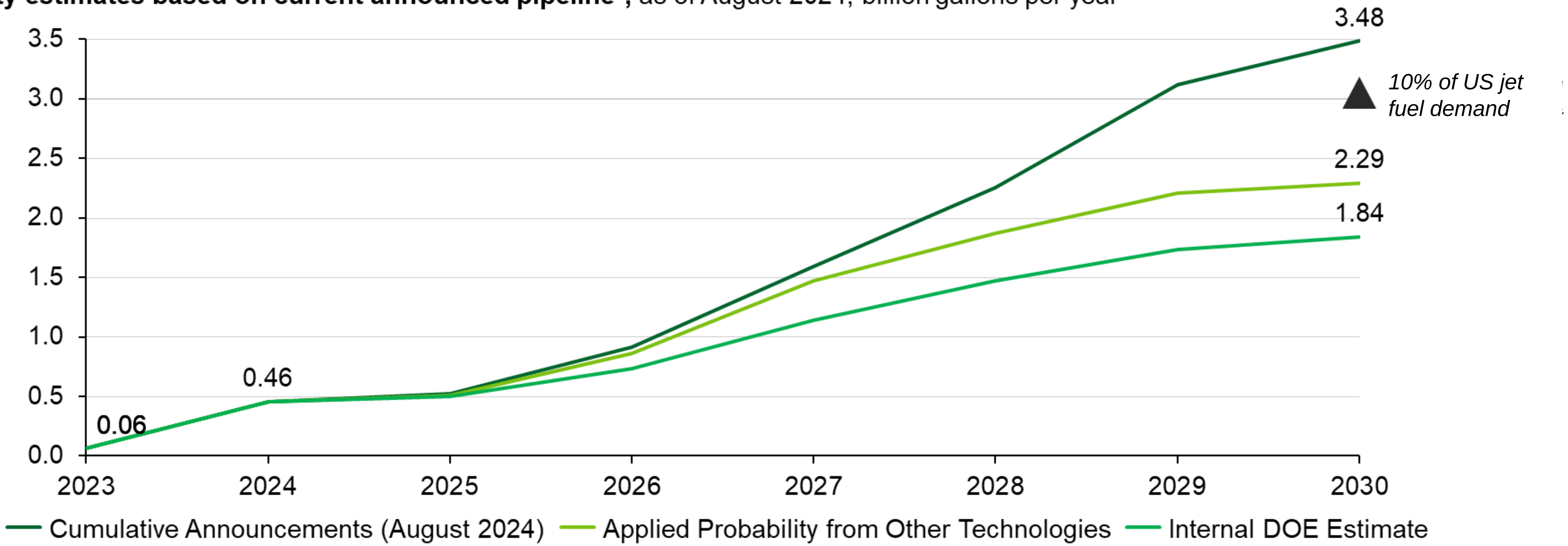
U.S. DEPARTMENT OF ENERGY

Pathways to Commercial Liftoff

Sustainable Aviation Fuel | November 2024

The U.S. is on track to meaningfully ramp production output by 2030, even with project delays and cancellations associated with emerging technologies.

U.S. SAF nameplate capacity estimates based on current announced pipeline[1], as of August 2024, billion gallons per year



Success Factors	2024	2025	2026	2027	2028	2029	2030
Applied Probability from Other Technologies[2]	98%	98%	90%	90%	60%	40%	20%
Internal DOE Estimate[3]	99%	75%	60%	60%	50%	30%	30%

Figure Footnotes: 1. Announced capacity includes 100% of announced SAF production capacity from announced projects located in the U.S. Production capacity does not include any assumptions about additional capacity that may come online if projects convert more RD production to SAF production in later years. Total SAF capacity is not necessarily equal to total SAF production, as facilities may not be running at 100% production at all times. Of announced projects through 2030, 56% of nameplate capacity will be greenfield projects, while 44% will be brownfield projects; 2. Success factors are on based analogous clean energy technologies like offshore wind and clean hydrogen. This methodology assumes that projects with CODs in the next two years are less subject to project delays and cancellations than projects announced today that are not expected to come online until 2030; 3. Success factors are applied on a project-by-project basis according to DOE.

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SAF faces a variety of scale-up challenges.

