The Inflation Reduction Act: Fueling Clean Energy in the United States

Columbia University
School of International and Public Affairs

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Purpose of This Report

In the spring semester of 2024, a team of graduate students from the School of International and Public Affairs (SIPA) at Columbia University undertook a capstone project in partnership with Captona, a prominent North American investment firm specializing in constructing, acquiring, and operating renewable energy assets. This collaboration was initiated to examine the implications of the Inflation Reduction Act of 2022 (IRA) on the clean energy sector and identify strategic investment opportunities facilitated by this significant legislation.

Captona, with a robust portfolio that includes investments in wind, solar, fuel cell technology, renewable natural gas, and energy storage systems, has distinguished itself by repowering and enhancing aging solar and wind farms. With nearly $1 billion in deployed capital across 23 assets, the firm is keenly positioned to leverage the expanded incentives offered by the IRA, such as enhanced tax credits and new financial structures including tax credit transferability.

The team's research is guided by Jeanne Fox, a seasoned expert in environmental policy and administration. The project aims to dissect the IRA's key components, focusing on solar, wind, battery energy storage systems, alternative fuels, green hydrogen, and carbon capture technologies. The analysis encompasses evaluating new and expanded tax incentive structures, assessing market size and growth potential, and identifying capital deployment strategies within the industry.

The information contained herein is a combination of market research, economic analysis, and interviews with investors, researchers, and practitioners across the clean energy industry.

Acknowledgments

Contributors

Jerry Ding: BESS Functional Lead, Report Editor

Kathryn Ford: Alternative Fuels Functional Lead, Report Editor

Elizabeth Westbrook Gee: Wind Functional Lead, Report Editor

Hudson Hoyle: Project Manager, Wind Functional Support

Grant Opperman: CCUS Functional Lead

Shreya Tiwari: Hydrogen Functional Lead

Aurela Xie: Solar Functional Lead

Emma Yan: Research Manager, BESS Functional Support, Wind Functional Support

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Glossary

ATB: Annual Technology Baseline

ATJ: alcohol-to-jet

BESS: battery energy storage systems

CAISO: California Independent System Operator

CCUS: carbon capture, utilization and storage

CFPC: clean fuel production credit

CORSIA: Carbon Offsetting and Reduction Scheme for Aviation

CPUC: California Public Utilities Commission

DAC: direct air capture

DOE: Department of Energy

EIA: Energy Information Administration

EPA: Environmental Protection Agency

ERCOT: Electricity Reliability Council of Texas

FCA: Forward Capacity Auction

FT: Fischer-Tropsch

GE: General Electric

HEFA: hydroprocessed esters and fatty acids

IATA: International Air Transport Association

IRA: Inflation Reduction Act

ISO: Independent System Operator

ISO-NE: Independent System Operator for New England

ITC: investment tax credit

LCFS: Low Carbon Fuel Standard

LFP: lithium-iron phosphate

MMT: million metric tons

MWac: megawatt alternating current

NMC: nickel manganese cobalt oxide

NREL: National Renewable Energy Laboratory

NYISO: New York Independent System Operator

OCC: overnight capital cost

O&M: operations and maintenance

PEM: proton exchange membrane

PJM: Pennsylvania-New Jersey-Maryland Interconnection

PTC: production tax credit

PWA requirements: prevailing wage and apprenticeship requirements

RD: renewables diesel

REAP: Rural Energy for America Program

RFS: Renewable Fuel Standard

RIN: renewable identification number

RNG: renewable natural gas

SAF: sustainable aviation fuel

SGRE: Siemens Gamesa Renewable Energy

SPP: Southwest Power Pool

USDA: United States Department of Agriculture

WECC: Western Electricity Coordinating Council

WWTF: wastewater treatment facility

Introduction

Our report aims to analyze the Inflation Reduction Act of 2022 (IRA) and the investment opportunities that arise from this landmark legislation. By understanding the IRA's impact on the clean energy industry, we distill insights that could guide project sponsors in making the right investment decisions to shape a more sustainable future.

Our report starts with an overview of the Inflation Reduction Act's tax provisions, then takes a deep dive into six different technology pillars:

- Solar
- Onshore Wind
- Alternative fuels
- Carbon Capture, Utilization and Sequestration (CCUS)
- Battery Energy Storage Systems (BESS)
- Hydrogen

In each technology pillar, we assess the current market size, total addressable market, and expansion opportunities resulting from the IRA.

We analyzed both qualitative and quantitative data. We conducted an in-depth review of policy documents and industry research to condense key demand drivers and risk factors. Collecting data through desktop research and interviews with industry insiders, we built financial models that are representative of an average project and performed sensitivity analysis on different demand scenarios. Consolidating our findings, we identify additional capital needs created through the IRA and recommend promising ways for capital deployment. Finally, we conclude with remaining risks and challenges in investing in the renewable energy space.

General Impact of the Inflation Reduction Act

Across our market research and stakeholder interviews, we have found some common themes that describe the impact of the Inflation Reduction Act (IRA). The IRA has enabled many transformative benefits for the clean energy sector, but falls short of addressing other key challenges. We summarized the general impact in bullet points below:

Benefits of the IRA

- The IRA put in place a longer expiration timeline for tax benefits and ensured policy consistency for project developers.
- New credits for more nascent technologies–like CCUS and Hydrogen–spurred markets that were not financially viable.
- Tax credit transferability greatly expanded the market for project financing, creating more opportunities for small developers and riskier projects.

"The IRA gave a lot of optionality to the industry, allowing developers to choose the best tax benefit to fit their project."

- Senior Associate at an Investment Bank

Limitations of the IRA

- The IRA boosted new clean energy investments, but did not address the interconnection queue. Interconnection is becoming increasingly expensive and cumbersome in every single jurisdiction.
- NIMBYism is on the rise and the permitting process for new projects has become harder.
- In order for the industry to capture all of IRA's incentives, there needs to be greater grid capacity. Grid transmission capacity remains a key bottleneck in the buildout of renewable energy projects.

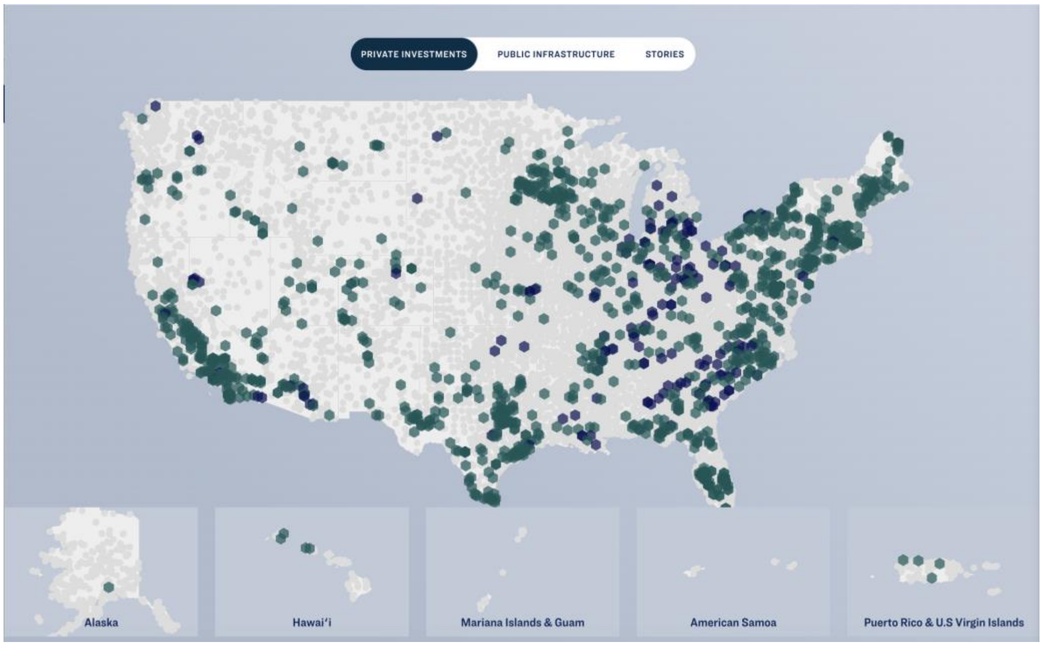
"70% of the IRA won't be realized if there is no increase in transmission capacity."

- CEO of an Infrastructure Investment Firm

IRA Impact on New Investment Deals

- **Deal flow:** The IRA did not increase deal flow for projects that previously did not need tax credits to be financeable. Projects with proven technology (e.g. solar, wind) that relied on tax credits are now considering more options to monetize tax benefits.
- **Regional focus:** The IRA has not driven a regional shift in project investments. The IRA has enabled more project buildout in the geographic areas most suitable to that technology.
- **Tax credit adders and investment decisions:** The adders themselves are not driving investments. Most projects are currently being developed and financed without considering adders. The 10% domestic content adder has attracted the most interest, with large developers signing multiyear contracts with manufacturing companies to shoulder the additional costs of domestic content.

Figure 1: Private Investment in Clean Power and Batteries Since 2021

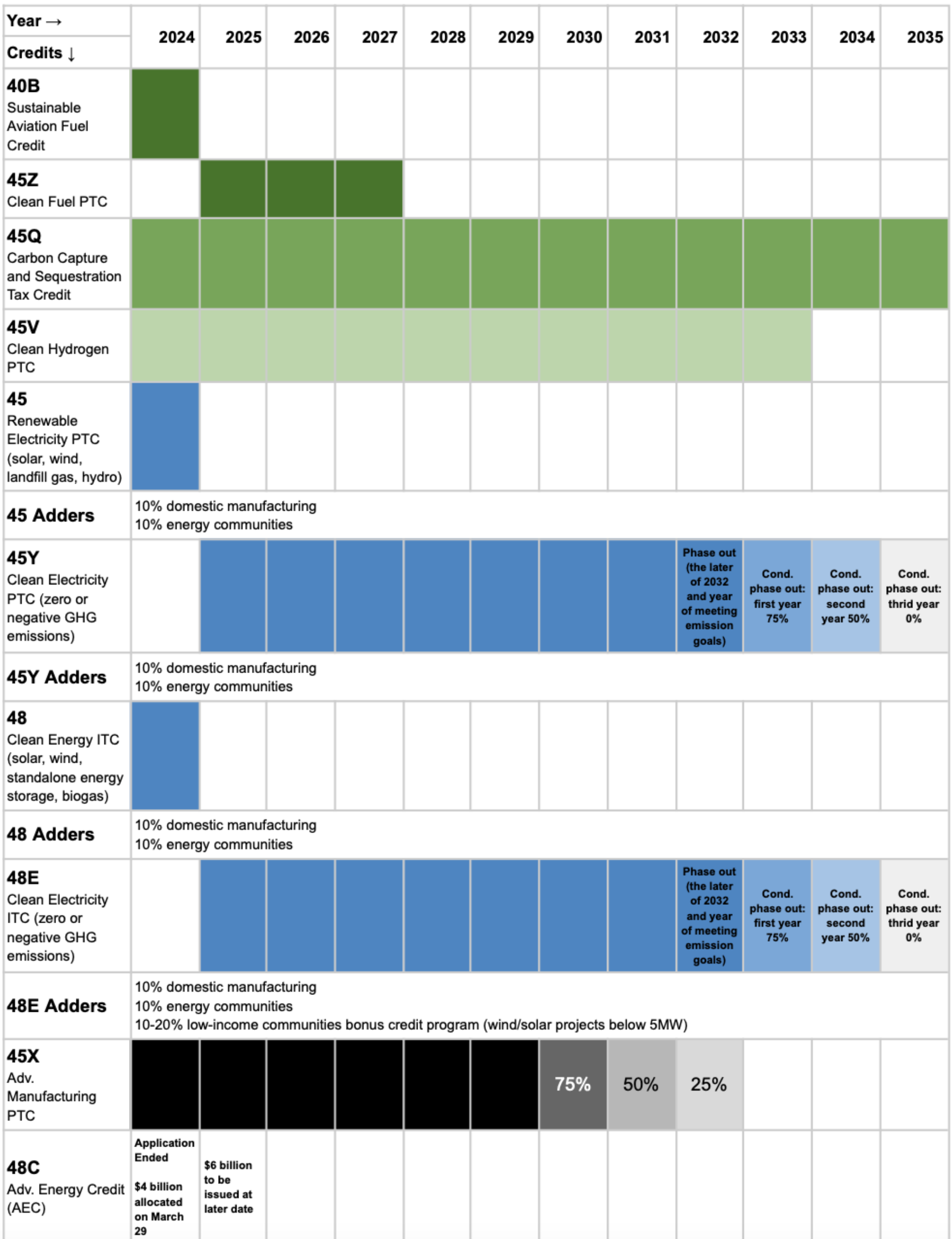


Source: Invest.gov

Inflation Reduction Act Tax Provisions

We carefully reviewed the Inflation Reduction Act and relevant guidance and regulations issued by the Department of Treasury. We have organized our findings in the charts below. In Figures 2 through 4, the first column orders and groups tax credits by category: clean fuel production (40B, 45Z), carbon capture (45Q), hydrogen (45V), clean electricity production (45, 45Y), clean electricity investment (48, 48E), and manufacturing (45X, 48C).

Figure 2: Timeline of Tax Credits



Source: Internal Revenue Service 2024a

Figure 3: Tax Credit Stackability

	40B Sustainable Aviation Fuel Credit	**45Z** Clean Fuel PTC	**45Q** Carbon Capture and Sequestration Tax Credit	**45V** Clean Hydrogen PTC	**45Y** Clean Electricity PTC (zero or negative GHG emissions)	**48E** Clean Electricity ITC (zero or negative GHG emissions)	**45X** Adv. Manufacturing PTC	**48C** Advanced Energy Credit (AEC)
40B Sustainable Aviation Fuel Credit	X	X						
45Z Clean Fuel PTC	X	X						
45Q Carbon Capture and Sequestration Tax Credit			X					
45V Clean Hydrogen PTC				X				
45Y Clean Electricity PTC (zero or negative GHG emissions)					X			
48E Clean Electricity ITC (zero or negative GHG emissions)						X		
45X Adv. Manufacturing PTC							X	
48C Advanced Energy Credit (AEC)								X

Source: Sadler 2023

X N/A

Explicit limitation on stacking

Legislation silent on stacking

Figure 4: Treasury Guidance Timelines as of April 25, 2024

IRA Tax Credits	IRS Guidance Timeline
40B Sustainable Aviation Fuel Credit	Minimum GHG reduction requirement: 12/15/2023
45Z Clean Fuel PTC	Guidance expected "early 2024" (but still not out); by 2025 at the latest
45Q Carbon Capture and Sequestration Tax Credit	Instructions for claiming the credit: Decermber, 2023
45V Clean Hydrogen PTC	Proposed rulemaking and notic of public hearing: 12/26/2023
Phaseout for elective payment projects **(45, 45Y, 48, 48E)**	Statutory Exceptions to Domestic Content Requirements: 12/28/2023
10% Domestic content adder **(45, 45Y, 48, 48E)**	Initial guidance: 05/12/2023
10% Energy communties adder **(45, 45Y, 48, 48E)**	Additional guidance: 04/04/2023 Census tracts: 05/31/2023
10-20% LMI adder **(48, 48E)**	Final regulation: 08/15/2023
45X Adv. Manufacturing PTC	Notice of proposed rulemaking and public hearing: 12/15/2023
48C Advanced Energy Credit (AEC)	Additional guidance: 05/31/2023

Source: Internal Revenue Service 2024a

Tax Transferability

One fundamental change that the IRA enabled is the transferability of tax credits. Although currently nascent, the market for tax credit transfers is projected to ramp up as the Internal Revenue Service releases finalized guidelines and industry players become more familiar with the process. Based on observations of existing transactions, insurance is being baked into the pricing of tax credit transfer deals. So far, main buyers are large corporations or financial institutions who would transfer tax credits to their high-net-worth clients. Banks are also willing to lend against tax credit transfer agreements and extend bridge loan facilities at a discount, provided that buyers have strong credit ratings. It is worth noting that, given the different risk profiles of investment tax credits (ITCs) and production tax credits (PTCs), banks place a more material discount on PTC transfer agreements to account for variable generation.[1]

"Tax credit transferability is the game changer [...] but the market needs a lot more time to develop."

- Professional at a Senior Lender

[1] One senior lender quoted an advance rate of 97-98 cents on the dollar for bridge loan facilities for projects selling ITCs. The rate drops to 94-96 cents on the dollar for a project with a 10-year PTC purchase agreement. For a project with 10 years of project life and only a 5-year PTC purchase agreement, the rate is 90 cents on the dollar for the first 5 years (covered by the purchase agreement) and drops to 50-60 cents for the remaining 5 years.

Based on our interviews, project sponsors are optimistic about tax credit transferability. The ability to sell tax credits effectively provides financing for small developers who don't have access to tax equity. Moreover, tax credit broker platforms have emerged to help small developers find buyers and save on legal fees. Meanwhile, the tax credit transfer market also faces serious limitations. Project sponsors cannot monetize depreciation benefits and face large discounts when selling tax credits. Tax credit transfer itself does not allow for an FMV step-up on the ITC basis, which could lead to 10-20% loss in ITC value compared to a traditional tax equity partnership. However, developers can and have used work-around structures where the project is sold to a joint venture with another equity partner to effectuate the FMV step-up (Davis, 2023).

"Tax credit transfers ideally should enable easier documentation and faster execution. However, recently the new type of complex structure called a 'T-Flip' brings us back to square one."

- Managing Director at a Senior Lender

A hybrid model called the "T-flip" has recently emerged as an attempt to surpass some of the limitations on tax credit transfer and enable more players to participate. In essence, "T-flip" deals are structured as a single point transaction between a project developer and a bank group. The bank group will take on most of the recapture risk through tax equity partnership, monetize depreciation benefits, and sell any leftover tax credits that they don't need. However, such a convoluted structure adds back the processing burden that tax transfer deals are seeking to avoid.

Figure 5: Tax Credit Transferability

IRA Tax Credits	Eligible for Direct Pay	Eligible for Transferability
40B Sustainable Aviation Fuel Credit	No	No
45Z Clean Fuel PTC	Yes	Yes
45Q Carbon Capture and Sequestration Tax Credit	Yes	Yes
45V Clean Hydrogen PTC	Yes	Yes
45 Renewable Electricity PTC (solar, wind, landfill gas, hydro)	Yes	Yes
45Y Clean Electricity PTC (zero or negative GHG emissions)	Yes	Yes
48 Clean Energy ITC (solar, wind, standalone energy storage, biogas)	Yes	Yes
48E Clean Electricity ITC (zero or negative GHG emissions)	Yes	Yes
45X Adv. Manufacturing PTC	Yes	Yes
48C Advanced Energy Credit (AEC)	Yes	Yes

Source: Internal Revenue Service 2024b

Tax Credit Eligibility

For each technology pillar, we summarized eligible credits and requirements in Figure 6. The columns "Eligible Tax Credits" and "Adders" together make up the base rate of the tax credit. The column "If Satisfies Prevailing Wage" applies a "5x" multiplier to the base rate for projects that satisfy the prevailing wage and apprenticeship requirements. The column "If in Low-Income Communities" assigns an additional 10-20% bonus ITC credit to projects that applied and qualified for the Low-Income Communities Bonus Credit Program. The final column "Maximum Eligible Tax Credits" shows the maximum amount of tax credits that a project can possibly claim.

Figure 6: Tax Credit Eligibility by Technology Pillar

Technology	**Solar**	**Wind**	**BESS**	**Alternative Fuels**		**Hydrogen**	**CCUS**		
Eligible Tax Credits	**45, 45Y/48, 48E:** 6% base rate	**45, 45Y/48, 48E:** 6% base rate	**48, 48E:** 6% base rate	**40B:** $1.25/gallon	**45Z: for clean fuel produced at <50 kg CO2/mmBTU** Maximum 20¢/gallon for nonaviation fuel, adjusted for emission factor Maximum 35¢/gallon for aviation fuel, adjusted for emission factor	**45V:** calculated based on 45VH2-GREET model	**45Q:** $17/metric ton of CO2 base rate for **geologically sequestered** CO2	**45Q:** $12/metric ton of CO2 base rate for **geologically sequestered CO2 with enhanced oil recovery**	**45Q:** $12/metric ton of CO2 base rate for **other qualified use of CO2**
Adders	2% base rate for Domestic Content (min 40% of direct costs) 2% base rate for Energy Commmunities	2% base rate for Domestic Content (min 40% direct costs for onshore, min 20% for offshore) 2% base rate for Energy Commmunities	2% base rate for Domestic Content (min 40% of direct costs) 2% base rate for Energy Commmunities	1¢/gallon for each pp. over 50% reduction of the life cycle GHG emissions for the SAF as compared to petro-based jet fuel	n/a	n/a	DAC: raise to $36/metric ton of CO2 base rate	DAC: raise to $26/metric ton of CO2 base rate	DAC: raise to $26/metric ton of CO2 base rate
If Satisfies Prevailing Wage	x5 bonus on the base rate with adders	x5 bonus on the base rate with adders	x5 bonus on the base rate with adders	n/a	Raise cap to $1.75 /gallon for aviation fuel Raise cap to $1/gallon for non-aviation fuel	n/a	Raise to $85/metric ton of CO2 Raise to $180/metric ton of CO2 for DAC	Raise to $60/metric ton of CO2 Raise to $130/metric ton of CO2 for DAC	Raise to $60/metric ton of CO2 Raise to $130/metric ton of CO2 for DAC
If in Low-Income Communities	10-20% for qualified projects < 5MW Applies to 48, 48E ITC only	10-20% for qualified projects < 5MW Applies to 48, 48E ITC only	10-20% for qualified projects Must be co-located with solar/wind and has capacity < twice of the connected facility	n/a		n/a	n/a		
Maximum Eligible Tax Credits	50% for projects > 5MW 70% for projects < 5MW	50% for projects > 5MW 70% for projects < 5MW	50% for standalone BESS 70% for co-located BESS < 10MW	Capped at $1.75 /gallon	$1.75/gallon for aviation fuel $1.00/gallon for non-aviation fuel	Capped at $3.00/kg	$180/metric ton of CO2 for geologically sequestered CO2 using direct air capture		

Source: Internal Revenue Service 2024a

For instance, a solar project that qualifies for both the domestic content adder and the energy communities adder will have a base rate of 6% + 2% + 2% = 10%. If the project further satisfies the prevailing wage requirements, a "5x" bonus multiplier will be applied to the 10% base rate to arrive at 10% x 5 = 50% ITC/PTC. If the project has a nameplate capacity of less than 5MW, applied for the Low-Income Communities Bonus Credit Program, and is awarded an additional 20% ITC, the project will achieve the maximum amount of eligible tax credits–70%.

Prevailing Wage and Apprenticeship Requirements

By meeting the requirements below, project developers can increase the base rate incentive by 5 times:

- "Pay laborers and mechanics employed in construction, alteration or repair no less than applicable prevailing wage rates" and
- "Employ apprentices from registered apprenticeship programs for a certain number of hours" (Internal Revenue Service 2024c)

The "5x" multiplier makes a material difference for the amount of tax credits that a project can claim. Hence, it is expected that these requirements will become the industry norm and be incorporated into standard EPC contracts.

Domestic Content Adder

A project qualifies for an additional 2% base rate if, upon completion of construction, have no less than the "adjusted percentage" of the total costs of manufactured components that are mined, produced, or manufactured in the United States. The "adjusted percentage" is 20% for an offshore wind facility and 40% for an onshore wind, solar, or battery storage facility. For onshore wind, solar, or battery storage facilities whose construction begins after 2026, the "adjusted percentage" increases to 55%. For offshore wind facilities whose construction begins after 2027, the "adjusted percentage" increases to 55% (IRS Notice 2023-38).

"Starting 2026, we will see domestic projects having a better economic profile than non-domestic projects."

- Head of M&A, a Utility-Scale Solar and Storage Developer

Conditional on satisfying the prevailing wage requirements, the domestic content adder offers an additional 10% tax credits. Developers need to evaluate the tradeoff between additional tax benefits and higher EPC as well as labor costs. Our interviews with project developers show a cautious interest. Many believe the benefits won't materialize until after a couple of years. The major concern pertains to the long lead time of domestic manufacturing. For instance, a senior engineer at a manufacturer points out that the wait time for domestic transformers and converters is at least 2-3 years.

Energy Community Adder

A project that meets energy community provisions can claim an additional 2% base rate. The IRA and the Department of Treasury have provided detailed definitions of energy communities (Interagency Working Group on Coal & Power Plant Communities & Economic Revitalization 2024):

- A "brownfield site" as defined in the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA)
- A "metropolitan statistical area" or "non-metropolitan statistical area" that has significant employment or tax revenue related to the fossil fuel industry and has above-national-average unemployment rate
- A census tract or directly adjoining census tract where a coal mine has closed after 1999 or where a coal-fired power plant has been retired after 2009

From interviewing project developers, the energy community adder is being treated as a "good-to-have". The project itself needs to make economic sense without factoring in the adder. Meanwhile, the geographic distribution of the energy communities does create some unique opportunities in regulated markets. According to the head of M&A at a utility-scale solar developer, in regulated markets where qualified energy community areas are sparse (e.g. Georgia, North Carolina, South Carolina), a solar project located in an energy community area has a decisive competitive advantage in winning request for proposals (RFPs). In contrast, in regulated markets where qualified energy community areas are plenty (e.g. Mississippi), there is no competitive advantage for projects claiming the adder.

Low-Income Adder

The Low-Income Communities Bonus Credit Program awards an additional 10% to the Section 48 ITCs to qualified solar and wind projects in low-income communities or on Indian Land. If the facility is built as part of a Qualified Low-Income Residential Building Project or a Qualified Low-Income Economic Benefit Project, this additional bonus is bumped up to 20% (U.S. Department of Energy 2024). These additional credits are referred to as the “Low-to-moderate (LMI) Income Adder.” According to the final regulations that the IRS published on August 15, 2023 (IRA 2023-17078), eligible solar and wind projects must have lower than 5MW net capacity. Eligible co-located battery projects must be charged at least 50% by the connected facility, or have a power rating that is less than 2 times the capacity rating of the connected facility.

Figure 7 presents the allocated and remaining capacity of the Low-Income Communities Bonus Credit Program (U.S. Department of Energy 2024). We can see that industry players have exhausted the Eligible LI Community Project Option. Community solar developers acknowledged that the LMI adder is helpful, but more projects are being built without considering the adder. For community solar projects, each new market needs to be legislatively enabled (e.g. Virginia’s shared solar program). Once there is state legislation support, a 30% ITC is sufficient to improve project economics and reduce project attrition.

Figure 7: Low-Income Communities Bonus Credit Program Allocation Dashboard

Category Type	Application Option	Total Capacity (MW)	Approved Allocations (MW)	Applications Pending Allocation (MW)	Capacity Remaining (MW)
Category 1	Eligible Residential Behind-the-Meter (BTM)	245	304	0	0
Category 1	Eligible Residential BTM – Additional Selection Criteria	245	91	0	154
Category 1	Other Eligible LI Community Project	105	0	3,071	0
Category 1	Other Eligible LI Community Project – Additional Selection Criteria	105	207	465	0
Category 2	Located on Indian Land	100	18	0	82
Category 2	Located on Indian Land - Additional Selection Criteria	100	23	0	77
Category 3	Qualified Low-Income Residential Building Projects	100	102	1	0
Category 3	Qualified Low-Income Residential Building Projects - Addt'l Selection Criteria	100	35	0	65
Category 4	Qualified Low-Income Economic Benefit Projects	350	145	2,983	0
Category 4	Qualified Low-Income Economic Benefit Projects - Addt'l Selection Criteria	350	539	88	0

Source: U.S. Department of Energy 2024

Onshore Wind Energy

Onshore Wind Energy

Key Insights for Onshore Wind Investment

We believe that onshore wind technology is a promising investment opportunity because of the standardization of PPA contracts and declining costs per kilowatt hour. Furthermore, it is likely that the Inflation Reduction Act's (IRA) Domestic Content Adder will reduce the United States' dependence on European turbine supply chains. One trend that emerged from our interviews was how wind energy development's "cookie cutter" nature has equally apparent pros and cons (Ozturkeri 2024). On one hand, onshore wind development isn't as attractive to developers and investors as it was in previous decades because turbine technology has stagnated. Turbines became more effective simply by making them bigger, and small-scale residential wind never took off. In summary, onshore wind technology today is "old news." However, this long legacy in the U.S means that onshore wind contracts are also "cookie cutter" (Ozturkeri 2024). The standardization of PPA contracts makes onshore wind significantly less risky than newer technologies, such as hydrogen fuel cells. The downside of this standardization is that in states like California, the best wind resources have already been developed. Therefore, we believe that the New England Independent System Operator (ISO-NE) is ideal for onshore wind investments because of the region's untapped resources, supportive regulatory structures, low costs per kilowatt hour, and transmission opportunities.

The largest risk when pursuing wind development is the global nature of turbine supply chains. 75% of the turbines being used in the U.S' installed wind capacity are manufactured by General Electric (GE), Vestas, Siemens Gamesa (SGRE), and Siemens AG. GE is the only major manufacturer of wind turbines that is headquartered in the United States. The other manufacturers are headquartered in Germany, Denmark, and Spain, which means that U.S. wind development relies on European manufacturing. Historically, turbine supply chains between the U.S and Europe have not been hindered but it remains a risk. However, we believe that most of this risk will be circumvented by the IRA's domestic content credit adder. The domestic content adder gives the only U.S based turbine manufacturer, GE, a competitive advantage (Analyst From a Large O&M Company, 2024). New U.S onshore wind projects are incentivized to buy from GE, which in turn encourages GE to build more domestic factories. The reshoring of wind turbine manufacturing will take many years, but it will eventually minimize U.S. wind developers' reliance on European supply chains.

The tax credits created by sections 45X, 45Y, and 48E of the U.S. Internal Revenue Code (IRC) are the most pertinent to onshore wind development. Section 45X provides tax credits for companies who manufacture advanced components used in renewable energy projects, section 45Y states that project owners receive production tax credits (PTC) per kilowatt hour of renewable electricity they generate, and 48E explains that companies who invest in renewable energy projects receive a percentage of their investment back in the form of investment tax credits (ITC). PTC and ITC are transferable (Murray 2023) but the Advanced Manufacturing credit under 45X is not.

The IRA benefitted all renewable energy developers by creating and extending policy incentives. Credits offered under IRA will phase out in 2032 or when total greenhouse gas emissions in the power sector decline to at least 75% below 2022 levels. IRA helped wind developers by extending tax credits' applicability timeline and raising wind's PTC value. PTCs and ITCs have been available to wind developers since the Energy Policy Act of 1992 (EIA 2012). The IRA helped wind developers by raising the value of PTCs from 2.2¢ per kilowatt hour to 2.6¢ per kilowatt hour for the first ten years of a project's operation. The 2009 American Recovery and Reinvestment Act (ARRA) set the PTC for wind technology at 30% of the credit's value. IRA raised the credit value for wind and all other renewable technologies, except batteries, to

60% for projects constructed after 2022 (DOE 2022). Lastly, the IRA extended the credits' phase out timeline from 2025 to 2032.

