WHAT FUTURE ROLE FOR CONVENTIONAL REFINERIES IN THE DECARBONISATION TRANSITION?

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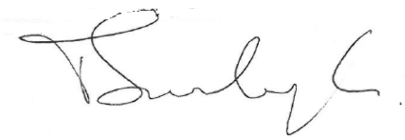

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EXECUTIVE SUMMARY

This report

This is the final report from the study Transport & Environment (T&E) commissioned to Ricardo Energy & Environment (Ricardo) entitled '*What future role for conventional refineries in hydrogen/e-fuels production?*' (with title of this report broadened to encompass the report scope). The study has been conducted in the first half of 2022. It was led by Ricardo and delivered with input from Argus Media Limited (Argus). It was a desk-based study drawing on both publicly available information and exclusive Argus Media data and research products.

The main study aim is to understand the operation of the current refinery system and what role it can play in hydrogen and synthetic fuels production (as well as the production of advanced biofuels), and the associated challenges. This is in the context of the deep transformation that oil and gas refineries will need to undergo in the next decades in transitioning to a carbon neutral economy.

Policy Context

In the EU, to address the climate crisis, legislators have been most recently developing climate policies to target climate neutrality by 2050. The policies directly and indirectly affect refineries, through addressing the demand for fossil-origin (carbon intensive) fuels, as well as through placing requirements on refiners as suppliers. Transitioning away from high carbon fuels to low and zero carbon fuels – such as 'drop-in' biofuels / synthetic fuels, or different fuels such as electrofuels (e-fuels) based on green hydrogen – or electrification for some transport modes is the implication, and given road transport is the largest consumer of liquid fuels, the legislation has included a particular focus here historically. While the EU has been tightening CO_2 emission performance standards for many years, the most recent policy development is the proposed date of 2035 for zero CO_2 cars. This proposed vehicle legislation is a part of the European Commission's 'fit for 55' policy package released in July 2021 under the Green Deal which also includes other proposals affecting fuel demand:

- Amendment of the Renewable Energy Directive
- for road, a proposal to introduce emissions trading;
- for maritime, the FuelEU Maritime initiative, extension of the Emission Trading System, and revision of the Directive on deploying alternative fuels infrastructure;
- for aviation, the ReFuelEU Aviation initiative (to support the existing CORSIA developments)

And since then, further legislative proposals have been released affecting the supply side, including the 'hydrogen and gas markets decarbonisation package', the Circular Economy policy package, and proposed revisions to the Industrial Emissions Directive as part of the zero pollution ambition.

Collectively, the requirements and targets from these policies will have a significant impact on the fossil fuel mix used today. The potential role for conventional refineries in producing alternative fuels will be influenced by demand in the regions transitioning first to alternative fuels, as well as depending on how other neighbouring regions implement climate change regulations.

Demand and supply trends

As a consequence of the beginning of the transformation shifts encouraged by policy, as well as the impacts of the covid pandemic, demand for refined products is changing, with road fuel demand particularly projected to decrease, principally due to electrification, as well as vehicle efficiency improvements. One projection of the electrification of the car fleet is for a 10-20 fold increase in the EV stock by 2030. Not all demand is declining though – demand is increasing for chemical feedstocks, encouraging the conversion of refineries to integrated petrochemical refining.

Refinery capacity must adjust to this change in demand. This has already been occurring through rationalisation (closures): around 13% of refining capacity in Europe closed over the last decade, leaving a capacity today of around 13.6 million barrels per day. Argus' forecast of road fuel demand is for a decline of 31% between 2021 and 2035. If the demand were to drop more sharply – a scenario was run of a 56% decline – it is estimated that 43% of the remaining refinery capacity would close (or convert).

Transition to low carbon fuels: examples

But it is not just closures to address the change in demand. Many investments in low carbon fuels have begun. This includes conversions to biorefining as well as dedicated plants for green hydrogen and synthetic fuels. Biofuel production in Europe is forecast to more than double between 2020 and 2025 to ~2.6% of fossil-based road fuel production, with examples of refineries being converted into bio-refineries. On green hydrogen projects – which can be used for synthetic fuels or directly as a transport fuel or within refinery processes – some 30 European refineries plan to implement green hydrogen capacity at their existing facilities.

As well as developments at existing sites, nearly 30 investments in new greenfield sites for novel production processes to produce advanced biofuels and e-fuels in Europe have been identified. These projects could produce up to 9.3 million tonnes per year of low-carbon liquid fuels by 2030, and include:

- Advanced biofuel projects with output capacities ranging from 0.1 to 0.75 million tonnes per year.
- Green hydrogen projects to reduce the GHG intensity of manufacturing processes or to combine with captured carbon to produce synthetic fuels with an annual capacity of up to 3.4 million tonnes.
- Waste-to-fuel projects, with a production capacity of up to 0.1 million tonnes per year in output (derived from municipal solid waste).

The report includes further details on these investments.

Transition to low carbon fuels: technology and site considerations

More generally, the report presents an overview of the most relevant low carbon fuels and the available entry points for non-fossil feedstock into a conventional refinery for the production of low carbon fuels. There are different options for the processing of non-fossil feedstocks, including dedicated plants, co-processing and refinery conversion. Overall, there is no clear general preference for investment either in dedicated plants, co-processing plants or refinery conversions for the production of low carbon fuels, as the relative merits differ on a case-by-case basis due to a range of influencing factors. Capital cost considerations include sharing conversion assets, the availability of storage facilities for products, the investments needed on plant utilities, the available fuel transportation infrastructure. Whilst many of these considerations point towards the use of existing refinery assets (i.e. conversion), some potential drawbacks to this approach include the space available and the permitting arrangements.

For the particular case of e-fuels (produced from green hydrogen and CO_2) the feedstocks for these fuels are expected to primarily be obtained from new plants. In this context, there can be advantages to repurposing decommissioned oil refinery sites for sustainable e-fuel production. The synergies are economic in nature, with benefits such as land ownership, access to workforce, opportunity for sharing or reusing fuel storage and handling assets and utilities, and repurposing waste from conventional processes as feedstocks for low carbon fuels production processes. Other factors such as feedstock supply chains can however benefit alternative locations for dedicated plants.

The technical capacity to manufacture e-fuels based on green hydrogen and renewable carbon is not constrained by existing refinery capacity or capabilities, because existing refineries do not provide the input streams nor conversion units to enable this production path. The critical element to de-bottleneck production of e-fuels is the up-front investment for these novel processes.

Cost competitiveness of low carbon fuels

The main cost driver affecting the costs of producing e-fuels are the costs of renewable energy, which are largely driven by the costs of electrolysis. These costs are expected to scale down substantially by 2050 until they are no longer dominant cost components. Further cost drivers are the status of technology development, the utilisation rate for conversion plants, economies of scale and the choice of the carbon feedback.

On the latter point, making use of carbon captured from industry processes (for example, within refinery complexes), is typically much less expensive than processes such as Direct Air Capture, owing to large volumes of product being available at high concentrations from waste streams. Direct Air Capture costs per tonne of CO_2 are around five times the costs of capture from waste streams.

A comparison of the capital costs of new build e-fuels plants with new build HVO plants identifies the e-fuel plant Capex is expected to be 5 times higher than the HVO plant. However, costs may be expected to drop with time with technology maturity. Although the capex intensities are very different, this does not lead to the conclusion that the more Capex-intensive projects are unlikely to proceed for two reasons: 1) operating costs are not quoted here, and (2) feedstock availability could be a constraint.

Energy intensity of producing low carbon fuels

The energy intensity of producing renewably derived synthetic diesel is shown to be around six to seven times higher than for conventional diesel, while the energy intensity of renewably synthesised methanol is at least twice that of conventional methanol synthesis, with the higher values for both processes when assuming CO_2 from Direct Air Capture. Despite the increased energy intensity of production, the synthetic fuel routes nevertheless offer greater than 90-95% reductions in upstream GHG emissions compared to conventional production routes. The comparison used well-to-tank energy intensity values which take into account the energy intensities of the production processes while excluding the energy content of the feedstock, i.e. using the 'Net Energy Analysis' (NEA) approach.

Deep dive case studies into five European oil majors' investments into hydrogen and biofuels

Regarding the strategy of European refiners, significant investments have been made in alternative fuels, much of it related to their existing refining portfolios. Advanced biofuels have been the most typical route for diversification, leveraging the existing liquid fuels storage, processing and logistics infrastructure. Hydrogen is more nascent but an area where many of the firms analysed have made at least some initial investment. The announcements made by these companies on the future share of their capital expenditure on renewable and low carbon energy suggest that their focus will be in large or majority part on these new energy pathways. However, for the moment, the share of energy production from fossil sources still dominates.

Use of renewable energy sources

In addition to the production of low carbon fuels, a wide range of approaches and technologies are required for oil and gas companies to achieve emission reduction efforts for minimising the CO_2 intensity of their production processes, both conventional and novel. These may include energy efficiency improvement, the introduction of renewable energy sources lowering the carbon footprint of their energy sources, capture of CO_2 for long-term storage or reuse as well as the inclusion of renewable fuels in the portfolio of oil and gas industries. Energy efficiency is already under the control of the refiners and builds on on-going efforts. Further emission savings can be achieved through the use of renewable energy sources. There are different alternatives for producing and/or crediting renewable energy sources (e.g., green hydrogen from renewables electricity) for European refineries, including the direct co-location with renewable energy assets, consuming electricity from the grid using a power purchase agreement with a dedicated renewable generation asset, consuming electricity from the grid in hours of low grid carbon intensity or trading renewable energy certificates.

A Just Transition for refinery workers

Finally, the transition from conventional refineries to the future of refineries, including the introduction of low carbon fuels in their portfolios, has the potential to have only a small impact on the existing workforce, with consideration to the main areas that will require upskilling: it is expected that 5-10% of refinery workers will need significant skills changes. Wider trends in European labour markets are predicted to also impact refineries, such as an aging workforce, globalisation, and digitalisation. The EU refining industry currently employs approximately 130,000 workers directly, and an additional 1.2 million jobs indirectly, including highly skilled technical positions, logistics and marketing. Some of the potential newer roles include carbon cycle managers, to reduce the amount and cost of GHG generated in refineries; novel supply chain specialists, purchasing and resolving issues on the acquisition of biomass and waste as feedstocks; renewable energy specialists, aiming to minimise the cost of renewable energy acquisition via wide variety of options; and bio-based process engineers, with deep knowledge of processes such as fermentation. In the most part, the production processes for a transition to bio and green hydrogen products will continue to require the existing skills for the majority of direct and indirect workers.

As the refinery sector moves towards low carbon production guided by ambitious EU policy objectives for a carbon neutral EU it is clear that investment will be needed. A Just Transition would mean that this is done in such a way that job creation, job upgrading, social justice and poverty eradication are taken into consideration. There are several EU funds to support the technical and Just Transition to which refineries may be eligible, as discussed further in this report.

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GLOSSARY

Abbreviation	Definition
ATJ-PSK	Alcohol-to-Jet Synthetic Paraffinic Kerosene
Capex	Capital expenditure
CCU	Catalytic cracking unit
CHJ	Catalytic hydrothermolysis synthetic jet fuel
CHP	Combined heat and power
DME	Dimethyl ether
e-fuels	Electrofuels
ESG	Environmental, Social, Governance
EU	European Union
EV	Electric vehicle
FCC	Fluid catalytic cracking
FTS	Fischer-Tropsch synthesis
FT-SKA	Fischer-Tropsch synthetic kerosene with aromatics
FT-SPK	Fischer-Tropsch synthetic paraffinic kerosene
GHG	Greenhouse gases
GRM	Gross refining margin
HEFA	Hydroprocessed Esters and Fatty Acids
HEFA-SPK	Hydroprocessed Esters and Fatty Acids Synthetic Paraffinic Kerosene
HFS-SIP	Hydroprocessed Fermented Sugars to Synthetic Isoparaffins
HVO	Hydrotreated Vegetable Oil
LCOE	Levelized cost of energy
MEG	Mono-ethylene Glycol
NOC	National oil company
OME	Oxymethylene ethers
Opex	Operating expense
POX	Partial Oxidisation Unit
PtL	Power-to-liquid
RES	Renewable energy source
RFNBO	renewable fuels of non-biological origin
R&D	Research and Development
SAF	Sustainable aviation fuels
t/y	Tonnes per year
toe	Tonne of oil equivalent
TRL	Technology readiness level

1. INTRODUCTION

1.1 THIS REPORT

This is the final report from the study Transport & Environment (T&E) commissioned to Ricardo Energy & Environment (Ricardo) entitled '*What future role for conventional refineries in hydrogen/e-fuels production?*'. The study has been conducted in the first half of 2022. It was led by Ricardo and delivered with input from Argus Media Limited (Argus). It was a desk-based study drawing on both publicly available information and exclusive Argus Media data and research products.

1.2 AIMS AND OBJECTIVES OF THE STUDY

The main study aim is to understand the operation of the current refinery system and what role it can play in hydrogen and synthetic fuels production (as well as the production of advanced biofuels), and the associated challenges. This is in the context of the deep transformation that oil and gas refineries will need to undergo in the next decades in transitioning to a carbon neutral economy.

The objectives within this main study aim are to conduct an in-depth assessment of existing refinery infrastructure; assess the impact of declining oil demand on that infrastructure and its workers; and describe scenarios of what role existing refineries can play in ramping up the production of advanced biofuels, hydrogen and synthetic e-fuels.