Deep dive follows

SAF sustains **high production costs relative to fossil jet fuel.**

Federal production tax credits for SAF and low-carbon fuels are expected to expire by 2027 and low-carbon fuel standards provide more of an incentive for other low-carbon fuels.

Foreign mandates diverge in definitions and qualifications for SAF, limiting demand certainty for U.S. producers and international trade.

The SAF industry is complex involving **diverse stakeholders**, and achieving consensus is difficult.

One of SAF's biggest scale-up challenges is its price premium; domestic SAF costs two-to-ten times more jet fuel.

SAF price estimates by pathway[1], USD per gallon

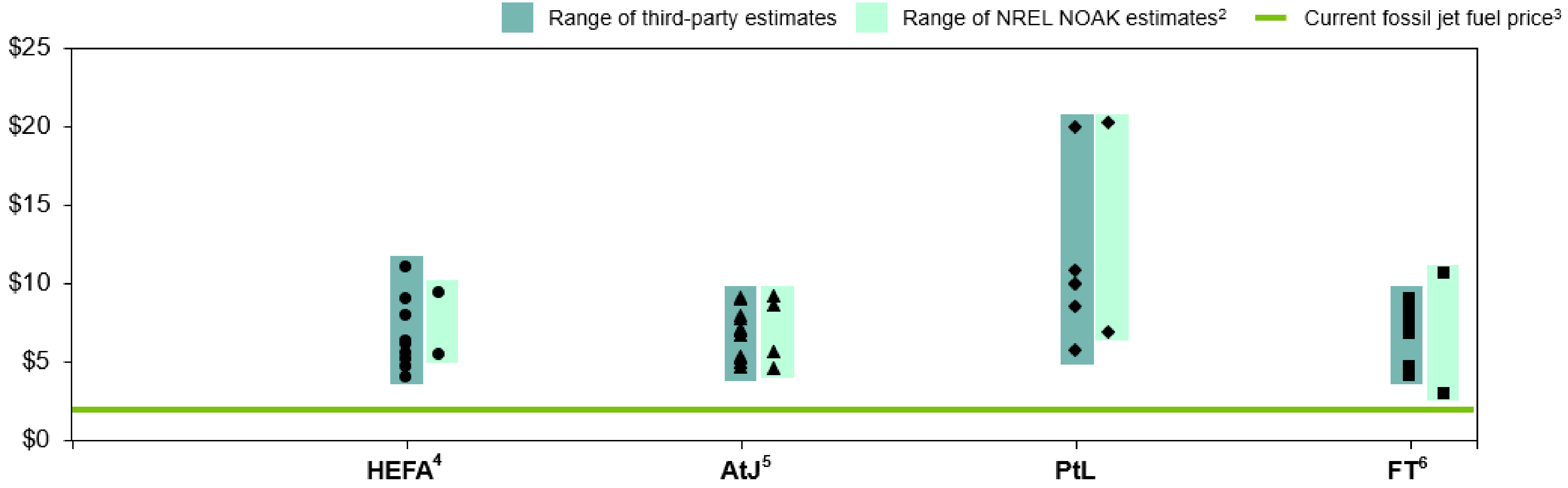
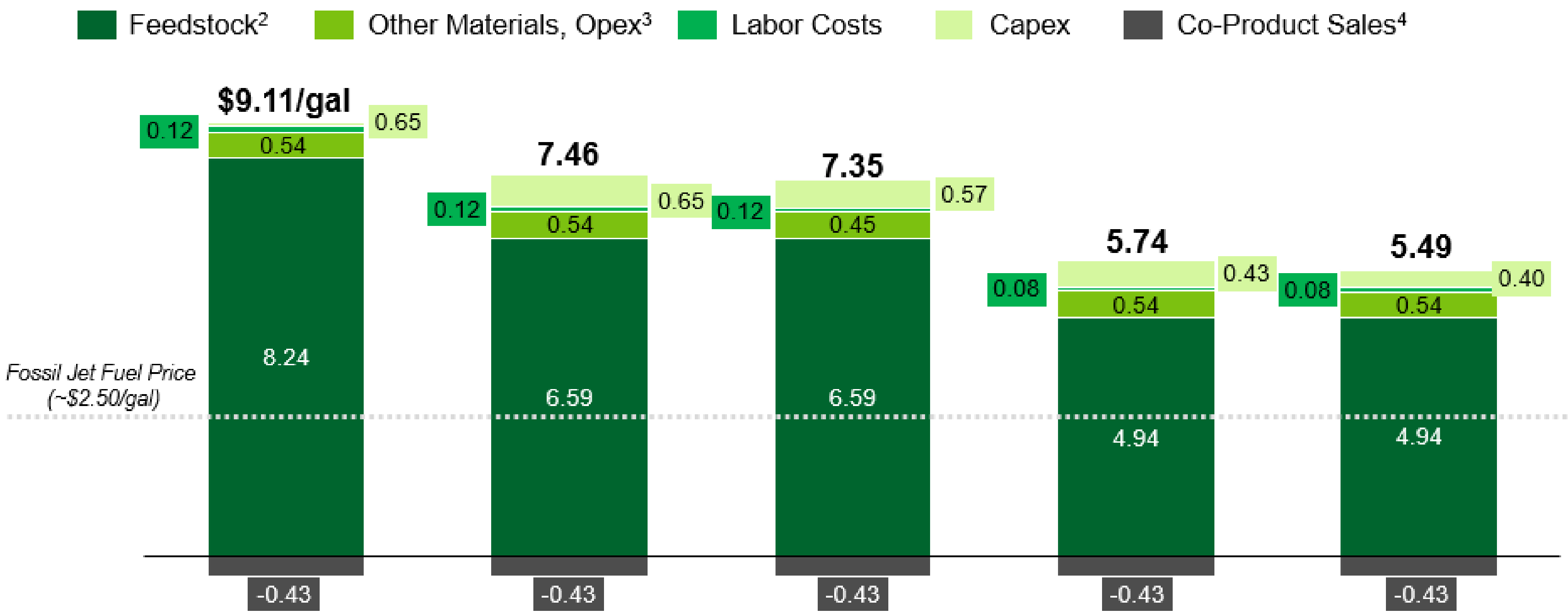


