



TECHNOLOGICAL PATHWAYS FOR DECARBONIZING PETROLEUM REFINING

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EXECUTIVE SUMMARY

Highlights

- Even with ambitious decarbonization policies and growing electric vehicle penetration, demand will remain for transportation fuels and petrochemicals in the coming decades. The refineries that make these products must decarbonize to meet U.S. climate goals.
- Decarbonizing refineries has the potential to reduce nearly 3 percent of U.S. greenhouse gas emissions and improve local air quality. That potential stems from reducing emissions from on-site heat generation and refining processes.
- The refining sector can meet its annual heat demands while cutting emissions by switching from fossil fuels to low- and zero-carbon hydrogen fuel and/or through electrification of low-to-medium-grade heating. Process emissions can be abated through carbon capture and storage technology.
- Most of the technological options are available today at various levels of development, and innovation and deployment will expand their usage.
- Immediate access to carbon dioxide and hydrogen uniquely situates refineries to produce low-carbon and carbon-negative fuels today through existing approaches such as Fischer-Tropsch synthesis.
- In the long term, refineries could switch from processing crude oil for conventional fuel to renewable feedstocks for synthetic fuels, primarily for aviation and trucking. This could reduce fuel carbon intensities by up to 80 percent.

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Background

As the United States cuts greenhouse gas (GHG) emissions to stay within a global temperature increase of 1.5–2 degrees Celsius called for in the 2015 Paris Agreement, the industrial sector must transform if it is to reduce its substantial emissions. Industry's direct emissions amount to ~22 percent of the U.S. total, and indirect emissions from generating electricity used by industry amount to ~8 percent of the U.S. total (Vine and Ye 2018). Petroleum refining is one of the highest polluting industrial sectors, emitting nearly 200 million metric tons of carbon dioxide equivalent in 2018 (EPA 2018). Steps must be taken immediately to drastically cut its impact. Additionally, despite an anticipated reduction in fossil fuel demand, the economy in 2050 will continue to use and rely on fossil fuels and chemicals in end uses where substitutes are costly or not available, such as aviation, shipping, or long-haul trucking (Larson et al. 2020). Following aggressive efforts to shift away from fossil fuels, any remaining petroleum refineries, which manufacture these products, will continue to operate but must steeply reduce facility-level emissions. Alongside decarbonizing refining processes, these facilities can produce fuels that emit fewer GHGs than traditional fuels in response to increasing pressure for emission-free energy.

Deep decarbonization in the refining sector is possible with existing technologies at various stages of readiness. While refineries are complex and heterogenous, their emissions can be divided between stationary combustion and process emissions. *This paper assesses the technical opportunities for using hydrogen fuel switching, electrification of heat, and carbon capture and storage technology to collectively reduce the largest sources of stationary combustion and process emissions.* It recognizes that other options, such as energy efficiency, can also reduce emissions but does not examine them.

In addition to deeply reducing facility emissions, the refining sector can transition from producing traditional fuels from crude oil to low-carbon fuels from several renewable feedstocks. This paper illustrates an idealized refinery of 2050 that could, depending on resource availability, convert lipids, waste biomass, low- and zero-carbon hydrogen, and captured carbon dioxide (CO₂) into synthetic fuels. The facility would use existing and novel refining processes like hydrogen production, hydrocracking, biomass gasification, Fischer-Tropsch synthesis, and possibly direct air capture.

Technological Recommendations

Process emissions where high volumes of CO₂ derive from a single source are best mitigated through carbon capture, use, and storage technology. The two largest process emission sources in the refining sector are fluid catalytic crackers (FCCs) and steam methane reformers (SMRs). For FCCs, carbon capture technology (e.g., post-combustion with solvents, oxy-combustion) that has been proved in other industries and demonstrated in refining would be the ideal reduction method. For SMRs, using CO₂ separation technology like multistage pressure swing adsorption is already done at commercial scales, and should be expanded to all refineries with on-site SMRs.

Stationary combustion emissions are too diffuse for point source capture but can be mitigated through fuel switching to clean hydrogen fuel or electrification. Refineries are already the largest consumers of hydrogen and have supply chains and infrastructure that would enable low-carbon hydrogen produced on-site or from nearby dedicated hydrogen plants to be used as fuel for high-heat processes. Electrification with clean energy would be able to generate low and medium temperatures but would likely comprise a relatively small percentage of total energy generation. Because refineries primarily combust self-produced refinery fuel gas for heating, managing this waste by-product is a significant barrier that can be surmounted by using it in an SMR or gas turbines with carbon capture.

By 2050, refineries may be vastly different in terms of their products, processes, and feedstocks to meet lower demand for transportation fuels and decarbonization requirements. In addition to incorporating the recommendations above for short-term decarbonization, refineries in 2050 may switch their feedstocks from crude oil to renewable materials like lipid oils and waste biomass, as well as self-produced hydrogen and CO₂. By expanding common processes like methane reforming and hydrocracking along with novel and less conventional processes like electrolytic hydrogen, Fischer-Tropsch synthesis, and direct air capture, future refineries can make products far cleaner than today's and reduce overall facility emissions. While this new refinery is possible in principle, it would require ambitious modifications.

About This Working Paper

This paper provides policymakers and stakeholders with an overview of refinery emissions today and the possibilities for and barriers to mitigating them. The options discussed aim to serve as an independent and accessible outlook on refinery decarbonization amid a small but growing body of literature and research largely published by the oil and gas sector and punctuated by some academic studies.

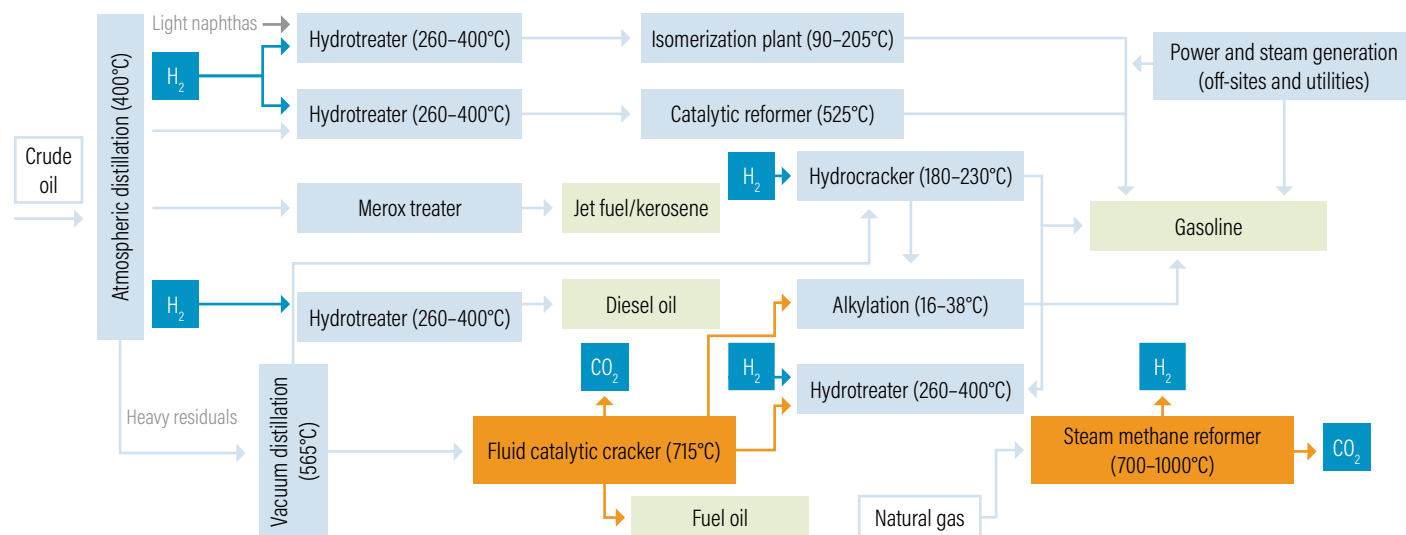
Literature reviews, original analyses of public data, and expert interviews inform this paper's conclusion that decarbonizing refineries is possible and would require ambitious expansion of existing and novel technologies. Further research could more quantitatively model different decarbonization scenarios and their emission reductions and assess the policies that would decrease technology costs and increase uptake. A future project could expand this work to include the petrochemical supply chain, which is closely linked with petroleum refineries. Other World Resources Institute research on industrial decarbonization, most notably on

cement and steel production, provides similar sector overviews with greater emphasis on policy options, of which there are substantial overlaps (see Fransen et al. 2021).

1. UNDERSTANDING REFINING

Petroleum refining is among the largest industrial emission sources in the United States, producing approximately 13 percent of all industrial greenhouse gas (GHG) emissions, or 198 metric tons of carbon dioxide equivalent (MtCO₂e), and approximately 3 percent of all U.S. emissions in 2018, not including indirect emissions (EPA 2018). In 2018, there were 140 refineries spread across the country, largely clustered along the Gulf Coast, in the Midwest, and in Southern California. Decarbonizing refineries is complex compared with other industries because individual facilities contain many dispersed emission sources and vary greatly, with different production units on-site, local distribution demand and networks, and equipment ages.

Figure 1 | **Representative Flow Diagram of a "Typical" Refinery and Its Major Units' Heat Requirements**



Notes: Refineries primarily produce transportation fuels as pictured, with some petrochemical production, which demands higher-temperature cracking conditions not shown since these products do not represent the majority and are usually produced either at neighboring petrochemical plants or in most cases sourced through natural gas as a feedstock. Hydrogen is also represented as an output of steam methane reforming and input during hydrotreating and hydrocracking. Orange units delineate large process emission sources from light blue units, which contribute to stationary combustion emissions through their heat needs.

