinois, Plant

For the plant in Decatur, Illinois, the load serving entity is Ameren Illinois (Ameren). Ameren's rate structure consists of two major components: energy and delivery charges. The energy component includes the actual cost of energy procured by Ameren; unless an alternate supplier has been chosen by the customer, Ameren claims no additional markups on the energy supply charges. We use the hourly marginal electricity cost from the 2021 Cambium data set for the Mid-Case scenario in Year 2030 as the estimate for the energy supply component. The delivery component constructs and maintains the delivery system to get electricity from the supplier to the customer, regardless of the energy suppliers. The Ameren website details the historical rates on their website, and monthly average rates below are calculated based on the historical rates in

2019–2021, and to estimate locational marginal price, we use Mid-Case scenario marginal energy charge from Cambium for year 2030 (Ameren 2022), which is summarized in Table 5.

Table 5. Ameren Illinois Historical Average Retail Rates (adapted from Ameren 2022)

	Rate Unit	Average Value	Note
Customer Charge	$/electric service account	1,498.78	
Meter Charge	$/electric service account	13.43	
Distribution Delivery Charge	$/kW	0.19	
Transformation Charge	$/kW	0.264	
Reactive Demand Charge	$/kVAR	0.38	
Electric Distribution Tax Cost Recovery	$/kWh	0.0012	
Capacity Cost	Amount ($/PLC-Day)	0.005	Peak load contribution (PLC) is kW demand assigned to a customer in Midcontinent Independent System Operator's planning year; we assume PLC is the kW demand needed for the CO2U facility
Locational Marginal Price	$/kWh	0.031	2030 marginal energy cost in Mid-Case Standard Scenario
Ancillary Service	$/kWh	0.00008	
Market Settlement	$/kWh	-0.0001	
Supply Balancing Adjustment	$/kWh	-0.0003	
Supply Cost Adjustment—Procurement	$/kWh	0.0002	
Supply Cost Adjustment—Working Capital	Percentage	0.45%	Percentage applies capacity cost, energy charge, and supply cost adjustment—procurement charge
Supply Cost Adjustment—Uncollectible Factor	Percentage	0.35%	Percentage applies capacity cost, energy charge, supply cost adjustment—procurement charge and supply cost adjustment—working capital charge
Supply Cost Adj. Rider Electric Uncollectible Adjustment	$/kWh	0.0025	

The annual electricity cost under this rate schedule is $166 million per year, and the average electricity cost is around 3.4¢/kWh.

4.2 Physical PPA

We develop four different 2030 wind PPA prices: two based on historical data and two based on modeled data. Linear extrapolation and capacity-weighted averages (in and after 2016) are based on historical data. Remaining PPA estimates are based on two separate model-based data for wind LCOEs.

For each of these options, we include separate consideration of PTC subsidies (i.e., both with and without the presence of the PTC based on the construction commencement dates of the wind facilities). If the PTC exists, it is assumed to serve as a separate revenue source for the PPA seller, thereby reducing the PPA price to the buyer.

A list of historical PPA contracts was filtered for land-based wind with signing dates from 2012 to 2019 and with PPA off-taker or provider locations in Illinois or Kansas. These data were used to project two sets of 2030 PPA wind prices: linear extrapolation and capacity-weighted average. We use the same PPA values to estimate for all three locations, and we compile data from two states because we have limited state- and site-specific historical PPA wind contracts in each region. The trendline and capacity-weighted average calculation is likely to be more accurate when we have more datapoints.

4.2.1 Linear Extrapolation

For linear extrapolation, we develop trendlines for PPA prices, separately for the signing years 2012–2015 and 2016–2019. As showed in Figure 9, linear trendline Piece 2 is used to estimate PPA prices in 2030.

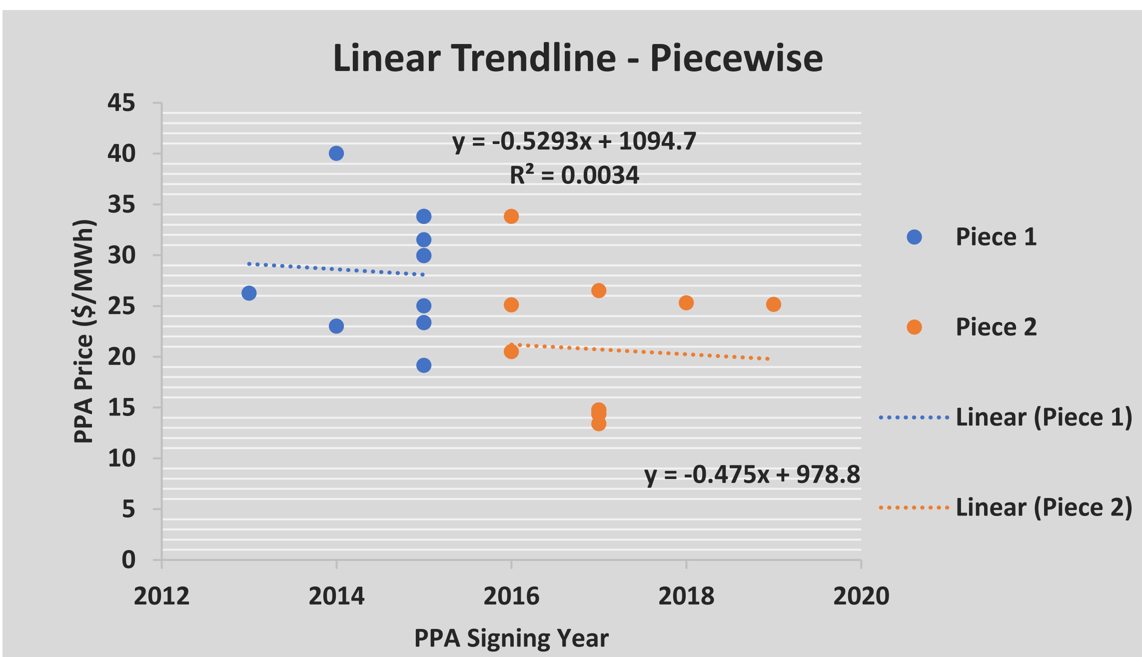

Figure 9. Linear extrapolation trendlines

Source: (BloombergNEF 2020)

The year 2016 is used as a breakpoint because: (1) China flooded the photovoltaic market around 2016, which increased competition in renewable energy markets (IEA 2016), and (2) wind PTC full credit qualification decreased for wind projects that commenced construction after 2016 (EIA 2021).