Wind energy projects qualify for the IRA's stackable credit bonuses, also known as adders. The Prevailing Wage and Apprenticeship (PWA) adder stipulates that for a number of the tax credits created or modified by the IRA, the base credit amount is increased by five times for projects that meet requirements for paying prevailing wages and using registered apprentices. The Domestic Content adder gives onshore wind projects a 10% credit bonus if they are built with 100% domestic steel or iron and 40% domestically-manufactured components (DOE 2022). The Energy Communities adder grants wind projects operating in communities with fossil fuel-based economies or brownfield sites receive a 10% credit bonus.[2] Finally, the Low-Income adder rewards wind projects under five megawatts for operating in low-income or tribal communities with a 10% stackable credit bonus. Developers must apply for the Low-Income Communities adder but do not need additional applications for the PWA and Domestic Content adders.

Tax credits rolled out by IRA and unblocked supply chains post pandemic led the U.S. to add 8.5 gigawatts of wind power capacity in 2022. By the end of 2022, the U.S' cumulative onshore wind capacity was 144 gigawatts (DOE 2023). These new onshore wind projects constituted 22% of all new renewable energy development projects, making it the second most popular technology after solar. The majority of new wind development occurred within the Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP). These two regions remain ideal for wind development because of their lower construction costs compared to other ISOs, historical leadership in wind development, and unique grid infrastructure (DOE 2023).

Through our interviews we found that the IRA counteracted onshore wind developers' increasing material costs by tackling high inflation rates but it did not address five other key issues (Silverman and Tandon 2024). Developers interested in onshore wind investment will still have to contend with limited transmission opportunities, interconnection costs, land permitting challenges, competition with substitute energy generation forms, and the global nature of wind turbine supply chains.

Technology

Dominant and Proven Technology

A wind turbine generates electricity by converting the aerodynamic force of airflow. The spinning rotor blades are connected to the generator, either directly or through a gearbox that speeds up the rotation and enables a smaller-size generator (DOE).

There are two main types of wind turbines: horizontal-axis and vertical-axis turbines. Vertical-axis turbines have the advantage of being omnidirectional–they don't need to face into the wind to generate electricity. There has been some adoption of vertical-axis turbines by small commercial operators or individuals on building rooftops and other urban

[2] Energy community is defined as (1) an area with 0.17% or greater direct employment or 25% or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas; and has an unemployment rate at or above the national average unemployment rate for the previous year, or (2) a census tract in which a coal mine has closed after 1999; or in which a coal-fired electric generating unit has been retired after 2009.

locations. In contrast, all utility-scale projects adopt horizontal-axis turbines because they demonstrate better performance and achieve higher wind energy efficiency (EIA 2024).

Different turbines apply to different settings. Land-based wind projects benefit from the cost-effectiveness of grouping large wind turbines (several megawatts each) to generate bulk power for the grid. Currently, most offshore wind turbines are installed on fixed-platforms and are more common along the east coast where seabed conditions are more favorable. West coast states like California are also investing in research for floating offshore wind to capture higher wind potential.

Promising Innovations

NREL research efforts have focused on achieving longer blades, taller towers, and low-specific-power wind turbines. Other innovations mainly involve operational improvements, such as advanced tower manufacturing that enables on-site creation of wind turbines, climbing cranes to enable efficient turbine installation and reduced costs in moving conventional cranes, as well as wake steering to achieve 1%-2% annual energy production gains (NREL 2023). Venture capital is being channeled into artificial intelligence and robotics & automation in wind farm optimization (Harrison-Atlas et al. 2022).

Project Economics

Revenue Trends

Wind power purchase agreement prices have been rising since approximately 2018, with a recent range from below $20/MWh to more than $40/MWh (DOE 2023).

Non-utility buyers entered into more contracts to purchase wind than did utilities in 2022. Direct retail purchasers of wind—including corporate offtakers—buy electricity from at least 44% of the new wind capacity installed in 2022 (DOE 2023).

Cost Trends

Despite a decline by 50% between 2008 and 2020, recent supply chain pressures and elevated commodity prices have led to increased turbine prices over the last several years: $900/kW - $1,200/kW5 on average (a level roughly similar to that last seen in 2017 and 2018 and up from a range of $800-$1,000/kW for 2019–2021) (DOE 2023).

Installation costs differ by region, with the lowest-cost projects in ERCOT (averaging $1360/kW) and SPP ($1470/kW), and MISO ($1730/kW) (DOE 2023).

Levelized costs vary by region, with the lowest costs in SPP and ERCOT. The lowest average LCOEs for projects built in 2021 and 2022—only considering regions with at least two plants in the sample—are found in SPP and ERCOT (both ~$33/MWh on average), with PJM averaging the highest at $46/MWh (DOE 2023).

Despite limited data, recent projects (last 16 years) show lower O&M costs than older ones. O&M costs tend to rise with project age, especially for older projects analyzed (DOE 2023).

PTC vs ITC Project Financing Decisions

Figure 8: Installation and Interest Cost for PTC Decision

Installation & Interest Costs (After-Tax Levered IRR) - PTC							
	Interest Rate						
Installation $ Cost per KWH	5.2%	5.7%	6.2%	6.7%	7.2%	7.7%	8.2%
$ 1,600	25.1%	24.1%	23.2%	22.4%	21.6%	21.0%	20.4%
$ 1,650	23.2%	22.3%	21.6%	20.8%	20.2%	19.6%	19.1%
$ 1,700	21.6%	20.8%	20.1%	19.5%	18.9%	18.4%	17.9%
$ 1,750	20.1%	19.5%	18.9%	18.3%	17.8%	17.3%	16.9%
$ 1,800	18.9%	18.3%	17.7%	17.2%	16.8%	16.3%	15.9%
$ 1,850	17.7%	17.2%	16.7%	16.2%	15.8%	15.4%	15.1%
$ 1,900	16.7%	16.2%	15.8%	15.4%	15.0%	14.6%	14.3%

Figure 9: Installation and Interest Cost for ITC Decision

Installation & Interest Costs (After-Tax Levered IRR) - ITC							
	Interest Rate						
Installation $ Cost per KWH	5.2%	5.7%	6.2%	6.7%	7.2%	7.7%	8.2%
$ 1,600	24.2%	24.1%	23.9%	23.8%	23.6%	23.4%	23.2%
$ 1,650	23.6%	23.5%	23.3%	23.1%	23.0%	22.8%	22.6%
$ 1,700	23.0%	22.9%	22.7%	22.5%	22.4%	22.2%	22.0%
$ 1,750	22.4%	22.3%	22.1%	22.0%	21.8%	21.6%	21.4%
$ 1,800	21.9%	21.8%	21.6%	21.4%	21.2%	21.1%	20.8%
$ 1,850	21.4%	21.2%	21.1%	20.9%	20.7%	20.3%	19.5%
$ 1,900	20.9%	20.7%	20.6%	20.4%	20.0%	19.1%	18.4%

A sensitivity analysis of several independent variables including interest rates and installation costs illustrates that ITC is typically the preferred tax incentive for wind developments, since the financial impact of PTCs can be highly dependent on interest rate outlook. However, due to the varying cost and performance profiles of wind projects across the U.S., certain confounding variables such as Net Capacity Factor may affect whether PTC or ITC is more economically beneficial to developers. Each project should be modeled individually to determine which tax credit is most beneficial to investors and developers.

Onshore Wind Markets

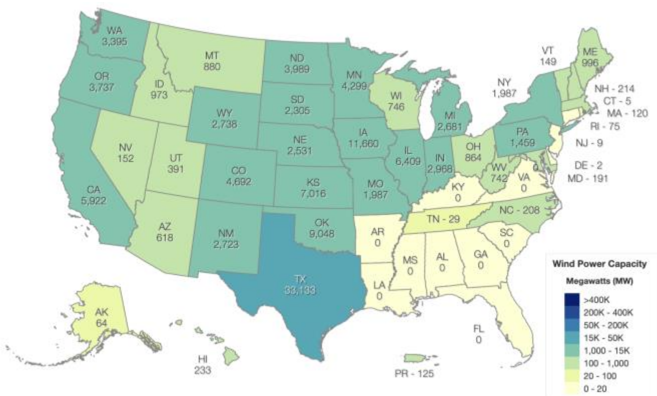
Wind manufacturing is a highly concentrated industry with four main competitors in the U.S.– General Electric (GE), Vestas, Siemens Gamesa Renewable Energy (SGRE) and Siemens Aktiengesellschaft. 75% of turbines used in installed onshore wind development in the U.S. are from one of these four companies (EIA 2016).

Although wind turbine prices declined by 50% between 2008 and 2020, recent supply chain pressures and elevated commodity prices have led to increased turbine prices. Still, manufacturing profits remain highly constrained and, at times, negative.

Wind is the second largest source of U.S. electric-power capacity additions in 2022 at 22%, behind solar's 49%. However, in certain markets, wind represents a larger fraction of new capacity–e.g. SPP (85%), ERCOT (49%), MISO (47%), and non-ISO West (30%) where it enjoys more favorable economics due to higher net capacity factors, PPA prices, and interconnection to the grid (DOE 2023).

Geography plays an important role in the economic profile of wind developments, with capacity factors and LCOEs varying significantly across regions.

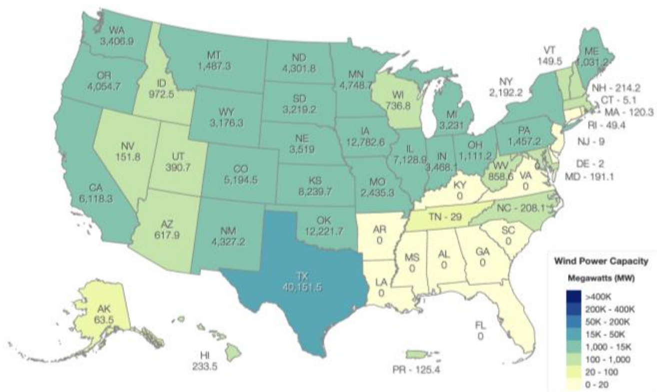
Figure 10: Installed Wind Capacity in 2020 (MW)



Total Installed Wind Capacity: 122,465 MW

Source: U.S. Department of Energy

Figure 11: Installed Wind Capacity by State in 2022 (MW)



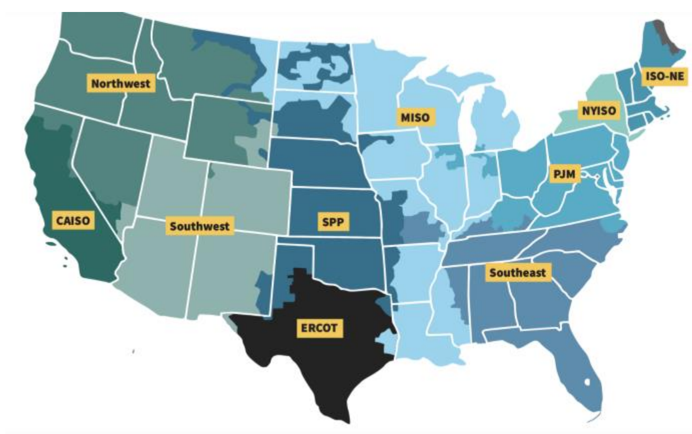
Total Installed Wind Capacity: 144,133 MW

Source: U.S. Department of Energy

Regional Markets Analysis

There are ten Independent System Operators (ISOs) in the United States that oversee the operation of regional electrical grids. Each ISO regulates the generation, transmission, and distribution of electricity in the states within their assigned region. Their primary responsibility lies in managing the flow of electricity across high-voltage transmission lines, ensuring that generation matches demand in real-time to maintain grid stability (FERC). Additionally, ISOs operate wholesale electricity markets where generators sell power to utilities and other participants, employing mechanisms like auctions to determine prices and allocate resources efficiently. They play a pivotal role in dispatching power, balancing supply and demand, and overseeing grid planning to ensure reliability and efficiency. Each ISO's unique market characteristics create unique opportunities and challenges for onshore wind developers. Therefore, it is important for renewable energy developers to understand how each of these diverse regional environments could affect their project outcomes (FERC).

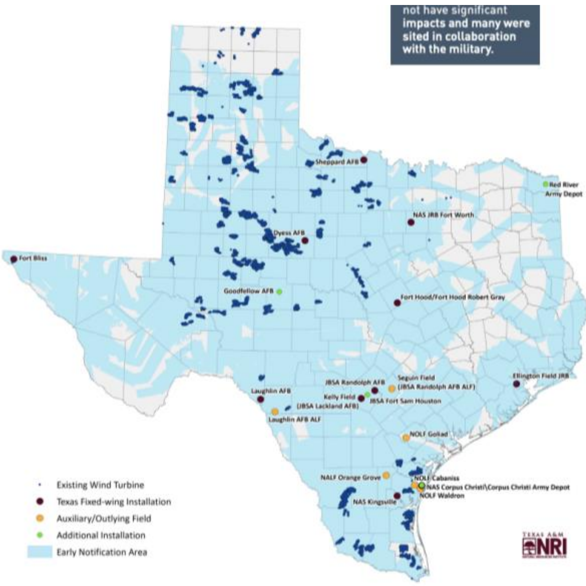
Figure 12: Map of the U.S. Regional Independent Systems Operators (ISOs)



Source: Federal Energy Regulatory Commission

The Electric Reliability Council of Texas (ERCOT)

Figure 13: Map of Operating Onshore Wind Turbines in Texas



Source: Texas A&M University

The Electric Reliability Council of Texas (ERCOT) operates the largest wind energy market in the United States. The DOE estimates that wind penetration for ERCOT in 2022, as expressed as a percentage of total load, is 24.2%. 49% of the nation's total 8.5 gigawatts of new wind capacity was constructed in Texas (DOE 2023). New wind projects account for 10% of Texas's interconnection queue. ERCOT stands out as a particularly favorable region due to its vast land area, strong and consistent wind resources, supportive regulatory environment, deregulated electricity market, and growing demand for renewable energy. Wind development in Texas is concentrated in the northwestern and southeastern portions of the state (DOE).

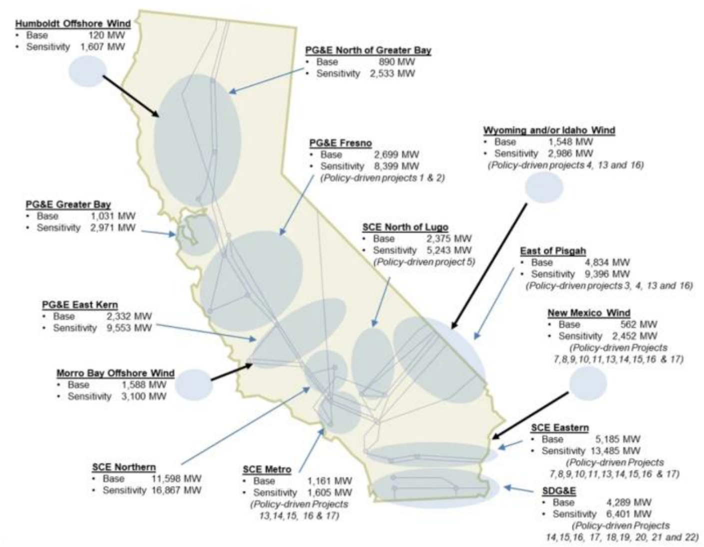
ERCOT has invested heavily in its transmission infrastructure to accommodate the growth of renewable energy, including onshore wind. ERCOT is unique in that decades ago grid transmission lines were built to where scientists thought successful wind projects would be sited (Silverman, 2024). This foresight allowed ERCOT to largely avoid physical transmission connectivity issues that many other ISOs spread over a large area face. The region benefits from a robust network of transmission lines that can efficiently transport electricity from wind-rich areas to population centers and major load centers. This infrastructure development has reduced congestion and improved the reliability of the grid, further incentivizing investment in onshore wind projects.

While Texas has addressed many of its physical grid issues, the primary remaining challenges lie in regulatory reforms necessary to ensure grid resilience and reliability. In the past, ERCOT offered financial incentives to increase the number of small energy suppliers who could enter the deregulated market. This regulatory choice, combined with wind developers receiving federal tax credits in 1992, has made Texas the top energy producing state in the U.S. However, Texas regulators in the state government now think that financial incentives are not needed anymore because of how much the electricity market has grown. In June 2023, Texas Republicans proposed several state house bills that would create regulatory hurdles and reduce incentives, making it increasingly challenging for wind development in the state (Gold 2023). ERCOT's strategic plan for 2024-2028 states that it is highly aware of the public's loss of confidence since Winter Storm Uri in 2021. The plan also mentions that ERCOT's first priority is to be an "industry leader for grid reliability and resilience," assumably to win back Texans trust in them (ERCOT 2024). The rollback of state-level financial incentives and ERCOT's prioritization of grid resilience post Uri point to a plan to stall the grid's growth so Texas policymakers can better manage the large electricity market they have. ERCOT regulators seem to think that the prevention of new wind energy capacity will free up more resources for grid reliability improvements.

California Independent Systems Operator (CAISO)

The California Independent System Operator (CAISO) runs the fourth largest market for wind energy in the United States. California uses wind energy for 28.3% of its total electricity demand (DOE 2023). The DOE estimates that wind penetration for CAISO in 2022, as expressed as a percentage of total load, is 8.4%. California's natural climate makes the state more attractive to solar development, but wind resources thrive in a small cluster of geographic regions. Although this is a significant amount of electricity generation, it occurs in only a few parts of the state. Namely, turbines are located in the Tehachapi area in Kern County, in the Altamont Pass area in Alameda, and in the San Gorgonio Pass in Riverside County (California Energy Commission).

Figure 14: Map of Installed and Planned Wind Capacity in California



Source: California Energy Commission

Onshore wind development within CAISO has stagnated because the few wind resources California has have already been exploited. Nancy Rader, the Executive Director of the California Wind Association (CalWEA) stated that "land-use restrictions outside of the major existing wind resource areas [largely in the California desert as a result of the Desert Renewable Energy Conservation Plan] made it very difficult to develop wind projects in California." All the remaining sites with onshore wind potential are protected against development unless the federal government loosens its standards. Moreover, the huge interconnection queues mean that projects, on average, don't come online for at least five years (Silverman, 2024). Some 4,000 megawatts of in-state wind projects are waiting in California's interconnection queues, and 2,500 megawatts of additional in-state wind capacity is included in the California Public Utilities Commission's integrated resource plan. However, nearly all of this planned capacity is coming from offshore wind projects. CAISO's 20-Year Transmission Outlook Plan states that North Coast and Central Coast offshore wind farms will provide 7-13 additional gigawatts to the electricity supply (CAISO 2022). CAISO plans to import 10 gigawatts of onshore wind energy from the surrounding ISOs but building in-state capacity is not a priority.

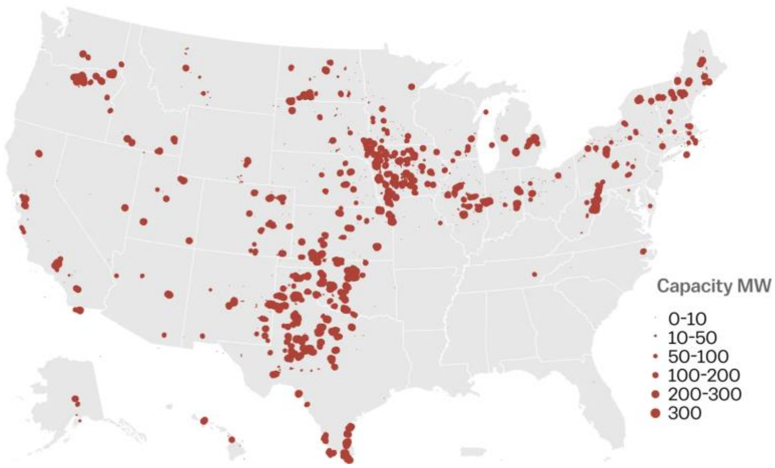
California offers several incentives to promote onshore wind development, aiming to bolster renewable energy generation and reduce carbon emissions. One prominent incentive is the Renewable Portfolio Standard (RPS), which mandates that a certain percentage of electricity sold in the state comes from renewable sources, including wind power (DOE). This creates a steady demand for renewable energy, encouraging investment in wind projects. Additionally, the California Energy Commission (CEC) provides funding through various programs such as the USDA Renewable Energy for America Program (REAP) and the Electric Program Investment Charge (EPIC) Program, which offer grants and loans for renewable energy projects, including onshore wind farms (DOE). Furthermore, the California Solar Initiative (CSI) Thermal Program and the Self-Generation Incentive Program (SGIP) also support wind development indirectly by promoting renewable energy technologies and grid resilience, which can benefit wind projects. These incentives, combined with California's ambitious renewable energy goals and favorable regulatory environment, make the state an attractive destination for onshore wind development, fostering sustainable energy growth and environmental stewardship (DOE).

California's robust state incentives for onshore wind development are juxtaposed with significant challenges that may hinder investors from fully capitalizing on these policies. Despite the incentives, the state faces constraints such as limited available land for new wind projects and lengthy interconnection queues. The scarcity of suitable land, combined with competing land uses and stringent environmental regulations, restricts the potential for large-scale wind farm development (Holbein 2024). Moreover, the extensive interconnection queues exacerbate delays in connecting new wind projects to the grid, prolonging the time from project inception to commercial operation. These barriers not only increase project development costs but also introduce uncertainties that deter investors seeking timely returns on their investments (Holbein 2024).

Southwest ISO and Southwest Power Pool (SPP)

All of the members in the Southwest ISO and SPP have state level incentives for onshore wind development that works additionally to IRA tax credits. Arizona offers several incentives to promote onshore wind development, aligning with its commitment to renewable energy and sustainability. One key incentive is the Arizona Renewable Energy Standard and Tariff (REST), which mandates that utilities generate 15% of their electricity from renewable sources by 2025, with a portion specifically allocated to wind energy. This creates a stable market for wind power and provides long-term demand certainty for developers (DSIRE).

Figure 15: Map of Installed Wind Turbines in the U.S.



Source: Vox News

Additionally, the state offers property tax incentives for renewable energy facilities, including wind farms, through the Renewable Energy Production Tax Credit. This credit reduces property taxes for qualifying projects, making wind development more financially attractive. Furthermore, Arizona's Renewable Energy Investment Fund (REIF) provides grants and loans to renewable energy projects, supporting the development and deployment of onshore wind infrastructure (DSIRE).

Midwestern states within the SPP have taken a different approach to encouraging market growth. For example, Kansas offers property tax exemptions for renewable energy facilities, including wind farms, through the Renewable Energy Property Tax Exemption (DSIRE). This exemption reduces property taxes for qualifying projects, making wind development more financially viable. Furthermore, the state provides sales tax exemptions for renewable energy equipment and materials used in the construction of wind projects, further lowering the costs of development (DSIRE).

New England ISO (ISO-NE)

Wind projects make up nearly 50% of new resource proposals in the ISO Queue – Most are offshore wind proposals in southern New England, but some are onshore wind proposals in northern New England and would require transmission to deliver the energy to load centers (ISO NE 2023).

Onshore Wind queue is 2325 MW as of June 2023, taking up around 6.7% of total capacity in the interconnection queue, whereas offshore wind takes up around 41.3% of total capacity (ISO NE 2023). All onshore addition is concentrated in Maine. Overall, onshore wind investment remained relatively stable pre vs post IRA, while there are more offshore wind proposals post-IRA (ISO NE 2024).

For FCAs 14, 15, and 16, the region was divided into four zones: NNE (VT, NH, and ME), "Nested" Maine, a separate capacity zone within NNE; SENE (East MA, RI, and Greater Boston); and ROP (CT, West and Central MA) (ISO NE).

Figure 16: Forward Capacity Auctions for 2022 in ISO-NE

Auction Commitment Period	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/kW-month)
FCA 14 in 2020 for CCP 2023/2024	323	335	$2,001
FCA 15 in 2021 for CCP 2024/2025	170	950	ROP: $2,611 NNE: $2,477 SENE: $3,980
FCA 16 in 2022 for CCP 2025/2026	230	311	ROP: $2,591 NNE: $2,531 SENE: $2,639
FCA 17 in 2023 for CCP 2026/2027	2,940	619	$2,590
FCA 18 in 2024 for CCP 2027/2028	105	998	$3,580

Source: ISO-NE Strategic Plan

FCA 17, 18 divided the region into three zones: NNE, Maine, and ROP (Greater Boston, MA, CT, and RI).

The forward capacity market is taking up an increasingly small share of the annual value of wholesale electricity markets. (largest in 2018-2020, decreasing since then)(ISO NE). The 2023 average wholesale electricity price was $35.90/MWh (ISO NE). The price hit its peak in July 2022 when it was $90.68/MWh.

Pennsylvania, New Jersey, and Maryland ISO (PJM)

Onshore wind trends: Growth is occurring fastest in areas with favorable wind speed and sustained duration in order to achieve energy production levels that generate profit-making revenue streams (PJM Planning Division 2022). PJM continues to see developer interest in western subregions (including Illinois, Indiana and Ohio).

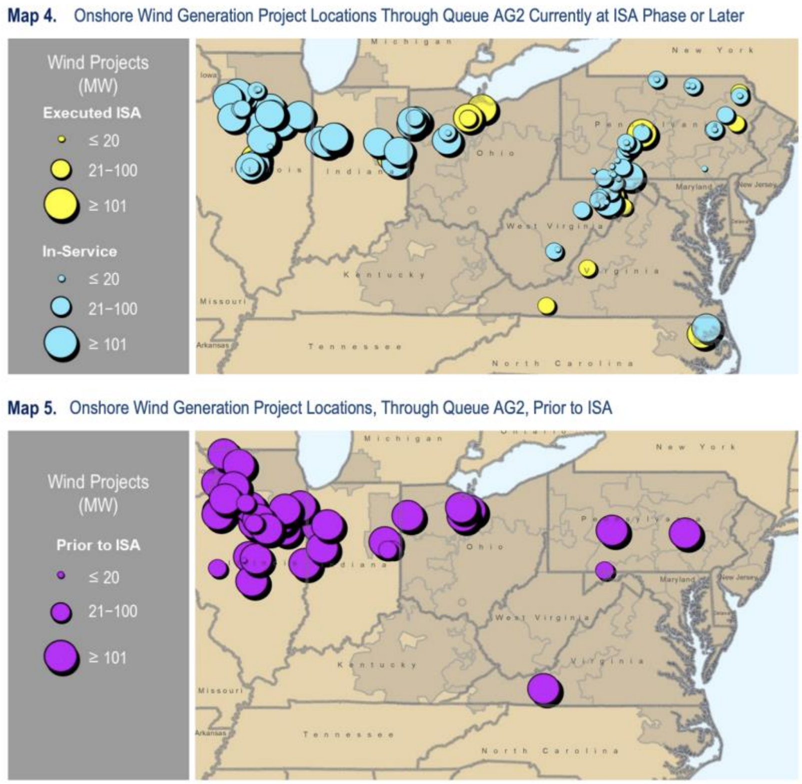
Figure 17: Installed and Planned Wind Capacity in PJM

Source: PJM Strategic Plan

As of February 2023, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the Reliability Pricing Model (RPM) capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources (PJM Planning Division 2022).

PJM on 2023 Feb. 27 reported a footprint-wide capacity market clearing price of $28.92/MW-day for the 2024/2025 delivery year, down from $34.13/MW-day for the prior delivery year (Hale 2023). In the real time markets, the Load-weighted average Locational Marginal Pricing for 2023 was $30.87/MWh. In September 2023 the marginal pricing was $31.60/MWh, which is much lower than September 2022 ($78.30/MWh) and also lower than September 2021 ($49.60/MWh) (PJM 2023).

Figure 18: Map of Planned and Installed Wind Capacity in PJM



Source: PJM Strategic Plan

Risk Analysis

Technological

- Competition from other cost-competitive energy sources such as solar and natural gas
- Limited transmission: The limited capacity of transmission lines to transport electricity from these remote locations to consumers can restrict the growth of wind power. Building new transmission lines is expensive and can encounter regulatory and community opposition (Tandon 2024).
- Interconnection costs and timeframes: Developers must navigate complex interconnection processes, including studies to assess the impact on the grid and upgrades to existing infrastructure. These requirements can increase the cost and delay the deployment of new wind projects.
- Cybersecurity threats: cyberattacks can significantly reduce energy generation and cut off communication between turbines and operators. Federal agencies are working to strengthen security measures, policies, and IT infrastructure for wind farms. This could also imply higher costs for future projects (DOE 2023).

"It is imperative that we remain cognizant of the real threat that cyber and other attacks can pose to our energy systems."

- Jim Ahlgrimm, Director of the IEA Wind Technologies Office

Market/Financial

- Inflation rates: Rising costs for materials, labor, and other inputs can affect the economics of wind projects (Silverman 2024).

Operational

- Supply chain issues: The wind industry relies on a global supply chain for components such as turbines, blades, and electrical equipment. Disruptions in the supply chain, whether due to political issues, pandemics, or other factors, can delay project timelines and increase costs (Analyst From a Large O&M Company, 2024).

Regulatory

- Siting and permitting challenges: The permitting process can be lengthy and uncertain, involving multiple local, state, and federal agencies. Issues such as visual impact, noise, and potential impacts on wildlife can lead to opposition and delays (Silverman 2024).

- Federal Administration Change: Most policy analysts agree that in the case former President Trump wins the 2024 election, a complete repeal of the IRA is unlikely. However, Congress Republicans proposed cutting 45V and 45Y credits as means to reauthorize the Tax Cuts and Jobs Act (TCJA), which is set to expire in 2025. It is not unreasonable to assume that the IRA's large pool of funding could be expropriated in the new 2025 tax policy (Martin and Gimigliano 2024). Experts at Norton Rose state that the IRA credits that are most likely to be cut in 2025 are 45V and 45Y because they were unpopular to begin within. The IRA credits 45X and 48E, which support onshore wind development, were popular in the law’s infancy so major changes are unlikely (Martin and Gimigliano 2024).

Solar Energy

Solar Energy

Introduction

The Inflation Reduction Act (IRA) marks a pivotal shift in the U.S. energy landscape, significantly influencing solar investment opportunities. It has revitalized interest in renewable energy, with solar power standing out due to its scalability, decreasing costs, and substantial support through tax incentives.

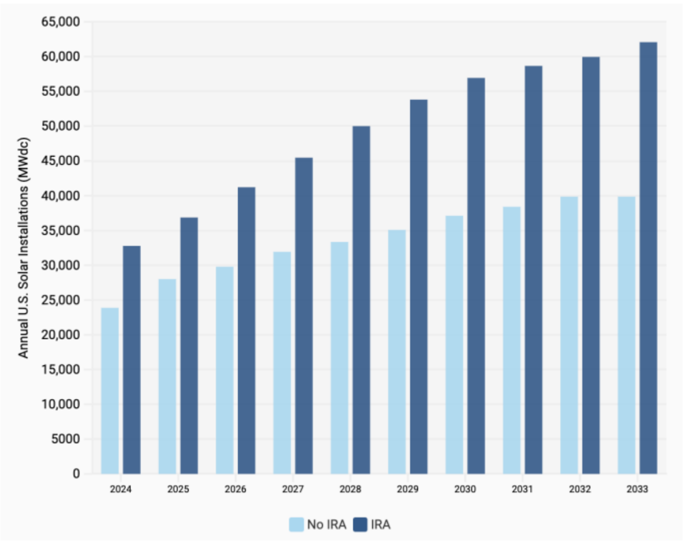
Technology

Crystalline silicon remains the cornerstone of solar technology, used in more than 90% of solar panels globally. However, new materials and cell structures are emerging that promise higher efficiencies and potentially lower costs. One of the most promising developments has been in the field of tandem solar cells, particularly those combining perovskite and silicon. Tandem cells use two different light-absorbing layers to capture a broader spectrum of sunlight, thereby achieving higher efficiencies. Recently, these have exceeded 33% efficiency in laboratory settings, a significant improvement over the maximum 30% for traditional silicon cells (MIT Technology Review 2024).