The report addresses the objectives by:

- Assessing existing refinery capacity and technical challenges of shifting refineries to produce renewable based low carbon fuels, comprising biofuels (from biomass), hydrogen (H_2) and electric fuels (e-fuels)
- The current and near-term plans of the oil & gas sector with existing or new refineries
- The possibilities for a Just Transition for refinery workers

1.3 STRUCTURE OF THE REPORT

To meet the objectives, this report has been structured as follows:

- Section 2 provides a short policy context background for the study.
- Section 3 gives an overview of the existing sectoral landscape in Europe, both from a demand and capacity perspective, as well as the emerging trends occurring in the sector.
- The transition to low carbon fuels is described in section 4 in terms of:
    - the technologies needed with examples of investments in novel processes;
    - case studies on changes in demand for new products;
    - a comparison of the energy intensity of producing low carbon fuels;
    - the cost competitiveness of such fuels
- We then present a summary of the near-term alternative fuel investments being planned by five European oil majors in section 5, based on public announcements on new facilities. All of the European oil majors have announced infrastructure plans and investments of various sizes and forms, some overlapping with existing refining infrastructure.
- Finally, recognising that the transition is not only about technology, section 6 describes the re-skilling needed for a Just Transition for refinery workers by characterising current direct and indirect workforce of the refinery sector.

The transition to hydrogen and e-fuel production is the main focus of our analysis. However, it is important to note that there are additional trends relating to non-fuel products of refineries not covered in this report which also influence the overall context of the sector.

2. POLICY CONTEXT

The use of carbon-based fuels is driving climate change, and hence the policies to mitigate climate change affect such fuels at their core. Transitioning away from such fuels demands alternatives, which differs for each fuel-consuming sector, depending on their needs. Alternatives include 'drop-in' biofuels / synthetic fuels, or different fuels such as electrofuels (e-fuels) based on green hydrogen.

Countries across the globe are tightening their policy focus on the reduction of greenhouse gas (GHG) emissions following the Paris Agreement. The resulting policies affect all aspects of the energy value chain, both directly affecting refineries as suppliers, but also through targeting sectors that demand fuels such as the transportation sector given its significant impact on GHG emissions. In the EU, within the context of the Green Deal, the European Commission's 'Fit for 55' package[1] released in July 2021 included several policy proposals, many of which will affect refineries directly or indirectly by influencing supply or demand. The primary policies announced which will most significantly affect supply or demand of refined fuels include:

- Revision of the Regulation setting CO_2 emission performance standards for new passenger cars and for new light commercial vehicles – with a 2035 date for new zero CO_2 vehicles
- Revision of the EU Emissions Trading System (ETS), including maritime, aviation and CORSIA
- Emissions trading for road transport
- Amendment to the Renewable Energy Directive (RED)
- Revision of the Directive on deployment of alternative fuels infrastructure

Then at the end of 2021, the Commission released a proposal for a new EU framework to decarbonise gas markets, promote hydrogen and reduce methane emissions: the 'hydrogen and gas markets decarbonisation package' (European Commission, 2021).

In addition, the continued push for a more circular economy – for example, in the EU, the Commission's Circular Economy policy package part 1 released in March 2022 – is also a driver (and opportunity) for diversifying feedstocks and fuels, and so to reduce emissions, as part of the expected deep transformation. And in early April 2022, the Commission proposed revisions to the Industrial Emissions Directive – which covers EU refineries – and which aims to support the EU's zero pollution ambition for a toxic-free environment as well as its climate, energy and circular economy policies. Among the proposals is requiring industrial installation operators to produce transformation plans by 2030 as a contribution towards achieving EU objectives on a clean, circular and climate neutral economy and stimulate a deep agro-industrial transformation.

Because of the trends signalled by the policies, sales of conventional fuels (refined from fossil feedstocks) in more ambitiously regulated regions are expected to decrease significantly due to substitution by biofuels, e-fuels and other lower carbon options as well as electrification trends. Implementation of higher levels of renewable fuels into the transport fuel mix is a key element of EU's decarbonisation goals as per the 'Fit for 55' package, which called for a 13% GHG intensity reduction in the EU transport fuel mix by 2030. Similarly, the proposed ReFuelEU Aviation regulation proposes a 5% target for sustainable aviation fuels (SAF) by 2030. These aggressive targets will have a significant impact on the fossil fuel mix used today. The potential role for conventional refineries in producing alternative fuels will be influenced by demand in the regions transitioning first to alternative fuels, as well as depending on how other neighbouring regions implement climate change regulations.

The scope of this context is not limited to refineries, however. Several alternatives to current refinery units could take place outside refinery installations. For example, electrolysers producing green hydrogen do not need any feed or utilities from a refinery. Therefore, there are also business opportunities for oil and gas refineries: not only in manufacturing new low / zero carbon fuels but also in playing other roles such as treatment and recovery (valorisation) of waste streams as part of the circular economy.

[1] The European Union's 'Fit for 55' package of regulatory proposals was announced on 14 July 2021 as part of the EU's strategy to reduce emissions by 55% by 2030, compared to 1990 levels.

3. AN OVERVIEW OF THE CURRENT EUROPEAN REFINERY LANDSCAPE

What impact has the shift to electromobility and the political push for e-fuels already had on the plans of oil and gas companies for their downstream operations?

Based on the Commission's 'Fit for 55'-scenario and T&E's own 2050 roadmaps (with e.g. an accelerated transition to electromobility), what will be the impact on refineries' operations of e.g. a 56% drop in diesel and gasoline demand by 2035?

Summary:

- Demand for refined products is changing, with historical growth in demand from road transport plateauing from around 2007 as vehicle efficiency improvements kicked in, and the demand is forecast to decline in the future principally due to electrification. Demand from other sectors dropped in the 1990s and 2000s as the power sector shifted away from oil-firing.
- Current refinery capacity is ~13.6 million barrels per day (b/d)
- Refinery capacity needs to adjust to this change in demand – this is occurring through rationalisation (closures), as well as investments in low carbon fuels – including conversions to biorefining as well as dedicated plants for green hydrogen and synthetic fuels.
- A scenario of a 56% drop in diesel and gasoline demand by 2035 is estimated to lead to a rationalisation (drop) of refining capacity in Europe of 5.8 million b/d, or approximately 43%
- Demand is also increasing for chemical feedstocks, encouraging the conversion of refineries to integrated petrochemical refining

3.1 INTRODUCTION

Oil and gas refineries are often seen solely as conventional fuel manufacturing sites, but their product portfolio is quite large. Refineries manufacture not only a large variety of fossil fuels for direct use but also produce feedstocks for the organic and inorganic chemical industries. FuelsEurope (2018) provides an indicative share of refined products as being 65% are fuels for transport/mobility, 10% are chemical feedstocks for the chemical industry[2], and the remaining other 25% includes fuels for power.

The design of refineries depends both on the available feedstocks as well as their product portfolio. There are many different oil and gas refinery arrangements, most being quite complex, containing several conversion units. The Nelson Complexity Index provides a metric for quantifying and ranking the complexity of various refineries and units.

3.2 DEMAND FOR REFINED PRODUCTS IS CHANGING

The demand for refined products is changing, primarily as a result of the collectively impact of the demand for personal mobility coupled with the decarbonisation trends playing out in these industries as encouraged by the policies set out in section 2.

Figure 3-1 shows the demand for petroleum products from European refineries, split by the end use demand, covering both historical data from 1995 to 2020, together with a projection out to 2040 (Source: Argus). The historical data in the figure shows some fluctuation around an overall increasing trend from 1995 to the late 2000s,[3] before a flattening of demand, and then a projection from the 2020s – after a post-covid pandemic recovery – of a decline in demand for petroleum fuels, particularly from road transport. This projection reflects how refineries' product portfolios could evolve taking into account the transition policies and strategic plans shared by energy sector associations.

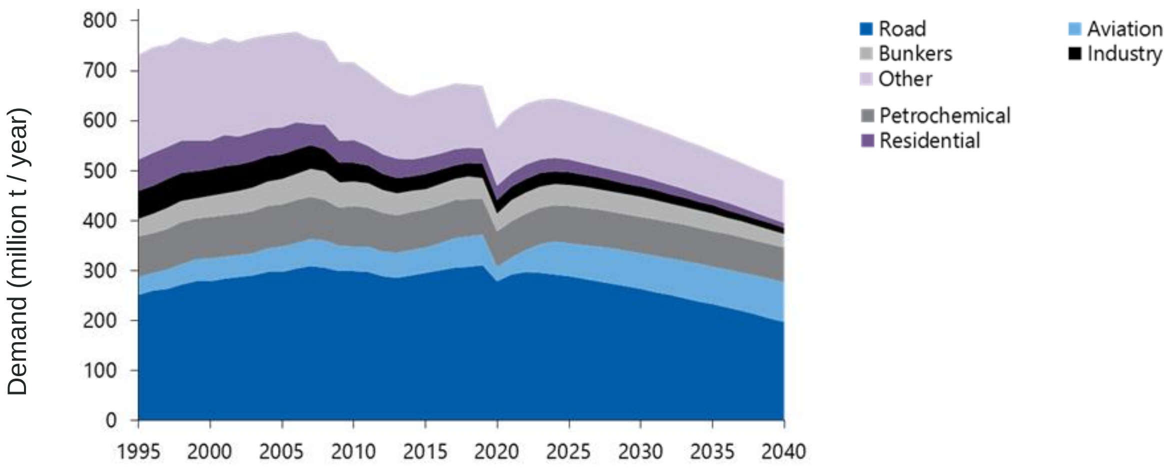
Critically for refiners, these trends for road transport fuel demand are still in their relative infancy. As more efficient new vehicles replace older models in the vehicle parc, average fuel consumption per km declines, in part driven by policy efforts. In addition, electrification is today only beginning to make its presence felt (5.5 million EVs in Europe in 2021), but already by 2030 the IEA is projecting between a 10 and 20 fold increase in

[2] For example, polymer and plastic production in the chemical industry rely on chemical feedstocks manufactured in oil and gas refineries. Polymers and plastics have a wide range of uses, including lightweighting of vehicles to reduce energy consumption.

[3] The 2000s saw a decline in the demand from the 'other' sector for oil consumption in the power generation sector.

the EV stock compared to 2021 levels (IEA, 2022). The European Commission's projections for the proportion of the car stock in 2030 and 2050 that could be EVs in their 'Fit for 55' policy package modelling was 13% and 70% respectively (European Commission, 2020).

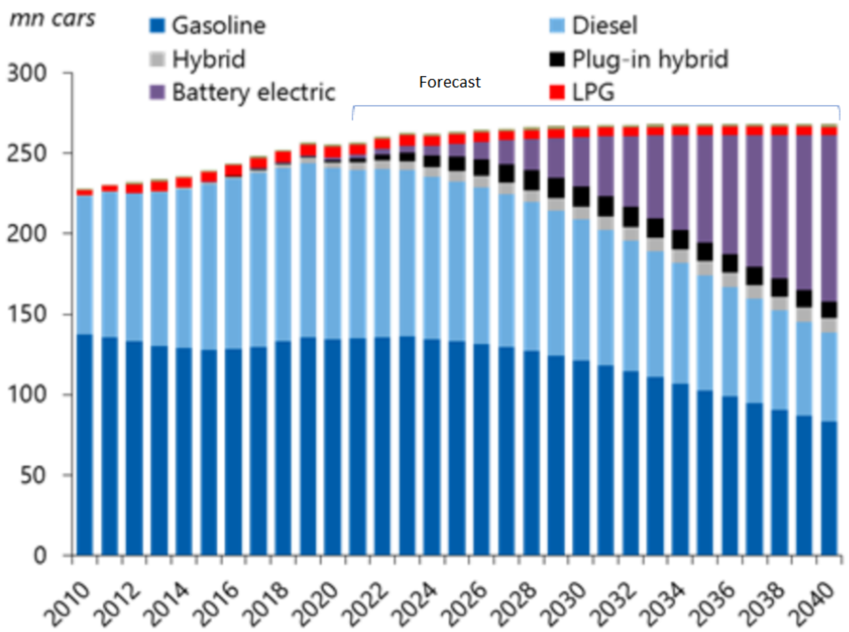
Figure 3-1 European (EU27, UK and Norway) refined product demand by end-use



Source: Argus

Driving this trend is the EU's plan to prohibit the sale of new cars with CO_2 emissions greater than zero from 2035, and some countries in Europe have already announced sooner timescales for similar bans on new internal combustion-engined cars. The expected evolution of the European passenger car parc is shown in Figure 3-2. The chart is an output of internal modelling by Argus. In this scenario, the battery electric vehicle fleet increases by 100 million cars between 2020 and 2040. With subsidies for zero-emission vehicles and pledges to eliminate internal combustion engine vehicles from various governments, the penetration of electric vehicles will accelerate, which will have significant implications for the future of oil demand.

Figure 3-2 European passenger car parc, 2010-2040



Source: National Statistics, Argus Consulting

The COVID-19 pandemic has demonstrated that unforeseen market shocks can have vast effects on fuel demand. The pandemic exacerbated the effect of falling European demand in 2020 and, despite a recovery in 2021/2022, demand is forecast to remain below 2019 levels in the foreseeable future (Figure 3-1). The effects of the pandemic on demand have started to ease and, looking ahead, additional demand recovery is expected as the world returns to the pre-pandemic norm. But the new norm will not be the same. Some effects of the pandemic, like working from home, have created a more permanent decline in demand that were not accounted for pre-2020.