4.2.2 Capacity-Weighted Average In and After 2016

Several existing physical PPA prices increase each year by a preset percentage, and we calculate those prices in 2030. Figure 10 shows the PPA contracts signed in and after 2016. We use the capacity (x-axis) weighted PPA price (y-axis) average for these existing PPA contracts for another set of estimates.

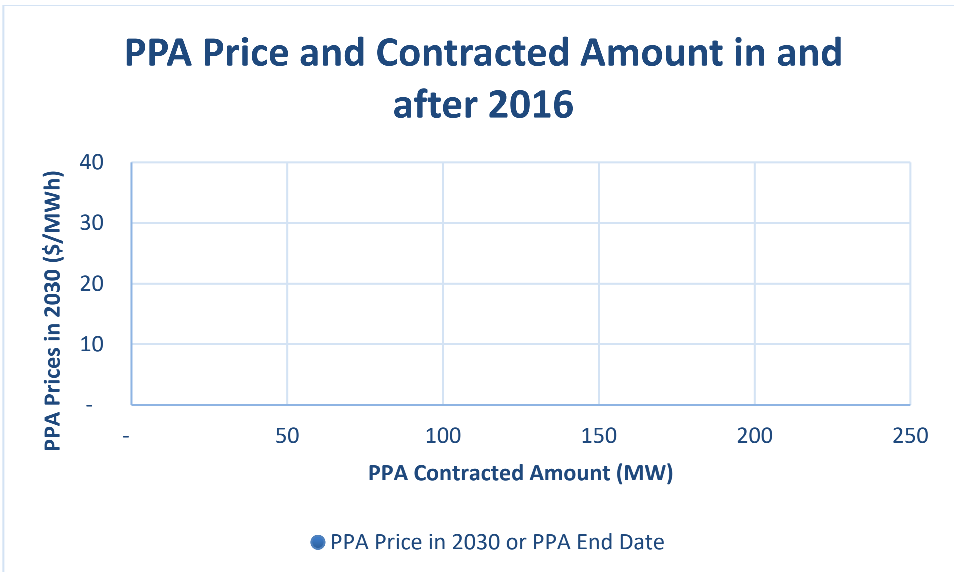

Figure 10. PPA historical price and contracted amount signed in and after 2016

Source: (BloombergNEF 2020)

4.2.3 ReEDS LCOE

ReEDS LCOE was taken directly from the 2021 ReEDS Standard Scenario Mid-Case results (Ho et al. 2021), which assume that future wind markets are sufficiently competitive to approximate PPA prices as the projected LCOE.

4.2.4 ATB LCOE

ATB LCOE was taken directly from NREL's 2021 Annual Technology Baseline (ATB) onshore wind "Moderate" case (average of all wind classes) for 2030 (NREL 2022). The major difference between the two models is that the ATB is a bottom-up engineering model for wind turbine and plant technologies with predicted technology advancements, and while cost and performance data used in ReEDS are based on the ATB, its generation profiles are locational-specific. Table 6 shows the physical PPA rates for four different methods.

Table 6. Physical PPA Rates

Method	PPA Buyer Price if PTC Does Not Exist	PPA Buyer Price if PTC Does Exist
Linear Extrapolation	$38/MWh	$15/MWh
Capacity-Weighted Average	$43/MWh	$20/MWh
ReEDS LCOE	$43/MWh	$20/MWh
ATB LCOE	$26/MWh	$3/MWh

We assume PTC is the separate revenue source for the PPA seller, and results in a $23/MWh reduction in prices. If PTC does not exist, the annual electricity cost with physical PPA contracts ranges between $38 million and $64 million per year for the Liberal, Kansas, plant; $30 million and $50 million per year for the Rochelle, Illinois, plant; and $125 million and $207 million per year for the Decatur, Illinois, plant. The average electricity cost is around 2.6–4.3¢/kWh for the three locations.

If PTC does exist, the annual electricity cost is $4 million–$30 million per year for the Liberal, Kansas, plant; $4 million–$23 million per year for the Rochelle, Illinois, plant; and $14 million–$96 million per year for the Decatur, Illinois, plant. The average electricity cost is around 0.3–2¢/kWh with PTC as additional revenue. However, physical PPA costs discussed here are on the lower end, because when the PPA developer's output doesn't match or meet the need of CO2U load, the CO2U plant would need to acquire additional electricity from the grid; physical PPA also entails contractual utility adders; these associated costs are not considered.

4.3 Financial PPA

Financial PPA prices are based on the difference of an agreed-upon "strike price" and wholesale electricity prices, where the buyer pays—or is credited—the net of the difference (EPA 2022b). We approximated a potential future financial PPA price as the projected wholesale electricity price +/- an uncertainty range. For the wholesale electricity price, we approximated the average of the hourly marginal electricity costs from the 2021 Cambium Mid-Case for year 2030 (from the ReEDS Standard Scenarios). Marginal electricity cost is the sum of the marginal energy cost, marginal capacity cost, and marginal renewable portfolio compliance cost. We chose +/-15% as the uncertainty range, and assumed the renewable attributes are not sold for additional revenue (e.g., renewable energy certificates). Table 7 shows the financial PPA rates with a lower and upper bound for each location.

