U.S. DEPARTMENT OF ENERGY

Pathways to Commercial Liftoff: **Decarbonizing Chemicals & Refining**

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Comments

The Department of Energy welcomes input and feedback on the contents of this Pathway to Commercial Liftoff. Please direct all inquiries and input to liftoff@hq.doe.gov. Input and feedback should not include business-sensitive information, trade secrets, proprietary or otherwise confidential information. Please note that input and feedback provided are subject to the Freedom of Information Act.

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Purpose of this report

These Pathway to Commercial Liftoff Reports aim to establish a common fact base and ongoing dialogue with the private sector around the path to commercial liftoff for critical clean energy technologies across core U.S. industries. Their goal is to catalyze more rapid and coordinated action across industries and the full technology value chain.

This Pathway to Commercial Liftoff report specifically focuses on decarbonizing the downstream production of chemicals & refining. It is one in a multi-part series focused on industrial decarbonization. The Industrial Decarbonization Liftoff series provides an overview of the pathways to decarbonization across eight industrial sectors of focus in the Inflation Reduction Act (IRA): **chemicals, refining, iron & steel, food & beverage processing, pulp & paper, cement, aluminum, and glass**.[1] DOE has conducted deep analysis and developed reports in the Liftoff series focusing on chemicals & refining and cement. All other sectors, and cross-cutting perspectives, are covered in the report Pathway to Commercial Liftoff: Industrial Decarbonization.

1 Inflation Reduction Act, H.R. 5376, 117th Cong. § 50161(g)(3) (2022). https://www.congress.gov/bill/117th-congress/house-bill/5376/text

Glossary

Term	Definition
45Q	Tax incentive that encourages carbon capture, utilization, and storage (CCUS) projects
45V	IRA tax incentive that encourages production of clean hydrogen
48C	Tax incentive for a variety of different types of energy projects with a $10 billion limited allocation
48E/45Y	IRA tax incentive that is technology-neutral for clean energy generation projects placed in service after December 31, 2024 based on emission measurements, which requires zero or net-negative carbon emissions
ARL	Adoption readiness level (1-9); Represents important factors for private sector uptake beyond technology readiness, including value proposition, market acceptance, resource maturity, and license to operate
BAT	Best available technology
BIL	Bipartisan Infrastructure Law (also known as IIJA - Infrastructure Investment and Jobs Act)
CBA	Community benefit agreement
CCS	Carbon capture and storage
CI	Carbon intensity
CO2	Carbon-dioxide
Demonstration stage	Technology in a stage in the research, development, demonstration, and deployment (RDD&D) continuum in which the objective is to determine the technical and commercial feasibility of new technologies.
Deployable stage	Technology in a stage of the RDD&D continuum in which the objective is to develop commercial deployments.
FOAK	First of a kind
GWP 100	Global Warming Potential of greenhouse gasses over a 100-year time horizon
H2	Hydrogen
IRA	Inflation Reduction Act of 2022 (Pub. L. 117-169)
LDES	Long-duration energy storage
Liftoff	"Liftoff" represents the point where solutions become largely self-sustaining markets that do not depend on significant levels of public capital and instead attract private capital with a wide range of risk.
MACC	Marginal abatement cost curve
MT	Million tonnes
NG	Natural gas
NGP	Natural gas processing
NOAK	Nth of a kind
R&D / Pilot stage	Technology in a stage in the research, development, demonstration, and deployment (RDD&D) continuum in which the objective is to discover and determine technical feasibility of new technologies in lab or in small pilots.

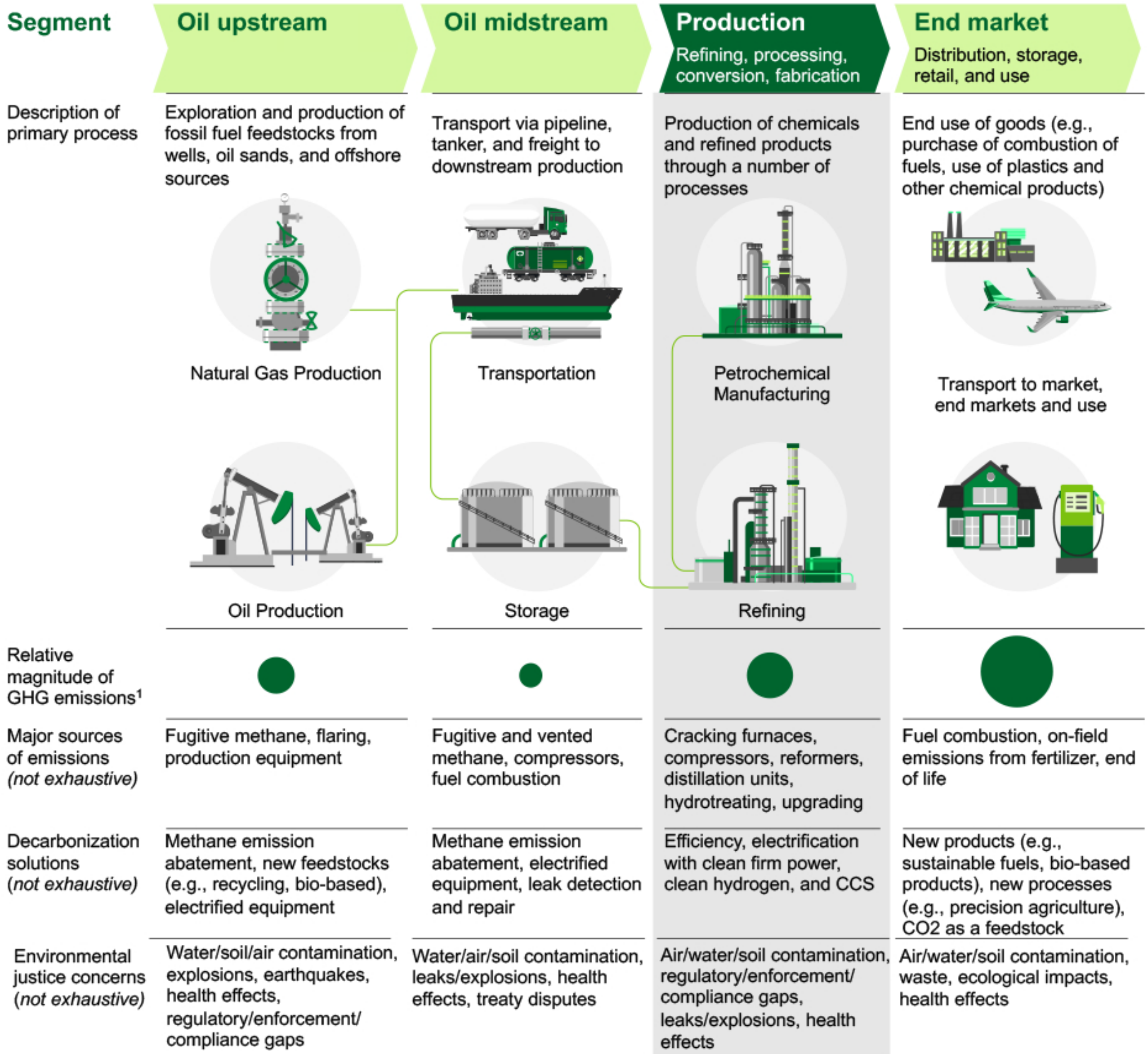
Term	Definition
RDD&D	Research, development, demonstration, and deployment (RDD&D) continuum—defines the path to commercialization where a technology starts as an innovative idea in research, moves to development where the first prototype is created, then to demonstration where the solution is tested in the real world and ending with commercial scale deployment. Although RDD&D is a continuum, the pathways across stages are not always linear and technologies may need to go back to earlier stages to be refined.
RFS	Renewable fuel standards
Scope 1 emissions	Direct emissions from the company's owned or controlled sources. This includes refrigerants, and emissions from combustion in owned or controlled boilers, and furnaces as well as emissions from fleet vehicles
Scope 2 emissions	Indirect greenhouse gas emissions from purchased or acquired energy, like electricity, steam, heat, or cooling, generated offsite and consumed by the reporting company
Scope 3 emissions	Indirect greenhouse gas emissions associated with a company's value chain activities both upstream and downstream, including emissions from sources not owned or controlled by the company, such as suppliers, customers, and product use
SMR	Steam methane reforming
TES	Thermal energy storage
TRL	Technology readiness level (1-9); Metric used for describing technology maturity. It is a measure used by many U.S. government agencies to assess maturity of evolving technologies (materials, components, devices, etc.) prior to incorporating that technology into a system or subsystem.

Executive Summary

The U.S. chemicals & refining sectors are key economic drivers, employers, and export commodities. U.S. chemicals production and oil refining contribute ~8% to GDP and are critical for energy security.[2] These sectors produce primary fuels for transportation, power, and heat; provide essential inputs to widely used downstream products, including plastics, fertilizer, and pharmaceuticals; and represent major U.S. export commodities. In 2022, the United States was both the world's top oil producer and oil refiner, responsible for ~20% of refined products globally.[i] The United States is responsible for ~11% of global chemicals production.[ii] For context, chemicals is the largest export sector for the U.S. at 9% of all exports, with a 12% growth potential by 2030.[iii,iv,v] Continuous access to secure, affordable, and reliable oil, chemicals, and derivative products is critical to the American public, the clean energy transition, and the national security of the United States.

Chemicals & refining production are interconnected, sharing many linked production pathways and opportunities to decarbonization. For example, fossil fuels are used as a feedstock across both sectors, with refined oil products used for heating in many chemical processes. The markets are also interlinked, with many global companies producing both refined oil and chemical products. Both sectors generate greenhouse gas (GHG) emissions associated with upstream feedstock extraction, production processes, and downstream usage (Figure 1). This report focuses on **production process emissions** generated "inside the fence" at today's chemicals plants and oil refineries as well as indirect emissions from electricity purchases (Scope 1 and 2 emissions of U.S. chemicals & refining production). Additional detail on the specific processes considered is included in Figure 7 in Chapter 2. Where relevant, sector-specific nuances between the chemicals & refining industries are noted throughout—including technologies, plant assets, and market dynamics (e.g., growth and margin profile).

2 Includes manufacturing of coal products, Bureau of Economic Analysis (BEA).



Segment	Oil upstream	Oil midstream	Production Refining, processing, conversion, fabrication	End market Distribution, storage, retail, and use
Description of primary process	Exploration and production of fossil fuel feedstocks from wells, oil sands, and offshore sources	Transport via pipeline, tanker, and freight to downstream production	Production of chemicals and refined products through a number of processes	End use of goods (e.g., purchase of combustion of fuels, use of plastics and other chemical products)
	Natural Gas Production	Transportation	Petrochemical Manufacturing	Transport to market, end markets and use
	Oil Production	Storage	Refining	
Relative magnitude of GHG emissions[1]				
Major sources of emissions *(not exhaustive)*	Fugitive methane, flaring, production equipment	Fugitive and vented methane, compressors, fuel combustion	Cracking furnaces, compressors, reformers, distillation units, hydrotreating, upgrading	Fuel combustion, on-field emissions from fertilizer, end of life
Decarbonization solutions *(not exhaustive)*	Methane emission abatement, new feedstocks (e.g., recycling, bio-based), electrified equipment	Methane emission abatement, electrified equipment, leak detection and repair	Efficiency, electrification with clean firm power, clean hydrogen, and CCS	New products (e.g., sustainable fuels, bio-based products), new processes (e.g., precision agriculture), CO2 as a feedstock
Environmental justice concerns *(not exhaustive)*	Water/soil/air contamination, explosions, earthquakes, health effects, regulatory/enforcement/ compliance gaps	Water/air/soil contamination, leaks/explosions, health effects, treaty disputes	Air/water/soil contamination, regulatory/enforcement/ compliance gaps, leaks/explosions, health effects	Air/water/soil contamination, waste, ecological impacts, health effects

1. The circle plots represent the magnitude of GHG emissions relative to other segments of the chemicals and refining value chain. Circles are not sized to represent actual emission percentages.
Source: American fuel & petrochemical manufacturers, EPA GHGRP, EIA

Figure 1 (also Figure 4): Across the chemicals & refining value chain, the leading source of emissions is end-market use, mostly from the combustion of fuels. Production emissions account for significant emissions from the production of fuel and chemicals due to industrial processes discussed in this report. Upstream emissions from the production of chemicals & refining feedstocks mostly come from methane leaks and the operation of extraction equipment. Midstream emissions occur during transport and storage due mainly to fugitive methane leaks.

Chemicals production and refining accounted for ~11% (~533MT) of energy-related carbon dioxide (CO2) emissions in 2021 and ~38% of all industrial energy-related CO2 emissions (Figures 1, 5).[vi,vii,vii] This amount is equivalent to 1.5 times the total emissions of New York State, or one-third of all annual emissions from U.S. transportation.[10, ix,x] Of the eight industrial sectors of focus, chemicals & refining account for ~60% of industrial emissions. The pathways to decarbonize the processes discussed throughout this report face financial, technological, infrastructure, public acceptance, and policy challenges. However, reducing emissions in the chemicals & refining sectors is critical to bolstering American competitiveness, retaining the ability to sell in global markets, and achieving U.S. emission reduction targets in the decades to come. Decarbonizing these sectors also presents an opportunity to address systemic environmental justice issues associated with chemicals and refining production processes.

The chemicals & refining sectors are not on pace to meet national decarbonization goals. As of spring 2023, two-thirds of large chemicals companies analyzed have made decarbonization commitments, ranging from 15–50% of Scope 1 & 2 emissions reduction by 2035.[3] Most companies have found it economic to implement efficiency measures, with a modest number advancing exploratory investments in small projects to decarbonize production. The barriers to further adoption are detailed later in the report; they include cost/performance gaps and operational challenges. Investments in areas such as recycling, bio-based materials, and sustainable fuels are growing but are still limited relative to the scale of sector emissions.

The path to net zero

Absent swift and widespread measures to decarbonize production emissions, the chemicals & refining sectors will continue to be major contributors to U.S. emissions over the coming decades.[4] In a business-as-usual (BAU) pathway, downstream chemicals production and refining emissions could grow by ~20% by 2050, driven by a ~35% rise in chemicals emissions due to demand growth.[xi] To remain on track with national industrial decarbonization goals, chemicals & refining production must reduce emissions by ~35% through 2030 and more than ~90% by 2050 (Figures 2 and 3).

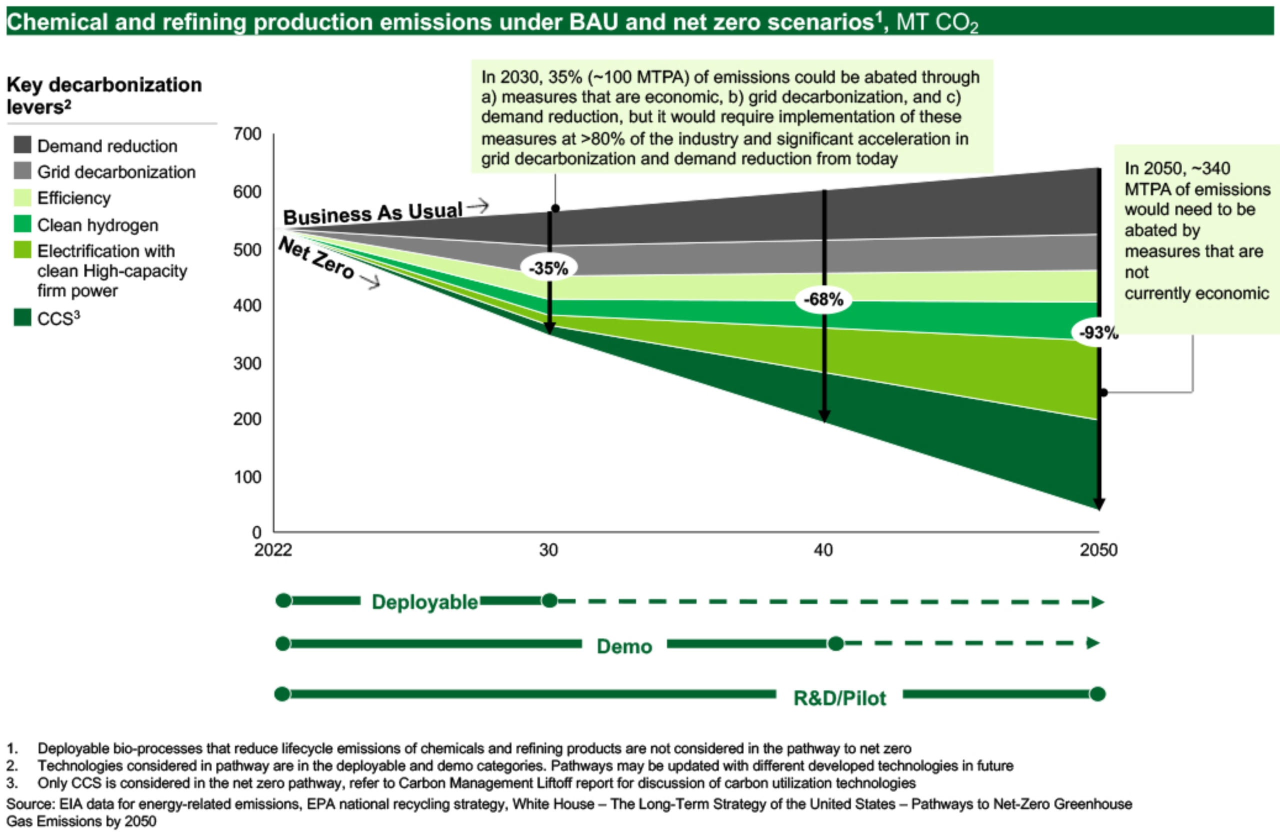


Figure 2 (also Figure 15): In a BAU scenario, chemicals production emissions are expected to grow by 35% (2021 to 2050). Refinery production emissions are forecasted to remain flat due to stable demand. Please note the above pathway only includes deployable and demonstration technologies; please see chapters 3 and 4 for additional detail on pilot and RDD&D technologies.

3 Largest companies selected based on market share.

4 Production emissions must be decarbonized in addition to the upstream and downstream emissions illustrated in Figure 1, however, upstream/downstream emissions reductions are not the focus of this report.

Today through the mid-2030s, ~20% production emissions reductions could be achieved by the application of a suite of measures that are economic now without further government support, including (i) energy and operational efficiency, (ii) electrification with clean power, (iii) clean hydrogen, (iv) CCS on concentrated streams, and (v) the use of other fuels and feedstocks. These measures take place within the existing footprint of a facility and could offer at least a ~10% internal rate of return (IRR) in the current policy environment.[5] In addition, ~15% of production emissions in 2030 could be abated through (A) grid decarbonization and (B) demand reduction measures. This projection includes reduced demand for traditional fossil fuels aligned with the White House's long-term strategy and achieving a 50% recycling rate as laid out in Environmental Protection Agency goals, which—if achieved for key plastics (e.g., PET, PE, and PP-based plastics)—could result in a reduction in virgin plastic production.[xiii,xiiii]

A range of alternative chemicals and fuels are not considered in these near-term emission reductions, including but not limited to, bio-based chemicals and fuels, as well as other synthetic fuels and plastic waste feedstocks. Many of these solutions are at a commercial scale (e.g., 1,4 BDO; PLA; 1,3 PDO; waste plastics as chemical feedstocks; SAF from CO2), serving as substitutes for conventional technologies that could reduce life cycle emissions.

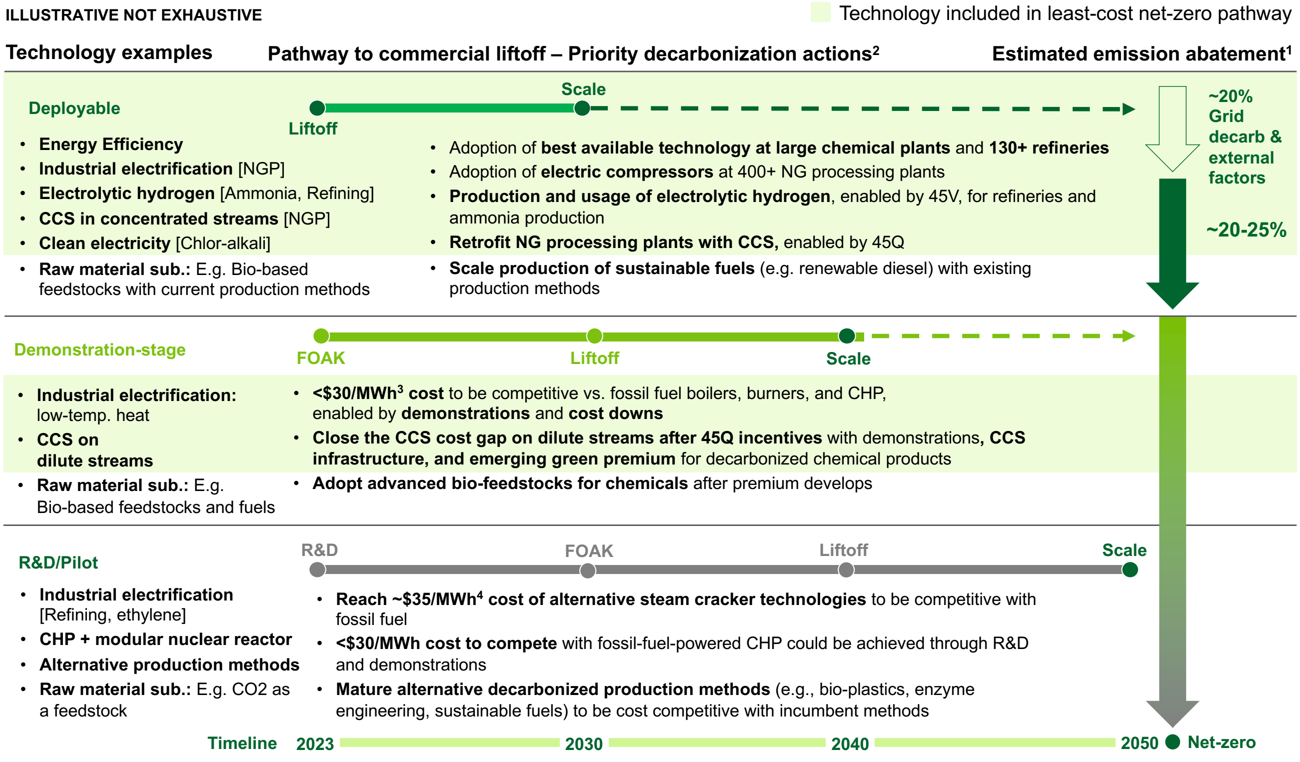
To achieve national decarbonization goals for 2050, alternative value chains in the demonstration and pilot phases (e.g., new bio-based pathways for low and net-zero carbon fuels and chemicals) **and lower Technology Readiness Level (TRL) technologies** (e.g., small nuclear reactors for industrial heat and power) **must scale.**[6] As these solutions mature, they will be necessary to bridge cost and performance gaps between the price of incumbent technology and the cost of implementing a decarbonized alternative. This necessity is particularly true in the late 2040s and early 2050s. By 2050, as many as ~55% of emission reductions could come from existing technologies that are not currently economic (i.e., below a 10% hurdle rate) but are expected to be deployed at scale (Figure 3). Levers to lower process emissions should be prioritized, with options like CCS leveraged when emissions are otherwise un-abatable.

In some cases, technologies with higher *production* emissions may be useful levers for decarbonization if they have lower overall *life cycle* emissions. Process-based life cycle GHG accounting evaluates and reports the full life cycle GHG emissions associated with the raw materials extraction, manufacturing or processing, transportation, use, and end-of-life management of a good or service.[7] Petroleum-derived products are often minimally processed from crude oil and have very low production emissions from refining itself compared to total life cycle emissions. The reverse is true for some biochemicals and biofuels pathways (e.g., adipic acid, 1,3-butadiene, and biodiesel), which require complex processing of a bio-based feedstock, but have lower life cycle emissions as carbon is absorbed during the growth of feedstock crops.[xiv] **While this report focuses on decarbonizing the production processes of chemicals & refining, reducing only those emissions is insufficient to achieve national emissions reduction goals in the chemicals & refining sectors.**

5 In comparison to the Industrial Decarbonization cross-cutting report which uses a weighted average cost of capital hurdle rate, this report has completed cash flow analysis modeling for select chemicals and refining assets and therefore uses an internal rate of return hurdle.

6 Technology Readiness Level (TRL) is a metric used for describing technology maturity. It is a measure used by many U.S. government agencies to assess maturity of evolving technologies (materials, components, devices, etc.) prior to incorporating that technology into a system or subsystem.

7 Life cycle emissions throughout this report refers to "attributional" or "process-based" life cycle analysis emissions, which are defined as "environmentally relevant physical flows to and from a life cycle and its subsystems." Additional information can be found through the National Academies of Sciences, Engineering and Medicine Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States | The National Academies Press.



1. Abatement share ranges are constrained and based on alternative decarbonization pathways, varying on factors such as the emergence of alternative production methods and chemistries
2. Indicative timeline presented R&D, FOAK, liftoff, and scale. Actual timelines will vary by technology based on technological maturity and barriers to adoption
3. Estimated as breakeven point on the MACC levelized cost of heat to reach $0/tCO_2$ abatement cost for refining CHP
4. Estimated as breakeven point on the MACC levelized cost of heat to reach $0/tCO2e abatement cost for ethylene steam cracking furnace

Figure 3 (also Figure 19): Reaching net zero in the chemicals & refining sectors requires a phased approach that sequences deployable technologies in the near term, technologies under demonstration in the medium term, and technologies that are in R&D and pilot phases in the long term.

A phased approach

The Administration has set a 2030 economy-wide GHG reduction target of 50–52% relative to 2005 levels.[xv] At present, the chemicals & refining sectors are not on track to meet these targets and will require concerted action to achieve net zero by 2050. The decarbonization pathway could evolve over a phased approach to 2050.

1. **Phase 1: Near-term acceleration of deployable pathway enablers (2023–2030)**: Chemicals producers and refineries decarbonize with deployable technologies that can be adopted within the footprint of their existing asset base. Levers to lower process emissions should be prioritized, with options like CCS leveraged when emissions are otherwise un-abatable.

   These levers include:

   i. accelerating energy and operational efficiency measures at most facilities, requiring a ~10% efficiency improvement at >80% of chemicals & refining facilities during this phase

   ii. adopting select electrification measures with a strong business case today and procuring or developing clean electricity in chemicals & refining facilities to reduce power-related emissions, accelerated with 48E incentives[8]

8 Based on cost curve analysis, the only near-term measure with a positive investment case (>10% IRR) is the electrification of natural gas process compressors. Other abatement options that do not pass this hurdle rate but remain under $100/tCO2 through 2030 include the electrification of steam methane reforming with Haber-Bosch for ammonia production, chlor-alkali processes, steam cracking to produce ethylene, propylene and BTX, in addition to other chemical processes.

iii. transitioning steam methane reformers to clean hydrogen in sectors like ammonia production and refining, accelerated with IRA incentives (~3-5 MTPA by 2030)[xvi,9]

iv. installing CCS on high-purity streams (e.g., natural gas processing with streams of >90% CO_2 concentration), accelerated with 45Q incentives[xvii]

v. Continuing to use existing technologies (e.g., bio-based feedstocks to replace petroleum in existing refineries)[10]

These five levers offer the most immediate path to emissions reduction with the least disruption to existing operations. Decarbonization measures (i) through (v) could provide a ~20–25% emissions reduction through 2030 with investments that could clear at least a 10% hurdle rate while laying the foundation for the next phase of deeper decarbonization.[11] Together, these levers represent a ~$90–120B investment opportunity by 2030 that could be implemented largely "inside the fence" of existing plants.[12] Swift and widespread deployment of these economic measures is critical before turning to more costly measures down the road.[13]

Even where decarbonization measures create attractive financial returns, investment can still be limited. These investments often have three-to-five-year lead times to implement and lack a short-term financial return profile. Additionally, when companies are capital constrained, they often hesitate to fund large efforts from their balance sheets. Many find the best return on investment (ROI) is to spend sustaining capital expenditure (capex) to keep existing assets running rather than investing in new growth or decarbonization assets**. Increased funding for asset decarbonization through creative joint venture (JV) structures and external sources of capital (e.g., private equity, green bonds) could help realize the ~$90–120B opportunity for value accretive decarbonization measures by 2030 and beyond.**[14]

Meanwhile, the near-term decarbonization trajectories of the transportation and power sectors have implications for process emissions in chemicals & refining. These changes include a ~25% reduction in transportation emissions by 2030 and continued progress toward a carbon-free grid (~83% progress by 2030 toward a 2035 zero carbon grid).[15] Taken together, demand reduction for fuels (e.g., transition to ZEVs) and decarbonizing the power sector could reduce downstream chemicals production and refining emissions by an additional ~15% by 2030, supporting the Administration's long-term strategy for decarbonizing industrials.[xviii]

Past the early 2030s, the path to decarbonization faces a larger cost/performance gap as the industry turns to measures unlikely to clear a ~10% IRR and as credits in the Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA) begin to expire. Investment is needed today in the technologies and value/supply chains that will close this gap. These include (1) alternative value chains that must mature (e.g., power-to-x) and (2) lower TRL technologies (e.g., small modular reactors, alternative production processes like catalytic cracking) that require investment today, so that they are ready in the future (see Chapters 2 and 3).

9 Range represents 2030 demand from the marginal abatement cost curve analysis described in Chapter 3 for 3-5 MTPA clean hydrogen demand. The MACC analysis leverages data from the US National Clean Hydrogen Strategy and Roadmap, and DOE Hydrogen liftoff report.

10 Due to the scope of the analysis pursued in this report being focused on production emissions, low-carbon fuels and feedstocks are not included in the marginal abatement cost analysis presented in Chapter 3 but were explored further in Chapter 2, Section e.

11 Business case will vary by facility-specific context and could be greater or less than this analysis, which uses assumptions that can be found in Appendix D.

12 For the analyses in this report, economics were considered positive if the decarbonization project could achieve 10% or greater returns. See the appendix for additional detail on the modeling approach and assumptions.

13 Still, even the options that clear a 10% hurdle rate can be costly to implement, and future revenue streams are uncertain. Even though near-term solutions rely on relatively proven technologies, adapting or upgrading facilities often requires changes to existing plant operations and layouts. This necessitates changes to engineering, daily operations, and even business models, which can slow or prevent the implementation of these measures, even when they offer attractive returns. Both chemicals production and refining facilities are highly optimized for 24/7/365 uptime with significant integrated and codependent assets, meaning scheduled adaptations and upgrades must happen soon in a highly calculated way.

14 See the appendix for additional detail on the modeling approach and assumptions.

15 In line with White House targets for a 100% zero carbon grid by 2035 and decarbonized transport by 2050 as part of an economy-wide net-zero goal.

2. **Phase 2: Scaling decarbonization measures currently being demonstrated (2030–2040):** Cost-effective deployment at scale of the decarbonization levers demonstrated during Phase 1 is key to making progress toward deep decarbonization across these sectors beyond 2030. In particular, the chemicals & refining industries will ideally be able to utilize the scaled infrastructure for clean hydrogen and CCS developed in the 2020s and early 2030s. Medium-term solutions will leverage levers (i) through (v) and further decarbonize transportation and the grid.

Additional emissions reduction in this timeframe will be driven by two factors: (vi) adopting CCS on dilute emissions streams and (vii) rapidly electrifying low- and medium-temperature heat sources.

Additional GHG emissions reductions could be driven by the expanded use of biofuels and alternative feedstocks, which displace fossil carbon and have been shown to have lower process-based life cycle GHG emissions than fossil fuels. A shift to a biomass-driven economy to satisfy fuel and chemicals demand could lead to dramatic overall emissions reductions.[xix,16]

Absent additional policy or technology cost/performance improvements, these levers will add cost in the 2030s. With the sunset of IRA incentives (i.e., 45Q, 45V, 48E) and measures with high returns already implemented during the first phase, adopting CCS on dilute streams and further electrification will face investment challenges.

Clean firm power capacity requirements present an additional hurdle. Up to ~180 TWh of clean firm power would be required by 2030 to support the electrification of the chemicals & refining industries. This capacity is likely to be a combination of significant renewables added to the grid and purpose-built generation and storage to supply chemicals & refining facilities—with the success of both linked to technology/cost performance improvements. These measures are unlikely to be adopted by industry in the absence of (1) additional regulation (e.g., incentives or mandates for emission reduction), (2) technology cost-downs beyond what is forecast at present, or (3) the ability to pass costs to consumers or others in the value chain (e.g., sustained premia for decarbonized products)—see Chapter 4 for further details.

3. **Phase 3: Achieving net zero with technologies currently in R&D and pilot (2040–2050):** Achieving net zero for downstream chemicals production and refining by 2050 would require near-universal adoption of the previously mentioned decarbonization measures (i) through (vii), plus several additional levers. Taken together, demand reduction for fuels and decarbonizing the power sector could reduce emissions of downstream chemicals production and refining by an additional ~20% by 2050, supporting the Administration's long-term strategy for decarbonizing industrials. Industry momentum, consumer demand, and/or additional government action could accelerate the time frame for any of the levers mentioned below.

Success after 2040 requires:

- Increased overall adoption of clean firm power with storage (e.g., long duration energy storage or thermal energy storage) for low- and medium-heat electrification
- Full adoption of clean hydrogen in ammonia production and significant uptake in refining, with at least 7–8 MTPA of clean hydrogen by 2050 (up from ~3–5 MTPA by 2030)
- CCS on dilute streams could play a critical role in abating the remaining emissions gaps and would be needed to capture up to ~170 MTPA of CO2 in the chemicals & refining sector.

To achieve full net zero in these sectors, carbon removals would be needed for the remaining ~7% of emissions, including those from incomplete carbon capture. Like the prior decade, adopting decarbonization measures during this phase will add cost to many of the processes and products of these

16 Additional information on bio-based fuels and products can be found in the Clean Fuels and Products Shot initiative at the U.S. Department of Energy. (n.d.-b). Clean Fuels & Products Shot Media Kit. Energy.gov. https://www.energy.gov/eere/bioenergy/clean-fuels-products-shot-media.

sectors (see Chapter 3). Companies and shareholders are unlikely to implement measures without further regulation, significant cost-downs beyond those projected, or revenue/price premia on decarbonized products. When accounting for grid and transport decarbonization, only ~45% of 2050 BAU emissions could be abated through measures with positive economics in 2050.

Most pathways to net zero for industrial sectors rely on external industries and technologies to significantly progress, including clean hydrogen and CCS. Decarbonizing downstream chemicals & refining relies on these measures to achieve net zero by 2050, requiring that they abate ~225 MTPA of CO2 by 2050 (~68 MTPA (~12%) abated through clean hydrogen and ~157 MTPA (~29%) abated through CCS), creating risks to the pathway if these solutions are not scaled quickly. Economics and feasibility significantly improve with large-scale shared infrastructure, like pipelines and storage. However, little infrastructure exists today, and build-out can be challenging, as projects require assured demand and have long-lead times for permitting.

As mentioned, a pathway to net zero by 2050 for chemicals & refining processes will require significant cost and performance improvements in today's nascent decarbonization technologies. Investment over the next decade is essential to ensure technologies that are lower-TRL today are available at scale after 2040. As legacy fossil plants reach end-of-life status, more substantial retrofits and/or greenfield development could allow innovative production methods and value chains to scale. As demand for current fuel products changes as the transportation sector decarbonizes, refinery configurations and optimization can be reconsidered. Biobased and waste feedstocks can be incorporated into existing or new facilities to produce drop-in or new fuel and chemicals products. Sustained demand for biobased solutions may be the cornerstone for developing large-scale collection and processing technologies using waste or biomass as feedstocks. In some cases, these solutions could leverage existing chemicals & refining infrastructure; other cases may rely on new biomanufacturing plants with domestic supply chains.

Achieving decarbonization across the chemicals & refining industries will be challenging without end-use shifts by consumers and coordinated efforts across all relevant companies and governments. The Department of Energy, in partnership with other federal agencies, has RDD&D investments and other demand-side support mechanisms to address the challenges in decarbonizing downstream chemicals production and refining. **Finally, DOE is committed to working with communities, labor unions, and the private sector to build a 21st-century industrial base that meets the country's climate, economic, and environmental justice imperatives.** Achieving a net-zero economy will have broad socioeconomic benefits, protect existing manufacturing employment, and create millions of good-paying job years, for a broad range of American workers, from now through 2050. Industrial decarbonization, if pursued with intention and attention to address legitimate public concerns and measurable harms, is a critical opportunity to: reinvigorate American industry, reduce hard-to-abate emissions, strengthen job security, enhance job creation, augment national economic security, and provide an avenue to abate health-harming pollutants from industrial operations that affect fence line communities.

Chapter 1: Introduction

Liftoff Reports describe the market structure, current challenges, and potential solutions for commercializing interdependent clean-energy technologies. Liftoff Reports are an ongoing, DOE-led effort to engage directly with communities and the private sector across the clean-energy landscape. Reports will be updated regularly as living documents based on the best available information at the time of publication.

U.S. chemicals production and oil refining contribute ~8% to gross domestic product (GDP) and are critical for U.S. energy security. At the same time, the production of chemicals and refined products is a significant contributor to U.S. emissions, accounting for ~11% (~533MT) of energy-related CO2 emissions in 2021 and 38% of total energy-related industrial emissions. Of the eight industrial sectors in focus, chemicals & refining account for ~60% of industrial emissions. Of the eight industrial sectors receiving Congressional support from the Infrastructure Investment and Jobs Act (IIJA), also referred to as the Bipartisan Infrastructure Law (BIL), and the Inflation Reduction Act (IRA), chemicals & refining account for ~60% of industrial emissions. Without significant action, these processes will continue as major contributors to U.S. emissions until 2050. For this report, the scope of the analysis is focused on the following:

- **Value chain segment in focus:** All analysis is based on emissions abatement in the ***processes*** associated with the production of chemicals & refining (see the shaded value chain segment in Figure 1). An evaluation of process-based life cycle emissions for biobased chemicals and biobased fuels is explored in Chapter 2.
- **Chemicals & refining subsectors producing emissions:** All analysis in this report considers the following subsectors, which account for 80% of emissions (Figure 5):
  - Oil refining
  - Natural gas processing (NGP)
  - Steam methane reforming (SMR) with Haber-Bosch for ammonia production[17]
  - Steam cracking for production of ethylene, propylene, benzene, toluene, and xylene (BTX)
  - Chlor-alkali processes
  - All other chemicals production
- **Primary sources of emissions:** This report analyzed the four primary sources of emissions created in the subsector processes (Figure 6):
  - Heat, including a delineation between low-, medium-, and high-temperature heat requirements
  - Process emissions
  - Electricity, including a delineation between on-site generation and grid electricity
  - Other sources, including fugitive emissions
- **Decarbonization pathway:** The least-cost decarbonization pathway considers the following levers:
  - Energy and operational efficiency
  - Clean hydrogen for use as an input in chemicals production and refining to replace carbon-intense hydrogen currently in use
  - Electrification with clean high-capacity firm power
  - CCS on both high-purity and dilute streams of CO2
  - Life cycle emissions: While not part of the decarbonization pathway for process emissions, the ability to reduce life cycle emissions via biobased chemicals and biobased fuels is explored in Chapter 2.

  The decarbonization levers discussed in this report tie to the DOE's Industrial Decarbonization Roadmap pillars and prior Liftoff reports. Energy efficiency, industrial electrification, and CCS are their own pillars in the Roadmap, while clean hydrogen aligns with the Low Carbon Fuels, Feedstocks,

17 This analysis assumes all current ammonia production uses SMR as a simplifying assumption.

and Energy Sources pillar. Further comparisons are made in this Liftoff report and the Industrial Decarbonization Roadmap in the appendix.

- **Nascent decarbonization measures discussed but not included in the pathway:** This report discusses a selection of nascent decarbonization measures that could meaningfully change the pathway and be included in future pathway updates as they develop and scale. These include:
  - Modular nuclear for combined heat and power (CHP)
  - Carbon utilization technologies
  - Non-amine-based carbon capture
  - Electric crackers
  - High-temperature heat electrification
  - High-efficiency/current-density electrolyzers
  - Biobased fuels
  - Biobased chemicals (e.g., biobased adipic acid, propylene glycol, isoprene)
  - Advanced recycling processes (e.g., mechanical recycling, pyrolytic recycling, municipal waste upgrades)
  - Alternative separation processes

Without significant action, the downstream production of chemicals & refining will continue as a major contributor to U.S. emissions until 2050. If downstream chemicals production and refining were to continue with current practices, emissions from these sectors could increase by approximately 20% by 2050.[xx] Due to growing global demand, chemical emissions are expected to grow by around 35% from 2021 to 2050.[18] For the U.S. chemicals & refining sectors to achieve net-zero emissions by 2050, significant decarbonizing production is necessary.

18 Refining emissions are predicted to remain relatively flat unless there is a significant transition to zero-carbon vehicles in the U.S. vehicle fleet. If such a transition to zero-emission vehicles were to occur, total emissions across downstream chemicals production and refining would remain roughly stable today, with refining emissions falling by roughly half and offset by increased chemicals emissions.

Chapter 2: Current state – technologies and markets

Key takeaways

Section 2a: Emissions baseline and process scope

- **Emission baseline:** Each stage of the chemicals & refining process has associated emissions, from the exploration and production of fossil fuel feedstocks upstream to midstream transportation, production processes, and end-use consumption.

- **Process emissions scope:** Approximately 80% of chemicals production and refining emissions are generated from five sub-sectors (i.e., refining, natural gas processing, steam methane reforming with Haber-Bosch for ammonia, steam cracking for ethylene, and chlor-alkali production). A long tail of hundreds of other chemicals production processes makes up the remaining ~20%.