°C = degrees Celsius; H₂ = hydrogen; CO₂ = carbon dioxide.

Source: CARB 2013.

Additionally, refineries are a major source of air pollution and toxins, which pose health risks to populations living nearby. Leaking equipment, flue stack emissions, and explosions release hazardous pollutants that harm adjacent, frequently low-income neighborhoods. And while hazardous emissions have decreased greatly in the past 40 years due to the Clean Air Act, they still pose harm and equity issues to nearby populations (Nelson 2012). Imperfect monitoring equipment likely underreports that harm's severity (McLaughlin et al. 2020). Thus, while this paper focuses on GHGs, it acknowledges that refineries pose other considerable environmental and health hazards that must be addressed concurrently.

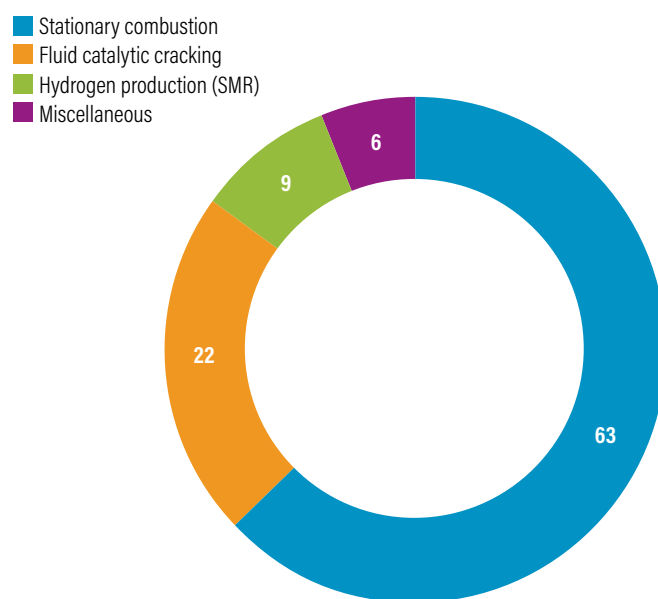
Figure 1 presents a flow diagram of the typical refining processes required to produce fuels. Most refineries produce a combination of motor gasoline, jet fuel, diesel, fuel oil, and liquified petroleum gas, as well as non-fuel products like asphalt and chemicals. First, crude oil is fed into the atmospheric distiller, which uses heat and varying boiling points to separate low-value hydrocarbons from their short-chain counterparts. Following distillation, the separated hydrocarbons undergo several refining steps depending on their molecular structure. For example, diesel oil requires only distillation and then desulfurization with hydrogen, but longer-chained hydrocarbons require additional steps, like fluid catalytic cracking, to break the hydrocarbon chains into shorter chains (CARB 2013). Although not represented in Figure 1, petrochemical feedstocks like olefins and lighter hydrocarbons are produced through steam cracking and fluid catalytic cracking.

Residual petroleum left over from the refining steps is processed into refinery fuel gas, which is used as a primary fuel in process heaters, turbines, boilers, and other combustion units. Refinery processes require different heat qualities, with cracking and heat generation operating at the highest temperatures (715–1600 degrees Celsius; °C); catalytic reforming and hydrotreating at medium temperatures (500–750°C); and low-grade heat (<400°C) exported for steam generation, distillation, and hydrotreating (Gudde 2019a).

Demand for different products, on-site space availability, systems integration with nearby transportation and processing infrastructure, and other factors determine what a refinery manufactures. This heterogeneity inhibits a standard decarbonization solution that can be applied at every refinery. Additionally, and unlike other industrial sources that produce concentrated single streams of CO₂, like cement and dedicated hydrogen production, refineries

may emit CO₂ from well over 100 point sources. Nonetheless, refinery decarbonization is possible. In many cases, the technological pathways to do so already exist, albeit at different stages of readiness and cost, some requiring further research and development (R&D) and others ready for deployment.

Figure 2 | **Percent Share of Emissions Attributable to Stationary Combustion and Process Emissions**



Notes: U.S. refinery emission sources. Fluid catalytic cracking and hydrogen production would be categorized as process emissions.

SMR = steam methane reformer.

Source: EPA 2018.

1.1 Refinery Emissions

Large polluting sectors like industry and power production are required to categorize and report their emissions to the Environmental Protection Agency (EPA).¹ From those data, refinery emissions, which consist of GHGs like carbon dioxide, methane, and nitrous oxide, can be divided into three categories: stationary combustion, process, and miscellaneous. Stationary combustion emissions come from burning fossil fuels in combustion units to generate heat for on-site processes like distilling crude oil, creating steam, and cracking hydrocarbons. Stationary combustion results in approximately 63 percent of the refining industry's total emissions, as shown in Figure 2 (EPA 2018).

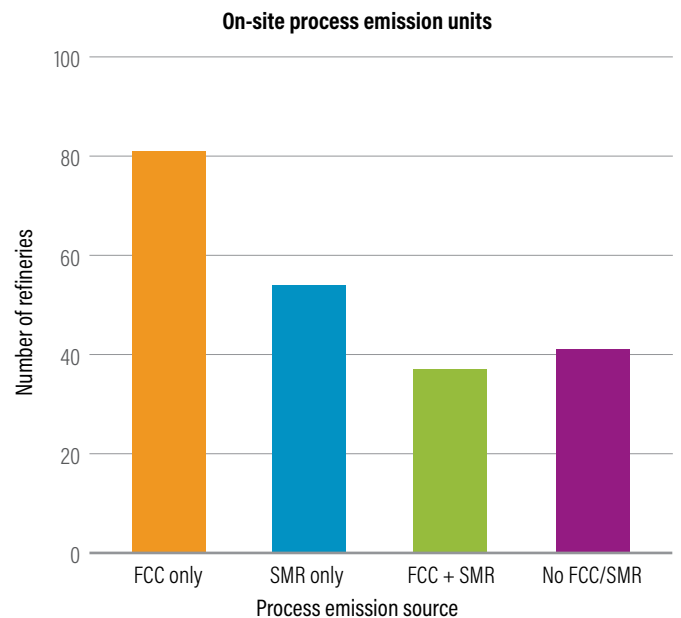
Process emissions are produced by chemical reactions inherent in the refining process. The two most notable sources of process emissions are fluid catalytic crackers (FCCs) and steam methane reformers (SMRs); these units require high temperatures and generate emissions originating from the chemical reactions they induce. FCCs and SMRs are not present at all refineries, as shown in Figure 3, and refineries generate fewer process emissions on average than stationary combustion emissions, putting them at a smaller share of total emissions (31 percent) compared with stationary combustion (63 percent) (EPA 2018).

The remaining emission sources constitute a small percentage (~6 percent) of the total, generally derived from gas flaring, catalytic reforming, electricity production, landfills, methane leaks, and sulfur recovery. Because these individual sources comprise a small portion of the emissions industry-wide, this study does not examine specific mitigation pathways for them. However, these sources may represent a larger portion of an individual facility's emissions profile if the facility does not have an FCC or SMR (Figure 3). For example, the Valero Texas City refinery does not report emissions from an FCC or SMR, and miscellaneous emissions comprise 38 percent of its 2.1 MtCO₂e total (EPA 2018). Additionally, miscellaneous emissions may be reduced as co-benefits from other mitigation approaches. For example, natural gas flaring would decrease as refineries replace natural gas with non-fossil energy.

1.2 Life Cycle Perspective

Any examination of the refining sector should keep in mind the life cycle emissions associated with fossil fuels: the refining step in that cycle produces significant emissions, but the overwhelming share of emissions occurs at the final step—that is combustion in transportation, buildings, and other sectors. The life cycle GHG intensities of fuels are divided among the recovery, refining, transport, and combustion phases. Standard motor gasoline, diesel, and jet fuel—three primary refinery products, in that order—have well-to-wheel carbon intensities (CIs) between 85 and 98 grams of carbon dioxide equivalent per megajoule (gCO₂e/MJ). Motor gasoline has a total CO₂e intensity of 89 g/MJ, of which 17 g/MJ are produced during extraction and refining, 1.5 g/MJ during blending with other feedstocks, less than 1 g/MJ for transportation to the pump, and approximately 71 g/MJ during its combustion (DOE n.d.-c).

Figure 3 | Number of Refineries with or without Major Process Emitters



Note: FCC = fluid catalytic cracker; SMR = steam methane reformer.

Source: EPA 2018.

These values may differ based on the measurement parameters and sources of crude oil. For example, U.S. crude oil extraction in the Gulf Coast region produces about 30 kilograms of carbon dioxide equivalent per barrel (kgCO₂e/bbl) of crude or 5 gCO₂e/MJ, whereas Canadian oil sands produce about 200 kgCO₂e/bbl of crude or 33 gCO₂e/MJ (Gordon et al. 2015). Differences arise through the crude type and extraction process, where some types of crude require energy-intensive upgrading before refining and some operations vent and flare methane at higher rates than others. This paper uses domestic crude as defined by the National Energy Technology Laboratory, which is the most common U.S. refinery feedstock and has below-average life cycle emissions.