Table 7. Financial PPA Rates (adapted from Gagnon et al. 2021)

Balancing Area	Lower Bound	Upper Bound
P53 (Liberal Plant)	$27/MWh	$36/MWh
P82 (Rochelle Plant)	$33/MWh	$44/MWh
P83 (Decatur Plant)	$33/MWh	$44/MWh

If the plant is under a financial PPA agreement, the annual electricity cost is between $40 million and $54 million per year (2.7–3.6¢/kWh) for the Liberal, Kansas, plant; $38 million and

$52 million per year (3.3–4.4¢/kWh) for the Rochelle, Illinois, plant; and $158 million and $213 million per year (3.3–4.4¢/kWh) for the Decatur, Illinois, plant.

4.4 RTP

RTP is a rate structure in which the energy charges vary hourly based on either the wholesale electricity market or the utility's cost of production:

$$\text{Typical RTP structures} = \text{hourly energy supply} + \text{delivery} + \text{monthly demand} + \text{customer charges}$$

We used the averages of hourly marginal electricity costs from the Cambium Mid-Case for year 2030 as estimates for the RTP program in 2030. These values aligned closely with several real-world RTP programs (Nezamoddini and Wang 2017). Then, we applied an adder of 7% to estimate the markups collected by RTP providers (Quackenbush 2020, Quilici et al. 2019).

Table 8. RTP Rates (adapted from Gagnon et al. 2021)

Balancing Area	Average RTP Cost With Markup
P53 (Liberal Plant)	$33.8/MWh
P82 (Rochelle Plant)	$41/MWh
P83 (Decatur Plant)	$41.1/MWh

If the plant is under an RTP schedule, the annual electricity cost is $50 million per year for the Liberal, Kansas, plant; $48 million per year for the Rochelle, Illinois, plant; and $198 million per year for the Decatur, Illinois, plant. The average electricity costs are 3.3¢/kWh, 4.1¢/kWh, and 4.1¢/kWh, respectively.

4.5 24/7 100% Clean Energy PPA

While the physical PPA structure discussed in Section 4.2 can provide carbon-free sources of wind (or other renewable) electricity for powering CO2U systems, this structure is premised on a "pay-as-produced" contract. In this structure, the off-taker (i.e., buyer) obtains the resulting energy as it is produced, which is often temporally mismatched with the demand (Figure 11). As a result, if a "24/7" hourly matching of carbon-free electricity is desired, PPA off-takers must augment the PPA-produced electricity with other generation resources. In many cases, this could require purchasing electricity from the grid with carbon-emitting generation.

The financial PPA structure discussed in Section 4.3 typically includes a more flexible renewable attribute accounting, whereby the renewable energy attributes can be reported on an annual (or other aggregate) basis. That is, if a CO2U facility purchased wind or other carbon-free electricity through such a financial PPA structure, the facility could pay based on an hourly or other temporal resolution, as described in Section 4.3, but could claim the renewable attributes on an aggregated basis. However, the actual hourly matching (or lack thereof) of that renewable generation with demand is typically not tracked (EPA 2022b).

One emerging solution to address the temporal mismatch is a 24/7 PPA, which typically combines renewable resource(s) with storage that can accommodate a fluctuating load. These PPAs measure demand and supply in smaller time units and are designed to balance resources in all hours (in normal weather years).

Because 24/7 PPAs have multiple resources, their projected prices can be approximated as the sum of the LCOE of constituent resources. We provide two estimates for 2030 using this additive approach:

- **NREL 2021 ATB**: Land-based wind LCOE + utility-scale energy storage LCOE = $173/MWh
- **McKinsey & Company Report** (McKinsey and Co. 2022): 100 MW 24/7 PPA in California with 100% of load met by the PPA = $86/MWh.

We do not include this rate in our results calculations because the current analysis focuses on a very specific market and location, and NREL 2021 ATB estimates are not economically competitive.

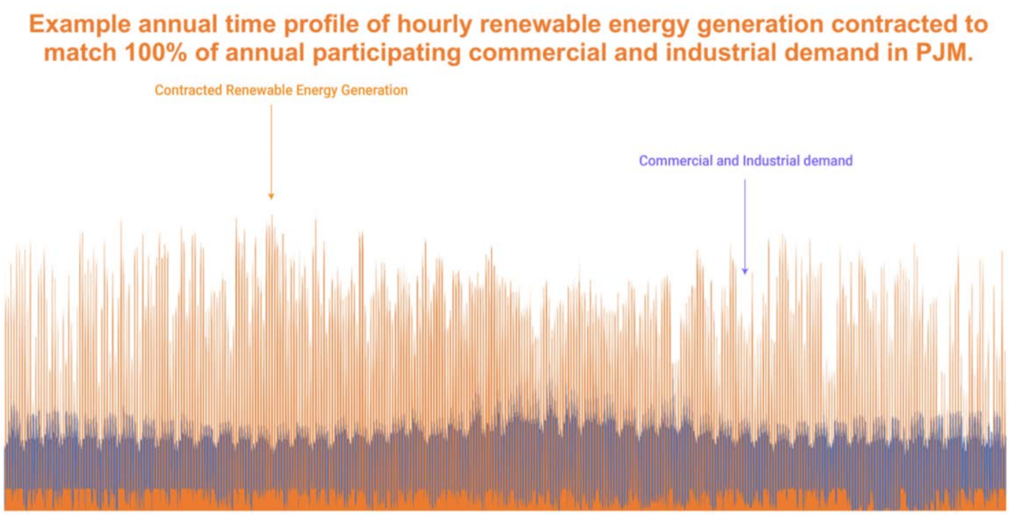

Figure 11. Supply mismatched with the demand

Source: (Xu et al. 2021)

4.6 Summary Table of all Options (unit-level)

Table 9 summarizes the rate for all four electricity purchase options. Actual prices are dependent on a wide range of factors, including additional costs (system-level and/or resource-level), revenues (e.g., capacity markets, policy-based subsidies, renewable energy credits), and market factors that could impact the relative cost. Physical and financial PPAs are based on as-produced electricity generation, and we assume the financial PPA maintains its renewable energy attributes (i.e., they are not sold for additional revenue).