Section 2b: Technology landscape and core assets

- **Chemicals:** The United States is the world's second-largest chemicals producer, with ~$517B of products produced annually from over 10,000 chemicals facilities nationwide, totaling 14% of the global chemicals market.[xxi] Core product lines include bulk chemicals, inorganics, and specialty chemicals. Production is complex, with two common processes and assets—steam cracking and steam methane reformation—totaling a large concentration of emissions.

- **Refining:** The United States produced 18.7 million barrels of finished petroleum products daily in 2022, including ~10–15% for export, from ~130 facilities nationwide.[xxii] Transport fuels comprise the majority share of products by volume, with core non-fuel products including propylene and BTX. Common assets in every refinery include distillation columns, crackers, reformers, and hydrotreating/cracking units.

Section 2c: Market dynamics & sustainability priorities

- The chemicals sector consists of thousands of companies of ranging sizes. Some segments are highly concentrated (e.g., inorganic and specialty chemicals), while others have a more fragmented landscape (e.g., five primary producers make 50% of bulk chemicals with a long tail of other producers). Customer pressure to address sustainability concerns in chemicals has been limited, with some exceptions (e.g., reducing virgin content in packaging). Most companies focus on efficiency measures and increasing recycled content, with a few examples of first movers investing in operational decarbonization pilots (e.g., electric crackers).

- Refining production is spread across ~80–90 domestic producers, with >50% of capacity concentrated in the top five companies across ~30 facilities. There has been limited industry momentum in decarbonizing refining, with some momentum in sustainable fuels (e.g., bio-based or power-to-liquid).

Section 2d: Initiatives to date

- Chemicals & refining companies are modestly investing across multiple sustainability and decarbonization priorities, including recycled feedstock, bio-based feedstocks for chemicals and fuels, products needed for other energy transition technologies, and operational decarbonization measures (with the majority of investment focused on efficiency improvements). However, progress is insufficient to remain on track for 2030 and 2050 goals. Significantly more investment is needed to abate emissions in downstream chemicals production and refining and to offset demand—and therefore emissions—growth in the chemicals sector.

Section 2e: Deep dive on bio-based chemicals and fuels

- This report focuses on pathways that reduce the direct emissions from production stages of chemicals and fuel production (Figure 1), which excludes solutions that address the life cycle emissions of these products (e.g., biotechnology). The Biden-Harris Administration has set ambitious goals related to the role of biotechnology and bio-based materials to harness innovation to further societal goals and transform industries, including bold goals on bio-based fuels and chemicals.

- Managing the full carbon life cycle across the myriad of products resulting from chemicals production and refining is challenging in terms of technology solutions, measurement, and data. However, these production processes are a large concentration of industrial emissions, and the resulting products are used by nearly every industry and household daily. Therefore, decarbonizing the industrial processes that create the many chemicals and refined products is an essential step, and this report focuses on decarbonizing the full product life cycle of hundreds of everyday products. The production focus of this report complements the Administration's goals for biotechnology as the chemicals & refining industry transforms both current production processes and wholly new production routes in future plants.

Section 2f: Deep dive on other renewable feedstocks

- This report also excludes a wide range of promising decarbonization solutions that use CO2 or industrial/consumer waste products (such as plastics) as feedstocks to produce carbon-based chemicals and fuels. The use of CO2 and plastic waste as feedstocks have the potential to replace fossil feedstocks, introduce circularity, and decarbonize the production of chemicals and fuels.

Section 2a: Emissions baseline and process scope

Chemicals production and refining are large and complex sectors with different market structures, product mixes, and consumer pressures. The full value chain for chemicals and refined oil is complex (Figures 1 and 7)**.**

- **Upstream:** Each process starts with upstream exploration and production of fossil fuel feedstocks, such as crude oil and natural gas. Methane leaks are a source of upstream and midstream emissions, resulting in over 186 MT CO2e—equal to ~25% of U.S. methane emissions—requiring measures to monitor and address leaks and plug abandoned wells.[19]

- **Midstream-to-feed production:** These feedstocks are transported through midstream infrastructure that feeds production facilities and refineries where materials are processed to produce chemicals and refined products. These products are transported through midstream infrastructure to end markets. This transport results in emissions from the energy required to run compressors and the trucks, ships, and trains carrying feedstocks and products.

- **Production processes:** More than 70,000 industrial and consumer products rely on a chemicals or oil-based feedstock as part of their ingredient list or production emissions, depending on petrochemical

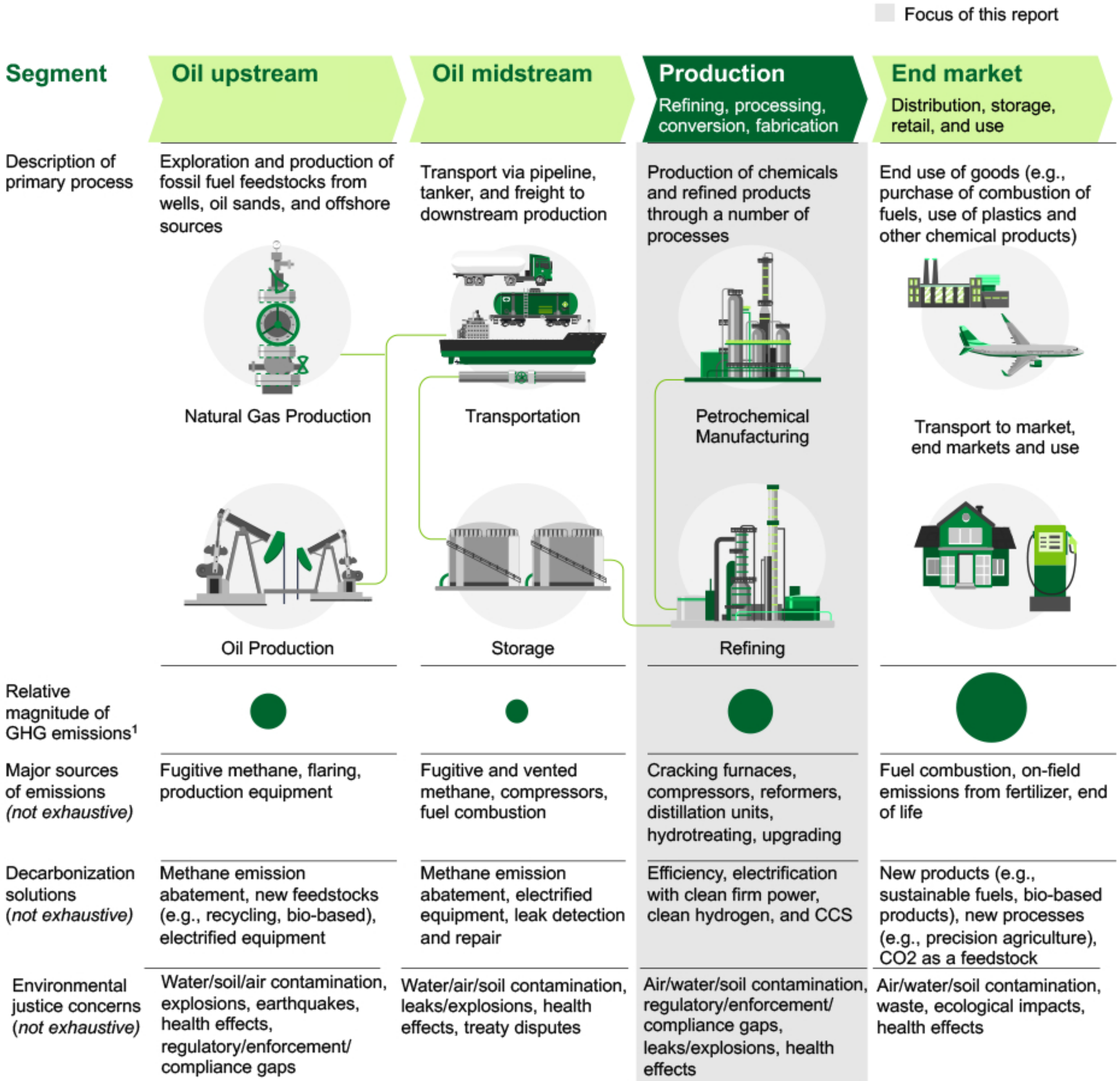
19 EPA Estimates of Methane Emissions by Segment in the United States, including abandoned wells, distribution, and transmission and storage compared to overall methane emissions from the EPA greenhouse gas Inventory: Environmental Protection Agency. (n.d.). Estimates of Methane Emissions by Segment in the United States. EPA. https://www.epa.gov/natural-gas-star-program/estimates-methane-emissions-segment-united-states; Environmental Protection Agency. (2023a). Inventory of U.S. greenhouse gas emissions and sinks: 1990-2021. EPA. https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Chapter-Upfront.pdf

manufacturing or oil refining type. These sources include cracking furnaces, reformers, distillation units, heat and electricity emissions, fugitive emissions, and more.

Managing the full carbon life cycle across the myriad of products is challenging—in terms of technology solutions, consumer behavior, measurement, and data. **Therefore, decarbonizing the industrial processes that create chemicals and refined products is essential—and this report's focus—to decarbonizing the full product life cycle.** Decarbonizing these production processes enables a reduction of emissions across a wide range of products at a single point, which abates emissions across the value chain and enables scaling targeted sets of decarbonization technologies.

- **End markets and consumption:** Reducing end-use emissions requires a different set of measures and a shifting of consumer behavior, including new products and processes such as transitioning to zero-emission vehicles, product circularity, and using less fertilizer through precision agriculture. Though there are references to the new products and processes that could fundamentally change the industry, these are not the focus of this report.[20] Instead, this report examines the measures needed for the industry to decarbonize the production processes of chemicals & refining as currently practiced.

20 Additional analysis on these new products and processes can be found in: Biden-Harris White House. (2023, March). *Bold Goals for U.S. Biotechnology and Manufacturing - Harnessing Research and Development to Further Societal Goals*. WhiteHouse.gov. https://www.whitehouse.gov/wp-content/uploads/2023/03/Bold-Goals-for-U.S.-Biotechnology-and-Biomanufacturing-Harnessing-Research-and-Development-To-Further-Societal-Goals-FINAL.pdf



1. The circle plots represent the magnitude of GHG emissions relative to other segments of the chemicals and refining value chain. Circles are not sized to represent actual emission percentages.
Source: American fuel & petrochemical manufacturers, EPA GHGRP, EIA

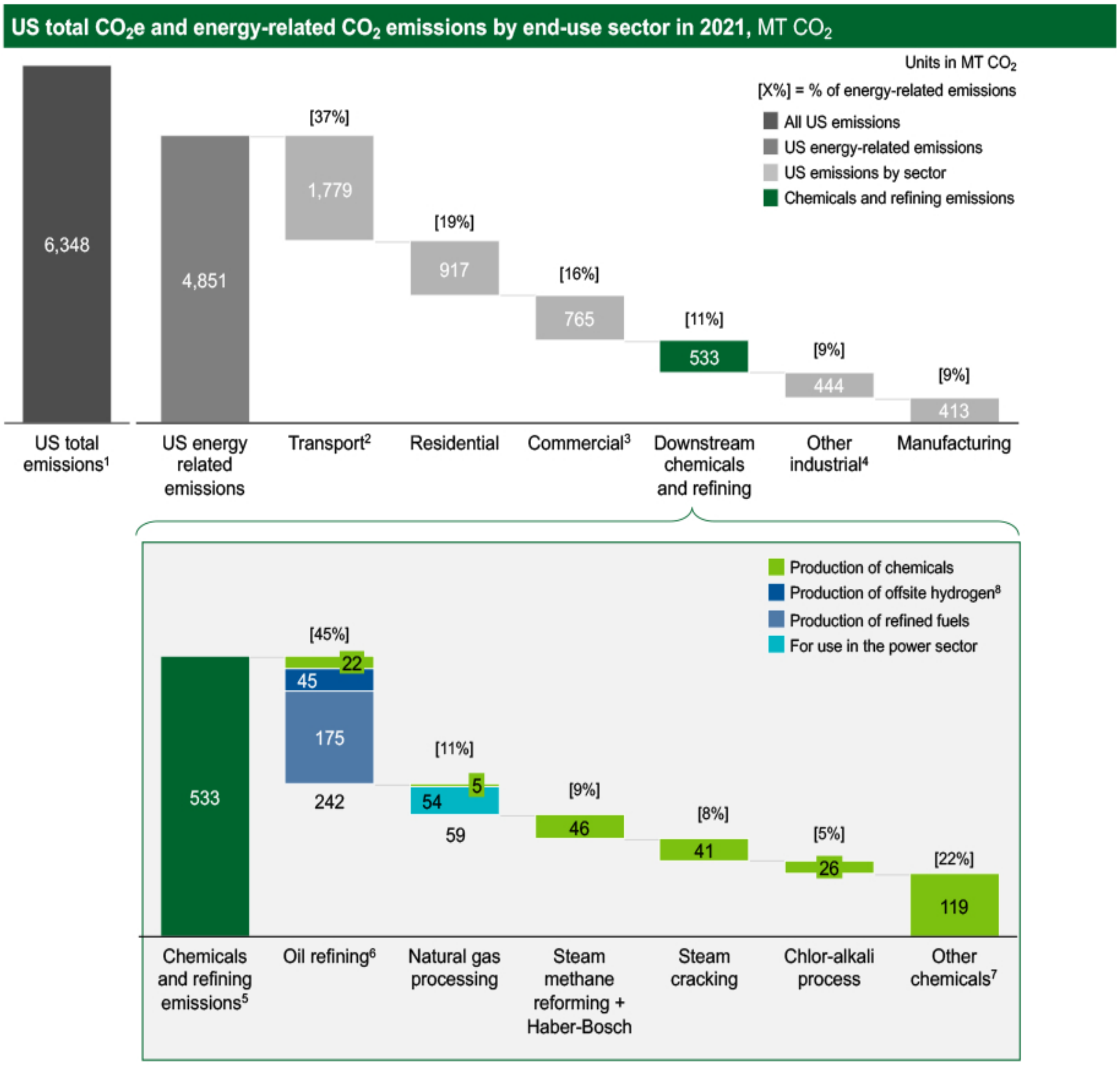
Figure 4 (also Figure 1): Across the chemicals & refining value chain, the leading source of emissions is end-market use, mostly from the combustion of fuels. Production emissions account for significant emissions from the production of fuel and chemicals due to industrial processes discussed in this report. Upstream emissions from the production of chemicals & refining feedstocks mostly come from methane leaks and the operation of extraction equipment. Midstream emissions occur during transport and storage due mainly to fugitive methane leaks.

To fully decarbonize, these industries' product and fuel mixes could change significantly as the U.S. transitions. For example, upstream, the industry could replace the entire supply chain with renewable feedstocks (e.g., biomass) and new processes (e.g., biomanufacturing). While this switch would maintain similar levels of process emissions, switching feedstocks to biofuels would reduce chemicals & refining life cycle emissions, with some examples showing GHG emission reductions of 35-100+%.[xxiii] Regarding end-use markets and consumption, a greater share of refined products is likely to be sustainable fuels, and the share of non-fuel products in refining could increase as the U.S. decarbonizes transport, thus reducing demand for traditional fuels.

However, while the fuel and product mix may change, many fundamental chemicals production and refining operations will likely remain and must be decarbonized. **For this reason, this report focuses on the decarbonization measures needed to abate emissions on production processes only (see the shaded section of Figure 4).**

Subsector production process emissions

Decarbonizing the refining and production processes of chemicals and oil is an important driver toward the Administration's long-term strategy to reach net zero (Figure 5).[xxiv]



1. Includes all greenhouse gas emissions, including fluorinated gas, and nitrous oxide, and upstream methane emissions. Gross emissions excluding emissions and removals from land use, land-use change, and forestry
2. An energy-consuming sector that consists of all vehicles whose primary purpose is transporting people and/or goods from one physical location to another
3. An energy-consuming sector that consists of service-providing facilities and equipment of businesses; Federal, State, and local governments; and other private and public organizations, such as religious, social, or fraternal groups
4. Including sectors like steel production, cement, and glass production
5. Emissions are estimated due to lack of data availability. Total sector emissions of 533 MT CO2 and oil refining are from EIA and include energy-related CO2 emissions only (excluding process emissions and non-CO2 GHG emissions). Emissions from natural gas processing, stream methane reforming, steam cracking, and chlor-alkali process were modeled bottom-up account for process related emissions. Emissions in other chemicals were calculated from the delta between EIA's reported emissions from all chemicals and those modeled bottom-up. Therefore, total sector emissions and total emissions for other chemicals could increase if process-related emissions and non-CO2 GHG emissions were included
6. Assumes that nearly all merchant hydrogen production in the U.S. feeds into the oil refining process. Refinery production of chemicals (e.g., propylene and BTX) are considered in the oil refining sector
7. Including production of multiple products derived from chemical building blocks, such as urea, formaldehyde, polyethylene, polypropylene, styrene, ethylene dichloride. All processes result in <5MT of emissions individually. Does not include process emissions, which could increase overall emissions in this segment
8. Includes Scope 1 and Scope 2 for refiners and chemicals producers only
9. 533 MT of CO2 emissions based on EIA energy-related CO2 emissions. Additional emissions come from process emissions and non-CO2 sources. 100% of emissions will contain non-CO_2 emissions in the chemicals and refining sector due to methane, N_2O, and other greenhouse gases

Sources: EIA data for energy-related emissions, EPA data for total US emissions, IEDO Industrial Decarbonization Roadmap, 2021 EPA Flight, EIA MECS, OPIS, IHS Markit, Argus, ITC, ICIS, McKinsey Chemical Insights, GREET GWP, Sci Rep 12 14490 (2022), FAO

Figure 5: Chemicals & refining production accounts for ~11% of U.S. energy-related emissions (533 MT CO2), with five main processes accounting for ~80% of emissions.

Approximately 80% of chemicals production and refining emissions are generated from five subsectors (Figure 5).[21] While decarbonizing the emissions from end-use sectors beyond chemicals & refining is possible and essential, they are not further detailed as they are beyond this report's scope.

1. **Oil refining** accounts for approximately 242MT (45%) of chemicals & refining emissions.[xxv] These emissions result from processes to remove impurities from crude oil, distilling and upgrading the oil into end-products, primarily for transportation fuels (~85% of refined end-products), industrial feedstocks and fuels (~10%), and lubricants (~1%).[22,23,xxvi,xxvii] The lowest quality products are typically used for asphalt production and road oil (1%).[xxviii]

2. **Natural gas processing** accounts for approximately 59MT (11%) of CO2 emissions from processes to remove impurities—such as sulfur and CO2—from raw natural gas and extract different products.[24] Over 90% of natural gas is used in the power sector, while a small portion is processed for chemicals production (e.g., ethane for use in ethylene production). While liquid natural gas (LNG) is an important part of the supply chain, this report is focused on domestic production and therefore emissions associated with LNG are out of scope.

3. **Ammonia production** produces approximately 46MT of CO2 from the steam methane reforming (SMR) and the Haber-Bosch process, which uses natural gas and nitrogen to create ammonia.[25] This ammonia is used to manufacture products such as urea and ammonium nitrate, commonly used as fertilizers. New use cases for ammonia as a carrier for clean hydrogen are being explored widely, which could significantly increase future ammonia production in the U.S. For example, 4.4 MMT of clean hydrogen projects for use in ammonia have been announced recently, making up 23% of all recent clean domestic hydrogen announcements.[xxix] Many of these announcements are in the context of new uses for ammonia, such as exporting ammonia as an energy carrier. This projected increase in demand for clean ammonia could increase the need for clean hydrogen production beyond the assumed BAU scenario.

4. **Steam cracking** to produce a variety of chemicals precursors results in approximately 41MT of CO2 emissions.[26] In the U.S., chemicals producers primarily process ethane gas through steam cracking to manufacture essential chemical building blocks. These precursors include ethylene, propylene, butadiene, benzene, toluene, and xylene (BTX), predominantly used for manufacturing plastics. Assuming equal allocation of emissions by tons of product produced, 90% of steam cracking emissions in the U.S. are driven by ethylene production.

5. **Chlor-alkali processes** producing chlorine and caustic soda result in approximately 26MT of CO2 emissions.[27] These emissions are produced from the treatment of saltwater brine using electricity and mid-temperature heat to generate chlorine gas and caustic soda. Chlorine gas is mainly used in plastics production, typically as PVC, while caustic soda acts as a reagent across various industries.

Additional processing of primary chemical building blocks into a range of products accounts for 20% of emissions. See the appendix for the methodology and assumptions used for this analysis.

21 Determine using the chemicals emission model described in the appendix on modeling methodology.

22 Includes finished motor oil, distillate fuel oil, kerosene-type jet fuel, and residual fuel oil.

23 Includes petroleum coke, still gas, hydrocarbon gas liquids, and petrochemical feedstocks.

24 Considers emissions from all facilities reporting above 20,000 tonnes of CO2 emissions per year and reporting to EPA GHGRP.

25 Calculated for this report using the methodology described for chemical emissions modeling in Appendix C.

26 Ibid.

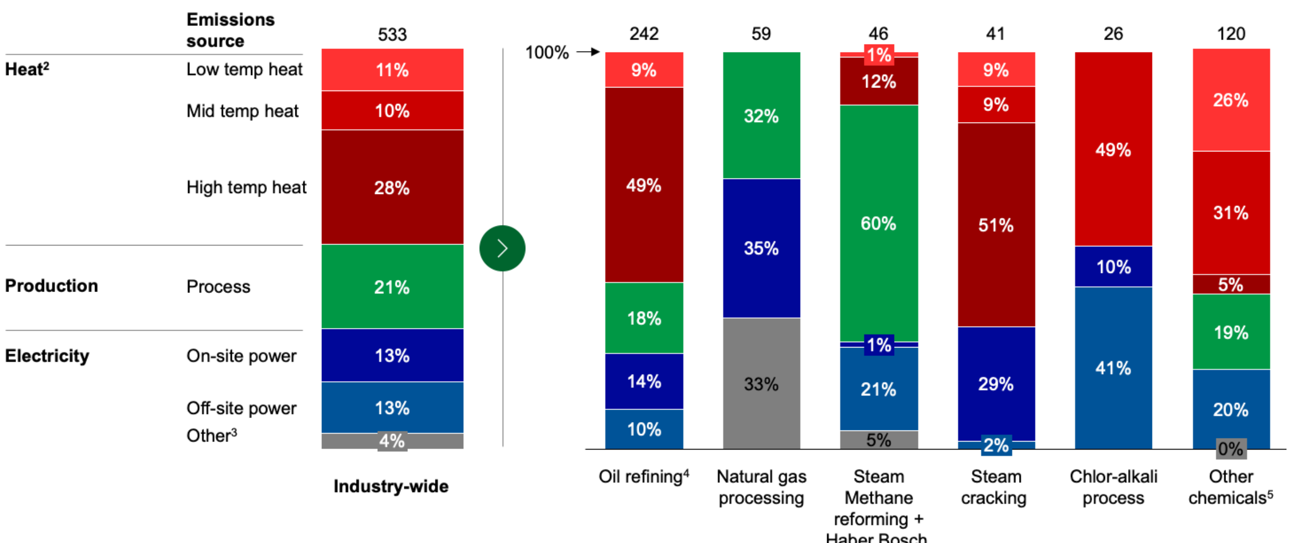
27 Ibid.

Production emissions from the subsectors outlined above come from four primary sources (Figure 6)**:**

- **Heat generation** accounts for approximately 50% of emissions.
- **Electricity generation**, including on-site generation and electricity from the grid, accounts for 25% of emissions.
- **Process emissions,** which are greenhouse gas emissions that are a by-product of chemical conversions, account for approximately 20%.
- The remaining 5% of emissions come from various sources, such as fugitive emissions and unplanned heat loss. See the appendix for the methodology and assumptions used for this analysis.

Certain subsectors, such as chlor-alkali and ammonia, release significant emissions from a few primary sources. For example, in the chlor-alkali process, approximately 50% of emissions come from electricity to electrolyze the brine, while the remaining 50% are from mid-temperature heat used to evaporate water from the solution. Similarly, around 60% of emissions in ammonia production stem from the steam methane reforming process, which directly releases CO2 when converting natural gas to hydrogen for the Haber-Bosch process. However, for other subsector production processes (e.g., refining, steam cracking), many emission sources are often from disparate flue streams in a facility.

Emissions breakdown from chemicals and refining industry in 2020,[1] MT CO_2



1. Includes Scope 1 and Scope 2 for refiners and chemicals producers only
2. Temperature ranges: low temperature heat is from -30 C to 200 C, medium heat is from 200 C to 400 C, and high heat is 400+ C
3. Includes electrochemical processes, refrigeration, and cooling for ethylene / propylene; cooling, heat loss for ammonia, and fugitives or leakage emissions from NG processing
4. Based on EERE combustion breakdown for on-site / off-site power generation and process heat
5. E.g., production of urea, formaldehyde, polyethylene, polypropylene, styrene, ethylene dichloride

Source: 2018 EPA Flight, 2018 EERE Manufacturing Energy and Carbon Footprints report, 2022 IEDO Report, Energy Environ. Sci., 2020,13, 331-344, EIA, 2020 USGS, DOE Natural Gas Supply Chain report.

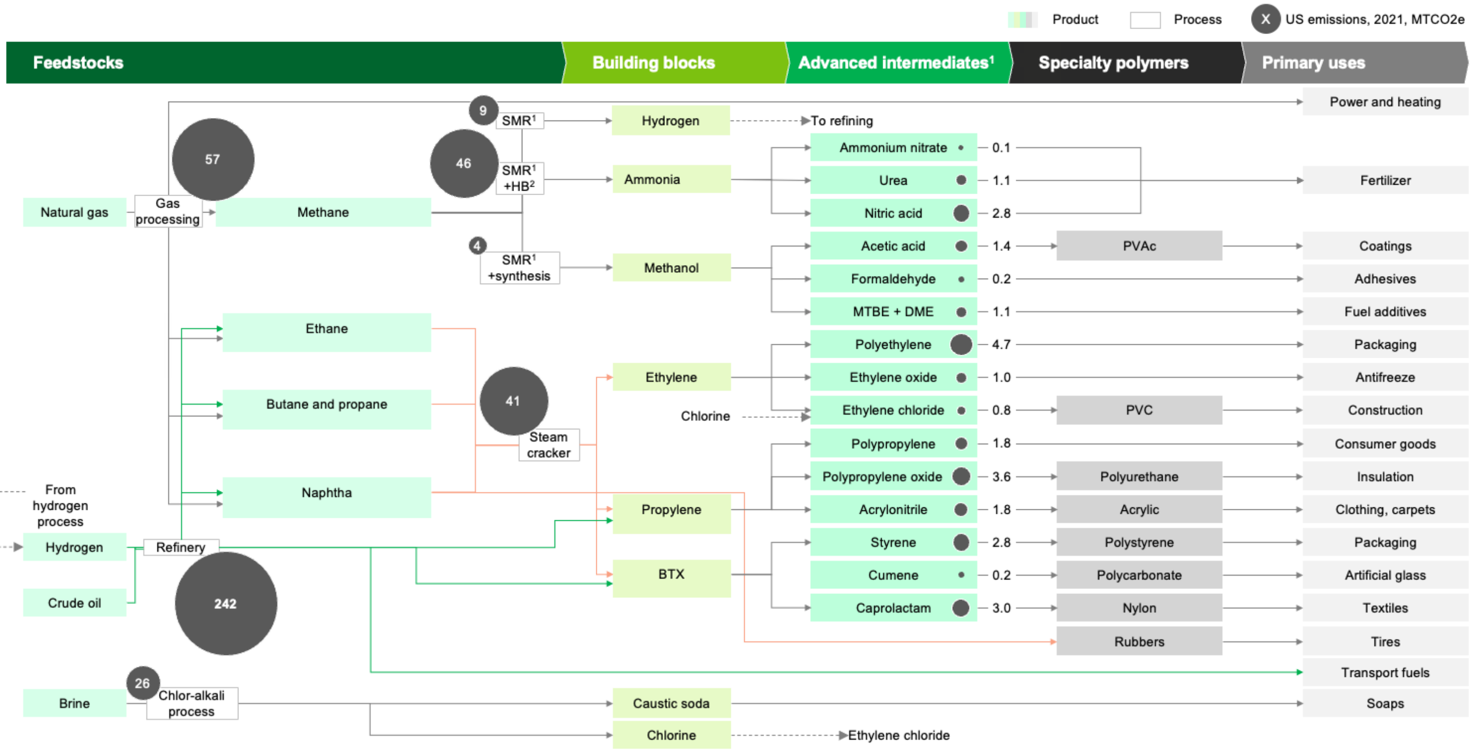
Figure 6: Chemicals & refining production accounts for ~11% of U.S. energy-related emissions (~533 MT CO2), with heat accounting for ~50% of emissions, CO2 from chemical conversion processes accounting for ~20% of emissions, and power accounting for ~25% of emissions.

Specific technologies can address the largest cluster of chemicals & refining emissions. For example, technologies that can decarbonize high-temperature heat could have applications across many sectors (e.g., oil refining, steam methane reforming, steam cracking). These technologies could translate into reduced costs to decarbonize mid- and low-temperature heat and could include technologies like electrification and CCS, which address a wide range of emission sources. Cost reduction and deployment of these cross-cutting technologies could be a win across various sectors, including those beyond chemicals & refining. Additionally, industrial sectors could learn from each other as more decarbonization technologies are deployed. The emissions impact of cross-cutting technologies is further explored in Chapter 3 (Figure 20) and Chapter 4 (Figure 26), as well as in the Pathway to Commercialization: Industrial Decarbonization report.

Section 2b: Technology landscape and core assets

Chemicals

The United States is the world's second-largest chemicals producer, with $517B of products produced annually from over 10,000 chemicals facilities nationwide.[xxx] The U.S. makes up 14% of the global chemicals market.[xxxi]



1. Emissions associated with advanced intermediates represents production process emissions and not material use emissions

Sources: S&P, Process Economics Program (2023), Opis a Dow Jones Company, Chemical Market Analytics (2023), Solomon, S., et al. "IPCC fourth assessment report (AR4)." *Climate change* 374 (2007), Hajny, Salmon et. Al, (2019), Observations of Methane Emissions from Natural Gas-Fired Power Plants, *Environmental Science & Technology* **2019** *53* (15), 8976-8984, DOI: 10.1021/acs.est.9b01875

Figure 7: Core chemicals processes and their associated greenhouse gas emissions.[28]

Primary products: Primary chemicals products can be divided into three key categories:[xxxii]

1. **Bulk chemicals** (~$153.3B U.S. market, e.g., ethylene, propylene, BTX) are used as feedstocks for a variety of products, including:[xxxiii,xxxiv]
   - **Plastic resins** (~$90B U.S. market) include High Density Polyethylene (HDPE), Low Density Polyethylene (LDPE), Polyethylene terephthalate (PET), and Polyethylene (PE), and Polypropylene (PP), among others, which are purchased in bulk for use in applications such as packaging, electronics, and vehicles.[xxxv]
   - **Synthetic rubbers** (~$7B U.S. market) are used in products like tires, gaskets, and medical devices.[xxxvi]
   - **Manufactured fibers** (~$5B U.S. market) include polyester and nylon. These fibers are used in textiles, medical devices, and coatings.[xxxvii]
2. **Inorganic chemicals** (~$45B U.S. market, e.g., chlorine, caustic soda, and hydrogen) are used primarily as feedstocks in plastics (e.g., Polyvinyl Chloride or PVC) with a long tail of ancillary uses, including soap and glass production.[xxxviii,xxxix]

28 For a further breakdown of emissions by chemical product, see: Nicholson, S. R., Rorrer, N. A., Uekert, T., Avery, G., Carpenter, A. C., & Beckham, G. T. (2023a). Manufacturing Energy and greenhouse gas emissions associated with United States consumption of organic petrochemicals. ACS Sustainable Chemistry & Engineering, 11(6), 2198–2208. https://doi.org/10.1021/acssuschemeng.2c05417

3. **Specialty chemicals** (~$92B U.S. market) differ from bulk chemicals as specialty chemicals mostly have one or two uses while bulk chemicals may have dozens. Specialty chemicals are wide-ranging, including adhesives, pharmaceuticals, flavors, cosmetic additives, and pesticides.[xl]

Chemicals production: Chemicals production involves hundreds of processes and pieces of equipment. Today, most emissions come from bulk chemicals production—typically via steam cracking at integrated cracker facilities (Figure 8)—and hydrogen production via steam methane reforming (SMR).[29]

1. **Integrated cracker facilities:** Cracker facilities produce bulk chemicals, including ethylene, propylene, and BTX. These facilities contain critical pieces of equipment that can be decarbonized, including:
   - Large cracking furnaces where feedstocks (e.g., heavy hydrocarbons) are "cracked" (i.e., broken by heat and pressure) into smaller molecules,
   - Compression facilities to cool and pressurize cracked gas while reducing its volume, and
   - Distillation facilities where cracked gas is separated (i.e., from other products, impurities, or unreacted starting materials) into the main products. The cracking furnaces and onsite power emit the highest concentration of CO2 (Figure 8).

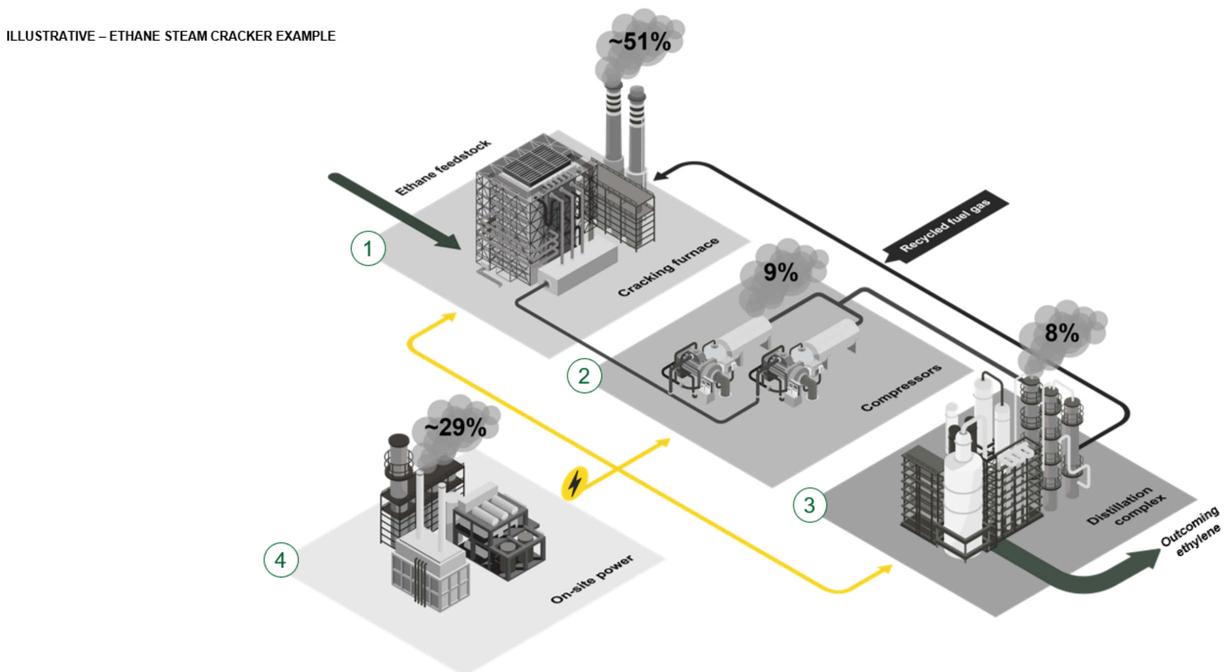


Figure 8: Simplified view of key equipment and emissions in a typical ethane-based steam cracking facility. Emissions from the cracking furnace are driven by high heat production; compression emissions come from the heat needed to cool and compress cracked gas; distillation emissions come from separating key products from the cracked gas stream and leaving fuel gas; and electrical power is used to power processes throughout the process. Fuel gas left after distillation is recycled into the furnace to power the cracking process.[30]

2. **Steam methane reformers (SMR):** SMRs produce hydrogen for industrial processes and as an inorganic feedstock to make specialty chemicals (e.g., ammonia, methanol). SMR emissions primarily come from the steam reformer, where methane (CH4) and steam (H2O) are converted to hydrogen (H2) and carbon dioxide (CO2). This produces a concentrated stream of CO2, which can be captured. See the Hydrogen Liftoff report for more details on decarbonizing hydrogen production.

Assets, including integrated crackers and SMRs, maintain 24/7/365 uptime for several years to offset the significant capital required for development. In addition, many pieces of equipment operate at high

29 Note: there are new processes for hydrogen production, including Autothermal Reforming (ATR). See the Hydrogen Liftoff report for additional detail.

30 Archetypical refinery assumes a 1.2 MT per year facility with an 85% utilization rate and emissions of ~1 MT CO2 per year.

temperatures and can take hours—or even days—to reach the correct operating threshold. Planned downtime for major repairs occurs every ~5 years, with standard maintenance to repair compressor equipment occurring continuously between major downtimes.

Refining

The U.S. refining sector produced 18.7 million barrels of finished petroleum products daily in 2022, including ~10–15% for export, from ~130 facilities nationwide.[xli]

Primary products: The primary refining products can be divided into two key categories:

1. **Transport fuels** accounted for >90% of U.S. refined products in 2022, with a rising share of exports up to ~9–10 mbpd of production in December 2022.[xlii] Three main transport fuels are generated by refineries, accounting for most of the production volume.
    - **Gasoline** is one of the primary products of a refinery and is used mainly for light-duty automobile fuel.
    - **Diesel** is a longer-chain fuel used in heavy-duty transport such as truck, bus, and train fuel.
    - **Jet fuel** is a highly refined fuel that provides the high-energy density and stability needed for airplane operation.
2. **Non-fuel products** account for ~5% of refined products but could increase as demand for transport fuels declines as electric vehicles and other technologies are adopted.[xliii] These products include:[31]
    - **Petrochemical feedstocks,** such as liquified petroleum products and naphtha, are used in downstream facilities to create basic chemicals
    - **Petrochemicals** are often produced in refineries; common products include propylene and BTX
    - **Byproducts,** including asphalt, petroleum coke, and bitumen

Key equipment used in production: Refineries consist of 30–40 process units across the separation, conversion, and finishing components of the production process. Key assets include the atmospheric distillation unit, fluidized catalytic cracker, reformer, hydrocracker, and hydrotreater (Figure 9).[xliv] These assets are operational for at least 30 years, with planned downtime for upgrades and retrofits every ~5 years.[xlv]

ILLUSTRATIVE – REFINING EXAMPLE

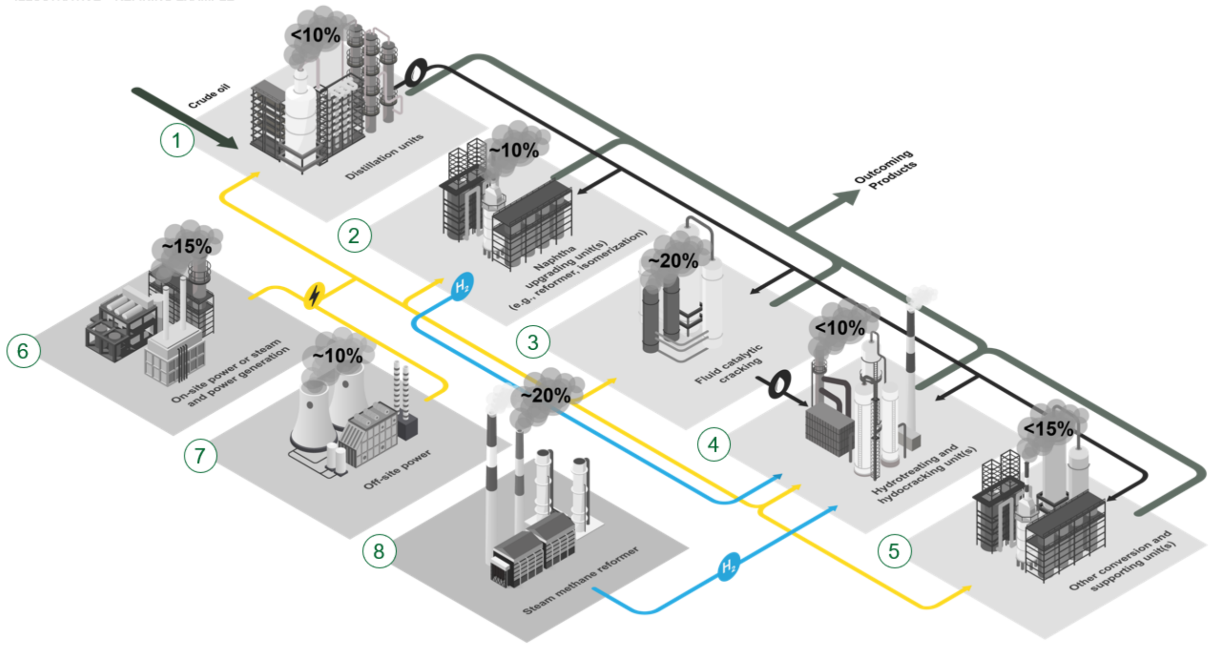


Figure 9: Simplified view of key equipment and emissions in a typical refinery. Emissions come from several sources, the largest being SMR for hydrogen and fluid catalytic cracking units. SMR emissions are driven by process emissions, process heat, and steam. Fluid catalytic cracking emissions are driven by process heat.[32]

31 Gross value added by these non-fuel products is accounted for in other markets, such as chemicals for petrochemicals and construction for asphalt production.