Over motor gasoline's, diesel's, and jet fuel's life cycles, the refining stage produces approximately 15–20 percent of those emissions, with the fuel's combustion comprising the largest portion and extraction and transportation providing the small remainder. A decarbonized refinery both reduces atmospheric pollution of GHGs and particulate matter and may enable fuels from that refinery to meet clean fuel standards (e.g., the California Low Carbon Fuel Standard). These will deliver climate, air quality,

and business benefits as the United States weans itself off fossil fuels in the coming decades. For non-combustible products, refinery emissions comprise a larger percentage of their life cycle and would therefore achieve greater life cycle reductions, but these products generally make up less than 10 percent of a refinery's product output (EIA 2020).

1.3 Current Abatement Projects

This paper assesses the application of fuel switching on-site heat generation and applying carbon capture to the major process units and possibly gas turbines where necessary. Carbon capture, use, and storage (CCUS) technologies are an effective tool for mitigating process emissions because these flue streams come from large, single-point sources rather than varied and dispersed exhaust systems. Fuel switching and electrification, on the other hand, can be applied to dispersed combustion systems, providing clean heat if the electricity or fuel is low or zero carbon.

The extent to which these technologies have been deployed in the refining sector today has been limited, at least relative to their use in other industries. A few past and current examples include the following:

- ION Engineering CCUS Project, Norway: Between October 2016 and April 2017, ION Engineering tested CO₂ capture on a combined heat and power plant and fluid catalytic cracker at the European CO₂ Test Centre Mongstad. It cumulatively captured 14,820 tons of carbon dioxide (tCO₂) from the two projects over that period, with an average capture rate of 85–90 percent and per-ton capture cost of US\$35–44 (Awtry 2018).
- Sturgeon Refinery, Canada: This refinery gasifies bitumen waste from its operations into hydrogen and a pure CO₂ stream, with potential to store between 1.2 and 1.4 million tons of CO₂ annually in off-site enhanced oil recovery (EOR). The refinery estimates that capturing and storing this CO₂ reduces its emissions by 70 percent (MIT 2016).
- Quest Carbon Capture Project, Canada: Shell's Quest project at a bitumen upgrading facility uses an amine capture system on a steam methane reformer for hydrogen production. Since its start in 2015, it has captured over 1 MtCO₂ per year (Tucker et al. 2016).
- Air Products Hydrogen Plant, Texas: Air Products deployed the first commercial-scale SMR to use vacuum-swing adsorption to separate CO₂ during hydrogen production located at a Valero refinery in Port Arthur. Operating since 2013, it captures approximately 1 million tons per year, which are transported to Texas oil fields for EOR (Preston 2018). It was 1 of 12 refineries in the United States that produced hydrogen and sold the CO₂ for external use in 2018 (EPA 2018).
- Petrobras Oxy-Combustion Demonstration, Brazil: Whereas most commercial facilities that capture CO₂ use post-combustion, solvent-based technology, Brazilian petroleum firm Petrobras used a large pilot-scale oxy-combustion system to create a 95 percent CO₂ flue stream in an FCC. Oxy-combustion uses pure rather than atmospheric oxygen to regenerate the FCC catalyst, creating a high-purity stream of CO₂. This demonstration, the larger of two pilots over one year, yielded higher CO₂ recovery and a lower per-ton capture cost than the post-combustion baseline (Mello et al. 2013). And while a per-ton cost was not released from this demonstration, other studies based off these pilots estimate a per-ton cost of 55–85 euros (\$65–100 in 2020 US\$) (Gulec et al. 2020).
- The Essar Refinery Complex, United Kingdom (UK): This complex is one of several sites that the UK government is assessing for industrial fuel switching to hydrogen. The estimated total cost of installing and operating a new gas turbine with combined heat and power fueled by hydrogen would cost 48.7 million pounds per year (\$62.5 million in 2020 US\$), which is 36.5 million pounds more than a natural gas turbine (Progressive Energy and Pilkington 2020). Although more expensive than a natural gas turbine, it is important to recognize that on a mass basis, hydrogen contains roughly three times as much energy as natural gas, which will ultimately lead to reduced capital costs per unit of energy.
- BASF: BASF is currently developing an electrical furnace that could be used in its large steam crackers that produce olefins, aromatics, and lighter hydrocarbons. These furnaces, scheduled for 2025, could generate high enough temperatures to satisfy the steam crackers' heat needs of > 850°C using external renewable electricity or low-carbon electricity generated at the refinery. The furnace technology could likely be modified for use in other refining units as well (Davis 2019).
- Chevron and John Zink Hamworthy, Oklahoma: Using commercially available burners from John Zink Hamworthy, Chevron tested the technical feasibility of switching from refinery fuel gas to hydrogen fuel to

generate refinery heat. They found that fuel switching generates sufficient heat and does not require large or costly retrofits—minor changes such as replacing burner tips are sufficient (Lowe et al. 2011).

Commercial, demonstration, and lab-scale abatement technologies continue to develop in refining, as well as in other industrial and power sector facilities where their technological maturities vary greatly. Those other sectoral applications can and will likely be instructive as the refining sector further invests in emission reductions.

2. PROCESS EMISSIONS

Production processes are the second-highest category of emissions, representing roughly 34 percent of the refining industry's emissions footprint at 72.6 MtCO₂e. Fluid catalytic crackers and steam methane reformers, the largest sources of process emissions, comprise 60.2 MtCO₂, or 31 percent.² Because these two large point sources generate the greatest proportion of process emissions, CCUS technology is the best abatement option for existing flue streams, although future hydrogen plants could avoid emissions entirely by using electrolysis rather than SMR, which will be discussed in Section 2.4. Prior work assessing the abatement potential of CCUS with a 90 percent capture rate on process emissions from refining estimates a reduction potential of approximately 56 MtCO₂ (Pilorgé et al. 2020a).

2.1 Carbon Capture, Use, and Storage Technology

Point source CCUS technology is the key solution to mitigate process emissions from high-volume single sources across all industries (EFI and SU 2020). Point source capture can be designed as pre-combustion, post-combustion, or oxy-combustion systems, although R&D seeks to expand the viability of other novel systems. Pre-combustion and oxy-combustion produce higher-purity CO₂ by separating it before combustion but can be applied only to new builds. Post-combustion can be retrofitted onto existing plants—and is thus better suited for plants far from their end of life—but may result in a higher per-ton capture cost depending on the flue stream's CO₂ concentration. Additional system considerations include scale of emissions, gas pressure, and availability of thermal energy for regenerating the sorbent (Wilcox 2012).

The process entails diverting flue gas into an absorption column containing chemicals that capture the CO₂. The two most common chemical mediums are liquid solvents

that absorb CO₂, which is the most commercially mature technology, and solid sorbents that adsorb CO₂. Importantly, all systems must remove impurities from the CO₂ streams, which requires stripping away rather than emitting local pollutants like nitrogen oxide, sulfur oxide, and particulate matter that harm nearby communities. However, the degree of purification may vary depending on the system configuration (Forbes et al. 2008).

Captured CO₂ can be used as a feedstock for other products, but storage in geologic formations like saline aquifers, depleted coal and gas seams, and ultramafic rock will likely be the only means to ensure permanent, gigaton-scale carbon removal. By 2050, the United States may need to sequester between 0.9 and 1.7 GtCO₂ per year from fossil fuel and industrial sources to stay below 1.5°C warming, a formidable challenge from today's sequestration of under 100 MtCO₂ annually but well within the U.S.' estimated 2000 Gt of capacity (Larson 2020; NAS 2019).