Table 9. Summary Table for Different Purchase Options

Plant (Location)	Retail Rate				Physical PPA		Financial PPA	RTP
	Energy Charge ($/MWh)		Demand Charge ($/MW)		PPA Buyer Price if PTC Does not Exist ($/MWh)	PPA Buyer Price if PTC Does Exist ($/MWh)	$/MWh	$/MWh
	On-Peak	Off-Peak	Summer	Winter				
Liberal, KS Plant	82		7–11	7–14	26–43	3–15	27–36	34
Rochelle, IL Plant	84	36	17				33–44	41
Decatur, IL Plant	35		46				33–44	41

4.7 Summary Table of Total Annual Cost to Purchase Electricity ($/yr and $/kWh)

Table 10 below suggests that the short-term electricity prices may range from 0.3 to 8.3¢/kWh. The retail rate has higher costs in two locations, and a CO2U project developer is probably less likely to consider this option. Physical PPAs have the potential to provide the lowest electricity costs, especially if the PTC is available as an additional revenue stream to the renewable energy project developer. Financial PPAs have fewer restrictions than physical PPAs because they are not linked to specific generators but still offer the cost benefits to the project developer. Real-time pricing has the potential for lower costs if the load in the CO2U facility can be flexible.

Table 10. Summary Table of Total Annual Cost and Cost to Purchase Electricity

Plant (location)	Retail Rate		Physical PPA				Financial PPA				RTP	
			Without PTC		With PTC		Lower Bound		Upper Bound			
	Total $/yr	Avg. ¢/kWh	Total $/yr	Avg. ¢/kWh	Total $/yr	Avg. ¢/kWh	Total $/yr	Avg. ¢/kWh	Total $/yr	Avg. ¢/kWh	Total $/yr	Avg. ¢/kWh
Liberal, KS Plant	123 M–124 M	8.3	38 M–64 M	2.6–4.3	4 M–30 M	0.3-2	40 M	2.7	54 M	3.6	50 M	3.3
Rochelle, IL Plant	65 M	5.6	30 M–50 M		4 M–23 M		38 M	3.3	52 M	4.4	48 M	4.1
Decatur, IL Plant	166 M	3.4	125 M–207 M		14 M–96 M		158 M	3.3	213 M	4.4	198 M	4.1

A summary table of the average purchase rate ($/tonne CO_2) and average cost per gasoline gallon equivalent ($/GGE) jet fuel can be found in Appendix A.

4.8 Purchase Option Caveats and Limitations

Projection of the Future: Future prices are based on a complex set of factors that cannot be perfectly forecasted, including natural gas fuel prices, wind technology costs, electricity demand, and policy (e.g., PTC). For retail rates, price projections are assumed to be the same as today's rates—but with more renewable energy intergraded in the electric system, tariff structure and rate changes are likely for the local utilities considered here. For physical and financial PPA and RTP, the cost projections are based on either historical data or modeled scenarios, where future conditions may not accurately reflect past events or the modeled assumptions. Additionally, we have focused on three illustrative ethanol plants, but these may or may not capture the full range of the outlook of each price option.

Grid Impact Caveat: Electricity price projections do not account for the impact of the CO2U unit on the rest of the system, both for operation and investment outcomes. We plan to further analyze these impacts in the long-term analysis of this task.

Marginal Electricity Price: The marginal electricity cost values from Cambium include the marginal energy cost, marginal capacity cost, and marginal portfolio cost. The marginal electricity cost represents the cost of the grid system in serving additional loads. Marginal capacity cost includes the cost estimates of acquiring capacity to meet a system's planning reserve margin if peak demand increases marginally. Marginal portfolio cost refers to the cost of staying in compliance with policy requirements, such as renewable portfolio standards and clean energy standards. The marginal capacity cost is based on the shadow value of the capacity constraint from ReEDS, which is then applied to the top 100 load hours in Cambium (Figure 12). This approximation may or may not capture the actual hours of capacity needs or marginal capacity's reflection in realized electricity prices from an end user like a CO2U load.

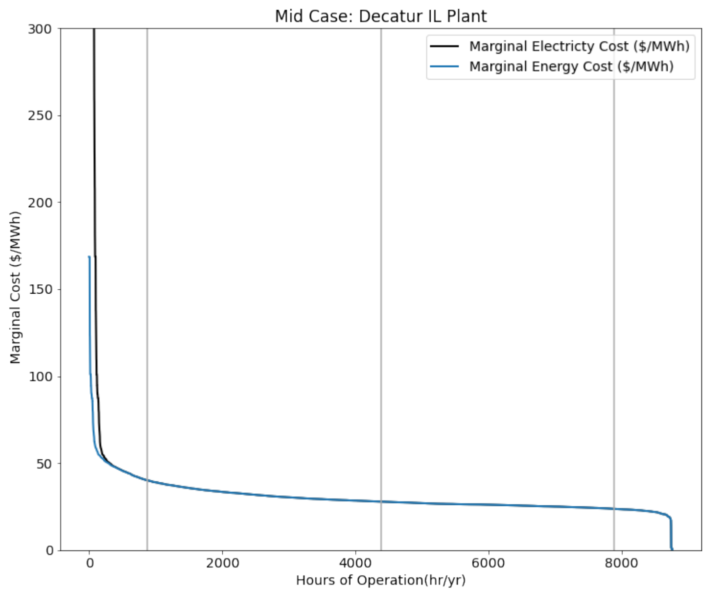

Figure 12. Mid-Case: Decatur, Illinois, plant marginal cost

5 Time-Dependent Electricity Prices and Marginal Emissions

In this section, we quantify the time-dependent electricity prices and the respective long-run marginal emissions for each location. The standard scenarios are used for balancing areas region 53 (p53) for Liberal, Kansas, plant, p82 (Rochelle, Illinois, plant), and p83 (Decatur, Illinois, plant) shown in Figure 5. The peak loads for each balancing area region are 9.7 GW, 2 GW, and 3.9 GW, respectively (calculated from Gagnon et al. [2021]).