Tax Credits and Eligibility

Under the Inflation Reduction Act (IRA) of 2022, substantial revisions have been made to the structure and application of tax credits for solar and broader clean energy projects. The IRA maintains Investment Tax Credits (ITC) and the Production Tax Credits (PTC), each with its eligibility criteria and benefits. The section 48E ITC continues to apply to solar energy generation but is significantly modified. The credit now offers a base rate of 6% and can be escalated to a 30% bonus rate if projects meet the newly implemented prevailing wage and apprenticeship requirements or if they are small-scale projects under 1MW (U.S. Department of the Treasury 2024). The section new 45Y PTC is a technology-neutral clean electricity credit that will replace the clean electricity PTC starting in 2025. The PTC credit starts at 2.6 ¢/kWh and is available for the first 10 years of a projects operation until the tax credit phases out.

Figure 19: Impact of the Inflation Reduction Act on Solar Market Outlook



Source: SEIA/Wood Mackenzie Power & Renewables Solar Market Insight Report Series 2023

Section 45Y PTC

- **Base PTC Rates:** For projects under 1 MWac (megawatt alternating current), the base PTC starts at 2.6 ¢/kWh in 2022 and experiences a slight annual increase to 3.2 ¢/kWh by 2032. After 2032, the rates gradually decrease until they reach zero by 2036. This structured phase-out incentivizes early adoption and investment in solar energy production.

- **Bonus Credits:** Additional bonuses are offered for meeting domestic content minimums and for siting in an "energy community." These bonus credits start at 0.3 ¢/kWh each and remain stable until they phase out following a similar trajectory to the base rate post-2032.
- **Labor Requirements:** Projects that meet labor requirements get an extra bump in their PTC rates. It's important to note that these adders for labor standards, domestic content, and energy community location can significantly enhance the value of the PTC for qualifying projects.
- **Inflation and Emission Considerations:** The PTC is adjusted for inflation annually, and the phase-down is connected to electric sector CO_2 emissions, with the full credit available until emissions are reduced by 75% from 2022 levels.

Section 48E ITC: Projects under 1 MWac

- **Base ITC Rate:** For projects under 1 MWac, the base Investment Tax Credit remains consistently at 30% from 2022 to 2032.
- **Domestic Content Bonus:** A bonus of 10% is granted for meeting domestic content requirements, maintaining the incentive at 40% through 2032.
- **Energy Community Bonus:** An additional 10% credit is available for projects sited in energy communities.
- **Low-Income Bonuses:** For projects in low-income communities or on Indian lands, the ITC can be increased by another 10%, and if they are part of a qualified low-income residential building project or economic benefit project, this bonus can be 20%.

The phase-out for these projects starts in 2034 with a 75% level of the original credits, 50% in 2034, and then drops to 0% in 2036.

Section 48E ITC: Projects over 1 MWac that begin construction less than 60 Days After Dept. of Treasury issues guidance

- **Base ITC:** These projects enjoy a 30% base credit through 2032, similar to the smaller projects.
- **Bonuses for Domestic Content and Energy Community:** Identical to smaller projects, these larger projects also benefit from the 10% bonuses for meeting domestic content minimums and being situated in an energy community.
- **Low-Income Bonuses:** These follow the same structure as the smaller projects, with 10% for low-income community projects and an additional 20% for low-income residential building projects.

Projects that start construction 60 days after the Department of Treasury issues guidance see a reduced base ITC of 6% with smaller additional bonuses for meeting specific requirements.

Phase-out Schedule: Starting in 2033, the ITC begins to phase out, reducing first to 75%, then 50% in 2034, and ultimately phasing out completely by 2036. This suggests a timeline for the green energy sector to mature and become self-sustainable without the need for federal tax incentives.

Market Analysis

The global solar PV market continues to expand rapidly. In 2023 alone, the installation of solar PV capacity soared, with significant contributions from both utility-scale projects and distributed systems such as residential and commercial rooftop installations. Distributed systems are particularly being driven by high electricity prices and favorable policy incentives, which have made small-scale installations an attractive investment for many consumers (IEA 2024). The U.S. saw a record installation of around 15.8 GW in just the first nine months of 2023 (NREL 2024).

The manufacturing landscape for solar PV is also evolving with significant capacity expansions planned, particularly in China, which dominates the market. This includes not only the expansion of existing technologies but also investments in new technologies like N-type cells and bifacial modules which can absorb light from both sides of the panel (NREL 2024). Despite a global increase in production capacity, the majority of manufacturing remains concentrated in China, accounting for up to 95% of new capacity (NREL 2024).

Economic factors such as the cost of raw materials and manufacturing efficiencies continue to play critical roles in the solar PV sector. Prices for key components like polysilicon have fluctuated, influencing overall module costs and market dynamics. Regulatory changes and government incentives, such as those introduced under the Inflation Reduction Act in the U.S., are also crucial in shaping the market (The Department of Energy's Energy.gov) (Merchant 2024). As the solar PV industry moves forward, continuous innovation and supportive regulatory frameworks will be essential to maintain growth momentum and to overcome the current challenges. The ongoing research and development in higher efficiency materials and the scaling up of production capacities are likely to further drive down costs, making solar energy even more accessible globally (Merchant 2024).

Community Solar Market

The Inflation Reduction Act (IRA) introduces significant opportunities and challenges for the community solar market, particularly targeting low-income areas. This policy is designed to make solar energy more accessible and affordable to a broader demographic and stimulate economic activity in underprivileged sectors.

The IRA substantially boosts the community solar segment by offering enhanced tax incentives, including added bonuses for those serving low-income communities. Specifically, projects can qualify for additional tax credits ranging from 10% to 20% of the project cost if they ensure that a significant portion of their benefits go to low-income consumers. These incentives are structured to lower the financial barriers for entry and make community solar projects more economically viable (Department of Treasury, 2024).

Despite these incentives, there are considerable hurdles to achieving widespread adoption among the target demographic. One primary challenge is the bureaucratic complexity involved in qualifying households as "low-income" which can deter participation. The process often requires extensive documentation and navigating through cumbersome governmental procedures, which can be a significant impediment. Moreover, there is a notable challenge in building trust within these communities (Lydersen 2024). According to an industry source, previous experiences with predatory practices in the energy sector have left a residue of skepticism that new community solar initiatives must carefully address. Building this trust is crucial to the successful deployment of community solar systems that genuinely benefit low-income households.

Another significant issue is the system's capacity to handle the surge in demand these incentives might generate (Lydersen 2024). For example, during the initial application period for the IRA's low-income bonuses, the program received an overwhelming number of submissions, significantly exceeding the available capacity. This over-subscription indicates a robust interest, but creates a potential bottleneck where many projects might not receive funding, leading to delays and potential disillusionment among stakeholders (Lydersen 2024).

For community solar projects to be sustainable and impactful, they also need to integrate effectively with local utilities and regulatory frameworks. Projects must ensure that the savings from solar energy are credited to consumers' bills and that the benefits are transparent and significant enough to warrant the switch from traditional energy sources.

Looking ahead, the community solar market under the IRA promises substantial growth. However, for this potential to be fully realized, project developers and advocates must navigate the regulatory landscape carefully, build trust with communities, and ensure that the administrative and financial frameworks supporting these initiatives are robust and user-friendly. These efforts will be essential in moving towards a more inclusive and sustainable solar energy infrastructure that not only contributes to environmental goals but also supports economic development in historically marginalized communities.

Commercial Solar Market

One of the central features of the IRA is its enhancement of financial incentives for commercial solar projects. The act notably increases the section 48E ITC to 30% of the total installation costs for commercial solar systems. This substantial tax credit is aimed at reducing the upfront financial burden on businesses and accelerating the payback period, making solar investments more attractive and feasible for a broader range of businesses. Furthermore, the IRA introduces direct pay options and performance-based incentives like meeting labor requirements, making it easier for non-taxable entities like nonprofits to benefit from solar investments. These entities can directly receive payments equivalent to the value of the tax credits, which democratizes access to solar incentives across different organizational structures.

By investing in solar technology, businesses can significantly lower their operational costs with solar Power Purchase Agreements, which provides a stable and predictably priced source of electricity, which can be particularly advantageous against the backdrop of rising energy prices and market volatility. Moreover, the shift to renewable energy can enhance a company's sustainability profile, appealing to an increasingly eco-conscious consumer base and potentially offering a competitive edge in the market.

In summary, the IRA provides a pivotal opportunity for businesses to invest in commercial solar projects, leveraging substantial tax incentives to mitigate upfront costs and enhance long-term profitability. However, success in this evolving market will require careful strategic planning, a thorough understanding of regulatory requirements, and proactive management of supply chain and infrastructure challenges. With the right approach, businesses can not only enhance their energy efficiency and sustainability but also position themselves competitively in a rapidly changing economic landscape.

Utility-Scale Solar Market

The utility-scale solar market is undergoing transformative growth under the Inflation Reduction Act (IRA), setting the stage for significant expansions and challenges in the renewable energy sector. This analysis delves into the opportunities, constraints, and strategic shifts necessary to navigate the evolving landscape of utility-scale solar.

Utility-scale solar projects benefit significantly from economies of scale (Bartlett et al., 2023). Larger installations reduce the cost per megawatt-hour (MWh) due to bulk purchasing of materials and more efficient deployment of labor and technology. Scalability allows project developers to phase their investments, start smaller if necessary, and expand as technology advances or as more funding becomes available. This flexibility is particularly advantageous in the rapidly evolving renewable energy market, where technological advancements can significantly enhance project outputs and economic returns (Bartlett et al., 2023).Technological advancements, such as more efficient photovoltaic cells and improved manufacturing processes, also drive down costs. Efficient project management and operations contribute to reducing the lifecycle costs of these projects, making solar power increasingly competitive with traditional energy sources (Bartlett et al., 2023).

In an interview with a renewable private equity investor, we learned that the geographic location of utility-scale solar projects heavily influences its capacity factor, or the measure of how much electricity the plant produces compared to its maximum potential output. Areas with high solar irradiance naturally provide higher energy yields. Furthermore, the incorporation of tracking technology, which allows solar panels to move and follow the sun’s trajectory, significantly enhances energy production. The interviewee also noted that these systems can increase the capacity factor by up to 25% compared to fixed systems, making them particularly valuable in maximizing output and project returns.

In summary, the utility-scale solar market under the IRA represents a landscape filled with opportunities and challenges. Success in this rapidly growing market requires stakeholders to adopt innovative approaches to risk management, and technology utilization. As the industry navigates these changes, the potential for significant investment and expansion offers a bright future for renewable energy in the United States.

Project Economics

We used a financial model to assess the potential economics of utility-scale solar projects. The model inputs and assumptions are shown in Figure 20. Based on our model assumptions, as shown in the sensitivity analysis in Figure 21, the upfront tax credit provided by the PTC generally offers a higher rate of return than the ITC. When interest rates are increased, the immediate financial benefit provided by ITC can reduce debt levels more rapidly. This will make ITC more appealing.

Figure 20: Utility Solar Model Inputs, Assumptions and Returns

Operating Assumptions	
Technology Type:	**Utility Solar**
Nameplate Capacity (MW):	**100.0**
Useful Life (years):	**20**
Capacity Factor:	**24.2%**
Annual Generation (MWh):	**211,992**
PPA Price ($ / MWh):	**25.5**
PPA Tenor (years):	**20**
Merchant Price ($ / MWh):	**-**
Merchant Years:	**-**

Tax Assumptions	
Federal Tax Rate:	**21.0%**
Tax Credit:	**Investment Tax Credit**
ITC % of Capex	**30.0%**
ITC Amount ($M):	**29.4**
PTC Price ($ / MWh):	**-**
Annual PTC Escalator:	**-**
PTC Transfer Price (per $1 PTC):	**-**

Financing Assumptions	
Project Cost ($M):	**98.0**
Debt Amount ($M):	**48.1**
Debt Tenor (years):	**10**
Interest Rate:	**6.70%**
Minimum Annual DSCR:	**1.50x**
Equity Amount ($M):	**49.9**
Equity % of Financing:	**50.9%**

Returns	
Debt Repaid (years):	**11.0**
DSCR Minimum:	**1.50x**
DSCR Average:	**1.50x**
Equity Holders Pre-Tax NPV:	**43.4**
Equity Holders Pre-Tax IRR:	**8.0%**
Equity Holders After-Tax NPV:	**0.7**
After-Tax Levered IRR:	**8.8%**
After-Tax Unevered IRR:	**8.6%**

Figure 21: Utility Solar Model Sensitivity Analysis: ITC vs. PTC

Net Capacity Factor v. Interest Rate Sensitivities (After-Tax Levered IRR) - PTC

Net Capacity Factor	5.20%	5.70%	6.20%	6.70%	7.20%	7.70%	8.20%
	Interest Rate						
18.0%	5.1%	5.0%	4.9%	4.8%	4.7%	4.6%	4.5%
20.0%	6.5%	6.3%	6.2%	6.1%	5.9%	5.8%	5.7%
22.0%	7.9%	7.7%	7.5%	7.4%	7.2%	7.1%	6.9%
24.0%	9.3%	9.0%	8.8%	8.7%	8.5%	8.3%	8.1%
26.0%	10.7%	10.5%	10.2%	10.0%	9.8%	9.6%	9.4%
28.0%	12.2%	11.9%	11.6%	11.3%	11.1%	10.8%	10.6%
30.0%	13.9%	13.5%	13.1%	12.8%	12.4%	12.2%	11.9%

Net Capacity Factor v. Interest Rate Sensitivities (After-Tax Levered IRR) - ITC

Net Capacity Factor	5.20%	5.70%	6.20%	6.70%	7.20%	7.70%	8.20%
	Interest Rate						
18.0%	5.1%	5.0%	4.9%	4.8%	4.7%	4.7%	4.6%
20.0%	6.4%	6.3%	6.2%	6.1%	6.0%	5.9%	5.8%
22.0%	7.7%	7.6%	7.4%	7.3%	7.2%	7.1%	7.0%
24.0%	9.0%	8.8%	8.7%	8.5%	8.4%	8.2%	8.1%
26.0%	10.3%	10.1%	9.9%	9.7%	9.6%	9.4%	9.3%
28.0%	11.6%	11.4%	11.2%	11.0%	10.8%	10.6%	10.4%
30.0%	13.0%	12.7%	12.5%	12.2%	12.0%	11.8%	11.6%

For projects with higher upfront costs and lower capacity factors, typically found in residential solar projects, the ITC is generally more beneficial. The ITC provides an immediate tax credit based on a percentage of the installation costs, which can significantly offset the initial investment and is particularly attractive for smaller-scale projects with higher costs per watt. In this case, ITC's upfront value tends to outweigh the benefits of the PTC.

On the other hand, utility-scale solar projects, characterized by lower costs per watt and higher capacity factors due to efficient installation techniques and economies of scale, are more likely to benefit from the PTC. In such cases, the ongoing tax credit based on the electricity produced over a decade can offer greater returns than the immediate reduction in installation costs provided by the ITC. These projects fall within the orange areas of the chart, indicating a higher propensity to elect PTC over ITC.

In addition, the tax-equity flip strategy is a critical financing mechanism within the solar industry, especially in light of the IRA (Weaver 2022). This strategy involves a partnership between a solar project developer and a tax equity investor. Initially, the tax equity investor provides the capital for the project in exchange for the majority of the tax benefits (ITC, PTC) and cash flows. Once the investor achieves a predetermined return on investment, the financial structure "flips," and the majority share of profits transitions to the project developer (Weaver 2022).

The IRA's introduction of transferable tax credits adds a new dimension to the tax-equity flip strategy. Now, developers have the option to monetize the tax credits directly, offering greater flexibility in financing projects. This could potentially simplify the investment structure and attract a broader pool of investors, enhancing the liquidity and scalability of solar projects.

Regional Opportunities

The IRA has catalyzed solar investment opportunities across the U.S., with particular regions standing out due to a combination of natural solar resources, policy support, and existing infrastructure.

Southwest (e.g., California, Arizona, Nevada)

High solar irradiance and supportive state policies make this region a prime candidate for continued solar investment growth under the IRA. California's ambitious climate goals and incentives align well with the IRA, likely leading to increased solar capacity.

Southeast (e.g., Florida, North Carolina, Georgia)

Although traditionally slower in adopting solar, the IRA could significantly impact this region by making solar projects more financially viable, overcoming historical hesitance from utilities and state governments.

Northeast (e.g., New York, New Jersey, Massachusetts)

High electricity prices and strong state-level incentives complement the IRA, making solar investments particularly attractive. The focus on community solar can also drive growth in distributed solar projects.

PJM Interconnection Region

The diverse policy landscape across the PJM states means the IRA's impact will vary. However, the IRA's emphasis on clean energy and grid reliability, along with PJM's capacity market, presents unique opportunities for utility-scale solar and storage projects.

Additional Regional Considerations

Despite the promising outlook, challenges such as interconnection delays, varying local policies, and supply chain issues could affect project timelines and costs. Additionally, regions with less favorable solar conditions or weaker state-level support may not experience growth as rapidly as those with more aggressive clean energy policies.

Remaining Challenges

The strong benefits of the IRA are accompanied by complex eligibility requirements that could pose challenges for project planners and financiers in ensuring compliance and maximizing potential credits.

Firstly, the capacity of Engineering, Procurement, and Construction (EPC) firms is a major bottleneck (Bartlett et al. 2023). With the IRA's aggressive installation targets, EPC capacity needs to nearly triple by 2027 to keep up with demand (Bartlett et al. 2023). This shortage of qualified EPCs could lead to delays and cost overruns as competition for their services increases, putting upward pressure on prices and potentially stifling the speed of solar deployment.

Another critical issue is labor shortages (Bartlett et al. 2023). The solar sector is already competing for resources with other booming industries like broadband and public infrastructure, which are also buoyed by recent federal initiatives. This competition is intensifying under the IRA, as rapid expansion in renewables drives an even greater need for skilled workers. The shortage of labor may slow down project timelines and increase costs as companies vie to attract and retain talent.

The supply chain for solar projects is a critical component of their successful deployment, but it currently faces significant risks that could hinder the growth of the solar industry, especially under the ambitious targets set by the Inflation Reduction Act (IRA). One of the primary issues within the supply chain is the dependency on foreign materials and components. When interviewing with a community solar developer, despite the IRA's incentives for increasing domestic production, the reality is that the U.S. solar industry has been heavily reliant on imported solar panels, cells, and other critical components from countries like China. This reliance poses a risk of supply disruptions due to geopolitical tensions, trade disputes, or shipping and logistical issues, which could delay project timelines or increase costs unexpectedly.

Moreover, the IRA encourages the use of domestically manufactured components through additional tax credits, intending to foster a more localized and secure supply chain. However, scaling up domestic manufacturing facilities to meet the demands of the solar industry is not an instantaneous process. There is a considerable gap between the current production capacity in the U.S. and what is required to meet the IRA's objectives. This gap signifies that, in the short to medium term, there will likely be shortages of domestically produced solar components. These shortages could be exacerbated by the time it takes for new factories and production lines to become operational, during which the industry may still need to rely on imported goods.

Furthermore, the transition to a more localized supply chain is compounded by challenges in the availability of raw materials, such as polysilicon, used in solar cell manufacturing. The global market for these materials is volatile and has been subject to intense price fluctuations, which can significantly impact the cost structure of solar projects. The U.S. has limited control over these global market conditions, which adds an element of unpredictability to project budgets. In addition to material shortages and geopolitical risks, the supply chain for solar projects is also vulnerable to regulatory risks. Changes in import tariffs, trade policies, or local manufacturing incentives could swiftly alter the economic landscape for solar projects, potentially making some projects financially unviable overnight.

According to a solar private equity associate, interconnection is another hurdle. The process of connecting solar projects to the national grid has become more expensive and time-consuming, with projects often languishing in interconnection queues for years. This not only delays the realization of projects but also adds financial uncertainty, affecting overall project viability. And price volatility due to inflation and fluctuating commodity prices adds another layer of complexity. Materials essential for solar installations, such as steel, aluminum, and copper, have experienced significant price instability, which can drastically alter project budgets and financial forecasts.

Lastly, The ITC recapture risk under the IRA is chiefly concerned with the retention of the tax credits in case of a sale or transfer of the asset or if the project no longer meets the qualifying conditions. Under new regulations, the risk of recapture generally resides with the transferee rather than the transferor, meaning the new owner assumes the risk and potential liability for the tax credits after acquisition (Linklaters 2023).

These challenges collectively highlight the complex landscape in which solar projects are being developed under the IRA. Each poses unique risks that must be managed carefully to harness the full potential of the incentives offered by the legislation.

Battery Energy Storage Systems

Battery Energy Storage Systems

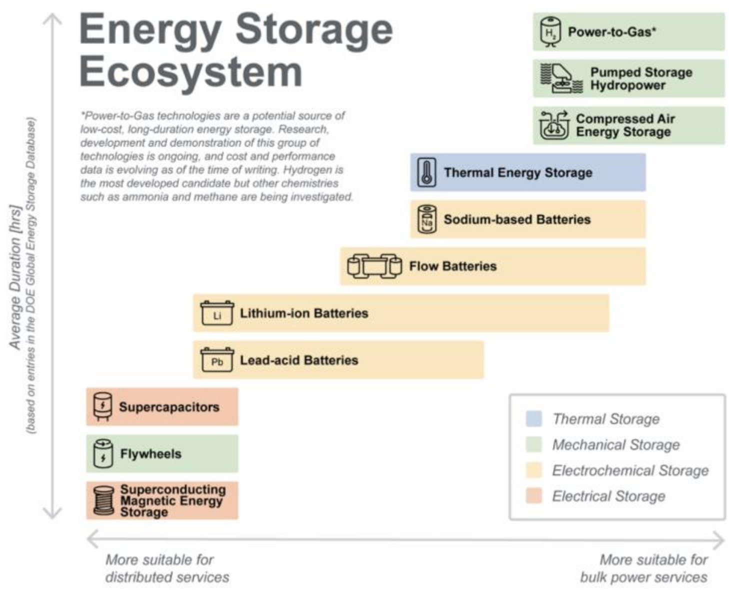
Key Insights

Battery Energy Storage Systems (BESS) are a critical component of the United States' shift towards a cleaner and more resilient energy grid. Through substantial tax incentives, the IRA is transforming the BESS industry by improving project economics, supercharging domestic supply chain expansion and cost reduction, and facilitating the deployment of intermittent resources, which expand revenue opportunities for BESS. By analyzing IRA tax credits, the shifting BESS revenue model, regional operating parameters, as well as alternative battery chemistries, we find that developers and investors should pay attention to standalone long-duration LFP BESS located in ERCOT West. If possible, stakeholders should aim to qualify for the energy community adder whenever possible to allow for a greater margin of error.

Technology

As shown in Figure 22, different energy storage technologies have different discharge time and power capacity, making them fit for serving various functions. Energy storage systems with short discharge time and low capacity, such as nickel-based batteries and flywheels, are suitable for frequency regulation. Energy storage systems with long discharge time and high capacity, such as pumped hydroelectric and compressed air energy storage, help perform bulk power management. The most recent technological innovations pertain to thermal energy storage systems, which are advantageous in having long discharge time, relatively high power capacity, and low upfront costs. Finally, energy storage systems with medium discharge time and low to medium capacity can be deployed for the broadest range of services: transmission and distribution, operating reserves, and black starts.

Figure 22: Energy Storage Ecosystem

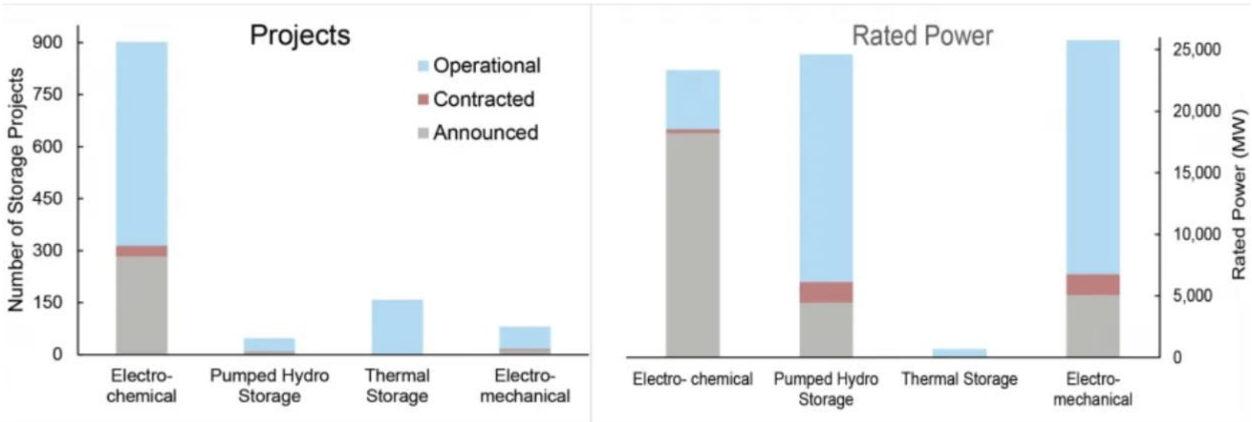


Source: Brown et al. 2021

Lithium-ion batteries fall in the aforementioned category and are preferred over lead-acid batteries for its energy density and flexibility in terms of discharge time. Moreover, lithium-ion batteries also benefit from being an established technology with strong potential for project bankability (Joshi and Gokhale-Welch 2022). According to National Renewable Energy Laboratory (NREL)'s 2023 Annual Technology Baseline (ATB), among lithium-ion batteries, lithium-iron phosphate (LFP) batteries have become the primary chemistry for stationary storage since 2021. BESS projects have moved away from lithium nickel manganese cobalt oxide batteries (NMC) due to concerns about material availability, ethical sourcing, and upfront battery pack costs (Martineau 2023).

As shown in Figure 23, most of the current operational storage capacity in the U.S. are pumped hydro and electro-mechanical storage. However, a large amount of electro-chemical storage capacity has been announced and will come online as part of the buildout of renewable energy projects.

Figure 23: U.S. Energy Storage Projects by Technology Type in 2021



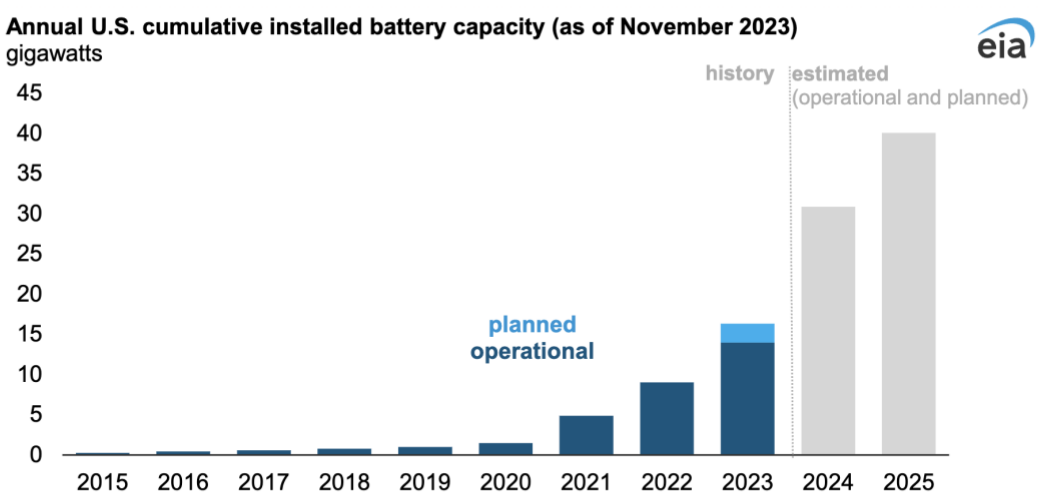
Source: Center for Sustainable Systems 2021

Market Overview

The U.S. utility-scale BESS market has seen rapid growth since 2021. Total operational BESS capacity in the U.S. grew from 8.8 GW at the end of 2022 to 15.4 GW at the end of 2023, representing a 75% increase (EIA 2023a). Based on S&P Global's most recent quarterly report, total capacity in the U.S. was 14.7 GW by the end of Q3 2023. Regions with the highest capacities are CAISO and ERCOT, with 7.0 GW and 4.1 GW, respectively. Other regions have much smaller-scale BESS deployment. The next largest market, WECC excluding CAISO, has 1.8 GW. Other regions with meaningful BESS deployment, such as Florida, PJM, ISO-NE, and NYISO, each have several hundred MW deployed (S&P Global 2023a).

In terms of additions, ERCOT led with 763.4 MW, or 40.0% of total U.S. additions in Q3 2023. CAISO also grew rapidly, with 584.0 MW of new capacity, or 30.6% of total U.S. additions (S&P Global 2023a). With a total capacity of 15.4 GW at the end of 2023, developers expect to add 15.0 GW in 2024 and 9.0 GW in 2025, bringing the total U.S. capacity to around 40.0 GW by the end of 2025. Notably, 50% of these planned additions are in ERCOT (EIA 2023b).

Figure 24: Annual U.S. Cumulative Installed BESS Capacity



Source: EIA 2023

The fact that CAISO and ERCOT lead in BESS capacity and additions should not come as a surprise. By the end of September 2023, CAISO and ERCOT had 17.3 GW and 18.4 GW of solar capacity, the highest nationally (Hao and Chronicle 2023). The same can be said about wind – by the end of 2023, CAISO and ERCOT had 6.2 GW and 41.6 GW of wind capacity, also the highest nationally (DOE 2024). In 2022, CAISO generated 26.8% of its energy using solar and wind (California Energy Commission 2023). In 2023, ERCOT generated 31.6% of its energy using solar and wind (ERCOT 2024). With high total capacity and penetration of intermittent resources, CAISO and ERCOT are characterized by volatile power prices and high scarcity pricing, which offer attractive energy arbitrage opportunities for BESS. Considering the current regional distribution of BESS, this analysis will focus on CAISO and ERCOT.

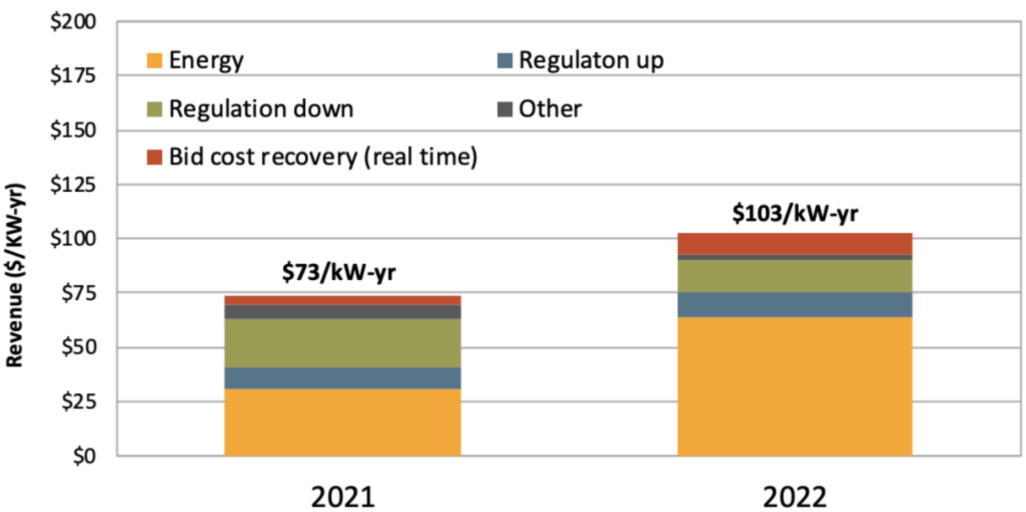
Project Economics

Contracted vs. Merchant Revenues

Owners of BESS projects can receive revenue in many different ways. Broadly speaking, revenue streams are either contracted or merchant. Contracted revenues arise from long-term agreements, whereas merchant revenues are drawn directly from real-time or day-ahead markets. For example, contracted revenue can be generated by a tolling agreement, in which the BESS is effectively leased to the offtaker, who is granted authority to initiate charging and discharging. In return, the BESS owner receives compensation based on a predetermined price and is shielded from market volatility. Alternatively, the owner can remain the operator and generate contracted revenue through PPAs, capacity sale agreements, and ancillary services contracts.