2.2 Fluid Catalytic Cracking

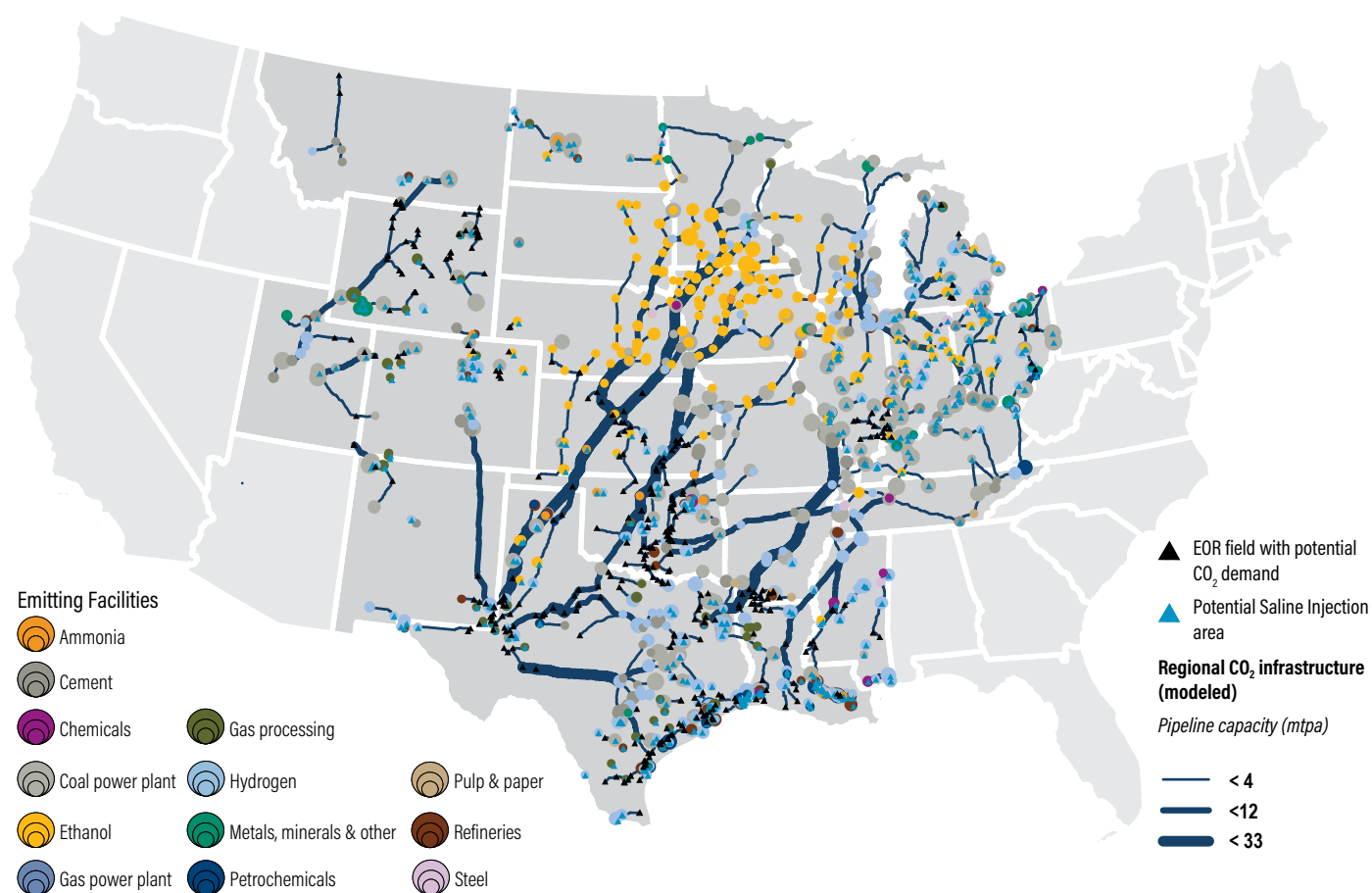
Across all refineries, fluid catalytic crackers are the largest source of process emissions (Gulec et al. 2020; EPA 2018). In 2018, FCCs emitted 42.4 MtCO₂ over 81 facilities, or an average of 305,000 tons per facility. The FCC breaks long-chain hydrocarbons into smaller chains using heat and a zeolitic catalyst, refining lower-value crude oil into higher-value products like gasoline, propane, butane, and fuel oil. During the cracking process, heavy, non-desorbed carbonic molecules permeate and accumulate within the catalyst's pores, coating it with a layer of coke (Den Hollander et al. 1998). This can deactivate the catalyst, necessitating that the coke be burned off for its reuse in the unit's regenerator. CO₂ created by burning the coke constitutes 15 percent of the flue stream's molecular content (Pilorgé et al. 2020b).

The per-ton cost of capturing and compressing CO₂ from an nth-of-a-kind FCC equipped with solvents is approximately \$50/tCO₂, and the full levelized cost of capturing, compressing, transporting, and storing one ton of CO₂ ranges between approximately \$70 and \$120 (Pilorgé et al. 2020a). These costs will decrease, perhaps substantially, with further deployment and “learning by doing,” as shown by the power sector, where capture costs fell from \$110/ton in 2014 at a first-generation plant to \$65/ton by 2017 in the second generation (Baylin-Stern and Berghout 2021).

The CO₂ transport and storage methods affect the end cost of CCUS, which can vary depending on whether pipelines or trucks transport CO₂ and if it is stored through enhanced oil recovery or dedicated geologic sequestration. Trucking to EOR sites yields the highest costs because it entails transporting small amounts to a singular point within a large sedimentary basin; dedicated geologic storage, on the other hand, benefits from more flexible siting within the geographic boundaries in the identified

basin area, with the main shortcoming being greater mapping of possible injection sites (Pilorgé et al. 2020a). And because pipelines transport large volumes of CO₂, pairing them with dedicated storage yields the lowest per-ton cost. The current network of CO₂ pipelines is currently insufficient for gigaton-scale sequestration, but building out new pipelines will incentivize new capture and storage opportunities by greatly reducing transport costs.

Figure 4 | **Carbon Dioxide Pipeline Network in the Midcontinent for Ambitious Saline Sequestration**



Notes: EOR = enhanced oil recovery; CO₂ = carbon dioxide; mtpa = million tonnes per annum.

Source: Abramson et al. 2020.

Currently, CO₂ pipelines span about 5,000 miles within the United States, the majority of which are concentrated, due to energy and industry clusters, along the Gulf Coast, Permian Basin, Upper Midwest, and Northern Rocky Mountains for delivery to EOR injection sites and other offtakers. That network is insufficient to connect CO₂ storage sites with the multitude of facilities across numerous industries countrywide with CCUS potential, let alone at the scale needed to reduce megatons of emissions annually. One optimization analysis using conservative assumptions estimates that the cumulative pipeline network in the Midcontinent region would need to span over 29,000 miles to deliver 358 MtCO₂ from industrial facilities and power plants to saline and EOR sites—that tonnage delivered increases to 669 MtCO₂ when lifting cost constraints (Abramson et al. 2020).

For an aggressive refinery-to-saline scenario, the pipeline network in the Midcontinent, as shown in Figure 4, would offtake 30.9 MtCO₂ captured and stored from 36 refineries by 2035 and 34.2 MtCO₂ from 65 refineries by midcentury (Abramson et al. 2020). That study assessed facilities that emit a certain tonnage per the federal 45Q tax credit (100,000 and 500,000 for industrial and power facilities, respectively); removing the eligibility threshold would expand the amount of CO₂ captured and stored.

The regional refining and industry hubs with infrastructure that can be used for transporting, using, and storing CO₂ from FCCs also often contain hydrogen supply chains. Because hydrogen production is also a large emission source, these hubs are an opportune starting place to abate these two major refining process emissions.

2.3 Hydrogen Production – Steam Methane Reforming

The United States produces 10 million tons of hydrogen each year, 95 percent of it through a steam methane reformer (SMR). Refining is the largest U.S. hydrogen consumer, using 70 percent of production for processes like hydrocracking and hydrotreating (DOE 2020). Because refinery hydrogen demand is so large, 55 out of 139 refineries in 2018 had an SMR plant on-site, constituting the sector's other main process emission source (EPA 2018). Refineries without their own SMR are often located next to a nearby merchant plant that establishes a convenient, local supply chain. This paper only considers SMRs located within a refining complex, but the technological recommendations are applicable to merchant plants given their similarities and interdependency.

Steam methane reforming mixes natural gas with hot steam from waste heat and partially oxidizes methane to form carbon monoxide (CO) and hydrogen. After the natural gas is reformed, a water-gas shift takes place where steam, heat, and a catalyst convert CO to CO₂ to produce more hydrogen. Next, multistage pressure swing adsorption (PSA) separates hydrogen and CO₂.

The first PSA separates hydrogen from the off-gas containing CO₂, CO, and trace methane. The off-gas is sent to the combustion furnace to drive the reforming process, along with additional natural gas to achieve the necessary amount of heat. A second PSA separates the process CO₂ from the process off-gas, capturing approximately 45–55 percent of the CO₂ for a unit of hydrogen produced. To capture up to 99 percent, a third PSA can be installed to separate CO₂ from the combustion flue stream (Allam et al. 2003). These steps can also be reconfigured based on costs and system boundaries (Forbes et al. 2008).

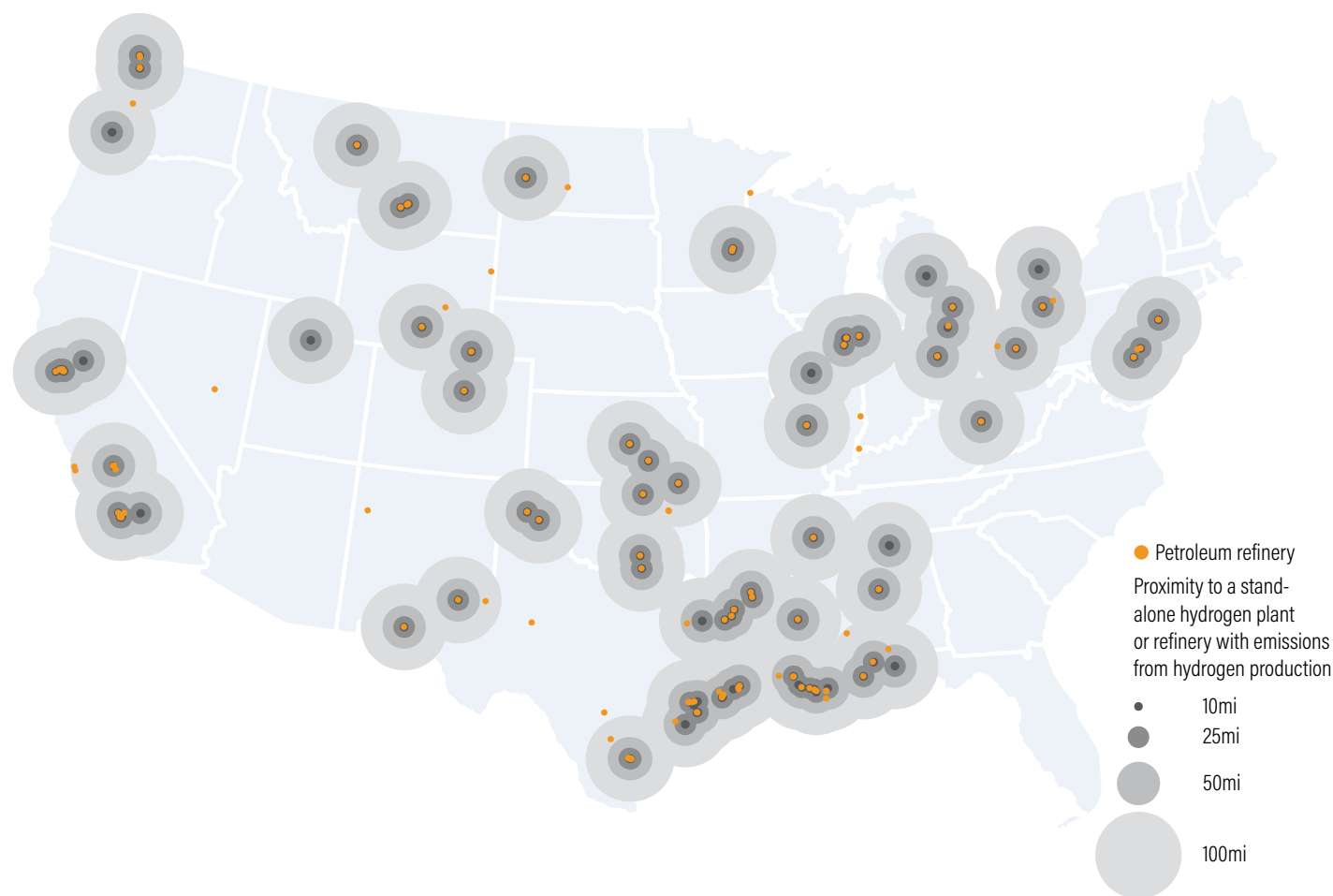
Widespread adoption of any form of zero-emission reforming is only prospective today. Most SMR CO₂ is vented into the atmosphere because selling CO₂ to buyers like the oil and gas, food and beverage, and chemicals industries does not always offset the cost of separating and transporting it. Out of the 55 refinery hydrogen plants with SMRs in 2018, only 12 exported an unreported amount of CO₂ to customers (EPA 2018). This indicates that making clean hydrogen is doable today, but markets and sequestration opportunities must expand while production costs fall.