Figure Footnotes: 1. Prices are based on a range of production facility designs, inputs, and assumptions, including year, inflation, and NOAK vs. FOAK deployment. Delivered cost/price may be higher depending on infrastructure needed to deliver fuel to the airport; 2. Minimum selling fuel price is for hypothetical NOAK facilities; 3. According to IEA, the average spot price for jet fuel between January to August 2024 was $2.41/gallon; 4. Estimates pull multiple feedstocks, including FOGs (lower end of range) and virgin oils and crops (higher end of range); 5. Estimates pull both starch and cellulosic feedstocks. The high end of the cellulosic AtJ range ($9.6/gallon) exceeds the high end of the starch-based range ($8.60/gallon) although the low ends of these ranges are similar ($4.50-4.60/gallon); 6. Although FT costs appear lower than HEFA and AtJ, the gasification technology of these feedstocks is nascent and will require more time (e.g., after 2030) to validate these estimated ranges.

Feedstock represents over 80% of HEFA unit production costs; increasing facility capacity or reducing financing costs might only reduce costs 10-20%.

Unsubsidized unit production costs from an illustrative NOAK HEFA facility[1], USD per gallon



Feedstock Price[4] (USD per pound)	$0.91	$0.73	$0.73	$0.55	$0.55
Facility Capacity (MGPY)	100	100	300	300	300
Debt Interest Rate	8.0%	8.0%	8.0%	8.0%	4.0%
FOAK cost estimate (USD per gallon)	10.69	8.98	8.84	7.17	6.77

Policy

40B: Qualifies

ReFuel EU: May qualify

Assumptions:

Electricity: $0.084 / kWh

Hydrogen: $0.97 / lb

Location: Agnostic

Feedstocks: UCO, Tallow

IRR: 10%

Figure Footnotes: 1. This analysis calculates the production cost of SAF. Delivered cost, or the price of SAF to airlines, includes blending, transportation and storage costs, which vary; 2. Feedstock scenarios are based on reasonable future prices based on expert input. Feedstock cost includes cost of collection/transport. Feedstock includes a combination of virgin oil and used cooking oil; 3. Cost includes hydrogen, electricity, other chemicals, waste disposal and excludes corporate overhead; 4. Sales include revenue from gasoline and propane.