32 Archetypical refinery assumes 185 kbpd facility with an 87% utilization rate and emissions of ~2 MT CO2 per year.

1. **Atmospheric distillation unit:** Boils crude oil inputs at high temperatures to separate hydrocarbons based on boiling points.
2. **Naphtha upgrading units (e.g., reformer):** Upgrades heavy naphtha into a gasoline blend and generates hydrogen as a byproduct.
3. **Fluid catalytic cracker:** Uses a catalyst under high temperatures to break down large hydrocarbons into smaller molecules to produce light products such as gasoline.
4. **Hydrotreater and hydrocracker:** The hydrotreater removes sulfur and other contaminants using hydrogen and solid metal catalyst before blending the final refined product. The hydrocracker uses hydrogen mixed with hydrocarbon to crack hydrocarbons in the presence of a catalyst to produce high-quality diesel, kerosene, and gasoline.

Section 2c: Market dynamics and sustainability priorities

Chemicals

Market landscape: The chemicals sector comprises thousands of companies of various sizes throughout multiple value chains. The industry is concentrated, with some segments more concentrated than others. For example, domestic production of key bulk chemicals (e.g., ethylene, propylene, and BTX) is concentrated in five primary producers that comprise ~50% of the U.S. market across ~40 facilities. At the same time, inorganic and specialty chemicals production is highly concentrated. Inorganic chlor-alkali production has five domestic producers, accounting for ~85% of production capacity. And 75% of specialty chemical ammonia is produced by five primary producers.

Market growth: In a business-as-usual scenario, chemicals production is expected to grow by ~35% by 2050 (relative to a 2021 baseline) due to demand growth.[33,xlvi] This demand growth of key sectors, such as ethylene production, cannot be met by existing capacity and will require greenfield development—requiring up to 15 MT of new ethylene steam cracker capacity by 2050.[34] However, greenfield facilities could leverage new cracker technologies (e.g., e-cracker) or new feedstocks (e.g., ethanol).

Decarbonization efforts to date: Decarbonizing chemicals production, and its associated end products, remains limited. To date, decarbonization commitments have come in the form of both near-term goals (<2035) and long-term net-zero goals (2050+). As of spring 2023, two-thirds of large chemicals companies have made decarbonization commitments, with Scope 1 & 2 emissions reduction ranging from 15–50% by 2035.[35]

Currently, the focus on sustainability is driven by pockets of consumer demand rather than a direct regulatory/policy mandate. Plastic packaging has seen the most consistent and widespread pressure to decarbonize and is a significant end-use of basic chemicals. For example, plastics account for >80% of ethylene end-use.[xlvii]

In limited product lines, including some textiles and finished consumer packaged goods, customers have been willing to pay a premium for initiatives focused on increasing recycled content and reducing virgin plastic and plastic waste.[36] These price premia are isolated to specific product verticals, most often for higher-margin CPG products sold directly to the end consumer (e.g., packaging for shampoo and skincare products), textiles (e.g., plastic-based clothing textiles), and automobiles. These consumer plastics account for ~30% of U.S. consumed plastics and a much smaller component of overall chemicals production. Based on the evidence of recycled content, there could be a potential willingness to pay a premium for sustainable

33 Assuming a 35% increase in ethylene emissions has a linear increase in demand.

34 Assuming a 35% increase in ethylene emissions has a linear increase in demand with similar facility utilization rates and U.S. production data from IHS Markit.

35 Largest companies selected based on market share; decarbonization commitments extracted from company sustainability reports.

36 The depth of the market for these premia is unknown, and there has not been the same evidence of premia for decarbonized products.

chemicals products in select segments of the market (e.g., consumer plastics, premium markets). For example, there has been evidence of a 100% premium for natural recycled HDPE over virgin HDPE.[xlviii] State-level policies, such as extended producer responsibility in Oregon and Colorado, are beginning to encourage or require consumer plastics producers to manage the life cycle of their products.[xlix,l]

The complex value chains connecting chemicals & refining producers to end-consumers add multiple steps to capturing premiums. For example, the ammonia/fertilizer products value chain (Figure 10) has several steps separating retailers from ammonia producers. Therefore, capturing end customers' willingness to pay would rely on price increases at each stage of the value chain.

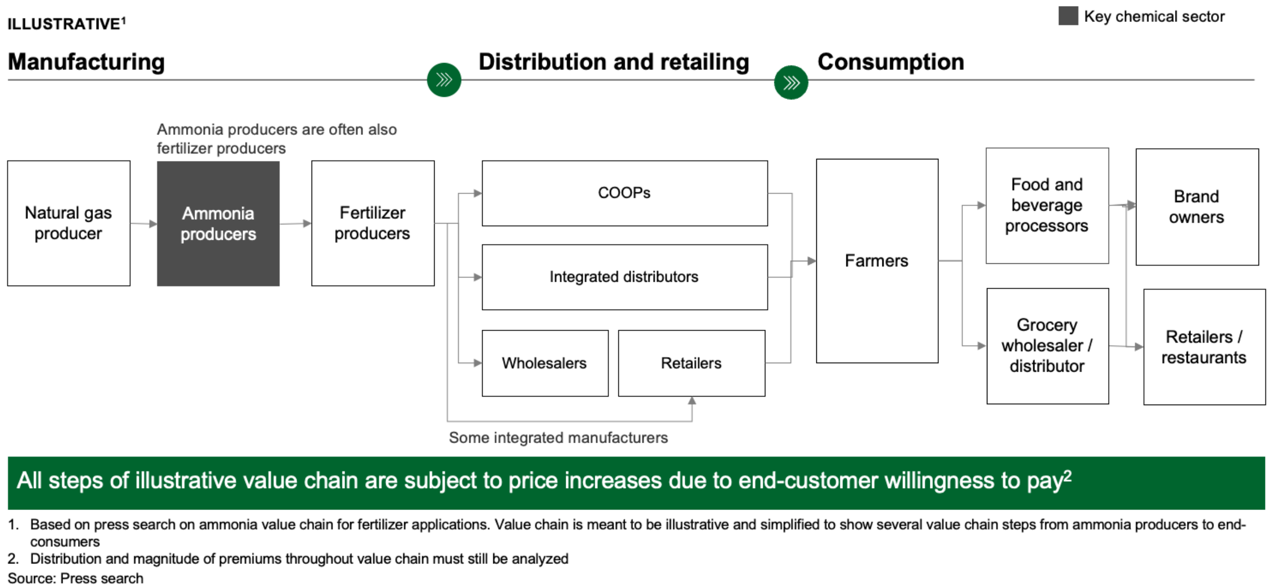


Figure 10: Illustrative and simplified ammonia value chain; end-customer willingness to pay must travel through the complex chemicals & refining value chains to incentivize the increased cost of decarbonized materials.

Refining

Market landscape: Refining production is spread across ~80–90 domestic producers, with >50% of capacity concentrated in the top five companies across ~30 facilities. Geographically, over 40% of U.S. refining capacity is on the Gulf Coast, with smaller clusters of refineries in California and Illinois representing another ~15% (Figure 11). The remaining ~45% of capacity consists of smaller refineries across the country.[li]

Market growth: In a business-as-usual scenario, refining output is expected to grow by ~7% by 2050 (relative to a 2021 baseline). This slight demand growth may require the construction of new refineries, which could leverage new refinery assets (e.g., electrified processes) and/or new feedstocks (e.g., biomass, clean hydrogen).

Existing policies of interest: The EPA regulates refinery flaring events and sulfur level thresholds in gasoline.[lii] However, at the federal and state levels, few regulatory drivers explicitly require decarbonizing refining production processes. Some legislation at the state and federal levels incentivizes the reduction of life cycle emissions in transport fuels. However, it is important to note that recent studies have shown widespread failure to enforce regulating policies such as the Clean Air Act and Clean Water Act.[liii,liv] A detailed discussion of the environmental justice concerns related to refineries can be found in Section 3e.

At the federal level, the Renewable Fuel Standard (RFS) provides renewable identification number (RIN) credits for biofuel production.[lv] Federal tax credits are available for producing or blending biodiesel (IRA section 40A) and sustainable fuels (IRA section 45Z PTC for clean fuels, and IRA section 40B for SAF). [lvi,lvii] [37]

37 A list of federal incentives for alternative fuels can be found on the Department of Energy's website: https://afdc.energy.gov/laws/all?state=US

Furthermore, states like California, Washington, and Oregon provide incentives for fuels with reduced carbon intensities through a Low Carbon Fuel Standard (LCFS).[38] Although these regulatory forces impact the mix of fuels produced by a refinery, they do not explicitly require operational decarbonization (i.e., reduction of CO2 emissions at the refining step).

Decarbonization efforts: Some refineries are focused on shifting production to renewable fuels. However, full-scale refinery conversion to bio-based feedstocks has happened recently at relatively small U.S. refineries, ~500–700 million gallons/year.[lviii,lix] Overall, public announcements of biofuel conversions are unlikely to have a significant impact on capacity between today and 2030.[lx,lxi,39]

Short-term (pre-2035) decarbonization commitments in the oil refining sector vary greatly, with an average reduction target of ~30% of refinery emissions (Scope 1 and 2) by 2030 amongst the major companies analyzed.[40] Beyond reducing Scope 1 and 2 emissions (i.e., for a refining company, including emissions from direct operations and purchased electricity), the industry has sustainability targets around reduced methane intensity, zero flaring, and Scope 3 ambitions. There have been few net zero targets in the U.S. refining industry, with most longer-term commitments building on existing 2030 targets for reduced Scope 1 and 2 emissions.[lxii] These targets are generally global goals for companies, and therefore, emissions reduction in the U.S. may vary from this overall goal due to economics, production, or operational considerations.

In both chemicals production and refining, emissions can be quite concentrated. For example, for some companies, more than 10% of their Scope 1 and 2 emissions may be concentrated in one to two large facilities. There is then typically a longer tail of smaller point source emissions for a company. See Figure 11 for concentrations of chemicals production and refining emissions in the U.S.

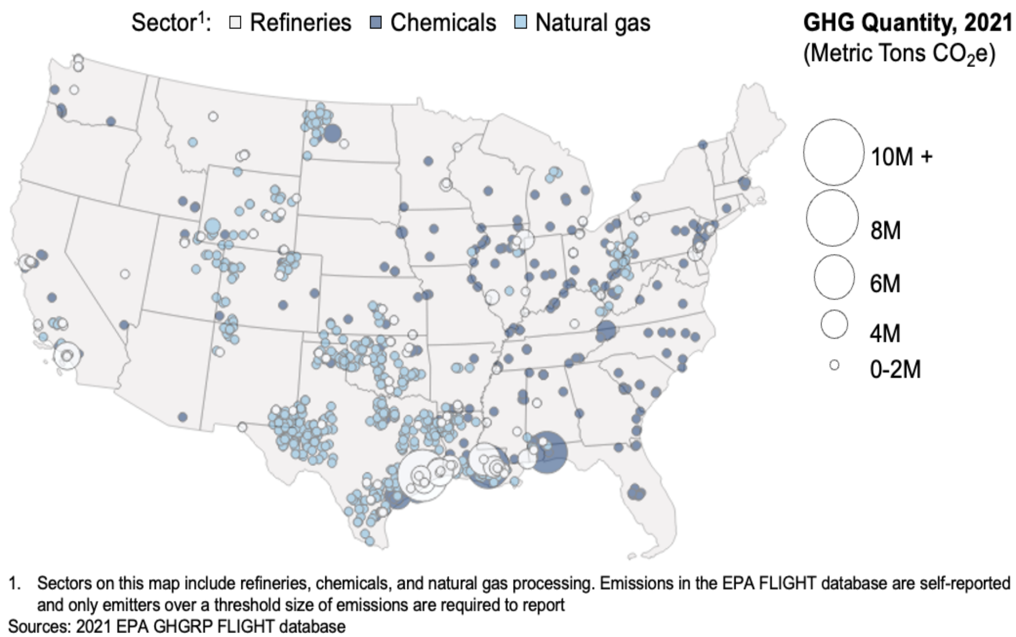


Figure 11: U.S. downstream chemicals & refining CO2e emissions in 2021, from self-reported EPA FLIGHT data.

38 State-level LCFS regulations for CA, WA, and OR, respectively: LCFS regulation. California Air Resources Board. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about Clean fuel standard. Washington State Department of Ecology. (2023, January 1). https://ecology.wa.gov/Air-Climate/Reducing-Greenhouse-Gas-Emissions/Clean-Fuel-Standard. Clean fuels program. Oregon Department of Environmental Quality. (2016). https://www.oregon.gov/deq/ghgp/cfp/pages/default.aspx

39 Actual changes will likely differ due to yet-unannounced closures or plant expansions.

40 Refining companies analyzed included: Marathon Petroleum, Valero Energy, Philips 66, ExxonMobil, Chevron, BP, Shell, Citgo, and PBF Energy. Analysis based on public reports and press search.

Section 2d: Initiatives to date

Chemicals producers and refineries balance multiple sustainability-related priorities (Figure 12)**.** These include:

1. Reducing virgin materials (e.g., recycled content),
2. Using bio-based or renewable feedstocks to produce chemicals (e.g., bio-based, CO2 and waste-derived feedstocks),
3. Using renewable feedstocks to make fuels with lower life cycle GHG emissions (e.g., advanced biofuels, CO2 and synthetic fuels), and
4. Operational decarbonization measures.

This report focuses on methods to reduce the production emissions of the chemicals & refining sector (Figure 1). However, the initiatives shown in Figure 12, and additional technologies not shown, have different impacts on emissions. For example, some technologies produce higher levels of production emissions, but the net process-based life cycle emissions are often lower than conventional products. Because biomass feedstocks capture carbon from the atmosphere while they are growing, products made from them could be "net-negative" if the product is long-lived and durably sequesters the newly fixed carbon. Beyond those included in Figure 12, alternative fuels such as sustainable aviation fuel (SAF) produced using renewable energy and water to transform CO2, or by converting electrolytic hydrogen and CO2 into carbon monoxide to form synthetic gas are promising innovations that could shift the sector away from fossil resources and reduce life cycle emissions.[lxiii,lxiv]

High Low

	1. Recycled content	2. Bio-based & renewable materials	3. Bio-based & renewable fuels	4. Operational decarbonization
Description & Drivers	Increase use of recycled materials as feedstock for chemicals processes Driven by consumer pressure for waste reduction, recycled content targets from brand owners, and national goals	Increase substitution of fossil-based feedstocks with biodegradable bio-based feedstock or feedstocks derived from CO2 Driven by consumer demand for waste reduction and demand from brands	Increased production of fuels derived from renewable feedstock Driven by projected demand in hard-to-abate sectors with few decarbonization alternatives (e.g., aviation, marine) and incentives	Measures to decarbonize emissions from production (e.g., efficiency, CCS) Some interest driven by incentives (e.g., IRA), but limited industry momentum
Scope 1 & 2 emissions benefit	Varies Mechanical recycling can reduce emissions by~75% Chemical recycling can reduce emissions for certain materials[1]	Varies Reduction of production emissions varies significantly by product and production route	Varies Production emissions vary significantly by product and production route, but often higher than traditional fuel	High Levers all reduce emissions from production
Scope 3 emissions benefit	Varies Plastics recycling can offset 10-15% of US household waste[2], but impact varies greatly with choice of process	High Materials derived from bio-feedstocks or CO2 can act as long-duration carbon storage, reducing lifecycle emissions by up to 100%[3]	High Bio or CO2 sourced carbon may reduce lifecycle emissions for diesel and jet fuels by up to 100%, depending on feedstock source[4,5]	n/a Operational changes are captured by scope 1&2
Industry priority[6]				

1. Uekert, Taylor, et al. "Technical, Economic, and Environmental Comparison of Closed-Loop Recycling Technologies for Common Plastics." *ACS Sustainable Chemistry & Engineering* (2023).
2. Anshassi, M., Townsend, T.G. The hidden economic and environmental costs of eliminating kerb-side recycling. Nat Sustain (2023). https://doi.org/10.1038/s41893-023-01122-8
3. Liang, Chao, et al. "Life-Cycle Assessment of Biochemicals with Clear Near-Term Market Potential." ACS Sustainable Chemistry & Engineering 11.7 (2023): 2773-2783.
4. Hannon, John R., et al. "Technoeconomic and life-cycle analysis of single-step catalytic conversion of wet ethanol into fungible fuel blend stocks." *Proceedings of the National Academy of Sciences* 117.23 (2020): 12576-12583.
5. Prussi, Matteo, et al. "CORSIA: The first internationally adopted approach to calculate life-cycle GHG emissions for aviation fuels." *Renewable and Sustainable Energy Reviews* 150 (2021): 111398.
6. Sourced from industry publications and press databases

Figure 12: Many sustainability priorities for chemicals producers and refiners have an environmental benefit (e.g., recycling to reduce plastic pollution) or life cycle emissions benefit but may not directly reduce Scope 1 and 2 greenhouse gas emissions.

The chemicals & refining sectors have primarily invested in #1–3 above (i.e., increased recycled content, bio-based materials, sustainable fuels), with more limited investment into operational decarbonization levers (i.e., #4), except when concerning efficiency improvements. Sustainability and decarbonization initiatives have not been deployed at the pace or scale required for a net-zero pathway:

- **Recycled content** reuses plastic waste as feedstocks for chemicals processes, reducing the need for virgin plastic and displacing the need for other chemicals and fuels. With waste plastics accumulating in landfills and the environment, recycling is an important means of reducing pollution and its systemic health impacts on ecosystems and communities (see Chapter 3, Section e). While recycling reduces waste, the impact on production emissions varies depending on recycling type. For example, mechanical recycling can reduce production emissions by as much as 75%, but these materials can have degraded material properties (e.g., clarity, hardness).[lxv] Pyrolytic recycling can increase overall production emissions by up to 25%, but it generates a high-quality alternative product.[lxvi,lxvii] Other advanced recycling processes are also in development, including chemicals recycling processes (e.g., methanolysis, solvolysis), which can potentially yield plastics with properties comparable to virgin plastics. Demonstration scale projects of methanolysis are underway and have the potential to make resins with recycled content that is 20-30% less greenhouse gas intensive than using fossil fuel based feedstocks.[lxviii] Consortia, like Bio-Optimized Technologies to Keep Thermoplastics out of Landfills and the Environment (Bottle.org), is working as a part of the DOE Strategy for Plastics Innovation to accelerate technologies that can deliver truly circular materials that offer reductions in production emissions.[lxix, lxx]

- **Bio-based materials** provide sustainable alternatives for fossil-based chemicals, reducing the need for conventional virgin plastic and the combustion of non-renewable fuels in two main ways:
  - **Bio-feedstocks for conventional chemicals and materials:** Renewable biomass can produce bio-based chemicals feedstocks, such as bio-based ethylene or bio-naphtha, which can directly replace traditional chemicals with the same end-use specifications.[41]
  - **Bio-based replacement materials:** Bio-based feedstocks can also be made into new materials, such as biodegradable Polyhydroxyalkanoates (PHA) and Polyhydroxybutyrates (PHB).[lxxi,lxxii] These bioproducts can replace fossil-based plastic and provide performance-advantaged properties (e.g., increased strength, tolerance for heat or moisture).

- **Bio-based fuels,** such as hydrotreated vegetable oil (HVO), hydro-processed esters and fatty acids (HEFA), alcohol-to-jet, and lignocellulose-derived fuels, have the potential to reduce life cycle emissions to varying degrees compared to petroleum-based fuel and in many cases can be used in current combustion systems.[lxxiii,lxxiv] These fuels will be important for the U.S. to achieve overall net-zero goals, particularly in sectors that will be difficult to electrify due to energy density and power/weight requirements (e.g., aviation, maritime, rail, heavy-duty road transport).[lxxv] The DOE has made investments into bio-based fuels via the Bioenergy Research Centers, with some initiatives now moving into the commercialization phase.[lxxvi] To minimize these fuels' life cycle carbon emissions, operational decarbonization measures could reduce emissions from production, further enhancing the benefit.

  Economic incentives, such as state low-carbon fuel standards, federal Renewable Identification Numbers (RIN) credits, and incentives in the IRA, are accelerating the production of sustainable fuels, and many refiners are investing in this area. The Biden-Harris Administration has set bold goals to further accelerate the production of sustainable fuels, including a goal to reach 3B gallons of sustainable aviation fuel (SAF) by 2030, rising to 35B gallons by 2050.[lxxvii] Even though life cycle emissions for many biofuels are lower than traditional fuels, the production of sustainable fuels results in Scope 1 and 2 emissions, which would be addressed with operational decarbonization.[42, lxxviii] Abating these production

41 Bolstering and coordinating federal investment in bio-feedstocks is a priority of the Administration and supported by an Executive Order on Advancing Biotechnology and Biomanufacturing Innovation for a Sustainable, Safe, and Secure American Bioeconomy | The White House.

42 Pre-treatment is needed for nearly all biofuels to break the bio-feedstock into intermediaries such as crude bio-oils, syngas, sugars, and other chemical building blocks. Pre-treatment processes vary and can include physical (mechanical), chemical, thermochemical or biochemical methods.

emissions through operational decarbonization, biotechnology, and complementary chemical catalysis approaches will therefore be important in maximizing the life cycle emissions reduction from sustainable fuels and achieving Administration goals.

- **Operational decarbonizing production** is occurring on a limited basis. Chapter 3 explores the cases in which operational efficiency measures are economic in the current policy and economic environment. Most companies have consistently adopted measures to improve efficiency where cost savings are also available (e.g., identifying sources of waste from unused heat). In many cases, the 'low hanging fruit' of efficiency measures that are value-creating have already been tackled by chemicals producers and refineries.

  Further operational decarbonization is possible and would improve efficiency and reduce emissions. However, chemicals & refining operators often note that asset downtime and the opportunity cost of investment (versus higher-return opportunities) limit these levers' adoption. Most large-scale asset decarbonization is happening today through pilots outside the U.S. Activity includes countries where high natural gas prices and carbon taxes strengthen the business case for decarbonization investments (e.g., European Union) and in geographies where incoming policies and valuable natural resources motivate companies to generate fully decarbonized assets (e.g., Canada). Additional detail on the current state and developments of individual decarbonization measures, including CCS and clean hydrogen, can be found in other Liftoff reports.[lxxix]

  In the refining sector, most operational decarbonization is focused on energy efficiency and carbon intensity reduction for fuels sold into states with low-carbon fuel standards (e.g., California, Oregon). Adoption of operational decarbonization measures in refining faces similar challenges as chemicals production, with limited investment, especially for older assets near the end of life.

Section 2e: Deep dive on bio-based chemicals and fuels

This report's pathway to net zero focuses on reducing direct emissions from chemicals and fuel production (Figure 1). This report excludes some solutions, such as biotechnology, that have a strong promise to reduce the sector's life cycle emissions.

Biotechnology aims to reduce life cycle emissions by using carbon captured from the atmosphere by plants—rather than fossil carbon—to make chemicals and fuels. There are two greenhouse gas advantages of bio-based fuels and chemicals that are not captured in the production emissions of the chemicals & refining sector but are captured from a life cycle emissions viewpoint:

- First, they contain carbon recently captured from the atmosphere and stored in biomass (i.e., plants) during growth. This carbon would often be released back into the atmosphere as plants decompose. Transforming this carbon into plastics may prevent this carbon from being released, reducing net-GHG emissions. Or burning this carbon as fuel prevents the release of additional fossil carbon from conventional fuels. Net GHG emissions can be reduced by intercepting this carbon before it is released and transforming it into fuels and products. Robust life cycle assessment is critical to quantify the GHG emissions reductions for bio-based fuels and chemicals as important implications for land, water, and biodiversity must be considered.

- Second, sustainable land management practices for purpose-grown biomass crops can increase soil-carbon storage—further reducing net-GHG emissions. Key land management practices can result in soil-carbon gains, including no-till agriculture and cover crop adoption.[lxxx] Further research is needed to understand the magnitude and permanence of soil-carbon storage potential from these practices under different conditions as they are increasingly adopted.

Given these advantages, the Biden-Harris Administration has set ambitious goals related to how biotechnology and bio-based materials can harness innovation to further societal goals and transform industries related to: (1) climate change solutions, (2) food and agriculture innovation, (3) supply chain resilience, (4) human health, and (5) cross-cutting advances. These include bold goals for bio-based fuels and chemicals.

While bio-based fuels and chemicals have a distinct life cycle emissions advantage, significant challenges must be overcome to deliver on the technology's promise. These challenges can be categorized into four key areas:

1. Limited supply chain infrastructure to cost-effectively harvest, preprocess, and transport biomass feedstocks to production facilities without degrading quality.[lxxxi]

2. Limited infrastructure to process biomass—a challenge that the White House's Bold Goals for U.S. Biotechnology and Biomanufacturing aims to address.[lxxxii]

3. Higher current costs than conventional chemicals and fuels—certain bio-based chemicals and fuels have higher delivered costs than conventional technologies. These costs are driven by insufficient processing infrastructure to convert biomass. There is evidence of premiums for bio-based materials on a small scale, such as a 30–50% premium on bio-PE produced in Brazil.[lxxxiii] However, some bio-materials are cost-advantaged, such as 1,3 PDO, which is used in many applications due to superior performance compared to petroleum-based substitutes and a lower cost of production from biomass versus conventional materials.

4. Like conventional production, bio-based methods still generate emissions in the production process.[lxxxiv] As explored below, the production emissions of different biotechnologies differ significantly. This means there remains an opportunity for operational decarbonization measures to reduce the overall emissions of these biotechnologies.

Some biofuels and biochemicals exhibit higher emissions during the production phase than comparable fossil-fuel-based processes but lower overall life cycle emissions. To illustrate this, a comparison of life cycle and production emissions for bio-based chemicals and fuels is included below (Figure 13). Crucially, these production emissions can be reduced using the same operational decarbonization levers as traditional fossil processes, potentially leading to lower net emissions. In addition, the current chemicals industry has refined its process for decades to achieve very high efficiencies. Bio-based processes have similar potential for improvement and are likely to have a higher rate of community acceptance due to fewer environmental and energy justice concerns.[lxxxv]

Bio-based fuels

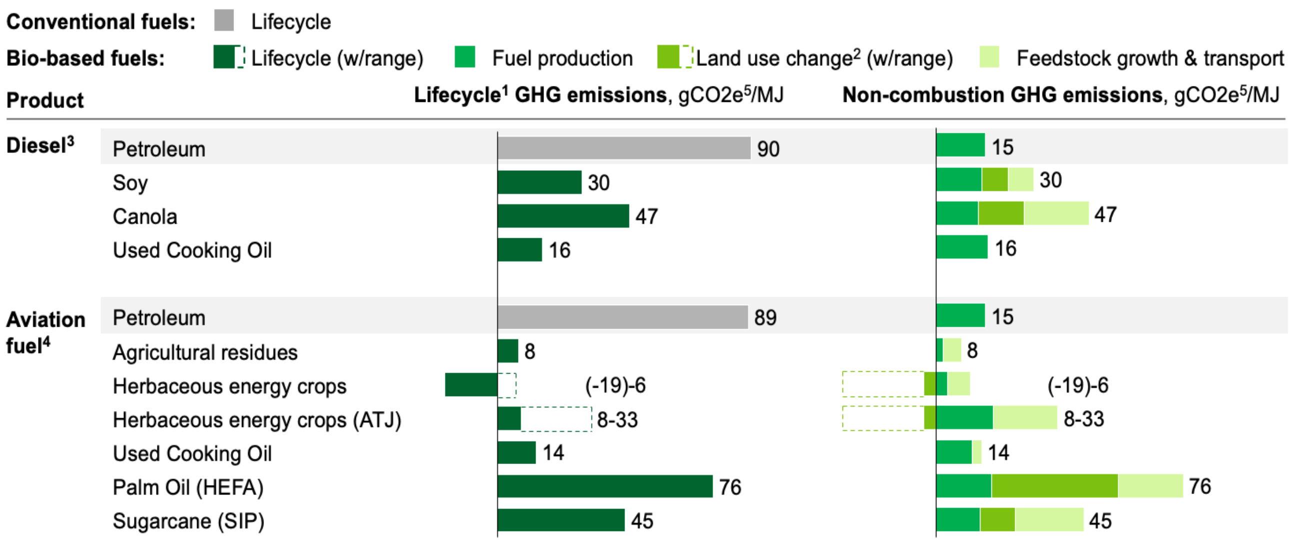
Bio- and recycled feedstocks for sustainable fuels may provide reductions in life cycle emissions of up to ~70–100%. Production emissions, however, remain significant for these fuels and sometimes exceed the production emissions from petroleum fuels (Figure 13). Maximizing the abatement potential of these fuels will require operational decarbonization measures. The three key subcategories of current or near-term bio-based fuels and their relevant emissions profiles are:

- **HEFA feedstocks** are fatty oils from vegetables and other processing waste to generate bio-based diesel and jet fuels. The availability of feedstocks significantly limits this pathway. Fuels produced from HEFA can result in a <50% reduction in life cycle emissions but have higher production emissions due to energy requirements for processing and upgrading the feedstock.

- **Alcohol-to-jet (AtJ) feedstocks** are alcohols, often derived from corn in the U.S., that are converted to make jet fuels. This process is limited due to the high levels of capital investment it requires. While feedstock may be limited today, more ethanol feedstock may become available as transport decarbonization reduces demand for ethanol-blended gasoline. Additional ethanol could be generated from waste lignocellulosic feedstocks, which would have far lower life cycle GHG emissions than corn. AtJ can reduce life cycle emissions by ~70% but has higher production emissions than conventional jet fuel production due to the energy required to process and upgrade the feedstock.

- **Gasification feedstocks** often use woody biomass and municipal solid waste as a feedstock in the gasification process. This process has access to a low-cost feedstock with the added benefit of reducing landfill waste, but significant capital expense and technology risks are associated with scaling gasification. Fuels produced with gasification can reduce life cycle emissions by ~80% but have ~13x higher production emissions.

Example modeled life-cycle emissions of conventional and bio-based diesel and aviation fuels



1. Lifecycle emissions includes feedstock growth, transport, fuel production, and fuel use. Combustion emissions of biofuels are emitted as the carbon is already in the carbon cycle. Ranges represent the potential variation in indirect land-use impacts given in [4]
2. Based on US soy, canola, and herbaceous crops, and Brazilian sugarcane, using ranges of potential land-use impacts given in [4]
3. Comparison of petroleum-based diesel and bio-based renewable diesel. Additional bio-based diesel alternatives are available beyond those listed here and technologies used to produce aviation fuel can often also be used to produce diesel. Source: Xu, Hui, et al. "Life cycle greenhouse gas emissions of biodiesel and renewable diesel production in the United States." Environmental Science & Technology 56.12 (2022): 7512-7521.

Figure 13. Life cycle and production emissions of select conventional and bio-based diesel and aviation fuels using current technologies.[lxxxvi,lxxxvii]

Bio-based chemicals

New processes to reduce production emissions and operational decarbonization measures on bio-plastics production are emerging and are supported, amongst other technologies, by the Department of Energy's Bioenergy Technologies Office's Multi-Year Program Plan (MYPP), which aims to address these concerns by increasing feedstock harvesting and processing volumes, developing innovative products, and decreasing GHG emissions.[lxxxviii]

The impact on production emissions and scalability varies significantly, though the impact on life cycle emissions is positive for many bio-based chemicals (Figure 14). For example, consider a substitute for fossil fuel feedstocks, which is the subject of industry attention:

- **Bio-PE** can provide significant life cycle emissions reduction due to biogenic carbon uptake in feedstock, but the production emissions remain similar as a conventional cracker is often used to convert the bio-feedstock to PE. However, this pathway is difficult to scale due to limited feedstock supply and high-value alternatives for bio-naphtha (e.g., biofuels).

There are significant opportunities for bio-pathways to provide significant life cycle emission reduction for materials with broad access to feedstocks and opportunities for bio-based chemicals to become deployed commercially. Some of the chemicals of note are shown in Figure 14.

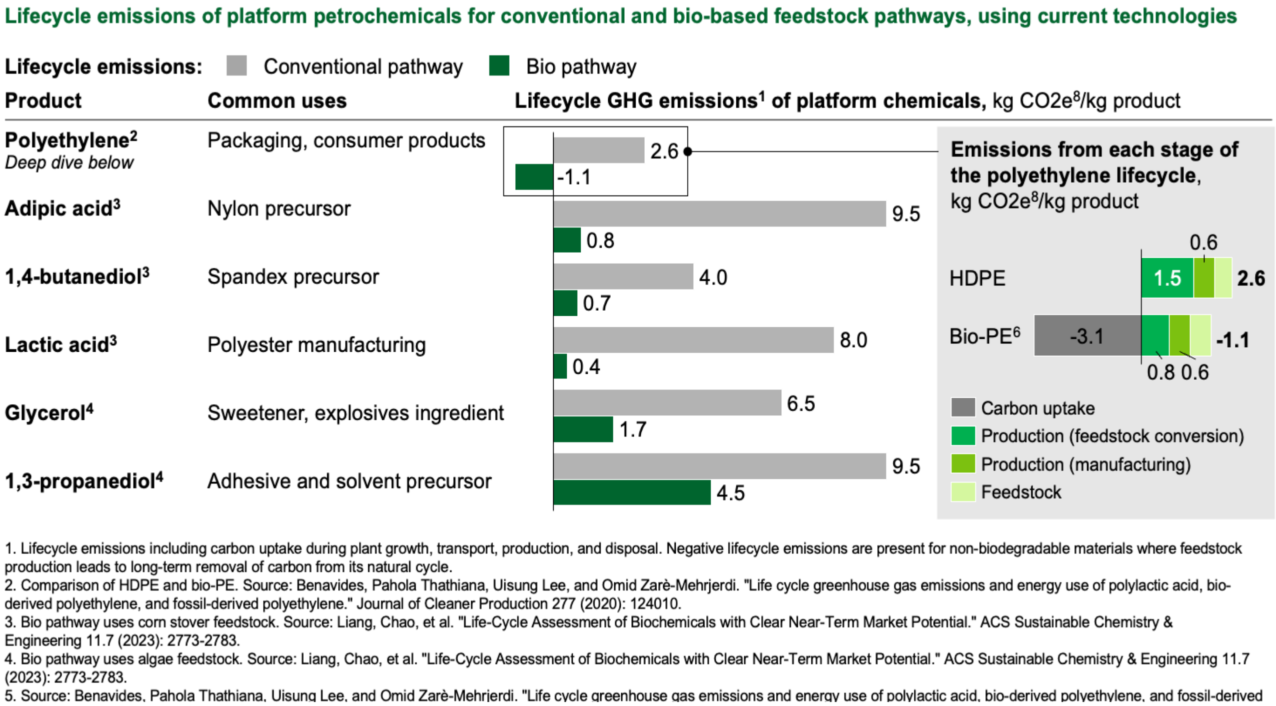


Figure 14: Life cycle and production emissions for bio-based feedstock and plastics pathways with the currently available assessment of technologies.[lxxxix,xc]

Section 2f: Deep dive on CO2 and waste plastic to chemicals and fuels

Like bio-based solutions discussed in Section 2e, also beyond the scope of this report is a wide range of promising decarbonization solutions that use CO2 or industrial/consumer waste products (such as plastics) as feedstocks to produce carbon-based chemicals and fuels. The use of carbon oxides and plastic waste as feedstocks have the potential to replace fossil feedstocks, introduce circularity, and decarbonize the production of chemicals and fuels. **Technologies for leveraging carbon oxides and waste plastics as feedstocks range in TRL, with examples of commercial scale demonstrations and deployment projects online today.**

Carbon oxides to fuels and chemicals

Using carbon oxides captured from air or industrial point sources as a feedstock for making chemicals and fuels aligns with DOE objectives and initiatives, including the Clean Fuels and Products Shot. **These processes for producing chemicals and fuels have the advantage of 1) reducing reliance on non-renewable fossil feedstocks 2) reducing/eliminating emissions from the combustion of fuels and chemical products by introducing circularity between atmosphere and product, and 3) converting green electrons directly into products that are easy to store and transport (for example, liquid fuels) with high energy density.** There is also the potential to de-centralize the production of chemicals and fuels with carbon oxides from point source and direct air capture projects.

There are several demonstrated routes for producing chemicals and fuels from carbon oxides. In general, these technologies combine CO2 or CO with hydrogen/water (and potentially nitrogen) to make a wide array of carbon-based molecules. These production methods primarily involve **electrochemical** and **thermocatalytic** processes. Like traditional production methods from fossil based crude oil, multiple intermediates and stages are needed to generate end use fuels and products from CO2.

As represented in Figure 6, process heat is a significant emission source across the chemicals and refining sector. This includes the use of heat/steam to drive high temperature reactions and separations, much of which is driven by the combustion of fossil fuels. Similarly, energy is required to drive reactions that convert CO2 and water into fuels and products. In many cases, the energy inputs required to break bonds in stable water and CO2 molecules (endothermic reactions) will be higher than for petroleum-based processes. While thermocatalytic routes for CO2 to chemicals are typically at higher TRLs than electrochemical routes, the electrochemical routes have the potential to achieve lower energy requirements.

The use of CO2 as a feedstock requires building larger molecules from smaller molecules (such as converting CO2 to CO). A handful of small molecule chemicals as feedstocks can produce complex compounds that address much of today's chemicals value chain. Some of the basic small molecules demonstrated at various scales include:

- Electrochemical reduction of CO2 to carbon monoxide, methanol, ethanol, carboxylates, ethylene, and other C1 to C4 compounds
- Thermocatalytic conversion of CO2 and hydrogen to small molecules (ethanol and methanol) with conversion to larger chain products such as sustainable aviation fuel (SAF)

CO2 supply

The utilization of carbon is not considered in this decarbonization pathway, however, the use of CO2 as a feedstock can play a role in reducing global dependence on fossil resources. The Department of Energy has several initiatives in place, including the Carbon-Negative Earth Shot, to remove CO2 from the air (using direct air capture) and from hard-to-abate industrial point sources (using point source capture). Carbon dioxide removal (CDR) can supply relatively high concentrations CO2 and could encourage the buildout of a network of pipelines and other infrastructure for moving the supply of CO2 to sequestration sites. This anticipated supply may play a role in meeting the demand side pull for carbon utilization in fuels, chemicals, building materials, and other CO2 applications. The modularization of process equipment for converting CO2 could enable a decentralization of chemicals production. This may lead to a distribution of fuels and chemical production to take advantage of stranded supplies of CO2 from both DAC and point source capture.

Waste plastics

Using waste plastics as feedstocks for the production of chemicals, including new plastics, represents an opportunity to introduce circularity to the industry while also providing valuable embodied energy and materials from non-fossil sources. Additionally, this approach reduces plastic waste leaking into the environment. Methods exist, including at commercial scale, that successfully use waste plastics as feedstocks to generate monomers useful for making new chemicals and products, including new plastic products and fibers. This approach does not have some of the quality disadvantages associated with thermal processing of waste plastics into recycled products.

Chapter 3: The path to net zero

Key takeaways

Section 3a: Emissions outlook

- In a BAU scenario, downstream chemicals production and refining emissions will grow approximately 20% by 2050, driven primarily by an approximately 35% demand increase for chemicals. Given this trajectory, concerted, accelerated action is needed to reach net zero.
- The technologies to decarbonize downstream chemicals production and refining can be separated into near-term (deployable), medium-term (demonstration), and long-term (R&D and pilot). Though these technologies exist today, the majority are costly and not widely adopted. The least-cost measures to abate chemicals & refining emissions that are deployable, or later-stage demonstration today include operational efficiency, electrification with clean high-capacity firm power, clean hydrogen, and CCS on high-purity streams.[43]

Section 3b: A net-zero pathway

- **The chemicals & refining sectors can decarbonize in phases** aligning with U.S. goals while balancing economic, infrastructure, and operational constraints. A least-cost decarbonization pathway to meet net-zero goals could include (Figure 19):
  - **Near-term acceleration of deployable technologies (2023–2030):** The first phase could focus on accelerating the adoption of deployable and economically viable measures, such as (i) energy and operational efficiency upgrades, (ii) adopting select electrification measures (e.g., natural gas process compressors), (iii) transitioning certain processes to clean hydrogen, (iv) installing CCS on high purity streams, and (v) the use of other fuels and feedstocks.
  - **Scaling decarbonization measures (2030–2040):** The next horizon of decarbonization for these industries would build on the success of the first phase, as well as rely on (vi) adopting CCS on dilute emission streams and (vii) broad electrification with clean high-capacity firm power, both levers that will not be economically viable without demand measures.
  - **Achieving net zero (2040–2050):** Achieving net zero for downstream chemicals production and refining by 2050 would require implementing technologies that are not cost-competitive without demand measures, such as premium or regulation, including near-universal adoption of the previously mentioned decarbonization measures (i) through (vii).
- Achieving the U.S. net-zero pathway will be challenging and require a concerted effort across industry and government—as well as end-use shifts by consumers.

Section 3c: Accelerating adoption of decarbonization measures

- Decarbonizing up to 35% of chemicals & refining emissions by 2030 will require the broad and rapid adoption of deployable decarbonization measures. However, there is portfolio risk associated with these levers.
- The path to net zero could be accelerated or facilitated through breakthrough technologies, though they have not yet been proven at scale.

43 This analysis considers jobs required for adopting decarbonization technologies in the pathway detailed above. These numbers are not net of any job changes that could occur due to shifts in demand for chemicals & refining products.

Section 3d: Capital requirements

- Today through 2030, there is a ~$90–120B investment opportunity in decarbonization levers with >10% IRR, and an additional investment of ~$610–730B needed between 2030 to 2050.
- Beyond 2030, the speed and scale of investment must accelerate, requiring approximately $25-30B invested per year between 2030 to 2050.