Going forward, biofuel mandates, further electrification and fuel efficiency vehicle standard legislation are expected to continue to decrease the per-km vehicle fossil fuel demand, more than counteracting any growth in vehicle ownership and distance travelled.

Overall, the refined product demand is expected to decline by 2% per year over the coming decades, as implied in Figure 3-1 and as shown in Table 3-1. Split by product, Table 3-1 illustrates Argus' forecast of demand of various refined fossil-derived fuels, expressed as compound annual growth rate (CAGR), calculated as the mean annual growth rate over a five-year period.[4] The gasoline and diesel projections suggest that fossil-origin road fuel demand decline is a permanent trend.

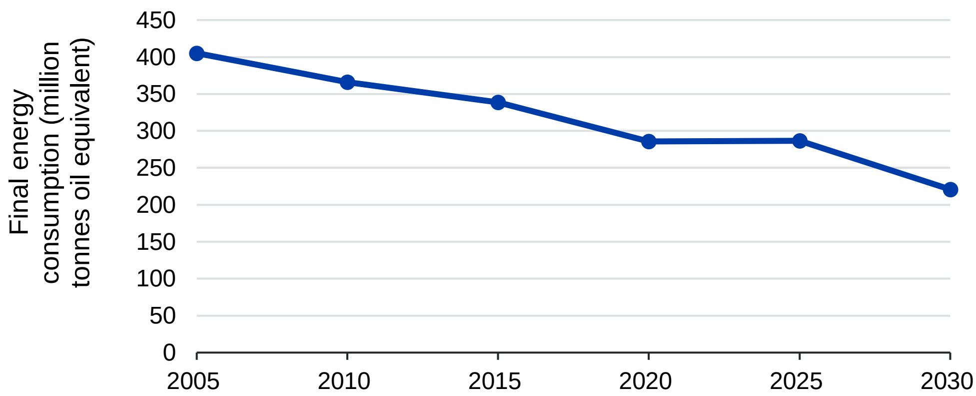
Table 3-1 Projections of future demand growth/decline rates by product, for North and Central Europe (expressed as compound annual growth rates)

	2020	2025	2030	2035	2040		
LPG	0%	3%	0%	-1%	-1%	Petchems	Residential
Naphtha	-2%	-1%	-1%	-1%	-1%	Petchems	Residential
Gasoline	-1%	-2%	-4%	-5%	-5%		Road
Jet/Kero	-10%	15%	1%	0%	0%	Aviation	
Gas oil/diesel	-1%	0%	-2%	-4%	-4%		Road, Industry
Fuel oil	-4%	2%	-1%	-2%	-4%		Bunkers, Industry
Total Demand	-2%	2%	-1%	-2%	-2%		

Source: Argus

The European Commission's projections of EU27 refined petroleum product consumption (as a total, for all sectors) consistent with its "MIX scenario" associated with the July 2021 'Fitfor55' policy package show rates of decline around 2.5% a year, leading to overall a 23% reduction in demand from 2021 to 2030 (Figure 3-3). The trend overall matches Argus' forecasts, though there are differences in scope of fuels included between each projection.

Figure 3-3 EU27 petroleum product consumption forecast associated with the 'Fit for 55' policy package



Source: European Commission; PRIMES model (DG ENER, 2021) *MIX scenario*

[4] The year in the table indicates the end of each five year period. Projections of future product portfolios are used to estimate the pool of conversion units that refineries will need to operate.

3.3 PRODUCTION CAPACITY HAS BEEN DECLINING THROUGH REFINERY CLOSURES FOLLOWING THESE DEMAND DRIVERS

The decline in demand will result in major over-capacity, with subsequent margin shrinkage and closures. The competition for supply from European refineries is set within the global context of differences in environmental regulations between Europe and elsewhere, as well as access to cheaper crude and natural gas in the Middle East and new refining capacity additions in Africa. This can be expected to result in lower exports to Europe's traditional markets of East Coast USA, Africa and parts of the Middle East.

As a rule, we may expect European refining capacity to reduce by a smaller proportion than the drop in European fuel demand. There are many factors that play into the decision to close a refinery including:

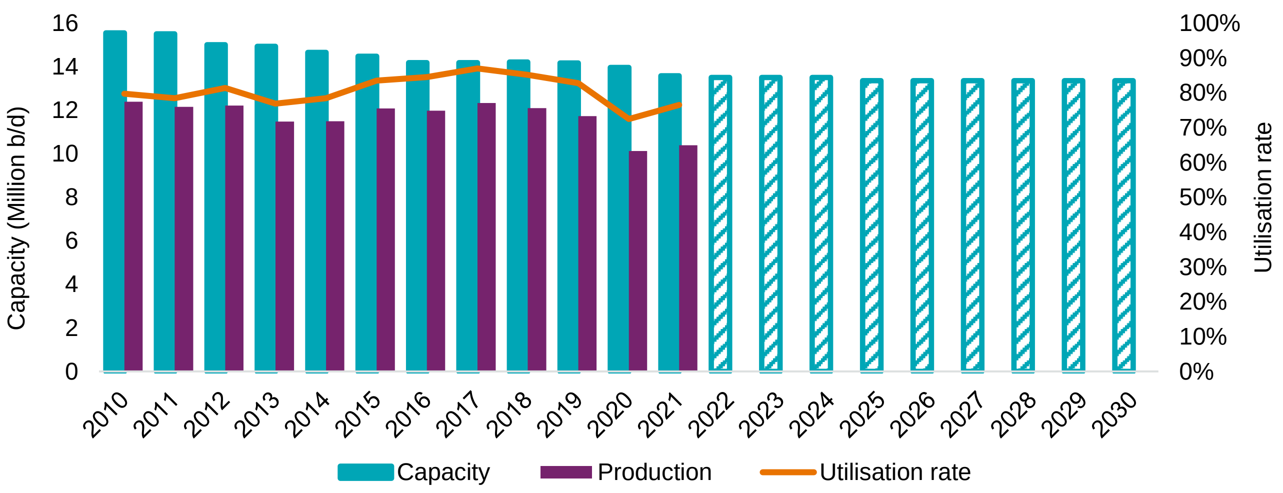
- Relative volume reductions of individual fuels within the overall demand decline e.g., if diesel declines more severely this may drive a greater capacity closure
- Ability of refiners to place volumes in other markets, e.g., ability to place gasoline in export markets
- Tolerance of lower utilisation and gross refining margin

Europe's refineries vary by size, age, complexity, and ownership structure. At one end of the spectrum are nine refineries of more than 300,000 barrels per day (b/d) operated by the oil majors and national oil companies. At the other end of the spectrum, there is a long tail of refineries under 100,000 b/d capacity, often with low complexity and owned by traders, private investors and small oil companies.

The gross refining margin (GRM) of an individual refinery depends on factors including the price of crude oil and input feedstocks, plus the realised price for the refined products sold to the market as well as operating and logistical costs. Generally, larger and more complex refineries are able to produce larger quantities of higher value fuels such as gasoline and jet/kerosene, and smaller quantities of lower value products such as fuel oil. One broad measure of the overall susceptibility of an individual refinery to closure is its complexity, usually expressed within the industry on the Nelson Complexity Index. Generally, but not always, lower NCI is correlated with lower GRM, and hence simpler refineries may be among the first to close when system capacity is reduced.

Reflecting some falls in demand and the worsening outlook for demand, crude oil distillation unit capacity has declined since 2010, with further cuts announced or expected in the coming years. Current refining capacity in Europe is estimated at 13.6 million b/d. Figure 3-4 shows the European oil refinery capacity, production and utilisation rate since 2010; the projection after 2021 only includes announced closures, suggesting that further as yet unannounced closures can be expected considering the demand projections.

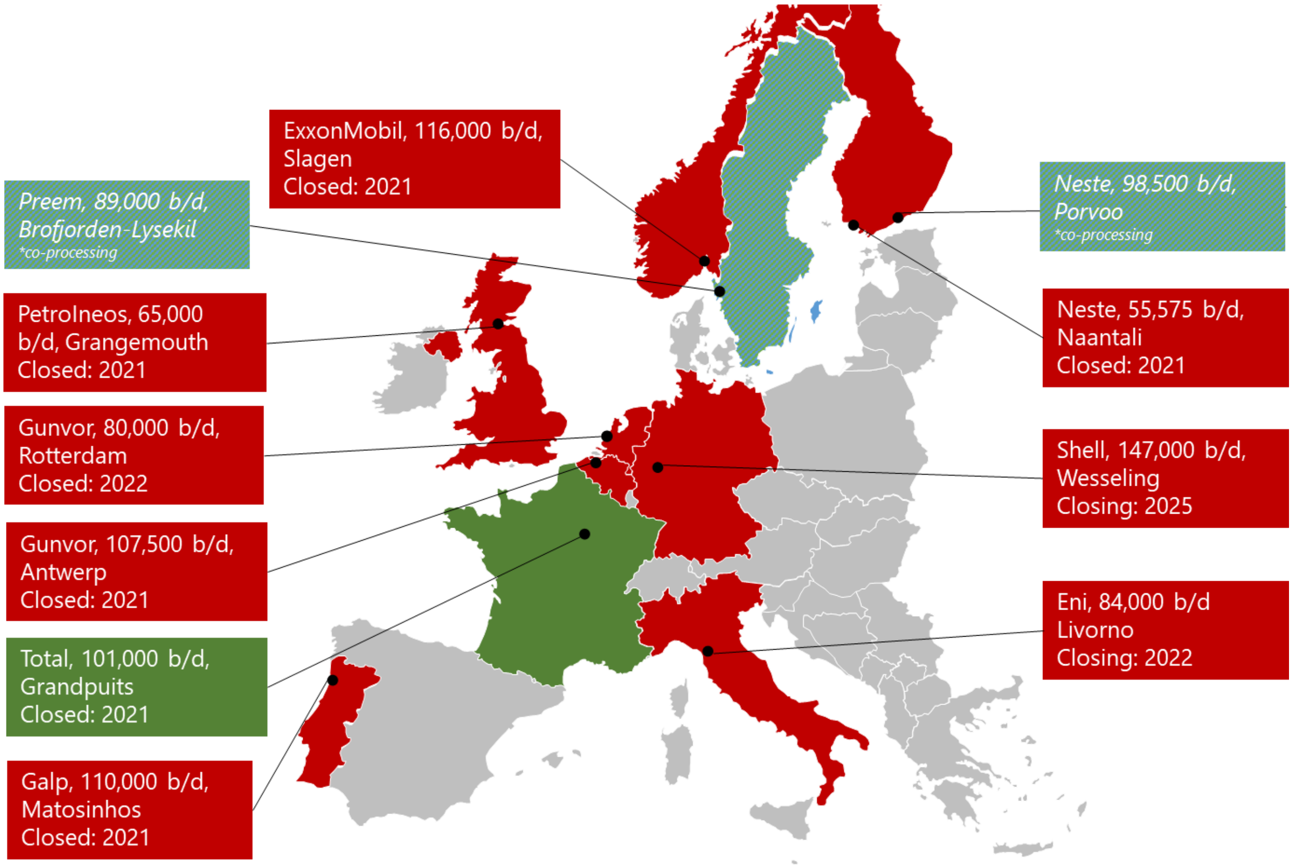
Figure 3-4 European (EU27, UK and Norway) oil refinery capacity, 2010 - 2030



Source: Argus, 2022. NB projections include only announced closures as of early 2022.

As shown in Figure 3-4, between 2010 and 2021 a net of nearly 2 million b/d, or 13%, of European refining capacity has been closed, mostly as a result of poor refining economics. Regulatory developments are a cause for urgency to find solutions beyond the current refinery structure, which has proved unsustainable in the long term. Refiners across Europe strive to find the right solution for their facilities in order to keep them running and, more importantly, to keep them economic. The rationale for installation closures, where it has occurred, varies depending on the scale of operating profit (or loss), likely required future investment, and suitability of the product slate for ongoing requirements. Figure 3-5 shows some selected examples of the recent closures.

Figure 3-5 Recent European refinery closures



Source: Argus 2021

The pandemic in 2020 accelerated the rationalisation process in Europe which is now drawing further impetus from operators' plans to deal with falling demand and investor impetus for a move to low carbon operations. In 2020, capacity was closed or mothballed at Antwerp in Belgium and Grangemouth in UK. Portugal's Galp completely shut down its Porto refinery in 2021. In Finland, Neste has converted Naantali to an import terminal and Exxon is doing the same at Slagen in Norway, after shutting the refinery in 2021. In total over 570,000 b/d of capacity has closed since the start of the pandemic.