Data Sources: NREL input; RMI input

Federal and state incentives help make SAF more cost competitive with fossil jet, although the value of these incentives decrease over time.

The impact of federal and state incentives on SAF unit production costs from an illustrative NOAK HEFA facility with a CI score of 18 (80% reduction compared to fossil jet) located in California, a state with LCFS but no specific SAF subsidy[1], USD per gallon

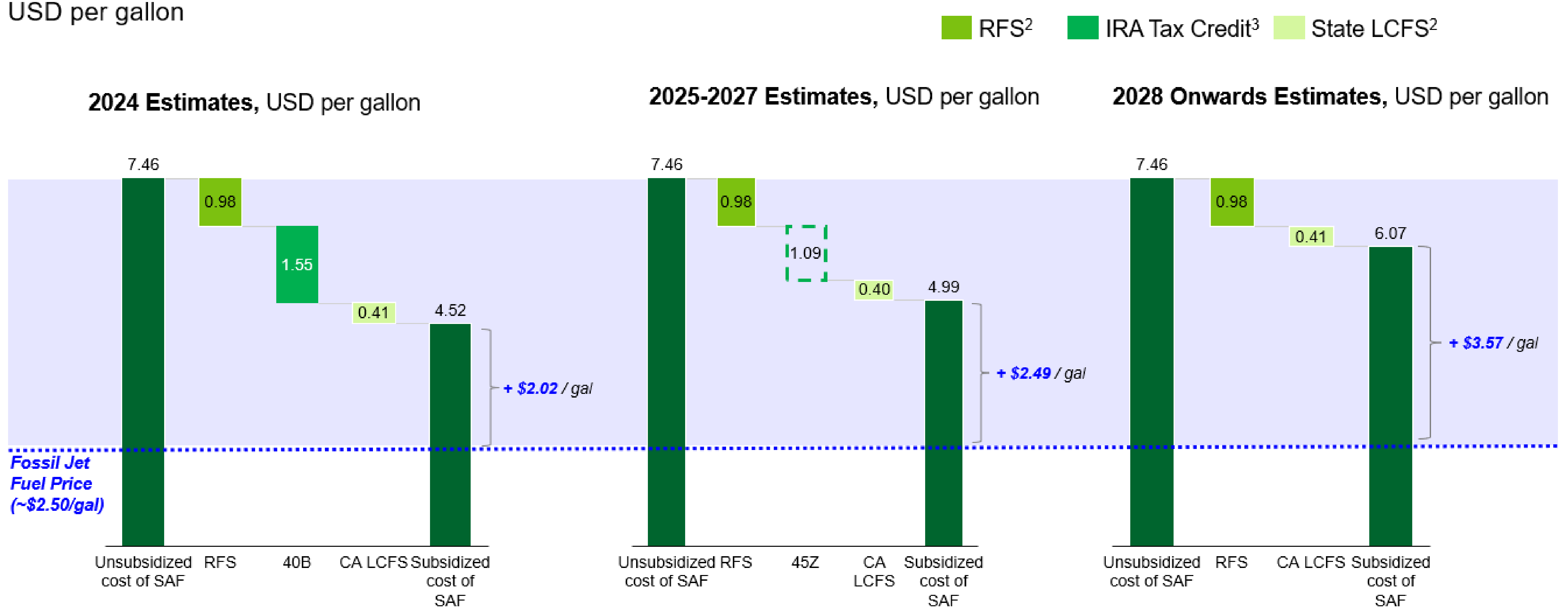


Figure Footnotes: 1. This analysis assumes prevailing wage and apprenticeship requirements are met; 2. This analysis uses June 2024 RIN and LCFS values; 3. Final treasury guidance for 45Z is to be released. Calculations for this analysis follow NREL's methodology.

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What will it take to achieve SAF Liftoff?

Three actionable imperatives enable SAF’s path to liftoff.

Supply

8-12 operational, commercial-scale facilities

Demand

Normalized 10+ year offtake agreements with airlines

Policy

Robust supply and demand side policy in the U.S. and abroad

Eight action items will accelerate SAF's liftoff by 2030.