Section 3e: Socioeconomic considerations

- Achieving a net-zero pathway in chemicals & refining production could create up to ~5.5M good paying job-years[44] and ~$700B in gross value adding (GVA) to the economy by 2050.
- During the build-out phase of projects, most estimated jobs, ~54%, are expected to be generated from direct spending on the asset through roles such as construction and planning. The remaining jobs, ~46%, are expected to be tied to indirect supply chain spending and supporting new assets.
- Industrial decarbonization presents a critical opportunity to abate health-harming pollutants from industrial operations that impact frontline communities.
- Common community concerns related to industrial decarbonization include environmental and human health impacts, safety and emergency response, facility operator accountability and transparency, emissions monitoring and reporting, and renewable energy access and cost.

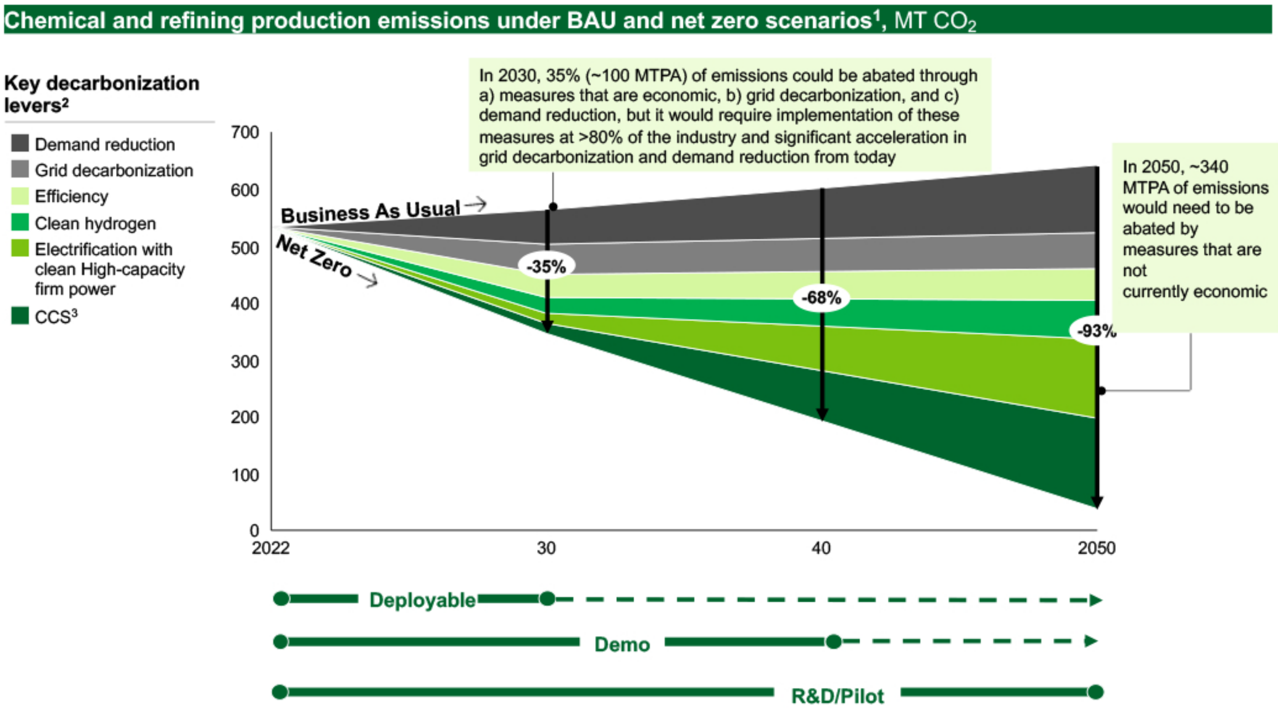
Section 3f: International & trade dynamics

- The U.S. chemicals & refining industry exported $481B in products in 2022 and has remained competitive as global exporters partially due to abundant feedstock access.
- Decarbonizing these trade-exposed industries could lead to "leakage" if U.S. producers lose market share to global competitors with higher carbon intensities in their production processes.

Section 3a: Emissions outlook

Absent additional decarbonization measures, chemicals production and refining will continue to be major contributors to U.S. emissions through 2050. In a BAU pathway, emissions could grow approximately 20% by 2050, driven by a ~35% rise in chemicals emissions due to demand growth.[xci] To remain on track with national goals for industrial decarbonization, the chemicals & refining sectors must reduce emissions by ~35% through 2030 and more than ~90% by 2050 (Figure 15).

44 Use of biofuels or hydrogen as a fuel source was not included in the least-cost pathway analysis conducted for this report as it currently is not cost-competitive with other measures.



1. Deployable bio-processes that reduce lifecycle emissions of chemicals and refining products are not considered in the pathway to net zero
2. Technologies considered in pathway are in the deployable and demo categories. Pathways may be updated with different developed technologies in future
3. Only CCS is considered in the net zero pathway, refer to Carbon Management Liftoff report for discussion of carbon utilization technologies

Source: EIA data for energy-related emissions, EPA national recycling strategy, White House – The Long-Term Strategy of the United States – Pathways to Net-Zero Greenhouse Gas Emissions by 2050

Figure 15 (also Figure 2): In a BAU scenario, chemicals & refining production emissions are expected to grow by 20% by 2050; in a net-zero scenario, a combination of technologies can reduce emissions by 93% by 2050.

The chemicals & refining sectors must decarbonize in phases, first, with high TRL technology that is investable today. These technologies, (i) through (v) below, can be implemented within the footprint of existing operations and, in many cases, with at least 10% IRR today through 2030. Levers to lower process emissions should all be prioritized, with options like CCS leveraged when emissions are otherwise un-abatable. In parallel, the industry must pursue R&D and pilot deployments of more nascent technologies to bring down costs and improve technology performance for critical processes. This is especially true for high-temperature industrial heat and clean electricity procurement, which account for ~50% of the sector's emissions.

Near-term, investable decarbonization technologies include:

i. **Efficiency measures:** Three types of efficiency measures can reduce both cost and emissions:

- **Operational improvements that require little investment.** These could include improved monitoring and tracking of energy efficiency, prevention of flaring, and maintenance of assets. These small improvements can reduce losses, optimize operations, and enhance operational efficiency. These improvements lead to improved emissions intensity of facilities and overall reduced emissions.
- **Efficiency measures that require investments <$1M.** These include fixing steam leaks, cleaning heat exchangers, and upgrading small equipment.
- **Large efficiency investments >$1M.** These include replacing large-scale equipment with new or best-available technologies. For example, steam methane reformer catalyst technologies have improved and can be upgraded to permit better conversion rates and/or reduce catalyst coking. Implementing these technologies allow facilities to reach higher overall efficiency while reducing emissions.

Large multinationals that have not yet undertaken widespread efficiency initiatives estimate that as much as 10–15% of emissions through 2030 could be abated with efficiency measures.[45] However, most large, emitting assets (e.g., crackers, SMRs) may only have one repair cycle through the rest of the decade, meaning corporates must make major upgrade and efficiency plans now to achieve 2030 targets.

ii. **Electrification with clean power:** Technology to electrify low and medium heat (e.g., heat pumps and e-boilers) and electrify certain equipment (e.g., compressors) is proven and can be paired with on-site renewables, power purchase agreements (PPAs), or other clean power contracting. Electrification could account for ~25% emissions reductions by 2050 but would require:

- **On-site storage:** Variable renewables require long duration energy storage (LDES) or thermal energy storage (TES) to fully time match zero-carbon power purchases to continuously operating chemicals & refining assets. Inter-day and multi-day storage will be needed to ensure continuous uptime of assets in these sectors. Companies can build renewable energy sources with LDES on-site; however, most existing facilities offer little space to expand their footprint for renewables (see Chapter 4, Operational challenges).[46]
- **Accessibility:** At present, companies cite challenges with accessing cost-competitive PPAs due to (1) lack of sufficient availability of renewables, (2) on-site constraints (e.g., space for storage, proximity to renewables), (3) competition with other corporates who are also attempting to access clean high-capacity firm power, and (4) performance of electrified alternatives (e.g., e-crackers).[xcii]

iii. **Clean hydrogen:** Clean hydrogen can replace carbon-intensive hydrogen already used in chemicals plants and refineries.[47,48] Clean hydrogen can also be directly combusted to serve as a low-carbon fuel source (e.g., to provide industrial heat) or converted to electricity by a fuel cell (e.g., combined heat and power).

- Near-term, clean hydrogen is expected to directly replace carbon-intensive hydrogen already used in sectors, including ammonia and oil refining. The U.S. National Hydrogen Strategy and Roadmap shows that up to 10 MTPA of clean hydrogen per year can be deployed by 2030, with up to 5 MTPA used directly in ammonia and oil refining. Based on the current cost of technologies and the surrounding cost of capital, policy, and supply chain, this Commercial Liftoff report estimates that ~3-5 MMTpa of electrolytic hydrogen could provide more than 10% IRR, specifically for use as a feedstock to directly replace carbon-intensive hydrogen in 2030 and ~7–8 MTPA in 2050.
- Clean hydrogen can also be combusted to produce industrial heat. For industrial heating uses, clean hydrogen competes against the low cost of domestic natural gas and, in some cases, against coal or other fuels. Using clean hydrogen as a fuel source is costly relative to these options and is therefore not included in this least-cost pathway. Section 4b explores the $/kg threshold at which clean hydrogen could break even for industrial heating uses, absent any additional policy or mandates.

iv. **Carbon Capture and Storage (CCS):** CCS can mitigate hard-to-abate emissions by capturing CO2 before it enters the atmosphere and storing it long-term. Carbon capture on high-purity streams is a proven technology (e.g., in natural gas processing). However, there are few applications of CCS on lower-purity streams (5–15% concentration) and distributed process emissions. The cost of carbon capture for dilute streams is currently uneconomic, even with 45Q tax credits.[xciii]

45 Information provided during anonymized industry interview.

46 Ibid.

47 The clean hydrogen market will be accelerated by historic commitments to America's clean energy economy, including the hydrogen production tax credit (PTC, 45V) and the carbon sequestration credit (45Q). Current supply-side incentives can make clean hydrogen cost-competitive with incumbent technologies in the next 3–5 years for numerous applications. 5.5 MTPA of clean hydrogen production has been announced by chemicals & refining companies since August 2022. See the Clean Hydrogen Liftoff report for further detail.

48 E.g., as part of the ammonia production process or as an input into refining to reduce the sulfur content of fuel.

- » Beyond certain niche applications, CO2 utilization pathways (CCUS) are nascent and currently uneconomic relative to incumbent products. Deployment incentives such as the 45Q tax credit also provide a greater revenue source on a per-tonne basis for dedicated geologic storage relative to utilization. As such, CCS is explored on the pathway to decarbonize today through 2030, while CCUS is highlighted as a more nascent opportunity. See the Carbon Management Liftoff report for further detail.[49]

v. **Raw material substitution:** Raw material substitution, including biochemicals, biofuels and other low-carbon feedstocks, are umbrella terms for various production pathways and processes. Across various production processes, raw material substitution can play a role in decarbonizing the chemicals and refining sectors. However, this report excludes these technologies from the net-zero pathway.

Project economics: Marginal abatement cost curves

Marginal abatement cost curve (MACC) analysis can help illuminate the comparative economics of decarbonization measures for industry. The analysis includes comparing the economics of the various technologies that could decarbonize each emission source, selecting the least cost measure, and then lining up the full suite of measures required to decarbonize the industry based on the cost to abate with a 10% return. MACC analysis should not be seen as definitive, as it only considers a snapshot in time and does not represent the unique set of considerations each company uses when deciding how to decarbonize a facility. However, it can clarify economic challenges for each measure. To understand the MACC figure, the width of the bar shows the amount of emissions that could be decarbonized through the individual measure, while the height of the bar represents the cost to implement the measure. All measures on the left side of the chart with a negative cost represent the measures that will be value-accretive to implement with a 10% or greater return. Detailed assumptions used for the MACC analysis in this report can be found in the appendix.

The previously mentioned decarbonization measures all have relatively high technology readiness levels (TRL) but have not yet been adopted at scale in downstream chemicals production and refining.

Marginal Abatement Cost Curves (MACC) demonstrate that:

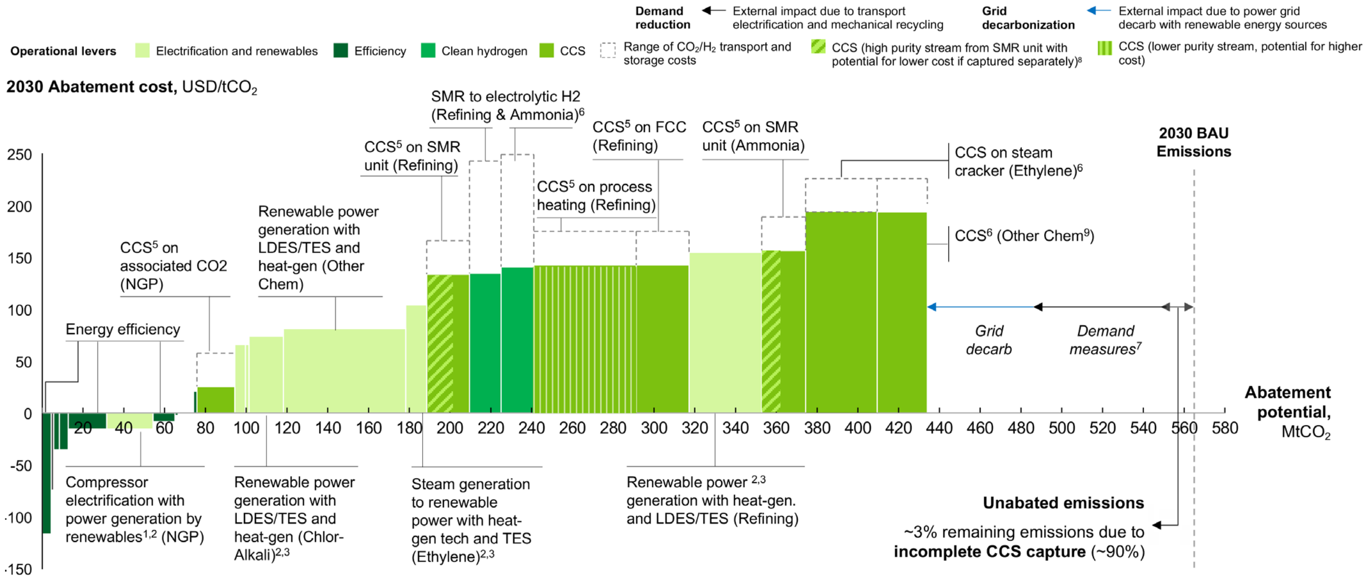
- In 2030: The IRA and BIL have doubled the volume of industrial emissions that can be economically abated by 2030. Without IRA and BIL, ~15% of chemicals & refining emissions that remain after grid decarbonization and demand reduction could be abated with measures that offer >10% IRR (Figure 16). With the IRA and BIL, this number rises to ~30% of chemicals & refining emissions that can be economically abated after grid decarbonization and demand reduction; these emissions can be abated with measures with an IRR >10% (Figure 17).[50] Technologies with significant infrastructure, CCS, and clean hydrogen have abatement cost ranges that are both NPV-positive and NPV-negative due to the range of possible capex, compression, transportation, and storage costs. This range highlights the importance of infrastructure availability for these levers to be economically viable, and asset-specific conditions and location will dictate if abatement via CCS and clean hydrogen is economic. If over 80% of chemicals & refining facilities pursued all 2030 decarbonization measures with at least a 10% IRR (Figure 17), the chemicals & refining sectors would remain on the path to achieving net zero by 2050 (Figure 15).

49 Demonstration projects through 2030 can support cost declines for carbon capture on lower-purity streams and distributed process emissions—through learning by doing and standardizing project development structures. Additionally, increased policy support (either via regulation or incentives) or technology premiums for low-carbon products (e.g., low embodied carbon steel and concrete) would lead to more CCS and CDR projects.

50 The abatement potential numbers represented in the MACC curves assume the deployment of technologies with an IRR >10%; the numbers do not indicate the unique factors considered across individual companies when making investment decisions.

- By 2050: ~20% of 2050 emissions that would remain, after grid decarbonization and demand reduction, could be abated with measures that offer at least a 10% return in 2050 (Figure 18).[51] Commonly, companies will only seek to make investments if they can reach an internal hurdle rate, often determined as a risk premium over the company's cost of capital. Due to the nature of early deployment and next-of-a-kind projects, companies tend to have a high risk-premium on developing decarbonization technologies. At present, many chemicals & refining companies require a 15+% hurdle rate to consider investing in a technology.[52, xciv]

2030 Marginal Abatement Cost Curve (MACC) for US Chemicals and Refining industry, without IRA



1. Electrification of compressor results in significant efficiency improvements over steam turbines (95% vs. 35% efficiency)
2. Renewable cost assumes Class 5 onshore wind production from NREL Annual Technology Baseline for 2030 and excludes the costs associated with transmission and delivery of electricity. IRA-inclusive scenarios includes investment tax credit of 35%, 30% from a base construction that meets the prevailing wage an apprenticeship requirements and an additional 5% due to an assumption that half of projects will claim the 10% domestic content adder. No adders included for low-income communities and energy communities. Net capex cost assumed is $956/kW and opex is $39/kW
3. Heat generation technology assumes the costs associated with charging and TES as an archetypical setup; however, asset specific heat generation can be achieved with other technologies such as heat pumps and resistive heaters. Technology development and asset specific considerations could significantly impact the choice of heat generation technologies.
4. Ethylene process assumptions used to model propylene and BTX processes (e.g., propane and naphtha cracking)
5. Displayed CCS cost estimates based on EFI Foundation capture costs with transport (GCCSI, 2019) and storage (BNEF, 2022) costs of ~$10-40/tonne (representing the lower and upper bounds of the displayed range) except where noted. All in 2022 dollars. All CCS figures represent retrofits, not new-build facilities. The inflation variance on each cost estimate represents the range of cost increases on a generic chemical processing facility due to inflation from 2018 using the Chemical Engineering Plant Cost Index (CEPCI)
6. The range of 2030 electrolytic hydrogen costs for Refining is estimated at $2.02-3.02/kg H2. The range of 2030 electrolytic hydrogen costs for Ammonia is estimated at $2.08-3.08/kg H2. All hydrogen cost assumptions for this modeled scenario are based on DOE's Clean Hydrogen Liftoff report, which relied on the 2022 McKinsey Hydrogen Model. It is important to note that the assumptions underlying this analysis of hydrogen cost are uncertain, and the Clean Hydrogen Liftoff report is continually being updated. DOE electrolyzer cost estimates have already increased since the values published in the report, due to variables such as supply chain constraints and inflation.
7. Demand reduction consists of primarily transport sector electrification as well as the impact of a mechanical recycling rate of 25% of all plastics
8. Split of emissions streams assumed to be ~60% concentrated and ~40% dilute in SMR unit. Portion of SMR concentrated streams assumed to be smaller for ammonia due to captive usage of concentrated CO2 streams for urea production
9. Assumes CCS implementation on other chemicals high temperature heat sources with costs based on ethylene steam cracker capture costs

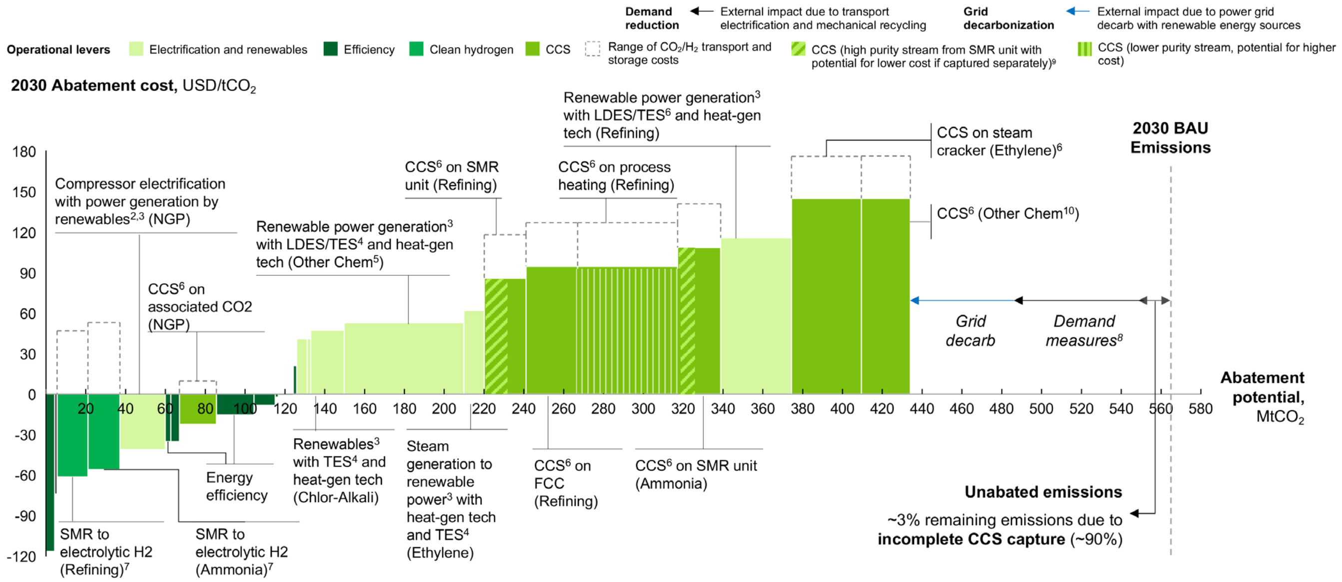
Sources: GREET 2022, NREL, DOE Hydrogen Liftoff Report, EFI CCS Report – "Turning CCS projects in heavy industry & power into blue chip financial investments", Inflation Reduction Act, LDES Council, Expert interviews, Danish Energy Agency, Netherlands Enterprise Agency, GHG Protocol, White House Net-Zero targets, McKinsey Global Energy Perspective, EFI Foundation, "Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments

Figure 16: Before the implementation of the IRA, only ~15% of emissions that would remain after grid decarbonization and demand reduction could have been abated through economic measures in 2030. See Appendix C for a description of the methodology and assumptions used for this analysis.

51 Ibid.

52 Presented hurdle rates consider a representative weighted average cost of capital from the sector assembled from company 10-K reports.

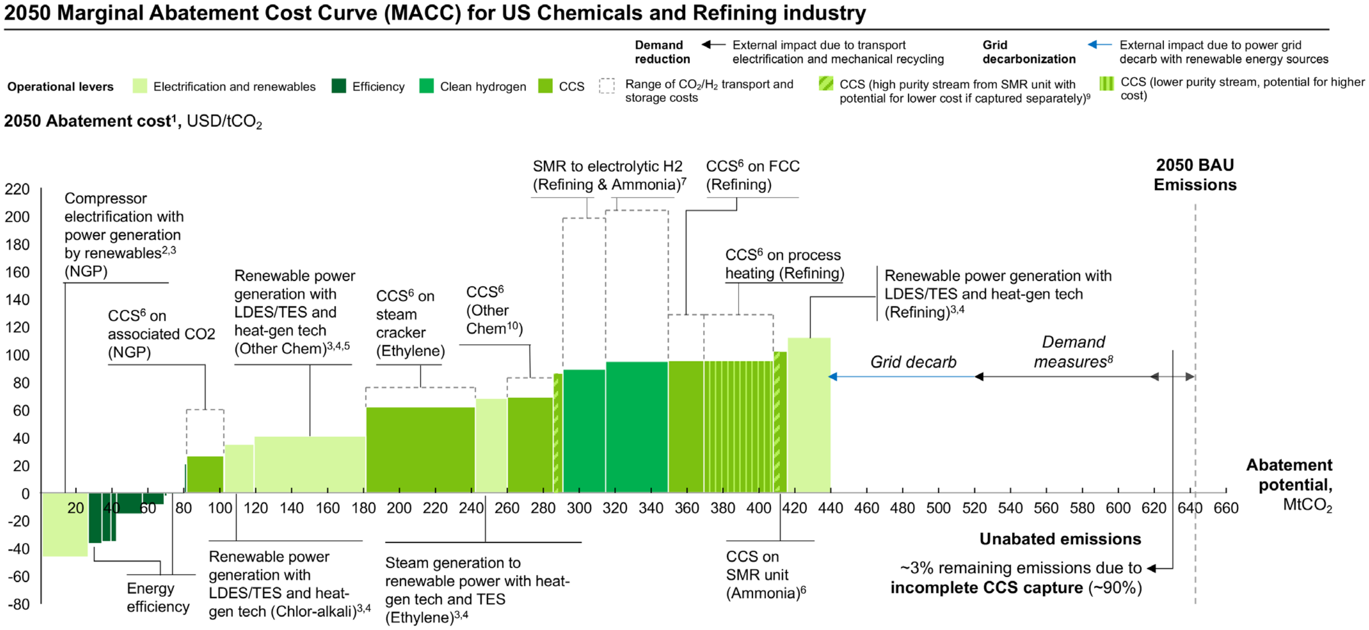
2030 Marginal Abatement Cost Curve (MACC) for US Chemicals and Refining industry, with IRA[1]



1. Heat electrification analysis includes IRA 48E incentive assuming the projects meet the prevailing wage and apprenticeship requirements and half of projects meet qualify for the domestic content adder. ITC incentives are included. Other policies are not considered in this analysis due to unclear economic impact (e.g., downstream impact of policies) and local impact (e.g., state and local policies). Asset and geography specific consideration of policies could significantly impact choice of technology and resulting abatement costs.
2. Electrification of compressor results in significant efficiency improvements over steam turbines (95% vs. 35% efficiency)
3. Renewable cost assumes Class 5 onshore wind production from NREL Annual Technology Baseline for 2030 and excludes the costs associated with transmission and delivery of electricity. IRA-inclusive scenarios includes investment tax credit of 35%, 30% from a base construction that meets the prevailing wage an apprenticeship requirements and an additional 5% due to an assumption that half of projects will claim the 10% domestic content adder. No adders included for low-income communities and energy communities. Net capex cost assumed is $621/kW and opex is $39/kW
4. Heat generation technology assumes the costs associated with charging and TES as an archetypical setup; however, asset specific heat generation can be achieved with other technologies such as heat pumps and resistive heaters. Technology development and asset specific considerations could significantly impact the choice of heat generation technologies.
5. Ethylene process assumptions used to model propylene and BTX processes (e.g., propane and naphtha cracking)
6. Displayed CCS cost estimates based on EFI Foundation capture costs with transport (GCCSI, 2019) and storage (BNEF, 2022) costs of ~$10-40/tonne (representing the lower and upper bounds of the displayed range) except where noted. All in 2022 dollars. All CCS figures represent retrofits, not new-build facilities. The inflation variance on each cost estimate represents the range of cost increases on a generic chemical processing facility due to inflation from 2018 using the Chemical Engineering Plant Cost Index (CEPCI)
7. The range of 2030 electrolytic hydrogen costs for Refining is estimated at $0.22-1.22/kg H2. The range of 2030 electrolytic hydrogen costs for Ammonia is estimated at $0.28-1.28/kg H2. All hydrogen cost assumptions for this modeled scenario are based on DOE's Clean Hydrogen Liftoff report, which relied on the 2022 McKinsey Hydrogen Model. The impact of the 45V tax credit is modeled as a $1.80/kg H2 reduction in OpEx cost, based on assumptions of 10% WACC, 10 years of tax credit, and a 20-year project lifetime. It is important to note that the assumptions underlying this analysis are uncertain, and the Clean Hydrogen Liftoff report is continually being updated. DOE electrolyzer cost estimates have already increased since the values published in this report, due to variables such as supply chain constraints and inflation. Additionally, the impacts of tax incentives on cost will be subject to guidance from the U.S. Department of Treasury.
8. Demand reduction consists of primarily transport sector electrification as well as the impact of a mechanical recycling rate of 25% of all plastics
9. Split of emissions streams assumed to be ~60% concentrated and ~40% dilute in SMR unit. Portion of SMR concentrated streams assumed to be smaller for ammonia due to captive usage of concentrated CO2 streams for urea production
10. Assumes CCS implementation on other chemicals high temperature heat sources with costs based on ethylene steam cracker capture costs

Sources: GREET 2022, NREL, DOE Hydrogen Liftoff Report, EFI CCS Report – "Turning CCS projects in heavy industry & power into blue chip financial investments", Inflation Reduction Act, LDES Council, Expert interviews, Danish Energy Agency, Netherlands Enterprise Agency, GHG Protocol, White House Net-Zero targets, McKinsey Global Energy Perspective, EFI Foundation, "Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments

Figure 17: With the implementation of the IRA, MACC analysis shows that ~30% of remaining emissions after grid decarbonization and demand reduction could be abated through economic measures in 2030. See the appendix for a description of the methodology and assumptions used for this analysis.

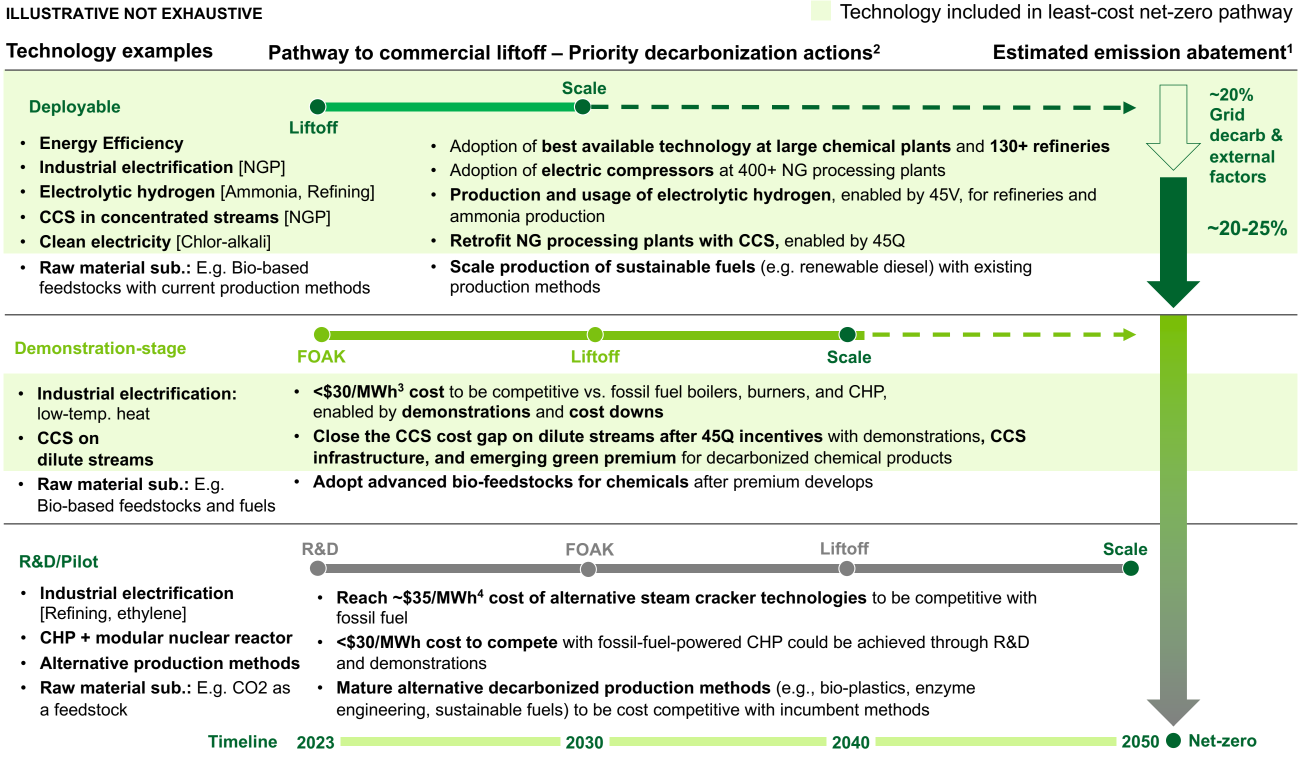


1. Analysis for 2050 does not consider additional policy incentives after the expiration of the IRA. Other policies are not considered in this analysis due to unclear economic impact (e.g., downstream impact of policies) and local impact (e.g., state and local policies). Asset and geography specific consideration of policies could significantly impact choice of technology and resulting abatement costs.
2. Electrification of compressor results in significant efficiency improvements over steam turbines (95% vs. 35% efficiency)
3. Renewable cost assumes Class 5 onshore wind production from NREL Annual Technology Baseline for 2030 and excludes the costs associated with transmission and delivery of electricity. IRA is assumed to have expired before 2050. Net capex cost assumed is $765/kW, and opex is $33/kW
4. Heat generation technology assumes the costs associated with charging and TES as an archetypical setup; however, asset specific heat generation can be achieved with other technologies such as heat pumps and resistive heaters. Technology development and asset specific considerations could significantly impact the choice of heat generation technologies.
5. Ethylene process assumptions used to model propylene and BTX processes (e.g., propane and naphtha cracking)
6. Displayed CCS cost estimates based on EFI Foundation capture costs with transport (GCCSI, 2019) and storage (BNEF, 2022) costs of ~$10-40/tonne (representing the lower and upper bounds of the displayed range) except where noted. All in 2022 dollars. All CCS figures represent retrofits, not new-build facilities. The inflation variance on each cost estimate represents the range of cost increases on a generic chemical processing facility due to inflation from 2018 using the Chemical Engineering Plant Cost Index (CEPCI)
7. The range of 2050 electrolytic hydrogen costs for Refining is estimated at $1.60-2.60/kg H2. The range of 2050 electrolytic hydrogen costs for Ammonia is estimated at $1.66-2.66/kg H2. All hydrogen cost assumptions for this modeled scenario are scenario are based on DOE's Clean Hydrogen Liftoff report, which relied on the 2022 McKinsey Hydrogen Model. It is important to note that the assumptions underlying this analysis of hydrogen cost are uncertain, and the Clean Hydrogen Liftoff report is continually being updated. DOE electrolyzer cost estimates have already increased since the values published in the report, due to variables such as supply chain constraints and inflation. Demand reduction consists of primarily transport sector electrification as well as the impact of a mechanical recycling rate of 25% of all plastics
8. Split of emissions streams assumed to be ~60% concentrated and ~40% dilute in SMR unit. Portion of SMR concentrated streams assumed to be smaller for ammonia due to captive usage of concentrated CO2 streams for urea production
9. Assumes CCS implementation on other chemicals high temperature heat sources with costs based on ethylene steam cracker capture costs

Sources: GREET 2022, NREL, DOE Hydrogen Liftoff Report, EFI CCS Report – "Turning CCS projects in heavy industry & power into blue chip financial investments", Inflation Reduction Act, LDES Council, Expert interviews, Danish Energy Agency, Netherlands Enterprise Agency, GHG Protocol, White House Net-Zero targets, McKinsey Global Energy Perspective, EFI Foundation, "Turning CCS Projects in Heavy Industry & Power into Blue Chip Financial Investments

Figure 18: MACC analysis shows that ~20% of emissions that would remain after grid decarbonization and demand reduction could be abated through economic measures in 2050. See the appendix for a description of the methodology and assumptions used for this analysis.

Section 3b: Net zero pathway for production of chemicals & refining



1. Abatement share ranges are constrained and based on alternative decarbonization pathways, varying on factors such as the emergence of alternative production methods and chemistries
2. Indicative timeline presented R&D, FOAK, liftoff, and scale. Actual timelines will vary by technology based on technological maturity and barriers to adoption
3. Estimated as breakeven point on the MACC levelized cost of heat to reach $0/tCO_2$ abatement cost for refining CHP
4. Estimated as breakeven point on the MACC levelized cost of heat to reach $0/tCO2e abatement cost for ethylene steam cracking furnace

Figure 19 (also Figure 3): Reaching net zero in the chemicals & refining sectors requires a phased approach that sequences deployable technologies in the near term, technologies under demonstration in the medium term, and technologies that are in R&D and pilot phases in the long term.

With concerted action, the decarbonization pathway for downstream chemicals production and refining could evolve over a phased approach to 2050, aligning with U.S. national decarbonization goals while balancing economic, infrastructure, and operational constraints.

Phase 1: Near-term acceleration of deployable technologies (2023–2033): Across the coming years, companies must focus on accelerating economically viable measures and adopting technologies that can be integrated into their existing asset base. These five levers include: (i) energy and operational efficiency upgrades, (ii) adopting select electrification measures, (iii) transitioning certain processes to clean hydrogen, (iv) installing CCS on high-purity streams, and (v) integrating other low-carbon fuels and feedstocks. These five levers over the near-term offer the most immediate path to emissions reduction with the least cost and disruption to existing operations.

i. **Energy and operational efficiency:** Significantly accelerated adoption of measures to improve energy efficiency and reduce waste of feedstock or fuels that impact emissions, such as preventing leaks and reducing production losses. This is particularly relevant at smaller or less competitive facilities that have not yet invested in the best available equipment.

ii. **Electrification with clean high-capacity firm power:** Rapid electrification of select economically viable equipment. Based on cost curve analysis, the only near-term measure with a positive investment case (>10% IRR) is the electrification of natural gas process compressors with renewable power. Some abatement options do not pass this hurdle rate but remain under $100/tCO2 through

2030, including the electrification with LDES of steam methane reforming with Haber-Bosch for ammonia production. Using solar power with LDES to transition chemicals processing to electric boilers—currently at capex cost—would have meaningful abatement potential. This includes electrifying boilers in chlor-alkali processes and steam cracking to produce ethylene, propylene, and BTX, among others.

iii. **Clean hydrogen:** Broadly adopting clean hydrogen to replace carbon-intensive hydrogen in chemicals & refining production (i.e., direct feedstock switching in refineries). Projects that adopt clean hydrogen during this time window will benefit from 45Q or 45V tax credits. Achieving clean hydrogen production cost-downs and infrastructure buildouts before credit expiration will be important to ensure the increased integration and adoption of this technology. In addition, provisions in the IRA support the build-out of clean hydrogen infrastructure critical for cost-effective storage. DOE Regional Clean Hydrogen Hubs will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store tremendous amounts of energy. In particular, switching a significant portion of steam methane reformers that supply refineries to electrolytic hydrogen could abate up to 35 million tonnes of CO2e by 2030 but would require significant new clean electricity buildout**.** In many cases, chemicals plants and refineries are expected to select reformation-based hydrogen pathways if they have an existing SMR on-site and are close to CCS infrastructure. In these situations, companies integrating CCS into facilities with SMRs will likely only capture the concentrated process emission streams as these provide the most economic capture costs. For example, concentrated CCS costs are 25–55% less expensive than capturing all emissions.[xcv] At the same time, only ~60% of SMR emissions are concentrated, leaving ~40% of emissions unabated. To remain on the path to net zero, companies must weigh the trade-off between adopting electrolytic hydrogen with associated clean electricity demand or incurring the cost of capturing and storing dilute carbon streams.

iv. **CCS:** Adoption of CCS on high-purity CO2 streams, such as natural gas processing, is critical during this period to benefit from the 45Q tax credit in the IRA and support from the Bipartisan Infrastructure Law. The early roll-out of CCS projects on high-purity streams with better financials can help build out the infrastructure needed to reduce costs for projects on low-purity streams in the future. Within concentrated streams, early deployment is likely to occur in assets with nearby access to existing transport and storage infrastructure. During this period, pilots and commercial demonstration projects can help prove the feasibility of capture on lower-purity sources.

v. **Raw material substitution:** Raw material substitution, including biochemicals, biofuels and other low-carbon feedstocks, are umbrella terms for various production pathways and processes. Low-carbon feedstocks can replace fossil fuels for heat and feedstock needs in the chemicals & refining industry. Some biofuels are carbon negative (e.g., renewable natural gas (RNG) produced from biogas that otherwise may have entered the atmosphere), and some are net carbon-emitting, albeit with a lower carbon intensity than fossil fuels (e.g., sustainable aviation fuel produced from waste oils or gasified waste woody biomass). There is also a wide range of promising decarbonization solutions that use CO2 or industrial/consumer waste products (such as plastics) as feedstocks to produce carbon-based chemicals and fuels. Though the industry has reported interest various alternative feedstock materials, companies cite cost and access to sufficient biomass as concerns.[53] Due to the focus of the analysis pursued in this report on production emissions, low-carbon fuels and feedstocks are currently not included in the marginal abatement cost analysis presented below but were explored further in Section 2e and 2f.

While levers (i) through (v) will be critical for chemicals & refining companies to keep their process emissions on track to eventually meet net zero by 2050, other industry transitions must happen alongside direct

53 Industry interviews.

company action. Near-term decarbonization trajectories of the transportation and power sectors affect process emissions in chemicals & refining. In line with the White House's long-term strategy for net zero, these changes include a 25% reduction in transportation emissions by 2030 and continued progress toward a carbon-free grid (80% progress by 2030 toward a 2035 zero-carbon grid).[54, 55] Additionally, reaching a 50% recycling goal in line with EPA's 2030 target could reduce production emissions from chemicals by 2–3% due to reduced demand for virgin plastic.

Looking beyond 2030, the path to decarbonization faces a more persistent cost/performance gap. Investments must flow into lower TRL technologies this decade to improve their chances of developing into viable options in the future. Today's refineries and chemicals processing plants may look very different than those in 2050. These changes will largely be a factor of shifts in end-use consumer demand and whether alternative upstream feedstocks are cost competitive.