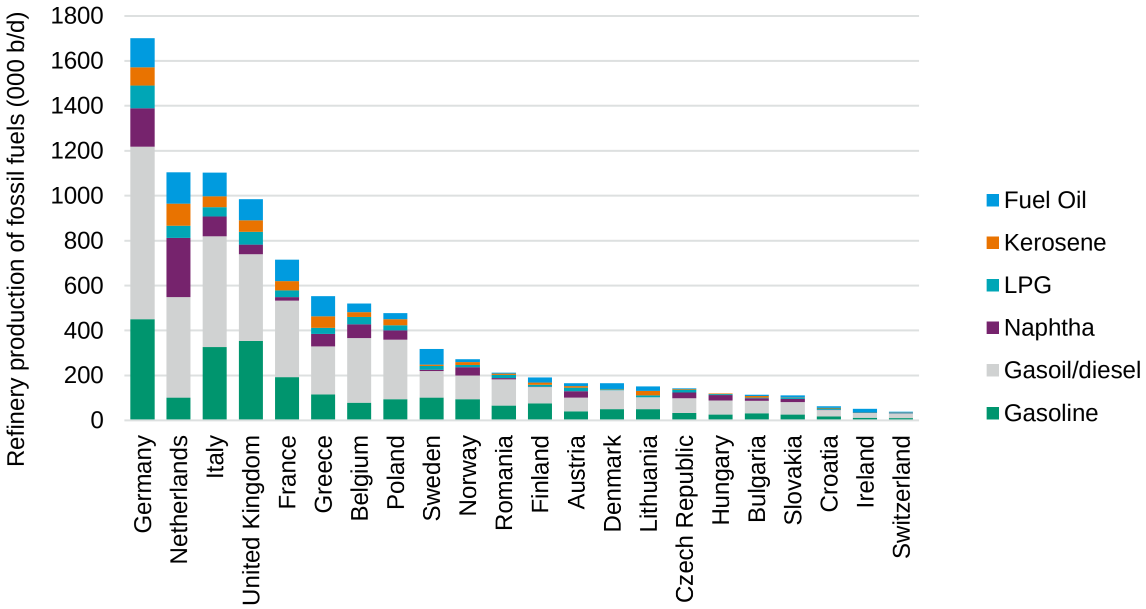
The decision to close, re-purpose, invest in green technology, or otherwise change a refinery is not purely an economic one. Some oil and gas companies have links to national governments, and many are major employers. In such circumstances, closure and redundancy may be avoided despite commercial pressures and investments made to secure a smaller or less complex refinery's future.

How much more crude processing capacity will close? Argus forecasts a refinery rationalisation rate of 4.4% between 2020 and 2025 based on announced closures.

In Argus' base case forecast, road fuel demand declines by 31% between 2021 and 2035 from 343 million tonnes to 232 million tonnes respectively which would be expected to lead to further closures beyond this 4.4% rationalisation. Argus also ran a sensitivity to model what might happen to refining capacity if demand for road fuels were to decline by 56% between 2021 and 2035 (equivalent to a -3.2% CAGR). The resulting outcome was a decline in refining capacity of 5.8 million b/d, or approximately 43% of the current refining capacity.

In the context of the potential for significant impact of demand reduction on capacity, Figure 3-6 shows the distribution of fossil fuel production by European country and by product. From the figure it is clear the significance of how much of the current output is made up of road fuels across all country refinery output.

Figure 3-6 Refinery production in 2021 of fossil fuels by country (EU27 + Norway, Switzerland and the United Kingdom), in thousands of barrels per day

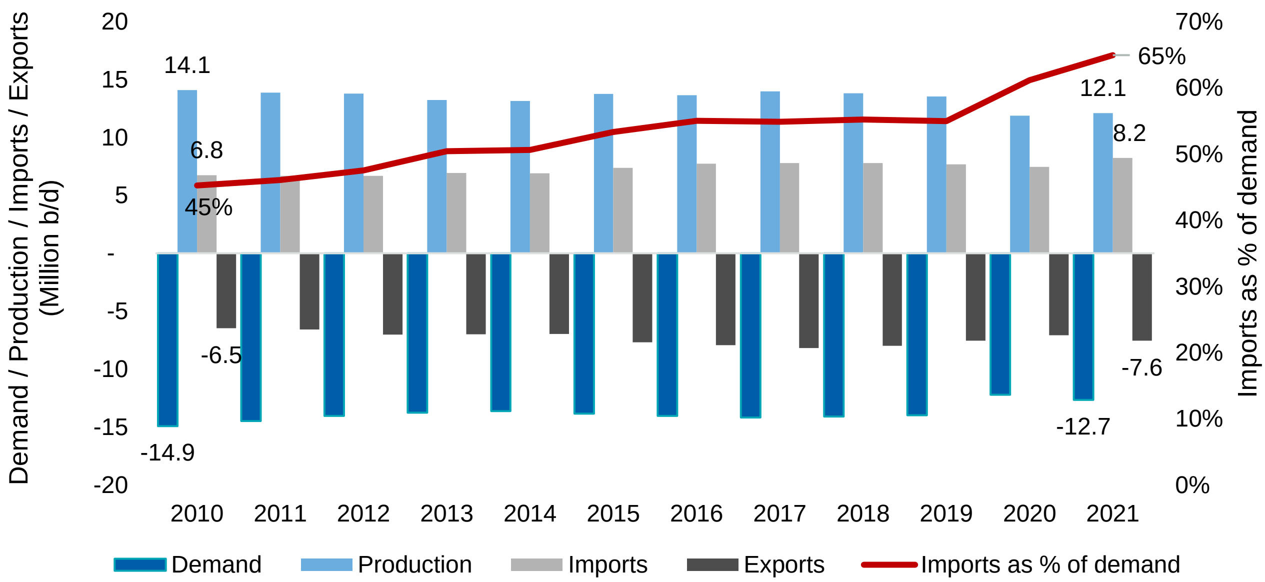


Data Source: Argus

3.4 WHILE EUROPEAN REFINING CAPACITY IS DECLINING, IMPORTS ARE UP

When considering the rationalisation of European refineries, the overall impacts of the fuel consumed should take into account imported petroleum products. Indeed, European product imports have been steadily increasing at an average rate of 100,000 b/d between 2010 and 2021. In 2010, product imports comprised 45% of total product demand in Europe. In 2021, that number increased to 65%, which is depicted in Figure 3-7.

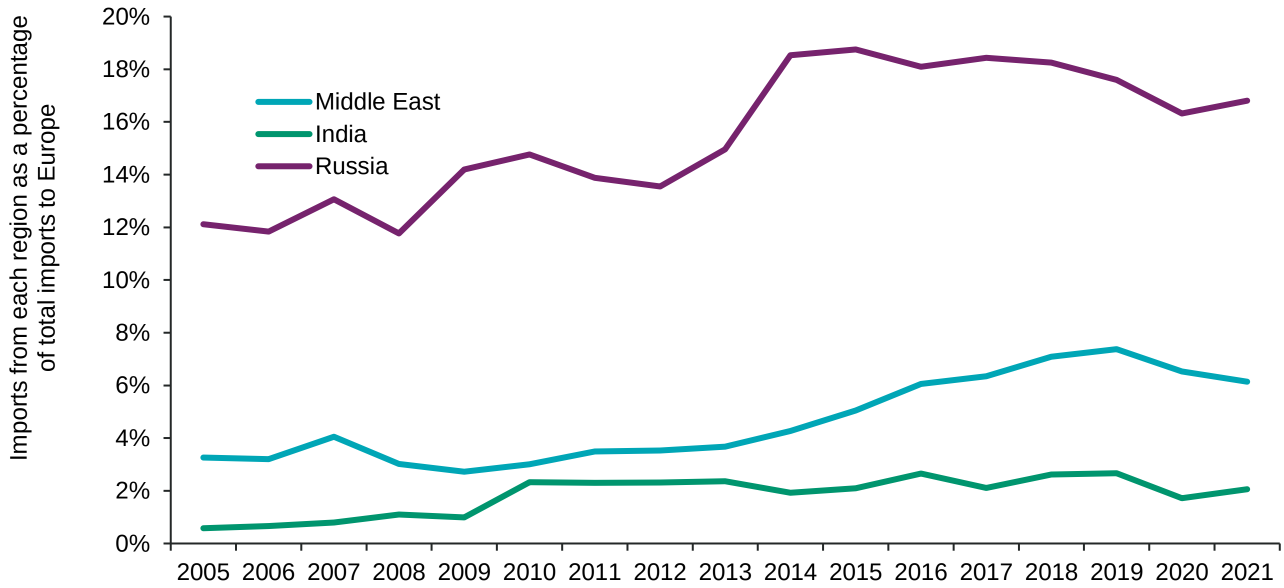
Figure 3-7 Trends in European road transport fuel demand, production, imports and exports 2010-2021



Source: Argus

The highest levels of increase are recorded from Russia, India and the Middle East – all of which have either very large complex refineries or access to cost-advantaged crude. This is depicted in Figure 3-8.

Figure 3-8 OECD Europe total petroleum products imports



Note: Percentages based on tonnage

Source: (IEA, 2021)*, Argus*

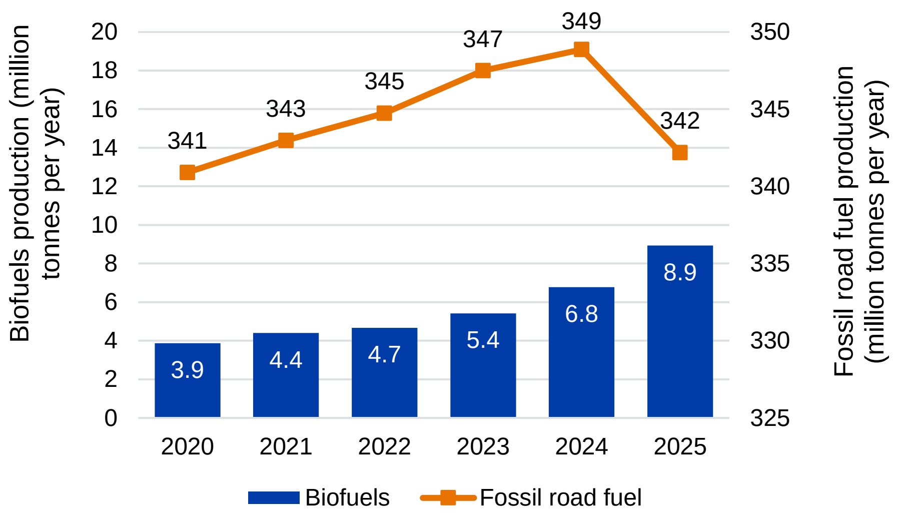
3.5 BIOFUEL PRODUCTION IS INCREASING

Conversion to biofuels production increasingly offers an alternative to closure or divestment for European refiners. Refiners are adapting their operations to align with policy changes and though refinery biofuel production has been low, we expect to see a relatively large increase over the next couple of years. Specific examples of European capacity changes converted from fossil fuel refining include:

- In France, TOTAL has shut down hydrocarbon refining operations at Grandpuits, investing more than €500m to turn the site near Paris into a biorefinery. The plant was vulnerable to closure because of a long-standing issue with the pipeline that provided ~90% of its feedstock, causing the refinery to operate at just 70% of capacity. TOTAL has indicated it was also influenced by France's proposals for the energy transition. The 400,000 t/y biorefinery, scheduled to start in 2024, will produce biojet, biodiesel, and bioplastics.
- In Finland, Neste plans to gradually convert the Porvoo refinery to co-process crude oil and renewable feedstocks.
- Sweden's Preem is similarly planning to partly convert the Lysekil refinery to process up to 40% renewable raw materials by 2024, with the share likely to increase in the long term.
- TOTAL converted its La Mede refinery into a biorefinery in 2019, and the plant was its only refinery to achieve a positive result in 2021.

Figure 3-9 depicts Argus' biofuels production forecast from refinery co-processing, which accounted for approx. 1% of fossil road fuel production in 2020 and is expected to reach 2.6% in 2025. Total biofuels production from repurposed/converted fossil into biofuels refineries and co-processing capacity from other refineries amounted to circa 4.4 million t/y or 1.3% of fossil fuel-based road fuel production. This number is forecast to more than double by 2025 to 8.9 million t/y or 2.6% of fossil-based road fuel production.

Figure 3-9 European (EU27, UK and Norway) refinery biofuels (left hand y axis) and fossil road fuel production (right hand y axis – Note scale)



Source: Argus

3.6 HYDROGEN PATHWAYS ARE ALSO BEING FOLLOWED

In addition to renewable fuels being explored as a decarbonisation strategy, green hydrogen is another method of abating growing GHG emissions, which refiners are investigating. Renewable hydrogen can be targeted for three primary applications: as energy storage, as a feedstock, and as a fuel. In the transportation sector, hydrogen can be used directly as a fuel, and indirectly by reducing emissions in refineries and making synthetic fuels. The EU plans to invest over $550 billion into hydrogen and infrastructure on the back of its commitment to decarbonisation (Forbes, 2020).

Many European refiners have put forth investment plans in renewable hydrogen at or close to their refining facilities in varying stages of commitment. Several are subject to government funding. Some 30 European refineries plan to implement green hydrogen capacity at their facilities, including OMV, Shell, Bayernoil, BP, Gunvor, Klesch Group, Shell, Hellenic Petroleum, MOH, ENI, Saras, Total, Lukeoil, Equinor, Grupa Lotos, PNK Orlen, Galp Energia, Repsol, Preem, ExxonMobil and Valero in Austria, Denmark, Germany, Greece, Italy, the Netherlands, Norway, Poland, Portugal, Romania, Spain, Sweden and the United Kingdom.

3.7 DEMAND IS INCREASING FOR CHEMICAL FEEDSTOCKS FROM REFINERIES – IMPLICATIONS FOR REFINERIES

Wood Mackenzie have analysed how oil and gas refineries will decrease their conventional fuel production share and increase the share of low carbon fuels and other products, such as chemicals feedstocks (Wood Mackenzie, 2018). In contrast to the declines forecast for road fuels described above, the demand for petrochemical feedstocks is forecast to increase, globally, by 7 million b/d from 2020 to 2040. Wood Mackenzie suggest that the optimisation of refineries to supply the chemical feedstock demand is driven by the higher value of the chemical feedstocks. A more circular economy would, however, be expected to decrease the demand for chemicals (plastics) and increase the use of recycled polymers.