2.4 Blue, Green, and Emerald Hydrogen

Hydrogen is typically categorized by color, according to its production pathway and emissions. The vast majority is “gray” hydrogen, created when the SMR emits CO₂ into the atmosphere and thus discounts it from being considered clean. Low-carbon refining's challenge is replacing gray hydrogen with clean varieties while increasing total production to both serve as fuel and process feedstock.

Clean hydrogen production pathways include “blue,” which captures and permanently stores SMR CO₂ rather than emitting it; “green,” which uses 100 percent carbon-free energy (most likely solar and wind energy, but possibly also nuclear, geothermal, or hydropower) to power electrolyzers that use electricity to split water into hydrogen and oxygen molecules; and “emerald,” which uses plant waste from forests, mills, and agriculture as feedstock and converts the material into syngas and then hydrogen.

Figure 5 | Proximity of Refineries to Hydrogen Production



Source: Original data analysis by Elizabeth Abramson, Great Plains Institute, assessing refinery and hydrogen plant proximities on behalf of World Resources Institute, 2021.

By 2050, U.S. hydrogen production is expected to grow at least eight-fold from today's annual production of 10 Mt as new end users and producers come online, much if not most of that growth from green hydrogen accelerating in the 2040s (Larson et al. 2020). Blue hydrogen from steam methane reforming and autothermal reforming (ATR)—another production route using natural gas—will likely continue meeting refinery demand until 2050 because of existing refining and hydrogen clusters that enable cost-reducing economies of scale built upon natural gas and hydrogen transport networks. Figure 5 illustrates these clusters and shows that just 22 percent of refineries are beyond 10 miles of a hydrogen plant, and only 8 percent beyond 100 miles.³

Today, the per-kilogram cost of blue hydrogen, at \$1.50–3.16, is slightly higher than that of gray, at \$1.00–2.14, whereas green hydrogen ranges between \$2.80 and \$28.75 (Liguori et al. 2020). While green's variation is due to the current high cost of electrolyzers and the capacity factor and availability of renewable or zero-carbon energy, these are all expected to greatly improve by 2050. On a marginal-cost-per-ton-of- CO_2 -reduced basis, blue hydrogen in 2020 ranges between \$51 and \$74, with cost increasing with higher capture rates (53–89 percent) (Bartlett and Krupnick 2020). By 2030, some decarbonizing blue hydrogen plants may transition to ATR due to its low cost of \$22 per-ton-reduced at 90 percent capture and fit with present infrastructure. After 2050, it is likely that some refineries, particularly those that do

and Gulf Coasts and in the Upper Midwest, there exists great potential for negative-emission emerald hydrogen, although the refineries would likely compete with other facilities that produce bioenergy or biofuels.

2.5 Miscellaneous Process Emissions

In addition to these major stationary combustion and process emissions, refineries produce lesser volumes of process GHGs through flaring, catalytic reforming, sulfur recovery, and other minor sources. These miscellaneous emissions are typically small relative to a refinery's entire carbon profile, averaging 27,000 tons of CO₂e per facility in 2018. Given miscellaneous emissions' variation and limited volume, dedicated actions to decarbonize them may not always be economical. However, they may decrease by reducing the larger emissions (e.g., cutting down on or eliminating flaring after fuel switching from hydrocarbons).

There are outliers where miscellaneous emissions comprise a large portion of a refinery's total, particularly for smaller refineries with fewer processes. For example, the Martin Resource Management refinery in Kilgore, Texas, is relatively small, producing 323,581 tons of CO₂e in 2018. But flaring comprised 87 percent of its emissions and is greater in absolute terms than any other refinery in the country. That high percentage is likely due in part to very limited dedicated hydrogen production and the absence of an FCC. In contrast, the Galveston Bay Refinery in Texas is one of the largest in the country, emitting 6.9 MtCO₂e. Only 3 percent of its emissions in 2018 were from flaring—the average across all facilities—but due to its overall emissions level was the second-largest flare emitter, polluting over two times as much as the third largest (EPA 2018).

3. STATIONARY COMBUSTION, HEAT, AND POWER

Heat generation from burning fossil fuels produces the largest portion of a refinery's emissions. In 2018, it comprised 63 percent of the industry's emissions, ranging between 1,800 tCO₂e and 8.9 MtCO₂e, and averaging 903,000 tons of CO₂e per facility (EPA 2018). The variety and complexity of refining processes require a wide range of temperatures. Some processes, like basic facility heating or low-grade steam, use low temperatures. Conversely, a steam cracker, which converts heavier hydrocarbons into olefins and lighter hydrocarbons, requires up to 1600°C (Lee and Elgowainy 2018).

Most refinery energy comes from combusting fossil fuels for process heating, followed by steam from boilers and combined heat and power (CHP) systems. Small amounts of electricity from CHP systems and the grid mainly go toward machine drives and non-process energy (DOE n.d.-b). Process heaters are the most used heating systems, followed by thermal oxidizers and furnaces (EPA 2018); CHP systems likely generate a notable amount of stationary combustion emissions as they provide 15–20 percent of on-site energy, but are not reported by name to the EPA (DOE n.d.-b).

Because a refinery may use dozens of heating units with widely dispersed exhaust streams, employing CCUS for every if not most units is not as feasible as it is for a large point source like an FCC. Thus, fuel switching from fossil fuels to clean hydrogen or electrifying with clean electricity can abate these dispersed emissions. When hydrogen is burned, it releases water vapor instead of CO₂ and can achieve temperatures high enough for the hottest processes. While electrification is less promising for heat-intensive processes, it can satisfy low and medium temperatures. Among the options, the combination of quality heat needs, existing infrastructure, and system integration favors a higher proportion of hydrogen to electrification. Before a refinery can switch, however, it must contend with the barrier of managing unused refinery fuel gas.

3.1 Refinery Fuel Gas

In 2018, 75 percent of on-site U.S. refining heat was generated by burning refinery fuel gas (RFG), a residual waste product created by refining processes that has little export value. It contains high levels of impurities like sulfur and cyanide and thus must be used on-site due to the difficulty and cost of safely disposing of it. Sixty-eight percent of refinery heating units use RFG, 21 percent use natural gas, and the remainder use small volumes of other fuels like kerosene (EPA 2018).

Chemically, RFG is like natural gas. They both have similar carbon intensities and are primarily composed of methane. While RFG generates more heat than natural gas—1.38 thousand British thermal units per cubic foot (Btu per ft³) compared with 1.027 thousand Btu per ft³, respectively—they are near substitutes (Law Information Institute n.d.). The key difference, however, is that refineries import processed natural gas, whereas RFG is created on-site and must be processed prior to use. Because RFG is an unavoidable by-product of refining and cannot be economically exported or disposed of in large volumes, successfully transitioning to clean fuels or electricity

creates a waste management problem for unused RFG—the portion of a facility’s RFG heat is a soft cap on decarbonization. One report estimates that refineries in the European Union (EU) could electrify only one-third of process heat because the remaining two-thirds use RFG (Gudde 2019a).

This paper recommends taking advantage of RFG’s similarity to natural gas and using it to make clean electricity or hydrogen on-site where possible. It is difficult to estimate the amount manageable through these options, but these recommendations are starting points to handle a significant amount of the waste.

By stripping impurities and pressurizing its flow, RFG can be used in a natural gas turbine to generate electricity—equipped with carbon capture technology, the turbine would produce low-carbon electricity. CCUS has long proved to be technologically viable for natural gas units—see, for example, early plants like the Bellingham plant in Massachusetts, which captured 85–95 percent of its emissions between 1991 and 2005 (DOE 2016). That electricity could be used internally or possibly exported to the local grid to provide low-carbon power when renewables are not operating. Alternatively, RFG can be reformed or partially oxidized to produce blue hydrogen as it contains methane levels similar to that of natural gas. This would deliver three benefits: managing RFG, producing clean hydrogen, and reducing natural gas imports.