Biofuels, including sustainable aviation fuel and renewable diesel, will play a significant role in decarbonization through 2030. The Sustainable Aviation Fuel Grand Challenge aims to produce 3B gallons of SAF with >50% GHG reduction by 2030, constituting over 10% of U.S. aviation fuel demand. Additionally, the Clean Fuels & Products Earthshot aims to meet the 2050 projected demand for 100% of aviation fuel: 50% of maritime, rail, and off-road fuel, and 50% of carbon-based chemicals by using sustainable carbon resources.[56]

Phase 2: Scaling decarbonization measures currently being demonstrated (2030–2040): Building on successes from the prior decade, Phase 2 will ideally be able to leverage the scaled infrastructure for clean hydrogen and CCS developed in the 2020s and early 2030s. In addition to levers (i) through (v) implemented in Phase 1, decarbonization over the medium term would rely on two other key transitions: (vi) adopting CCS on dilute emission streams and (vii) rapidly electrifying low- and medium-temperature heat sources.

vi. **CCS:** Accelerating adoption of CCS on dilute emissions sources, such as from steam crackers in the ethylene sector. Although the capture technology is proven, there are few at-scale demonstrations of CO2 capture on dilute streams (concentrations <15%) in chemicals & refining. Therefore, demonstration and scale-up could achieve learnings, improve implementation, and achieve modest cost declines. In addition, these projects could benefit from shared CCS infrastructure built out in the prior decade (e.g., CO2 pipelines and sequestration sites), which would reduce transportation and storage costs.

vii. **Electrification:** Continued improvement on the pathway to net zero over the medium term relies heavily on access and availability of clean firm power. In addition to the electrification implemented in Phase 1, companies must continue the rapid electrification of low- and medium-temperature heat sources with electric boilers coupled with firm high-capacity clean power and thermal energy storage. Up to ~180 TWh of clean firm power would be required by 2030 to support the electrification of the chemicals & refining industries. Cost declines are expected to primarily be driven by LDES technology and the cost declines of installing firm power capacity for onsite generation. The Biden-Harris Administration has set a goal of 100% emission-free electricity by 2035. Achieving this target would strengthen the decarbonization case for electrification and help chemicals & refining companies abate their Scope 2 emissions.[57]

Absent additional policy or technology cost/performance improvements, these levers are expected to add costs in the 2030s as IRA incentives (45Q, 45V) expire for facilities constructed after 2032. For CCS, modest cost declines could be possible in both capex and operating expenses (opex) as replicability improves both implementation and

54 In line with White House targets for a 25% transport emission reduction by 2030 in the high-ambition scenario, assumed to result in a 25% reduction in transport fuel demand from conventional refineries.

55 In line with White House targets for a 100% zero-carbon grid by 2035 and decarbonized transport by 2050.

56 DOE Energy Earthshots aim to accelerate breakthroughs and adoption of more abundant, affordable, sustainable, and reliable clean energy solutions. More information can be found at Earthshots Clean Fuels & Products factsheet (energy.gov).

57 Scope 2 emissions are indirect emissions associated with the purchase of electricity, steam, heat, or cooling.

operation, though capex cost decreases are likely to be more limited for retrofits where replicability is less likely.

Because of persistent cost challenges, achieving widespread adoption, in line with a net-zero pathway, will likely require either new government measures or customer demand pull, such as carbon-intensity targets for end products.

Phase 3: Achieving net zero with technologies currently in R&D and pilot (2040–2050): Achieving net zero for downstream chemicals production and refining by 2050 would require implementing technologies that are not cost-competitive. In addition to near-universal adoption of the previously mentioned decarbonization measures (i) through (vii), decarbonization by 2050 requires:

- Increased overall adoption of clean firm power with storage (LDES or thermal energy storage) for low- and medium-heat electrification, nearly doubling the dedicated clean high-capacity firm power to >300 TWh for chemicals & refining production.
- Full adoption of clean hydrogen in ammonia production and significant uptake in refining, with at least ~7–8 MTPA of clean hydrogen, up from ~3 MTPA by 2030.
- CCS on dilute streams could play a critical role in abating the remaining emissions gaps and are needed to capture up to ~170 MTPA of CO2 in the chemicals & refining sector.

The technologies above needed to reach net zero from 2040 onward may not require full implementation if other more nascent technologies (e.g., e-crackers, catalytic crackers, high-temperature heat electrification with thermal batteries) have reached the deployment stage. Key nascent technologies are outlined in Sections 3c and 4a.

Adopting these measures at scale would enable a ~93% reduction in emissions compared to BAU, in line with the White House's Long-Term Strategy for industrials. To achieve full net zero in these sectors, carbon removals (~40 MTPA) would be needed for the remaining ~7% of emissions, such as those from incomplete carbon capture and assets that are not fully decarbonized.

If the current policy environment holds through 2050, measures required to abate ~360 MTPA of CO2 are not expected to be economic. Only 20% of emissions, after factoring in 100% decarbonizing vehicle emissions in 2050, widespread mechanical recycling, and reducing the demand for fuel and chemicals, could be abated through measures with positive economics in 2050. These include the electrification of natural gas process compressors with renewable energy and efficiency improvements in fuel consumption.

Section 3c: Accelerating adoption of decarbonization measures

Decarbonizing up to 35% of chemicals & refining emissions by 2030 will require the broad and rapid adoption of the deployable decarbonization measures outlined above. For example, achieving the 35% emissions reduction pathway by 2030 would require the following adoption rates by the end of the decade:

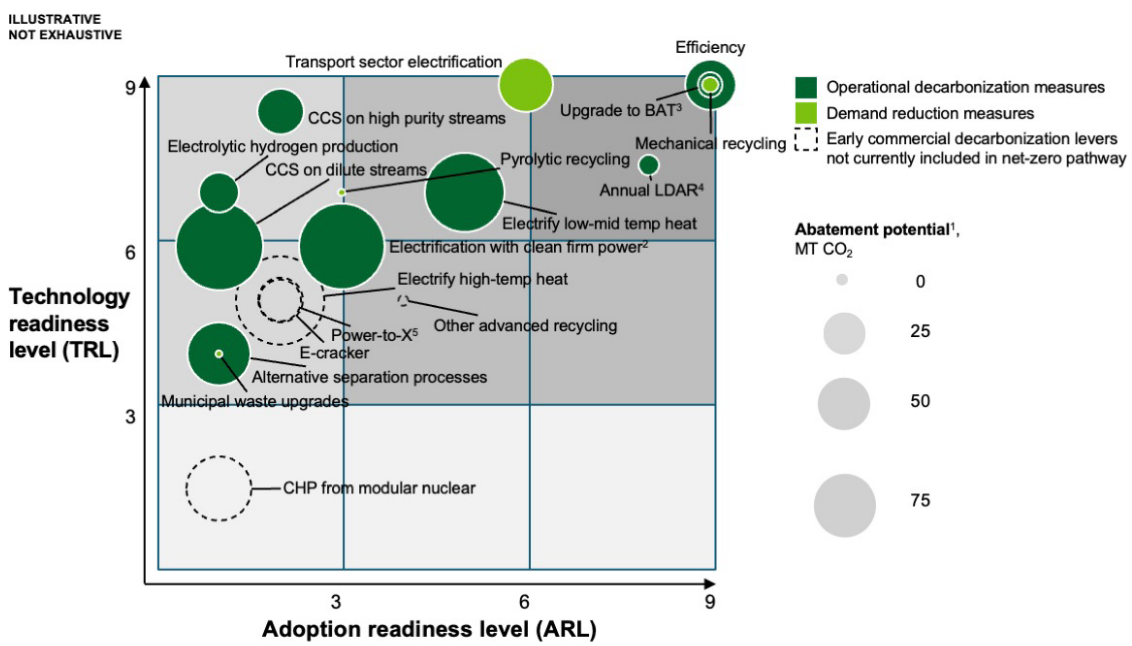
- **CCS:** Carbon capture must be installed on over 80% of natural gas processing facilities that do not already use CCS by 2030, a 100% increase from the 14 MTPA of point source CCS capacity currently operational.
- **Electrification with clean high-capacity firm power:** By 2030, over 80% of compressors for natural gas processing must be electrified with clean high-capacity firm power.
- **Clean hydrogen**: By 2030, 33% of all hydrogen used in ammonia and refining production must be clean hydrogen, representing a >350% increase from today's production of electrolytic hydrogen.
- **Energy efficiency**: Broadly implementing efficiency measures across all chemicals & refining facilities to reach an average of ~10% efficiency improvement.

- **Transport electrification:** This pathway assumes the U.S. is on track to meet the 2050 goal of a 100% transition to zero-emission vehicles. This would require a 25% emission reduction from U.S. transportation by 2030. Today, the penetration of zero-emission transport is growing but remains limited. For example, EV penetration today is less than 1%.[xcvi]

- **Recycling:** This pathway also assumes achieving EPA goals of 50% recycling of all waste in 2030, which is assumed for key plastics.[58] With a 9% recycling rate of plastic today, this would require a significant increase in recycling by 2030, or ~15 million tons more recycled plastic yearly.[xcvii]

Hitting these deployment milestones will likely require rapid acceleration of corporate long-term decarbonization commitments (spanning multiple CEO tenures), allocating today's capital toward decarbonization activities (potentially increasing capital spend plans or shifting priorities away from other core business areas), overcoming ecosystem challenges, and overcoming practical downtime barriers when retooling plants. Some of these adoption challenges are outlined below.

The key technologies included in this pathway have been broadly demonstrated or deployed but face barriers to market adoption (Figure 20). The key measures included in this pathway (CCS, clean hydrogen, energy efficiency, and electrification with clean high-capacity firm power) were selected based on their emission abatement potential, least-cost position, and technology readiness level. However, there is portfolio risk associated with these levers. For example, the pathway laid out in this analysis relies on CCS to abate ~27% of emissions, while clean hydrogen is needed to abate ~9% of emissions in 2050. The pathway is at risk if either technology fails to reach scale in the coming decade. Therefore, RDD&D is needed to develop other nascent technologies that could replace these technologies should they fail to reach scale. Chapter 4 discusses the Adoption Readiness Level (ARL) for various nascent technologies that could play a role in decarbonizing the chemicals and refining sector. The ARL framework assesses the adoption risks of a technology and translates this risk assessment into a readiness score, representing the readiness of a technology to be adopted by the ecosystem (Figure 20).



1. Analysis from production emissions reduction in 2030 post-IRA MACC for relatively mature levers and DOE analysis for more nascent levers. Multiple levers shown for potential to abate emissions streams and therefore emissions do not total to sector emissions
2. Combined levers: renewable power, storage, and electrification
3. BAT = best available technology; 4. LDAR = leak detection and repair; 5. ARL and TRL for PtX limited by direct air capture (DAC) technology

Source: DOE CADAT ARL, DOE hydrogen and carbon management pathways reports, ADAT, expert interviews, press search

Figure 20: Technology and adoption readiness for select decarbonization technologies [xcviii]

58 Assumes a 50% recycling rate for all U.S. generate PET, PE, and PP-based waste.

The path to net zero could be accelerated or facilitated through breakthrough technologies, though they are unproven. Alternative pathways to decarbonize downstream chemicals production and refining rely on a series of technologies that have yet to reach commercial scale. These technologies could have significant emissions abatement potential (see technologies represented by dotted lines in Figure 20) and reduce the need for CCS or electrification with clean high-capacity firm power. However, they all require research, development, and deployment to prove readiness and competitiveness with mature measures today. Several examples of potential nascent technologies are discussed in more detail in Chapter 4.

Section 3d: Capital requirements

Today through 2030, there is a ~$90–120B investment opportunity in decarbonization levers with >10% IRR, and an additional investment of ~$610–730B is needed between 2030 to 2050. This includes not only capital for direct decarbonization levers but also enabling infrastructure. Understanding the investment outlook across clean hydrogen markets, advanced nuclear buildouts, long duration energy storage, and carbon management is key to assessing the capital needs for decarbonization across chemicals & refining processes.

For example, while ~$14B would be required for carbon capture equipment by 2030, significant additional spending would be needed to build out the pipelines and sequestration sites for carbon. Reaching the capital investment required by 2030 would mean over $10B invested annually through 2030—a significant acceleration relative to the industry's current momentum. **Beyond 2030, the speed and scale of investment must accelerate, requiring approximately $25–30B invested annually from 2030 to 2050.**

To meet these capital needs, investment must come from both public and private sources. As larger capex decarbonization projects (e.g., hydrogen, CCS) have gained interest, the industry has often been willing to self-fund pilots through strategic partnerships and industry consortia. For cost-effective levers applicable to existing assets, corporations will likely use bank financing, their balance sheets, and government incentives to fund decarbonization.

However, as represented in the MACC analysis, many projects are non-economic under the current policy environment and have even worse economics once IRA tax credits expire. **These large-scale infrastructure developments are where the federal government can play an impactful role in buying down risk, to help scale and lower costs for future decades.** For example, refineries have mostly focused on shifting production to renewable fuels or increasing exports without decarbonizing existing refinery capacity. The federal government can support FOAK CCS retrofits to encourage future investments.

Industry can serve in the critical offtake capacity. For example, while there have been ~$15B in planned investment for U.S. hydrogen production projects, only ~$6B has been announced for midstream and end-use investment. Beyond 2030, later-stage, lower-cost capital (e.g., infrastructure funds, institutional investors, banks) must see a positive investment case for the U.S. to achieve net zero across chemicals & refining processes. Beyond industry corporations and the federal government, institutional capital providers must reestablish a commitment to helping the sector decarbonize. Many existing financing instruments (e.g., ESG funds, sustainability-linked loans, green bonds) have avoided heavy-emitting sectors, including refineries and chemicals. However, a handful of private equity and infrastructure firms have recently established large transition funds, with many targeting opportunities in hard-to-abate sectors. In many cases, the projects that need financing to decarbonize chemicals & refining processes are infrastructure-like investments, meaning they have large upfront capex requirements but the potential to produce steady IRRs over a long period. With the growth projected in the chemicals sector, in particular, communicating the emission reduction opportunity to institutional investors stands to unlock necessary capital.

Additional considerations within the chemicals & refining sector could impact capital investment. A key nuance is the industry concentration of sub-sectors (e.g., ammonia vs. ethylene), which is discussed in Section 2c. Additionally, key companies could influence the timeline of decarbonization investments due to their own economic position and project pipeline. These sector- and company-specific conditions have implications for capital deployment. Further details on capital requirements and needed capital formation are discussed in Chapter 4 (Figures 22 and 30).

Section 3e: Socioeconomic considerations

Decarbonizing the U.S. industrial sector at large is essential to becoming a net-zero economy. Decarbonizing chemicals and refining processes are essential for a successful clean energy transition. Clean energy technologies are reliant on many of the end use products to come out of chemicals and refining processes. As discussed throughout this report, abating these emissions will require a wide variety of technological levers and project-specific approaches, and each facility may have unique features that dictate the range of approaches available and their feasibility. Some levers, which often are the subject of public concern, may be a key option today for decarbonization (e.g., carbon capture on concentrated flue streams). Many of these industries, critical for manufacturing the clean energy economy, are sited in environmental justice communities.

Decarbonization of the chemicals and refining sector must occur in a way that ensures the development of good quality job years and respects the concerns of fence line communities in order to meet the country's climate, economic, and environmental justice imperatives. This report takes a broad look at workforce and environmental justice concerns to highlight the key opportunities that can arise from industrial decarbonization as well as the risks that must be mitigated in order to protect communities from additional harms beyond what they have already suffered.

While this report offers a quantitative analysis of GHG baselines and CO2 emissions abatement and an initial qualitative analysis on workforce and EEJ topics, it does not include a comprehensive analysis of non-GHG emissions from industrial processes, specific industry workforce considerations, or technical solutions for EEJ concerns. This qualitative analysis is the beginning in what must be a robust and quantitative discussion on how to implement a societally just decarbonization strategy. Additional work from many stakeholders is needed to outline tactical solutions toward a shared goal of a prosperous, just net-zero economy.

Workforce

Achieving a net-zero pathway in chemicals & refining production could have broad socioeconomic and employment impacts, creating up to ~5.5M good-paying job-years through direct and indirect jobs in the investment phase through 2050.[59] There are many potential benefits, particularly if existing employment is sustained and labor standards and community benefit plans are implemented to ensure good quality job-years. The investment required for this pathway could contribute ~$7,000B in gross value added (GVA) to the U.S. economy.[xcix] As of 2023, the total employment in chemicals & refining is ~1.9M jobs. This sector is segmented by chemicals manufacturing (918,000 U.S. workers), petroleum manufacturing (101,000 U.S. workers), and the plastics manufacturing industry (751,000).[c,ci,cii]

During the build-out phase, most estimated new jobs (~54%) are expected to be generated from direct spending on infrastructure projects through roles such as construction trades and planners. The remaining jobs (~46%) are expected to be tied to indirect supply chain spending and support of the new assets (Figure 21). Trades and engineers account for roughly 26% and 22% of direct job creation, respectively.[60]
The number of construction job-years increases over the near- and medium-term and begins to decline as the sectors approach 2050. Due to the increased infrastructure build-out, operational job-years consistently increases through 2050.

59 This analysis considers jobs required for adopting decarbonization technologies in the pathway detailed above. These numbers are not net of any job changes that could occur due to shifts in demand for chemicals & refining products.

60 Welders, electricians, metal workers, fabricators, installation, maintenance, repair technicians, and other construction and manufacturing trades workers.

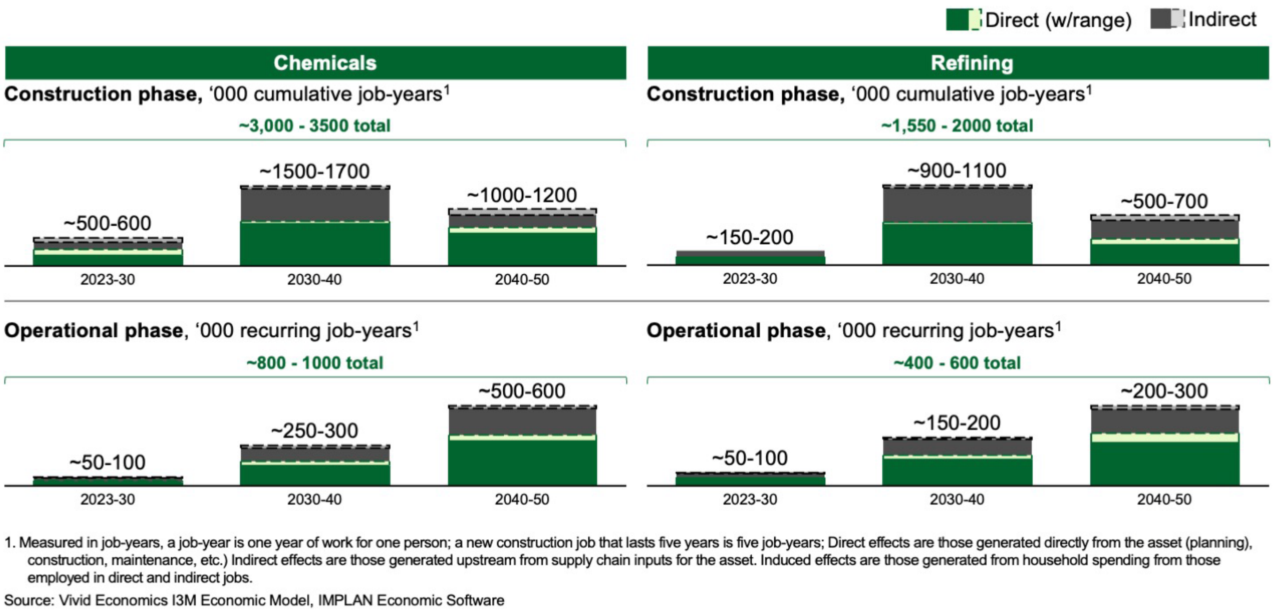


Figure 21: The investment required to reach this net zero pathway in downstream chemicals production and refining could generate up to ~5.5M jobs-years by 2050.

Ensuring a just energy transition requires engaging workers throughout the implementation process. Jobs in the industrial sector have long provided middle class incomes and benefits for workers. The introduction of decarbonization technologies that impact the number and types of jobs available must include concerted planning and direct engagement with workers to ensure that there are pathways to retirement, reemployment, or retraining, including on-the-job training to staff new occupations, and that jobs are good jobs. Consideration should be taken to retain skilled workers within industries. Collaboration with labor and management groups across the industrial sector can lead to just outcomes for workers and help employers hire, train, and retain skilled workers. For example, the Battery Workforce Initiative aligns stakeholders (employers and unions) on critical skills for the industry, and the electrical training ALLIANCE offer models for apprentice and training programs.

Creating jobs does not always translate to filling jobs. The skilled trades and professional roles required for scale-up comprise ~15% of the current workforce in those fields. The build out of industrial decarbonization will also require millions of hours of work. Across industries, staffing could be challenging as other decarbonization technologies come online simultaneously. This challenge could be particularly acute in the skilled trades (e.g., electrical, plumbing, mechanical trades). The build-out of decarbonization technology should be pursued in collaboration with labor and management groups in the construction, oil, gas, and chemicals industries and include a focus on promoting registered apprenticeships.

To attract and retain a skilled workforce, these jobs must be high paying with strong labor protections, training/placement opportunities (e.g., registered apprenticeships), and pathways for long-term career growth. Project Labor Agreements (PLAs)—described below—can be useful tools for attracting and training a skilled workforce for the infrastructure build-out, and other collective bargaining agreements will support operations and maintenance workforce needs. PLAs and collective bargaining agreements can be part of community workforce agreements and community benefits plans that also address community and environmental justice concerns. The Pathways to Commercial Liftoff: Introduction document provides an in-depth discussion of the significance of these quality jobs characteristics and how they can be achieved.

Project Labor Agreements (PLAs)

- A Project Labor Agreement is a collective bargaining agreement negotiated between construction union(s) and employer(s). The agreement, unique to the construction industry, establishes terms and conditions for certain projects.
- PLAs generally specify wages and benefits for project workers, require contractors to hire union represented workers, and have no strike and no lockout clauses to ensure timely project completion.
- Since construction projects often interface with multiple trade unions, PLAs can streamline the process of coordinating labor contracts under one agreement.
- PLAs also often contain provisions on worker safety and can have additional clauses relating to employing local workers, environmental equity, engaging with underserved communities, and small businesses.

Commercial Liftoff: Overview of Society Considerations and Impacts offers additional information and guidance on cross-cutting issues related to EEJ, community and labor engagement, workforce development and quality jobs, and diversity, equity, inclusion and accessibility.

If jobs are high paying and offer the free and fair choice to join a union, strong labor standards, and training/placement opportunities such as registered apprenticeships, they will likely attract the skilled workers required and draw new workers to the field and the locations where they are needed.

As the U.S. transitions to a net-zero economy, other job impacts may occur that were not included in this analysis. For example, reduction of demand for fuel as the U.S. transitions to a zero-emissions fleet could reduce jobs in the refining industry. While out-of-scope for this analysis, these jobs impacts will be critical to mitigate—both to ensure the strength of the U.S. economy and that workers have the necessary skills to support new-energy industries with significant labor needs.

Energy and environmental justice (EEJ)

Ensuring decarbonizing chemicals & refining processes supports energy and environmental justice is critical as a moral and liftoff imperative. Effectively implementing decarbonization projects also depends on the engaging with and garnering the support of surrounding communities, who have effectively challenged many industrial projects based on environmental justice and environmental health concerns. The energy and environmental justice impact of integrating any decarbonization levers detailed in this report depend on benefits and harms, who experiences them, and how the impacts alleviate or compound existing burdens**.**

Across all decarbonization levers, how technologies are deployed can combat or exacerbate existing inequalities, especially if technology is installed in communities already overburdened by existing infrastructure and underserved by government programs. The magnitude and nature of local concerns—and the scale of potential impacts or benefits—vary by project type, technology, and local context, requiring that community impact and perceptions are assessed on a project-by-project basis. The lived experiences of frontline communities inform **concerns around safety, accountability, transparency, and the continued operation's potential environmental and health impacts.**

Decarbonizing chemicals & refining assets can provide a critical opportunity to remediate social, economic, and health burdens experienced by fence-line communities disproportionately harmed by industrial sector emissions. In addition to emitting large quantities of GHGs, industrial facilities emit other pollutants, waste streams, and by-products that may harm human and environmental health.[ciii] Decarbonization efforts can include measures to address these impacts.

The Pathways to Commercial Liftoff: Overview of Societal Considerations and Impacts offers specific considerations and actions related to the distribution of impacts (i.e., who experiences benefits and who experiences burdens) and process (i.e., enabling impacted individuals/groups to make decisions about projects that affect them). To proactively account for societal considerations and impacts, project developers should meaningfully engage with impacted communities, tribes, and labor unions early and often to support real accountability and transparency; assess and address energy and environmental justice concerns and opportunities; create quality jobs and invest in career-track workforce development; and support diversity, equity, inclusion, and accessibility.

There are long-standing feelings of mistrust among many frontline communities who feel they are ignored, experimented on, and treated as disposable by government and industry.[civ,cv] **At the community and stakeholder level, there are many concerns, including safety, accountability, transparency, the potential environmental and health impacts of continued operation, and a lack of benefits for local communities.** The magnitude and nature of local concerns and potential impacts or benefits vary by project type, technology, and local context, requiring that community impact and perceptions be assessed on a project-by-project basis.

In the U.S., larger and more chemical-intensive facilities tend to be located in counties with larger Black or African American populations, across counties with higher median incomes and high levels of income inequality. There is also a greater risk of accidents for facilities in heavily Black or African American counties.[cvi] Overall, Black and indigenous communities, communities of color, and low-income communities are disproportionately exposed to elevated levels of air pollution and, consequently, experience higher rates of adverse health impacts than the general population.[cvii] In all but four states, race, not poverty, is the most direct link to particulate matter (PM) exposure. Black populations were exposed to 1.54x more small pollution particles, known as PM 2.5, than white populations. PM 2.5 is frequently linked to lung and heart disease and is mainly attributed to burning fossil fuels.[cviii]

Under the Clean Air Act, the Environmental Protection Agency (EPA) regulates many of the key pollutants released from industrial assets, such as criteria air pollutants including sulfur oxide (SO_x), nitrogen oxides (NO_x), and PM. These pollutants adversely impact health—contributing to chronic and acute respiratory issues, asthma, heart disease, and heart attacks—and the environment, causing acid rain, smog, damage to plant growth, and nutrient pollution.[cix] **In April 2023, the EPA announced a proposal to strengthen standards at chemicals plants to reduce hazardous pollutants, including highly toxic ethylene oxide and chloroprene**.[cx] The Clean Water Act, also overseen by the EPA, limits the discharge of harmful pollutants based on the performance of well-designed and well-operated control and treatment technologies. **For the chemicals sector, the EPA oversees the Risk Management Program (RMP) which issues guidance for chemicals accident prevention.** As of the publication of this report, no U.S. regulation directly addresses emissions of CO2, and few domestic regulatory drivers require decarbonizing chemicals & refining production. However, as this report suggests, BIL and IRA legislation provides incentives that could make decarbonization technologies more attractive.

However, because federal regulations focus on the health impacts of isolated pollutants rather than the potential cumulative impacts of multiple types, the limitations set by the Clean Air and Clean Water Acts may not accurately reflect the emission levels needed to mitigate health risks.[cxi] Additionally, enforcement discretion lies with state regulatory bodies, meaning that EPA processes do not always result in permit compliance or penalties for those who do not comply.[cxii]

Noncompliance with these acts and programs, whether chronic or as the result of one-off accidents caused by equipment malfunction, human error, supply chain disruptions, or extreme weather, has led to the release of hundreds of millions of pounds of "excess emissions" beyond levels stipulated in facility permits.[cxiii] Analysis of the Texas Commission on Environmental Quality's (TCEQ) database of industry-reported pollution shows that industrial facilities emitted 1.1 billion pounds of pollution beyond permit levels between 2002 and 2021, with excess emissions increasing over time.[cxiv] TCEQ automatically exempted more than 99% of these events from regulatory scrutiny or corrective action between 2016 and 2022.[cxv]

The Clean Air Act requires oil refineries to install fence line air pollution monitors to prevent harmful emissions from escaping to surrounding neighborhoods.[cxvi] In 2020, thirteen refineries exceeded EPA's action level for benzene, a carcinogen dangerous to human health. More than 530,000 people live within three miles of these refineries, with 57% being people of color and 43% living below the poverty line.[cxvii] Additionally, RMP facilities reported an average of approximately 190 accidental releases per year from 2010 through 2019.[cxviii] Such accidents pose a risk to human and environmental health and can lead to declines in nearby home values and significant levels of chronic stress.[cxix, cxx] **Reducing the frequency of these events—and securing proper monitoring, reporting, and emergency alert systems—are key concerns for EEJ advocates and local communities.**

When emissions events occur, nearby communities face elevated health risks from exposure to high levels of toxic and carcinogenic pollutants. **Accurate and publicly available emissions reporting, and timely and effective emergency alert systems, are critical so communities can take steps necessary to protect their health, including sheltering in place, turning off air conditioners, and reducing exposure to outside air.** Alert systems also help companies, workers, and regulatory agencies respond more quickly and appropriately to emissions events. However, some industrial facilities misreport the duration or timing of emissions events, report them far after they have occurred or not at all, and/or do not use effective emergency alert systems.[cxxi,cxxii] Efforts to decarbonize the industry may present new safety risks that must come with appropriate monitoring, reporting, and emergency response, but these facility upgrades also present an opportunity to build strong safety and alert systems.

To solve for public acceptance and community perception concerns, community benefit agreements (CBAs) are avenues for developers to engage with communities to understand how their project can meet with their goals while ensuring that community needs are met. CBAs can incorporate mechanisms designed to mitigate the impacts from project development that the community is concerned about. Examples include requiring the usage of state-of-the-art SO_x scrubbers for hydrogen burning facilities, investments in local infrastructure, job training and local hiring requirements, implementation of GHG reduction programs.

Community Benefit Agreements (CBAs)

- A Community Benefit Agreement is an agreement made between a developer of a project and a coalition of local community stakeholders wherein return for public support of a project, the developer will provide a number of benefits for the community hosting the project.
- Coalitions that sign CBAs on behalf of the community can include neighborhood associations, unions, environmental groups, faith-based organizations, non-profit organizations, and other local stakeholders.
- CBAs are flexible in that the developer and community can work together to negotiate a CBA which suits both parties. Benefits CBAs can provide include local hiring and job training commitments, project labor agreements (PLAs), agreements on wages and benefits, funding for local infrastructure, support for local businesses, and more.
- Strong CBAs center on promoting inclusiveness, enforceability, transparency, coalition building, and efficiency.

Commercial Liftoff: Overview of Society Considerations and Impacts offers additional information and guidance on cross-cutting issues related to EEJ, community and labor engagement, workforce development and quality jobs, and diversity, equity, inclusion and accessibility.

There are several cross-cutting EEJ technology concerns and benefits relevant to decarbonizing the chemicals & refining sectors**,** including:

- There is a basic concern around the potential for companies to pass the costs of commercial-scale demonstrations and early implementation of new technologies onto consumers. The end-use products from the chemicals & refining industries are everyday items for many Americans. In many cases, the 45Q credit, other tax incentives, and BIL programs will help to defray costs and insulate ratepayers from the costs of FOAK projects.
- Some EEJ advocates are concerned that decarbonization projects extend the life of fossil-fuel industrial facilities beyond when they would have otherwise shut down, thereby continuing to harm nearby communities. Advancing these technologies may provide financial support to companies who have harmed disadvantaged communities.[cxxiii]
- Supporting decarbonization solutions may provide continued financial support to fossil fuel companies despite their role in causing the climate crisis and delaying climate action.

There are also several technology-specific EEJ concerns and benefits across the various decarbonization levers:

Industrial electrification and clean electricity

- Fully electrifying industry could double national electricity demands, generating concerns about competition for clean firm power between communities and industry. To avoid competing with communities for clean energy, facilities must build additional renewable capacity rather than drawing from the local grid. Expanding clean energy generation can increase land use change.[cxxiv] Facilities developing additional generation capacity should consider the environmental and cultural impacts of land use change and limit negative impacts (e.g., by building on brownfield sites).
- Replacing carbon-based feedstocks with clean electricity may lower direct pollutants and decrease associated health risks (e.g., respiratory, cancer).[cxxv]
- Industrial electrification technologies, such as process heat pumps, can generate significant noise pollution, requiring noise mitigation measures.[cxxvi]
- Electrical workers face risks associated with shocks, burns, and fires. Workers need electrical safety initiatives to keep them safe among increased electrical infrastructure.[cxxvii]
- Critical minerals for electrification include copper, nickel, manganese, cobalt, and others. Mining for these will increase negative environmental impacts, including increased pollution and land use change, especially in developing countries.[cxxviii]
- Without proper on-site storage, some clean electricity feedstocks may be at risk of intermittency. Installing certain types of battery storage may increase fire or explosion risk, requiring proper fire safety measures to protect communities.[cxxix] Battery disposal and decommissioning can also lead to increased air, water, and soil pollution (see DOE's Pathways to Commercial Liftoff: Long Duration Energy Storage for more on EEJ considerations).

Energy efficiency

- Increased efficiency reduces fuel needs, leading to reductions in emissions of greenhouse gases and health-harming pollutants like NO_x and SO_x, in addition to driving down energy costs.[cxxx] Energy efficiency measures may be taken with other decarbonization measures to increase facility retrofit benefits for communities.
- Certain waste heat recovery techniques have large footprints; companies should consider the environmental and cultural impacts of land use change and take steps to limit negative impacts.[cxxxi]

Raw material substitution

- Recycling materials can limit impacts caused by material disposal, such as plastic pollution.[cxxxii] It can reduce hazardous substance use and waste, reducing water and soil contamination.[cxxxiii]
- Gasifying plastic waste to produce syngas emits less CO, SO2, HCl, and dioxins than incinerating it, a typical disposal method.[cxxxiv]

Alternative fuel (non-hydrogen)

- Criteria air pollutants from biomass, including volatile organic compounds, NO_x, SO_x, CO, and PM, can lead to public health issues. The danger of carbonaceous aerosols, the primary chemicals composing PM 2.5, to human health is not well known.[cxxxv] Additional steps should be taken to mitigate and monitor emissions.
- Biomass as an alternative fuel has significant land and water use implications. Opponents argue that biomass can displace food crops.[cxxxvi]
- Waste-as-fuel can reduce pollution and contamination from landfills and decrease land use by reducing disposal in landfills.[cxxxvii] However, it can also introduce and concentrate potentially toxic air pollution at a new point source. Different wastes and uses or conversions will have varying environmental impacts and pollution, depending, for instance, if the waste stream includes toxic elements.[cxxxviii]
- Alternative fuels soluble in water decrease the risk of fire and explosions, while other fuels may increase these risks. Proper worker training and emergency response systems are needed to minimize these risks.[cxxxxix]

The discussion below presents a high-level overview of the EEJ considerations related to CCS and hydrogen described in the Pathways to Commercial Liftoff reports on Carbon Management and Clean Hydrogen.

Carbon capture and sequestration and reformation-based hydrogen

- In certain applications, point-source carbon capture can reduce emissions of criteria air pollutants, such as SO_x, NO_x, PM, and hazardous air pollutants, such as mercury and hydrogen chloride, relative to non-CCS operations. These benefits may occur as a result of engineering necessity or as a result of major modifications that may trigger the New Source Review for National Ambient Air Quality Standards for criteria pollutants.[cxli]
- Some compounds associated with the capture unit (e.g., aerosols such as nitrosamines from solvent-based capture systems) can add new pollutants to a site. Pollution monitoring and control mechanisms for these pollutants are currently standard operating procedure for CCUS facilities employing these capture technologies.[cxlii]
- The energy needed to operate the capture unit can introduce additional energy demand and, depending on the energy source, associated pollutants at the capture point and over the feedstock supply chain. Pollution control equipment could mitigate these risks.

Hydrogen

- Because of the multiple pathways to produce, distribute, and use hydrogen, the type and magnitude of benefits and harms—and who experiences them—varies significantly by project, making it critical to assess impacts on a project-by-project basis.
- Hydrogen combustion emits NO_x, which can impair lung growth in children, harm cardiovascular function, and lead to higher rates of ER visits and premature death.[cxliii] Reducing NO_x emissions requires improving pollution control technology and/or lowering flame temperatures. Flame

temperatures can be reduced by supplying lower volumes of hydrogen—and more fossil fuels—to the burner, de-rating the engine—causing efficiency losses and power decreases or changing burner design by using more novel burners that are less understood by industry.[cxliv] In hydrogen fuel cells, the only products are electricity, water, and heat. Therefore, fuel cells eliminate air pollutants relative to fossil-based processes (e.g., internal combustion engines, natural gas peaker plants without CCS).

Section 3f: International and trade dynamics

The U.S. chemicals & refining industry exported $481B in products in 2022. Chemicals and associated products comprised 12% of all U.S. exports, as did refined petroleum products.[61] The chemicals industry's largest exports include pharmaceutical products, organic chemicals, and cosmetics. The refined products industry's largest exports are refined petroleum liquids, liquefied natural gas, and propane. U.S. exporters have remained competitive in these global markets partly because of their access to abundant feedstocks from domestic oil and gas production and their high degree of technical sophistication.

Decarbonizing these trade-exposed industries also presents challenges for international competitiveness. If U.S. producers incur decarbonization costs that are not otherwise offset, domestic industries' production costs could rise relative to global competitors in countries without analogous decarbonization costs. This divergence could cause U.S. producers to lose market share, domestically and internationally, to global competitors. Even after accounting for U.S. emission reductions, global emissions could increase if global competitors have higher carbon intensities in their production processes than U.S. producers. In addition, U.S. producers might relocate to countries with less stringent policies and ship their products to the U.S. market. These challenges in attempting to reduce emissions from trade-exposed industries are often called "leakage" because domestic emission reductions are offset by emissions that "leak" to other countries through increased production by global competitors and relocation of current domestic producers.

There are several possible strategies to mitigate the effects of decarbonization costs on international competitiveness in producing chemicals, refined products, and other trade-exposed industries. One well-known approach is a carbon border adjustment mechanism (CBAM), which imposes tariffs on imported products with higher carbon intensity and lower regulatory compliance burdens than domestic products. CBAMs aim to eliminate the competitiveness impact of domestic decarbonization policies and encourage other countries to establish similar policies. The European Union's CBAM will begin a transitional phase (for preparation and information-gathering) on October 1, 2023, with actual tariffs beginning in 2026.[cxlv] The EU CBAM is projected to impose tariffs totaling roughly $630M annually on U.S.-produced fertilizer and raw chemicals.[62,cxlvi] The Biden-Harris Administration has considered a CBAM as well.[cxlvii] If the United States were to establish decarbonization policies for chemicals, refineries, and other industries, U.S. exports might not be subject to tariffs from the EU or other jurisdictions with CBAMs.

61 U.S. Census Bureau data via Trade Data Monitor. For these two data points, "chemicals and associated products" are goods categorized in Harmonized Tariff System (HTS) chapters 28-38, while "refined petroleum products" are goods in HTS subheadings 2710 to 2715.

62 Charge calculated based on expected CBAM charge of ~$100/ton CO2 and embodied emissions of sector end products.

Chapter 4: Challenges and solutions to decarbonization

Key takeaways

Section 4a: Challenges to decarbonization

- Contributing ~11% of U.S. energy-related emissions and ~38% of energy-related industrial emissions, decarbonizing chemicals & refining production is critical to achieving U.S. net-zero goals. Over 90% of emissions in chemicals & refining could be abated with relatively high technology readiness measures.[63] However, there are seven main challenges to deploying these technologies at the necessary scale and cost (see Figure 22):

  1. **Operational challenges:** Adapting or upgrading facilities requires alignment with asset downtime, changes to engineering, daily operations, and business models, which can slow or prevent implementation, even when they offer attractive returns.
  2. **Unattractive economics:** 70% of emissions require abatement with measures that do not pass company hurdle rates of 10%+ today and will require additional revenue sources or cost-downs.
  3. **Low technology readiness:** Outside of deployable technologies included in the pathway in Chapter 3, several emerging technologies could meaningfully change the decarbonization pathway for chemicals & refining beyond 2030. However, these technologies are nascent and must be further demonstrated.
  4. **Capital formation challenges:** Even financing technology upgrades and retrofits that are technologically scaled and economically viable, a ~$90–120B opportunity in chemicals & refining can be challenging due to misalignment between short-term company goals of sustaining current assets and long-term benefits of decarbonized assets.
  5. **Nascent ecosystem of value chain partners:** Measures including clean hydrogen, CCS, and on-site renewables require extensive coordination of established and emerging companies across the value chain. These companies also face supply chain and human capital constraints, adding complexity to this coordination, which will likely increase as energy transition technology deployment expands.
  6. **Lack of enabling infrastructure and challenges with permitting:** Most pathways to net zero for chemicals & refining include clean hydrogen and CCS as key decarbonization measures, requiring extensive infrastructure that does not yet exist at the scale needed in the U.S. and which has lengthy permitting timelines to develop.
  7. **Social/community acceptance:** Community opposition can result in increased costs to developers due to both lost productivity and time spent engaging with the community to solve the conflict, possibly a result of developers conducting limited community engagement.

Section 4b: Solutions required for a net-zero pathway

- Seven types of interventions could drive meaningful progress toward net zero in downstream chemicals production and refining.

  1. **Integrate long-term capital planning into decarbonization operation plans early** to reduce the operational challenges currently hindering chemicals & refining assets from decarbonizing.
  2. **Close the persistent revenue gap between incumbent and decarbonized technology**, via sustained price premiums for decarbonized products, modest cost-downs from scale and learning curves, and market or policy interventions.