To change the product portfolio from a refinery, sites will need to amend or retrofit their conversion units, considering that many of these units produce both fuels and chemicals. Each refinery has a set of core processes that are required to facilitate the fractionation of the crude material and are at the initial (upstream/ inlet) stages of the process. In a transition away from the production of conventional fuels, most of these refinery units will remain relevant such as atmospheric or vacuum distillation but will need customisation and changes in their design and operation as the chemical composition of the crude materials which enters the refinery process changes. Specific processes to deliver chemicals and non-fuels products (such as coke or lube oils) will also remain quite similar. For these units, certain small retrofits and operational conditions changes might be required. The processes to manufacture conventional fuels will undergo the greatest changes. Some units will no longer be needed, other will dramatically reduce throughputs and other will need significant retrofits, for example to increase the yield of chemicals being manufactured.

4. TRANSITION TO LOW CARBON FUELS

In this chapter:

- Section 4.1 describes technologies needed for refining low carbon fuels, and whether to accommodate these within existing refineries or stand-alone plants. Examples of investments are given.
- Section 4.2 describes two case studies on demand drivers from the maritime and aviation sectors influencing refiners.
- A comparison of the energy intensity of low carbon fuels against the conventional equivalents is provided in section 4.3
- Section 4.4 describes the cost competitiveness of e-fuels

Summaries are provided in each subsection.

4.1 TECHNOLOGIES FOR THE PRODUCTION OF LOW CARBON FUELS

In light of the changes facing the refining sector in Section 3, the production of low carbon fuels is essential to the future growth of the sector. This section outlines:

- A short background on conventional oil refinery processes (section 4.1.1)
- Refining processes for bio-based fuels and renewable fuels of non-biological origin (section 4.1.2)
- The economic advantages for accommodating the production of low carbon fuels in either stand-alone sites or in existing refineries (section 4.1.3)
- The factors affecting the production of sustainable e-fuels (section 4.1.4)
- Examples of investments being made in low carbon fuels (section 4.1.5)

How should adaptations to an existing refinery (e.g. adding an electrolysis plant) be realised (i.e. as an integral part of the refineries/co-located plants (e.g. to use waste heat) or as separate, remote entities?)

How do these compare to a situation where a completely new plant and production system for green hydrogen/e-fuels is built?

Overview of the refinery unit operations and the relevance of the unit processes to hydrogen and synthetic fuels production (e.g. hydrocracker/distillation units, other equipment).

Summary

- There are three options for the processing of non-fossil feedstocks: dedicated plants, co-processing plants or refinery conversions. Co-processing could be the most beneficial to de-bottleneck the incorporation of non-fossil feedstocks into transportation fuels because it makes use of the existing infrastructure.
- The optimal or preferred location should be defined through a case-by-case analysis. Different approaches will be viable for different novel processes.
- Stand-alone plants are already working (i.e. are economically viable) for some of these processes such as FAME manufacturing or pyrolysis units.
- Transporting lower density feeds or intermediates is often not economic and this encourages novel plants to be located close to feed sources. Gasification plants and electrolysers will always need to be co-located with the capacity for Fischer-Tropsch synthesis (or methanol synthesis) because they produce gases which generally are not efficient to transport. If drop-in hydrocarbons are to be produced, a closer location to a refinery can facilitate blending in the end product prior to further distribution.
- However, if the process generates an energy dense product like FAME, pyrolysis oil, or bio-crude, there is less need to co-locate the infrastructure, as it may be then more advantageous to locate the plant closer to a renewable energy source. And if the target products are methanol or ammonia, there is no evident benefit to placing these manufacturing plants alongside a refinery. Section 4.1.5 includes examples of new e-fuels sites built outside existing refineries.

Synergies for e-fuels with other products in refinery

Summary:

- There are many opportunities and synergies between conventional processes and e-fuels production. However, most of these are not associated with technical synergies.
- The most relevant synergies are economic drivers: sharing feeds, sharing assets, sharing utilities or reusing waste streams from conventional processes as feed for novel processes for the production of low carbon fuels.

What would be the maximum technical feasibility to produce sustainable e-fuels, if partial/all the refineries are converted?

Summary:

- The technical capacity to manufacture e-fuels based on green H_2 and renewable carbon in the future is not limited by any existing refinery feature nor any existing refinery asset, mainly because these existing sites will not provide critical raw materials or key conversion assets to enable this production path.
- The maximum e-fuel manufacturing capacity in Europe will thus mainly depend on the policy measures implemented and their impact on the market, as well as on the economic viability of the investment and the availability of key feedstocks, such as green H_2 and renewable CO_2.

Are there any existing examples or pilot studies of adaptations for novel processes to an existing refinery?

Summary:

- There are ~30 projects for low carbon liquids in Europe that have already been started or that are planned until 2030 which can potentially account for 9.3 million tonnes of low-carbon liquid fuels produced per year by 2030. This is information from Concawe and elaborated in Appendix C of this report.
- However, further projects are also being announced in the press by different companies, including oil and gas companies. Many of these projects are planned to be incorporated into existing refineries, such as Cartagena and Bilbao refineries from Repsol (Spain), Fredericia refinery from Crossbridge Energy Fredericia and Everfuel (Denmark), Venice refinery from ENI (Italy) or Seine-et-Marne refinery from TotalEnergies (France).

4.1.1 Background on conventional oil refineries

In conventional refining, crude oil is the raw material that enters the refinery. Crude oil is a mixture of molecules almost exclusively comprised of carbon and hydrogen i.e., hydrocarbons. Although crude oil is predominantly carbon and hydrogen, it is chemically complex. The molecules in crude oil vary in molecular weight (i.e., chain length) and chemical structure – at the most basic level, crude oil can be thought of as consisting of *n*-paraffins, *iso*-paraffins, naphthenes, olefins and aromatics.

The purpose of refining is to reduce the complexity of this mixture and produce products that can be utilised for a specific purpose – most commonly fuels. When crude oil enters a refinery, it is first distilled. The purpose of distillation is to separate the mixture into various fractions based on their boiling point (i.e., molecular weight/chain length). This is a purely *physical* process, the chemical *structure* of the constituent molecules of each fraction are not altered, although the chemical/physical *properties* of the fractions are different from those of the crude.

Following distillation, the fractions enter their relevant refinery stream and undergo a series of *chemical* transformations before they are converted to finished fuels.

4.1.2 Refining processes for bio-based fuels and renewable fuels of non-biological origin (RFNBO)

Of the conventional processes, the processes most relevant to low carbon fuels have been identified (Table 4-1). These should be considered as the viable entry points for non-fossil feedstocks into a conventional refinery for the production of 'drop-in' hydrocarbon fuels. Drop-in fuels are fully fungible with existing fuel infrastructure and not subject to any technical blending limits, i.e. they can be blended with existing conventional fuels without concerns around safety or impacts on technical parameters such as performance and fuel efficiency.

Table 4-1 Entry points for non-fossil feedstocks into a conventional refinery for the production of drop-in hydrocarbon fuels

Process	Description
Hydrotreating	Uses hydrogen to remove impurities (sulphur, nitrogen, oxygen etc.). Can also convert double bonds in olefins and aromatics to single bonds i.e., saturation of unsaturated molecules. Can be used to saturate lipid-based feedstocks to give paraffins. Can also be used to remove oxygen from bio-derived feedstocks. Hydrotreatment is essential for the production of drop-in (i.e., hydrocarbon based) low carbon fuels.
Fluid Catalytic Cracking	Converts long chain hydrocarbons into shorter chain molecules using a catalyst. Primarily used to produce gasoline from long chain fractions.
Hydrocracking	Converts long chain hydrocarbons into shorter chain molecules using hydrogen and a catalyst. Primarily produces diesel and kerosene. Feedstocks *must* be hydrotreated before they can enter the hydrocracking process as oxygen can poison the catalyst.

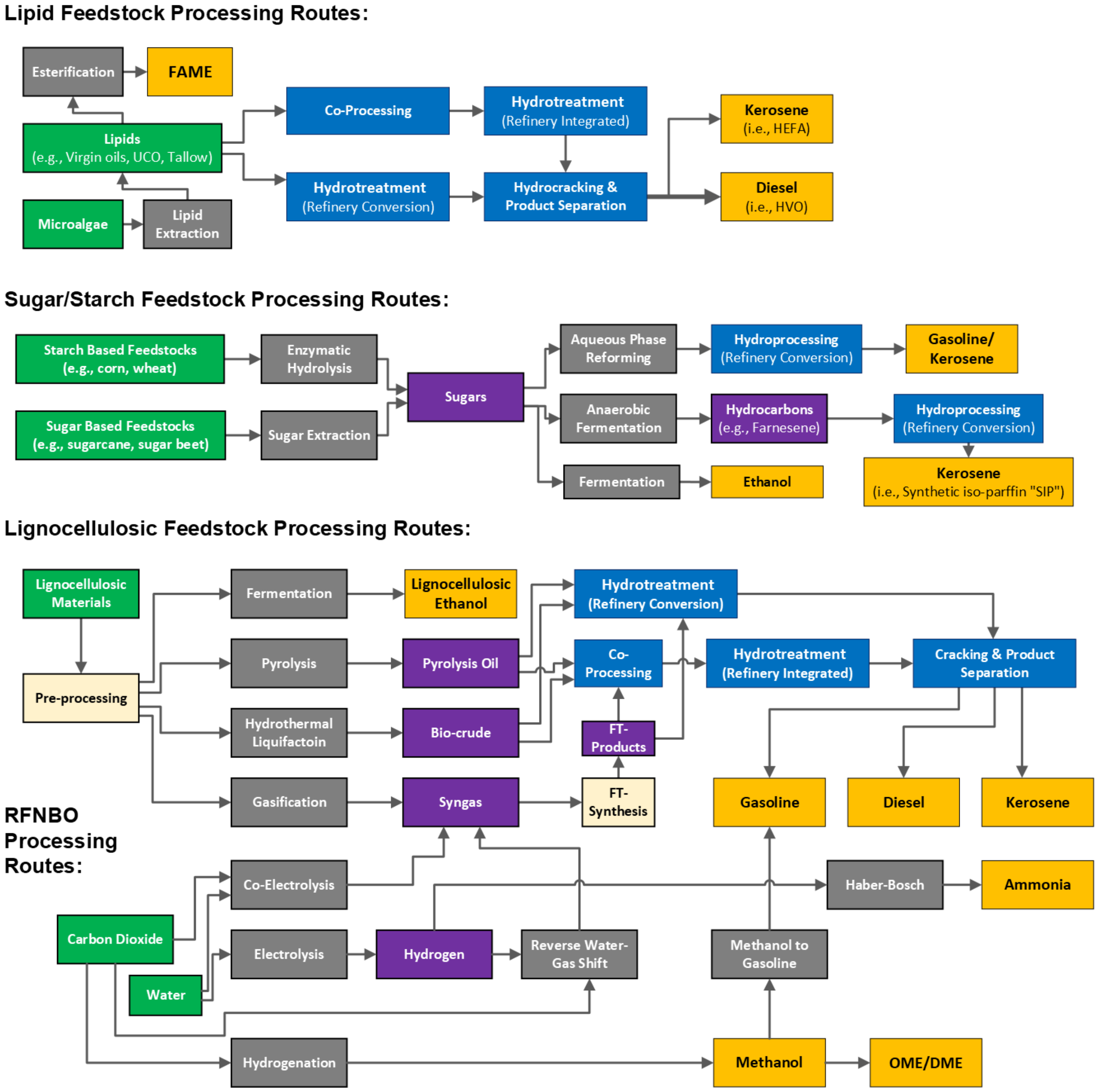
Source: Ricardo

Refinery processes that are most relevant to the production of drop-in (i.e., hydrocarbon based) low-carbon fuels are those that either remove oxygen or convert long chain hydrocarbons into shorter chain molecules. In particular, hydrotreating is essential for the processing of bio-based feedstocks. This is because bio-based feedstocks contain significantly higher levels of oxygen than fossil-based feedstocks – which contain almost no oxygen – that must be removed. The presence of oxygen in finished fuels can have adverse effects on the performance and properties of the fuel and is strictly limited by fuel certification standards. Cracking serves a similar role in the processing of bio-based/RFNBO (renewable fuels of non-biological origin) feedstocks to fossil-based feedstocks – tailoring the fraction (chain length) towards the desired product. Most of the processes currently used by refineries in refining crude oil are not relevant to the production of fuels from non-fossil-based feedstocks.

A simplified schematic showing the interactions between non-fossil feedstock conversion routes and conventional refinery process is shown in Figure 4-1. The feedstocks can be broadly split into four categories:

1. Lipids – typically either virgin oils (e.g., oilseed rape, palm oil, soybean oil) or waste oils (e.g., used cooking oil or tallow).
2. Starch and sugar-based feedstocks – this refers to annual energy crops such as sugar beet, sugar cane, wheat etc.
3. Lignocellulosic Materials – this refers to any lignocellulosic biomass.
4. Non-Biological Feedstocks – renewable electricity and CO_2.