BESS owners can generate merchant revenues by operating the project and actively participating in the real-time and day-ahead markets. For example, the owner can earn a net revenue from energy arbitrage if it charges when the wholesale electricity price is low and discharges when the price is high. Although ancillary services can be offered through long-term contracts, they can also generate merchant revenue in some markets. For example, CAISO has real-time and a day-ahead ancillary services markets. See Figure 25 for an example of BESS merchant revenues.

Figure 25: Market Revenue Streams in CAISO



Source: CAISO 2023

Revenue Stacking

Given the multitude of potential revenue sources, BESS owners typically engage in "revenue stacking," in which multiple revenue streams are aggregated. Broadly speaking, there are three types of revenue streams. First is energy arbitrage revenue. Since the wholesale electricity price is lower during the day and higher in the evening, BESS can charge when the price is low and discharge when the price is high, generating net revenues. Second is capacity revenue, where BESS owners commit that power capacity would be available upon request in exchange for a fixed periodic payment per megawatt committed. This is obtained through long-term contracts, typically with ISOs and load-serving entities. Third is ancillary services revenue, where BESS are compensated for services such as frequency regulation and spinning reserves.

In CAISO and ERCOT, revenue is stacked differently given their unique market rules. In CAISO, BESS owners can earn revenues from the California Public Utilities Commission's (CPUC) resource adequacy framework. Under this framework, all load-serving entities under CPUC jurisdiction are required to demonstrate that they have enough capacity to meet peak demand plus a planning reserve margin (CPUC 2021). To satisfy this requirement, load-serving entities such as utilities sign long-term contracts with BESS owners, who provide capacity guarantees in exchange for fixed periodic payments (Ibid.). BESS in CAISO can also earn ancillary services revenues by bidding into real-time and day-ahead markets, providing services including frequency regulation, spinning reserves, non-spinning reserves, and replacement reserves. Finally, BESS owners can earn revenue through energy arbitrage, which includes additional revenue from scarcity events.

In ERCOT, there is neither a formal capacity market nor a resource adequacy requirement for load-serving entities, meaning no capacity revenue for BESS. Consequently, BESS rely much more heavily on ancillary services and energy arbitrage. To earn ancillary services revenue, BESS owners enter into a competitive bidding process in ERCOT's day-ahead ancillary services market, where they offer to provide frequency regulation, spinning reserves, non-spinning reserves, and contingency reserves (ERCOT 2023). With volatile wholesale electricity prices in ERCOT, energy arbitrage is another important source of revenue, especially during scarcity events (EIA 2022).

Figure 26: BESS Revenue Sources in CAISO and ERCOT

	Energy Arbitrage	Capacity	Ancillary Services
CAISO	BESS can engage in energy arbitrage and capitalize on scarcity pricing.	No formal capacity market. BESS can sign long-term capacity provision contracts with load-serving entities looking to fulfill the resource adequacy requirement.	BESS can bid into real-time and day-ahead markets to provide frequency regulation, spinning reserves, non-spinning reserves, and replacement reserves.
ERCOT	BESS leverage energy arbitrage as an important source of revenue, as there is no capacity revenue. Scarcity pricing is a critical component.	No formal capacity market and no resource adequacy requirement.	BESS can bid into day-ahead markets to provide frequency regulation, spinning reserves, non-spinning reserves, and contingency reserves.

Impact of the IRA

Investment Tax Credit for Colocated and Standalone BESS

The IRA is transforming the BESS industry in multiple ways. First, it introduced the new section 48E ITC, which replaces the section 48 ITC and extends the maximum 6% base rate and 30% bonus rate until at least 2033. While the ITC was typically renewed every one or two years, this timeline alleviates uncertainty for investors and allows for more time to generate returns (Utility Dive 2022). Second, standalone BESS are now eligible for the ITC. While the ITC was previously only available to BESS colocated with solar generation facilities, the IRA extended both the existing section 48 ITC and the new section 48E ITC to standalone BESS. Taken together, these two provisions are expected to drive up to $1 trillion in BESS investments by the early 2030s (Ibid.). Moreover, the extension of the ITC to standalone BESS shifts the relative attractiveness of standalone vs. colocated BESS.

Despite having received no ITC before the IRA, standalone BESS still accounted for 42% of total U.S. capacity in 2023 (Lenoir and Marjolin 2023). This is a result of standalone BESS having more siting and operational flexibility. According to a 2021 study by Lawrence Berkeley National Laboratory, BESS are useful for mitigating the volatility associated with increased renewable energy penetration, but they do not have to be interconnected to the grid at the same point as these resources. By choosing the optimal location in which BESS are most needed, such as a point of transmission congestion, standalone BESS can bring even more value to the electricity network than colocated BESS. The study found that adding a 4-hour BESS with half the nameplate capacity of a renewable power plant adds $10/MWh of electricity market value across the seven main ISOs, whereas a standalone BESS sited at the optimal location can add $12.5/MWh of value (Gorman et al. 2021). In terms of operational flexibility, standalone BESS do not have to operate in parallel with a generation resource, enabling them to more efficiently capitalize on scarcity pricing and high prices of ancillary services (Carolina Clean Energy Business Association 2023).

With standalone BESS now eligible for the same ITC benefits as colocated BESS, siting and operational flexibility is expected to make standalone BESS the more attractive option. While standalone BESS account for 43% of the overall pipeline in 2023 (Lenoir and Marjolin 2023), there is evidence that the share of standalone BESS among new projects under consideration is much higher (Leonti and Kline 2023). Although one should note that economies of scale of colocated systems can be an edge over standalone systems (Lenoir and Marjolin 2023).

Supply Chain Expansion and Cost Reduction

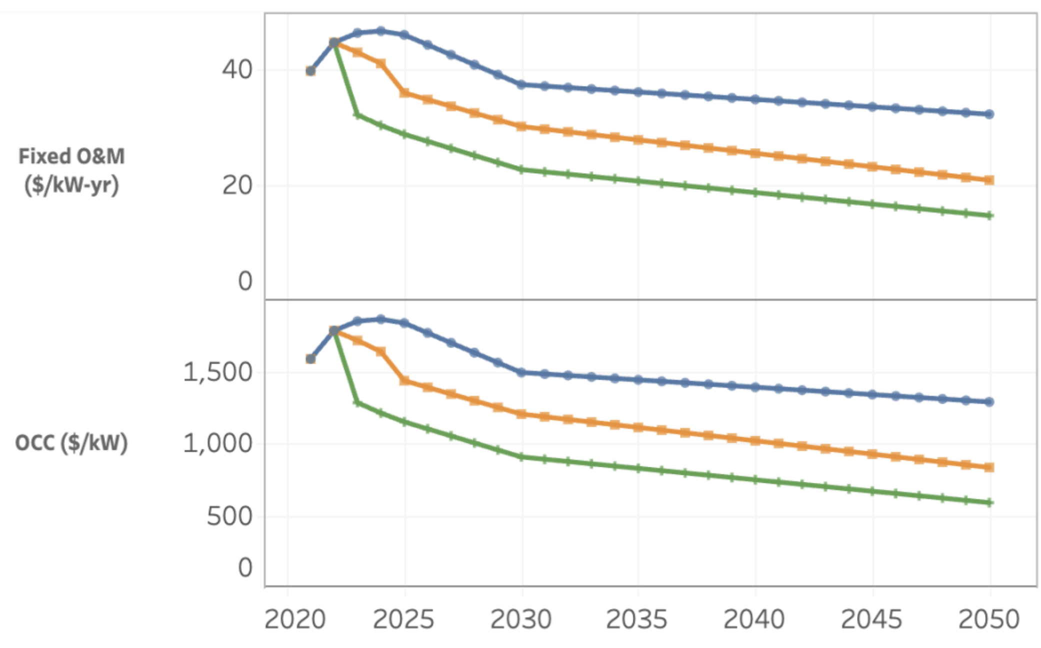
The IRA is supercharging BESS supply chain expansion in the U.S. and creating conditions for long-run cost reduction. By extending the ITC timeline and making standalone BESS eligible, the IRA is fueling expectations of growing downstream demand. In addition, the IRA created the section 45X advanced manufacturing credit for various technologies, including battery cells, modules, and inverters. Although storage inverters are not explicitly listed, the industry believes this to be an oversight rather than an intentional exclusion (Manghani 2023). Since the IRA was announced, there has been $120 billion of announced investments in U.S. assets along the BESS supply chain, according to a senior expert at Lawrence Berkeley National Laboratory. From the passage of the IRA to August 2023, developers have announced 14 new battery manufacturing facilities that would serve the BESS market (Manghani 2023). Note, however, that a December 2023 guideline excluded the cost of acquiring raw materials from the section 45X credits, leaving little support to domestic processing of critical minerals (Moerenhout and Brunelli 2024).

Domestic supply chain expansion, combined with the new section 45X credit, will likely have a two-fold effect. First, increased investment in domestic manufacturing spurs innovation, while the new manufacturing credit helps domestic producers compete, both leading to a lower cost of BESS inputs. Second, more competitive domestic input prices will help American manufacturers close the gap with Chinese producers and eventually allow BESS developers to qualify for the domestic content adder without compromising on the cost side. Both dynamics are long-term tailwinds for the economics of BESS. They are complemented by a trend unrelated to the IRA – the secular decline in battery cell and pack prices. As the industry continues switching to the low-cost LFP chemistry, and as new technologies such as silicon and lithium metal anodes and solid-state electrolytes mature, battery cell and prices will continue to decline, improving BESS economics over time (BloombergNEF 2023).

According to the NREL's Annual Technology Baseline (ATB) estimates, shown in Figure 27, utility-scale battery storage had an overnight capital cost (OCC) of $1,715/kW in 2023, which is projected to decline to $1,639/kW in 2024, drop further to $1,346/kW in 2025, and decline steadily to $1,111 by 2035. Fixed operations and maintenance (O&M) costs was $42.9/kW-yr in 2023 and is expected to drop to $41.0/kW-yr in 2024, $35.9/kW-yr in 2025, and decline steadily to $27.8/kW-yr by 2035 (NREL 2023).

Despite these long-term tailwinds, one should caution that short-term input prices can be volatile. On the one hand, lithium carbonate hit a low of 95,500 CNY / ton in early 2024, while lithium-ion battery pack prices hit a record low of $139/kWh in November 2023 (BloombergNEF 2023). As China came out of lockdown and producers ramped up production, demand did not follow. High interest rates, as well as the slower-than-expected adoption of EVs, dampened demand further (Khan 2023). On the other hand, the supply of processed raw materials and battery components is currently controlled by an oligopoly industry concentrated in China (European Commission 2022), so supply chain shortages and disruptions can cause short-term increases in BESS input prices.

Figure 27: Utility-Scale BESS Cost Projections

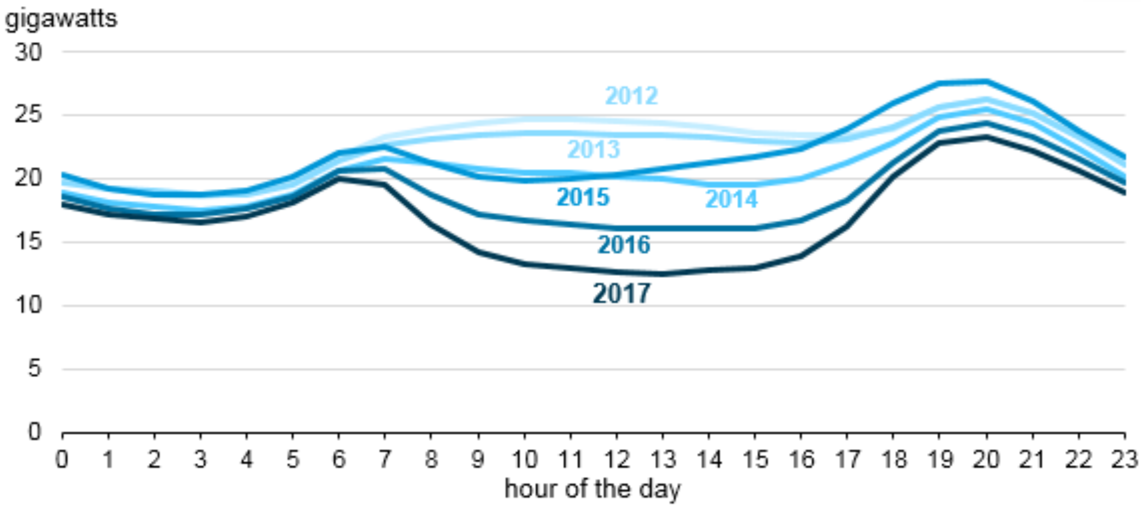


Source: NREL 2023

Growing Variable Energy Sources and Arbitrage Opportunities

A significant portion of BESS revenue comes from energy arbitrage, which is the most profitable when there is a high intraday spread in its wholesale electricity price, where a larger margin can be earned by charging during low-cost hours in the middle of the day and discharging during high-cost early evening hours. The intraday price spread and the profitability of BESS is highly correlated with solar and wind deployment. As more solar is deployed, net load decreases during mid-day when solar output is the highest, and the intraday price spread grows. As shown in Figure 28, CAISO's diurnal pattern of power prices became more pronounced from 2012 to 2017 as its solar capacity grew. Therefore, BESS economics tends to become more attractive with higher levels of solar deployment. As wind penetration levels increase, power price volatility increases due to the variability of wind power output (Martinez-Anido et al. 2016), making scarcity events more likely and creating arbitrage opportunities for BESS. To illustrate, a 2022 EIA study simulated power prices in ERCOT for four scenarios – 1) normal peak load and normal wind, 2) high peak load and normal wind, 3) normal peak load and low wind, and 4) high peak load and low wind. As shown in Figure 29, the authors find that when wind output is normal, normal and high peak loads result in peak power prices of $90/MWh and $105/MWh, respectively, with little scarcity pricing. When wind is low, however, normal and high peak loads result in peak power prices of $709/MWh and $2,905/MWh, respectively, with the majority of increases attributable to scarcity pricing (EIA 2022). Therefore, arbitrage opportunities and BESS economics improve with higher levels of wind penetration and associated scarcity pricing.

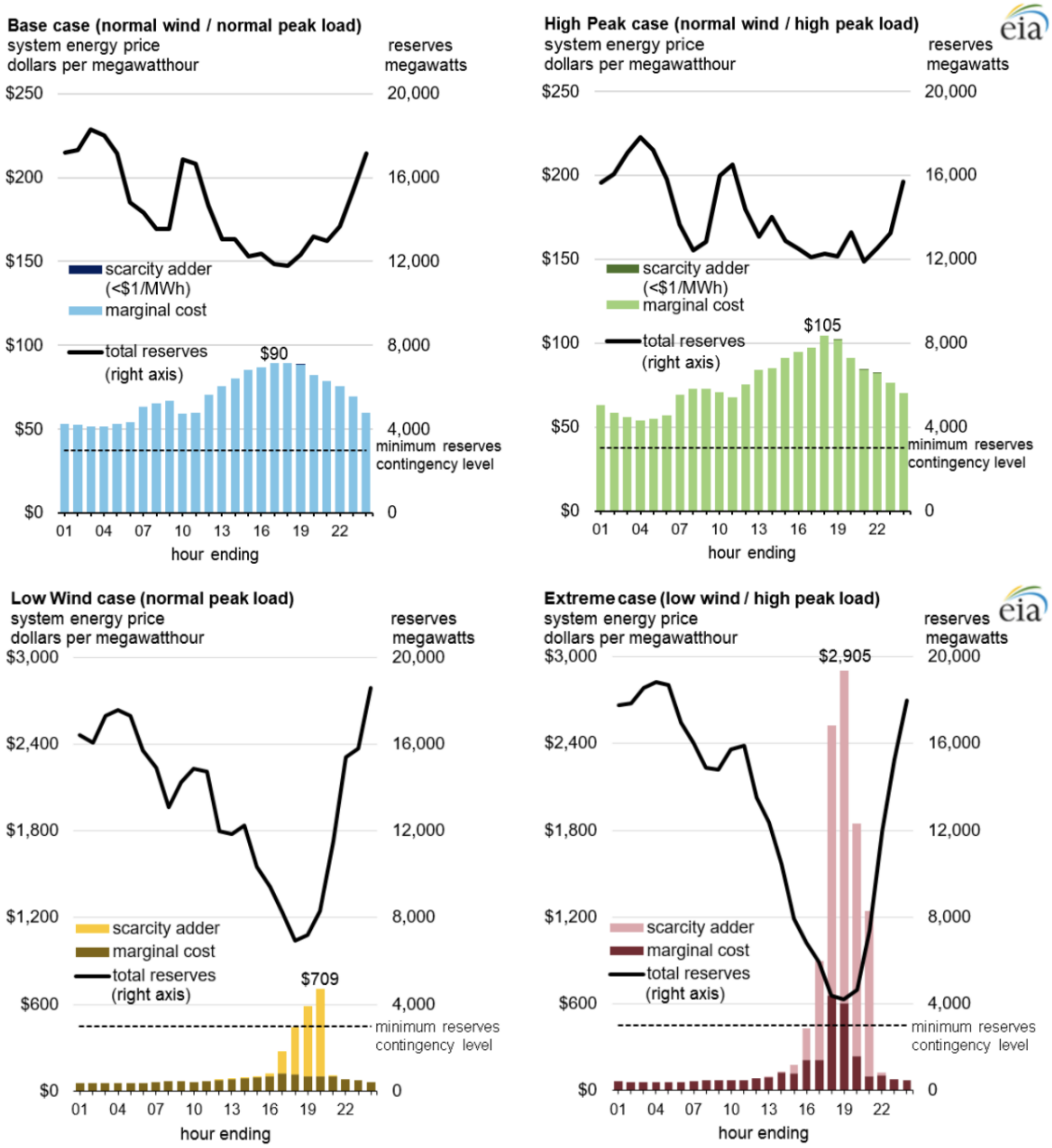
Figure 28: CAISO Average Net Electric Load



Source: EIA 2017

By encouraging higher levels of solar and wind deployment, the IRA is indirectly improving the economics of BESS. As discussed in our solar and wind sections, the IRA is facilitating project financing via the ITC and the PTC, as well as expanding supply chains via manufacturing tax credits. As solar and wind increase their footprints across ISOs, BESS arbitrage revenues are expected to increase significantly. Like the extension of ITC to standalone storage, this dynamic also shifts the relative attractiveness of standalone vs. colocated BESS. While BESS colocated with solar are designed for energy time-shifting, they have less flexibility to capitalize on the increasingly profitable scarcity events driven by wind. Similarly, BESS colocated with wind are less effective at arbitraging across the duck curve. In contrast, standalone BESS have much more flexibility to capitalize on the most profitable pricing events.

Figure 29: ERCOT Power Prices Under Various Scenarios



Source: EIA 2022

New Rules on Credit Eligibility and Accounting Treatment

The Internal Revenue Code section 50(b)(3) states that the ITC cannot be applied to a property used by a tax-exempt entity unless the property is used "predominantly in an unrelated trade or business the income of which is subject to tax." In practice, this means that BESS developers must be careful when working with tax-exempt offtakers and ensure that any offtake agreement with tax-exempt entities cannot be construed as a lease contract, in which case section 50(b)(3) can disqualify the BESS project from the ITC (IRS 2024). The IRA reduces uncertainty for BESS developers and investors by clarifying four safe-harbor criteria under which a BESS service contract will not be characterized as a lease:

1) The offtaker cannot have a right to operate the facility, 2) cannot have a purchase option other than for fair market value, 3) cannot benefit from operational cost savings, and 4) the tax-exempt entity must have meaningful rights in the case of the project's nonperformance (McGuireWoods 2022). Being able to rely on specific criteria when drafting offtake agreements allows BESS developers and investors to deploy capital with greater confidence.

The IRA also offers BESS the option to elect out of the "public utility property" normalization accounting method for projects exceeding 500 kWh in capacity, outlined in section 50(d)(2) of the International Revenue Code (IRS 2024). As this normalization method typically reduces the tax credit value, this provision is poised to raise the tax credit benefits for qualifying BESS projects (McGuireWoods 2022).

Opportunities

This section identifies the attributes BESS developers and investors should look for. Based on the above analysis as well as supplementary analysis on battery chemistry, project economics in different ISOs, and how the ITC affects equity returns, we find that standalone long-duration LFP BESS based in ERCOT West are the most attractive, and stakeholders should aim to qualify for the energy community adder whenever possible to allow for a greater margin of error.

Standalone BESS

The attractiveness of standalone BESS relative to colocated BESS arises from their siting and operational flexibility, features independent of the IRA. Standalone systems are not restricted by the production profiles of adjacent power plants, which allows them to perform energy arbitrage more efficiently and capitalize on more scarcity events. Since their siting is not tied to a facility, standalone BESS can be strategically placed in areas that maximize their utility and financial return. For instance, situating standalone BESS at points of high transmission congestion or in regions with the highest peak demand can significantly increase returns through more profitable arbitrage and scarcity pricing opportunities. This flexibility is expected to become even more important as more renewable facilities are deployed and relative value shifts from ancillary services to energy arbitrage. With the IRA leveling the playing field by extending making standalone storage eligible for the ITC, standalone BESS are now the more attractive option.

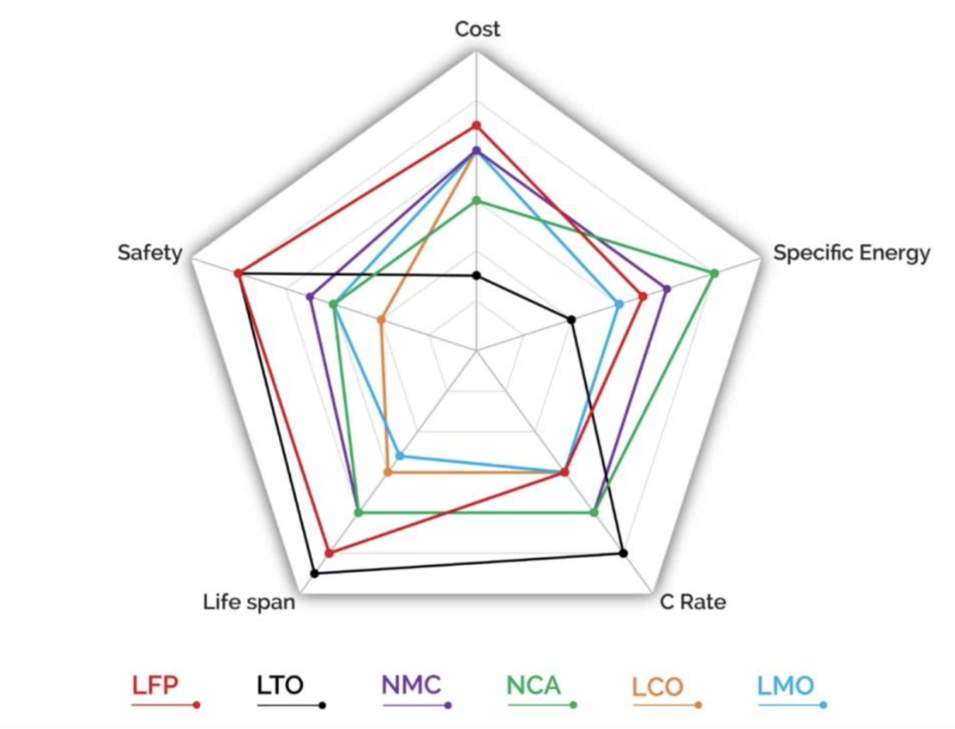
Long-Duration BESS

The value of long-duration BESS (2+ hours) lies in their ability to charge and discharge at full capacity for several hours. This capability is vital for managing evening peak loads or providing continuous power during periods of low solar or wind generation, both essential for sustained high ancillary services and capacity revenues. More importantly, a longer duration allows the BESS to charge for longer during trough hours and discharge for longer during peak hours, earning more in arbitrage revenue per kW per day. Shorter-duration BESS perform well in the ancillary services markets, but as ancillary services revenues dry up due to market saturation, BESS need to look elsewhere for revenue opportunities. To transition toward the lucrative capacity and arbitrage markets, a longer duration is desirable.

LFP BESS

Most of the BESS deployed in the U.S. are built with lithium-ion batteries, primarily due to their high energy density, reliability, and well-established manufacturing processes. Among various lithium-ion chemistries, LFP stands out as particularly attractive for BESS applications. LFP batteries offer significant advantages, including a longer cycle life and enhanced safety, as they are less prone to thermal runaway compared to other lithium-ion chemistries. Furthermore, LFP batteries are typically less expensive on a per-cycle basis due to their durability. These attributes align well with the requirements for large-scale energy storage, making LFP an increasingly preferred choice for BESS developers. While some point to the potential need for longer-duration batteries (10+ hours), a senior expert at Lawrence Berkeley National Laboratory argues that lithium-ion is hard to displace until there is much higher levels of renewables deployment, and lithium-ion will remain dominant in at least the next 5-10 years.

Figure 30: Comparison of Battery Chemistries



Source: Flash Battery 2022

ERCOT West

Given the high levels of solar, wind, and BESS deployment in CAISO and ERCOT, we perform a quantitative comparative analysis between the two and aim to identify the region with the more attractive economics for BESS. Since ERCOT West has the highest renewables penetration rate and intraday power price spreads than the rest of the ISO, we focus on ERCOT West.

A financial model is built for a 100 MW / 400 MWh BESS with 2.5% annual degradation, assumed to start operating at the beginning of 2024. OCC and fixed O&M in 2024 are taken directly from NREL ATB's estimates, and fixed O&M is assumed to decline at 2.6% per annum, a rate consistent with NREL ATB projections. Minimum debt service coverage ratio for debt sizing purposes is assumed to be 1.6x, and maximum debt financing as a percentage of project cost is assumed to be 80%. Debt is assumed to amortize over 18 years. Percentages of capex eligible for 5-year and 15-year modified accelerated cost recovery system depreciation are 95% and 5%, respectively. Finally, the tax rate is set at 21%.

For CAISO, capacity revenue in 2024 is assumed to be $76/kW-yr. This is the 2023 weighted average resource adequacy system capacity price of $6.35/kW-mo multiplied by 12 (CPUC 2021). Arbitrage revenue and ancillary services revenue in 2024 are assumed to be $71/kW-yr and $32/kW-yr, respectively, based on actual 2022 revenue data published by CAISO (CAISO 2023a). Note that we use aggregate BESS revenue data across CAISO as model inputs for a 4-hour BESS, a decision justified by the fact that 4-hour BESS is the norm in CAISO (CAISO 2023b). Based on S&P Global's forecasts, unit capacity and arbitrage revenues are assumed to grow at 1.4% and 8.5% per annum (S&P Global 2023b). Given the saturating ancillary services market, we assume that unit ancillary services revenue will decline at 10.0% per annum.

For ERCOT West, we assume no capacity revenue due to the lack of a formal capacity market. From analysis by Modo Energy, we learned that BESS earned on average $196/kW-yr across ERCOT in 2023, 15% of which came from arbitrage, and 85% of which came from ancillary services. Note, however, that BESS in ERCOT tend to have lower durations because they previously focused on providing ancillary services, so this revenue mix is not representative of 4-hour BESS, let alone one in the more lucrative ERCOT West. Based on supplementary analysis by Modo Energy, we know that long-duration (2+ hour) BESS earned "more than $100k/MW" (Modo Energy 2023). To be conservative, we assume that our 4-hour BESS in ERCOT West earns $100/kW-yr of arbitrage revenue in 2024, and we assume that its total revenue equals the $196/kW-yr ERCOT average, yielding an ancillary services revenue of $96/kW-yr. Based on S&P Global's forecasts for ERCOT West, unit arbitrage revenue is assumed to grow at 7.0% per annum (S&P Global 2023c). Due to the saturation of the ancillary services market, we assume that unit ancillary services revenue will decline at -10.0% per annum.

Based on the above assumptions, we calculated the after-tax levered IRR. For CAISO, we sensitize unit energy arbitrage and capacity revenues in 2024. For ERCOT, we sensitize unit arbitrage and ancillary services revenues in 2024. Most of the operating assumptions discussed above are used as the base case with the exception of the $71/kW-yr arbitrage revenue in CAISO. Since the data is from 2022, and CAISO arbitrage revenue received a boost by the September 2022 heat wave, we treat the $71/kW-yr arbitrage revenue as the bull-case assumption. The CAISO and ERCOT sensitivity tables are presented in Figure 31 below, assuming a 30% ITC.

Figure 31: CAISO and ERCOT West Returns Assuming 30% ITC

After-Tax Levered IRR – CAISO, 30% ITC

Capacity Revenue in 2024 ($ / kW-year)	Energy Arbitrage Revenue in 2024 ($ / kW-year): 41	46	51	56	61	66	71
48	2%	3%	4%	6%	8%	9%	11%
58	3%	5%	6%	8%	10%	12%	14%
68	5%	6%	8%	10%	12%	15%	18%
78	7%	8%	10%	12%	15%	18%	22%
88	9%	11%	13%	16%	19%	23%	29%
98	11%	13%	16%	20%	25%	31%	31%
108	14%	17%	21%	26%	31%	31%	31%

After-Tax Levered IRR – ERCOT West, 30% ITC

Ancillary Services Revenue in 2024 ($ / kW-year)	Energy Arbitrage Revenue in 2024 ($ / kW-year): 70	80	90	100	110	120	130
66	3%	5%	8%	11%	16%	22%	31%
76	3%	6%	9%	13%	18%	26%	31%
86	4%	7%	10%	14%	20%	30%	31%
96	5%	8%	11%	16%	23%	31%	32%
106	6%	9%	13%	18%	27%	31%	32%
116	7%	10%	15%	21%	31%	31%	32%
126	8%	12%	17%	24%	31%	32%	32%

In our base case, after-tax levered IRR is 16% in ERCOT West, higher than CAISO's 12%. Assuming an equity hurdle rate of 16%, a 4-hour BESS in ERCOT West is at the money with our base-case operating assumptions, but it is not the case with CAISO. In other words, the attractive arbitrage opportunities and lucrative ancillary services markets created by the volatile price signal more than offset any negative impact of the lack of capacity revenue.

The relative attractiveness of ERCOT West arises from a combination of factors. First, the isolation of ERCOT from neighboring ISOs means it cannot draw from external power sources during times of scarcity and peak demand, which translates into high ancillary services and power prices. Second, while it means one less revenue stream, the lack of a formal capacity or resource adequacy market in ERCOT also means a more volatile price signal, which translates into more arbitrage opportunities. Third, ERCOT has an extremely high penetration of wind. As discussed earlier, an EIA study found that the low wind output corresponds to the most extreme scarcity events, where power prices can reach $2,905/MWh with low wind and peak demand (EIA 2022). With high wind dependence and high scarcity pricing, ERCOT presents the most attractive arbitrage opportunities for BESS. Fourth, ERCOT is also home to a disproportionate number of extreme weather events, which can lead to significant fluctuations in power demand and supply, creating additional opportunities for energy storage systems.