5.1 Methodology

We use the 2021 Mid-Case and Low RE Cost scenarios from NREL's Standard Scenarios that were processed through Cambium to obtain hourly time series results and focus on two outputs: (1) marginal electricity cost, which serves as the electricity price, and (2) long-run marginal emission, which serves as the marginal carbon emission rate estimates for this analysis. We also include sensitivity analyses on short-run marginal emissions and the impact of high natural gas prices on the marginal generation mixes.

Price duration curves (left diagram of Figures 13 through 15) are based on sorting hours with the highest to lowest marginal electricity cost values (Hour 1 = highest cost, Hour 8,760 = lowest cost). The corresponding long-run marginal emission values for each hour are shown as a scatter plot color-coded by the technology type of the marginal energy sources. In the right diagram of Figures 13 through 15, we calculated the cumulative average for each successive hour, moving from right to left for marginal electricity costs and long-run marginal emission rates.

5.2 Results

5.2.1 Mid Case Results

Mid-Case results for 2030 (Figure 13, Figure 14, and Figure 15) show that the Liberal, Kansas, location (p53) has higher renewable energy in its marginal mix. A lower capacity factor (fewer hours purchased) corresponds to primarily coal- and gas-combine cycle generator-driven emissions, and a higher capacity factor sees marginal emission driven by a greater contribution of gas combustion turbine and oil-gas-steam generation.