Deep dive follows

2024 | 2030 | 2040 | 2050

Supply
Demand
Policy

- Focus on the most technologically-ready pathways for near-term deployment
- Pursue alternative offtake agreements
- Expand supply-side tax policies
- Standardize the calculations for SAF's environmental attributes
- Bolster upstream supply chains
- Support permitting and usage regulation
- Develop demand-side incentives to ensure long-term offtake
- Continue to support R&D for nascent and lower-CI pathways to diversify production pathways

Lead Times

HEFA and AtJ are the most technically and commercially mature of the analyzed SAF production pathways and will represent the majority of 2030 production, although more nascent pathways may achieve greater emissions reductions.

Production Method *Feedstock*	**Carbon Intensity Reduction[1,2], %** *Compared to Fossil Jet A*	**Expected 2030 Production[3], %**	**NOAK cost,** USD per gallon	**TRL**	**ARL[4]**
HEFA *Used Cooking Oil*	80–90%	66%	$4 – 11	8–9	7
HEFA *Soy*	55–65%		$4 – 11	8	5
AtJ[5] *Corn*	15–50%	23%	$4 – 9	7	3
AtJ[5,6] *Corn + CCS*	55–90%		$5 – 9	6	3
FT[7] *Biomass*	*Up to 100% depending on inputs and assumptions*	0%	$3 – 11	4	1
PtL[8] *Captured CO_2 & Clean H_2*	*Up to 100% depending on inputs and assumptions*	8.6%	$6 – 20	3–4	1

Axis (Carbon Intensity Reduction, %): 0 10 20 30 40 50 60 70 80 90 100

Figure Footnotes: 1. For available pathways in the 40BSAF-GREET 2024 model, carbon intensity reduction (GHG 100-year reduction) is calculated using sample inputs unless otherwise noted. Note that these sample model values are illustrative only and meant to be modified by users to calculate lifecycle carbon emissions associated with their projects. For pathways in this table that are currently unavailable in 40BSAF-GREET (FT and PtL), carbon intensity reduction is calculated based on other publicly available models and literature; 2. Consistent with carbon emission reduction strategies provided in 40B guidance and 40BSAF-GREET, across all available pathways, the high-end of CI reduction assumes use of renewable electricity credits (RECs) to reduce grid-related emissions, use of landfill gas-derived renewable natural gas with a counterfactual of flaring in place of fossil natural gas, and use of 45V modeled H with the sample 45V modeled H CI (3 kg CO e/kg H) in place of fossil H ; 3. HEFA production capacity is not broken out by feedstock and AtJ production capacity is not broken out by inclusion of CCS; 4. The methodology for ARL determinations is available in Appendix 5; 5. The high-end of CI reduction for AtJ pathways assumes use of landfill-gas derived renewable natural gas in place of fossil natural gas for ethanol production, in addition to the SAF production assumptions listed in Figure Footnote 2; 6. AtJ + CCS assumes 285,000 metric tons of CO^2 captured and stored as part of the ethanol production process; 7. FT is not an available pathway in 40BSAF-GREET, although FT with certain biomass feedstocks could result in 100% carbon intensity reduction depending on inputs and assumptions including but not limited to available co-products, transport emissions for biomass feedstock, and inclusion of CCS; 8. PtL is not an available pathway in 40B-SAF-GREET, although PtL can result in 100% carbon intensity reduction depending on inputs and assumptions including but not limited to the biogenic CO^2 source and electricity source for clean H^2 production.

Data Sources: 40BSAF GREET 2024, accessed October 2024; Other publicly available models and literature on carbon accounting

Planned projects are sited in states with ample feedstock supply, existing refinery infrastructure, or clean fuels incentives.