Energy Community

While we did not find that the energy community adder played a significant role in project siting, we do recommend obtaining the adder for BESS due to the inherent volatility in revenue streams. Leveraging the model discussed above, we generate ERCOT West after-tax IRR sensitivity tables for three scenarios – 30%, 40%, and 50% ITC earned. As shown in Figure 32, going from 30% to 40% ITC significantly improves returns and allows for a greater margin of error in our operating assumptions. Given the volatility in power and ancillary services prices, BESS projects would benefit from the additional safety provided by the 10% energy community adder. For example, with energy arbitrage revenue dropping down to $90/kW-yr and ancillary services revenue declining to $86/kW-yr, levels significantly below 2023 data, a 40% ITC still keeps the BESS project at the money with a 16% IRR. While the domestic content adder is more difficult to achieve given the structure of the BESS supply chain, developers should actively seek out this adder once it becomes feasible, as a 50% ITC allows for even a greater margin of error.

Risks and Mitigations

Despite the new standalone investment tax credits, battery storage systems still face significant roadblocks in the path to large-scale deployment.

The most notable challenge is constraints in the critical mineral supply chain. On December 15, 2023, the Treasury proposed a rule on 45X Advanced Manufacturing Production Tax Credits, defining eligible components that can claim the benefit (Federal Register 2023). This proposed rule explicitly excludes the cost of acquiring raw minerals – which is more than 70% of lithium sales price–and gives very limited support to domestic processing of critical minerals (Moerenhout and Brunelli 2024). Currently, China holds 67% of global refined lithium and dominates the upstream supply chain for LFP batteries (Brunelli et al. 2023). However, there have been reports that connect forced labor with the production of lithium in China and U.S. government agencies might take actions to ban raw material/battery stack component imports from China (similar to the Uyghur Forced Labor Prevention Act for the solar industry) (Clean Energy Associates 2023). To mitigate these risks, project sponsors should work with suppliers that improves accountability and traceability in

Figure 32: ERCOT West Returns Under Various ITC Scenarios

After-Tax Levered IRR – ERCOT, 30% ITC

Ancillary Services Revenue in 2024 ($ / kW-year)	*Energy Arbitrage Revenue in 2024 ($ / kW-year)* 70	80	90	100	110	120	130
66	3%	5%	8%	11%	16%	22%	31%
76	3%	6%	9%	13%	18%	26%	31%
86	4%	7%	10%	14%	20%	30%	31%
96	5%	8%	11%	16%	23%	31%	32%
106	6%	9%	13%	18%	27%	31%	32%
116	7%	10%	15%	21%	31%	31%	32%
126	8%	12%	17%	24%	31%	32%	32%

After-Tax Levered IRR – ERCOT, 40% ITC

Ancillary Services Revenue in 2024 ($ / kW-year)	*Energy Arbitrage Revenue in 2024 ($ / kW-year)* 70	80	90	100	110	120	130
66	5%	8%	12%	17%	25%	34%	34%
76	6%	9%	14%	20%	30%	34%	34%
86	7%	11%	16%	23%	34%	34%	35%
96	8%	12%	18%	26%	34%	34%	35%
106	9%	14%	21%	31%	34%	35%	35%
116	11%	16%	24%	34%	34%	35%	35%
126	12%	18%	28%	34%	34%	35%	36%

After-Tax Levered IRR – ERCOT, 50% ITC

Ancillary Services Revenue in 2024 ($ / kW-year)	*Energy Arbitrage Revenue in 2024 ($ / kW-year)* 70	80	90	100	110	120	130
66	8%	13%	19%	29%	37%	37%	38%
76	10%	15%	22%	34%	37%	38%	38%
86	11%	17%	26%	37%	37%	38%	38%
96	13%	20%	30%	37%	38%	38%	39%
106	15%	23%	36%	37%	38%	38%	39%
116	18%	27%	37%	37%	38%	38%	39%
126	21%	32%	37%	38%	38%	39%	39%

preparation of greater scrutiny of supply chains. The supplier should demonstrate traceability in both the physical flow of materials (e.g., barcode affixation, automated data input for verification, etc.) and the flow of information along the supply chain (e.g., contracts with embedded ESG requirements and Codes of Conduct) (Clean Energy Associates 2023).

Another regulatory hurdle pertains to fire hazards. Authorities having jurisdiction are concerned about the threat of thermal runaways exploding or catching fires in lithium-ion batteries. However, most local authorities often lack experience and knowledge about the required permitting process to support BESS construction projects (Quiroga 2023). The need for BESS technology to comply with local fire codes presents new and unique challenges to local governments, causing delays in permitting and preventing efficient project execution. To streamline the process and minimize waiting time, project sponsors can take proactive measures like determining which codes are required, preparing early due-diligence studies, and sharing information on all ancillary project elements to expedite permitting (Ibid.).

In terms of project economics, BESS are more exposed to merchant risk than other renewable energy projects. Few markets are willing to offer fixed capacity payments for utility-scale battery systems. Utilities and system operators are hesitant to take on energy arbitrage risk. For instance, ISO New England is using storage as transmission-only assets, effectively stopping them from competing in the electricity markets and disrupting wholesale prices (Walton 2023).

According to the U.S. Energy Information Administration's 2022 report on standalone battery storage deployment, battery systems are hard to finance without capacity contracts. When raising capital for merchant BESS projects, project sponsors should structure the revenue stack to maximize cash flow certainty. As new data centers continue to drive demand for 24/7 clean electricity, standalone BESS projects can aim for offtake contracts with data centers to provide mid-duration energy storage and backup power (Reppas 2024).

Energy arbitrage has been one of the main drivers for new investments in BESS (Dilekci et al. 2023). Projects benefit from high price volatility in regions with scarcity pricing (e.g., ERCOT). However, as renewable generation buildout slows down and energy markets become saturated with battery storage, scarcity pricing will decrease and dampen arbitrage gains. Hence, project sponsors will be rewarded for early entry in unsaturated energy markets.

Finally, use of arbitrage strategies comes with the caveat of faster asset degradation (Pavageau and Kordyukova 2023). Project sponsors will need to cope with augmentation risk as they decide the frequency and timing of battery pack replacements. Between augmentations, sponsors also bear the cost of lost revenue resulting from lower project net capacity. A common practice to mitigate this risk is initial overbuild – installing extra capacity upfront to provide enough energy capacity through the project's lifetime (Burns & McDonnell 2022). If the project chooses to design for periodic augmentation, it is helpful to align battery supplier agreement with operational and performance requirements (Kleinberg 2021).

Alternative Fuels

Alternative Fuels

Introduction

Low-carbon alternative fuels will play a critical role in the energy transition, helping to decarbonize sectors that face cost or technological barriers to other decarbonization options like electrification. Alternative fuels can also be used as a transition fuel in hard-to-abate sectors like aviation and heavy-duty transport, where electrification or zero-carbon options are not feasible. Fuels like renewable diesel (RD), sustainable aviation fuel (SAF) and renewable natural gas (RNG) benefit from their compatibility with existing fuel infrastructure and end uses. Historically, low-carbon fuels have not been able to reach cost-parity with their fossil counterparts, making it difficult for low-carbon fuel producers to compete in the marketplace.

Policy support is critical for increasing the development and adoption of low-carbon fuels. The Renewable Fuel Standard (RFS) mandated the use of renewable fuel blends, guaranteeing a market for producers and de-risking investment. Nonetheless, low-carbon fuels continue to be uncompetitive and sell at a premium. The IRA seeks to bring the cost of low-carbon fuels down by stimulating investment in production through several tax credits aimed at low-carbon fuels. This section will explore IRA incentives for alternative fuels, focusing on the adoption opportunities of Renewable Natural Gas, an underutilized resource with significant potential, and SAF, a burgeoning technology vital for decarbonization, both poised for growth through IRA support.

IRA Fuels Tax Incentives

40B Sustainable Aviation Fuel PTC The first of its kind, SAF PTC is eligible for aviation fuel with at least 50% lower emissions than standard jet fuel.[3] Beginning in 2023, the SAF PTC will be available until December 31, 2024 at which point SAF will be eligible for the 45Z Clean Fuel Production Tax Credit. The base credit for SAF produced is $1.25/gallon with a $1.01 adder for every percentage point above 50% emissions reduction, with a maximum credit value of $1.75/gallon.

45Z Clean Fuel Production Credit (CFPC) The IRA introduced the section 45Z CFPC, a technology-neutral PTC that will consolidate expiring fuel credits beginning January 1, 2025. Any non-aviation fuel produced with emissions less than 50kg CO2e/MMBtu will qualify for the base credit of $0.20/gallon. The CFPC is calculated by multiplying the base credit amount per gallon by the fuel's emissions factor[4], with a 5x multiplier for meeting prevailing wage and apprenticeship (PWA) requirements, as shown in Figure 33. The maximum credit value for non-aviation fuels is $1.00/gallon for facilities with 0 kg CO2e/MMBtu emissions that meet PWA requirements (Congressional Research Service 2023).

[3] A SAF GREET Model is expected to be complete in early 2024 for SAF producers to verify emissions. Until then, CORSA LCA models can be used to assess emissions. ASTM approved SAF pathways are also eligible.

[4] Emissions factor = [(50kg of CO2e per MMBTU) – (Fuel kg of CO2e per MMBTU)] / [50kg of CO2e per MMBTU]

Figure 33: Estimated §45Z CFPC Values

Assumed kg of CO2e per MMBTU	Emissions Factor	Does not meet PWA reqs	Meets PWA reqs
Non-aviation Fuels			
0	1.0	$0.20	$1.00
10	0.8	$0.16	$0.80
25	0.5	$0.10	$0.50
40	0.2	$0.04	$0.20
50	0.0	$0.00	$0.00
Aviation Fuels			
0	1.0	$0.35	$1.75
10	0.8	$0.28	$1.40
25	0.5	$0.18	$0.88
40	0.2	$0.07	$0.35
50	0.0	$0.00	$0.00

Source: Calculations by Congressional Research Service based on IRC §45Z

The CFPC also includes SAF, following the sunset of the 40B tax credit in 2024. The base credit for SAF is $0.35/gallon of SAF produced. Like non-aviation fuels, the aviation credit increases with emissions reductions and meeting PWA requirements, for a maximum credit of $1.75/gallon produced, as shown in Figure 33 (Congressional Research Service 2023).

The CFPC will be eligible for fuel produced after December 31, 2024 and sold before December 31, 2027. The CFPC cannot be stacked with the 45Q CCUS tax credit, the 45V clean hydrogen PTC or the section 48 ITC for a specified clean hydrogen facility (Congressional Research Service 2023). Further guidance on the CFPC implementation has yet to be released from the Department of the Treasury and Internal Revenue Service (IRS).

Section 48 Energy Property Investment Credit This ITC allows for investments into qualified energy properties to receive an investment tax credit of up to 50%. Eligible energy properties include “qualified biogas properties,” as facilities that convert biomass into biogas that is captured for use or sale, and facilities that clean and condition the gas. The Department of Treasury released a correction to the section 48 proposed regulation to ensure that upgrading equipment necessary for the production and pipeline injection of RNG is considered a qualified biogas property and thus eligible for the ITC (Department of Treasury 2024).

The ITC credit ranges from 6-50% of investment. The base credit is 6%, plus a 5x multiplier for meeting PWA requirements, plus a maximum of 10% domestic content adder, plus a maximum of 10% energy community adder. Projects eligible for the ITC must begin construction prior to December 31, 2024.

Alternative Fuels Excise Credit This tax credit was extended under the IRA until December 31, 2024, and provides a $0.50/gallon tax credit to eligible fuels. Eligible fuels include natural gas, liquefied hydrogen, propane, P-Series fuel, liquid fuel derived from coal through the Fischer-Tropsch process, and compressed or liquefied gas derived from biomass (includes RNG).

Second Generation Biofuel Credit The IRA extended the section 40B second generation biofuel credit until January 1, 2025. Second generation biofuels are made with agricultural waste feedstocks. The PTC starts at $1.00/gallon of biodiesel produced and $1.01/gallon of cellulosic ethanol[5] produced.

Alternative Fuels Tax Credit Transfers

The transferability of tax credits in the IRA has streamlined market participants to easily buy and sell tax credits while increasing liquidity and investment in clean energy projects.

The section 48 ITC has seen a high number of tax credit transfers in bioenergy, second only to standalone solar tax credit transfers, according to Crux, a tax credit transfer marketplace (Crux 2023). Crux has found that the average section 48 ITC deal size is $18.28 million, with an overage credit price of $0.90, but some public deals have closed at over $50 million (Crux 2023). Aemetis Biogas closed a sale of $53 million in section 48 tax credits, generated from a variety of biogas and RNG projects, to a corporate buyer in late 2023 (Aemetis 2023). Aemetis will use the tax credit sale to support additional projects and investments, including CCUS and SAF. In January 2024, Anaergia Inc. entered into agreement to sell $15.6 million in tax credits generated at a subsidiary's biogas facility (American Biogas Council 2024). In February 2024, Virentis Advisors announced the closure of three section 48 RNG tax credit sales to corporate buyers for a total of $55 million (Virentis Advisors 2024).

ITC transfers can help projects to get off the ground by addressing up front capital needs or be used as a source of financing that needs to be competitive in an existing market and maximize returns.

Close Up: Renewable Natural Gas

Key Insights

RNG is produced from biogas, which comes from biomass sources such as landfills, agricultural sites, food waste, and wastewater treatment facilities. The biogas is then refined and upgraded to be used for heating, electricity, and as fuel for vehicles, or injected into natural gas pipelines. Most RNG in North America comes from landfill biogas, with Texas and California being significant producers (Wood Mackenzie 2023). While investments are increasing following the passage of the IRA, it does not allow for RNG production to be cost-competitive with natural gas without previous existing regulatory incentives.

Despite the high cost of production compared to conventional natural gas, the aforementioned incentives make RNG production economically viable. These incentives include the section 48 Energy Property ITC, the Alternative Fuels Excise Tax Credit, the federal RFS, and Low Carbon Fuel Standard (LCFS) which allow RNG to be sold at a premium. LCFS programs currently exist in California, Oregon, and New Mexico. Without policy and regulatory incentives, RNG would not be economically viable, and the RNG market is conditionally existent upon these policies.

The costs for RNG projects can be extensive and vary by facility, with considerations for location, feedstock procurement, digestion, upgrading, and injection. Larger projects tend to have lower per-MMBTU costs. The feasibility

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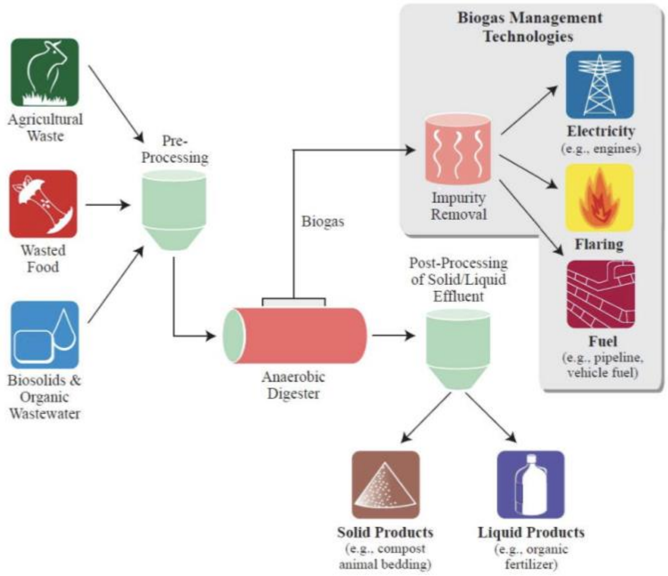
[5] Cellulosic feedstocks include non-food based crops and residues, energy crops, and other waste materials.

of pipeline-RNG projects is contingent on the proximity to natural gas pipelines (O'Malley and Pavlenko 2023). The Midwest has the highest capacity potential, attributed to agriculture and landfill biogas production (Wood Mackenzie 2023), but without the same financial incentives as states like California or Oregon with established LCFS.

RNG currently makes up less than 1% of the natural gas market, often seen as a transitional fuel towards cleaner energy systems (Chase 2023). While there's no lack of use for RNG due to its compatibility with existing infrastructure, the supply is expected to grow slowly, reaching only 3% of the total U.S. natural gas supply by 2050 under optimistic scenarios (Wood Mackenzie 2023b)

Technology

Figure 34: Biogas Production and End-Use Schematic



Source: EPA 2017

RNG is produced by separating and refining methane from biogas. Biogas is generated from biomass at landfills, agricultural sites, from food waste, or at wastewater treatment facilities (WWTF), primarily through anaerobic digestion. Biogas on its own is roughly 60% methane, and cannot be injected into pipelines, but can be used to produce heat or electricity, typically for onsite use, or is flared onsite to reduce the emissions of methane. Once biogas is upgraded to RNG, it can be used for local vehicle fleets or injected into a pipeline network (Alternative Fuels Data Center 2024)

The section 48 Energy Property ITC allows for biogas facilities to displace flared methane by improving their system efficiency by re-using biogas onsite, as well as for RNG upgrading and injection equipment. RNG can be directly injected into existing natural gas pipelines, but the cost of production renders RNG uncompetitive with standard natural gas. However, financial incentives like the section 48 ITC, on top of existing policy incentives including the RFS and LCFS that allow RNG to sell at a premium and RNG production has become more attractive to large biogas producers.

Of the nearly 200 RNG projects online in the United States in 2016, only 50 included upgrading and pipeline injection (EPA 2017).

Project Economics

Costs of RNG projects can vary greatly depending on the characteristics of the facility. Project costs primarily account for feedstock procurement, anaerobic digestion, upgrading equipment, compression and injection, interconnection, and potentially pipeline extension (EPA 2016). Existing biogas producers with anaerobic digesters and located near gas pipeline networks will only need to pay for upgrading and injection. Upgrade and injection costs decrease as project size increases (EPA 2017). Upgrading, injection, and interconnection tend to be the largest costs in production, with interconnection alone ranging from $1.5 - $3 million (EPA 2017, 2020). Research suggests that existing biogas facilities in California can produce RNG for pipeline injection from $7/MMbtu to $25/MMBtu depending on project size (EPA 2017).

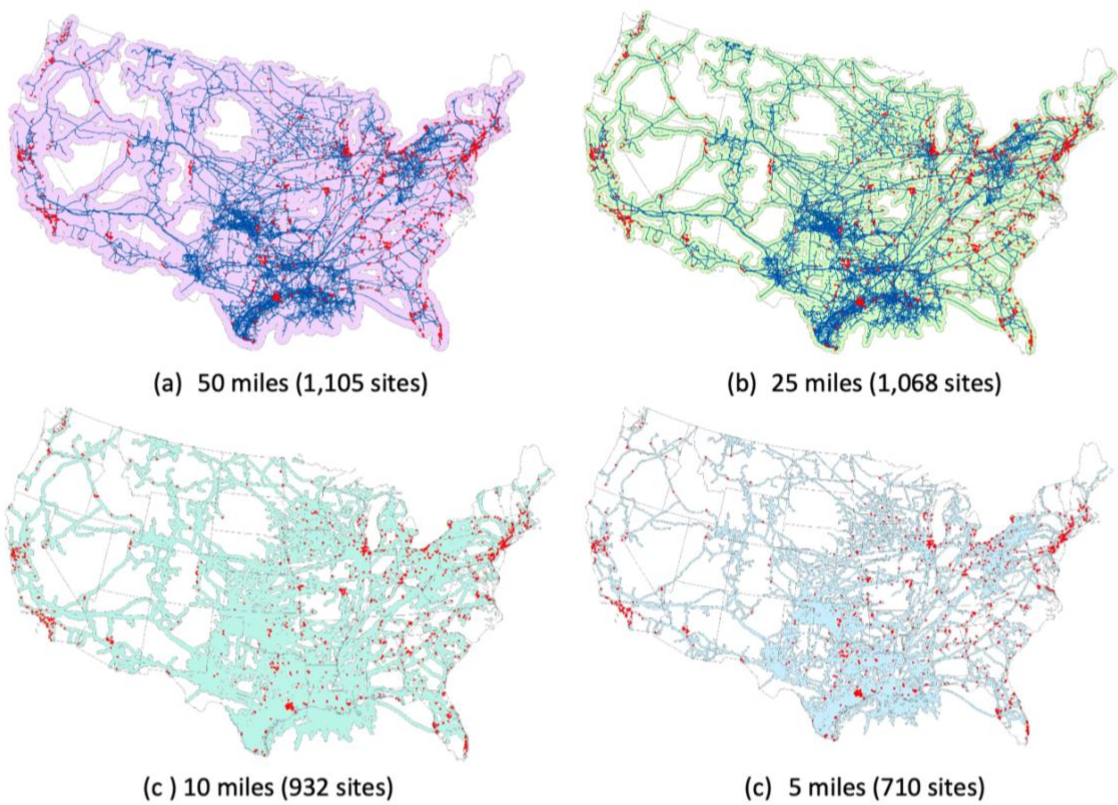
Texas and California, due to large landfill gas, are already key markets. Developers are also targeting new markets in the Midwest with large agricultural and landfill feedstocks that have yet to be capitalized on (PR Newswire 2023). Large biogas producers, like WWTF and agricultural facilities, that are within 5 miles of natural gas pipelines as well as in LCFS states will benefit from more advantageous economics. WWTFs are near large population centers and generally within 5 miles of pipeline networks (Ha et al. 2022), as shown in Figure 35.

Plants that already generate their own biogas-electricity on site, particularly combined heat, and power projects at WWTFs, have an additional advantage as there is no additional electricity cost for the power that is required in the RNG conversion process (Ha et al. 2022). WWTF could potentially provide up to 12% of U.S. electricity demand from biogas, which could spur further RNG production at these facilities (NACWA, WERF, WEF, 2013).

"We are at the tip of the iceberg of waste water potential."

- RNG Industry Source

Figure 35: WWTFs within 5, 10, 25, and 50 miles of natural gas pipelines

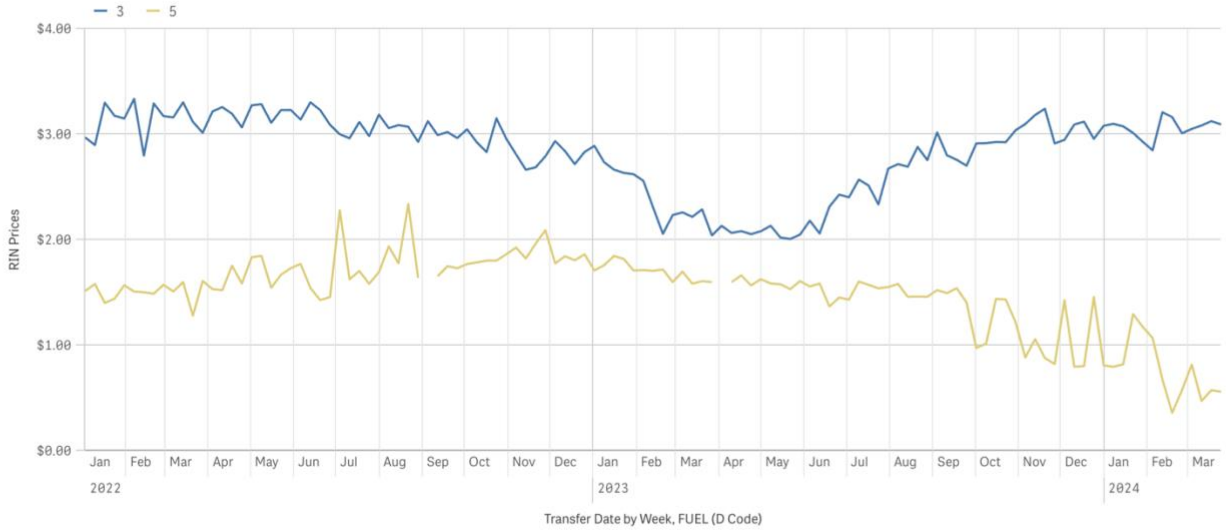


Source: Argonne National Laboratory 2022

Fuel standard incentives like the RFS and state LCFS assign higher values to renewable fuels like RNG. Under the RFS, RNG is typically identified by D3 Renewable Identification Numbers (RINs), except for RNG from WWTFs, that produce D5 RINS due to higher carbon intensity. Recent oversupply of renewable diesel has resulted in steep declines in the value of associated RINs, but D3 RIN values have remained high (Herring et al. 2024), despite historical volatility (EPA

2020), as shown in Figure 36. RFS RIN prices do not always guarantee favorable project financing as they can pose a regulatory threat if programs get overturned, however this market still offers the highest returns (MJ Bradley 2019). RNG projects can also contract long term PPAs with utilities to meet Renewable Portfolio Standards in states that mandate targets (EPA 2020).

Figure 36: D3 and D5 RIN Prices, 2022 – March 2024



Source: EPA 2024

By offsetting up to 40%[6] of upfront costs, the section 48 ITC can reduce the risk of RNG projects and increase confidence of investors and lenders. Costs can be further offset by a renewed Alternative Fuels Excise Tax Credit, which offers $0.50 per gallon of RNG used as a transportation fuel until December 31, 2024. Finally, RNG producers that can reduce emissions to less than 50kg CO2e/MMBtu can qualify for the 45Z CFPC beginning in 2025. In addition to tax credits, the IRA expanded the existing Rural Energy for America Program (REAP) which awards funds through loans and grants to rural small business and agricultural producers to make renewable energy investments (USDA 2024).

Findings from RNG Financial Modeling

Using a financial model, we were able to analyze the returns of a hypothetical RNG upgrading project. Our model assumed a biogas producer was already equipped with anaerobic digestion and upgrading their system to produce RNG for pipeline injection. Under these assumptions, the main cost drivers are upgrading and injection equipment and annual fixed costs. The assumptions are based on EPA cost estimates for this type of project (EPA 2017). This project model can elect for the section 48 ITC are Alternative Fuel Excise tax credit for $0.50 per gallon equivalent of RNG produced. The ITC is available for up to 40% of investment for qualified biogas properties, and generally generates a better return than the PTC, given that the PTC is only available until 2025 and does not address up front capital needs, which tend to pose the biggest barrier to adoption. The 45Z CFPC may be a profitable option for RNG projects, but the emissions guidance has yet to be released as of March, 2024, and it is not clear if RNG projects will qualify.

[6] Qualified biogas properties are not typically eligible for the 10% energy community adder.

Project size, offtake agreement, and offtake tenor are key drivers of our economic analysis. Our model also incorporated the value of D3 RNG RINs which was material in generating positive returns. Larger projects have higher upfront costs, but lower fixed costs and higher outputs that can valorize RFS and LCFS credits. Larger projects can handle lower offtake prices and shorter tenors, while small projects will require higher offtake prices and benefit from shorter project tenors. Figure 37 and 38 show an example model of a relatively small project producing about 14,000 MMBTU per year.

According to their press release, Aemetis Biogas not only completed a sale of $53 million of section 48 tax credits, but expects to qualify for more than $800 million of IRA benefits in the coming years that will support "biogas projects, CO2 re-use by [their] ethanol plant, the construction of [their] sustainable aviation fuel plant and CO2 sequestration" (Aemetis 2023). This type of IRA financing emphasizes the synergistic benefits across emerging technologies that can qualify for additional IRA tax incentives.

In addition to tax incentives, RNG co-products can also be recovered and used or sold. Nutrients from the feedstock, particularly at WWTFs, are often wasted but can be recovered as biosolids. Containing high amounts of nitrogen, potassium, and other micronutrients, the biosolids can be spread over soil or processed to produce fertilizer. However, due to potential contaminants in biosolids, some states do not allow for biosolids to be spread over soil, and processing for fertilizer should be the preferred end use. Several WWTFs in the U.S. have cost-effectively recovered nutrients for fertilizer production (Ha et al. 2022).

Figure 37: RNG Sample Model Inputs, Assumptions, and Returns

Operating Assumptions	
Technology Type:	**Alt Fuels**
Product Methane (MMBtu/H)	**2.6 Mmbtu/h**
Useful Life (years):	**20**
Capacity Factor:	**60.0%**
Annual Generation (MMBtu):	**13,666**
Offtake Price ($ / MMBtu):	**30.0**
Offtake Tenor (years):	**20**
Merchant Price ($ / MMBtu):	**-**
Merchant Years:	**-**

Tax Assumptions	
Federal Tax Rate:	**21.0%**
Tax Credit:	**Investment Tax Credit**
ITC % of Capex	**30.0%**
ITC Amount ($M):	**0.9**
PTC Price ($ / MMBtu gallon-e):	**-**
Annual PTC Escalator:	**-**
PTC Transfer Price (per $1 PTC):	**-**

Financing Assumptions	
Project Cost ($M):	**3.1**
Debt Amount ($M):	**2.1**
Debt Tenor (years):	**20**
Interest Rate:	**6.70%**
Minimum Annual DSCR:	**1.50x**
Equity Amount ($M):	**1.1**
Equity % of Financing:	**33.7%**

Returns	
Debt Repaid (years):	**6.0**
DSCR Minimum:	**0.24x**
DSCR Average:	**1.70x**
Equity Holders Pre-Tax NPV:	**0.0**
Equity Holders Pre-Tax IRR:	**5.5%**
Equity Holders After-Tax NPV:	**0.2**
After-Tax Levered IRR:	**7.1%**
After-Tax Unevered IRR:	**7.7%**

Figure 38: RNG Sample Model Sensitivities

Offtake Price Sensitivities (After-Tax Levered IRR) - ITC

Offtake Price ($ per MMBtu)	Interest Rate 5.20%	5.70%	6.20%	6.70%	7.20%	7.70%	8.20%
$24.00	-8.9%	-9.0%	-9.0%	-9.0%	-9.0%	-9.0%	-9.1%
$26.00	-4.6%	-4.7%	-4.7%	-4.7%	-4.3%	-4.3%	-4.3%
$28.00	-2.5%	-2.6%	-2.7%	-2.3%	-2.4%	-2.4%	-2.5%
$30.00	-0.6%	-0.8%	-0.6%	-0.7%	-0.8%	-0.9%	-0.6%
$32.00	1.6%	1.3%	1.1%	0.9%	0.7%	0.9%	0.7%
$34.00	4.2%	3.7%	3.4%	3.0%	2.7%	2.4%	2.2%
$36.00	7.5%	7.1%	6.3%	5.6%	5.0%	4.6%	4.2%

Offtake Term Sensitivities (After-Tax Levered IRR) - ITC

Offtake Term (years)	Interest Rate 5.20%	5.70%	6.20%	6.70%	7.20%	7.70%	8.20%
12	11.9%	11.4%	11.0%	11.0%	11.0%	10.2%	9.4%
13	11.5%	11.0%	10.6%	10.6%	10.4%	9.3%	8.7%
14	11.1%	10.6%	10.2%	10.1%	9.4%	8.8%	8.1%
15	10.7%	10.3%	9.8%	9.7%	8.9%	8.1%	7.7%
16	10.4%	9.9%	9.4%	9.2%	8.2%	7.8%	7.3%
17	10.0%	9.6%	9.0%	8.4%	7.9%	7.4%	7.0%
18	9.7%	9.2%	8.6%	8.0%	7.5%	7.0%	6.6%

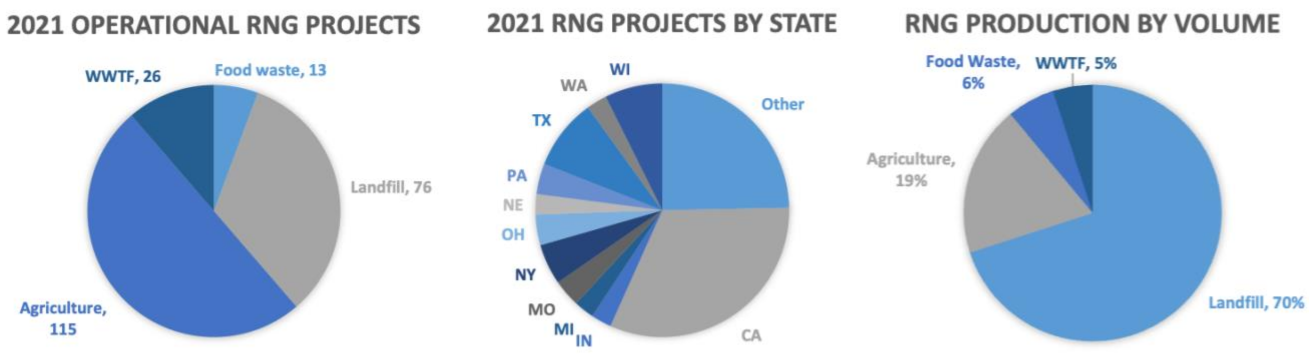
Due to the varied scale and unique economic features of RNG projects, it's essential to model each one individually, accounting for specific factors. However, we anticipate that environmental credits, like RINs, and IRA incentives will continue to play crucial roles in ensuring their success.