63 In line with the Administration's Long-Term Strategy for Net-Zero.

3. **Increase funding for low TRL 'breakthrough' technologies that could fundamentally change the path to net zero**. This could include (i) targeted investment in capital-intensive but low-operating-cost technologies that could dramatically reduce cost through deployment, (ii) buyer's clubs to reduce costs, and (ii) reducing the cost of capital.
4. **Increase funding for asset decarbonization** through green bonds for asset decarbonization and creative joint venture (JV) structures between asset owners and private equity. This dual approach could help realize the ~$90–120B opportunity for value accretive decarbonization measures by 2030.
5. **Develop a strong ecosystem to share learnings, promote scale, and minimize cost.** Most decarbonization measures require coordination throughout full value chains that are still developing and learning to collaborate. Organizing and strengthening the ecosystem to improve coordination, speed the development of enabling infrastructure, and support at-risk supply chains can address several challenges to decarbonization.
6. **Removing infrastructure bottlenecks**, especially in permitting. This could include collaboration between organizations to develop a resilient supply chain and develop key needed infrastructure, such as pipelines
7. **Implement robust community benefit plans and agreements** which respond to labor and community concerns and mitigate potential harms. Community Benefit Agreement negotiations are avenues for developers to engage with communities to understand how their project can meet with their goals while ensuring that community needs are met. DOE's "Community Benefit Plans" are a requirement for applicants to most BIL/IRA funding to develop plans to engage with their communities on Justice40, DEIA, Good Jobs, and workforce and community agreements.

Section 4a: Challenges to decarbonization

Deeply decarbonizing downstream chemicals & refining production is critical to achieving U.S. net-zero goals and requires a holistic and concerted effort to overcome significant challenges. While this pathway is achievable, it requires an immediate and significantly accelerated implementation of decarbonization measures that are already economic. It also requires structural changes in technology, policy, and market incentives to close persistent cost/performance gaps that prevent investment in the long tail of critical decarbonization levers.[64] Over 90% of emissions in chemicals & refining could be abated with relatively high-technology-readiness measures. However, there are seven main challenges to deploying these technologies at the scale and cost necessary.

Seven key structural challenges must be addressed to accelerate operational decarbonization:

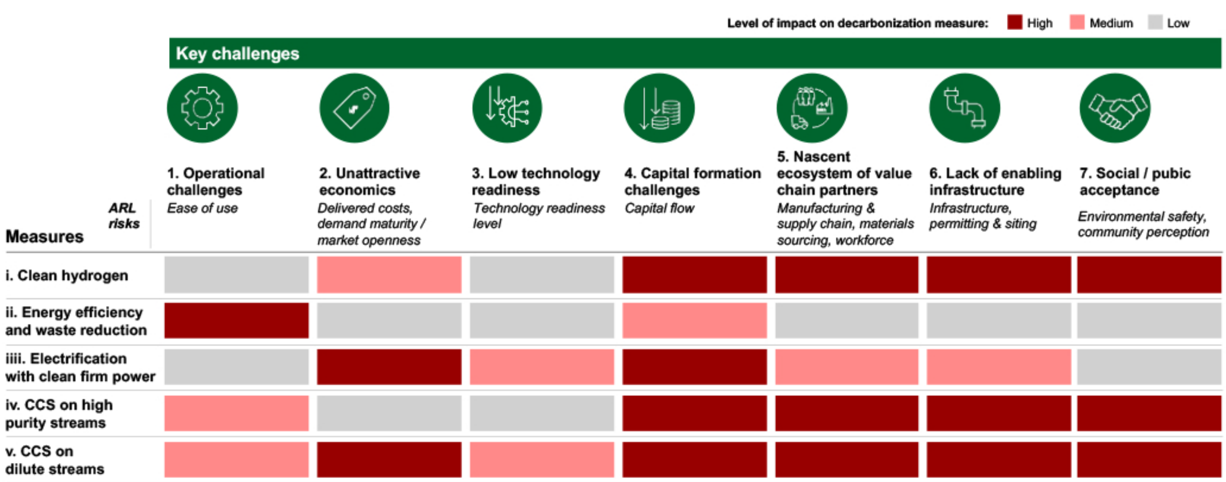


Figure 22: Seven key challenges to scaling the measures needed to decarbonization chemicals & refining

64 In line with Administration's Long-Term Strategy for Net-Zero.

1. **Operational challenges:** Most operating plants were built before the 1980s, and major capital upgrades in the chemicals & refining sectors usually happen every 1–5 years, depending on the asset.[cxlviii] Many of these assets operate 24/7, and taking any one component offline can mean downtime for the entire operational unit. This downtime has cost and output implications. Companies indicate that implementing efficiency measures in a refinery could increase planned downtime from 10–50%, costing the operators millions in lost revenue. Adapting or upgrading facilities necessitates changes to engineering, daily operations, and even business models, which can slow or prevent the implementation, even when they offer attractive returns. However, failure to make retrofits during a once or twice-in-a-decade window could risk missing the opportunity to decarbonize critical assets before 2030.

   - **Steam crackers:** Emissions from a typical cracking furnace can be >50% of emissions in ethylene production, driven by the high heat requirements. Typical steam crackers are optimized to maximize output chemicals and recycle all waste byproducts. Often a furnace will recycle some byproducts as fuel gas. If operational decarbonization measures change fuel usage, facilities must rebalance system operations and find new uses for the fuel gas.

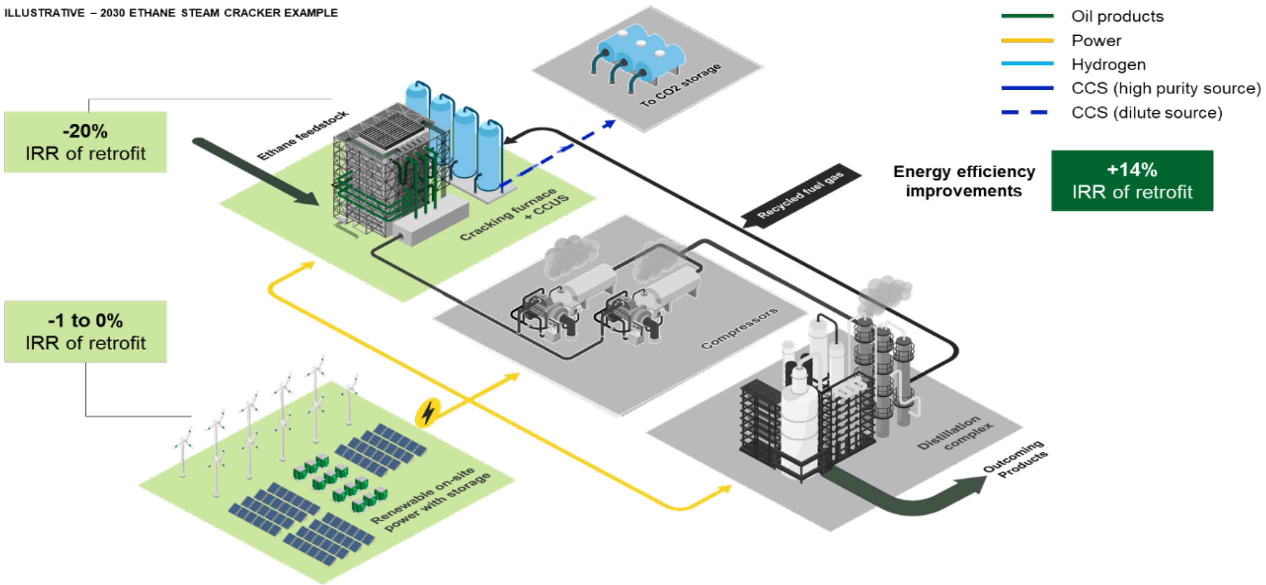


Figure 23: Simplified view of measures that could be used to decarbonize a steam cracker

- **Refineries:** The largest sources of emissions in refineries are fluid catalytic crackers, steam methane reformers (for hydrogen production), power (onsite and offsite), naphtha upgrading units, and hydrotreating and hydrocracking units.

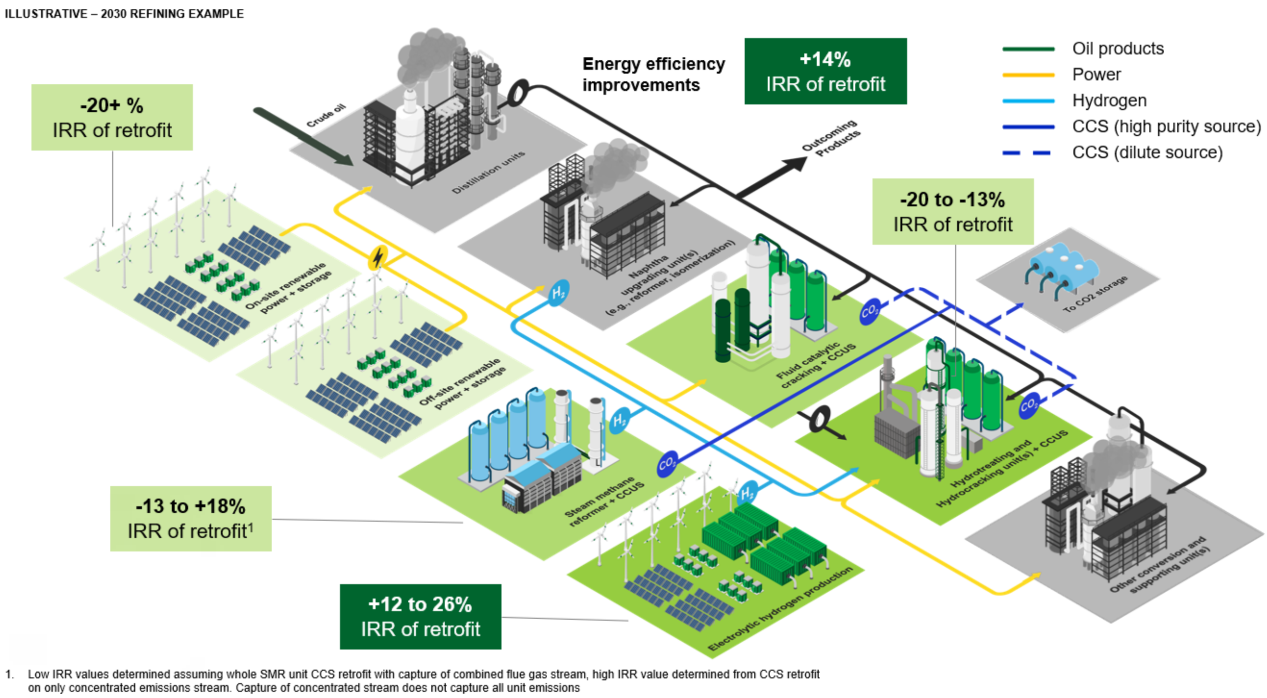


Figure 24: Simplified view of measures that could be used to decarbonize a refinery

2. **Unattractive economics:** Companies only invest in decarbonization measures if they see a ~10–25% ROIC for capital projects, depending on risk adjustment.[cxlix] In the current policy environment, only 30% of emissions can be abated with levers that meet this threshold, after transport and grid decarbonization effects are factored in. In many cases, there is a persistent opex gap between the incumbent technology and the decarbonization technology—see Section 4b, which explains what it would take to improve the economics for these measures.

   Phase 1: Near-term (today–2030): As referenced earlier in the MACC analysis, the only >10% IRR decarbonization measures during Phase 1 include energy efficiency upgrades, switching to low-carbon hydrogen feedstocks in ammonia and refining, CCS on concentrated streams, and electrification of natural gas compressors. Even with IRA incentives, most technologies available today are not economically viable. Many electrification options (e.g., renewable power for ammonia and other chemicals processing; renewable power for electric boilers in chloralkali and ethylene heating; integrating LDES) are under \$100/tCO2. However, the operational and downtime costs of upgrading systems make these hurdles more challenging to overcome. Many CCS options are ~\$100/tCO2. The solutions to address some of the highest emitting assets, such as refining and ethylene steam crackers, are well over \$100/tCO2, making the investment case nearly impossible today.

   Phase 2: Medium-term (2030–2040): As IRA credits expire in the early 2030s, the economics for many decarbonization levers become even more challenging. To stay on track to meet the Administration's long-term strategy to reach net zero, the infrastructure for clean hydrogen and CCS must be scaled and become cost competitive by the 2030s.

   Phase 3: Long-term (2040–2050): Looking to 2050, the economics are positive for very few options. Only ~20% of remaining emissions in 2050 will be economic to abate even with assumed learning rates and after accounting for decarbonizing grid and transport. No clean hydrogen or CCS options meet a >10% IRR hurdle. The only real remaining positive IRR option is the electrification of natural gas processors. With chemicals production expected to grow 12% by 2030 and 35% by 2050, companies must think beyond immediate economics. [cl] Planning in decarbonization from the beginning could reduce capex cost for greenfield builds by 10–20% vs. retrofit of existing facilities and is essential to future-proofing long-duration assets.[65] Chemicals producers operating globally cite that they must invest in decarbonization for growth as a primary driver of their decarbonization targets (e.g., retain the ability to sell in geographies with a carbon tax).[cli]

This business case could be improved via better technology performance, higher revenues, market changes, or regulatory incentives. In uncertain economics, companies implement solutions with a positive business case while leaving other emissions unabated. Figure 25, below, shows anticipated returns for decarbonization investments across chemicals & refining. Key takeaways include:

- **IRA sunset creates uncertainty:** ~30% of emissions that remain after accounting for decarbonizing grid and transport could be abated by measures with a positive investment case by 2030.[66] After the sunset of incentives included in the IRA, economics worsen. Only ~20% of remaining emissions in 2050 will be economic to abate, even with assumed learning rates and after accounting for decarbonizing grid and transport.
- **Clean power approaches positive economics by 2050, but the technology cost hurdle is high.** Measures like clean high-capacity firm power approach a positive IRR threshold (Figure 25) but will require widespread transmission build-out and 40–60% cost down on LDES and clean electricity capex. See the LDES Liftoff report for additional detail on how LDES technologies could reach commercial scale.
- **Some measures, like electrifying heating with clean high-capacity firm power, are unlikely to approach BAU corporate hurdle rates, even by 2050, without accelerated cost down or increased demand side premiums:** Power cost must be at ~$10–15/MWh, including the cost of transmission and long duration heat storage.[67] More likely, a decarbonization premium, either in the form of carbon regulation or increased willingness-to-pay for decarbonized products, would be needed to justify investment in low- and medium-temperature heat electrification. Premiums exist today at a small scale for some recycled and bio-based products but haven't been widely observed for fully decarbonized products.[68, clii]

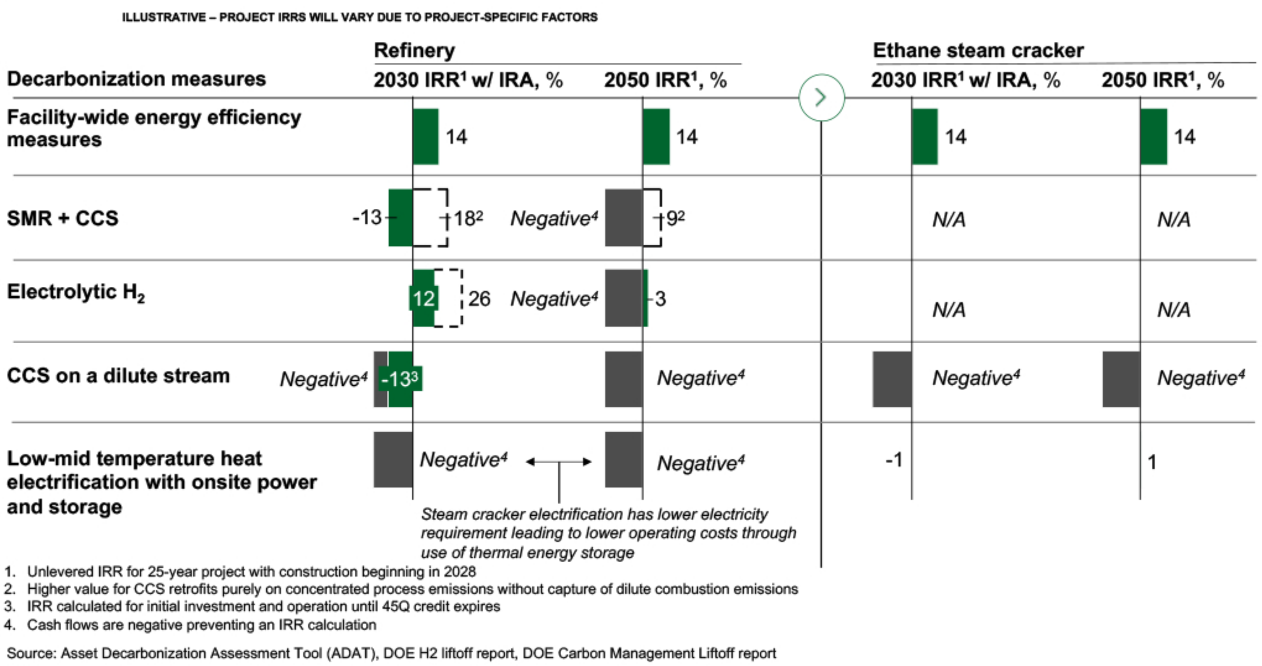


Figure 25: Illustrative project returns for select decarbonization measures

65 Based on retrofit cost factors from DOE Carbon Management Liftoff Report, which models expected additional capex costs for retrofit installation.

66 Economic viability is considered to mean the potential for a 10% IRR-positive business case.

67 Assuming natural gas prices ~$3-5/MMBTU.

68 CMA for recycled versus virgin HDPE prices, S&P Global Platts for 2022-2023 indicative bio-based naphtha price range (x2 virgin naphtha).

3. **Low technology and/or adoption readiness:** Several emerging technologies could meaningfully change the decarbonization pathway for chemicals & refining beyond 2030, as discussed in Chapter 3. Some require additional RDD&D (e.g., catalytic steam cracking, modular nuclear), and some are based on existing technologies and must be proven at scale (e.g., e-methanol/MTO, power-to-liquids). To achieve the learning curves and proof points from scale, technologies must go through replicable deployment, which requires significant capital—both challenging for decarbonization technologies in chemicals & refining. Referred to as Adoption Readiness Level (ARL), adoption risk often comes from unaddressed ecosystem economics and critical players that have not yet come on board. The layout and production mix of chemicals & refining facilities varies widely. This makes it difficult to achieve learnings through replicable deployment as the decarbonization technology may require a bespoke set-up based on the needs of an individual facility. Details of the ARL barriers for certain technologies relevant to the chemicals & refining sectors can be found in the appendix. Lower-TRL technologies that could close significant decarbonization gaps post-2030 are discussed in greater detail in the Solutions section below.

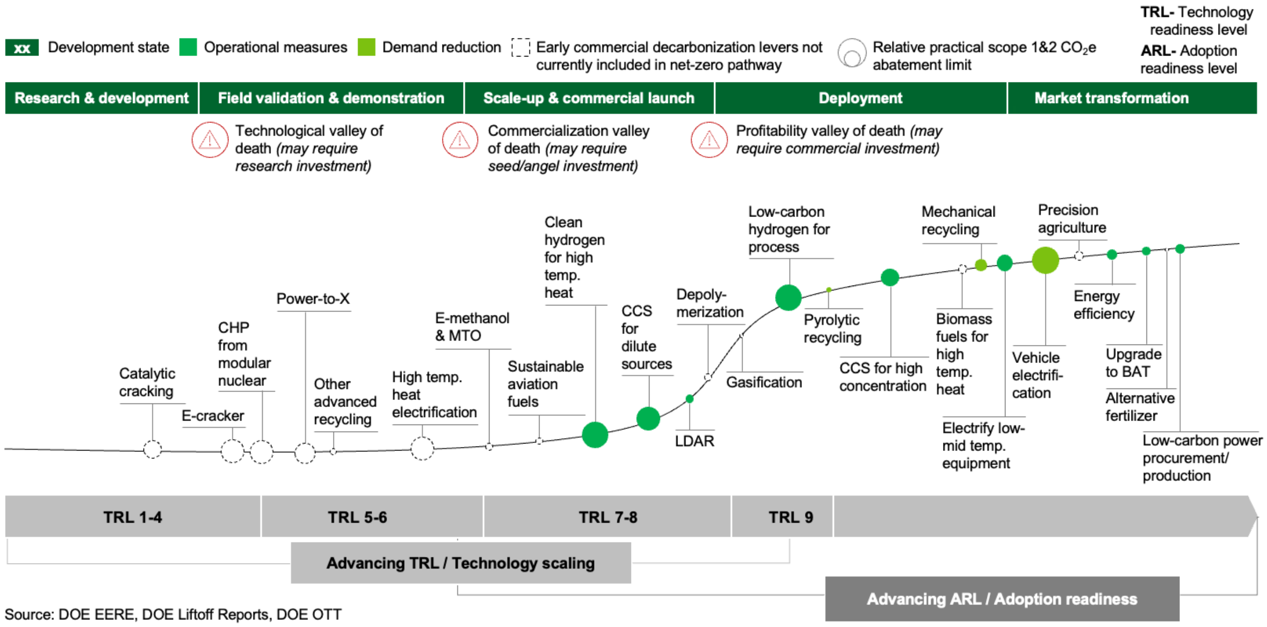


Figure 26: Nascent technologies struggle to access venture and private equity financing based on technology risk and capital requirements

4. **Capital formation challenges:** Even financing technology upgrades and retrofits that are technologically scaled and economically viable can be challenging. These investments often have three-to-five-year lead times to implement and may outdate a typical CEO tenure or earnings cycle. When companies are capital constrained, they are often hesitant to fund large efforts off their balance sheets. Many find the best return on investment (ROI) is to spend sustaining capex to keep existing assets running rather than investing in new growth or decarbonization assets**.** Increased funding for asset decarbonization through creative joint venture (JV) structures and external sources of capital (e.g., private equity, green bonds) could help realize the ~$90–120B opportunity for value accretive decarbonization measures by 2030 and beyond. Additionally, the total investment needed to fully decarbonize the chemicals & refining sectors along this pathway accounts for ~$600–900B, which accounts for ~60–85% of the capital needed for decarbonizing industrial sectors.

   Accessing the capital needed for deployment is also difficult due to project scale, which can require millions of dollars invested for a single demonstration plant. Addressing the capital formation challenges will require different types of investors with varying risk-return profiles.

- **Early demonstration capital:** It is often difficult for demonstration-stage technologies to access venture and growth private equity financing. This is because of a mismatch between the risk appetite and typical funding ticket size of the capital intensity of first-of-a-kind projects (e.g., next-generation nuclear/modular nuclear pilots can be hundreds of millions of dollars). Most venture investors are interested in smaller ticket sizes and have investment timelines of a few years. While they may not be the ideal partners for billion-dollar demonstration projects, they are essential for investing in the lower TRL ideas today, which will be necessary for the industry to meet net zero by 2050.

- **Commercialization/scale-up capital:** Early commercial technologies require heavy investment for deployment to access economies of scale in manufacturing and sourcing, as well as access to lower cost capital to compete with incumbent energy technologies. For example, hydrogen electrolyzer costs are projected to drop 60–80% by 2030 but will require ~$90—120B in deployments globally to work down their learning curves. The U.S. has invested in hydrogen through the IRA, enabling hydrogen capex and financing costs to drop.[cliii] However, other technologies (e.g., e-methanol/MTO) may not have sufficient supports to pay the "learning investment." This type of capital is well positioned to invest alongside corporates, who can provide de-risking mechanisms such as offtake agreements and purchase guarantees. However, without many proven examples, this type of capital is typically expensive and traditional investors can be challenging to secure.

- **Long-term debt capital:** Market participants such as banks or large institutional investors are a key segment of the capital markets to unlock. Many of the types of projects needed to help chemicals & refining plants decarbonize are large-scale infrastructure investments. Until long-term debt providers are more actively engaged in these opportunities, it is difficult to see how multi-million-dollar projects get financed at the scale required. Projects must be significantly de-risked to unlock this type of capital.

Establishing new partnership structures and/or leveraging market structures not traditionally used for cleantech investing will be important to drive the needed investment in this space. Without creative thinking behind capital formation, it will be challenging for the chemicals & refining industries to finance the projects necessary to decarbonize.

5. **Nascent ecosystem of value chain partners:** Several decarbonization levers, such as clean hydrogen, CCS, and on-site renewables, require extensive coordination of established and emerging companies across the value chain. For example, to implement CCS on an ethylene cracker, a chemicals producer must collaborate with a carbon capture equipment provider (possibly a startup), an engineering, procurement, and construction (EPC) company, a midstream company handling CO2 transport, and a provider of CO2 storage. While some companies may be integrated, that is not always the case.

   Furthermore, partners across these value chain segments can struggle with a lack of human capital, supply chain constraints (Figure 28), and friction points in the collaboration process. For example, electrolytic hydrogen, LDES, and electrification measures face meaningful supply chain risks in sub-components or manufacturing and assembly, which could hamper their deployment. There are significant supply chain risks for electrolytic hydrogen, particularly around electrolyzer capacity (additional detail can be found in the Pathways to Commercial Liftoff: Clean Hydrogen report).[cliv] For LDES, the highest risks are in the manufacturing and assembly of inter-day storage, including compressed air and liquid air storage apparatuses (additional detail can be found in the Pathways to Commercial Liftoff: Long Duration Energy Storage report).[clv] These projected constraints are largely due to demand uncertainty, creating lower supply stock-up by manufacturers and risks to imports from regions with supply chain volatility.

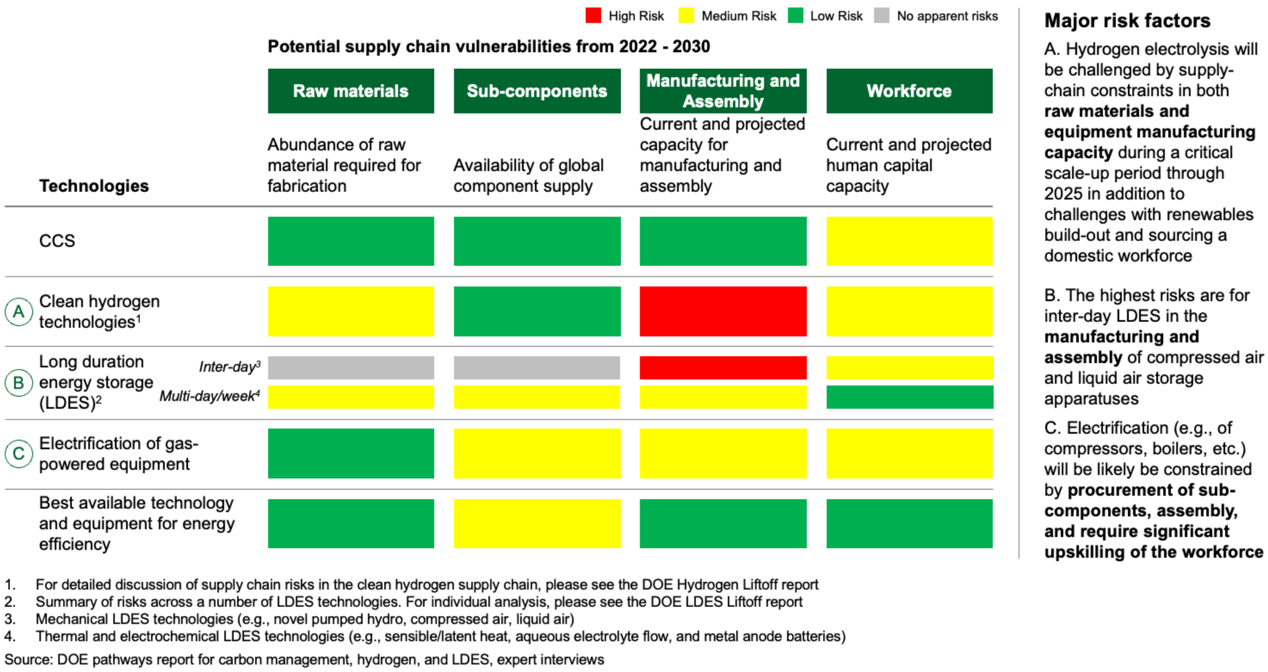
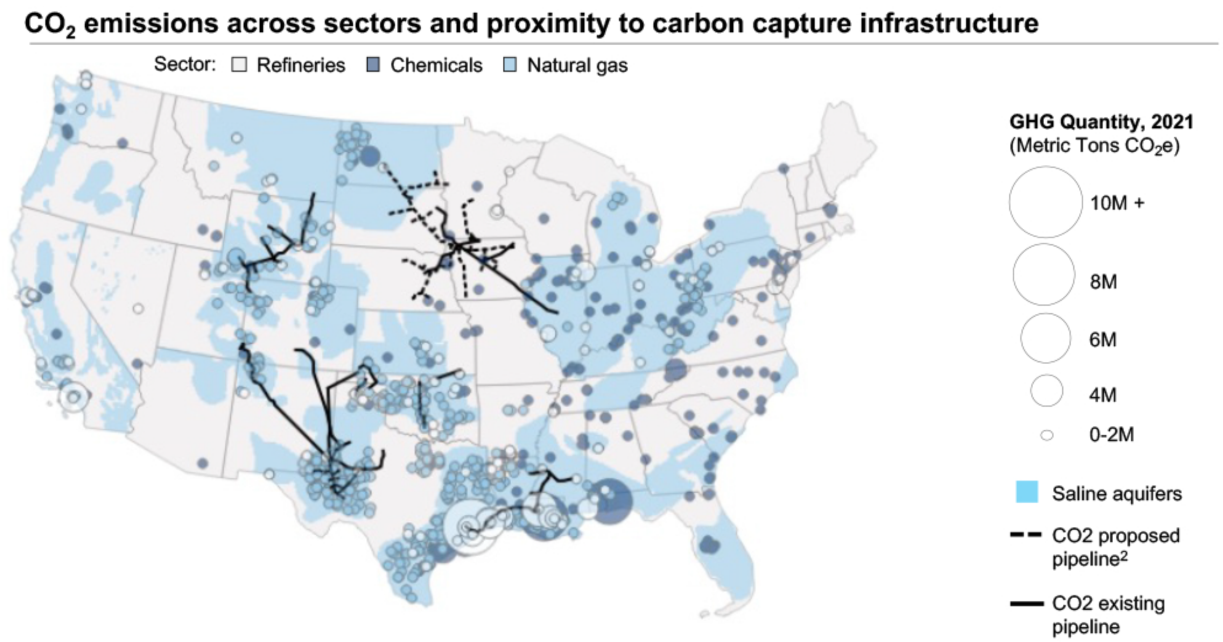


Figure 27: There are supply chain risks for measures including clean hydrogen, LDES, and electrification, particularly in the critical scale-up period through 2025

6. **Lack of enabling infrastructure and challenges with permitting:** Most pathways to net zero for chemicals & refining include clean hydrogen and CCS as key decarbonization measures. For the pathway laid out in this analysis, CCS is used to abate ~27% of emissions, while hydrogen is needed to abate ~9% of emissions in 2050. The economics and feasibility of the broad adoption of CCS and clean hydrogen significantly improve with large-scale shared infrastructure, like pipelines and storage. However, little infrastructure exists today, and build-out can be lengthy and challenging. For example, pipelines are typically sized to fit the projected amount of hydrogen or carbon they will carry rather than upsized to allow for projects that may come online in the future and could benefit from shared infrastructure. This need for assured demand inhibits optimized build-out of infrastructure. For pipelines, obtaining the right-of-way for the project can take months or even years. For long-term geologic storage of CO2, wells are permitted through the Underground Injection Control Program's (UIC) Class VI requirements administered by the EPA or delegated to states. The UIC program is designed to ensure that injected CO2 does not impact underground drinking water sources or otherwise impact human health and the environment.[69,clvi] EPA has approved six Class VI wells so far—two wells are in operation. The first four Class VI permits issued took less than two years. The two wells that are currently operating took between three and six years. The EPA has stated that it anticipates permits will be issued in approximately two years.[clvii]

   The geographic proximity of emissions to existing and potential infrastructure can further complicate the picture. However, the chemicals and refining industries are better co-located than other industries. CCS has a concentration of chemicals & refining assets and associated emissions on the Gulf Coast, where they have access to nearby storage. Yet still ~5% of chemicals & refining emissions sites are more than 50 miles from existing CO2 pipelines or potential sequestration facilities (Figure 28). Implementing CCS at facilities without existing infrastructure or access to sequestration sites is even more costly and challenging.

69 It includes requirements for site characterization, well construction, operation, monitoring, financial responsibility (including during post-injection care), and reporting / record-keeping.



Note: Sectors on this map include refineries, chemicals, and natural gas processing. Emissions in the EPA FLIGHT database are self-reported and only emitters over a threshold size of emissions are required to report

Sources: 2021 EPA GHGRP FLIGHT database; Summit, Navigator, ADM, and Tallgrass CO2 pipeline project websites; NatCARB Atlas V Database; Emissions from EPA FLIGHT database, DOE Industrial Decarbonization Roadmap, and McCoy et. al (2016) for Ethanol, Sagues Et. al (2020) for Pulp and Paper

Figure 28: Many chemicals & refining emissions are near potential sequestration sites and/or existing CO2 pipelines. However, ~5% of emissions are located >50 miles from potential storage sites.

7. **Social and public acceptance concerns:** In many cases there is inconsistent public acceptance and community perception with decarbonization levers for these sectors due to environmental and human health risks, environmental justice and labor concerns. Local communities often have concerns regarding pollution that make them wary of any chemical or refining developments located within proximity of their homes. **Community opposition can result in increased costs to developers due to both lost productivity and time spent engaging with the community to solve the conflict, possibly a result of developers conducting limited community engagement**.[clviii] Lack of community buy-in to a project can also stymie projects to the point that they are no longer feasible to develop. Public push back to industrial decarbonization projects is more prominent with CCS and hydrogen levers, as communities are more likely to oppose projects which could require large amounts of new infrastructure, are perceived to allow the continued use of fossil fuels and could possibly introduce increased amounts of new pollutants unique to decarbonization levers.

Section 4b. Solutions required for a net-zero pathway

Seven types of interventions could address the barriers outlined above and drive meaningful progress toward net zero in the downstream production of chemicals & refining:

1. integrate long-term capital planning for decarbonization into company operations,
2. close the persistent price gap between incumbent and decarbonized technology,
3. improve technology cost/performance to increase funding and accelerate nascent technologies,
4. increasing the availability of financial tools for asset decarbonization,
5. develop a strong ecosystem to share learnings, and
6. clear the pathway to infrastructure deployment, including CCS transport and storage, hydrogen midstream infrastructure, and expanded renewables and grid capacity

7. Design and implement robust community benefits plans and agreements which respond to community concerns and mitigate potential harms.

Near-term actions must be rapidly taken across these seven solution spaces to address the meaningful challenges outlined above. These solutions require coordination and commitment from both private and public sector stakeholders.

Challenges: Operational challenges | Capital formation challenges | Unattractive economics | Lack of enabling infrastructure | Nascent ecosystem of value chain partners | Low technology readiness | Social/public acceptance

Solution area	Example actions	Challenges addressed
1. Integrate long-term capital planning into decarbonization operation plans early	• Develop funds specifically targeted at transition finance • Incentivize incumbents to build green business units	
2. Close the persistent economic cost gap between incumbent and decarbonized technology	• Develop an embodied carbon tracking standard and label products with a carbon intensity score • Promote buyer-side consortiums and commitments to generate demand and premia for decarbonized goods	
3. Improve technology cost/performance to increase funding and accelerate nascent technologies	• Increase investment in capital intense, but low operating cost technologies that could dramatically reduce in cost through deployment • Set up buyers' clubs to purchase common components for startups pursuing nascent technologies	
4. Increased usage of nascent technologies is needed to prove technology readiness and recognize cost declines from learning	• Focus on deploying technology that have clear pathway to seeing significant cost reduction • Increase availability of financial mechanisms to expand funding for asset decarbonization	
5. Develop a strong ecosystem to share learnings, promote scale, and minimize cost	• Convene value chain members to share learnings and develop best practices for ecosystem collaboration • Develop advanced market commitments to facilitate build-out of shared infrastructure for CCS and clean hydrogen	
6. Removing infrastructure bottlenecks, especially in permitting	• Developing resilient supply chains with industry participation to avoid supply chain constraints that could slow technology adoption	
7. Implement robust community benefit plans and agreements	• Develop community benefit plans as an avenue for developers to engage with communities to understand how project goals and community needs can both be achieved	

Figure 29: Seven types of solution areas could address key barriers to deploying decarbonization measures in chemicals & refining.

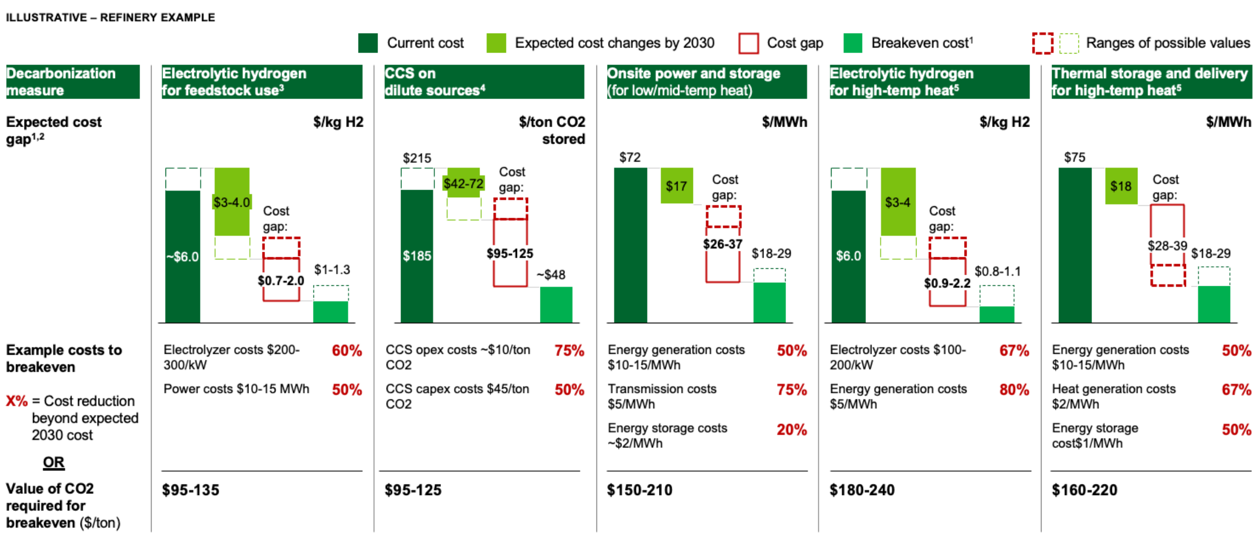
1. **Integrate long-term capital planning into decarbonization operation plans early.** Major capital upgrades in the chemicals & refining sectors usually happen every 1–5 years, depending on the asset. Decarbonization upgrades must be scheduled and budgeted years in advance. Many of these assets operate 24/7, and taking any one component offline can mean downtime for the entire operational unit. This downtime has cost and output implications.

   The Department of Energy's Office of Clean Energy Demonstrations and other agency efforts are focused on accelerating deep decarbonization projects for industrial processes. The recent $6B funding opportunity announcement aims to test and scale technology demonstrations that can address emissions in the near term. A key deliverable to these demonstration projects will be to streamline the process for integration, ideally reducing the time it takes for a company to upgrade an asset and limiting cost and output implications.

   Advanced planning and the possibility for streamlined implementation can reduce the operational challenges currently hindering chemicals & refining assets from decarbonizing.

2. **Close the persistent revenue gap between incumbent technology and decarbonized technology via:**

2a. Market or policy interventions: Potential policy interventions could include a carbon tax or revenue boost. In the downstream chemicals production and refining net-zero pathway presented in Chapter 3 (Figure 8), ~80% of emissions are uneconomic to abate in 2050 after the effects of grid and transport decarbonization are considered. While moderate cost reductions are expected and included in the analysis, these are not sufficient to be competitive with carbon-intensive processes (Figure 30). For example, electrification with clean high-capacity firm power for medium and low heating requirements is likely to always be more expensive than heat produced from natural gas combustion at $5–8 per MMBtu in existing furnaces. It would require the levelized cost of clean high-capacity firm power to decrease 70–80% from 2030, reaching $10–15/MWh power, $5/MWh transmission, and $5–10/MWh storage. With policy support from the IRA expected to expire by 2033, levers like clean hydrogen are also unlikely to be competitive on price (below $1/kg), and CCS will remain a net operating cost.



1. Reduction in cost required to be cost-competitive alternative to conventional technology. Electrolytic H2 for feedstock is compared to what would be required to breakeven (before 45V) with traditional unabated H2 costs (breakeven column is the cost of unabated H2). CCS will always add additional cost and therefore is compared to the cost for breakeven with 45Q incentives (breakeven column is $85/ton CO2 for 12 years of 45Q spread across the life of the project). Heat electrification is compared to the cost to breakeven with the current cost of electricity (breakeven column is cost of electricity). Electrolytic H2 for high-temp heat compared to the cost to breakeven with natural gas costs (breakeven column is cost of natural gas)
2. Based on 2030 and 2050 MACC analysis and published DOE liftoff reports
3. Cost of firm power from renewables with $25/ MWh of power generation, $70/ MWh of storage, and $15/ MWh of T&D
4. Breakeven cost for asset with access to IRA incentives for 45Q ($85/ton CO2 for 12 years amortized over 25 year life of project at 10% WACC). Displayed cost estimates based on EFI Foundation capture costs with transport (GCCSI, 2019) and storage (BNEF, 2022) costs of ~$10-40/t. All in 2022 dollars. All CCS figures represent retrofits, not new-build facilities. The lower bound costs represents a NOAK plant in a low cost retrofit scenario with low inflation. The higher bound costs represents a FOAK plant in a high cost retrofit scenario with high inflation. The inflation variance on each cost estimate represents the range of cost increases on a generic chemical processing facility due to inflation from 2018 using the Chemical Engineering Plant Cost Index (CEPCI).
5. Excluded from MACC analysis due to lack of cost competitiveness (hydrogen for high-temp heat) or technology nascency (storage for high-temp heat)

Figure 30: What is needed to bridge the gap to a positive business case for decarbonization measures that are uneconomic after the sunset of IRA incentives.