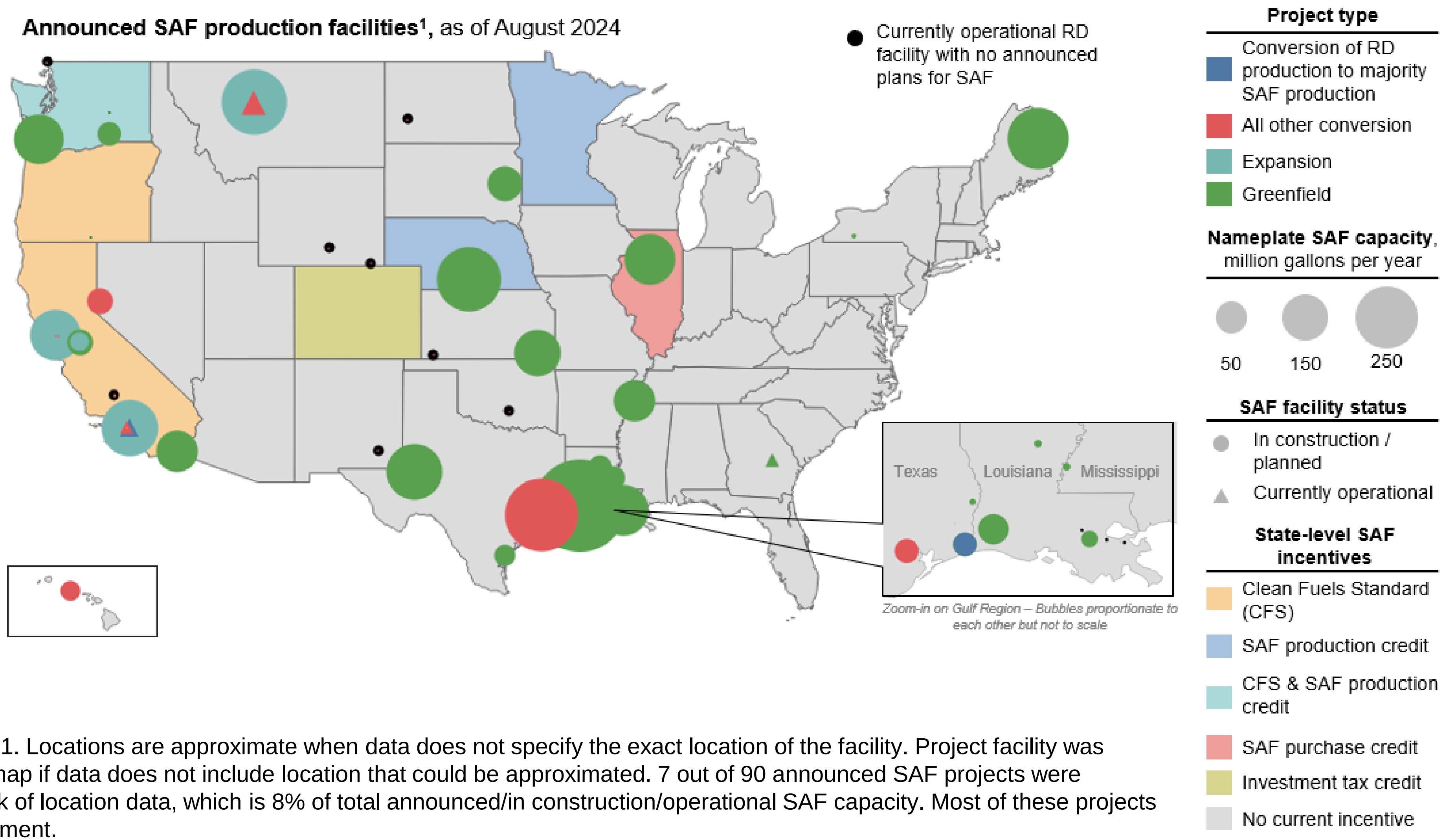

Figure Footnotes: 1. Locations are approximate when data does not specify the exact location of the facility. Project facility was excluded from the map if data does not include location that could be approximated. 7 out of 90 announced SAF projects were excluded due to lack of location data, which is 8% of total announced/in construction/operational SAF capacity. Most of these projects are early in development.

Data Sources: BNEF, "Global Renewable Fuel Projects Tracker v. 1.2.6," July 19, 2024; Industry and DOE input.

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At NOAK maturity, SAF may be cost competitive with DAC on a per-ton basis, which could help activate Scope 3 offtaker interest.