3.2 Heating with Hydrogen

Hydrogen holds great promise as a low- or zero-carbon fuel to reduce industry emissions because it can generate sufficient heat for energy-intensive processes. It is a particularly attractive option for refineries because they already exist within hubs that produce, transport, and consume hydrogen (Bartlett and Krupnick 2020). As such, the economic and social challenges associated with building transportation and storage infrastructure are low for this sector.

Retrofitting an industrial heating system for 100 percent hydrogen must account for flammability, the formation of nitrogen oxides (NOx), and pipe thickness/material modifications. These are technically simple considerations, requiring standard regulatory compliance regarding safety and pipe specifications along with new burner tips to accommodate the hydrogen flame. Retrofitting heat systems to use hydrogen fuel will likely lead to minimal production disruptions as heaters are frequently replaced throughout regular facility maintenance. That

is, unlike large single systems such as FCCs, which have lives of up to 40 years, heaters can be replaced piecemeal over time until the entire system has gradually been switched (EPA 1993).

While burning hydrogen emits water vapor rather than CO₂ emissions, it does emit NOx when burned above 1300°C (EPA 1999). Few processes require temperatures that high, but local NOx pollution is a concern as it increases ground-level ozone and particulate matter concentration, causes acid rain, increases risk of respiratory diseases, and induces other environmental and health impacts (EPA n.d.). NOx are common pollutants originating from vehicles, industry, and power plants. As such, all levels of government regulate it, and refineries must ensure they use low-NOx-burning technology to minimize pollution, particularly within densely populated areas.

3.3 100 Percent Hydrogen Heat

Using the heating unit data refineries report to the EPA, which include CO₂e emissions and fuel type, it is possible to estimate every unit’s heat demand and, subsequently, the upper bound of hydrogen fuel switching. As a theoretical estimate, 100 percent hydrogen heat optimistically assumes that all RFG is converted into low-carbon energy via an SMR or turbines with CCS or is otherwise safely disposed of and that no electrification takes place. In 2018, refineries generated 75 percent of their heat from refinery fuel gas. The remaining 25 percent was primarily natural gas, with marginal amounts of distillate fuel oil, motor gasoline, and propane. Cumulatively, these fuels generated over 2.1 quadrillion Btu of energy and emitted 126 million tons of CO₂e (EPA 2018). For comparison, that same year the United States consumed a total of 101.5 quadrillion Btu (McFarland 2019).

One hundred percent hydrogen heat would require at least 19 Mt of hydrogen to meet 2018 demand. In the case of 100 percent blue hydrogen, where every kilogram of hydrogen produces 5.5 kilograms of CO₂, this would create 105 million tons of CO₂ that would have to be sequestered. Most likely, refineries switching to hydrogen fuel would do so for the majority of their processes, but it is unlikely that the sector or most facilities would reach 100 percent because some processes can be electrified, particularly those requiring temperatures below approximately 350°C. Producing anywhere near 19 Mt would require building out new production and use hubs over time. The balance between hydrogen and electrification would depend on the facility and be based on its products, the age of its heaters,

the level of process integration with heat and power systems, and whether it has access to low-carbon hydrogen and electricity.

3.4 Electrification

Electrification with clean energy would likely hold a relatively small but still useful position in a facility's energy mix. An electric system is more efficient than fuel combustion, and electrification would avoid efficiency losses incurred during hydrogen generation (Bossel and Eliasson n.d.). Moreover, comprehensive energy efficiency gains could reduce facility fuel use up to 50 percent (Richter et al. 2020).

There are barriers, however. Notwithstanding RFG management as discussed earlier, the potential for electrifying heat with low-carbon energy is limited. Refineries derive less than 10 percent of their energy from electricity, the lowest of all industrial sectors (Deason et al. 2018). Additionally, as one-third of electricity is produced on-site—primarily from CHP systems that are deeply integrated for efficiency—expanding a refinery's internal electricity network to import more electricity would be complex (DOE n.d.-b). Finally, electrified process heat is more expensive than conventional fuel systems, although there exists great room for cost reductions through innovation and growing renewable energy production (Gudde 2019a).

Despite those constraints, refineries can begin by electrifying heat sources that are separate or less integrated into the facility-wide steam and CHP systems. To use RFG cleanly and reduce reliance on external renewable energy that may be limited, low and medium heat needs could be met through electricity generated by a CHP or turbine system with carbon capture. In the long term, electric steam crackers and innovative electric process heaters may reach commercial viability, enabling electrified high temperatures.

4. WHAT A REFINERY MIGHT LOOK LIKE IN 2050

Meeting the international goal of staying within a 1.5–2°C increase in global temperature will require making steep reductions across all sectors, which can be achieved only through international cooperation and new and improved policies across all levels of government. In most deep decarbonization modeling studies, domestic demand for transportation fuels is expected to decline by 2050, due to energy efficiency and a growing electric vehicle market (e.g., Larson et al. 2020). The results of one such study

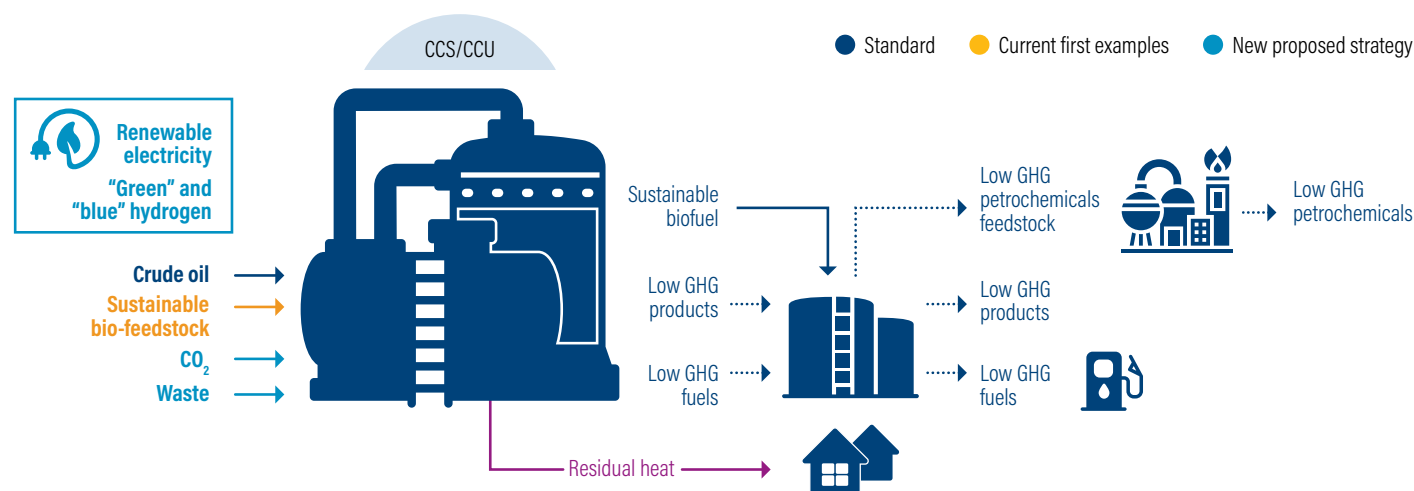
finds that highly ambitious electrification across the economy would cut conventional motor gasoline demand to 19 percent of 2020 levels and somewhat less ambitious efforts would cut demand to 57 percent (Larson et al. 2020). Conversely, because aviation is difficult to electrify, demand for jet fuel would likely shrink only marginally, although zero-emission substitutes like hydrogen and sustainable aviation fuel would likely grow (Larson et al. 2020).

In other words, even scenarios that optimistically project cutting fossil fuel use expect some refineries to remain and fulfill lower demand. Ensuring these facilities emit as little as possible requires ramping up production of hydrogen and electricity per the options outlined in this paper, transforming captured CO₂ from process emissions into an asset, and using these three products to manufacture new low-carbon fuels and petrochemicals (Dancuart et al. 2004). Where available, refineries can replace crude oil with these feedstocks, along with waste biomass and lipid oils where renewably available. This section provides a conceptual examination of a refinery optimized with low-carbon technology in 2050, using technology available today that is expected to grow and improve in the coming years.

4.1 Existing Concept—EU 2050 Refinery

In 2019, Concawe, a European think tank founded by oil companies that researches environmental issues, published *Refinery 2050*, a comprehensive concept report that assesses various feedstocks and decarbonized processes to reduce facility and product emissions in the EU (Gudde 2019b). The study estimated that by 2050 there would be a 60 percent reduction in gasoline demand, 30 percent reduction in crude intake, small reductions in diesel and marine fuels, and a 15 percent increase in aviation fuel. It then ran scenarios, using these 2050 demands, that estimated facility and product emissions by maximizing clean electrification, electrolytic hydrogen, or process CCUS. The scenarios estimated the impacts using fossil feedstocks or “alternate feedstocks.” Included among the alternate feedstocks are waste biomass, lipid oils, and syngas from captured CO₂ and green hydrogen; all feedstocks would undergo hydrocracking, with syngas first converted into wax and synthesized through the Fischer-Tropsch (FT) process and then cracked into “e-fuel.” Use of one technology did not necessarily exclude use of another in a scenario, and the greatest gains depended on feedstock renewability and electricity cleanliness. A simplified input-output diagram is shown in Figure 8.