Market

The use of biogas and RNG has primarily been limited to onsite electricity or fuel use, but political incentives like the IRA are expanding the potential for fuel end uses. RNG makes up a very small portion of the natural gas market, but is attracting attention as a transition fuel from internal combustion engines to EVs (Chase 2023). RNG production in 2022 was 385 million cubic feet per day (cfd), and estimates suggest that technology and policy can increase production up to 4 billion cfd in 2050, which would represent 3% of total American supply (Wood Mackenzie 2023b).

70% of RNG produced by volume in North America is fed by landfill biogas, followed by 19% agriculture, 6% food waste, and 5% waste water. Texas is the largest producer (about 38% of total supply), followed by California (about 16% of total supply) (Wood Mackenzie 2023b). Investment in biogas systems has been growing steadily since 2014. Following the passage of the IRA in 2022, investment increased further, with a total of roughly $9 billion in RNG merger and acquisition deals (Wood Mackenzie 2023b). Production capacity is estimated to increase as much as 50% in 2024 following the passage of the IRA and the section 48 ITC (Chase 2023).

Figure 39: US RNG Market Snapshot



Source: Argonne National Lab RNG Database 2022

The proximity and availability of low-cost feedstocks is key to RNG financing, and some states stand out as target markets for this reason. Texas and California, due to large landfill gas, are already key markets. Developers are also targeting new markets in the Midwest with large agricultural and landfill feedstocks that have yet to be capitalized on (PR Newswire 2023). Other developers are converting food waste to RNG, including a new New Jersey project that will inject the RNG into the local natural gas network (South Jersey Industries 2023).

Remaining Challenges

RNG works just as well as fossil based fuel but is more expensive to produce. Financing profitable RNG projects is dependent on factors beyond project costs and selling price. Renewable fuel standards, renewable portfolio standards, and tax incentives are all major drivers of profitability and are not the same across the board. RFS credit prices can be volatile, not all renewable portfolio standards recognize renewable fuels (Ha et al. 2022), and tax incentives expire.

The section 48 ITC requires that qualifying projects begin construction prior to the end of 2024, yet IRS guidance has been updated as recently as February 2024, leaving just a few months to secure project financing and construction contracting. While large projects have been able to take on this regulatory risk, not all have, especially those that are upgrading biogas to RNG, which was addressed in the most recent guidance, clarifying that RNG upgrading equipment is eligible. Complex implementation and unclear timelines from the Department of Treasury has led some potential RNG projects to disregard the potential benefits of the IRA because the risk of meeting the construction deadline and the eligibility requirements is too high, according to a RNG industry source. More time to implement the section 48 ITC for qualifying biogas properties would likely increase investment into RNG projects. Qualifying RNG projects may be eligible for the section 48C advanced energy project credit, which allocated $10 billion to qualifying projects. In order to receive section 48C funding, projects must first apply for the credit, which can be a lengthy and time-consuming process that small projects may not have the resources for (IRS 2023). The DOE has announced the first $4 billion in credits to the first round of projects (DOE 2024).

RNG projects generally require risk-averse actors, like municipal landfill operators, municipal wastewater facility operators, or farmers to make expensive changes to their functional systems. While interest has increased in recent years, these actors tend to dislike change and taking risks on new technologies, so incentivizing behavior changes without ‘sticks’ can be difficult (Ha et al. 2022). A study from NYSERDA and WERF found that utilities and local municipal operators often lack the leadership and community support needed to use biogas for renewable energy, and that the environmental benefit is not enough to justify the project and the relatively slow payback time and upfront capital needs (Willis et al. 2012). Further, despite the highest potential, WWTFs provide the lowest share of RNG. With already tight economics and high-risk aversion, there are very low incentives without royalties, and often require the help of a third-party developer, according to an industry source. Public agencies like the EPA and USDA are continuing to raise awareness and work with small and medium biogas producers on how they can benefit from RNG production.

The biggest challenge the RNG market faces, according to an industry source, is valorizing the benefits of production. RNG displaces natural gas, abates methane flaring from the anaerobic digestion process, creates potentially valuable co-products, and is cheaper to produce than to abate methane in oil and gas production. The IRA Methane Fee will begin applying to oil and gas producers in 2024, starting at $900/MT of methane emitted. This may divert investments from traditional natural gas projects, that now come with a hefty emissions fee, to lower-carbon alternatives like RNG. Nonetheless, the market is still nascent and not well understood by many actors. Further recognition and valorization of RNG will aid in market and technological development.

Close Up: Sustainable Aviation Fuel

Key Insights

The IRA has incentivized SAF production in ways that other fuel policies have failed to do, namely by creating SAF-specific tax credits and premiums. The federal support behind SAF has been able to give more assurances to industry that SAF is a key focus of the United States' decarbonization pathway. However, the impact of the IRA on SAF has been limited thus far, and the expiration date of tax credits may be too early for realistic project financing.

> ***"The IRA has incentivized SAF and given assurance to industry in ways that other policies have not, but without a regulated demand, we don't know how much it will amount to."***
>
> ***- CGEP, RMI Researchers***

SAF is made from non-petroleum feedstocks and has at least 50% emissions reduction compared to standard aviation fuel, or "Jet A." SAF is blended up to 50% with Jet A, which can then be used as a drop-in fuel, requiring no changes to the aircraft or its engine. The demand for SAF is growing rapidly, despite no economies or technologies of scale. SAF has faced a lack of capital while investors wait for a dominant production pathway to emerge and costs to come down (Bradbury 2023).

There are seven ASTM[7]-certified production pathways for SAF as a drop-in replacement for Jet A. The dominant method is hydroprocessed fatty acid esters and fatty acids (HEFA), which uses plant-based or waste oils. However, alternatives such as Alcohol-to-Jet (ATJ) and Fischer-Tropsch (FT) synthesis are under development to reduce reliance on limited resources and inflexible supply chains. Further, SAF mandates in the UK and EU discourage SAF made from HEFA and food feedstocks, respectively, due to these concerns (UK Dept. of Transportation 2023, European Council 2023). However, the Midwest United States, for example, has high potential for low-carbon Alcohol-to-Jet (ATJ) SAF production due to its existing ethanol resources and transportation infrastructure (DOE 2024).

[7] The American Society for Testing and Materials (ASTM) is an International Organization that establishes safety and quality standards for fuels.

SAF is estimated as 2 – 4 times more expensive than traditional jet fuel, and while regulatory incentives like IRA tax credits attempt to reduce this cost barrier (Herbert, 2022), additional support will likely be necessary. The cost of SAF is primarily influenced by feedstock prices and availability. Emission reductions also impact economic viability by qualifying SAF for subsidies under the IRA and other fuel programs like the Federal RFS and State LFCS. The IRA, RFS, and LCFS incentives could bring some types of SAF to cost parity with JET A, but the technology may not be ready before incentives expire (ICCT 2023). Despite its higher cost, there is a significant demand for SAF from the aviation and shipping industries. Independent of demand growth, production is potentially constrained by feedstock opportunity costs in which lead feedstocks are diverted to other fuels, like RD production in the case of HEFA SAF, that use the same feedstock and have better economics (Chen et al. 2024).

Technology

There are seven SAF production pathways that are ASTM certified to be used as a drop-in replacement for Jet A (IATA 2020). The majority of SAF today, as well as 85% of announced SAF projects, is made from hydroprocessed esters and fatty acids (HEFA) (IATA, 2023). HEFA SAF is produced when plant-based or waste oils and greases, commonly cooking oil, is deoxygenated and hydroprocessed to produce hydrocarbons (IATA 2020). HEFA SAF is considered commercial (US DOE, USDA, DOT 2022). HEFA SAF will likely be the dominant technology in the early stages of the SAF market, while producers and investors are developing alternatives that are less reliant on inflexible supply-chains and face less resource competition.

Alcohol-to-jet (ATJ) fuel and Fischer-Tropsch (FT) synthesis show promise in providing additional SAF production pathways. ATJ uses ethanol or isobutanol as a feedstock (IATA 2020). To be converted into hydrocarbons, the alcohol is dehydrated, the molecules are combined, and then further refined into the finished product (IATA 2020). Certified ATJ alcohol feedstocks include sugarcane, sugar beet, sawdust, and agricultural residues (IATA 2020). Corn-based ethanol, which is currently blended into motor gasoline, has existing infrastructure and supply chain, which could allow for near-term scaling of SAF production, but would require additional up-stream emissions reductions (US DOE, USDA, DOT 2022).

The first ATJ facility opened in 2024 at the LanzaJet Freedom Pines Facility in Georgia, USA (LanzaJet 2024). LanzaJet will use low-carbon ethanol produced from several waste and sustainable sources, that it claims does not pose a threat to feedstock supply or scaling (LanzaJet 2024).

Ethanol made from agricultural waste, municipal solid waste, or other carbon waste, or "cellulosic ethanol" is a second-generation biofuel with considerably lower life cycle emissions than traditional corn-based ethanol (Alternative Fuels Data Center, 2024). Following the passage of the RFS in 2005, there was interest in producing cellulosic ethanol, but it proved to be difficult and costly, and very few projects survived (Service 2022). Cellulosic ethanol being produced for SAF today at Facilities like Freedom Pines and Gevo's planned Net-Zero 1 facility (Gevo 2023), boast diverse feedstocks that can sustain feedstock supply and price shocks.

Bio-based ethanol, including the corn ethanol industry in the United States, has the potential to deliver cost-competitive SAF that can meet the Biden Administration's Sustainable Aviation Fuel Grand Challenge target of 35 billion gallons produced annually by 2050 (DOE 2024). This will not only require market and further technological development but will require substantial up-stream and midstream emissions reductions. CCUS is a viable option to reduce emissions from the ethanol refining and fermentation process (Emery 2022), but agricultural emissions, which require behavioral and practice changes, will prove to be more difficult. Further, midstream transportation of ethanol, primarily by rail and truck (USDA 2013), will need to decarbonize as well. It is also important to note that corn ethanol often strikes the food vs. fuel debate, and several potential export markets, including the United Kingdom and European Union, explicitly prohibit SAF derived from food or feed crops as eligible feedstocks that can be used to meet SAF mandates (UK Dept. of Transportation 2023, European Council 2023).

FT synthesis gasifies feedstocks like coal, natural gas, and biomass into syngas that contains hydrogen and carbon monoxide. The syngas then undergoes catalytic conversion, producing liquid hydrocarbons through the Fischer-Tropsch reaction that can be blended up to 50% with Jet A (IATA 2020). e-SAF could also be produced via FT from green hydrogen and carbon captured from the atmosphere or a stationary source. In this process, green hydrogen is produced via electrolysis of renewable electricity and water, which is then combined with carbon monoxide that has been captured, through the Fischer-Tropsch reaction (Chen et al. 2023). e-SAF is not near commercialization, but could provide SAF in the long run that does not compete for feedstocks, like other SAF production pathways. In the near term, we should expect to see SAF from bio-based feedstocks, but e-fuels down the line as bio feedstocks become potentially difficult to procure, according to a source at the Rocky Mountain Institute. All SAF plants in the United States that are currently in operation or under construction produce ATJ or bio-FT SAF (Clean Investment Monitor 2023).

Additional SAF conversion processes are ASTM approved and in development, but are further from market-readiness. Backed by United Airlines, Honeywell UOP, AvFuel, US DOD, and US DOE, the National Laboratory of Renewable Energy (NREL) has partnered with Alder Fuels to produce SAF from only sustainable feedstocks using Alder Fuel's pyrolysis technology (Ringle 2022).

SAF conversion processes have room to improve, as current technologies are only about 30% efficient, with 70% of input feedstock wasted (NREL 2024). Figure 40 shows a scheme of biofuel conversion efficiency. Figure 41 estimates product yield proportional to SAF feedstock and conversion pathways (ICCT 2023).

Figure 40: Estimated Fuel Yield Based on Feedstock and Conversion Pathway

Feedstock	Conversion Pathway	Percentage of Production Optimized for Jet Fuel
Vegetable and waste oils	HEFA	59%
Municipal solid waste	FT	50%
Agricultural residues	FT	50%
Forestry residues	FT	50%
Energy crops	FT	50%
Corn grain and sugarcane ethanol	ATJ	75%

Source: O'Malley et al. 2023

Economics

Due to the variety and variability of SAF technologies, economics vary greatly, but certain factors are generally more impactful. Feedstock cost and availability is the most important economic factor, while emissions reductions also play a role in making fuel eligible for IRA and LCFS subsidies (Watson et al 2024). Because so few SAF facilities have gotten past demonstration in the United States, cost estimates are primarily based on scientific research.

In addition to varying feedstock collection and conversion costs, feedstocks need to be transported, and this can inhibit the economics of some projects sourcing feedstocks over long distances (Lewis et al 2018). Mid-stream transportation by truck or rail may also increase lifecycle emissions, potentially rendering SAF too carbon intensive to qualify for federal and state subsidies. Successful SAF projects should consider the cost and availability of feedstock, as well as the proximity in determining the best production pathway. Table 7 shows the estimated net production cost of SAF based on different feedstocks, conversion pathways, and regulatory incentives.

Figure 41: Net Production Cost of SAF with Regulatory Incentives

Feedstock	Conversion Pathway	Levelized Cost of Production ($/JGE)	RFS RIN Credit ($/JGE)	40B tax credit ($/JGE)	CA-LCFS ($/JGE)	Net Production Cost ($/JGE)
Soy Oil	HEFA	5.16	1.48	1.3	0.61	**3.39**
Corn Oil	HEFA	4.06	1.48	1.56	0.89	**0.13**
Used Cooking Oil	HEFA	4.06	1.48	1.59	0.94	**0.05**
Animal Fats	HEFA	4.06	1.48	1.5	0.83	**0.26**
Agricultural Waste	FT	7.95	3.6	1.66	1.01	**1.67**
Municipal Solid Waste	FT	4.07	3.6	1.69	1.04	**-2.27**
Forestry Waste	FT	7.95	3.6	1.66	1.01	**1.69**
Energy Crops	FT	8.64	3.6	1.75	1.21	**2.08**
Corn Grain	ATJ	6.68	0.84	0	0.13	**5.72**
Sugar Cane	ATJ	7.06	1.5	1.4	0.72	**3.44**

Source: O'Malley et al. 2023
Note: Standard jet fuel has a levelized cost of production estimated at $2/gallon
JGE = jet gallon equivalent

While the IRA tax credits like the 40B and 45Z may be able to help the few existing SAF producers bring down the cost of production, they require fuel to not only meet emissions reductions requirements, but be produced before the end of 2027. Longer-term support and solutions will be required to develop, diversify, and scale the SAF market. This is why, in addition to the tax incentives, the IRA established the Sustainable Aviation Fuel Grand Challenge, which targets 3 billion gallons per year of SAF by 2030, and 35 billion by 2035 (DOE, DOT, USDA, EPA 2022). In 2022, 15.8 million gallons of SAF were produced in the United States, accounting for less than 0.1% of jet fuel in the U.S. (GAO, 2023). In addition to outlining key near and long-term market development objectives, the U.S. Federal Aviation Administration (FAA) is providing grants of up to $50,000,000 to support domestic SAF development, also under the IRA (Alternative Fuels Data Center 2022).

Feedstock competition creates high opportunity costs for SAF and other renewable fuels as technologies and supply chains scale up. As aforementioned, in the case of HEFA, the same feedstock can be made into RD, which has better economics (Chen et al. 2023). Most HEFA facilities are optimized for RD production, and converting to SAF production required facility adjustments. Co-producing SAF and RD improves the overall project economics. Multi-fuel facilities designed for SAF and RD, are expected to come online in coming years with the help of IRA tax credits, and will increase SAF output depending on the selling price of RD (Lavinsky 2022).[8] Aemetis Biogas has permitted a SAF RD co-production plant in California that will produce 90 million gallons of fuel when producing 50% SAF and 50% RD, and 78 million gallons a year operating at 100% SAF (Aemetis 2024).

While demand for SAF is worldwide, production will be more economically advantageous in specific regions within the United States due to supportive policies in addition to the IRA and availability of feedstocks. Federal policies like the IRA and RFS, in addition to state support in California and Oregon under the LCFS will help bring down the cost of producing SAF, but feedstock availability may play a bigger role in determining economics. Biobased SAF will benefit from being near agricultural regions with existing transportation infrastructure. Meeting near-term SAF goals will require optimizing existing markets and infrastructure while simultaneously decarbonizing them. For example, improving the carbon intensity of corn ethanol to produce low-carbon ATJ SAF in the Midwest corn belt region. Midwest states like Minnesota[9] and Illinois[10] are realizing their potential to produce low-carbon fuels like SAF and have initiated policy measures in the absence of LCFS to advance the development of said fuels. Ethanol producers that are equipped with carbon capture can also benefit from the section 45Q tax credit. This, in addition to state SAF incentives, may allow ethanol ATJ SAF producers to pencil out projects without the 40B or 45Z PTC. By encouraging SAF production and use, states can not only reduce greenhouse gas emissions but will also foster economic growth and job creation.

Finally, Airlines operate on a tight cost margin, and are not able to pay fuel premiums that will get passed down to consumers who can simply switch to a cheaper airline. In December 2023, S&P Global Commodity insights assessed that SAF coming out of the Netherlands was valued at $2,845.75/mt, while conventional jet fuel was valued at $849.75/mt in the northwest Europe region (Washington, 2023). Many airlines are contracting SAF offtake agreements to generate voluntary corporate carbon credits that can be sold (Mulder 2022). The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) is a United Nations program that allows airlines to use SAF to meet carbon offsetting

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[8] Renewable Diesel prices are dependent on the price of D4 RINs. Recent overproduction of renewable diesel has caused the price of D4 RINS to drop significantly, nearing the break-even price.

[9] SAF sold in Minnesota between June 30, 2024 and before July 1, 2030 can claim $1.50 per gallon of SAF that is produced and sold in Minnesota.

[10] Airlines operating in Illinois can claim $1.50 per gallon of SAF derived from domestic biofuels through 2032.

requirements with approved fuels, these offset credits can then be bought and sold on the Aviation Carbon Exchange (ACE) (IATA 2024).

Market

Despite a continued cost premium, the SAF market is facing huge demand from captive, credit-worthy airlines and shipping companies. Offtake agreements with airlines currently range from 1-20 years and the total contracted volume of public deals is over 52,000 million liters, which account for less than 1% of all aviation fuel use and 3% of renewable fuel use in 2023. The International Air Transport Association (IATA) expects SAF production volumes to triple from 2023 to 2024, to 1.9 billion liters, but will still only account for 6% of renewable fuels. IATA estimates that SAF needs to account for 25-30% of renewable fuels to improve decarbonization and bring costs down (IATA 2023).

Virtually all SAF sold in the United States has been in the form of long-term offtake agreements. This allows airlines to purchase SAF in the future if price conditions are met. However, if the contracted SAF is not produced or the price is too high, airlines are not required to buy it and can contract new agreements. Several SAF offtake agreements have failed and no fuel is delivered, and partners instead enter into a new agreement. Further, there is very little price transparency and discovery in the SAF market, and the few existing producers do not have to compete to sell the cheapest product (GAO 2023).

The demand and mandates (e.g. RFS) for other renewable fuels like renewable diesel means that new production capacity for SAF, especially HEFA SAF, is often being diverted for production of RD, which keeps prices for SAF high (IATA 2023).

Nonetheless, the IATA expects 69 billion liters globally by 2028, and increasing capacity with more project announcements through 2030 (IATA 2023). Short term market growth projections estimate a compound annual growth rate (CAGR) from 2023 to 2030 of 47.7%, from a value of USD 1.1 billion to USD 16.8 billion (Markets and Markets, 2023). Long term estimates from 2023 to 2050 estimate a CAGR of 2.6%, reaching USD 402 billion by 2050 (GlobeNewswire News Room 2024).

Since 2018, $26.3 billion has been invested in US SAF projects. Only about 1% of this investment represents operating projects, with a majority yet to start construction (The Clean Investment Monitor 2024).

Remaining Challenges

Existing SAF technologies face several challenges: high costs, feedstock competition for scarce resources, and supply chain development. A reliable, cost-effective feedstock that can be scaled has yet to emerge on the SAF market. While HEFA SAF is expected to be the feedstock of choice in the coming years, it is dependent on limited resources that cannot meet the growing demand (Holladay et al. 2020). Table 8 shows the estimated SAF feedstock supply in the US. Current feedstock supply represents less than 20 billion gallons of annual SAF potential, in the best case scenario. Therefore, meeting the goal of 35 billion gallons of SAF annually by 2050 will require greater domestic feedstock supplies.

Figure 42: Existing Feedstock Supply and SAF Production Potential

Feedstock	Available Quantity (MT)	Potential annual SAF Production Potential (billion gallons)
Soy Oil	4.2	0.74
Corn Oil	0.7	0.37
Used Cooking Oil	1.1	0.48
Animal Fats	0.5	0.42
Agricultural Waste	161.1	4.88
Municipal Solid Waste	75.8	1.35
Forestry Waste	33.6	1.14
Energy Crops	89.7	2.72
Corn Grain Ethanol	43.9	6.89
Sugar Cane Ethanol	0.3	0.05
Total	410.9	19.04

Source: O'Malley et al. 2023

Not only are the necessary feedstocks, waste fats, oils and greases (FOGs), relatively limited, but they are also the main feedstock for RD, which is more economical to produce. RD facilities can co-produce HEFA SAF but require additional costs to further refine and separate the fuel from diesel. Further, RD is a drop-in fuel for diesel engines and production is further incentivized under the RFS, which mandates a Renewable Volume Obligation (RVO) for renewable fuels. Aviation fuel is not currently mandated under the RFS, and it is currently opt-in in other fuel standard programs like California's Low-Carbon Fuel Standard (LCFS). In the United States, including all IRA scenarios, RFS, and LCFS incentives, HEFA-based SAF maintains a positive price differential compared to renewable diesel, with a $1.59 price differential (Chen et al. 2023). In sum, current renewable fuel policies are diverting feedstocks away from SAF to more profitable fuels (Holladay et al. 2020).

Conclusion and Recommendations

The Inflation Reduction Act has directly incentivized the adoption of alternative transportation and aviation fuels through the section 40B sustainable aviation fuel PTC, and the 45Z clean fuel PTC, among others. However, the limited lifetime of the credits, expiring at the end of 2024 and 2027, respectively, only allows for fuels that are market-ready or in advanced development to benefit. Many alternative fuels that will be crucial for decarbonization will not be eligible for IRA incentives due to time constraints, and thus development may not happen.

The IRA has helped indirectly encourage the development of key infrastructure and resources that will be needed for long-term alternative fuel solutions that are not yet ready. This includes incentives for clean electricity, hydrogen production, carbon capture, and infrastructure. In addition to PTCs, the IRA has developed additional funding programs and opportunities for sustainable aviation fuel that may help support market development beyond 2027. Further regulatory support will be required to develop the market for all alternative fuels that are not economic without it.

Despite challenges, alternative fuels have potential to provide transitional and long-term fuels solutions in the energy transition. Unlocking this potential will depend on the swift development of markets, supply chains, and affordable production.

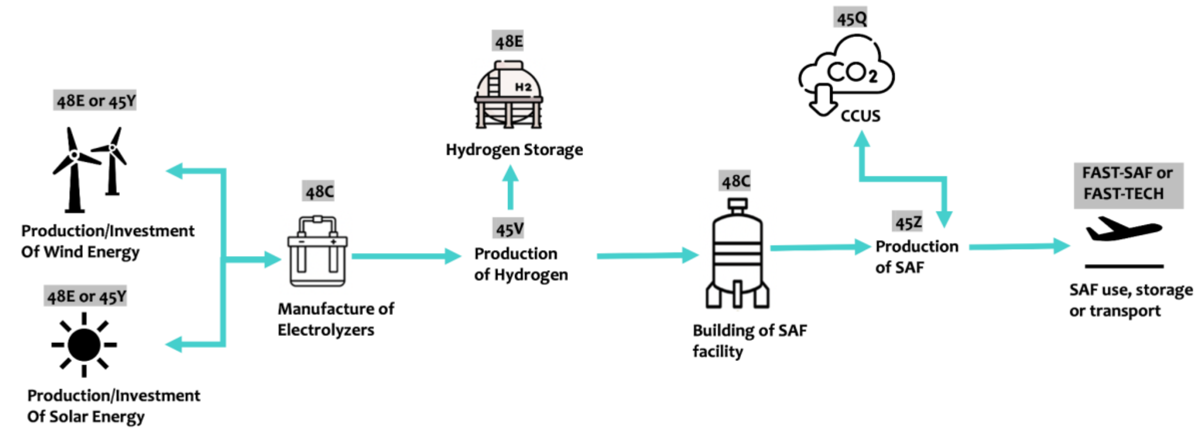
Renewable natural gas has the potential to be profitable immediately, with the advantage of mature technology, abundant feedstock potential, and strong regulatory incentives in addition to the IRA. However, the main driver of RNG projects under the IRA, section 48 ITC, is too short-lived and complex for many projects to obtain, which is inhibiting growth in RNG as a result. Without an extension of the 48 ITC, the economic viability of many RNG projects remains unchanged since the IRA.

Sustainable aviation fuel has seen huge increases in demand and investment since the IRA, but there are still relatively few projects operational or even under construction. This is likely due to the complex and still nascent SAF supply chain and technology, both of which have room for improvement. However, SAF that can take advantage of existing resources and infrastructure, such as ethanol-based alcohol-to-jet SAF, may be economical sooner than other types of SAF.

Bonus: E-Fuels

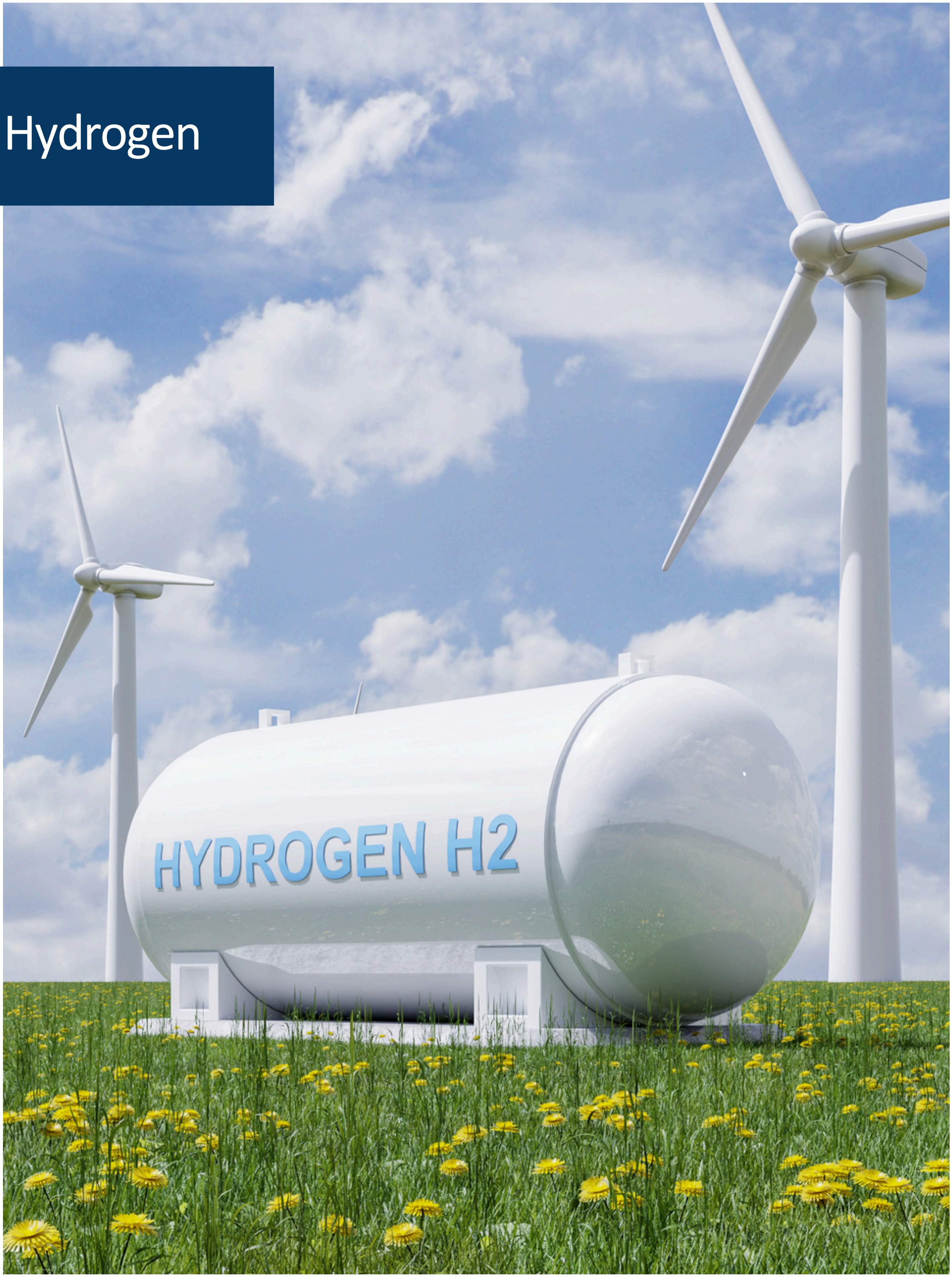
Electrofuels, or e-fuels, are clean, synthetic hydrocarbons produced from clean hydrogen and captured carbon. While not yet commercially viable, e-fuels can play a significant role in the long-term decarbonization of transportation. The IRA incentives e-fuels directly through tax credits like the 45Z CFPC, as well as indirectly through incentives for supply chain development. The 45V clean hydrogen production tax credit is seen as one of the biggest opportunities of the IRA, with the ability to reduce the cost of hydrogen by up to $3/kg of clean hydrogen production. With that, the section 48C advanced energy project investment credit provides up to a 30% credit on technology manufacturing investments, including for electrolyzers, which use clean electricity to separate hydrogen and oxygen in water. Clean electricity that powers the electrolyzer is also subsidized in the IRA, through either the 45Y production tax credit or 48E investment tax credit. Finally, the IRA increased tax benefits for carbon capture, utilization and storage under the 45Q credit. Captured carbon can then be synthesized with hydrogen into e-fuels through Fischer-Tropsch synthesis (DOE 2023). By bringing down the cost of the critical, cost-prohibitive elements of e-fuels production, the IRA clears a path to long-term market development for clean on-road and aviation transportation fuels.