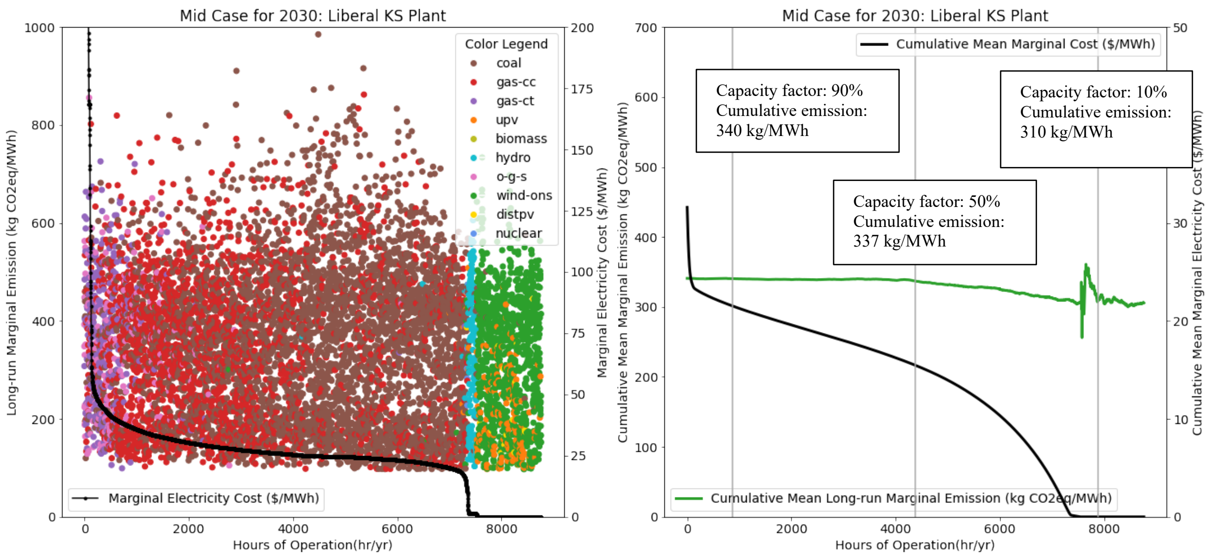

Figure 13. Mid-Case: Liberal, Kansas, plant

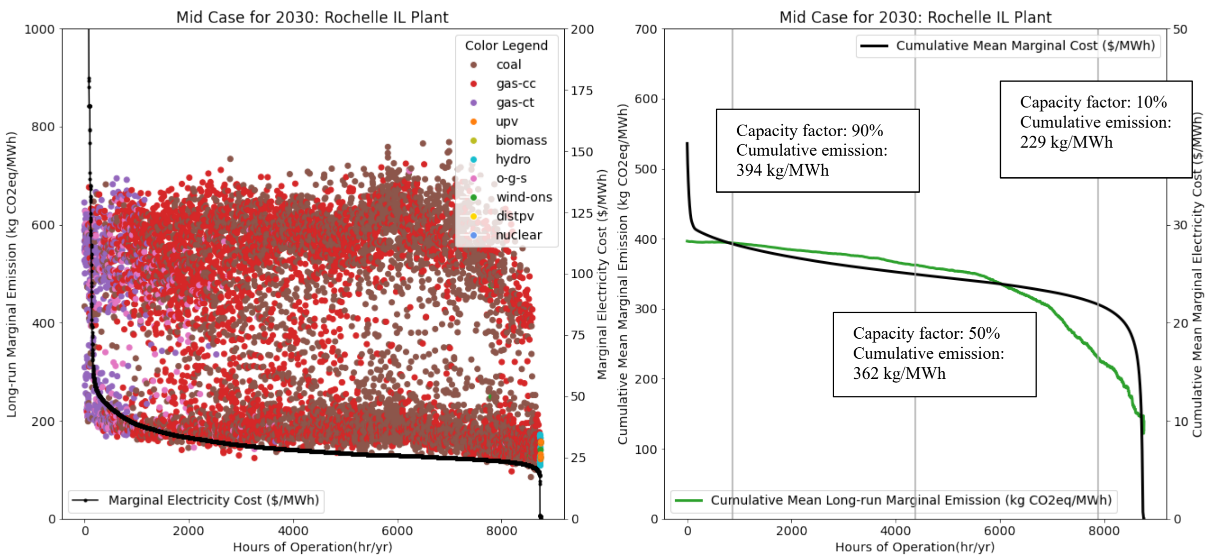

Figure 14. Mid-Case: Rochelle, Illinois, plant

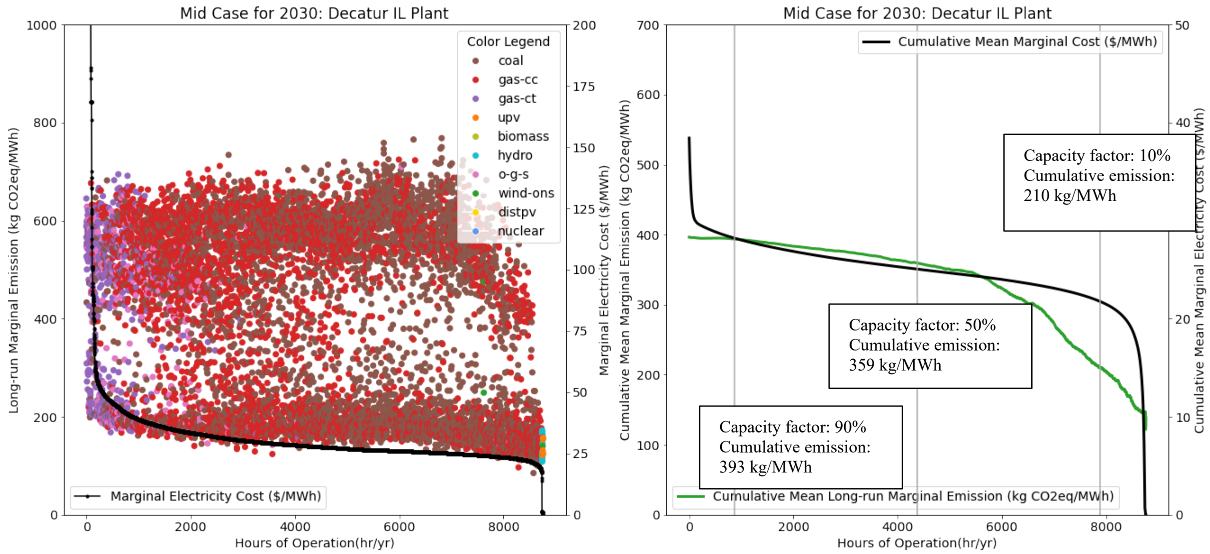

Figure 15. Mid-Case: Decatur, Illinois, plant

5.2.2 Low RE Case Results

Low RE Case model results for 2030 (Figure 16, Figure 17, and Figure 18) show more hours in the system with zero marginal electricity costs, which indicates greater renewable energy curtailment for these hours for resources like onshore wind (green dots), utility solar (orange dots), and distributed solar (yellow dots) in the region. Onshore wind and utility solar are more dominant renewable energy resources in our three studied areas. The vertical scatter lines, observed in hours when marginal electricity costs are zero, indicate the renewable generation induced or avoided by a long-term change in electrical demand and its marginal rate of emissions. For the hours when we start to see marginal energy costs greater than zero, there is a vertical scatter line for hydro energy. This indicates hydro energy on the margin and the cost of operating a hydropower facility is higher than wind and solar plants.