2b. Activate sustained price premiums for decarbonized products. Beyond extending existing policy, one solution is implementing demand-side measures to activate widespread willingness to pay a premium for decarbonized products in the market. These demand-side measures have generated early premia for circular and biobased products. Key actions that could cultivate a higher willingness to pay include:

- **Developing an embodied carbon tracking standard and labeling products with a carbon intensity score to account for their life cycle carbon impact.** No industry standard accounts for a product's life cycle carbon intensity (CI). This is particularly difficult in chemicals & refining production, where multiple types of products are produced through the same processes, requiring an allocation of emissions. Chemicals products, like plastics, face an additional accounting complexity as end-of-life treatment (e.g., if the plastic is recycled, thrown in a landfill, or incinerated) significantly impacts life cycle emissions. Some producers have developed their own accounting methodology for individual products but include bespoke assumptions for the individual process. This prevents direct comparison of CI across products and leads to uncertainty from customers seeking low-carbon products. Developing a clear and standardized process to measure and publish the carbon intensity of products—or an Energy Star-like program for carbon—could stimulate demand and willingness to pay a premium from customers seeking auditable ways to abate their Scope 3 emissions.

Establishing this methodology for measuring the carbon intensity of chemicals & refining production would require three key steps. First, aligning on an industry-specific baseline for product-level carbon accounting, learning from successful examples like California's Low Carbon Fuel Standard. Second, developing a step-by-step process for measuring and attributing carbon to different product streams from the same process and assumed end-of-life treatment. Third, developing a certification process and mechanism for transparently labeling products. Once established, these standards could bring transparency on environmental impact to consumers, similar to the use of environmental product declaration benchmarks for concrete and steel.[clix,clx] This approach could apply to both chemicals and fuels produced through the decarbonized production of traditional chemicals & refining products—and, although not the focus of this report, new products (e.g., bio-based fuels/chemicals).

- **Promoting buyer-side consortiums and commitments to generate demand and premia for decarbonized goods.** For example, this could include convening a low-carbon buyers' club for consumer product goods (CPG) companies, with commitments from participants to pay a set premium for decarbonized products from partner companies. With enough committed offtake capacity, producers could count on a reliable value pool for decarbonizing their operations, which could justify the investment. The Sustainable Aviation Buyers Alliance (SABA), the First Movers Coalition, and Frontier are all examples of how buyer alliances can function and justify investment in decarbonization. Additionally, the bankable revenue stream from such commitments could enable producers to access financing at more attractive terms. This model could learn from the similar success of the Ellen MacArthur Foundation in spurring commitments and demand for recycled content, as seen in Figure 31, where both recycled polyethylene and bio-based naphtha see significant price differential.

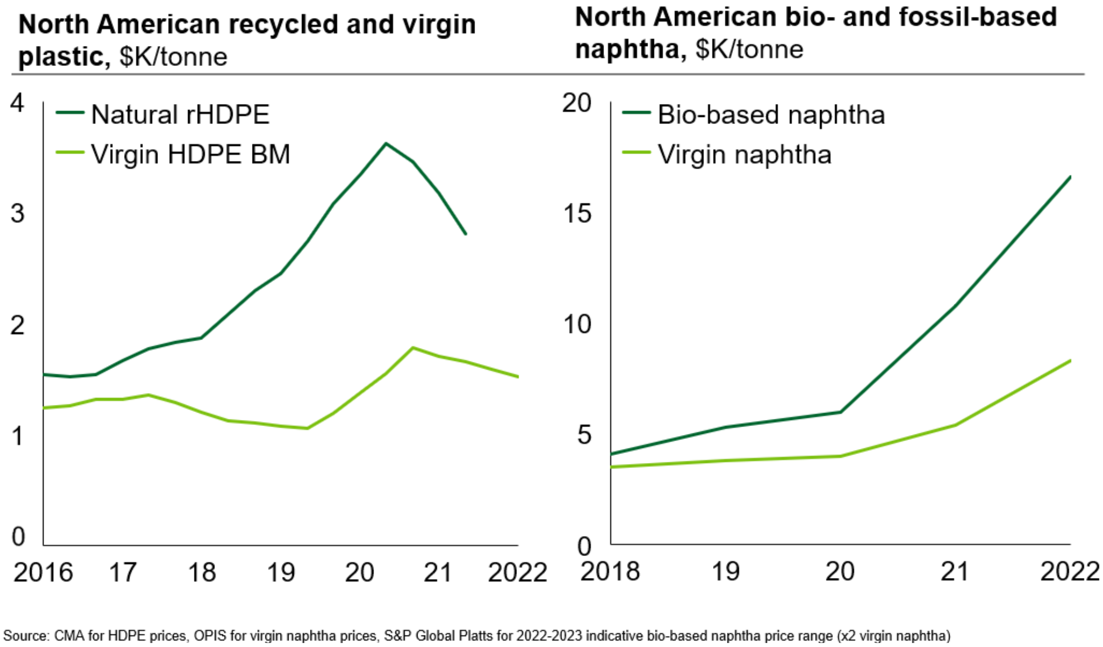


Figure 31: Price premium has been evidenced for select recycled and bio-based plastics on a small scale.

The Ellen MacArthur Foundation (EMF) fostered demand and willingness to pay for recycled content through marketing, customer education, and industry pressure for target setting. In 2009, EMF was launched to help address what MacArthur saw as an unsustainable and overuse of natural resources. EMF provided rigor behind the circular economy concept by quantifying the economic benefits in specific sectors and regions, and they gained buy-in by engaging consumer groups, business leaders, and other stakeholders. Key impacts of their work include:

- Aligned key stakeholders and ensured wide promotion of vision at the EMF's first CE100 summit in 2014 by gathering business leaders, innovators, governments, universities, and thought leaders
- Built momentum and secured commitments with a joint action plan from top responsible industries (e.g., 150+ companies backed a ban on oxo-degradable plastics)
- Orchestrated complementary initiatives and reinforced impact through cross-value-chain demonstrator projects, regional action hubs, and pre-competitive partnerships
- Scaled impact through public-private collaborations and policy frameworks to address specific barriers and set clear standards

The actions of EMF since 2013 serve as a useful playbook for generating similar demand pull for decarbonized products, if paired with rigorous emissions measurement standards, product labeling, and a marketplace of invested buyers and sellers

Ellen MacArthur Foundation – Case Study

3. **Improve technology cost/performance to increase funding and accelerate nascent technologies.** Nascent technologies, such as those described in Chapter 3, are not projected to meaningfully contribute to decarbonization over the near term but could play a critical role by 2050. Technologies like catalytic steam cracking, power-to-liquid fuels, e-methanol to olefins, novel carbon utilization, and modular nuclear could become major contributors to decarbonization by 2050 if they are commercialized and cost-competitive.

   Paving a pathway to cost parity would require further R&D funding and rapid deployment of demonstration-stage projects. Taken together, these solutions would bolster market confidence in lower-TRL technologies and could accelerate early-stage equity finance for the solutions listed below.

   High marginal costs are the Achilles heel for many technologies on the chemicals & refining decarbonization path, including some hydrogen, heat electrification, and amine-based carbon capture of dilute streams. These technologies could see some cost declines over time, but current analysis suggests these decreases are unlikely to reduce costs to the degree needed to be competitive with carbon-intensive alternatives. **However, breakthrough technologies could see steeper learning curves over time and be more cost competitive with traditional alternatives, though these learning curves remain unproven.**

   Technologies that current analysis suggests are likely to see faster cost declines would have some of the following characteristics:

   - Active technological advancement from R&D to demonstration scales (including potential for new scientific breakthroughs and engineering breakthroughs)
   - Technologies with broad applications or many use cases that will allow for significant cumulative deployment experience
   - Pull from intrinsic market forces and policies that support near-term adoption

- Potential for technology to reduce cost by leveraging economies of scale (e.g., standardization, modularization, or manufacturing cost decline)
- Technologies that are de-coupled from carbon-intensive alternatives

Though none of these characteristics alone guarantee cost declines, the occurrence of several characteristics could raise the likelihood that technology could see steeper learning curves. **Lower-TRL technologies that have the potential to capture rapid cost declines and close significant decarbonization gaps post-2030 include:**

- **Small, modular nuclear facilities for heat and power:** Modular nuclear for combined heat and power (CHP) could replace fossil fuel sources, accounting for around 70% of chemicals & refining emissions. CHP from nuclear could substitute the need for electrification of heat and the CCS needed for dilute high-heat sources. One reactor class that adopts the existing nuclear fleet's heat and steam generation concepts can replace 30–40% of the low- and intermediate-pressure industrial steam duties and heated-oil transport loops (TRL 7-8). High-temperature gas-cooled reactors can readily generate steam qualities for the next 30% of steam duties, using a heat exchanger and transport equipment constructed from metallurgical materials developed for supercritical and ultra-supercritical steam CHP systems (TRL 7-9). To reach high-temperature heat duties of steam/hydrogen-carbon cracking and steam/catalyst regeneration (the next 10-15% of industrial heat duties), the application of vapor-compression (TRL 5-6) or electrical topping heating (TRL 8-9) will be required to raise the temperature of nuclear-supplied heat transport media. The heat-delivery technical benefits of advanced molten-salt and liquid-metal reactors fall between light water reactors and high-temperature gas reactors, with light water reactors having the highest commercial readiness followed by high temperature gas, liquid metal, and molten salt reactors. In all cases, the prevention of radioactive contamination of the industry processes, products, and plant operations is essential, requiring the design and testing of the heat exchangers that will transfer nuclear reactor heat to an isolated secondary heat transport loop (TRL 3-9, depending on the class of small modular reactor). Commercial technology readiness can accelerate through non-nuclear, reactor-to-process heat delivery testing and demonstration (see the Nuclear Liftoff report for more details). Nuclear industrial CHP systems may see rapid cost declines because 1) there are many applications across industrial use cases, 2) small reactors could be standardized and modularized to drive down manufacturing and installation costs, 3) there is active research into new nuclear technologies which could yield meaningful breakthroughs, and 4) there is high capacity vs. renewables.
- **Carbon utilization technologies:** Technological advancements could utilize up to 10% of anthropogenic CO2.[clxi] The key to unlocking this potential is advancing the electrochemical conversion technology of CO2 to value-add chemicals. R&D must advance the technology on the TRL scale to develop catalysis and reactors able to better tolerate impurities and drive selective reactions. There are also technological hurdles to increasing single-pass conversion and energy efficiency. Knowledge from chlor-alkali can be used to address many of the R&D challenges, including accelerating the development of electrochemical CO2 conversion technology.[clxii] To achieve cost reductions, carbon utilization technologies must scale up gaps for electrolyzer mass transfer limitations, establish reactant/product solubility, improve component stability, and better manage heat. Many DOE initiatives target these goals, including the Clean Fuels and Products Shot.
- **Electrochemical synthesis of ammonia:** This report highlights using clean hydrogen as a decarbonization lever for the ammonia subsector. While clean hydrogen stands to abate a substantial portion of ammonia processing emissions, improvements to electrochemical synthesis can bypass the hydrogen production step by utilizing electrochemical methods to react water and nitrogen in a single step. Advancements will address the high-temperature heat and pressure requirements of the Haber-Bosch Process. To achieve cost reductions, it will be necessary to increase energy efficiency and selectivity through new catalyst and cell designs to lower HER activity, increase NRR activity and

improve mass transport. Downstream separation technologies will be needed for the extraction of synthesized ammonia.

- **Non-amine-based carbon capture:** Ongoing demonstrations and research are developing technologies that can abate or adsorb CO2 at reduced costs and at a broader range of CO2 concentrations. Cost reduction for this technology may be achieved due to 1) a high number of use cases from many emissive industries, 2) significant R&D and piloting of various capture technologies, and 3) existing policies that support carbon capture deployment could help near-term cost-down trajectories.

- **E-cracker:** The electrification of steam cracker furnaces addresses the most energy-intensive step of olefine production. This technology is being developed to allow for retrofitting in facilities. Barriers to bringing e-crackers down the cost curve include the capital cost associated with retrofitting and reaching cost parity with natural gas-fired crackers.

- **High-temp heat electrification:** Electrifying high-heat demand (i.e., 400–1,000^{o} C) could substitute for CCS on high-heat emissions. TRL for most high-heat electrification technologies remains low (2-6). Examples include (i) electric crackers and (ii) thermal batteries. Electric crackers could replace the traditional steam cracking furnaces, reducing the need for CCS from flue gas. Demonstration projects are underway in North America. These technologies may see a rapid cost decline as 1) variations of this technology are piloted, 2) regions with existing carbon taxes and electrification policies motivate companies to test and demonstrate new methods (e.g., e-crackers in Europe), and 3) there are broad applications in high-heat industries.

- **High efficiency/current density electrolyzers:** Hydrogen electrolyzer technology is improving to increase electricity conversion efficiency and electrolyzer throughput. The following characteristics could permit steeper cost declines: 1) many use cases for hydrogen inside and outside of chemicals & refining, 2) the potential to drive down costs through economies of scale (e.g., large-scale factories for electrolyzers and announced plans for large electrolytic projects), 3) strong existing policy support for hydrogen deployment (e.g., IRA production tax credit and H2Hubs).

- **Bio-based chemicals:** Bio-based chemicals are commercially produced today for some applications but are limited in market penetration due to cost and performance. It is difficult to compete on price alone with fossil-derived commodity chemicals due to fossil processes' economies of scale and fully depreciated capital. Additionally, some early bio-based chemicals replacements suffered from decreases in desired properties (e.g., thermostability). Since then, newer biobased polymers have achieved better properties than fossil-derived and seamless drop-ins for fossil chemicals have been used in multiple supply chains. Additional R&D to further decrease costs and improve properties are ongoing in DOE initiatives such as the Clean Fuels and Products Shot, the BOTTLE Consortium, the Agile BioFoundry, and other initiatives.

- **Biofuels:** There are billions of gallons of capacity for bio-based fuels in the United States.[clxiii] However, the feedstocks for those processes (e.g., starch, fats, oils, greases, oilseed crops) are limited. Expanding into additional waste feedstocks and lignocellulosic resources will be critical to achieving the GHG reduction impacts possible with biofuels, and costs for feedstock collection, preprocessing, conversion technologies, and downstream processing all must be addressed. Many DOE initiatives target these goals, including the Clean Fuels and Products Shot, the SAF Grand Challenge, and the Bioenergy Research Centers.

- **Mechanical recycling:** Mechanical recycling is reprocessing by melting thermoplastics. It is the preferred type of recycling because it minimizes the energy and emissions of making a "new" plastic products. However, it is limited to thermoplastic materials, faces property degradation due to the recycling process, and faces potential end-market constraints. Different types of polymers are incompatible, requiring mechanical sorting, which is often manually performed. Artificial intelligence, robotics, and other "smart" technologies are improving sortation, enabling more recyclable materials to be included in bales—potentially informing package and material design for recyclability. Characterization and tracking waste feedstocks, with the transparency of appropriate specifications, could increase the volume of recycled plastics and lead to higher value extraction.

- **Pyrolytic recycling:** Pyrolysis is the thermal decomposition of materials in a low-oxygen environment yielding pyrolysis oil, char, and other low-value byproducts. The pyrolysis oil can be upgraded through further refining processes into fuels and other chemicals, including polymer building blocks, which require additional processing steps to convert into polymers. The product distribution and yields are dependent on reactor conditions and catalysts. Although this is a method of managing mixed plastic waste streams, even pyrolysis requires removing certain contaminants in many mixed plastic feedstocks. Innovations that could improve the economics and energetics of pyrolysis include improved sorting and advancements in catalysts that could shift product distribution toward more valuable products, higher-quality fuels and chemicals, and increase contaminant tolerance.

- **Other advanced recycling:** For certain plastics or applications (e.g., food-contact, medical), mechanical recycling is unsuitable due to purity concerns, and pyrolysis is inefficient. Novel recycling processes are being developed to improve product purity and decrease the impacts of recycling (e.g., solvent dissolution and polymer recovery, chemical depolymerization approaches to recover monomers). These approaches allow the removal of additives, dyes, fillers, and other additives that are not removed in mechanical recycling and require fewer processing steps than pyrolysis to produce a new polymer. Cost for these technologies could significantly reduce as they continue to scale and mature and would be supported by the intrinsic market pull for recycled materials. Abatement potential for advanced recycling technologies can vary, depending on factors such as the electricity sources used.

- **Municipal waste upgrades:** The supply chain for recycled materials is complex and includes: collection, sortation, sizing, cleaning, pre-processing, and manufacturing. Improvements that can be made in this supply chain would make all forms of recycling more efficient and economic. For example, reverse logistics and automation can increase the collection and production of recycled feedstock streams suitable for recycling. Furthermore, the design of materials and products could facilitate their ability to be recycled efficiently. The REMADE Institute (remadeinstitute.org) is a public-private partnership working on these issues for various material classes, including plastics. Because plastics are often in low-density forms (e.g., films, thermoforms), transport is the highest cost in the recycling process. To get around this challenge, converting plastics to high-density, high-energy liquids for further processing would be advantageous. ARPA-E explored several technologies that could do this economically in their REUSE program.

- **Power-to-X:** Power-to-X (PtX) derived fuels and chemicals could meaningfully decrease demand for fossil feedstocks and transform fundamental chemicals & refining processes. While not a nascent technology, reducing emissions through PtX is difficult. In PtX, clean hydrogen and captured carbon are used to create fuel (e.g., from the Fischer-Tropsch process or electrochemical conversion processes) or chemicals that could make most plastics (e.g., methanol, which can be turned into plastics via the methanol-to-olefins process).[clxiv] While there is significant industry interest in PtX pathways, these pathways are still in early development, and competitiveness relies on low-cost CO2 and hydrogen. Many DOE initiatives target these goals, including the Clean Fuels and Products Shot.

- **Alternative separation processes:** Membrane separations are process-intensification methods for addressing thermochemical processes like distillation or fractioning. Possible membranes include polymeric membranes, zeolite membranes, metal-organic framework membranes, facilitated-transport membranes, mixed-matric membranes, and carbon membranes. Further R&D is necessary to reduce costs, which can be lowered by increasing membrane selectivity and permeability, stability, and mixed-gas permeation.

The technologies mentioned above all represent solutions within a medium TRL range. Today, they are mostly facing ARL cost barriers to becoming relevant levers in decarbonization pathways in the chemicals & refining sector. **However, given the sector's complexity, technologies currently in the applied R&D phase could further change the decarbonization pathways outlined in this report.** These include:

- **Rotary olefin crackers:** Rotary olefin crackers (ROCs) can potentially replace catalytic cracking units. ROCs drive reactions by physically heating the reaction area of the furnace using the kinetic energy generated by turbine blades. To advance the technology, additional R&D is needed to improve reactor optimization in high temperature ranges and reactor scaling. The most significant barrier to doing so is the higher capital costs compared to gas-fired catalytic crackers.

- **Oxidative dehydrogenation reactions:** The oxidative dehydrogenation (ODH) of ethane in the presence of a heterogeneous catalyst is an alternative to steam cracking. ODH has the potential to provide higher olefin yields. ODH technologies (e.g., chemically looping catalyst-ODH, membrane ODH, electrochemical ODH) can overcome the limitation of over-oxidation to CO and CO_2 To bring the technology up the TRL scale, R&D must address increased selectivity/activity, stability of catalysts and membranes, optimized reactor design, and reactor scaling.

- **Non-contact energy enhanced processes:** Non-contact energy methods (e.g., microwave, plasma, RF) facilitate targeted heating that reduces overall energy input needs. Advancing this technology will require improved selectivity, stability, and catalyst activity. Additionally, reactor design and scale-up will be necessary.

The above technologies are not modeled in this report's MACCs, which considers deployable and later-stage demonstration technologies. However, they could meaningfully shift the decarbonization pathway if cost and performance are competitive with higher TRL/ARL decarbonization measures. Given the long lead times needed for major plant transformations and greenfield development, chemicals companies and refineries must begin planning for 'plants of the future' today. These plants are likely to be characterized by greater production of bio-based or lower carbon feedstock and production. They will produce a greater product yield skewed toward chemicals, aviation fuel, and non-fuel products as demand for road transport fuel decreases. The DOE and U.S. National Labs have the tools and networks necessary to accelerate R&D on these technologies, including through the initiatives listed above.

Increasing investment in these nascent technologies is needed to prove technology readiness and recognize cost declines from learning. In addition, volume leverage in manufacturing and procurement is a primary cost-reduction lever, but it is difficult for startups. Aggregating buying power across multiple companies pursuing nascent technologies with similar component needs could help achieve scale earlier. For example, buyers' clubs like the First Movers Coalition and the Frontier Fund use a group of companies' purchasing power to lower the cost of new decarbonization technologies and products.

4. **Increase the availability of financial mechanisms to expand funding for asset decarbonization.** After grid and transport decarbonization, approximately 30% of emissions could be abated by measures with >10% return on capital in 2030, assuming IRA incentives (Figure 17). However, the rate of project announcements and the level of investment to date is not on pace with the needed deployment, as discussed in Chapter 3. Key actions to help accelerate investment include:

    - **Using public-private partnerships to buy down risk:** The DOE direct air capture (DAC) and hydrogen hubs (H2Hubs) exemplify how large, shared infrastructure can lower the delivered cost of key industrial decarbonization technologies.

    - **Forming JV partnerships between asset owners and investors**: Funding decarbonization investment from the balance sheet can be challenging, as discussed in Chapter 4. Dedicated funds could provide the necessary capital for decarbonization, sharing the financial upside with the asset owner. Joint venture structures between large industry players can potentially lower the cost of borrowing, share technology learnings, and scale successful solutions.

- **Capturing the value of new green businesses by carving them out as separate entities, which incumbents partially own:** These off-balance-sheet holding companies could (1) allow financial markets to value these "green" business units at a higher terminal value and multiple than the core business and (2) allow these "green" business units to attract different types of capital. For example, LG's energy storage business had an EV/EBITDA multiple of ~10 while part of LG chem but now has a different set of investors and a valuation multiple of ~30 as a carved-out entity.

- **Developing specific voluntary standards:** A critical step could be developing and deploying a new set of voluntary standards to incentivize investment in asset decarbonization in addition to new-build renewables (the main area that has received investment to date). Voluntary standards that characterize the impacts of decarbonization (e.g., carbon intensity) and track projects that meet these standards may help grow confidence in the positive value of transition finance. Learnings from the success of the Energy Star program could be used to transparently track and communicate information on decarbonization impacts to consumers and industry. Department of Energy's Fossil Energy and Carbon Management Office is in the process of accepting public comments on a sector wide strategy to support best practices in Carbon Management. This Responsible Carbon Management Initiative is developing shared principles for safely and transparently implementing carbon management to proactively address emerging public concerns.[70]

- **Developing green bonds specifically targeted at transition finance:** Green bonds/debt financing are an option for funding decarbonization and have grown significantly in the last 10 years, but less than 1% of climate-related financing is directed toward asset decarbonization projects for high-emitting sectors.[clxv] ~$90–120B in capital investment is needed for measures that could have a >10% return by 2030, a significant opportunity for investors. These funds could be specifically ring-fenced for projects with strong potential returns and be structured to tolerate the longer development timelines that these projects require.

- **Creating dedicated funds for asset decarbonization:** New financial products or funds are needed (e.g., green bonds to finance decarbonization) to raise capital from various investors. Many of today's climate tech venture and private equity funds focus on scaling technology. However, recent announcements indicate that investors increasingly see the opportunity to invest in asset decarbonization. Many funds are coming to market, focused on investing in hard-to-abate sectors.

- **Accelerating the shift to more bank debt in the capital stack:** Support for demonstration projects through grants, low-interest loans, or first-loss guarantees that improve underlying technologies through learnings and de-risk technologies through an established track record. This support can ultimately help unlock bank debt that currently views these projects as too risky. Aggregating demand pull through long-term contracts or advanced market commitments can also de-risk nascent technologies and unlock lower-cost bank debt.

5. **Develop a strong ecosystem to share learnings, promote scale, and minimize cost.** The majority of decarbonization measures require coordination throughout full value chains that are still developing and learning to collaborate. Organizing and strengthening the ecosystem to improve coordination, speed the development of enabling infrastructure, and support at-risk supply chains can address several challenges to decarbonization. Key actions to strengthen the value chain ecosystem include:

   - **Advanced market commitments to improve the investment case in production (or sequestration) and shared infrastructure for CCS and clean hydrogen.** Enabling infrastructure for hydrogen and CCS—including hydrogen and CO_2 pipelines and CO_2 storage—requires large

70 Federal Register: Notice of Intent and Request for Information Regarding Launching a Responsible Carbon Management Initiative.

volumes to be cost-effective but offers significant cost savings if shared. For example, hydrogen pipelines become cost-effective at approximately 100 ktpa and up, equaling the hydrogen demand of 3-4 refineries or ammonia production facilities. Similarly, developing a shared CO2 pipeline that can carry 15 MTPA CO2 (e.g., 36-inch diameter) for three facilities could result in a 40% cost savings compared to building three individual pipelines sized for smaller volumes (e.g., 24-inch diameter). Therefore, collaboration and advanced market commitments from three or more "anchor tenants" in a decarbonization hub could help to justify transport infrastructure investment, further spurring full-ecosystem development.

- **Convening value chain members to share learnings and develop best practices for ecosystem collaboration.** Building a "developer's toolbox" with standardized RFP templates, workflows, project designs, and learnings from previous projects can help promote faster learning cycles. Similarly, developing an anonymized database of project costs and partnership terms can help provide transparency to the market to set expectations between project developers, technology providers, midstream infrastructure providers, EPC companies, and investors. For DOE DAC Hubs and DOE H2 Hubs, the Department of Energy will work alongside applicants to ensure best practices are shared in each planning and construction phase.

6. **Removing infrastructure bottlenecks, especially in permitting**. One key challenge to building infrastructure is regulatory challenges that slow adoption and raise financing risk. Key regulatory challenges could be addressed by the expansion of state primacy for Class VI wells and/or acceleration of EPA permitting timelines, potential FERC involvement in pipeline siting (for hydrogen and CCS), streamlined studies to allow new renewables onto the grid with accelerated interconnection queues, and support for nationwide coordination of grid expansion. While improving the time of bringing project online is important, the need to ensure rigor in adequately addressing community concerns must be a part of the process.

   New incentives for decarbonizing technologies are likely to drive demand quickly, which could cause a significant slowing in the materials supply chain. Constraints have already been identified in key components for electrolytic hydrogen, certain LDES technologies, and electrification equipment. To mitigate supply chain risks, incumbents, technology providers, and EPC companies could work closely together in early implementation steps. Some materials may be hard to access due to nascency, but incumbents can address these supply chain constraints by adding redundancy in project planning well in advance. This could include the development of multi-year offtake commitments to incentivize producers and guarantee the production of key materials through clear demand signals. Targeted tenders, offering contracts to promising suppliers contingent on successful demonstrations, and other milestones could ensure sufficient pre-planning for supply chains. Finally, ecosystem convenings and partnership formation could also accelerate solutions to bottlenecks in supply chains.

7. **Implement robust community benefits plans and agreements which respond to labor and community concerns and mitigate potential harms.** Community benefits agreements (CBA) are signed between developers and community groups that negotiate community support for a project in return for benefits from the developer.[clxvi] CBA negotiations are avenues for developers to engage with communities to understand how their project can meet their goals while ensuring that community needs are met. These CBAs can incorporate mechanisms designed to mitigate the impacts from project development that the community is concerned about. Selected examples include requiring the usage of state-of-the-art SO_x scrubbers for hydrogen burning facilities, investments in local infrastructure, job training and local hiring requirements, implementation of GHG reduction programs. To prompt projects to consider the community impact of their work and engage with stakeholders, DOE requires applicants to most BIL/IRA funding opportunities to submit "Community Benefit Plans." These plans, generally weighted at 20% of the technical merit points for a project, prompt applicants to develop actionable plans for formal engagement with their communities on Justice40, DEIA, Good Jobs, and workforce and community agreements.[71]

71 More information on Community Benefit Plans can be found at https://www.energy.gov/infrastructure/about-community-benefits-plans

These seven solution areas require concerted action across industry, NGOs, and government. The Department of Energy, in partnership with other federal agencies, has tools to address these challenges and is committed to working with communities, labor unions, and the private sector to build decarbonization infrastructure in a way that meets the country's climate, economic, good jobs, and environmental justice imperatives.

Chapter 5: Metrics and milestones

The DOE will track two types of key performance indicators to understand the progress needed for successfully decarbonizing the chemicals & refining sector.

- **Leading indicators** are signs to evaluate the present status of technology readiness, market adoption readiness, and penetration of key technologies.
- **Lagging indicators** are retroactive verification of successful or unsuccessful scaling and adopting decarbonizing technologies (e.g., evaluations of progress toward net-zero targets).

DOE will use the indicators (Figures 32 and 33) to track industry milestones and evaluate the decarbonization progression of the chemicals & refining sector. To be quantified on sector-, corporation-, and facility-bases, these metrics allow the integrated tracking of leading and lagging indicators, which can be regularly updated and shared. Across the entire value chain, a few critical metrics can indicate whether the chemicals & refining sector is progressing toward commercial liftoff. These milestones do not represent DOE targets but are important progress markers to create confidence across the ecosystem.

Key milestone by 2030: 35% emission reduction (~142 MT) in downstream production of chemicals and refining

Level of action needed	Leading indicators by 2030	2030	2040	Net-zero 2050
Enabling infrastructure	Announced low-carbon electricity build out		*Tracking*	
	Chemical and refining companies with scope 2 reduction targets		*Tracking*	
	Announced CO2 pipeline capacity		*Tracking*	
	Announced H2 pipeline capacity		*Tracking*	
End market demand	Electrification of transport		*Tracking*	
	Market growth for low-carbon chemicals products		*Tracking*	
	Price premium for decarbonized products		*Tracking*	
	Increase in recycling rate for consumer plastics		*Tracking*	
Technology adoption	70+ GW of announced H2 electrolyzer capacity in chemicals and refining		*Tracking*	
	Chemical and refining assets converting to best available technologies		*Tracking*	
	Announced CCS project in chemicals and refining		*Tracking*	
Capital formation	Increase in decarbonization R&D spending		*Tracking*	
	# of FOAKs/NOAKs projects supported		*Tracking*	
	Capital raised by private equity and infrastructure funds for decarbonization		*Tracking*	
Industry action	Industry-average emissions reduction target		*Tracking*	
	Companies with net zero targets		*Tracking*	

Source: IEA, EPA ASMM

Figure 32: Key leading indicators to track the downstream chemicals & refining decarbonization pathway.

Key lagging indicator milestones by year

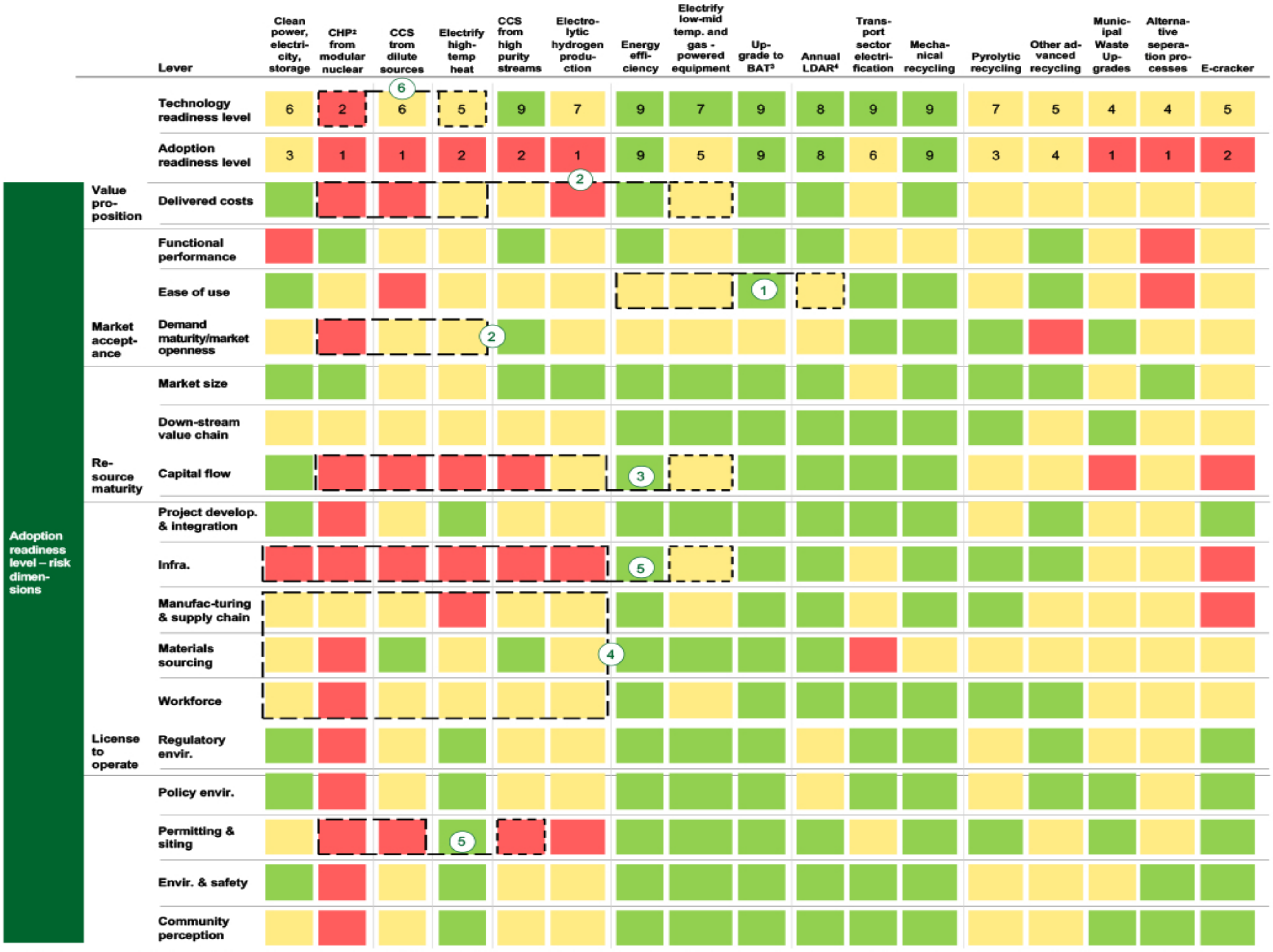
Key decarbonization lever	Lagging indicator	2030	2040	2050
Demand reduction	MT CO_2 emissions reduction reached	60	89	119
Grid decarbonization	MT CO_2 emissions reduction reached	53	59	64
Efficiency	MT CO_2 emissions reduction reached	42	48	54
Clean hydrogen	MT CO_2 emissions reduction reached	27	47	54
CCS	MT CO_2 emissions reduction reached	16	86	157
Electrification with clean firm power	MT CO_2 emissions reduction reached	19	80	141

Figure 33: Key lagging indicators to track the downstream chemicals & refining decarbonization pathway.

Appendix

Appendix A: ARL analysis

This analysis used the Adoption Readiness Level (ARL) framework to assess each technology detailed in the pathway to net zero. ARL represents important factors for private sector uptake beyond technology readiness and can be determined by performing a qualitative fact-based risk assessment across 17 adoption-risk dimensions spanning four risk areas. Designed to complement the widely used Technology Readiness Levels (TRL), the combination of ARL and TRL can illuminate the required technology to reach commercial scale. Often, commercialization fails not because of the technology's fundamentals, but because ecosystem economics have not been addressed or critical ecosystem companies have not come on board. The economic and business model requirements for deployment, and a technology's societal license-to-operate, can and should shape the technical problem definition and development of solutions at all stages of the RD&D continuum.



1. Abatement potential from 2030 MACC analysis with IRA incentives; 2. CHP = combined heat and power; 3. BAT = best available technology; 4. LDAR = leak detection and repair; 5. Incentives considered from BIL and IRA

Figure 34: ARL analysis for key decarbonization technologies.

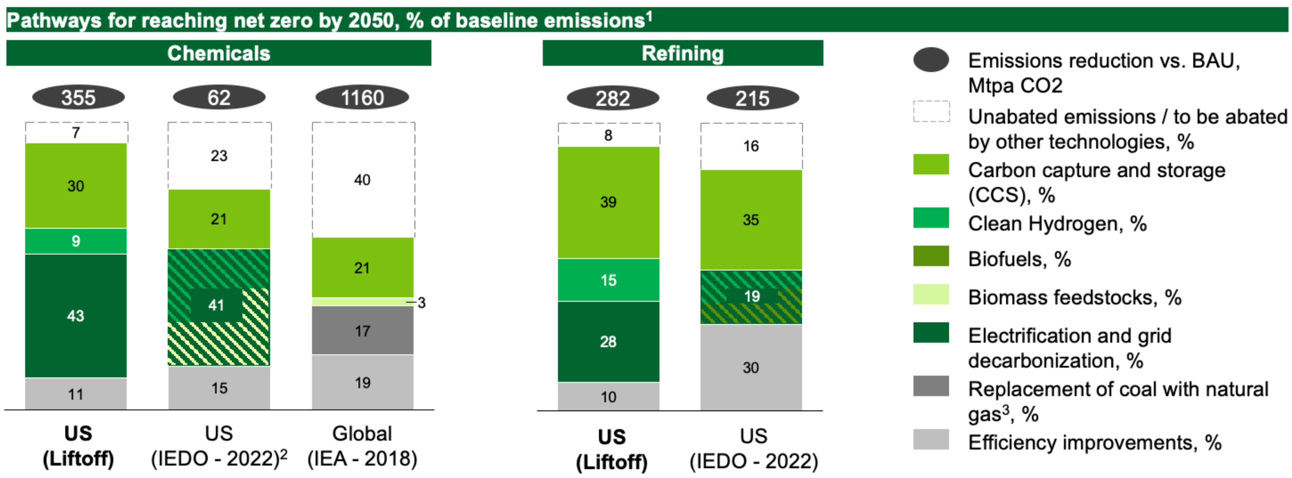
Appendix B: Decarbonization scenario comparison

This net-zero pathway was compared against other decarbonization pathways to understand the differences in assumptions and outlooks.

B.1 Comparison to other decarbonization scenarios

The Liftoff report provides a granular, quantitative pathway toward net-zero emissions for the U.S. chemicals and refining industries. It is broadly similar to other global reports on net zero for the chemicals and refining industry in its assumptions. Other reports on this topic also find that:

- Near-zero emissions reductions could be achieved through the scale-up of existing technologies, though the cost may be substantial, and some required technologies are not yet mature.
- Reaching near-zero will require the substantial scale-up of CCS at many stages in the chemicals and refining production process and the large-scale availability of clean electricity and clean fuel, such as hydrogen or biofuels. The degree of reliance on each technology varies by region (Figure 35).



1. Baseline year is 2022 for this report, 2021 for IEA report, and 2015 for DECC. Other reports not included here do not allow direct comparison with Liftoff report
2. IEDO includes Ammonia, Methanol, and Ethylene
3. IEA report is for primary chemicals: high-value chemicals, ethylene, propylene, benzene, toluene, xylenes, methanol, and ammonia; Coal-fired methane plants in China are one of the largest sources of emissions in the industry, and improving their efficiency is a major component in global/China-focused scenarios

Sources: IEA (2018), The Future of Petrochemicals, IEA, Paris https://www.iea.org/reports/the-future-of-petrochemicals, License: CC BY 4.0; IEA (2022), Chemicals, IEA, Paris https://www.iea.org/reports/chemicals, License: CC BY 4.0; Li, Wang & Xue (2022), Transforming China's Chemicals Industry: Pathways and Outlook under the Carbon Neutrality Goal, RMI, https://rmi.org/insight/transforming-chinas-chemicals-industry/; DOE (2022), Industrial Decarbonization Roadmap, https://www.energy.gov/eere/doe-industrial-decarbonization-roadmap; Fleiter, Herbst, et al. (2019), Industrial Innovation: Pathways to deep decarbonization of Industry. Part 2: Scenario analysis and pathways to deep decarbonization, ICF; DECC (2015), Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050: Chemicals; DECC (2015), Industrial Decarbonisation & Energy Efficiency Roadmaps to 2050: Oil Refining

Figure 35: Comparison of Chemicals & Refining Liftoff report (2023) with DOE IEDO (2022) and IEA global report (2018).

The levers required for deep decarbonization are also largely similar across reports:

- The need for accelerated RDD&D on low-carbon technologies. Priorities include electrolytic hydrogen, bio-fuels, CCS, and electrification.
- The need for commercial demonstrations of mature technologies
- The need for clean infrastructure creation. Key priorities include widespread deployment of renewable power; creating a CO2 transport and storage network; and creating a clean hydrogen production and distribution network.
- The need for greater policy action to incentivize decarbonization. Potential levers include the development of a skilled workforce; action to reduce the cost of decarbonization technologies and clean energy; incentives for recycling; and support for a market for clean products. China specifically needs to incentivize a transition away from coal fuel and feedstocks.

Specific reports are available for different geographies and scopes (Figure 36). Major reports and their takeaways include:

The **U.S. DOE IEDO Industrial Decarbonization Roadmap** (2022, results shown in Figure 36, detailed in Appendix B.2) shows a pathway toward a ~90% reduction in energy-related CO2 emissions by 2050 from U.S. ethylene, propylene, BTX, ammonia, and methanol production.[clxvii] Cost is not directly considered. Key steps for net zero include advancing RDD&D for low-carbon technologies; making commercial demonstrations of mature technologies; decarbonizing the electric grid; and engaging diverse communities to distribute the benefits of decarbonization.