Figure 8 | **Concawe's Conceptual Low-Carbon Refinery, Feedstocks, and Products in 2050**



Note: Scope of the 2019 *Refinery* 2050 report.

CCS = carbon capture and storage; CCU = carbon capture and use; CO₂ = carbon dioxide; GHG = greenhouse gas.

Source: Gudde 2019b.

The scenarios yield varied implications for facility-level emissions and product carbon intensities. Out of the crude oil feedstock cases, decarbonization primarily via electrolytic hydrogen reduces facility emissions the most, at 75 percent; however, the resulting fuel products' CI fell only marginally because of unchanging combustion emissions. Facility emissions are highest when crude oil is co-processed with 25 percent alternative feedstock unless biomass CO₂ is captured and all imported electricity for FT is clean, while product carbon content is up to 25 percent lower due to less fossil combustion.

Finally, nearly 100 percent of alternate feedstocks, the theoretical extreme, also emitted more facility emissions than the best fossil case due to biomass CO₂ and high indirect emissions from electricity production and feedstock imports, although CCUS and renewable inputs reduce the differences between those two cases. One scenario in which alternative feedstocks emit substantially fewer facility emissions is when biomass and lipids are used and

all biomass CO₂ is captured, which would yield substantial negative emissions. This scenario decreases the fuel's CI by at least 80 percent compared with the best fossil case.

These depend on many variables and often push feasibility to the theoretical max by assuming enormous renewable biomass and electricity availability. Despite the many variables, however, one key trend emerged, which is that there is usually a trade-off between ease and extent of facility decarbonization and product decarbonization. The best fossil feedstock case reduced refinery emissions the most with less facility overhaul than almost all the alternative feedstock cases, while the alternative feedstock cases achieved the greatest product CI reductions largely due to lower combustion emissions than fossil.

While this paper focuses on decreasing facility emissions, it recognizes that reducing combustion emissions has the greatest impact on cumulative CI and should thus take priority for a conceptual 2050 refinery in the United

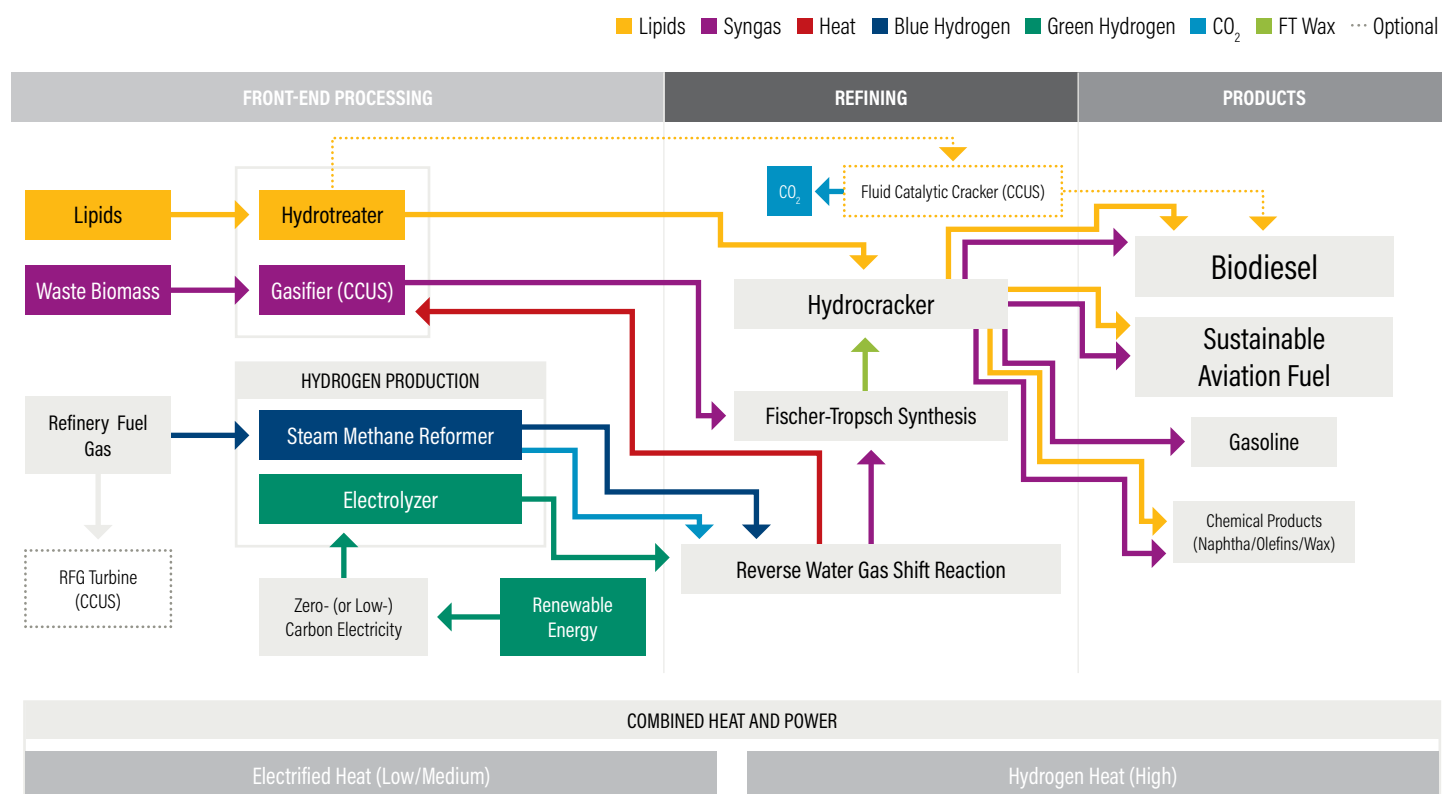
States. Additionally, even if replicating Concawe's modeling for the United States is out of scope, it is reasonable to assume that a major constraint of the negative emissions case will likely be availability of renewable waste biomass and lipids. Given those possible limitations and this paper's emphasis on captured CO_2 and hydrogen, the conceptual refinery of 2050 would rely heavily on FT synthesis with clean hydrogen and captured CO_2 and prioritize renewable feedstocks where possible.

The "semi-circular refinery" concept in the next section differs in scope and detail from Concawe's analysis but builds off its conclusion that an FT-based refinery shares moderate synergies with traditional refining and requires deployment of existing but relatively novel technologies—in short, the path forward is possible in principle but ambitious.

4.2 2050 Concept: Semi-circular Refinery

Despite their similarities, refinery designs are unique and shaped by many factors. The following conceptual design, then, should not be expected to be perfectly replicable in all or even most cases. Rather, the concept, illustrated in Figure 9, provides the menu of feedstocks, major processes, and main products for a 2050 low-emission refinery, optimized to co-process products and recycle CO_2 and RFG where possible. The deployed design can and should be altered to fit local resources and demand. For example, refineries near biomass waste could rely more heavily on that feedstock, while refineries that are not near CO_2 pipelines or storage infrastructure could rely more on recycling CO_2 produced on-site. Additionally, some

Figure 9 | Conceptual "Semi-circular" Refinery



Note: RFG = refinery fuel gas; CO_2 = carbon dioxide; CCUS = carbon capture, use, and storage; FT = Fischer-Tropsch.

Source: Original analysis by author Zachary Byrum.

important processes like gas separation and alkylation are left out for simplicity, but their use is implied among the listed units where needed.

The semi-circular refinery would phase out, underutilize, or greatly expand components of the conventional refinery presented in Figure 1. For example, initial distillation of crude oil (not pictured) is largely removed and relegated to bitumen production by some facilities. In its place is front-end processing of lipids and waste biomass feedstocks and greatly expanded hydrogen production.

A key difference between this concept and Concawe's is that the semi-circular model does not exclude steam methane reforming. While ambitious energy grid decarbonization will facilitate substantial green hydrogen growth, the electricity demand to produce enough hydrogen for e-fuels, process heat, and refining processes would be daunting. Concawe's high e-fuel scenario would require 25 percent of current EU electricity consumption to meet demand from half of its refineries (Gudde 2019b). Not excluding SMRs would reduce clean electricity demand from the grid, provide a clean use for RFG from lipid and biomass refining, create capturable CO₂ for synthetic fuels, and reduce overhaul expenses for existing facilities and hubs.

The refining portion relies heavily on Fischer-Tropsch synthesis and hydrocracking. FT converts syngas into combustible hydrocarbons. That syngas can be created through two means. The first is biomass gasification, which creates hydrogen, CO, and CO₂. The hydrogen and CO can be converted into syngas, while the CO₂ is either captured and stored (resulting in negative emissions) or used on-site. The second is by using an SMR or electrolysis followed by a reverse water gas shift to convert CO₂ into CO and combining it with hydrogen. An SMR would supply its own CO₂ while electrolysis would require CO₂ from elsewhere in the refinery or externally. Additionally,

FT creates a substantial amount of heat that can provide 80 percent of the heat for the gasifier's CO₂ capture unit (Gudde 2019b).