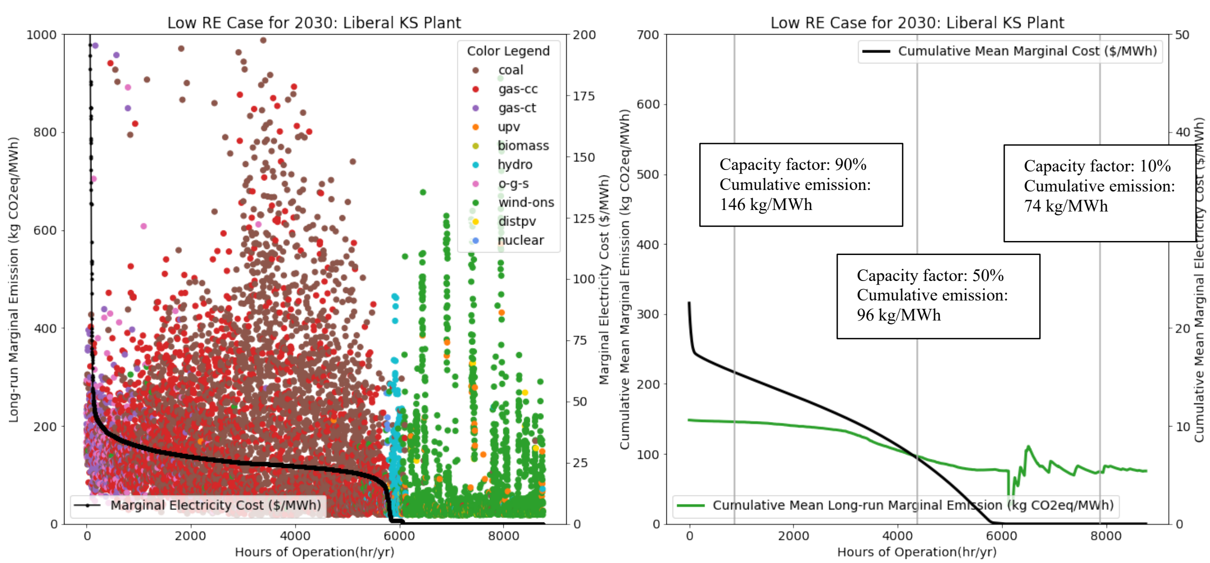

Figure 16. Low RE Cost Case: Liberal, Kansas, plant

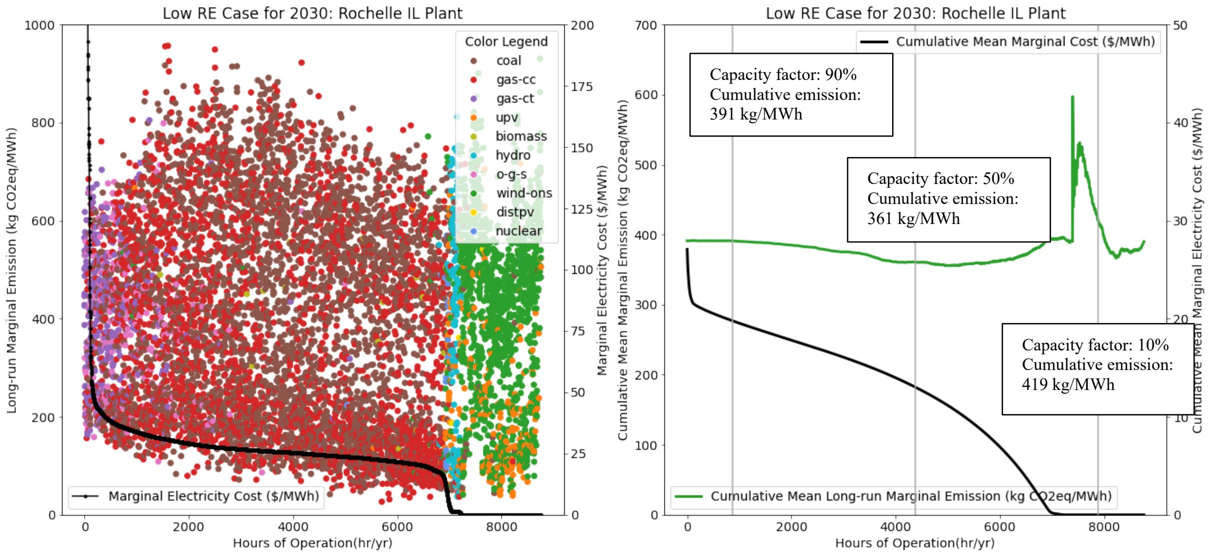

Figure 17. Low RE Cost Case: Rochelle, Illinois, plant

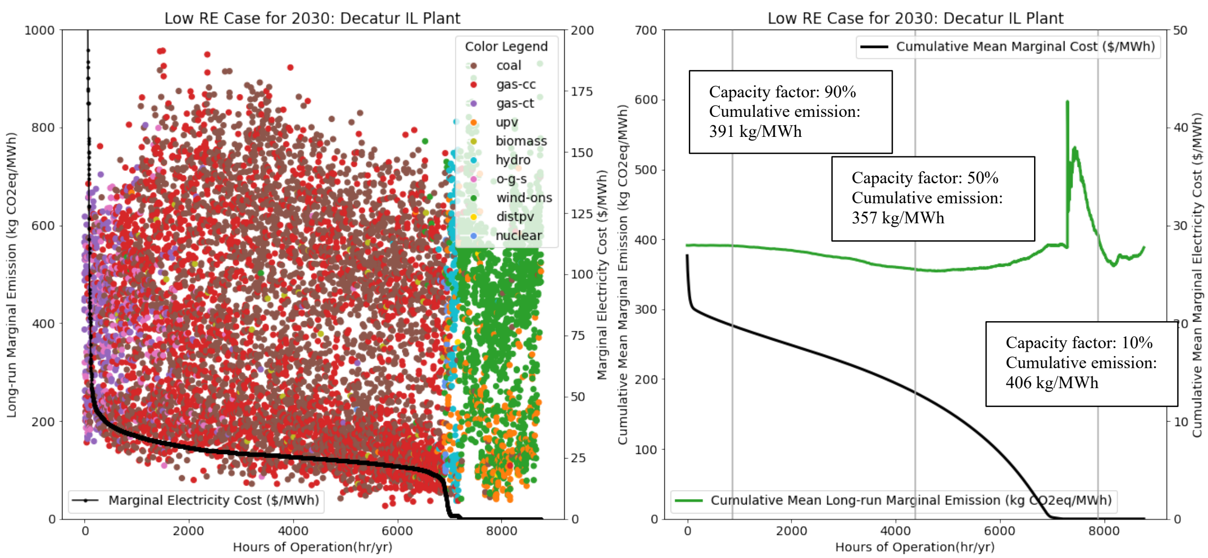

Figure 18. Low RE Cost Case: Decatur, Illinois, plant

5.3 Discussion, Caveats, and Limitations

Natural Gas Price: To estimate the potential impacts of recent gas price spikes in our analysis (EIA 2022), we manually adjusted the marginal electricity costs to be higher when the energy source on the margin is gas-combined cycle or gas-combustion turbine. As Figure 19 indicates, a lower capacity factor (fewer hours purchased) corresponds to primarily coal-driven emissions, and a higher capacity factor sees an emission rate driven by a greater contribution from gas-fired generation. Because increased natural gas prices are very likely to have a profound impact on grid buildout and dispatch, using the same marginal emission rate as the unadjusted case could introduce uncertainties and biases. Thus, these results should provide a sense of the impact, rather than being considered an analysis of higher natural gas prices.