Figure 43: Simplified e-Fuels Value Chain with IRA Incentives



Source: RMI 2023

Hydrogen



Hydrogen

Introduction

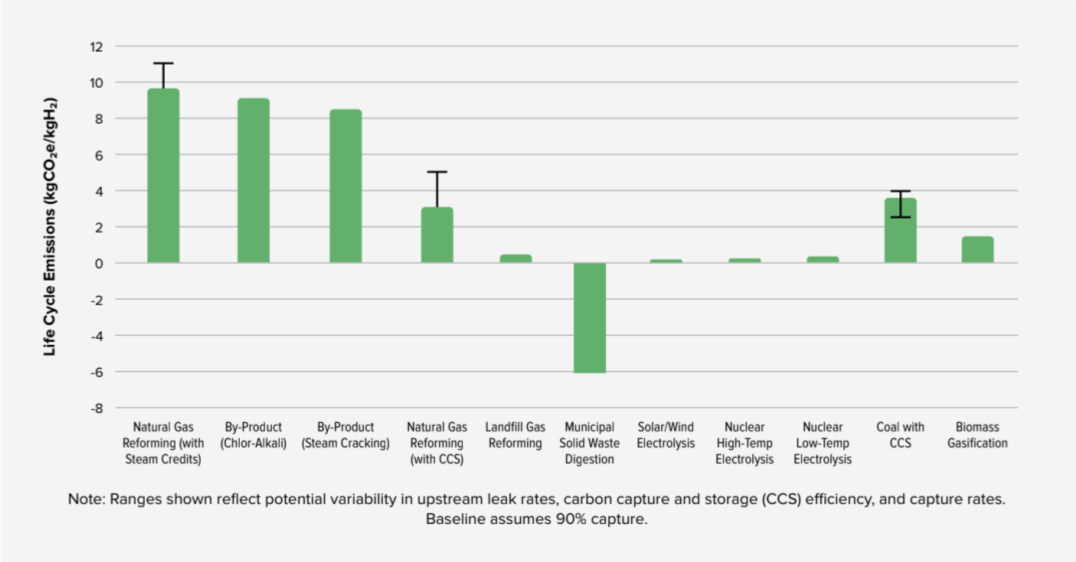
Hydrogen gas is a significant and internationally traded product, mainly utilized in various industries as a basic raw material or as an intermediate in processes like oil refining, methanol, and ammonia synthesis for fertilizers. Hydrogen also serves as a potential fuel or energy source, boasting the highest energy per unit of mass among current major fuels, such as diesel, natural gas, and petrol. 1 kilogram of hydrogen holds roughly the equivalent energy of 1 gallon (or 2.8 kilograms) of gasoline (Green Hydrogen Coalition, 2022).

The IRA's 45V tax credits significantly lower the cost of hydrogen production, fostering industry growth by making projects more financially feasible. The future growth and demand of hydrogen will depend on advancements in technology, reductions in production costs, supportive regulatory frameworks, and the expansion of infrastructure for distribution and storage.

"Green" Hydrogen

Carbon intensity refers to the amount of greenhouse gas emissions produced over the entire life cycle of a fuel per unit of energy or fuel delivered, encompassing all emissions from production to consumption (well-to-gate), not merely those released during consumption. The carbon intensity of hydrogen is quantified in terms of kilograms of CO2 equivalent (CO2e) per kilogram of hydrogen, where CO2e represents the quantity of CO2 that would cause a similar effect on global warming for any given amount and type of greenhouse gas. Figure 44 illustrates the life cycle emissions associated with various methods of hydrogen production (Green Hydrogen Coalition, 2022).

Figure 44: Lifecycle Emissions of Hydrogen Production



Source: Green Hydrogen Coalition 2022

The Global Hydrogen Council (GHC) has a broad and inclusive definition of green hydrogen, which does not limit the technology used for its production. For hydrogen to be classified as green, it must be generated from non-fossil fuel sources, and the total carbon intensity of its production process should be zero, negligible, or potentially even negative. While the document outlines some prevalent green hydrogen production methods, such as water electrolysis, steam methane reforming (SMR) of biogas, and biomass thermal conversion, it emphasizes that these are not the only options. The scope for green hydrogen production is wide, with expectations for numerous other methods to emerge and be commercialized in the near future (Green Hydrogen Coalition, 2022).

Technology

There are currently three dominant technologies with economic viability - Polymer Electrolyte Membrane, also referred to as Proton Exchange Membrane, Electrolyzers (PEM), Alkaline Electrolyzers and Solid Oxide Electrolyzers (DOE 2024).

Among the various types of electrolyzers, PEM and Alkaline electrolyzers are the most commonly used in commercial applications.[11] While the stack cost of an Alkaline electrolyzer is lower than that of a PEM electrolyzer, the scenario changes as the system size increases. Specifically, the complexity and the cost associated with the balance of plant (BOP) are lower for PEM electrolyzers when compared to their Alkaline counterparts in larger systems. Consequently, the total cost of ownership for a PEM electrolyzer is generally lower than for an Alkaline one, with estimates suggesting that the service costs for PEM are about one-third of those for Alkaline systems (Holst et al 2021).

Project Economics

To meet market demand, organizations will need to scale up and improve their green hydrogen plant designs. However, based on limited market data and low maturity in the space, optimizing plant designs and end-to-end green hydrogen systems can be costly and incredibly complex. (Ouziel and Avelar 2021).

Cutting costs will necessitate a steadfast commitment to achieving scale through vertical integration. The most immediate cost reductions will be achieved through massive, vertically integrated endeavors that cover the whole supply chain. These efforts will involve the large-scale production of solar panels and related components, wind turbines, electrolyzers, and the capabilities for in-house engineering, procurement, and construction, along with the creation of green hydrogen and its byproducts, all within a single facility.

According to a Senior Manager of a clean energy developer that we spoke with, developers are currently looking into co-located wind and solar facilities to take the full benefit of the tax credits.

Additionally, situating such a facility in a port area with a surrounding industrial network that handles the entire process from production to final consumption, leveraging green hydrogen and equipped to export hydrogen byproducts, can address some initial hurdles associated with long-term storage and transport. These vast projects will likely improve project delivery times and cut expenses by eliminating middlemen.

This strategy demands substantial capital investment and comes with risks associated with vertical integration, such as technological changes. Yet, it offers the most rapid progress towards achieving DOE’s 2031 target cost of $1 per kilogram

[11] Additional technologies exist that include thermal conversion of energy using Natural Gas, Coal and/or Biomass - coupled with a CCUS unit. However, these pathways do not lead to Green Hydrogen and therefore have been excluded from this analysis (NETL 2023)

(Adani 2024). It's vital that climate finance discussions take into account the significant capital requirements for such expansive integrated projects, especially in developing nations where high capital costs have been a constant barrier, despite the readiness of businesses to embrace the risks (Adani 2024).

45V Tax Credit

Treasury and IRS have proposed guidance for claiming the 45V Clean Hydrogen Production Tax Credit established under last year's Inflation Reduction Act. The Section 45V tax incentive offers up to $3 per kilogram in tax credits for hydrogen projects that demonstrate low greenhouse gas emissions throughout their lifecycle. This provision complements additional initiatives like the Department of Energy's Regional Clean Hydrogen Hubs Program. This program allocates $7 billion to stimulate almost $50 billion in investments in hydrogen across seven chosen Hubs (White House 2023). Figure 45 presents each tier of credit value for the section 45V credit. The value of the section 45V tax credit is based on the volume of greenhouse gases (GHGs) emitted during the hydrogen production process, including emissions from the electricity generation involved (de Marigny et al 2023).

Figure 45: 45V Credit Values

Emissions Intensity (kg of CO2e per kg of H2)	Maximum credit ($/kgH2, assuming prevailing wage and apprenticeship requirements are met)
0 - 0.45	$3.00
0.45 -1.5	$1.00
1.5 - 2.5	$0.75
2.5 - 4	$0.60

The proposed regulations at present stipulate that electricity used in clean hydrogen production must meet the following criteria:

1. It should be procured from power facilities that commenced commercial operations no later than 36 months prior to the hydrogen plant commencing service.
2. Starting January 1, 2028, and on an annual basis before this date, the electricity must be synchronized on an hourly basis with the clean power generation. Energy Attribute Certificates (EACs) may be considered if the electricity is generated during the same hour that the hydrogen production facility uses grid electricity.
3. The electricity must be sourced from a power producer located in the same region as the hydrogen production facility.

Section 45V is designed to be "technology-agnostic," meaning it does not prescribe specific technologies for producing clean hydrogen. Instead, it mandates that the lifecycle greenhouse gas (GHG) emissions are measured from "well-to-gate," using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model developed by Argonne National Laboratory. This is particularly relevant for hydrogen generated using electricity, such as green hydrogen produced via electrolyzers, where the power source and its associated emissions are critical in assessing the hydrogen's carbon intensity.

Typically, though, producers often utilize grid electricity but offset this by purchasing renewable energy certificates (RECs). This approach allows them to be recognized for using renewable energy, even though they are actually drawing power from the grid.

Furthermore, Section 48(a)(15) provides an option for taxpayers who own a clean hydrogen production facility to claim an investment tax credit (known as the 48 Credit) instead of the 45V Credits. The magnitude of the section 48 Credit typically varies between 6% and 30% of eligible Fair Market Value (FMV), provided that the facility meets prevailing wage and apprenticeship requirements. If these requirements are not met, the credit rate ranges from 1.2% to 6%. The credit can decrease the magnitude of initial capital needed to fund an electrolyser.

The application of tax credits significantly reduces the Levelized Cost of Electricity (LCOE) for both PEM and Alkaline electrolyzers, making hydrogen production projects more economically feasible for various industries. For PEM electrolyzers, the LCOE drops from a range of $4.77 - $7.37 per kilogram to $1.68 - $4.28 per kilogram after tax credits are applied. Similarly, for Alkaline electrolyzers, the LCOE decreases from $3.79 - $5.78 per kilogram to $0.83 - $2.83 per kilogram (Lazard 2023).

Inflationary pressures are significantly impacting the cost of renewable energy sources, which make up as much as two-thirds of the total production costs for green hydrogen. This rise in costs is prompting green hydrogen developers like Iberdrola and ENGIE to reassess their medium-term plans. The increasing prices of materials and services related to renewable energy technologies—such as solar panels and wind turbines—are affecting the overall economics of producing green hydrogen (Tatarenko et al. 2024).

Financial Model Summary

Using an internal financial model with various market-rate assumptions, we've generated summary financials for a medium-sized PEM Electrolyzer, adjusting variables to explore their impact on investment IRR across different scenarios. Figure 46 shows the model inputs and returns.

Figure 46: Hydrogen Model Sample Inputs, Assumptions, and Returns

Operating Assumptions	
Technology Type:	**Green Hydrogen**
Nameplate Capacity (MW):	**100.0**
Useful Life (years):	**20**
System Efficiency (kWh/kgH2):	**71.43**
Annual Generation (kgH2):	**12,264,000**
PPA Price ($ / kgH2):	**5.0**
PPA Tenor (years):	**5**
Merchant Price ($ / kgH2):	**2**
Merchant Years:	**15**

Tax Assumptions	
Federal Tax Rate:	**21.0%**
Tax Credit:	**PTC Transfer**
ITC % of Capex	**-**
ITC Amount ($M):	**-**
45V Price ($ / MWh):	**3.0**
Annual Escalator:	**2.0%**
Transfer Price (per $1 PTC):	**0.88**

Financing Assumptions	
Project Cost ($M):	**201.0**
Debt Amount ($M):	**140.7**
Debt Tenor (years):	**10**
Interest Rate:	**6.70%**
Minimum Annual DSCR:	**1.50x**
Equity Amount ($M):	**60.3**
Equity % of Financing:	**30.0%**

Returns	
Debt Repaid (years):	**6.0**
DSCR Minimum:	**1.50x**
DSCR Average:	**2.88x**
Equity Holders Pre-Tax NPV:	**118.5**
Equity Holders Pre-Tax IRR:	**33.6%**
Equity Holders After-Tax NPV:	**36.4**
After-Tax Levered IRR:	**19.4%**
After-Tax Unevered IRR:	**15.7%**

Our financial model has identified the following key findings regarding the viability of the project under current economic conditions.

Impact of 48(a)(15) Tax Credits: The model reveals that the project is not feasible with the 48(a)(15) tax credits alone, given the existing economic structure of the project. The 48(a)(15) credits act like ITCs, decreasing the upfront cost of construction for a project. The tax credits, although beneficial, are insufficient to offset the high costs involved, rendering the project uneconomical without additional financial adjustments or incentives.

Power Purchase Agreement (PPA) Pricing: The analysis shows that the project only becomes financially feasible with a PPA price exceeding $4 per kilogram of hydrogen (kgH2) for a five-year term. This threshold is necessary to cover the operational and production costs associated with the project, highlighting the sensitivity of the project's financial health to the pricing strategies of hydrogen sales.

Capital Expenditure (CapEx) Requirements: To compete effectively with the global market price of gray hydrogen, which is approximately $1.50/kgH2, the current capital expenditure of the project would need to undergo a significant reduction. This drastic decrease in CapEx is crucial to making the green hydrogen project competitive with conventional hydrogen production methods, which benefit from lower production costs.

Figure 47: Hydrogen Model Sensitivities

Contract Price and Interest Rate Sensitivities (After-Tax Levered IRR) - 45V

Purchase Price ($/kg)	Interest Rate 5.2%	5.7%	6.2%	6.7%	7.2%	7.7%	8.2%
3.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3.50	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4.00	9.2%	8.6%	7.9%	7.1%	6.0%	0.0%	0.0%
4.50	15.4%	15.0%	14.7%	14.3%	14.0%	13.6%	13.2%
5.00	20.2%	20.0%	19.7%	19.4%	19.1%	18.8%	18.4%
5.50	24.5%	24.3%	24.0%	23.8%	23.5%	23.3%	23.0%
6.00	28.6%	28.3%	28.1%	27.8%	27.6%	27.3%	27.1%

Contract Price and Capex Sensitivities (After-Tax Levered IRR) - 45V

Purchase Price ($/kg)	Capex 1260	1510	1760	2010	2360	2710	3060
2.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2.50	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3.00	22.1%	12.1%	0.0%	0.0%	0.0%	0.0%	0.0%
3.50	28.2%	19.0%	9.6%	0.0%	0.0%	0.0%	0.0%
4.00	34.3%	24.6%	16.4%	7.1%	0.0%	0.0%	0.0%
4.50	40.5%	29.7%	21.8%	14.3%	0.0%	0.0%	0.0%
5.00	46.4%	35.2%	26.4%	19.4%	9.6%	0.0%	0.0%

Hydrogen Market and Use Cases in the U.S.

Current Market

In the United States, around 10 million metric tons (MMT) of hydrogen is produced annually (not including the hydrogen recovered as a by-product of other industry processes), in contrast to the global production of approximately 94 MMT, primarily serving the petroleum refining, ammonia production, and chemical sectors (DOE 2023.) Often, the hydrogen produced is utilized within the same facility, leading to a slightly higher overall consumption. For example, the ammonia dissociation and steam-reforming (common in the metals industry) often has on-site hydrogen produced for internal use in the same facility (DOE 2018.)

The U.S. maintains about 1,600 miles of hydrogen pipelines and three geological storage caverns, including the largest in the world, with a capacity to store 350 gigawatt-hours (GWh) of energy—enough to supply 1.2 million homes for a week (DOE 2023.)

The scarcity of dedicated hydrogen distribution and transportation infrastructure, coupled with the concentration of production near consumption centers, restricts scaling of the green hydrogen economy where co-location is not feasible, necessitating cost-effective infrastructure development as distribution costs become a larger share of total hydrogen costs (CSIS 2023.)

Beyond its traditional roles in petroleum and fertilizer production, hydrogen is finding new applications, such as powering over 50,000 fuel cell forklifts, nearly 50 retail hydrogen fueling stations, upwards of 80 fuel cell buses, over 15,000 fuel cell vehicles, and more than 500 megawatts (MW) of fuel cells for stationary and backup power, including telecommunications, according to the U.S. National Clean Hydrogen Strategy and Roadmap.

Government Initiatives

Hydrogen Hubs

With a substantial investment of $7 billion from the Bipartisan Infrastructure Law, the Regional Clean Hydrogen Hubs (H2Hubs) are set to play a pivotal role in advancing clean energy across the United States. These hubs will establish networks linking hydrogen producers, consumers, and infrastructure to enhance the adoption of hydrogen as a versatile and powerful clean energy source.

The H2Hubs aim to match the expansion of clean hydrogen production with the increasing regional demand, fostering the development of large-scale, economically sustainable hydrogen ecosystems. This initiative is essential for transitioning away from carbon-intensive energy processes and moving towards low-carbon hydrogen solutions (DOE H2Hubs 2024).

H2 Hubs demand-side support initiative

The H2 Hubs demand-side support initiative, with $1 billion earmarked for it, is designed to facilitate the deployment of hydrogen through specialized applications tailored to each hub. The program includes differential contracts with producers to stabilize pricing and ensure economic viability. It also focuses on enhancing price transparency and standardizing contracting terms to streamline operations and foster market growth.

Hydrogen Shot

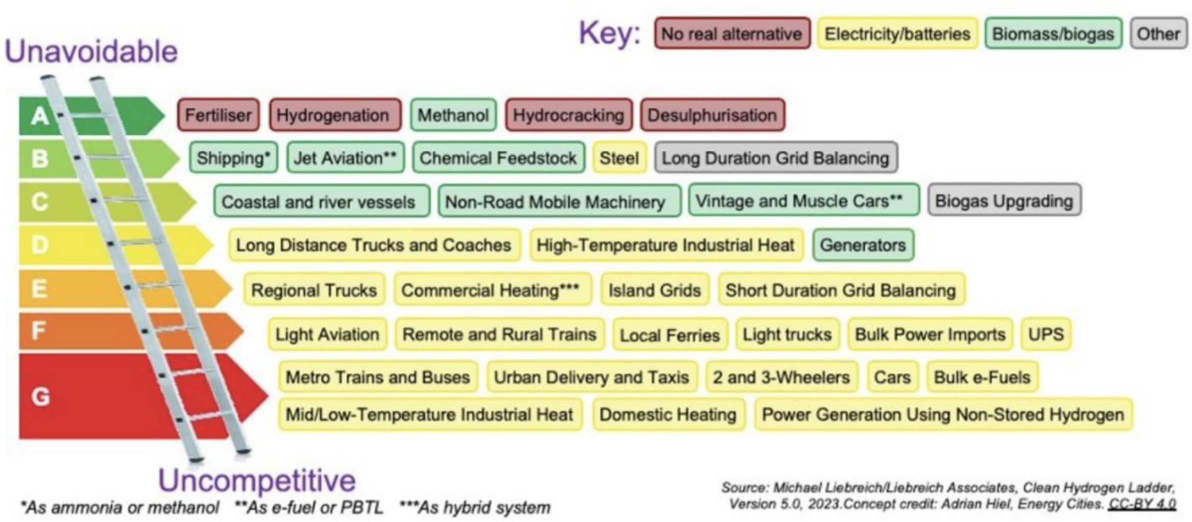
The DOE's Energy Earthshots Initiative aims to expedite clean energy solutions to achieve more abundant and affordable energy within a decade. Launched with the Hydrogen Shot on June 7, 2021, it targets reducing clean hydrogen costs by 80% to $1 per kilogram in ten years, facilitating broader use in industries like steel manufacturing and transportation. This reduction supports the Biden-Harris Administration’s goal for net-zero emissions by 2050, boosts the economy, and creates union jobs, while prioritizing environmental protection and community benefits (DOE Hydrogen Shot 2024).

Future Demand Cases

Hydrogen Ladder

The Hydrogen Ladder is a framework designed to assess the potential of hydrogen adoption for decarbonization in various sectors by 2035. The placement on the ladder is denoted by the following legend: A - no alternative; B - decent market share highly likely; C - some market share likely; D - small market share plausible (Liebreich 2023).

Figure 48: Hydrogen Ladder, Version 5.0

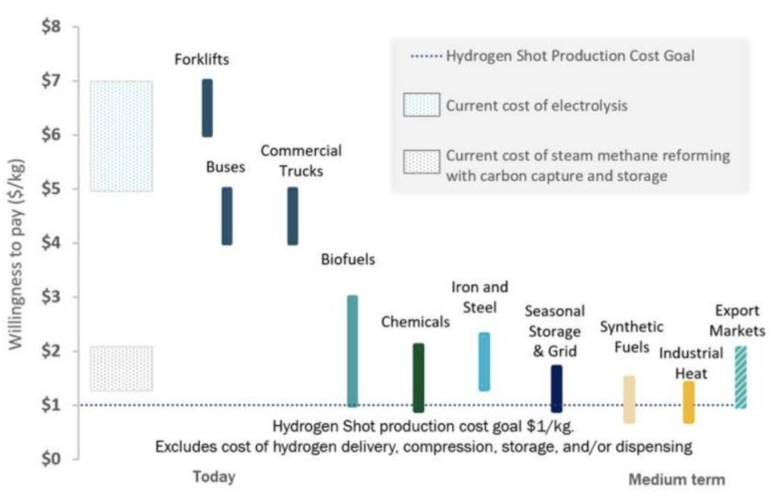


Source: Liebreich 2023

Willingness to pay

The willingness to pay, or threshold price, for clean hydrogen varies across different sectors, factoring in costs associated with production, delivery, and onsite conditioning, which can include compression, storage, cooling, and dispensing. The current cost analyses of hydrogen production do not account for the potential reductions from regulatory incentives, such as those provided by the IRA.

Figure 49: Willingness to Pay of Potential End-Users



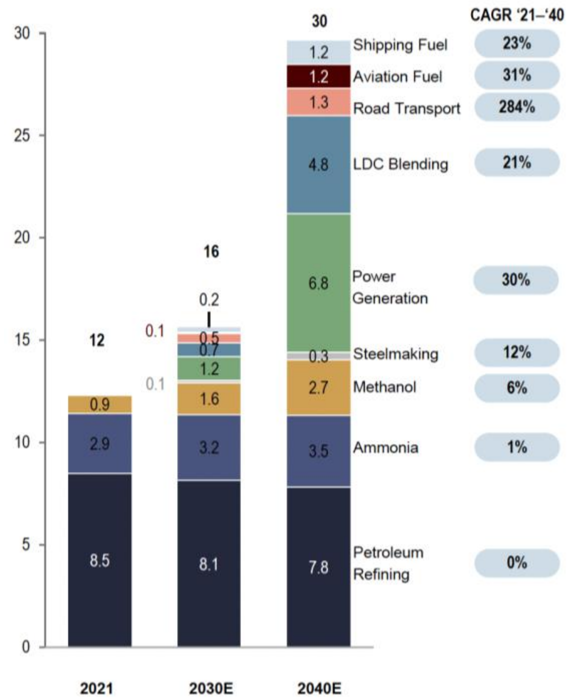
Source: DOE H2 Roadmap 2023

The demand for hydrogen at these threshold costs within various sectors will be influenced by the development and adoption rates of competing and incumbent technologies and fuels. Moreover, the willingness to pay for hydrogen is also shaped by policies aimed at reducing emissions. This includes federal regulations for new power plants and state-level mandates that set limits on emissions, which collectively encourage or necessitate the use of cleaner energy solutions like hydrogen.

Expected Sector Growth by 2040

The below graph shows expected sector growth of the U.S. Hydrogen industry. Ammonia and Methanol are expected to have a collective market share of 7% by 2040. Shipping, aviation fuel, road transport, LDC blending, and steel-making are also expected to have a considerable market share by 2040. The overall demand is expected to rise to 30 MMT by 2024, as shown in Figure 50 (Lazard 2023.)

Figure 50: Forecasted U.S Hydrogen Demand (million tons)



Source: Lazard 2023

After an evaluation using the Hydrogen Ladder framework, analyzing sector-specific willingness to pay, and assessing projected growth across various industries, it becomes evident that there is no definitive leader in hydrogen's use case. The interplay of these three factors—potential for hydrogen adoption, economic readiness to invest in hydrogen technologies, and anticipated sectoral expansion—creates a complex landscape with varying outcomes for different use cases. Figure 49 and 51 show the different willingness to pay across sectors.

Figure 51: Willingness to Pay by Sector

Sector	MMT Demand by 2040	Willingness To Pay ($/kgH2)	Hydrogen Ladder Placement
Shipping	1.2	1.5	C
SAF	1.2	1.0	B
Heavy duty vehicles	1.3	4.5	D
Iron and Steel	0.3	2.0	B
Grid Storage	6.8	1.5	B
Ammonia & Methanol	6.2	1.0	B

Shipping

The shipping industry, which could become the biggest industrial user of low-emission hydrogen by the middle of the century. In the last three years, the sector has seen the launch of its first methanol-powered vessel, the ordering of over 250 ships fueled by methanol, and the initial placement of orders for ships powered by ammonia (Mandra 2023). This year is poised to bring even more significant developments, as over 30 leaders in the shipping industry have already committed to increasing their use of renewable-based hydrogen fuels to nearly 11 million tons by 2030 (RMI 2023).

SAF

e-SAF, synthesized from green hydrogen and atmospheric or stationary-source captured carbon is not near commercialization but could offer a sustainable aviation fuel (SAF) option that doesn't compete for bio-based feedstocks, potentially becoming a viable alternative as the availability of biological materials becomes constrained (Fuel Cells and Hydrogen 2 Joint Undertaking 2020). Current pilot projects in Europe are aiming for commercialization by 2030 (Lhyfe 2024).

Heavy Duty Vehicles

A price point of about $5 per kilogram for hydrogen that is produced, delivered, compressed, and dispensed could effectively encourage early adoption in the fuel cell truck market (DOE H2 Roadmap 2023). Hydrogen fuel cells are well-suited for the trucking industry due to their refueling speed and driving range, which are similar to those of gasoline-powered trucks, and the predictability of truck routes simplifies the development of fueling infrastructure (Oak Ridge National Lab 2021).

Hydrogen fuel cells offer a higher energy density per unit mass compared to lithium batteries or diesel, allowing trucks to carry more energy without a substantial increase in weight. This is particularly advantageous for long-haul trucks subject to weight restrictions (Oak Ridge National Lab 2021).

Iron and Steel

The use of hydrogen in iron refining, depending on the development of alternative methods, could represent 10-20 percent of steel production by 2050. This shift could generate a demand for 1-3 million metric tons per year of clean hydrogen (DOE H2 Roadmap 2023).

The steel sector, responsible for 7% of global CO2 emissions, is exploring green hydrogen-based direct reduction of iron ore (DRI) combined with electric arc furnace (EAF) steelmaking as a decarbonization strategy. By 2050, the levelized cost of solar and wind-powered green steel could range between $535 and $831 per ton, with green hydrogen costs between $1.63 and $2.80 per ton, making it increasingly competitive against traditional blast furnace-basic oxygen furnace (BF-BOF) methods, especially as fossil fuel costs rise and renewable costs decline (Devlin et al 2023).

Grid Storage

Hydrogen serves as a versatile solution for delivering flexible, dependable, and on-demand power through combustion and co-firing, as well as acting as long-duration energy storage. This includes its use in forms like renewable natural gas, ammonia, and various other fuel types (DOE H2 Roadmap 2023). While costs are high due to storage and transportation challenges, technological advancements and economies of scale are expected to reduce costs over time (Ma et al. 2023).

Ammonia & Methanol

An additional 4-5 million metric tons (MMT) per year of clean hydrogen could be used by ammonia plants to fully decarbonize U.S. domestic demand for applications like fertilizer production. Since hydrogen is a crucial component in ammonia production, switching to clean hydrogen sources is vital for decarbonization, making the ammonia industry a likely early adopter with significant demand for clean hydrogen. Ammonia, widely used in fertilizers and other chemicals, can also serve as a hydrogen carrier, promoting broader market adoption through existing infrastructure. In the methanol industry, clean hydrogen could replace current alternatives like carbon capture and storage (CCS) with fossil feedstocks or biomass. Using clean hydrogen for half of the U.S. methanol production by 2050 would require an additional 1-3 MMT/year of hydrogen (DOE H2 Roadmap 2023).

Risk Analysis

Infrastructure Risk

The United States is significantly advancing its commitment to hydrogen infrastructure, spurred by the Infrastructure Investment and Jobs Act, which dedicates $8 billion to the development of seven (H2Hubs). These hubs aim to catalyze the hydrogen market by linking hydrogen producers, consumers, and local connective infrastructure, crucial for achieving state and federal emissions reduction targets.

The focus of these hubs is not just on production but also on establishing the necessary infrastructure to support the scaling up of hydrogen use. This includes the development of pipelines for efficient hydrogen distribution and storage facilities to handle supply fluctuations and maintain energy security. Public-private partnerships (PPPs) are proving pivotal in these efforts, facilitating the integration of public policy support with private sector investment and innovation (Higman and Zacarias 2022).

Each proposed hub is at a different stage of development, from forming working groups to conducting feasibility studies and initiating pilot projects. As the Department of Energy (DOE) prepares to announce selected projects, the need for supportive policy frameworks and regulatory environments becomes more pronounced. These frameworks will help manage the complexities of interregional hydrogen transfer and the financial burdens of infrastructure development (Higman and Zacarias 2022).

In essence, the success of the H2Hubs initiative and the broader hydrogen economy depends significantly on overcoming infrastructure challenges. Adequate development of pipelines and storage solutions is critical for meeting the ambitious targets set by the DOE and sustaining the momentum towards a sustainable hydrogen economy (Higman and Zacarias 2022).

Regulatory Risk

As of April 2024, there is still pending 45V regulation from the Treasury and IRS, following draft versions released in December 2023 and April 2024, is open for comments until May 13, 2024. The industry is closely watching to see what the final regulations will entail, as these will significantly influence project execution and costs.

The upcoming final U.S. Treasury rules on the 45V tax credits for low-carbon hydrogen, established by the Inflation Reduction Act (IRA), are set to shape the future of the U.S. hydrogen industry. Industry stakeholders are divided: some advocate for stricter regulations to guarantee that the growth in hydrogen genuinely curtails emissions, while others argue for broader eligibility criteria to accelerate infrastructure development (CRC-IB 2024). According to Wood Mackenzie, the proposed rules could maintain higher costs over an extended period because Engineering, Procurement, and Construction (EPC) contractors will need more time to adapt to delivering projects efficiently (Wood Mackenzie 2024). Figure 52 explains the potential implications of the three main pillars of the 45V guidance.

Figure 52: 45V Pillars and Implications

45V Condition	Description	Implication
Temporality	From 2028, all projects are required to transition to hourly matching.	Leads to electrolyzers operating at lower load factors, increasing the levelized cost of hydrogen.
Incrementality	Projects must use power from sources that started operation no more than 36 months ago.	Potential bottlenecks in the interconnection queue, supply chain problems, or cost increases related to renewable assets.
Deliverability	Electricity should be sourced from the same region	Potential delays in hydrogen projects if they need to manage interregional transfers where physical delivery occurs between regions

Conclusion

The final US treasury rules on 45V tax credits for low-carbon hydrogen (introduced in the IRA) will determine the future of the US hydrogen sector. Some industry stakeholders want more restrictive regulations to ensure hydrogen growth really reduces emissions. Others favor widening eligibility to boost the pace of buildout. The proposed rules would keep costs higher for longer, as EPC contractors would take longer to learn how to deliver projects (CRC-IB 2024).