Figure 4-1 A simplified overview of the processing routes available to produce biofuels and RFNBOs



Legend: green: feedstocks, grey: conversion route/process, purple: intermediate product, blue: entry points for non-fossil feedstocks into a conventional refinery, yellow: final product/fuel.

Source: Ricardo

The processing of non-fossil feedstocks typically occurs in two-stages. In the first stage, the feedstock is converted to an intermediate product. A summary of each of these conversion processes is given in Appendix A. In general, these conversion processes have no commonality with traditional refinery processes and are highly specific to the feedstock. Consequently, it is not essential that these facilities are co-located with existing refineries (further discussion in section 4.1.3). While these conversion technologies to intermediate products are well understood, the pathways for conversion of the intermediate products, discussed below, are generally less well advanced (IEA Bioenergy, 2019) and can be bottlenecks in the process. For example, the technology to gasify wood is more advanced than the technology to clean up the syngas you get from gasifying wood.

Following this initial conversion, the feedstock can then be upgraded to a fuel using a combination of the processes discussed above. This presents three options for the processing of non-fossil feedstocks:

1. **Dedicated plants** – refineries that only process non-fossil-based feedstocks.
2. **Co-processing** – conventional refineries that incorporate non-fossil-based feedstocks into their existing operation.
3. **Refinery conversion** – conventional refineries that are modified/upgraded to handle non-fossil feedstocks.

Each of these three options are discussed below.

Dedicated plants

Dedicated plants have been shown to be commercially successful in the case of lipid feedstocks (e.g., Neste). This is because the physical density of the feedstock enables this kind of large-scale dedicated operation. Similarly, plants that produce ethanol from crops have also achieved commercial scale whilst having little or no interaction with conventional refineries (aside from blending ethanol with gasoline). Conversely, lignocellulosic materials are much lower density. This presents significant logistical challenges for the commercialisation of dedicated refineries that utilise lignocellulosic materials. In addition to the feedstock specific conversion process, dedicated plants would also have to develop the capacity to upgrade the intermediate products i.e., hydrotreatment and cracking capabilities.

For example, FAME is a fully developed and widely used fuel and has been manufactured for many years at commercial scale. FAME is produced outside the refinery limits in other plants, potentially under different environmental permits, and sent to conventional refinery storage units for blending with conventional fuels.

Importantly, the feedstocks that, to date, have been most applicable to dedicated plants – oils and sugar/starch crops – are broadly disfavoured by policy because of the associated high levels of land use change and competition for use as food or animal feed. For example, RED II intends to phase out fuels from high land-use change feedstocks by 2030. Waste oil-based technologies are likely to be restricted by the limited supply of feedstock. Thus, lipid-based technologies are likely to be reliant on oils from micro algae in the longer term. Consequently, the demand for low carbon energy in the EU will need to be met by fuels from lignocellulosic materials (‘advanced biofuels’) and RFNBOs. As highlighted by Figure 4-1, these feedstocks generally present more opportunities for interaction with refineries than lipids/sugar/starch crops.

Co-processing

The simplest synergy between non-fossil-based feedstocks and conventional refineries is through co-processing of the non-fossil-based feedstock with crude oil. Co-processing involves the blending of a small proportion, typically 5-10%, of a non-fossil feedstock (e.g. lipids) with the fossil crude fraction. This small proportion ensures that the blended feedstock is compatible with the existing processing units. The blending is done in advance of the hydrotreating or fluid catalytic cracking stage. Generally, this does not require any modifications to be made to the refinery process infrastructure. This can be seen in Figure 4-1, in steps labelled as “Refinery Integrated”, e.g. hydrotreatment following co-processing of lipids. The advantage of co-processing is that it allows the immediate integration of bio-based feedstocks into conventional refineries and fuel production routes. The obvious disadvantage is that co-processing is inherently reliant on fossil feedstocks that are needed to ensure compatibility with the existing infrastructure.

Table 4-2 summarises the potential novel processes for manufacturing biofuels and e-fuels that could be integrated into conventional refineries. This table includes processes that are considered validated in relevant environments (TRL 5) and above in 2022. While the integration of other processes that are less developed (TRL 4 and below) may be possible, information regarding their potential future implementation into conventional refineries is less clear at this stage and, therefore, these are not included in the table. These novel processes may be integrated in future once these are fully developed at commercial scale. Strategies to integrate these processes may change in the future as processes and markets evolve.

Table 4-2 Novel processes for manufacturing biofuels and e-fuels that could be integrated into conventional refineries

Novel conversion process	Product/ fuel	Technology maturity (Technology Readiness Level, TRL)	Key value chain integration stage with conventional refinery plant	Existing refinery unit relevant for integration
Hydrogenation of oils (vegetable or used cooking oils)	HVO	TRL 9	Conversion	Hydrogenation units for fuels conversion
Pyrolysis	Syngas and pyrolysis oil	TRL 6-8	Feedstock treatment	Upstream atmospheric distillation or desalters
Transesterification of oil	FAME	TRL 8-9	Blending, storage of goods	Tanks for final products
Fischer-Tropsch catalytic conversion	Synthetic fuels	TRL 9 (non-renewable feedstock) TRL 5-7 (renewable route)	Conversion	Hydrocracker
Fermentation	Alcohol	TRL 6-9	Blending, storage of goods	Tanks for final products

Source: Ricardo

In the case of HVO, several European refineries have been hydrogenating vegetable oils for more than 10 years (such as Neste, Cepsa or Total). Vegetable oil feedstocks have similar characteristics and can be co-processed with intermediate product streams from conventional mineral oil feedstocks, and so are compatible with existing infrastructure.

Regarding pyrolysis, there are several units already in operation converting bio-based feedstocks to syngas, and more under construction in the EU. Their products are blended with conventional feedstock streams within refineries. For example, these can be sent to either the atmospheric distillation or any of the secondary conversion stages (e.g., FCC unit).

Refinery conversion

Existing refinery processing units could also be modified to handle 100% non-fossil-based feedstocks. This can be seen in Figure 4-1 in steps labelled as 'Refinery Conversion', e.g. hydrotreatment following the pyrolysis of oils. A logical extension of this change is that refineries would have to be modified to handle the front-end processing of these feedstocks i.e., incorporation of conversion technologies into the refinery. This is likely to entail significant investment costs (Concawe, 2019).

4.1.3 Comparison of new stand-alone sites and converting existing refining assets for producing low carbon fuels

Industrial operators will select the best location for fuel production based on technical and economic considerations. The three options in the previous section yield a choice between integration within existing assets or developing new stand-alone sites. In the past, for deploying novel production processes, both stand-alone sites and integration of industrial conversion assets have been selected. The two options are evaluated in this section based on economic advantages and disadvantages.

Integration of industrial conversion assets

The capital costs (Capex) are lower for utilising existing assets. Specifically, the following economic benefits have been identified:

- **Sharing conversion assets**: co-processing of both biobased (vegetable) oil and mineral oil in the same conversion units is a mature approach proven at commercial scale in EU refineries.

- **Availability of storage facilities for products**: product tanks take up a large area of a refinery site and represent significant investments. Re-using existing assets avoids further Capex.
- **Investment on plant utilities** such as plant air (to open and close valves), firefighting systems, wastewater treatment, etc. Minor enlargements of these utilities are more cost efficient than building new ones. Since some high GHG intensity units will decrease throughput, there will be spare capacities for these utilities in most old European sites.
- **Fuel transportation infrastructure** including seaport connections, train and truck loading stations are readily available at existing refineries and would also avoid significant investments
- **Investment on training or consultants**: Personnel skills on customs, taxes, regulations, permits, markets, customers are also a relevant synergy with existing conventional fuel sites.

Regarding operating costs (Opex):

- **Influence of feedstock collection or transport costs**: the lower the energy density of a given product (feed, intermediate or final) the higher the interest to reduce transport costs. Producers of biofuels based on crops (from degraded land or other non-food competitors) frequently calculate the radius around the processing plant that is cost-effective for feedstock collection.
- **Personnel**: these plants need large numbers of personnel (from 500 to 3000). Many positions can be shared within a site for a large set of conversion units.
- **Maintenance** costs will also be relatively cheaper if shared with other units.

Regarding potential wider technical synergies, two further economic benefits have been identified for the production of low carbon fuels in existing refineries.

Firstly, there is a benefit from sharing feedstocks. The existing oil and gas refineries operate conventional conversion units that consume hydrogen for e.g. desulphurisation processes, or to crack long chain hydrocarbons to generate lighter intermediate products. Green hydrogen used for e-fuel production could also be provided to the conventional hydrogenation units, which would reduce their GHG emissions.

Secondly, there is a benefit in using waste streams from conventional refineries as a feedstock for novel processes. The CO_2 required as a feedstock for e-fuels can be obtained from flue gas streams generated in conventional refinery units. The CO_2-rich sources include combustion units burning fuels to generate heat, such as steam boilers using fossil fuels or using non-commercial refinery streams. Capturing and re-using this CO_2 will reduce net scope 1 GHG emissions at the same time as enabling feedstocks for low carbon fuels.

However, there can also be drawbacks on using existing facilities. These are considered to have a minor impact but should still be evaluated. They include the potential lack of space available in existing facilities for new plant, and, potentially, more complex permitting arrangements for an integrated site – though this is highly dependent on the national, regional or local competent authority.

Stand-alone sites

Stand-alone sites have also proven competitive in the past for these investments. For example, stand-alone plants are already in operation for processes such as FAME or pyrolysis units to convert waste into feedstocks. The main benefit of stand-alone sites for producing low carbon fuels is the greater availability of space.

However, the density of feedstocks and/or intermediate products that must be transported to other facilities for further processing must also be considered when deciding on a stand-alone site. Transporting lower density feeds or intermediates is usually less economically viable and this leads to the locating of novel plants that process feedstocks close to feed sources. This is the case for gases from gasification and electrolysers, as these will need to be co-located with the capacity for Fischer-Tropsch synthesis or methanol synthesis. On the other hand, if the process generates an energy dense product such as FAME, pyrolysis oil, or bio-crude, there is less of a need to co-locate the infrastructure, as a closer location to refinery can facilitate blending in the final fuel product. In these cases, it may be more cost-effective to place the plant closer to a renewable energy source for the production of the renewable feedstock.

Section 4.1.5 of this report provides examples of new e-fuels sites being built or projected outside existing refineries.

4.1.4 Factors affecting the potential production of sustainable e-fuels

The technical capacity to manufacture e-fuels based on green hydrogen and renewable carbon is not constrained by existing refinery capacity or capabilities, because existing refineries do not provide the input streams nor conversion units to enable this production path, as indicated in the previous section. There may however be benefits in using the site of decommissioned crude oil refineries for the location of the sustainable e-fuel production, but similarly there can be reasons for the new e-fuel production facilities to be located elsewhere. Therefore, the potential production capacity of e-fuels is not directly related to existing refineries.

The maximum e-fuel manufacturing capacity in Europe will thus mainly depend instead on (at least initially):

- the **policy measures** implemented and their impact on the market,
- the **economic viability** of the investment, and
- the **availability of key feedstocks**, such as green hydrogen and renewable CO_2.

Policies measures are expected to have significant impact on the initial development of e-fuel production at an industrial scale, as these policies are expected to introduce a market demand for these fuels. For example, the recommended amendments to RED II in the 'Fit for 55' package set out specific targets for advanced biofuels and RFNBOs in the transport sector. Furthermore, more sector specific targets have also been proposed, such as in the ReFuelEU aviation initiative, which establishes minimum blending targets for sustainable aviation fuels (SAF).

Regarding **economic viability**, the investment and production costs of these fuels also have a significant impact on the viability of e-fuels processes and will depend on the ability to upscale production technologies and so increase production capacities.

In terms of investments, the critical element to de-bottleneck production of e-fuels is the up-front investment for these novel processes. Green hydrogen production, for example, requires a significant initial investment, which private stakeholders may seek to avoid due to high risks. However, there are already EU policy measures including subsidies or support measures for the development of low carbon fuels, including more sustainable fuels, RFNBOs, biofuels (per RED requirements), amongst others. For example, there are EU scenario analyses showing large shares of energy from these carriers (JRC, 2020), prospective analysis documents (European Commission, 2021), and funds awarded by EU to develop this technology (European Commission, 2020). Furthermore, the Hydrogen and Decarbonised Gas Package released by the European Commission in December 2021 will promote the demand and production of renewable and low carbon gases, including hydrogen (European Commission, 2021).

E-fuels also have a high cost due to the current state of the deployment of the technology. The costs of e-fuels are relatively high, accounting for up to €7 per litre (Concawe, 2020). Most of the information sources consulted in the report point to the costs of power generation and the capacity utilisation of conversion facilities as the factors most determining the future cost of e-fuels. Some authors forecast that these costs will decrease over time due to economies of scale, learning effects and a decrease in the price of renewable electricity (in particular from wind and solar), resulting in a cost between €1/litre and €3/litre in 2050 (without considering applicable taxes).

On the **availability of key feedstocks**: The key building feedstocks to manufacture e-fuels are green hydrogen and CO_2. Regarding CO_2, other manufacturing industries, such as cement, or power generation combustion units could also deliver the CO_2 needed if fitted with carbon capture. For green hydrogen, any new renewable energy generation investment could deliver green electricity to facilitate the production of green hydrogen – provided that the renewable electricity is produced with new additional renewable energy[5].