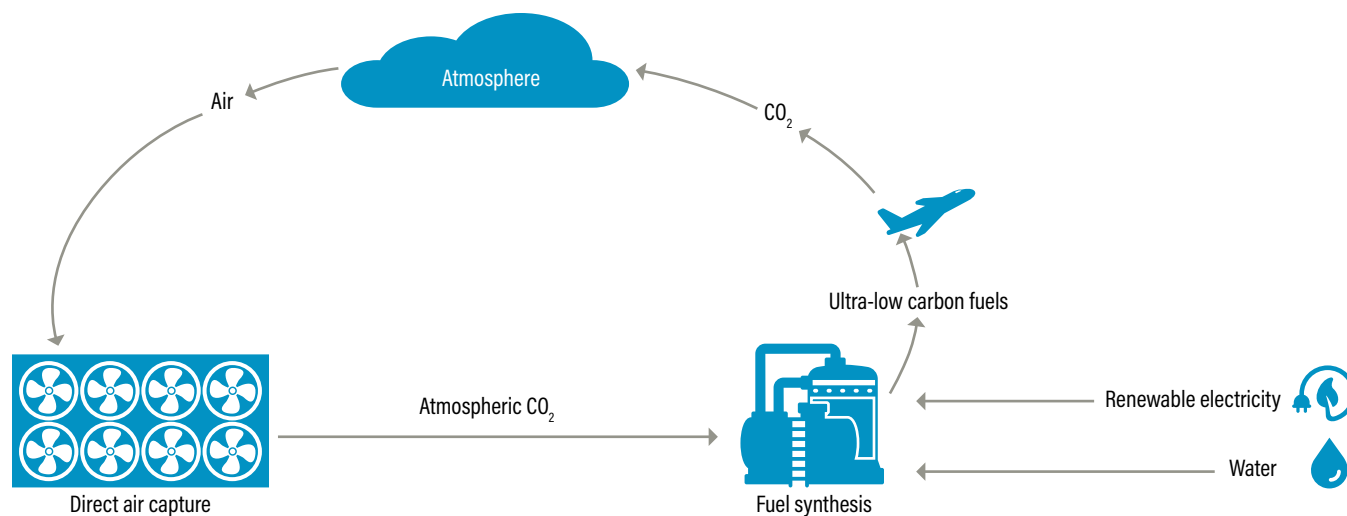
The hydrocracker breaks refined lipids or FT wax into various products, most likely biodiesel or sustainable aviation fuel but also gasoline and some chemicals. Hydrocrackers are a current refinery staple and would be used far more extensively in the model than they are today. FCCs with CCUS are an alternate lipid processor, but refineries may find it uneconomical to use what would likely be an underutilized FCC when the hydrocracker works similarly for a wider range of inputs.

The heat and power for these processes would use the hydrogen fuel and electrification options outlined earlier. The balance of electrification to hydrogen and the use of low- or zero-carbon energy to facilitate them depend on the facility's heat needs, CHP system, and RFG availability as well as the availability of external electricity from renewable or clean sources.

4.3 Low Renewable Feedstock, High Renewable Electricity Model: E-refinery

An alternate configuration where renewable energy is abundant, and perhaps biomass and lipids are limited, is an "e-refinery" that produces e-fuels from green hydrogen and CO₂ from direct air capture (DAC), a technological means of removing CO₂ from the atmosphere. This process, also known as "air-to-fuel" has recently been publicized by Carbon Engineering, one of the leading DAC companies. As shown in Figure 10, DAC removes CO₂ from the air, which then undergoes FT synthesis with green hydrogen to produce fuel that can be refined into various products, but most likely middle distillates like diesel and aviation fuel. When combusted, that CO₂ returns to the atmosphere where it can be cyclically removed again (Carbon Engineering n.d.).

Figure 10 | Conceptual Air-to-Fuels “E-refinery”



Note: CO₂ = carbon dioxide.

Source: Carbon Engineering n.d.

The climate benefit depends on the electricity’s cleanliness and what type of calciner—powered by natural gas or electricity—generates sufficient heat to liberate CO₂ from the capture medium. One life cycle assessment, carried out by Carbon Engineering staff, found that the electricity for electrolysis and DAC must be below 139 gCO₂e/kilowatt hour (kWh) to have a smaller impact than conventional diesel (Liu et al. 2020). Their baseline scenario uses an oxy-fired natural gas calciner where most CO₂ is captured and used for FT and assumes grid electricity at 13 gCO₂e/kWh. The resulting baseline fuel CI is 29 gCO₂e/MJ, compared with conventional diesel’s 104 gCO₂e/MJ, a significant reduction considering the system would use fossil fuels and that the electricity is highly, but not perfectly, clean. Using CO₂-free electricity and an electric calciner achieves a near-neutral fuel at 3 gCO₂e/MJ. While the latter scenario yields the largest reductions, the amount of room between both scenarios and the diesel fuel baseline indicates a significant amount of flexibility for grid cleanliness.

This e-refinery at scale is likely more speculative than the semi-circular refinery. The first large DAC plant that would capture 1 MtCO₂ is being built now, while the latter uses mostly proven and scaled technology, though that technology has not been designed to operate interdependently yet. However, it is also a simpler and more modular

design that faces fewer constraints than a brownfield refinery overhaul. Sourcing enough clean grid electricity to ensure that a semi-circular refinery or e-refinery processes low-carbon products would be one of the biggest obstacles, but clean generation is expected to rise significantly by 2050. The same study that estimated an eight-fold increase in hydrogen demand projects at least a doubling of today’s total electricity generation using clean sources (Larson et al. 2020).

5. CONCLUSIONS AND RECOMMENDATIONS

Achieving the U.S. climate goals outlined in the Paris Agreement requires economy-wide decarbonization as quickly as possible. While that entails massive deployment of renewable energy and a transition away from fossil fuels, the need for fossil fuels in hard-to-abate transportation sectors like aviation, shipping, heavy-duty transport, and some passenger transport will most likely persist into the coming decades. To meet this need, however low it falls, the refineries that manufacture these products must abate their significant share of total domestic emissions. Decarbonizing refineries and reducing their products’ carbon intensities would substantially reduce industrial and transportation impacts on the climate and air quality.

Large-scale emission reduction at the facility level entails capturing and storing or using the CO₂ from the two largest sources of process emissions in the sector, the fluid catalytic cracker and steam methane reformer, while switching the fuel for heat generation to clean hydrogen or electrifying where possible. CCUS, hydrogen fuel switching, and electrification are all proven and used to varying extents, but none have been demonstrated at commercial scale at a refinery, and use of only one of these solutions would likely be insufficient to decarbonize a given refinery, depending on its emission profile. To achieve any version of a conceptual low-carbon refinery by 2050 requires demonstrating the viability of all these technologies at commercial scale immediately.

While early adopters of new technologies and production methods may face higher costs and risks, there are opportunities for success. Although additional R&D will be needed, there already exist commercial and demonstration applications where CCUS, hydrogen fuel, and industrial electrification are proven and can be emulated. Additionally, industrial hubs with refinery supply chain linkages are ripe beds for a pioneering effort, particularly the Gulf Coast and Midcontinent regions given their access to CO₂ and hydrogen transport and storage infrastructure. Policymakers and refinery owners should capitalize on all emission reduction opportunities and adapt this sector for a new, low-carbon future.

ABBREVIATIONS

ATR	autothermal reforming
CCUS	carbon capture, use, and storage
CHP	combined heat and power
CI	carbon intensity
CO	carbon monoxide
CO₂	carbon dioxide
CO₂e	carbon dioxide equivalent
DAC	direct air capture
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
FCC	fluid catalytic cracker
FLIGHT	Facility Level Information on GreenHouse gases Tool
FT	Fischer-Tropsch
GHG	greenhouse gas
gCO₂e/MJ	grams of carbon dioxide equivalent per megajoule
kgCO₂e	kilogram of carbon dioxide equivalent
MtCO₂e	metric ton of carbon dioxide equivalent
NO_x	nitrogen oxides
PSA	pressure swing adsorption
RFG	refinery fuel gas
SMR	steam methane reformer

ENDNOTES

1. Data used in this report are sourced from the EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT), a publicly available database that lists detailed emissions data as reported by polluting entities, for year 2018. For the refining sector, these data include greenhouse gas emissions from heating units, fuel use, and petroleum processing units, among others.
2. Total process emissions are denoted in CO₂e and FCC and SMR emissions in CO₂, as smaller sources of process emissions contain other GHGs, whereas FCC and SMR GHGs are effectively 100 percent CO₂.
3. Original data analysis by Elizabeth Abramson, Great Plains Institute, assessing refinery and hydrogen plant proximities on behalf of WRI. 2021.

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ABOUT WRI

World Resources Institute is a global research organization that turns big ideas into action at the nexus of environment, economic opportunity, and human well-being.

Our Challenge

Natural resources are at the foundation of economic opportunity and human well-being. But today, we are depleting Earth's resources at rates that are not sustainable, endangering economies and people's lives. People depend on clean water, fertile land, healthy forests, and a stable climate. Livable cities and clean energy are essential for a sustainable planet. We must address these urgent, global challenges this decade.

Our Vision

We envision an equitable and prosperous planet driven by the wise management of natural resources. We aspire to create a world where the actions of government, business, and communities combine to eliminate poverty and sustain the natural environment for all people.

Our Approach

COUNT IT

We start with data. We conduct independent research and draw on the latest technology to develop new insights and recommendations. Our rigorous analysis identifies risks, unveils opportunities, and informs smart strategies. We focus our efforts on influential and emerging economies where the future of sustainability will be determined.

CHANGE IT

We use our research to influence government policies, business strategies, and civil society action. We test projects with communities, companies, and government agencies to build a strong evidence base. Then, we work with partners to deliver change on the ground that alleviates poverty and strengthens society. We hold ourselves accountable to ensure our outcomes will be bold and enduring.

SCALE IT

We don't think small. Once tested, we work with partners to adopt and expand our efforts regionally and globally. We engage with decision-makers to carry out our ideas and elevate our impact. We measure success through government and business actions that improve people's lives and sustain a healthy environment.