Hydrogen production technologies, particularly Proton Exchange Membrane (PEM), play a crucial role in enhancing efficiency and operational flexibility. PEM technology, despite being twice as costly as the alkaline alternative, offers significant operational advantages such as the ability to shut down during non-operational hours and a quick cold start capability within five minutes. The equipment used in PEM systems is less bulky and easier to replace, which contributes to potential cost reductions through automation and digitalization. Strategic placement of hydrogen production facilities near planned Hydrogen Hubs and participation in the H2 Demand Side initiative can secure fixed rate offtake agreements, further reducing costs. Additionally, co-locating these facilities with wind and solar energy sources can diminish grid interconnection expenses, thereby decreasing the overall cost of input energy.

On the consumption side, certain industries stand out as primary end-users of hydrogen due to their specific needs and readiness for integration. Heavy vehicles, such as trucks, exhibit a high willingness to pay around $5 per kilogram for hydrogen, favoring its adoption due to the predictability of truck routes which eases the development of fueling infrastructure. Hydrogen fuel cells provide a higher energy density than lithium batteries or diesel, allowing trucks to carry more energy without significantly increasing weight. The ammonia and methanol industries, important for their roles in marine fuels and fertilizer production, are poised for early adoption of clean hydrogen to facilitate decarbonization. With a projected demand of 6.2 million metric tons by 2040, these industries highlight the growing significance and potential of hydrogen as a sustainable energy source in various commercial applications.

Carbon Capture, Utilization and Storage

Carbon Capture, Utilization and Storage

Introduction

The focus of this section is the Inflation Reduction Act's impact on the United States' carbon capture, utilization storage (CCUS) industry. First, this section will cover the current landscape of the United States' carbon capture industry before turning to the outlook of the industry post-IRA. Next, the focus will shift to the underlying economics of carbon capture projects, which have changed dramatically due to the enhancement of the 45Q tax credit in the IRA. The report analyzes the advantages and disadvantages of utilizing the 45Q tax credit as an Investment Tax Credit or as a 5-year Direct Pay tax credit using a financial model with assumptions based on industry expert interviews as well as engineering design studies. Further within the project economic analysis, this section will cover current carbon capture costs by sector and technology as well as the potential for additional project revenue streams. The critical project risks that remain in the industry will also be discussed. Finally, this section draws insights from the analysis to point out the positive project attributes to look for and the negative project attributes to avoid when investing in carbon capture projects.

Current CCUS Landscape

At the end of 2022, the United States had ~24 million metric tons of CO2 capture capacity. Most of this capacity is used to capture the emissions from natural gas processing or petrochemical processes that require the separation of CO2 from the underlying commodity during the refining process. Because the refining process requires the separation of CO2 to begin with, the tax credit of utilizing or storing that CO2 is an added benefit for these projects. Most of today's captured carbon is used for Enhanced Oil Recovery (EOR) (DOE 2024). EOR is an oil-recovery technique that is employed after primary and secondary recovery of an oil reservoir has taken place. To recover the remaining hydrocarbons in a reservoir, CO2 is injected into the well to expand the reservoir, forcing additional oil to the surface (DOE 2024).

Figure 53: Section 45Q Credit for Carbon Oxide Sequestration

45Q End Use	$ / ton Pre-IRA	$ / ton Post IRA
Electric Generation Point-Source Capture and Utilization	$35	$60
Electric Generation Point-Source Capture and Storage	$50	$85
Industry Point-Source Capture and Utilization	$35	$60
Industry Point-Source Capture and Storage	$50	$85
Direct Air Capture and Utilization	$35	$130
Direct Air Capture and Storage	$50	$180

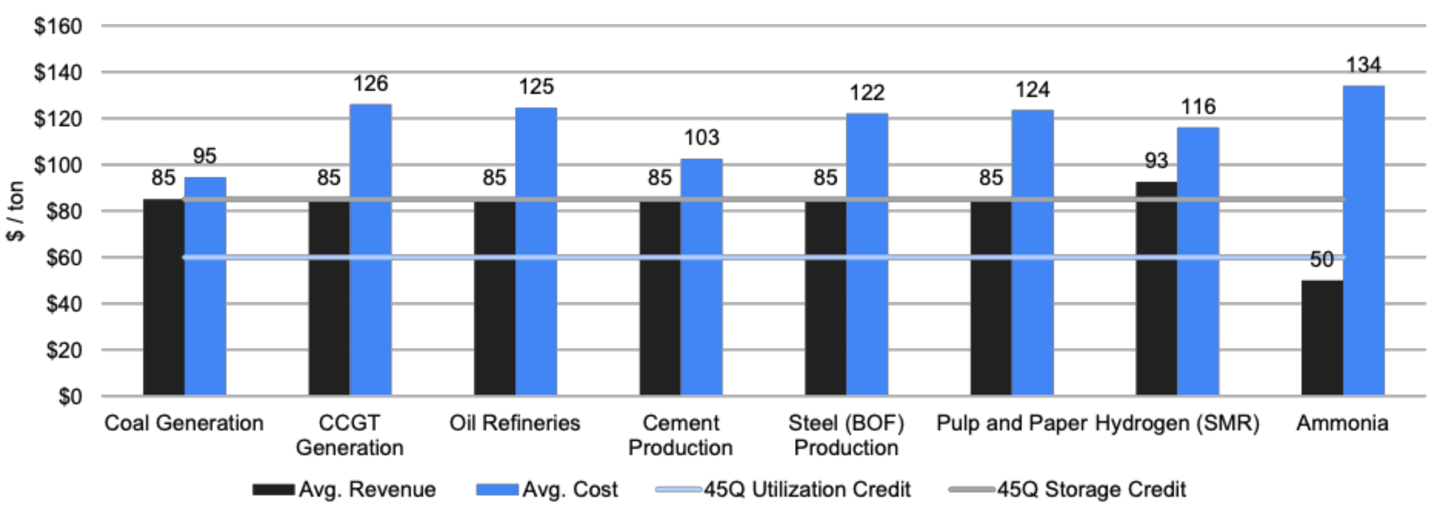
The Inflation Reduction Act increased the 45Q tax credit available for captured CO2 used for EOR (or any other purpose) from $35 / ton to $60 / ton (Aasen 2022), as shown in Figure 53. However, as the cost of climate change continues to mount, the carbon capture industry is planning for permanent storage rather than EOR. According to the U.S. Energy Information Administration (EIA), less than 5% of planned CCUS projects in the United States are built for EOR end-use (EIA 2024). Over two-thirds of the planned carbon capture capacity is for dedicated storage (2024). The Inflation Reduction Act's enhanced 45Q tax credit for carbon capture and permanent storage has been a major catalyst for this shift. Prior to the passage of the IRA, the 45Q tax credit was $50 / ton for point-source carbon capture and permanent storage. The IRA increased the 45Q tax credit for point-source carbon capture and permanent storage to $85 / ton. In addition to the increased point-source capture and storage tax credit, the IRA created a tax credit for direct air capture (DAC). The tax credit for direct air capture and utilization and direct air capture and storage is $130 / ton and $180 / ton, respectively. To date, no point-source or DAC projects have received the enhanced 45Q tax credit for any use case, according to CCUS industry participants and experts.

The IRA is not the only law promoting the value chain of carbon management. The Bipartisan Infrastructure Law, passed in 2021, provides $12B in funding for carbon management projects (DOE 2023). Recently, the first Direct Air Capture hub in Louisiana was awarded $50M from the Department of Energy's Office of Clean Energy Demonstrations to build multiple DAC facilities with an annual capture capacity of more than one million metric tons of CO2 (DOE 2024). State and local governments have also passed policies to encourage the carbon capture industry. California, New York, and Colorado have passed laws that require the embodied emissions of a product (e.g., cement) to be considered when being purchased by the State Governments (DOE 2023). In the example of cement, these policies encourage the utilization of captured CO2 to cure the concrete and lower the product's lifetime emissions. As a result of all these policies, 77 million metric tons of CO2 of direct air capture (out of 194 million metric tons of planned carbon capture), is projected to become operational in the United States by 2030, the equivalent of taking 16.7 million cars off the road each year (DOE 2023). The IRA has transformed the carbon capture industry from a tool to aid in more oil recovery to a tool used to combat, and potentially reverse, climate change.

CCUS Costs and Revenue Trends

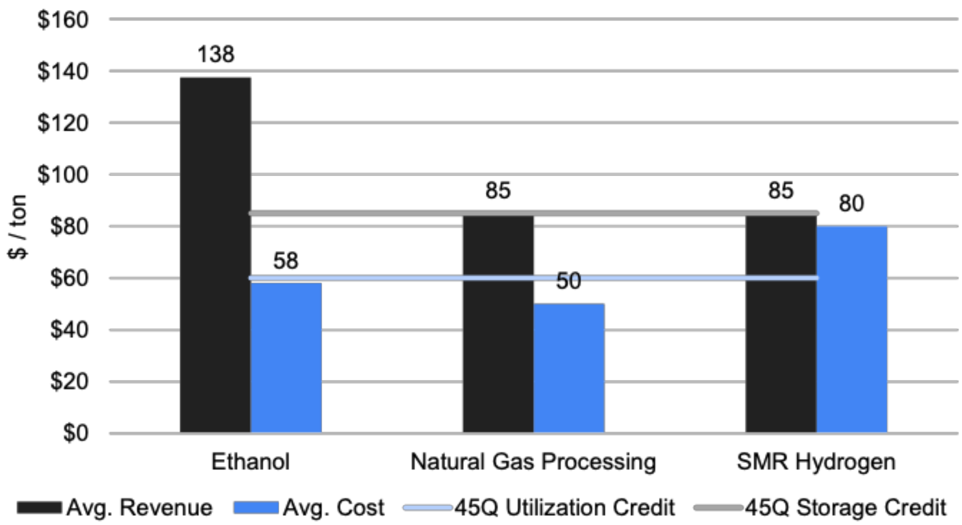
Point-Source Capture. The cost per ton of CO2 for a given carbon capture project is sector dependent, as shown in Figure 54. Every carbon capture and permanent storage project is now eligible for an $85 / ton Direct Pay 45Q for five years. Yet, the cost of capture and storage in many sectors is well-above $85 / ton, rendering projects entirely reliant on 45Q revenue uneconomical. Among heavy-polluting industries and fossil fuel power generation sources, cement kilns and coal power plants have the average lowest cost per ton of CO2 for capture and storage at $103 / ton and $95 / ton, respectively (DOE 2023).

Figure 54: Average Cost and Revenue of CCUS Projects by Industry



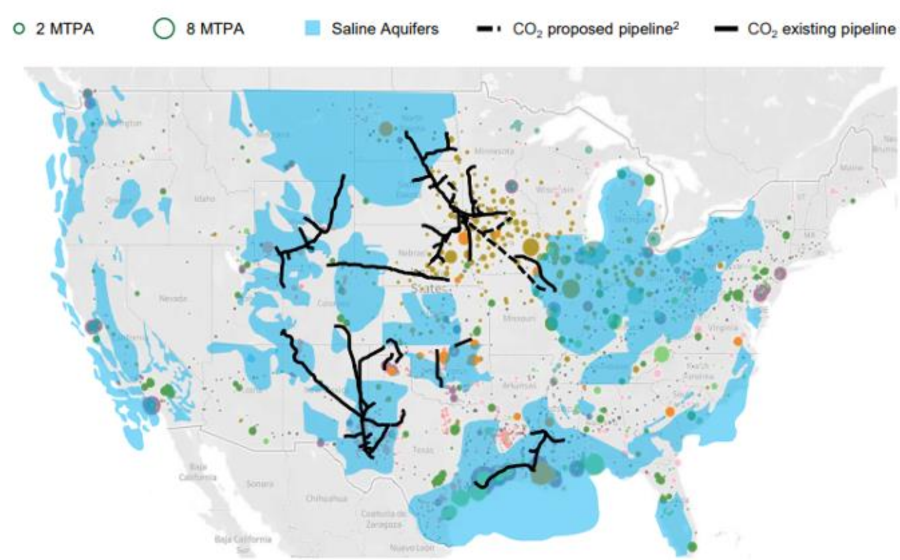
Cement production has the advantage of on-site storage in the form of CO2-cured concrete. Because the current CO2 pipeline in the infrastructure is limited (only ~5,000 miles), on-site storage is a major advantage for carbon capture cement kiln retrofits (DOE 2023). According to Princeton's Net Zero America report, the United States will need ~70,000 miles of CO2 pipelines to achieve its climate goals (Larson 2021). Prior to the buildout of CO2 pipelines, projects with zero or low-cost transportation are more likely to be financially feasible. Costs associated with carbon capture for sectors that are currently uneconomical could decrease as more capture technology is deployed in a given sector, however most point-source projects have unique characteristics, causing concern that learning curves will not significantly reduce costs.

Figure 55: Average Cost and Revenue of CCUS Projects with CO2 Separation Refining



On the other hand, certain hydrocarbon and petrochemical processes, that are mentioned above, already capture carbon during the refining process. For example, the refining process for ethanol reduction requires stripping out and capturing high-purity CO2, making carbon capture projects paired with ethanol production financially feasible. Because the economics of such projects are favorable, it is unsurprising that CO2 pipelines are clustered in the Midwest where ethanol is produced and the Southeast where natural gas is refined (DOE 2023). It is possible to transport captured CO2

Figure 56: Map of U.S. Point Source CO2 Emissions by Sector, 2019



Source: DOE 2023

using ships or rail and trucking, however the costs can be 5x – 12x more expensive than transportation by pipeline (Global CCS Institute 2011).

Direct Air Capture. On a per ton of CO2 basis, direct air capture is vastly more expensive than point-source capture. According to the Department of Energy, the cost per ton of direct air capture ranges from $225 / ton to $600 / ton. However, the climate benefits of carbon removal via DAC are much greater than the climate benefits of emission avoidance via point-source capture. Because of this, direct air capture projects have been able to procure advanced purchase commitments from large corporate buyers looking to offset their own greenhouse gas emissions. The large compliance carbon markets in the United States, California cap-and-trade and the Regional Greenhouse Gas Initiative in the Northeast, could also be sources of additional revenue for DAC projects. Both programs allow carbon removal offsets in their compliance markets (Berkeley 2019) (RGGI 2024). Currently, California's compliance market trades around $40 / ton of CO2 captured, but the price or number of allowances for carbon removal via DAC could be higher (CARB 2024). Contracted revenues from voluntary corporate buyers coupled with the $130 / ton or $180 / ton 45Q Direct Pay credit can result in favorable project economics. According to one United States DAC project developer, the $50 / ton difference between the 45Q permanent storage and 45Q utilization credits makes permanent storage more attractive relative to EOR, the most likely use case for captured CO2. One industry expert stated current demand for DAC removal credits, and the 45Q $180 / ton Direct Pay credit, could result in high single digit returns. Ideal geographic characteristics, like on-site storage or nearby abundant clean energy resources to provide the DAC facility with low-carbon energy, will dictate where to build DAC facilities. Because the location of point-source capture projects is dictated by existing polluting assets, the locational flexibility of DAC projects is an advantage over point-source capture projects. Another advantage for DAC is the higher likelihood learning curves can reduce costs meaningfully as the technology is deployed. DAC facilities can be largely replicated on any given site, unlike point-source capture projects which need to fit with existing polluting assets.

Project Economics

Point-Source Capture. Utilizing an internal financial model, our team analyzed the financial returns of a hypothetical ethanol production point-source carbon capture project with on-site storage. The assumptions used in the model are shown in Figure 57.

Figure 57: Point-Source Carbon Capture Project Model Assumptions

Operating Assumptions	
Technology Type:	Carbon Capture
Type of Capture:	Point Source
Use of Captured Carbon:	Permanent Storage
Capacity (million tons / year):	1.0
Useful Life (years):	20
Fixed Costs ($ / ton):	60.65
Variable Costs ($ / ton):	3.04
Total Costs ($ / ton):	63.68
Assumed Carbon Credit Price:	55.00
Assumed Carbon Offtake Price:	-
Carbon Offtake Term (years):	-

Financing Assumptions	
Project Cost ($M):	450.0
Debt Amount ($M):	309.6
Debt Tenor (years):	20
Interest Rate:	6.50%
Minimum Annual DSCR:	1.75x
Equity Amount ($M):	140.4
Equity % of Financing:	31.2%

Tax Assumptions	
Federal Tax Rate:	21.0%
Tax Credit:	Direct Pay Transfer
ITC % of Capex	-
ITC Amount ($M):	-
PTC / Direct Pay Price ($ / ton):	85.0
Annual PTC Escalator:	2.0%
Direct Pay Price (per $1 PTC):	1.00

The assumptions used above were based on industry interviews, technology FEED studies, and market research. The hypothetical point-source project benefits from the additional revenue stream of selling carbon credits into low carbon fuel standard (LCFS) programs, such as the LCFS markets in California (where prices are currently near $65 / ton). As a result of the LCFS revenue stream and the 5-year Direct Pay 45Q tax credit, the project earns returns near 8.00%. The return summary is included in Figure 58.

Figure 58: Point-Source Carbon Capture Project Model Returns

Returns	
Debt Repaid (years):	20.0
DSCR Minimum:	1.75x
DSCR Average:	1.75x
Equity Holders Pre-Tax IRR:	16.0%
After-Tax Levered IRR:	8.5%
After-Tax Unlevered IRR:	8.3%

Direct Air Capture. Similar to the analysis of a hypothetical ethanol production point-source carbon capture project, our team also analyzed the financial returns of a hypothetical DAC project. Again the assumptions used in the model were derived from industry experts, technology FEED studies, and market research. The assumptions used in the model are shown in Figure 59.

Figure 59: DAC Project Model Assumptions

Operating Assumptions	
Technology Type:	Carbon Capture
Type of Capture:	DAC
Use of Captured Carbon:	Permanent Storage
Capacity (million tons / year):	1.0
Useful Life (years):	20
Fixed Costs ($ / ton):	216.12
Variable Costs ($ / ton):	12.15
Total Costs ($ / ton):	228.26
Assumed Carbon Credit Price:	-
Assumed Carbon Offtake Price:	210.00
Carbon Offtake Term (years):	20

Financing Assumptions	
Project Cost ($M):	2,500.0
Debt Amount ($M):	1,691.1
Debt Tenor (years):	20
Interest Rate:	6.50%
Minimum Annual DSCR:	1.75x
Equity Amount ($M):	808.9
Equity % of Financing:	32.4%

Tax Assumptions	
Federal Tax Rate:	21.0%
Tax Credit:	Direct Pay Transfer
ITC % of Capex	-
ITC Amount ($M):	-
PTC / Direct Pay Price ($ / ton):	180.0
Annual PTC Escalator:	2.0%
Direct Pay Price (per $1 PTC):	1.00

The hypothetical DAC project assumes the low-end of the cost per ton range at ~$230 / ton and benefits dramatically from a carbon removal credit offtake agreement for 20 years at $210 / ton. The offtake agreement with a large creditworthy corporate buyer also allows for low-cost financing, which is particularly important for DAC projects given the high upfront capital cost (in this case $2.5B). The return summary is shown in Figure 60.

Figure 60: DAC Project Model Returns

Returns	
Debt Repaid (years):	20.0
DSCR Minimum:	1.75x
DSCR Average:	1.75x
Equity Holders Pre-Tax IRR:	11.0%
After-Tax Levered IRR:	8.4%
After-Tax Unlevered IRR:	7.8%

Project Risks

Point-source carbon capture projects and DAC projects share similar risks. The key risks for carbon management projects are summarized in Figure 61.

Figure 61: Key CCUS Project Risks

$	Minimal Revenue Opportunities	*Beyond the 45Q tax credit, taken as direct pay, there are limited reliable revenue streams available to carbon capture projects today.*

	Limited Transportation Infrastructure	*Limited CO2 pipeline capacity today prohibits the amount of carbon capture projects that can financially pencil-out in the United States due to high transportation costs.*
	Questionable Learning Curve	*Carbon capture projects are largely bespoke assets, making "learning-by-doing" more difficult if the technology scales (particularly for point-source projects).*
	Unclear Future Demand Uses	*There are few large-scale use cases for captured CO2 currently, starving carbon capture projects of a vital potential utilization revenue stream.*
	Can Require New Low-Carbon Energy	*Industry CCUS and DAC projects require a low-carbon power source in order to capture more CO2 than consumed, often requiring new renewable generation assets to be built.*
	Inflation & Interest Rates	*Carbon capture projects (particularly DAC projects) require high upfront capital, making them especially susceptible to interest rates.*

Key Findings and Recommendations

Point-Source Carbon Capture. Without additional revenue streams, such as compliance carbon markets or lucrative utilization offtake agreements, investment in point-source carbon capture should be limited to hydrocarbon and petrochemical processes that already separate CO2 during the refining process. These projects are financially feasible without additional revenue streams. The projects with on-site or nearby storage via pipeline access should be prioritized. Projects located in the Southeast natural gas processing and refining region, or the Midwest ethanol production region are most likely to generate high single-digit or low double-digit returns. For industries that are not currently profitable, projects that secure creditworthy or reliable additional revenue streams can be financially feasible. Again, projects that have on-site storage or nearby access to CO2 pipeline infrastructure are more likely to pencil out. For example, cement production carbon capture projects can utilize the on-site storage provided by curing concrete with captured CO2.

The 45Q Direct Pay tax credit will result in higher returns than a 45Q Investment Tax Credit (covering 30% of the upfront costs) for most point-source carbon capture projects, as shown in Figure 62.

Figure 62: Point-Source Direct Pay vs. ITC

Direct Pay: Interest Rate and Carbon Credit Price Sensitivities (After-Tax Levered IRR)

		Interest Rate						
		6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%
Carbon Credit Price	35.00	-3.2%	-3.3%	-3.4%	-3.4%	-3.5%	-3.5%	-3.6%
	40.00	-1.5%	-1.6%	-1.7%	-1.8%	-1.9%	-2.0%	-2.1%
	45.00	1.3%	1.1%	0.9%	0.7%	0.6%	0.4%	0.3%
	50.00	4.8%	4.5%	4.2%	3.9%	3.6%	3.4%	3.1%
	55.00	9.1%	8.5%	8.0%	7.5%	7.1%	6.7%	6.3%
	60.00	13.3%	13.2%	12.7%	11.9%	11.2%	10.5%	10.0%
	65.00	15.5%	15.4%	15.2%	15.0%	14.9%	14.7%	14.3%

ITC: Interest Rate and Carbon Credit Price Sensitivities (After-Tax Levered IRR)

Carbon Credit Price	Interest Rate: 6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%
35.00	-8.8%	-8.7%	-8.7%	-8.6%	-8.5%	-8.4%	-8.4%
40.00	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%	-6.0%
45.00	-3.2%	-3.3%	-3.3%	-3.3%	-3.4%	-3.4%	-3.5%
50.00	-0.2%	-0.3%	-0.4%	-0.5%	-0.6%	-0.6%	-0.7%
55.00	3.2%	3.0%	2.8%	2.6%	2.5%	2.3%	2.1%
60.00	7.1%	6.7%	6.3%	6.0%	5.7%	5.4%	5.2%
65.00	11.9%	11.2%	10.5%	9.9%	9.4%	8.9%	8.5%

Direct Air Capture. DAC projects that are able to secure high-priced carbon removal credit offtake agreements with corporations like Stripe, Alphabet, or Meta can generate high single-digit returns despite the high cost per ton figures (Frontier 2024). Similar to point-source carbon capture, DAC projects with on-site geological storage, which is abundant in the United States, will have economic advantages (DOE 2023). Moreover, DAC projects near baseload low-carbon electricity sources, such as nuclear or geothermal, will also have economic advantages. Direct Air Capture technology is also more likely to experience cost reductions over time due to learning curves given the ability to replicate similar projects. Given the high upfront costs of DAC projects, relative to point-source carbon capture retrofit projects, the 45Q Investment Tax Credit can be more economically beneficial than the 45Q Direct Pay tax credit, as shown in Figure 63.

Figure 63: DAC Direct Pay vs. ITC

Direct Pay: Interest Rate and Carbon Removal Offtake Sensitivities (After-Tax Levered IRR)

Carbon Removal Offtake Price (8.4%)	Interest Rate: 6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%
70.00	-7.7%	-7.7%	-7.7%	-7.7%	-7.7%	-7.7%	-7.8%
80.00	-6.5%	-6.5%	-6.6%	-6.6%	-6.6%	-6.6%	-6.7%
90.00	-5.4%	-5.5%	-5.5%	-5.5%	-5.6%	-5.6%	-5.6%
100.00	-4.4%	-4.4%	-4.5%	-4.5%	-4.6%	-4.6%	-4.7%
110.00	-3.3%	-3.4%	-3.5%	-3.5%	-3.6%	-3.7%	-3.7%
120.00	-2.3%	-2.4%	-2.5%	-2.6%	-2.7%	-2.7%	-2.8%
130.00	-1.3%	-1.4%	-1.5%	-1.6%	-1.7%	-1.8%	-1.9%

ITC: Interest Rate and Carbon Removal Offtake Sensitivities (After-Tax Levered IRR)

Carbon Removal Offtake Price (21.7%)	Interest Rate: 6.00%	6.50%	7.00%	7.50%	8.00%	8.50%	9.00%
70.00	-5.2%	-5.2%	-5.3%	-5.3%	-5.4%	-5.5%	-5.5%
80.00	-4.2%	-4.2%	-4.2%	-4.3%	-4.3%	-4.3%	-4.3%
90.00	-2.7%	-2.8%	-2.8%	-2.9%	-2.9%	-3.0%	-3.0%
100.00	-1.3%	-1.4%	-1.5%	-1.6%	-1.6%	-1.7%	-1.8%
110.00	0.1%	0.0%	-0.2%	-0.3%	-0.4%	-0.5%	-0.6%
120.00	1.5%	1.4%	1.2%	1.0%	0.9%	0.8%	0.7%
130.00	3.1%	2.8%	2.6%	2.4%	2.2%	2.0%	1.9%

Conclusion

Prior to the passage of the Inflation Reduction Act, nearly every ton of captured CO2 was injected into existing oil wells to recover more oil in a process known as Enhanced Oil Recovery (EOR). To promote the American carbon capture (and oil) industry, the United States Government was willing to issue a $35 per ton of captured carbon tax credit used for EOR. For captured carbon destined for permanent storage, the Government would pay $50 per ton of CO2. As a result, the American carbon capture industry never took off for a simple reason: the cost of capturing one ton of CO2 was multiples higher than the revenue earned from capturing one ton of CO2. The Inflation Reduction Act changed that arithmetic. By providing $85 per ton of point-source carbon capture and permanent storage, the Federal Government has caught the attention of large emissions-intensive industries like cement and steel and fossil fuel power generators.

The carbon capture tax credit, known as the 45Q tax credit, is the Government-provided carrot for industry and power emitters. If these emitters do not decarbonize quickly enough, lurking climate policy, in the form of carbon taxes, could be the stick. If emitters need more motivation to take up carbon capture technology, a handful of large corporations who want to brandish their green reputation with consumers have made advanced purchase commitments for high quality carbon offset and carbon removal credits. Given the recently forming tailwinds for the carbon capture industry, over eight times the existing United States capture capacity has been announced to be built. Limitations do still exist. Minimal CO2 infrastructure exists currently, limiting financially feasible locations to build carbon capture facilities. The cost to capture carbon remains high and added costs can easily top $85 per ton. Many carbon capture projects still do not pass the arithmetic test of revenues higher than costs. The increased 45Q tax credit changes that arithmetic for many carbon capture projects.

Concluding Thoughts

Concluding Thoughts

Cross-Cutting Risks and Challenges

Interconnection: Longer queues, more cumbersome processes, as well as higher costs are main roadblocks for new renewable projects being integrated into the grid. These uncertainties can significantly delay a project's Commercial Operation Date and negatively impact revenue streams from fixed-term contracts. To overcome this challenge, a common practice is to purchase old fossil fuel power plants and use their existing infrastructure to connect into the grid. Choosing to build renewable energy plants on old fossil fuel power sites also benefits developers by qualifying those projects for IRA's Energy Community adder.

> ***"Tax equity required returns used to be 5.5% (5 years ago). Nowadays, due to inflation and the implementation of Basel III regulation, tax equity requiring return is closer to 8.5%."***
>
> ***- Managing Director at a Senior Lender***

Basel III Implementation: On July 27th, 2023, the Department of Treasury, the Federal Reserve Board, and the U.S. Banking authorities jointly released a Notice of Proposed Rulemaking for the finalization of Basel III rules. The new rule assigns 400% risk-weight to equity investment exposures, effectively quadrupling the capital requirement for banks that are in tax equity partnerships and rendering it prohibitively costly to make tax equity investments (Burton and Lefko, 2023). Although it is unlikely that Basel III rules will proceed in the current form, project sponsors should expect higher required returns from tax equity investors.

> ***"A lot of key design decisions are made by the Treasury and IRS, advised by the DoE, the EPA and the White House. The fact that these key design decisions are vested in executive agencies means election results matter."***
>
> ***- Senior Expert at the Lawrence Berkeley National Laboratory***

Treasury Guidance: Treasury is still in the process of finalizing rules that spell out the eligibility requirements for IRA tax benefits, as well as the implementation process for tax credit transfers. For instance, the industry is still expecting clarifying rules on Section 45Z Clean Fuel PTC and Section 45Q CCUS Tax Credit. Without Treasury Guidance, players are hesitant to proceed and investments have been slow to ramp up. Less lenient rules could also undermine IRA's incentives.

Election Results: The 2024 presidential election may result in a change in administration. If such is the case, there is a higher risk for increased tariffs (via an executive order) on foreign suppliers of essential equipment for renewable energy projects (e.g. solar panels, battery packs). It is unlikely that we will see a complete repeal of the IRA.

Conclusion

In this study, we have evaluated the IRA and its implications for investment in the clean energy sector. Our investigation revealed that onshore wind is a promising investment opportunity because of the standardization of PPA contracts, declining costs per kilowatt hour, and the reduction of U.S. dependence on European turbine supply chains. Solar energy investments are bolstered by extended tax incentives and new financial structures such as direct pay and transferability. Attributes that stakeholders should look out for in a BESS investment are standalone, long-duration, based on the LFP chemistry, located in ERCOT West, and eligible for the energy community adder. With respect to alternative fuels, the IRA enhances the economic viability of fuels like SAF and RNG, but their future will depend on further support of the market, supply chain, and technological development. Hydrogen's future hinges on favorable policy frameworks, and industries such as heavy transportation and chemical production are likely early adopters. Finally, substantial tax credits have improved the economics of carbon capture, but financially feasible investment opportunities remain limited.

Each technology presents unique opportunities shaped by the IRA, but our findings are moderated by risks such as grid interconnection challenges, potential financial restraints due to Basel III, uncertainties in Treasury guidance, and political shifts that could alter policy. Addressing these risks is essential for unlocking the IRA's full potential and achieving attractive financial returns. With proactive planning and bespoke investment strategies, stakeholders can exploit the era-defining opportunities presented by the IRA and catalyze a robust pathway towards sustainable energy solutions.

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