Concerning the demand of e-fuels in the EU-27 in the coming years, various stakeholders have shared different projections for the role of e-fuels in the transport sector in the mid (2030) and long term (2050). According to the European Commission scenario 'A clean planet for all' (European Commission, 2018), e-fuels and hydrogen will be fully deployed and play a key role in decarbonising the transport sector, supplying between 15% and 50% of the sector's energy needs by 2050. This estimation considers the energy demand for the transport sector forecasted by the European Commission (European Commission, 2016) to be around 350 Mtoe per year by 2030–2050. The more recent MIX scenario of the 'Fit for 55' policy package from 2021 projects the transport sector energy demand to be 310 Mtoe in 2030.

[5] Implementing legislation on what constitutes "additionality" is forthcoming. See section 3 of this report for further information on this.

On the other hand, Concawe (2020) indicates that there is a high variability on the projections from different sources reviewed on the potential demand of e-fuels in Europe, particularly for 2050. E-fuels are not expected to play a significant role in the transport sector in the short-term (2030) (Concawe, 2019), according to most of the sources reviewed. However, estimates for e-fuels demand by 2050 range from more conservative references that suggest it to be in the order of <50 Mtoe/year[6] to more optimistic references that suggest it may reach 300-380 Mtoe/year. Therefore, in comparison to EU transport demands predicted by 2030 and by 2050, most references consulted by Concawe forecast the e-fuels potential contribution to be below 15% for 2030, and below 30% of the predicted transport demand by 2050 (Concawe, 2019). Notwithstanding, these scenarios are dependent on the ability to reduce current production costs and would require a significant increase in the renewable electricity infrastructure.

The scenarios presented in 'A Clean Planet for all' (European Commission, 2018) predict a role for e-fuels in all modes of transport and other sectors. However, other sources of information consider the anticipated role of e-fuels in transportation by 2050 to be dependent on the transport mode and its electrification options, as follows:

- E-fuels are widely accepted to play a significant role in sectors where technically feasible and cost-efficient alternatives are limited, such as maritime and aviation.
- There is a high variability in the demand predicted for e-fuel in other transport sectors where electrification alternatives are available, such as passenger vehicles and heavy-duty transport.

Regarding specific forecasts for the aviation sector, the situation is similar to estimations for other e-fuels as the majority of analyses forecast only low carbon fuel production based on hydrogenation of vegetable oil (HEFA) until 2030 and a potential increase in e-fuels in the mid- or long-term future.

4.1.5 Example investments in novel production processes

A selection of nearly 30 investments in new greenfield sites for novel production processes to produce advanced biofuels and e-fuels in Europe has been identified (Fuels Europe, 2022). An overview of these projects, which include some already underway and others still planned, is presented in Appendix C. These projects could produce up to 9.3 Mt per year of low-carbon liquid fuels by 2030 (Concawe, 2021) and include:

- Advanced biofuel projects with output capacities ranging from 0.1 to 0.75 million tonnes per year.
- Green hydrogen projects to reduce the GHG intensity of manufacturing processes or to combine with captured carbon to produce synthetic fuels with an annual capacity of up to 3.4 million tonnes.
- Waste-to-fuel projects, with a production capacity of up to 0.1 million tonnes per year in output (derived from municipal solid waste).

Among those projects, Porto Marghera, in Venice, was the first conventional refinery to be converted into a bio-refinery. Since 2014, about 360,000 tonnes of vegetable oil have been treated and converted into HVO (hydrotreated vegetable oil). In 2019, feasibility studies of a Waste-to-Fuel plant were realized at Porto Marghera, with an organic fraction of municipal solid waste processing capacity up to 150,000 tonnes per year. In 2021, the systems in Porto Marghera processed about 7.5 tonnes of used cooking oil and animal fats per hour; with the construction of new biomass treatment lines, the plant fully converted to waste and residue feedstocks.

However, further projects that have been recently announced in the press, of which three examples are presented below.

(1) Green hydrogen development at Heide refinery in Germany

Heide refinery is currently undergoing a transformation project (WESTKÜST100 project) (Raffinerie Heide, 2022), which includes the decarbonisation of heat, transport and industry. It is estimated that about a million tonnes less CO_2 will be produced as a result of this transformation. The project also entails the construction and operation of a 30 MW electrolysis plant, with the possibility of scaling it up to 700 MW in the future.

Furthermore, the German government has allocated funds for the HySCALE100 project (Raffinerie Heide, 2022), which will assist the Heide refinery in developing a large-scale green hydrogen production facility in

[6] Other reports, such as Ecorys (2017) estimated a potential e-fuel production of 10 Mtoe per year by 2050. However, different EU policies and objectives have evolved since the report from Ecorys was published and have become more ambitious. This could explain why this source's estimate is significantly lower than other more recent estimates.

collaboration with EDF-Hynamics, Holcim, and Ørsted. The project could be included as a part of the "Important Projects of Common European Interest" (IPCEI) initiative of the European Union.

HySCALE100 envisions integrating CO_2 capture with wind-powered hydrogen production. The project aims to produce e-methanol, from CO_2 captured from a cement factory to be synthesised with green hydrogen at Heide refinery. The e-methanol obtained will be used to fuel a methanol-to-olefin plant at the refinery, as well as placed in the market as a green fuel. The methanol-to-olefin plant will produce e-propylene and ethylene, from which a range of petrochemical based products are derived.

HySCALE100 plans to develop electrolyser capacity for 500MW by 2026 in subsequent phases. This phase would involve capturing refinery CO_2 and synthesising it with the green hydrogen produced. Additionally, the goal is to scale up electrolyser capacity to 2.1 GW after 2026, with CO_2 from the both the refinery and the cement factory captured and synthesised with the green hydrogen produced.

(2) Green hydrogen investment at Fredericia refinery in Denmark

In 2021, Crossbridge Energy Fredericia and Everfuel, in conjunction with the Danish Ministry of Climate, Energy and Utilities, began constructing the hydrogen project HySynergy, located at Fredericia refinery in Denmark. The purpose of HySynergy is to lower the carbon footprint of the existing refinery in Fredericia while also supplying green hydrogen for heavy transportation. The project will include green hydrogen production and storage capacities (State of Green, 2021).

The plant is expected to be completed by mid-2022 and the first phase will have a capacity of 20 MW, supplying approximately 8 tonnes of hydrogen daily. The refinery (70,000 b/d) will utilise 80% of the hydrogen produced from the HySynery Phase II plant as a feedstock in the refining process. The remaining 20% will be used for hydrogen mobility applications.

However, the initial capacity of 20 MW is expected to be significantly increased first to 300 MW in 2025 and then 1 GW in the longer term. According to Everfuel, when completed, the plant will cut 214,000 t/year of CO_2 emissions, decreasing Danish land transport-related CO_2 emissions by almost 5% by year 2025 (by increasing the use of hydrogen in mobility applications). This could contribute to Denmark’s objective of reducing CO_2 emissions by 70% by 2030.

(3) Green hydrogen plant to feed green ammonia plant and existing refinery in Spain

Iberdrola with Fertiberia Groups plans to invest in, together with the University of Huelva, the project *Puerta de Europa Green Hydrogen Cluster: A country project*. This cluster in the industrial hub of Huelva will be the largest hub in Spain of production, transformation and consumption of green hydrogen, integrating up to 600 MW of electrolysers. It will be supported by more than 80 companies and involve an investment of €2.2 billion (Huelva Información, 2022).

The cluster will enable companies and sectors to integrate renewable hydrogen supply into their processes and supply chains, fostering the transformation of their business models, developing new uses for renewable hydrogen, and displacing grey hydrogen consumption from fossil sources, resulting in significant reductions in CO_2 emissions. In addition to decarbonising industry, the project will enable the design and implementation of innovative solutions based on renewable hydrogen for various transport modes, including at the port in Andalusia.

As a specific example, Grupo Fertiberia will use green hydrogen as a natural gas substitute in the manufacturing of green fertilisers and ammonia. Furthermore, the production of green ammonia will open up new options for other hard-to-decarbonise sectors, such as the maritime sector (see case study in section 4.2).

4.2 TWO CASE STUDIES OF FUTURE DEMAND FOR NEW PRODUCTS FOR EUROPEAN REFINERIES TO CONSIDER

This section describes two examples of new products and markets emerging for refineries in the field of sustainable fuels:

- ammonia as a shipping fuel, and
- sustainable aviation fuels (SAF)

What are the synergies between refining and using ammonia as a shipping fuel?

Summary:

- At the refinery level, the opportunity for synergies with ammonia production appear to be limited.
- Some possibilities are oversizing the green hydrogen production facilities to replace refinery hydrogen or making use of some of the limited air separation units in refineries to provide the nitrogen for ammonia synthesis through Haber-Bosch process.
- The more likely outcome for large scale green ammonia production will be large newbuilt brown- or green-field dedicated hydrogen production plants (electrolysers).

How to parameter the technical changes to ensure the highest output of e-kerosene?

Summary:

- Many of the process routes for producing SAF are not mature and will need to undergo further optimisation and process development. Therefore, currently, there is insufficient evidence on a commercial scale to determine which technical parameters would need to be changed in order to obtain the highest output of e-kerosene without jeopardising the process efficiency.
- HEFA capacity produces predominantly diesel fuels, with a small fraction suitable for aviation. It is estimated that approximately 10% of current output could be destined to aviation fuel, although it is technically feasible to configure plants to produce 60% aviation fuel (Sustainable Aviation, 2020).
- However, there are technical challenges, as well as other barriers, such as production costs and investments and the certification process, that are expected to have a major influence on the rate of development of these fuels.
- As a result, SAF and Fischer-Tropsch e-kerosene will need policy support to become a reality, i.e. to start production and scale up to get the volumes needed by 2035 that can help to start reducing costs afterwards.

4.2.1 Ammonia as a shipping fuel

The international shipping industry's targets to reduce its carbon footprint over the next thirty years have set many players on a race to develop a suitable fuel; one that is abundant, safe and affordable. Among other candidates including methanol, ammonia is gaining traction, in its renewable form green ammonia, produced using electrolysis powered by renewable energy. While attractive in principle, many challenges must be overcome before green ammonia can lay claim to reducing even a small share of the shipping industry's emissions, which currently make up ~3% of global GHG emissions.

Ammonia serves as an efficient carrier of hydrogen and produces zero CO_2 during combustion. Moreover, ammonia is less flammable than hydrogen and has a considerably higher energy density. Its refrigerated tanks take up just half the space of cryogenic hydrogen tanks.

However, challenges include ammonia's toxicity, corrosive nature, and its low flammability which means that it does not sustain combustion well. In addition, and similarly to conventional fuels, when burned at high temperatures, it produces nitrogen dioxide and, to a lesser extent (but for which ongoing research is being carried out) nitrous oxide, which have to be treated using catalysts. Such catalysts, which are an established technology on-land and on road, significantly reduce N2O and NOX emissions leaving an exhaust of nitrogen and water, and themselves use ammonia as a urea solution.

The production of green ammonia at scale requires significant quantities of hydrogen to be produces, and hence requires an abundant renewable electricity supply. Ship engine manufacturers have begun the research and development of ammonia powered engines, and are targeting engines becoming commercially available from 2024 (MAN-ES, 2022). Some ammonia ship orders have been placed but whether commercial scale development takes off remains to be seen. The 22 vessels planned for delivery by 2025 (source: Argus) will result in limited ammonia demand in the short- to medium-term. But the policy drivers currently tabled (e.g. revision of the EU Emissions Trading System, FuelEU Maritime, and revision of the Directive on deployment of alternative fuels infrastructure – see section 2) at EU level should drive the transition forward also at international level until at least one low /zero carbon maritime fuel reaches the tipping point for mass adoption through fuel cost reduction / price parity with conventional fuels.

At the refinery level, the opportunity for synergies with ammonia production appear to be limited. Some possibilities are:

- Green hydrogen production facilities could be oversized to replace refinery hydrogen in addition to producing green ammonia.

- Nitrogen production from air separation plants in refinery processes that require them – e.g. partial oxidation (POX) units, MEG production (for integrated facilities) –, could use the nitrogen to produce ammonia. Some CO_2 from POX units could be redirected to produce e-fuels since it is already highly concentrated. Other usual synergies are common to any integrated facilities including using of waste stream (off-gases etc) as fuel or feedstock, energy integration, and common offsites.
- Synthetic fuels and hydrogen itself (used directly as a fuel) seem to offer the highest level of synergy with green ammonia production as both processes require hydrogen from renewable powered electrolysis. In the case of RFNBOs, the hydrogen produced can be directly used for producing methanol (or through other pathways discussed above). In the case of ammonia, nitrogen would be added and handled in a Haber-Bosch process.

4.2.2 Sustainable Aviation Fuels (SAF)

Introduction to SAF

Commercial aircraft OEMs guarantee that their aircraft will meet mandated performance standards on the basis that they are operated with fuel that meets an internationally defined standard. The most common standard employed is ASTM D1655 – Standard specification for aviation turbine fuels. Fuels that meet this standard are typically referred to as Jet A-1 (or Jet A in the USA). ASTM D1655 defines the physical and chemical properties a fuel must possess to ensure its compatibility with commercial aircraft. These properties are based on those of conventional, fossil derived Jet A-1. ASTM D1655 also allows synthetic aviation fuels to be blended with fossil kerosene to be classified as Jet A-1.