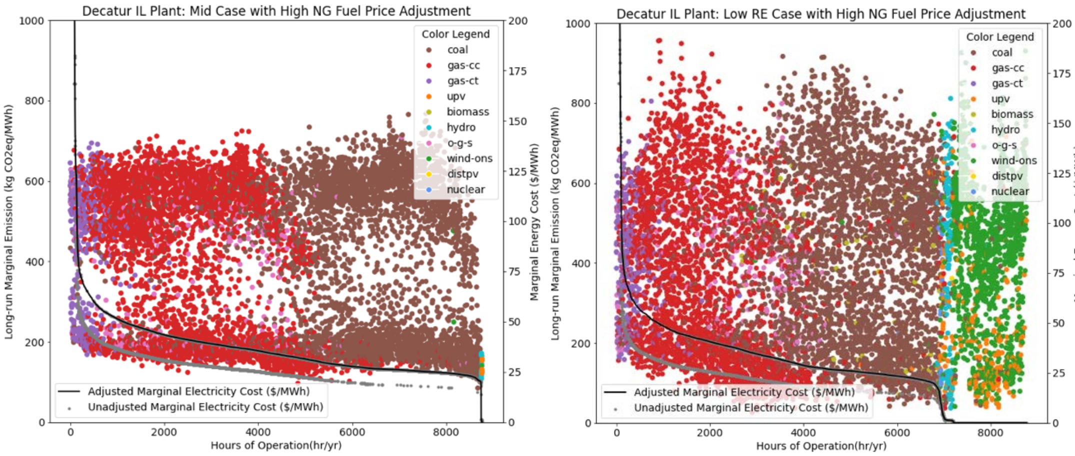

Figure 19. Mid-Case and Low RE Cost case with high natural gas fuel price adjustment for Decatur, Illinois, plant

Future Costs Projection: Future costs and emissions are based on modeled scenarios (from Cambium) that cannot accurately predict the future. These projections do not account for the impact of the CO2U unit on the rest of the system for both operation and investment outcomes. Furthermore, the modeled electricity costs may not accurately reflect the composition of future constituent cost components (i.e., energy, capacity, renewable compliance); see the caveat described in Section 4.8.

Long- and Short-Run Emission Rates: We use the long-run marginal emission rate in this analysis, which estimates emissions that would be either induced or avoided by a long-term change in the electric grid and electrical demand. The demand includes the incremental change that influences the structural evolution of the grid (i.e., new resource buildout, the retiring of capital assets such as generators and transmission lines). Long-run marginal emission rates also reflect the underlying evolution of the electric grid. Short-run marginal emission rates treat the electric grid assets as fixed (Gagnon 2021).

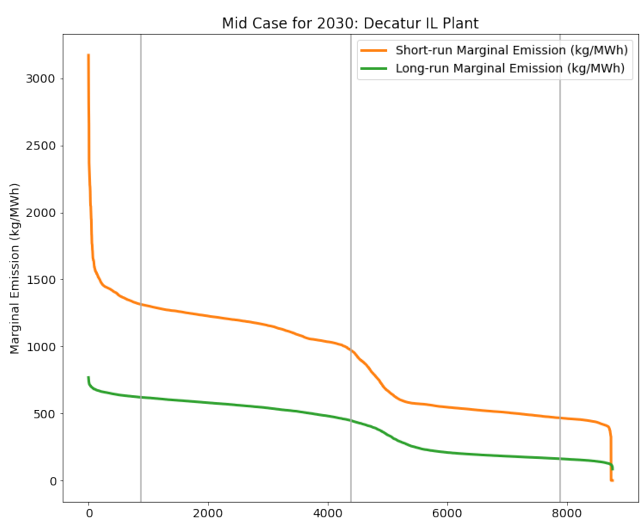

Figure 20. Mid-Case: Decatur, Illinois, plant long- and short-run marginal emission rates

The long-run marginal emission rate is lower than the short-run marginal emission rate. This is because the marginal energy source used to fulfill short-run electric demand is usually predominately natural gas and coal generators, whereas the long-term structural change in generation mixes often includes a greater contribution from renewable generators such as wind and solar, which results in a lower emission rate (Gagnon 2021).

Locations: We have focused on three illustrative ethanol plants, but these plants may or may not capture the full range of price and emission outlooks; in particular, the marginal emission rate and source can vary significantly by location.

6 Next Steps

This research assesses the location-specific electricity purchase prices, hourly electricity costs, and long-run marginal emission impacts for three preliminary CO2U facilities in the near term. In the future, the team will build up from the methodology and analysis in this report and further investigate the electricity costs, marginal generation mix, CO_2 sources, and CO2U product market size and value with coordinated input from NREL's TEA/LCA team and Argonne National Laboratory's MarkeRs & EEJ team.

In the near term, we will examine additional locations for sustainable aviation fuels produced through three identified pathways that can be put into production in 2030. In addition, we plan to examine the long-term CO2U market demand and size, CO_2 and hydrogen sources and transportation issues, the impact of the CO2U industry on power system buildout and operation, and the resulting electricity prices and CO_2 emissions, along with, in turn, their impact on the CO2U market in 2050.

The framework that we have developed in this report will be the starting point from which the medium- and long-term scenarios will be developed. The capability and the location-specific information we provide can be used to inform cost-efficient, low-carbon development of sustainable aviation fuel.

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Appendix A: Additional Summary Table

Table 11. Summary Table with Average $/$CO_2$ Tonne and Average $/GGE

Plant (Location)	Retail Rate		Physical PPA				Financial PPA				RTP	
			Without PTC		With PTC		Lower Bound		Upper Bound			
	$/$CO_2$ tonne	$/GGE	$/$CO_2$ tonne	$/GGE	$/$CO_2$ tonne	$/GGE	$/$CO_2$ tonne	$/GGE	$/$CO_2$ tonne	$/GGE	$/$CO_2$ ton	$/GGE
Liberal, KS Plant	636–641	6.4	199–329	2–3.3	23–153	0.23–1.5	206	2	278	2.8	259	2.6
Rochelle, IL Plant	430	4.3					249	2.5	337	3.4	314	3.1
Decatur, IL Plant	264	2.6					250	2.5	338	3.4	315	3.2