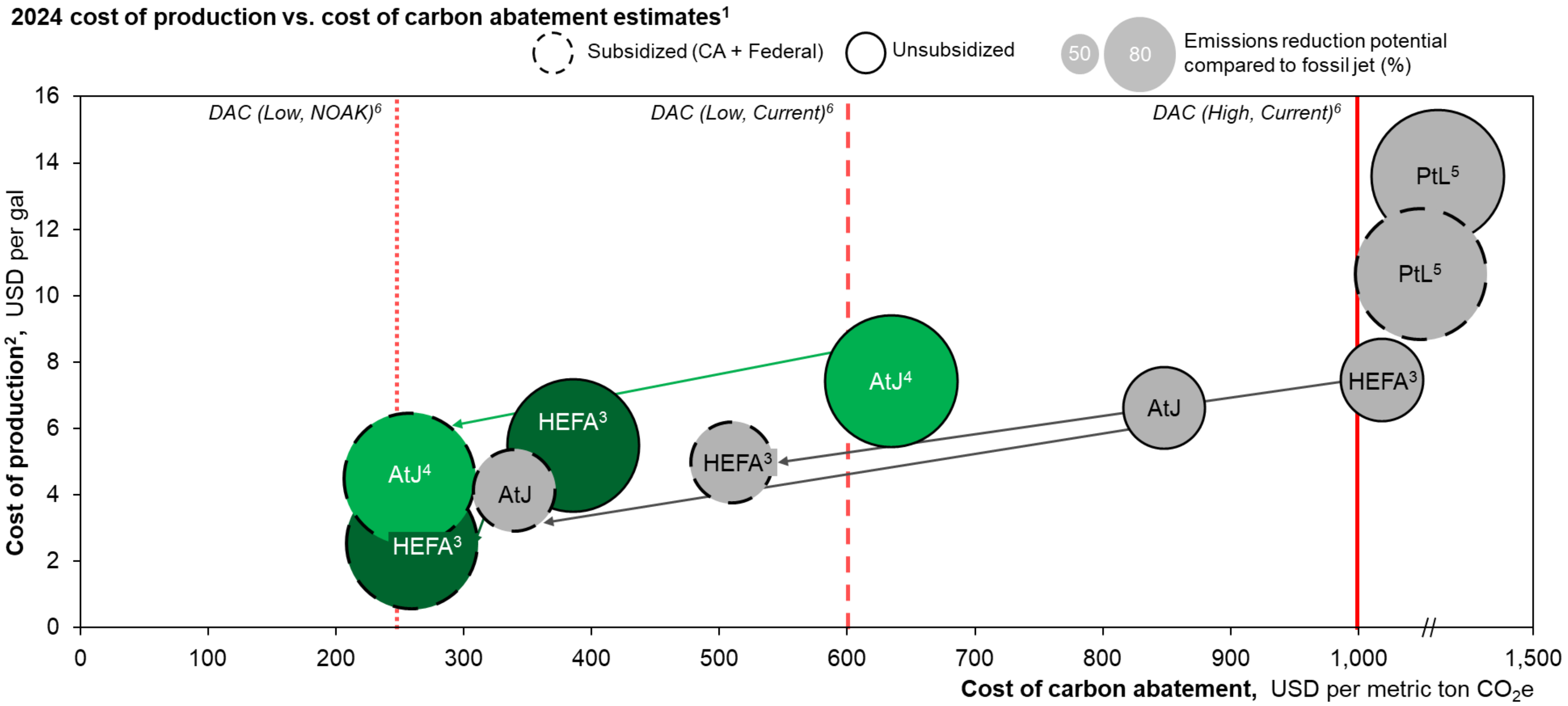

Figure Footnotes: 1. FT is not included in this figure due to significant uncertainty around its price range; 2. All production costs utilize a hypothetical NOAK facility using NREL estimates. See Appendix 4 for detailed assumptions behind each cost estimate; 3. Both HEFA estimates utilize a mix of oil-based feedstocks, with the 80% reduction estimate (dark green circles) using more FOGs, while the 50% reduction estimate (in gray) uses more virgin oils; 4. The AtJ with 80% carbon abatement estimate likely underestimates production and abatement costs because it underestimates the additional CCS required to generate this CI score; 5. PtL estimates use biogenic carbon captured from point sources, not DAC, as feedstock; 6. Industry estimates for DAC costs range between $600-1,000/metric ton. CDR puts the current DAC spot price at $690 based on real market data, which may be underpricing the cost of production. Over time, NOAK DAC facilities are expected to cost roughly $250/metric ton.

Use this QR code to learn more.

liftoff.energy.gov/SAF

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