The **IEA report on Chemicals** (2022, results shown in Figure 36) shows a pathway to net zero by 2050 for the global chemicals industry, and the **IEA report on the Future of Petrochemicals** (2018) shows a path to a ~50% emissions reduction by 2050 for the Refining industry.[clxviii, clxix] Cost is not directly considered, and progress toward Sustainable Development Goals (e.g., pollution reduction, water quality) is prioritized. Key steps for decarbonization include R&D into low-carbon technology like CCS, electrolytic hydrogen, and recycling; creation of infrastructure for CO2 transport and storage; creation of infrastructure for hydrogen production and distribution; and policy action to incentivize decarbonization, energy efficiency, recycling, and the creation of a market for clean products.

The **UK DECC reports on chemicals & refining** (2015) show a pathway to a 90% reduction in energy-related CO2 emissions for the U.K. Chemicals & refining Industries by 2050, including exploring alternative scenarios with lesser decarbonization.[clxx, clxxi] Cost is not directly considered for scenarios achieving >80% emission reductions. Key steps for net zero include accelerating R&D for commercial demonstrations of decarbonization technologies; building new supply chains for clean fuels and CO2 storage; nurturing government-industry collaborations; and taking policy action to build a cost-competitive decarbonized electricity grid.

The **RMI report on Transforming China's Chemicals Industry** (2022) shows a pathway to net zero by 2050 in China for emissions from ammonia, ethylene, and methanol production, at the lowest feasible cost.[clxxii] Chemicals production in China, unlike the U.S., currently relies heavily on coal power and feedstocks, and reducing this dependency is a high priority for decarbonization. Key steps for net zero for China include R&D on electrolytic hydrogen, electrification technologies, and coal-to-methanol coupling; creating an electrolytic hydrogen supply chain; and policy action to reduce the cost of carbon reduction and incentivize the phase-out of coal feedstocks.

The ICF pathway to deep decarbonizing industry for the EU (2019) shows a pathway toward a 95% reduction by 2050 in emissions from refining and for ammonia, ethylene, and methanol production, at the lowest feasible cost.[clxxiii] Key steps for decarbonization include accelerated R&D, commercial scaling, and policy changes intended to achieve the wide-scale deployment of renewable energy, plus some combination of material efficiency, circular economy, clean fuels, bio-fuels, and CCS.

Table 1: Scope of reports outlining net-zero pathways for the global chemicals and refining industries, and major levers expected to contribute to decarbonization.

	SCOPE AND PURPOSE				DEMAND										
Source	**Region**	**Industries**	**Emissions target (2050)**	**Optimizing for**	**Chem.**	**Oil**	**Natural gas[1]**	**Efficiency**	**Electrification**	**Hydrogen**	**Biofuels**	**Bio-feed-stocks**	**CCS**	**Recycling**	**Other**
This report	USA	Chemicals & Refining	Net zero	Cost	↑	↓		✓	✓	✓	✓	✓	✓	✓	✓
DOE IEDO [clxxiv]	USA	Select Chem.[2] & Refining	Net zero	Cost	↑	↓		✓	✓	✓	✓	✓	✓	✓	
DECC [clxxv, clxxvi]	UK	Chemicals	-90%	Fast tech. deployment	↑	n/a		✓			✓	✓	✓		✓
			-50%	Cost	↑	n/a	✓	✓			✓	✓	✓		✓
		Oil refining	-90%	Fast tech. deployment	n/a	↓↓		✓					✓		✓
			-50%	Cost	n/a	↓↓		✓							✓
RMI [clxxvii]	China	Select Chemicals[3]	Net zero	Cost	↑	n/a	✓	✓	✓	?[4]	✓	✓	✓	✓	
IEA [clxxviii, clxxix]	Global	Chemicals	Net zero	Cost	↑	n/a	✓	✓	✓					✓	
		Petrochemicals	-50%	Sustainable Dev. Goals	n/a	↑[5]	✓	✓				✓	✓	✓	
ICF [clxxx]	EU	Select Chem.[6] & Refining	-80%	Choice of tech.	↑	↓↓	✓	✓	✓		✓	✓	✓	✓	✓
			-95%	Cost	↑	↓↓	✓	✓	✓		✓	✓	✓	✓	

↑ Demand Increase expected (↓)↓ (Major) Demand decrease expected ✓ Major contributor ✓ Minor contributor

1 Includes both clean methane and conversion of coal-fired plants to natural gas. Coal-fired methane plants in China are one of the largest global sources of emissions in the industry, and improving their efficiency is a major component in global/China-focused scenarios.

2 Chemicals evaluated in IEDO: ammonia, ethylene, methanol, propylene, BTX.

3 Chemicals evaluated in the RMI report: ammonia, ethylene, methanol.

4 Contribution to emissions reduction depends on cost, which RMI considers highly uncertain.

5 Demand for petrochemicals is likely to continue increasing in the developing world; demand reduction is an effective strategy for emissions reduction only in the developed world.

6 Chemicals evaluated in ICF reports: ammonia, ethylene, methanol.

B2. Granular comparison to DOE IEDO report

The DOE previously reported potential pathways to net zero for the chemicals & refining industry as part of the 2022 IEDO Industrial Decarbonization Roadmap. This Liftoff report builds upon that work to address more than double the volume of emissions previously considered (Figure 38). Specifically, the IEDO roadmap considered ammonia, methanol, and ethylene, whereas this Liftoff report includes the entire chemicals industry. The IEDO report included only CO2 emissions from energy sources, whereas this report discusses other emissions sources.

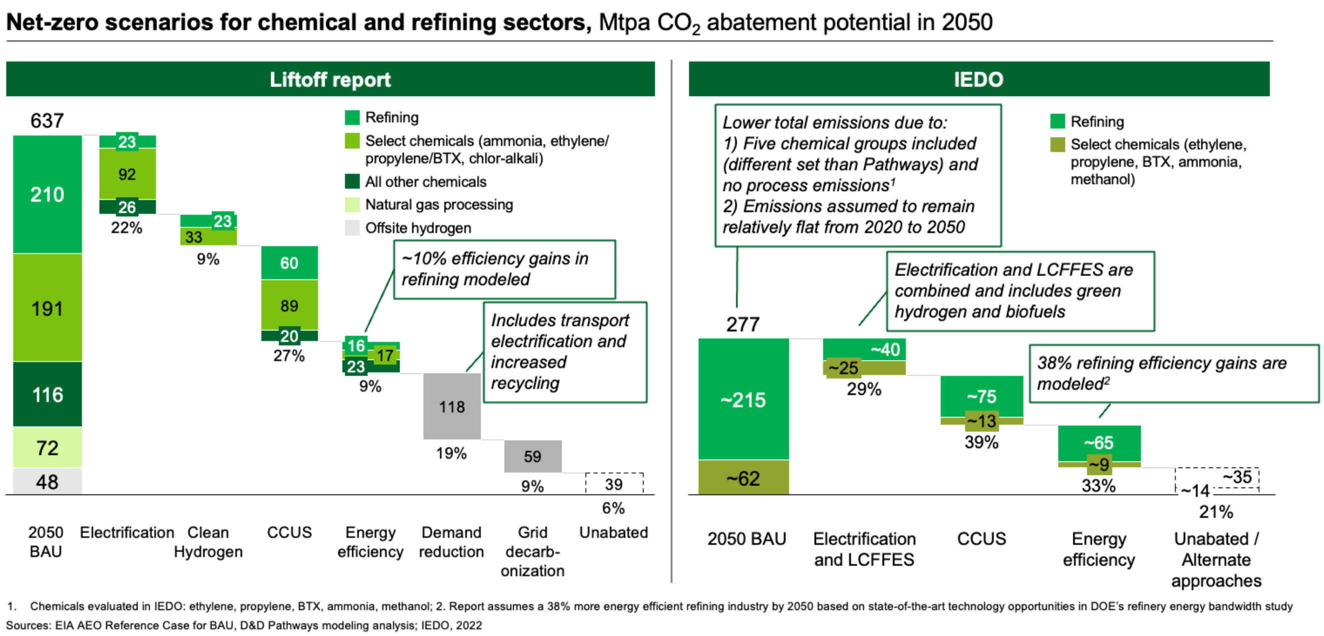


Figure 37: Comparison of DOE Liftoff (2023) and DOE IEDO Industrial Decarbonization Roadmap (2022) pathways for reaching net zero for the chemicals and refining sectors.

Key differences between the pathways presented in these analyses include:

- Granularity of time-bound decarbonization pathway: While the IEDO report outlines a phased decarbonization timeline broken out by key decarbonization measures for industrial emissions overall, it does not provide a time-bound outlook of levers for chemicals production and refining. Instead, only the breakdown of decarbonization measures required by 2050 is included (see Figure 37, showing the time-bound breakdown of measures for overall industrial emissions).
- Underlying assumptions:
  - This Liftoff report includes the impacts for transport and grid decarbonization from the Administration's long-term strategy to reach net zero, as well as the impact of EPA targets for recycling on the emissions of downstream chemicals & refining (included in demand reduction and grid decarbonization in Figure 38). While the importance of grid decarbonization is well-articulated in the IEDO report, it is not explicitly pulled out from electrification, and demand reduction was not included.
  - This Liftoff report includes emissions from all downstream chemicals production and refining, while the IEDO report includes a sub-set of chemicals (ethylene, propylene, BTX, ammonia, and methanol) in their analysis.
  - This Liftoff report includes a calculation of process emissions for the five largest sources of emissions in chemicals production (ammonia, ethylene/propylene/BTX, chloralkali, natural gas processing), while the IEDO analysis does not consider process emissions. This Liftoff report does not include a calculation of process emissions in chemicals beyond the five processes listed.

- Outlooks for chemicals & refining emissions growth vary between the two analyses. This Liftoff report considers the EIA 2021 Reference Case as the BAU scenario.

- Grouping of levers: In the IEDO report, Electrification and LCFFES are combined, while this Liftoff report separates electrification from clean hydrogen.

- Types of measures included in the pathway: This Liftoff report considers a least-cost pathway. Therefore, this report did not include certain decarbonization measures included in the IEDO pathway—such as biofuels and clean hydrogen as a fuel source—as they were not cost-competitive against alternative decarbonization measures.[72]

  Efficiency assumptions: Different outlooks on efficiency gains are included in both reports. The IEDO report considers higher potential efficiency gains (e.g., 38% in refining) based on DOE Bandwidth studies. This report considers lower efficiency gains of approximately 10% based on industry-reported expectations.

Appendix C: Modeling methodology and assumptions

Methodology 1: Chemicals production emission baseline analysis

The baseline chemicals emissions data used throughout the report for ammonia production, steam crackers to produce ethylene, propylene, and BTX, and chlor-alkali process production emissions was determined with a model on chemicals emissions. This data shown in Figure 2 was based on the chemicals emissions model, which uses IHS Markit data to understand the Scope 1 and 2 emissions of key chemicals.

To calculate Scope 1 and 2 emission factors for chemicals processes: First, process data from IHS Markit (e.g., utilities and natural gas consumption per tonne of chemicals product) was multiplied by utility emission factors from various sources. Second, associated process emissions were calculated based on the fundamental chemical equation, where outcoming moles of CO2 are converted to determine a process emission factor per tonne of product. Lastly, fugitive emissions are added based on average fugitive emission factors from natural gas power plants multiplied by the amount of natural gas used.

To calculate the Scope 1 and 2 emission factors for a chemicals product: Data was used to multiply and sum the process emission factor by the percentage of mass breakdown of different process technologies. IHS Markit data for key products is used to break down the process technologies (e.g., U.S. ethylene production breakdown from various technologies like ethane cracker, naphtha cracker, and other pathways).

To calculate overall Scope 1 and 2 emissions for a chemicals product: calculated Scope 1 and 2 emission factors are multiplied by the U.S. production of the product.

Objective of analysis: Calculate the Scope 1 and 2 emissions of key chemicals products to understand emissions concentration and provide baseline production emissions of key chemicals processes: steam crackers, steam methane reforming + Haber Bosch, and chlor-alkali process.

Considerations & limitations of approach: These calculations do not account for the following sources of emissions: upstream and downstream Scope 3 emissions, non-methane fugitive emissions, and do not account for process yield loss. Electricity-related emissions assume average U.S. grid intensity, which could miss regional differences in grid intensity. Fugitive emissions calculations are based on a single factor and account for standard methane leakage in natural gas usage, which won't account for acute leakage events.

72 In this Liftoff report, clean hydrogen is included only as a replacement for carbon-intense hydrogen used as an input in chemicals production and refining.

Key inputs and assumptions: See methodology section. Key data collected from the following sources:

- **IHS Markit (S&P Global):** Process economics program (PEP) sheets, prices, production outlook, technology mix, and plant capacities
- **Argus and ITC Trade data:** Supplemental price data
- **ICIS:** Supplemental technology mix and plant capacity data
- **Hajny et al. (2019):** Fugitive methane emission factor
- **IPCC:** Global warming potential conversions, AR4
- **EPA:** Emissions factor for stationary combustion of different fuels, U.S. grid emissions intensity, end-of-life emissions of materials

Methodology 2: Sources of emissions analysis

Seven categories of emissions sources were analyzed across the key processes considered for this report: low-temperature heat (-30–200°C), mid-temperature heat (200–400°C), high-temperature heat (400+°C), process emissions, fugitive emissions, on-site power emissions, and off-site power emissions. The approach to analysis and assumptions varied by process, as there is no centralized data source. A summary of the approach for each process follows:

- **Refining:** Expert input on refinery emissions sources across refineries was considered for the breakdown of major sources of emissions. The hydrogen-production emissions breakdown was determined from an academic source (see assumptions) for a steam methane reformer. DOE EERE MECS was used to determine the proportion of on-site and off-site power generation.
- **Natural gas processing:** Data from a DOE report written by Bradbury et al. provided an emissions breakdown from natural gas processing in Table 6 for "Processing."
- **Steam methane reforming + Haber Bosch:** The emissions breakdown was identified using data provided by Smith et al. (2019) and assumed stoichiometric CO2 emissions would be classified as process emissions. Steam-to-turbine and steam-to-SMR were categorized as high-heat emission sources. Other steam was categorized as a low-temperature heat emissions source. Heat loss/other was categorized as a fugitive and other emission source. Methane extraction was categorized as process emissions.
- **Steam cracking:** Expert input was considered to break down emissions sources for ethane steam cracker emissions and academic sources. Tau Ren et al. describe that 65% of energy consumption occurs in the cracking furnace step. With expert insight, it was assumed that 80% is high-temperature heat, 15% is mid-temperature heat, and 5% is from electrical generation. Tau Ren et al. describe compression as accounting for 15% of energy demand, which experts described as likely breaking down with 33% from electrical demand and 66% from mid-temperature heat. Tau Ren et al. describe 20% of energy demand coming from separation, of which approximately 50% is assumed to be low-temperature heat and 50% of emissions are assumed to be from electricity generation based on expert input. Based on most U.S. facilities having onsite generation, electrical power is assumed to be 90% onsite. The remaining electrical power is assumed to be off-site.
- **Chlor-alkali process:** IHS Markit data provides a breakdown of the technology mix in the U.S. Electricity-related emissions are classified as either on-site or off-site power emissions. IHS data shows that 8 of 41 (20%) U.S. chlor-alkali producers have onsite co-generation. Therefore, the analysis assumed that 20% of power generation was on-site, leading to ~10% of overall emissions. Onsite natural gas consumption was assumed to provide mid-temperature heat due to the requirements of

the chlor-alkali process.

- **Other chemicals:** Other emissions are calculated as the total emissions breakdown from DOE EERE. Process heating is treated as an equal split of high- and mid-temperature heat. Process cooling and refrigeration are treated as low-temperature heating. Other process uses are treated as low-temperature heat. Machine drive is treated as low-temperature heat. Facility HVAC is treated as low-temperature heat. Process emissions are treated as process emissions. The remaining emissions are treated as "other." Chemicals emissions from steam crackers, ammonia production, and chlor-alkali production are subtracted from total EERE emissions proportionally, and the remaining "other emissions" are used to determine the percentage of emissions.

Objective of analysis: Produce a representative emission breakdown for key chemicals & refining processes broken down into key categories.

Considerations & limitations of approach: Emissions profiles may vary between different technologies and may not be captured within this analysis (e.g., mercury vs. diaphragm-based chlor-alkali production). Expert insight was used to understand refining and steam cracking emissions breakdown based on published reports of energy utilization from facilities. The breakdown of emissions for any individual source will differ by facility and was not considered in this approach. Additionally, assumptions were made due to the lack of data in some areas. Therefore, the breakdown of emissions should be viewed as indicative of the processes rather than a precise description of any individual facility's emissions.

Key inputs and assumptions:

- DOE Manufacturing Energy and Carbon Footprint sector analysis
- Smith et al.—Current and future role of Haber–Bosch ammonia in a carbon-free energy landscape, 2019
- Bradbury et al.—Greenhouse Gas Emissions and Fuel Use within the Natural Gas Supply Chain – Sankey Diagram Methodology, 2015
- Tau Ren et al.
- Expert analysis

Methodology 3: Marginal abatement cost curve (MACC) analysis

MACC analysis can help visualize decarbonization measures based on the economic cost of abatement and the potential scale of emissions reduction, as shown in Figures 16–18. In this analysis, the 2030 and 2050 MACCs were built based on emissions baselining across the five prioritized sectors and aggregate downstream chemicals. The key emissions sources considered include heat generation—split between low-, medium-, and high-heat requirements—, on-site and off-site power generation, and industrial processes. Decarbonization measures were then considered for each industry against these emissions sources. For example, emissions associated with hydrogen production via steam methane reforming were split into 90% process emissions and 10% heat generation. These could be decarbonized using (a) CCS, (b) electrolyzers with renewable energy sources, or (c) bio-methane feedstock, amongst other measures. The least-cost decarbonization measures were selected based on a 10% hurdle rate and 25-year asset lifetime and visualized on the MACCs.

See below for a long list of decarbonization measure-specific assumptions reflected in the MACC analysis.

Objectives of analysis: Building on the IEDO's Industrial Decarbonization Roadmap published in September 2022, this MACC analysis aims to take the next step by detailing the economic considerations of implementing key decarbonization levers across the Chemicals & Refining sector. The analysis highlights the significant impact of the Inflation Reduction Act (IRA) on incentivizing investment into solutions such as CCS and clean hydrogen while visually displaying the need for public and private investment for sector decarbonization.

Considerations and limitations of approach: This analysis makes several simplifying assumptions regarding renewable energy solutions, energy efficiency levers, and external emissions reduction impact. Additionally, it is important to recognize that this is a sector-level MACC and that each asset's decarbonization pathway has many nuances. As a result, it is important to view this analysis with a sector decarbonization lens and not isolated to implementation in any specific facility.

On renewable energy, the MACC reflects the assumption that current on-site power / combined heat and power (CHP) facilities are replaced with on-site wind power generation and long duration energy storage (LDES). However, this is likely to unfold with a combination of on-site renewable energy sources based on geographic constraints (e.g., on- and off-shore wind, nuclear) and PPAs and grid power. Assumptions on LDES are consistent with the DOE's LDES Liftoff Report.

On energy efficiency, the analysis includes an assumption that several energy efficiency optimization levers can be combined to achieve ~10% fuel consumption efficiency gains on average. In practice, after consulting with several relevant companies, it is acknowledged that energy efficiency opportunities are unique to each asset and facility and thus have to be considered at that level by operators. This simplifying assumption considers average efficiency gains across all U.S. chemicals & refining plants.

Lastly, we have considered the impact of grid decarbonization, transport sector electrification, and mechanical recycling on external emissions reductions.

- The White House has set a target of 100% grid decarbonization by 2035, reflected on a linear scale for the 2030 and 2050 MACCs as an external emissions reduction factor instead of a decarbonization measure such as CCS. It is not included as a decarbonization measure since it is not under the purview of chemicals & refining companies.
- Transport sector emissions reduction goals of 25% by 2030 and 75% by 2050 are also based on the White House – Pathways to Net Zero report. Like grid decarbonization, it is assumed that these goals are met and thus reduce demand for Refining products in the transport sector.
- Recycling goals of a 50% recycling rate in 2030 and 2050 are based on the EPA's National Recycling Strategy. This is reflected in the model through mechanical recycling as a demand reduction measure and pyrolytic recycling as a decarbonization lever since the process only reduces emissions by 20% compared to virgin plastic production. There is a 50/50 split between mechanical and pyrolytic assumed in this analysis.

Table 2: Key inputs and assumptions

Category	Key assumption	Value	Unit	Source
Hydrogen	Unabated fossil hydrogen emission factor	7.6	t CO2/t H2	GREET 2022 (On-site GHG emissions for SMR running on natural gas)
Hydrogen	Cost of air separation unit for electrolytic hydrogen (ammonia)	0.055	$/kg H2	DOE Hydrogen Liftoff report (based on $70M air separator processing 750 kt/NH3 p.a. for 20 years assumed in TCO analysis)
Hydrogen	Feedstock demand for hydrogen production for SMR unit (refining & ammonia)	961,436	btu NG/ mmbtu H2	GREET 2022 (SMR for H2 production)
Hydrogen	Heat demand for SMR for hydrogen production (refining & ammonia)	426,784	btu NG/ mmbtu H2	GREET 2022 (SMR for H2 production)
Hydrogen	LHV of hydrogen	52,217	btu/lb H2	NREL Hydrogen fact sheet

Hydrogen	Electrolytic hydrogen capex (2030)	0.46	$/kg H2	DOE Hydrogen Liftoff report[73]
Hydrogen	Electrolytic hydrogen opex (2030)	1.16	$/kg H2	DOE Hydrogen Liftoff report[73]
Hydrogen	Electrolytic hydrogen capex (2050)	0.3	$/kg H2	DOE Hydrogen Liftoff report[73]
Hydrogen	Electrolytic hydrogen opex (2050)	0.9	$/kg H2	DOE Hydrogen Liftoff report[73]
Hydrogen	Hydrogen transport, compression, and pipeline cost (low end of the range)	0.3	$/kg H2	DOE Hydrogen Liftoff report[74] assuming low-cost compression, salt cavern storage, and H2 pipeline access
Hydrogen	Hydrogen transport, compression, and pipeline cost (high end of the range)	1.3	$/kg H2	DOE Hydrogen Liftoff report[74] assuming high-cost compression, compressed gas tank storage, and H2 pipeline access
Hydrogen	Hydrogen transport, compression, and pipeline capex/opex split	9:1	-	Derived from DOE Hydrogen Liftoff report
Hydrogen	Hydrogen on-site storage cost	0.1	$/kg H2	DOE Hydrogen Liftoff report
Hydrogen	Hydrogen compression, pipeline, and storage capex/opex split	90	% capex	Derived from DOE Hydrogen Liftoff report
Hydrogen	Electrolytic / Reforming + CCS hydrogen split (2030)	40	% electrolytic H2	Assumed to be primarily CCS on existing ammonia facilities, with electrolytic hydrogen procured from merchant H2 facilities for refining
Hydrogen	Electrolytic / Reforming + CCS hydrogen split (2050)	80	% electrolytic H2	Assumed that by 2050, it will be primarily electrolytic H2 with some remaining CCS solutions based on SMR asset lifetime / fleet turnover
Hydrogen	Levelized cost of 45V tax credit	1.80	$/kg H2	Inflation Reduction Act[73] - assumes 10% WACC, 10 years of tax credit, and a 20-year project lifetime
CCS	CO2 Transport and Storage cost (low end of the range)	10	$/t CO2	DOE Carbon Management Liftoff report; assumes $10–$40/t CO2 range for transport and storage cost
CCS	CO2 Transport and Storage cost (high end of the range)	40	$/t CO2	DOE Carbon Management Liftoff report; assumes $10–$40/t CO2 range for transport and storage cost
CCS	CO2 Transport and Storage capex/opex split	2:1	-	EFI CCS report - assumes 67% capex, 33% opex split on $
CCS	2030 Natural gas processing (NGP) carbon capture cost (without T&S)	14.05	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2030 NGP carbon capture average annual opex cost (without T&S)	2.73	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2030 NGP carbon capture average annual capex cost (without T&S)	11.32	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2030 Ammonia carbon capture cost (without T&S)	135.56	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)

73 It is important to note that the assumptions underlying this analysis are uncertain, and the Clean Hydrogen Liftoff report is continually being updated. DOE electrolyzer cost estimates have already increased since the values published in this report, due to variables such as supply chain constrains and inflation.

74 Transport and storage costs will vary depending on geography.

CCS	2030 Ammonia carbon capture average annual opex cost (without T&S)	27.3	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Ammonia carbon capture average annual capex cost (without T&S)	108.26	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Fluid catalytic cracker (FCC) carbon capture cost (without T&S)	122.62	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 FCC carbon capture average annual opex cost (without T&S)	25.73	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 FCC carbon capture average annual capex cost (without T&S)	96.89	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Ethylene carbon capture cost (without T&S)	175	$/t CO2	Calculated from EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Ethylene carbon capture average annual opex cost (without T&S)	65	$/t CO2	Calculated from EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Ethylene carbon capture average annual capex cost (without T&S)	110	$/t CO2	Calculated from EFI CCS report (FOAK, high inflation, high retrofit cost)
CCS	2030 Hydrogen SMR carbon capture cost (without T&S)	114.36	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost); assumes 90% capture from SMR and steam production
CCS	2030 Hydrogen SMR carbon capture average annual opex cost (without T&S)	16.62	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost); assumes 90% capture from SMR and steam production
CCS	2030 Hydrogen SMR carbon capture average annual capex cost (without T&S)	97.74	$/t CO2	EFI CCS report (FOAK, high inflation, high retrofit cost); assumes 90% capture from SMR and steam production
CCS	2050 NGP carbon capture cost (without T&S)	14.05	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); no assumed learning curve to maintain EFI source
CCS	2050 NGP carbon capture average annual opex cost (without T&S)	2.73	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); no assumed learning curve to maintain EFI source
CCS	2050 NGP carbon capture average annual capex cost (without T&S)	11.32	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); no assumed learning curve to maintain EFI source
CCS	2050 Ammonia carbon capture cost (without T&S)	82.01	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 Ammonia carbon capture average annual opex cost (without T&S)	16.63	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 Ammonia carbon capture average annual capex cost (without T&S)	65.38	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 FCC carbon capture cost (without T&S)	75.83	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 FCC carbon capture average annual opex cost (without T&S)	15.67	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 FCC carbon capture average annual capex cost (without T&S)	60.16	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost)

CCS	2050 Ethylene carbon capture cost (without T&S)	110	$/t CO2	Calculated from EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 Ethylene carbon capture average annual opex cost (without T&S)	41	$/t CO2	Calculated from EFI CCS report (NOAK, low inflation, low retrofit cost)
CCS	2050 Ethylene carbon capture average annual capex cost (without T&S)	69	$/t CO2	Calculated from EFI CCS report (NOAK, low inflation, low retrofit cost); to be discussed
CCS	2050 Hydrogen SMR carbon capture cost (without T&S)	67.69	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); assumes 90% capture from SMR and steam production
CCS	2050 Hydrogen SMR carbon capture average annual opex cost (without T&S)	10.12	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); assumes 90% capture from SMR and steam production
CCS	2050 Hydrogen SMR carbon capture average annual capex cost (without T&S)	57.57	$/t CO2	EFI CCS report (NOAK, low inflation, low retrofit cost); assumes 90% capture from SMR and steam production
CCS	Levelized cost of 45Q tax credit	48.26	$/t CO2	Inflation Reduction Act - assumes 10% WACC, 12 years of tax credit, and a 25-year asset lifetime
Renewables / LDES	2030 LCOE	22.6	$/MWh	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2030 onshore wind capex price (with IRA)	621	$/kW	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2030 onshore wind capex price (without IRA)	956	$/kW	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2030 onshore wind capacity factor	45	%	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2030 onshore wind opex price (with IRA)	39	$/kW	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2030 LDES energy capex	25.8	$/kWh capacity	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2030 LDES power capex	946.3	$/kW	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2030 LDES efficiency	61.9	%	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2030 LDES fixed opex	12540	$/MW/year	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2030 LDES proportion of total power	73	%	Expert interviews
Renewables / LDES	2030 Split between Diurnal and Seasonal	85	% inter-day	Assumes the majority of the LDES required will be shorter-term inter-day with a small share of longer-term as backup power
Renewables / LDES	2050 LCOE	18	$/MWh	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2050 onshore wind capex price	765	$/kW	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2050 onshore wind capacity factor	47	%	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2050 Solar opex price	33	$/kW	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2050 LDES energy capex	18.1	$/kWh capacity	NREL ATB data for Class 5 onshore wind production
Renewables / LDES	2050 LDES power capex	569.3	$/kW	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)

Renewables / LDES	2050 LDES efficiency	62.6	%	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2050 LDES fixed opex	6925	$/MW/year	DOE LDES Liftoff Report (Weighted average of BAU Inter-day and Multi-day with 85/15 split)
Renewables / LDES	2050 LDES proportion of total power	69	%	Expert interviews
Renewables / LDES	2050 split between Diurnal and Seasonal	85	% inter-day	Assumes the majority of the LDES required will be shorter-term inter-day with a small share of longer-term as backup power
Electrification	2030 E-boiler + RES LCOHt	34	$/MWh	McKinsey Global Energy Perspective, Danish Energy Agency
Electrification	2030 Electric steam boiler capex	77,000	$/MW	Danish Energy Agency
Electrification	2030 Electric steam boiler efficiency	99	%	Danish Energy Agency
Electrification	2030 Electric steam boiler fixed opex	1,122	$/MW/year	Danish Energy Agency
Electrification	2030 Electric steam boiler variable opex	0.55	$/MWh	Danish Energy Agency
Electrification	2030 Thermal energy storage (TES) LCOHt	1	$/MWh	LDES Council
Electrification	2030 Low-pressure TES power capex	18	$/kW	LDES Council
Electrification	2030 Low-pressure TES energy capex	3	$/kW capacity	LDES Council
Electrification	2030 Low-pressure TES fixed opex	2	$/kW/year	LDES Council
Electrification	2030 High-pressure TES power capex	48	$/kW	LDES Council
Electrification	2030 High-pressure TES energy capex	11	$/kW capacity	LDES Council
Electrification	2030 High-pressure TES fixed opex	6	$/kW/year	LDES Council
Electrification	2030 TES proportion of total power	73	%	Expert interviews
Electrification	2050 E-boiler + RES LCOHt	18	$/MWh	McKinsey Global Energy Perspective, Danish Energy Agency
Electrification	2050 Electric steam boiler capex	77,000	$/MW	Danish Energy Agency
Electrification	2050 Electric steam boiler efficiency	99	%	Danish Energy Agency
Electrification	2050 Electric steam boiler fixed opex	1,012	$/MW/year	Danish Energy Agency
Electrification	2050 Electric steam boiler variable opex	0.44	$/MWh	Danish Energy Agency
Electrification	2050 TES LCOHt	1	$/MWh	LDES Council
Electrification	2050 Low-pressure TES power capex	14	$/kW	LDES Council
Electrification	2050 Low-pressure TES energy capex	3	$/kW capacity	LDES Council
Electrification	2050 Low-pressure TES fixed opex	2	$/kW/year	LDES Council
Electrification	2050 High-pressure TES power capex	44	$/kW	LDES Council

Electrification	2050 High-pressure TES energy capex	3	$/kW capacity	LDES Council
Electrification	2050 High-pressure TES fixed opex	2	$/kW/year	LDES Council
Electrification	2050 TES proportion of total power	69	%	Expert interviews
Electrification	TES depth of discharge	100	%	LDES Council
Electrification	TES efficiency	97	%	LDES Council
Energy Efficiency	Reduction of fuel gas consumption	10	%	McKinsey Global Energy Perspective
Energy Efficiency	Share of fuel consumption optimization levers with a 3-year payback time	65	%	McKinsey Global Energy Perspective
Energy Efficiency	Share of fuel consumption optimization levers with an 8-year payback time	35	%	McKinsey Global Energy Perspective
Energy Efficiency	Fuel gas emissions factor	56	kg CO2/GJ	Netherlands Enterprise Agency
Energy Efficiency	2030 Fuel gas price	10	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	2050 Fuel gas price	3	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	Natural gas emissions factor	56	kg CO2/GJ	Netherlands Enterprise Agency
Energy Efficiency	2030 Natural gas price	4	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	2050 Natural gas price	4	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	Refinery gas emissions factor	65	kg CO2/GJ	McKinsey Global Energy Perspective
Energy Efficiency	2030 Refinery gas price	2	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	2050 Refinery gas price	2	$/GJ	McKinsey Global Energy Perspective
Energy Efficiency	Instrument air systems - share of methane emissions reduced	50	%	Assumed effectiveness - based on McKinsey Global Energy Perspective
Energy Efficiency	Lower heating value of natural gas	0.035	GJ/m3	General constant
Energy Efficiency	Global warming potential of methane	28		GHG Protocol
Energy Efficiency	Flare gas compression efficiency	75	%	McKinsey Global Energy Perspective
Energy Efficiency	Flow of gas in flare stacks	984	mm3/year	McKinsey Global Energy Perspective
Energy Efficiency	Amount of methane in flared natural gas	70	%	McKinsey Global Energy Perspective
Energy Efficiency	Gas to diesel conversion	1076	MM3/bbl	McKinsey Global Energy Perspective
Energy Efficiency	Diesel emission factor	72.5	kg CO2/GJ	Netherlands Enterprise Agency

Methodology 4: Net-zero pathway analysis

Two scenarios were generated to guide the modeling of decarbonizing the chemicals & refining sector toward net zero. First, a business-as-usual scenario was generated to demonstrate sector emissions without significant decarbonization. Second, a net-zero scenario was generated to demonstrate how sector emissions could be abated through 2050.

Business-as-usual scenario: U.S. EIA publishes an Annual Energy Outlook (AEO), which provides energy-related CO2 emissions across key sectors in the U.S. economy. The BAU case for this analysis was based on the 2021 annual energy outlook "reference case scenario." Data from Table 19: Energy-Related Carbon Dioxide Emissions by End-Use was used, of which data for "Refining," "Bulk-chemicals," and "Plastics" sectors were summed to provide the yearly sector emissions from 2022–2050.

Net-zero scenario: In 2021, the White House published "The Long Term Strategy of the United States: Pathways to Net-zero Greenhouse Gas Emissions by 2050." In this report, energy-related emissions of Industry are modeled for a 35% reduction by 2030 and a 93% reduction by 2050 from a 2020 baseline in the high-ambition scenario. The net-zero pathway for downstream chemicals & refining was assumed to follow this same trajectory, with a 35% emissions reduction by 2030 and a 93% emissions reduction by 2050 from a 2020 baseline. This Liftoff analysis also incorporates Administration targets for transport decarbonization by 2050 (as modeled in the Long Term Strategy), grid decarbonization by 2035, and EPA's 2030 goal of achieving a 50% recycling rate. Grid decarbonization is assumed to abate all off-site electricity demands for chemicals & refining, while transport decarbonization and increased recycling are modeled to reduce demand for chemicals and refined products. A linear path to grid and transport decarbonization was assumed.

Sub-sector emissions breakdown: Total emission breakdown by chemicals processes was achieved by using a bottom-up build of all chemicals & refining emissions. Emissions from refining are directly from EIA AEO data. Natural gas processing and hydrogen production were extracted from EPA greenhouse gas reporting data. Steam methane reforming with Haber Bosch, steam cracking, and chlor-alkali process emissions data were calculated using the chemicals emissions model (see Methodology 1 above). All of these emissions were summed, and the remaining chemicals emissions were included in an "other chemicals" category. This data was used to break down baseline emissions across key product categories. Growth rates were applied to all key products to project 2030 and 2050 emissions, with total emissions numbers matched to EIA's Reference Case 2050 outlook.

Decarbonization measures for net zero: Decarbonization measures must be used to reach 2030, 2040, and 2050 chemicals & refining emissions goals. Within the net-zero pathway, decarbonization is prioritized in the following order: grid decarbonization, demand reduction, NPV-positive decarbonization measures, and NPV-negative decarbonization measures. The emission abatement potential of these categories is determined by the marginal abatement cost curve analysis described in that methodology section.

Key inputs and assumptions: See the methodology section for the main inputs and assumptions. Key inputs come from the following sources:

- White House published "The Long Term Strategy Of the United States: Pathways to Net-zero Greenhouse Gas Emissions by 2050"
- DOE EIA Annual Energy Outlook 2022
- Marginal abatement cost curve analysis (See Methodology 3)
- EPA national recycling strategy

Objective of analysis: Generate two scenarios of chemicals & refining sector emissions that can be used to quantify the needed decarbonization at different years and to provide initial guidance on which measures are likely to contribute to decarbonization.

Considerations and limitations of approach: The business-as-usual scenario is based on the EIA AEO, which has limitations described elsewhere. The net-zero scenario is limited to the assumptions made by the White House report. Scenarios provide a single pathway to a goal, but many other combinations of decarbonization measures could be used to achieve net zero.

Methodology 5: Unit economics analysis on asset decarbonization

Models were developed for two archetypical assets: a refinery and an ethane-based steam cracker. These models were used to understand the financial implications and possible internal rate of return (IRR) for implementing different decarbonization measures.

- To calculate asset level IRRs:
- Archetypical plants were generated based on U.S.-average refinery and steam cracking assets. The analysis assumed a nameplate capacity, utilization rate, and associated emissions.
- Select decarbonization measures were analyzed, including efficiency improvements, CCS, hydrogen, and electrification of low- and mid-temperature heat.
- The assumptions of cost (e.g., capex, variable opex, fixed opex), lifetime, and construction period needed for each measure were based on assumptions in the marginal abatement cost curve analysis (see above).
- The costs were scaled to match the asset, and the total capex and yearly opex of each measure was calculated.
- Tax incentives associated with the decarbonization measures were calculated, including:
  - 45Q revenue for captured carbon
  - 45V revenue for producing clean hydrogen
- Functionality was added to measure the impact of a carbon tax or technology premium.
- Initial investment and recurring capex costs were fed through a cash flow model where an unlevered free cash flow was generated.
- Project level IRRs were then calculated.

Objective of analysis: The analysis aims to provide insight into expectations for returns on real-life assets to implement key decarbonization measures.

Considerations and limitations of approach: The IRR calculations are built for projects that retrofit an existing asset, and calculations are based on additional new capital expenditures and changes in the operating expenses of the asset. This model does not consider the implementation of new greenfield assets. This data does not reflect the acceptable rates of return that companies seeking to decarbonize asset are willing to accept. Actual project IRRs will vary significantly based on the context of the individual company and facility. The results of this analysis should be seen as indicative of the industry's economics but should not be viewed as pertinent to any individual project.

Key inputs and assumptions: See the methodology section of the marginal abatement cost curve for detailed assumptions surrounding cost for different decarbonization measures. Tax incentive assumptions were taken from numbers provided in the Inflation Reduction Act of 2022.

Methodology 6: Cost gap to economic feasibility analysis

This effort modeled the cost gap between a decarbonized technology and its conventional alternative. Conventional technologies were assumed to be depreciated, with costs driven by the material cost (e.g., natural gas, unabated fossil hydrogen). Conventional technology costs were evaluated using the current range of delivered costs of natural gas from the EIA U.S. Henry Hub natural gas spot prices, based on the average and maximum natural gas prices seen from the previous two years. Conventional hydrogen price ranges were evaluated from the 2020 DOE Strategy for Hydrogen.

The following decarbonization measures were examined for an example refinery: electrolytic hydrogen for feedstock use, CCS on dilute sources, onsite power and storage for low-mid temperature heat delivery, electrolytic hydrogen for high-temperature heat, and thermal storage and high-temp heat delivery. For each technology, the cost of production was determined from the marginal abatement cost curve analysis in 2030. These delivered costs were then converted into a common unit of comparison with conventional technologies (e.g., \$ per kg H2, \$ per MWh of heat delivered, \$ per tonne CO2 captured), and a range of gaps was calculated between decarbonized and conventional measures. A required value of carbon to reach parity with the conventional alternative was calculated by converting the unit of the gap calculation to \$/tonne

CO_2 using the emissions intensity of the conventional technology (e.g., multiplying the emissions intensity of natural gas by the gap) to illustrate the carbon tax needed to close the gap. Finally, cost reductions were sensitized to understand how much capital and operating expenses must be reduced to reach cost parity with conventional technologies.

Objective of analysis: Characterize the economic gap of decarbonization measures from a cost and required carbon value perspective.

Considerations and limitations of approach: This analysis accounts for a depreciated conventional asset and cannot be used to compare the economic gap between a greenfield or partially depreciated conventional technology and new decarbonized technology. In this analysis, conventional inputs, such as natural gas and conventional hydrogen, are assumed to remain constant until 2030, and price fluctuations could impact the gap.

Key inputs and assumptions: See the methodology section for the main inputs and assumptions. Key inputs from the following sources were leveraged for baseline cost figures, assumptions, and constants:

- Marginal abatement cost curve (see above methodology)
- LDES Council - Net-zero heat: long duration energy storage to accelerate energy system decarbonization (2022)
- EIA U.S. Henry Hub natural gas spot price (4/7/23)
- GREET 2022
- 2020 US National Hydrogen Strategy
- Inflation Reduction Act of 2022 (Pub. L. 117–169)
- Federal Register EPA; 40 CFR Part 98
- DOE Pathways to Commercial Liftoff: clean hydrogen
- DOE Pathways to Commercial Liftoff: long duration energy storage

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