In order to be eligible for blending, synthetic fuels must undergo a rigorous certification procedure defined in ASTM D4054. The purpose of this procedure is to demonstrate that the physical/chemical properties and in-engine performance of the synthetic fuel is equivalent to that of fossil Jet-A i.e., that the synthetic fuel is fully fungible with existing aviation infrastructure. Once a synthetic jet fuel has passed the ASTM D4054 procedure, it is added to ASTM D7566 - Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons. Once annexed in ASTM D7566, the synthetic fuel can be blended with fossil jet fuel and reclassified as Jet A-1, according to ASTM D1655. As of 2022, nine processes are annexed in ASTM D7566 that could potentially be used to produce drop-in synthetic fuels.

The use of the term ‘synthetic’ in this context refer to the fuels the standards refer to, as ASTM standards do not specify feedstocks in all the cases. In practice, SAF is understood to use bio- and waste-based feedstocks, including municipal solid waste streams, agricultural / forestry residues, used cooking oil and other fats/oils/greases, crops such as corn grain and dedicated energy crops.

Blends and technical feasibility

Currently, these synthetic fuels are limited to a maximum blend of 50% by volume with conventional aviation fuel. There are three primary reasons for this:

1. **Material compatibility** – synthetic fuels contain little to no aromatics compared to fossil derived Jet A-1. This has been shown to cause compatibility issues that compromise the operability of the aircraft, for example issues with swelling of seals within the fuel/engine system. This could be resolved through the addition of additive packages to the 100% synthetic fuels. This has only been shown to be an issue in aircraft that have previously been exposed to aromatics (U.S. Department of Energy, 2020).
2. **Chemical composition of the fuel** – The Total/Amryis pathway for the production of synthesised iso-paraffins (SIP) via fermentation of sugars produces a drop-in fuel containing one specific molecule (farnesane). Consequently, from a technical point of view, the blending of this fuel is limited to 10% as addition of larger fractions of SIP has an adverse effect on the physical/chemical properties of the fuel with respect to Jet A-1.
3. **Certification procedure** – A less stringent “fast-track” certification procedure was recently approved. Where synthetic fuels are certified via the fast-track procedure, they are restricted to a maximum blend fraction of 10%.

Despite the above, airlines have recently operated commercial flights on 100% SAF, demonstrating the technical feasibility (S&P Global, 2021).

What is 'sustainable' in the prevailing policies?

There is no single definition of SAFs agreed at the international level. In the EU, the sustainability of a fuel is defined in the carbon offsetting and reduction scheme for international aviation (CORSIA) and the renewable energy directive (RED II). CORSIA is a market-based approach to mitigating global aviation emissions. Airlines can either offset their emissions using emissions credits or use CORSIA eligible fuels to mitigate emissions. CORSIA stipulates 'sustainable' aviation fuels should have a 10% GHG saving relative to a fossil comparator with the fossil fuel they seek to replace and allows the use of food and feed feedstocks. Furthermore, CORSIA permits 'lower carbon aviation fuels', i.e., fossil kerosene where upstream emissions have been reduced to be used to mitigate emissions. There are no blending mandates in CORSIA.

The EU Renewable Energy Directive (RED II) allows SAF to count towards the achievement of the renewable energy targets provided for in the Directive in the EU Member States, on the condition that they comply with the sustainability criteria listed in the Directive.

A component of the 'Fit for 55' policy package set out in summer 2021 by the European Commission is a blending mandate for sustainable aviation fuel via the ReFuelEU Aviation initiative. The proposals outlined in the ReFuelEU Aviation initiative are more stringent than CORSIA, and mandate that fuels must meet a minimum of 65% GHG emissions savings in RED, excluding food and feed feedstocks – i.e. only biofuels produced using feedstocks listed in Annex IX of RED II can be counted. Furthermore, ReFuelEU contains blending mandates to promote the uptake of sustainable aviation fuels.

However, several of the ASTM-approved pathways for producing drop-in synthetic aviation fuel are compatible with fossil-based feedstocks e.g., FT-SPK and FT-SKA can utilise coal and natural gas as feedstocks as well as biomass. Therefore, it is not guaranteed that production of fuels by an ASTM-approved conversion route will yield 'sustainable' aviation fuel.

SAF production expansion

Taking into account feedstock availability and the deployment of novel conversion technologies, ICCT (2021) estimated that SAF production[7] in the EU could reach 3.4Mt/year by 2030 and that this would represent about 5.5% of the projected jet fuel demand in this year (though not accounting for the demand dip due to the COVID pandemic). The ICCT's paper further indicated that biogenic SAF alone would not be able to decarbonise aviation in the EU to the rates needed and is expected to only have a modest influence through 2030.

In contrast, the World Economic Forum (2021) forecasts higher SAF production, accounting for ~10% of total EU jet fuel demand in 2030, rising to ~75% of the total EU jet fuel demand in 2050. Of the pathways, the major growth is expected to be in power-to-liquids (PtL) – also known as electrofuels / e-fuels – followed by alcohol-to-jet (AtJ). Production of fuels derived from Hydrogenated esters and fatty acids (HEFA) is predicted to stabilise from 2030 onwards. These projections are based the following assumptions:

- Sustainable biomass resources are focused for use in aviation – with 40% of total biomass that is sustainably available in Europe dedicated to jet fuel production.
- New technologies overcoming technical barriers for production at commercial scale before 2030
- Strict sustainability criteria are met
- Planned projects to 2025 are completed and become operational on time
- All new and existing sustainable fuel plants with the capacity to produce SAF optimise output for jet fuel (once output meet current existing obligations in other sector)

Particularly regarding the latter two bullet points, Table 4-3 lists examples of existing conventional refinery installations that have announced investments on SAF processes drawn from the World Economic Forum (2021). There are also new SAF production plants located outside oil and gas refineries. For example, a number of PtL demonstration plants are being developed or are planned in Finland, Germany and Norway and Canada, and the EU has funded several research projects (e.g. Sun-to-Liquid, Kerogreen and ECOCOO).

[7] Including waste fats, oils and greases, agricultural residues, forestry residues, municipal and industrial waste, industrial flue gases feedstocks, and synthetic fuels.

Table 4-3 Announced projects in Europe with SAF production capacity, 2020–2025

Gasification + Fischer-Tropsch	HEFA	HEFA (under development)	Electrofuels	Alcohol-to-jet
• Velocys, Altatto • Fulcrum, Stanlow • Total, Dunkirk • Enerkem, Rotterdam • Kaidi, Kemi • UPM, Kotka • Neste, Porvoo • Engie, Normandy	• CEPSA, San Roque • Repsol, Cartagena • Total, La Mède • Neste, Rotterdam • ENI, Venice • Preem, Gothenburg	• Sunfire, Nordic Blue • Copenhagen Airport • Caphenia, Dresde • ST1, Gothenburg • Lanzatech, Wales	• IPM, Lappeenranta • Synkero, Amsterdam • Total, Grandpuits • SkyNRG, DSL01 • ENI, Gela	• Colabitoil, Norssundet

Source: Guidelines for a Sustainable Aviation Fuel Blending Mandate in Europe (World Economic Forum, 2021)

As well as the ReFuelEU proposals mentioned above, to encourage growth in SAF, some regions and countries have introduced policies supporting SAF.

- In the EU, the Emissions trading system (EU ETS) provides an incentive for aircraft operators to use biomass-based SAF certified as compliant with the sustainability criteria of RED II, by attributing them zero emissions under the scheme, cutting operators' reported emissions and the allowances they need to purchase.
- Netherlands, France, Finland, Sweden and Portugal have put in place SAF supply obligations.
- Germany and Spain have launched initiatives to support the development of SAF processes.
- Norway requires at least 0.5 % of advanced biofuel to be mixed with jet fuel sold from 1 January 2020 with the aim of increasing use of SAF to 30 % of aviation fuel by 2030.
- In the UK, the Renewable Transport Fuel Obligation scheme was extended to aviation in 2018 to support and reward the production of SAF.
- The United States has incentive programmes for fuel production and for fuel use (e.g. US Renewable Fuels Standard 2 (RFS2), the California Low Carbon Fuel Standard (LCFS)). This approach has resulted in faster SAF growth than in the EU and might have had an impact on the current situation, in which the majority of the SAF used by European operators is tanked or imported from other countries (EASA, 2019). KLM, the only European airline that uses SAF on a regular basis, obtains its fuel from the United States (EPRS, 2020).

Technical challenges for production processes

There is a consensus between fuel producers and airlines that a wide spectrum of production pathways and feedstocks, including more innovative, sustainable and cost-effective pathways, will be necessary to contribute effectively to decarbonising aviation. However, SAF technologies currently stand at different stages of commercial development and face various production challenges. Their respective trajectories towards large-scale deployment follow different timelines ranging from short- to medium-term based on different Technology Readiness Levels (TRLs)[8]. Also, most of the products do not have a well proven supply chain scheme to sort the complex and dispersed availability for feedstocks sources. Furthermore, other technical challenges may arise for these technology pathways, as they scale up from pilot plants to demonstration size and, finally, to commercial scale in the coming years.

The main technical production challenges are studied in this section: first, Table 4-4 introduces the main challenges for each of the production processes, and then after the table, further information on the challenges is described.

[8] Lower Technology Readiness Levels means further from being commercially available.

Table 4-4 Overview of challenges for different SAF categories

Product name	Process	Process	Feeds	TRL	Major challenges
Biofuels	HEFA SPK (Organic feed)	Hydrogenation + Separation or purification	Part A annex IX: algae, biowaste, tall oil, pam oil, etc.	9	Availability of feedstock Competition for other uses Weak/complex supply chain
	HEFA SPK (Organic waste)		(Animal fats cat 1& 2 & used cooking oil) Part B Annex IX	9	Availability of feedstock Competition for other uses Weak/complex supply chain Contribution caped by policy (REDII)
Advanced biofuels	HFS-SIP	Fermentation	Sugar, starch crops,	7-8	Higher production costs Large investments needed Weak/ complex supply chain
	ATJ-SPK	Dehydration, oligomerisation and hydroprocessing	Lignocellulosic biomass	6-8	
	CHJ	Catalytic hydrothermolysis	Triglycerides: soybean oil, jatropha oil, camelina oil, carinata oil, and tung oil	4-6	
	FT-SPK	Biomass Gasification + Fischer-Tropsch (Gas+FT)	Energy crops, lignocellulosic biomass, solid waste	6-8	
RFNBOs	FT-SPK	Electrolysis+ conversion FT	Non-biologic origin (renewable electricity)	4-7	Availability of green electricity (green H_2) Availability/cost of renewable carbon (CCU) High production costs
		Electrolysis+ Methanol			

Notes:
HEFA SPK: Hydroprocessed Esters and Fatty Acids,
HFS-SIP: Hydroprocessed Fermented Sugars to Synthetic Isoparaffins,
ATJ-SPK: Alcohol-to-Jet Synthetic Paraffinic Kerosene,
CHJ: Catalytic hydrothermolysis synthetic jet fuel,
FT-SPK: Fischer-Tropsch Synthetic Paraffinic Kerosene

Source: Ricardo

Further information on the challenges each of the production processes face is provided below.

- **HEFA (oil and fats):** There is currently limited production devoted to SAF from vegetable oil hydrogenation, as HEFA capacity produces predominantly diesel fuels, with a small fraction suitable for aviation. It is estimated that approximately 10% of current output could be destined to aviation fuel, although it is technically feasible to configure plants to produce 60% aviation fuel (Sustainable Aviation, 2020).

  Regarding feedstocks, HEFA from used cooking oil has a proven process and supply chain but limited production of SAFs. This is mainly because nearly all used cooking oil that is recovered in the European Union is already being used for on-road biofuel production. In 2019, waste fats, oils, and greases – including used cooking oil, animal fats, and others such as tall oil – accounted for 32% of consumed biodiesel and renewable diesel in the European Union (ICCT, 2021). Other feedstocks, such as animal fats are also used in heat and power production. Palm oil, on the other hand, is banned in several Member States due to its high land use and high GHG emissions and will be phased out under RED by 2030 across the Member States of the EU (European Parliament, 2018). The use of this feed for SAF production would most likely cause high indirect GHG emissions.

- **Alcohol to jet (AtJ).** The majority of techniques for converting alcohol to jet fuel have yet to be commercialised. Furthermore, no supply networks for these routes exist in Europe. Therefore, the economics of fuel upgrading procedures must be considered in order to evaluate the total AtJ conversion pathway and estimate its commercial feasibility. Because these methods are still in development, more research is needed to fulfil the requisite quick scale-up. The feedstock choice can impact many factors as well, such as pre-treatment methods, microorganism choice, alcohol yield, and process economics.

  Regarding feedstocks, lignocellulosic feedstocks from agricultural and forestry residues and from municipal and industrial waste are more technically challenging to convert than waste oils due to their physical and chemical properties. Neither pathway is in operation on a commercial scale, and these feedstocks are largely unused in the road sector. Even achieving low blending rates – on a par with the 3.5% advanced biofuels sub-target in the RED II for the road sector – would necessitate strong policy support. On the other hand, agricultural residues that have existing uses in other industries are considered to be unavailable for SAF production, according to ICCT (2021). Feedstock quantities consumed in these applications are expected to remain constant or grow in the next decades. Agriculture residues are also used in combustion units (heat and power generation) with quantities expected to increase in coming years.

- **Gasification and Fischer-Tropsch (FT) conversion.** The FT process is currently applied at commercial scale by Sasol, Petro SA, Shell and Oryx using fossil feedstocks. However, biomass or waste-based FT processes (BTL) are still at the pilot and demonstration stages, with first commercial scale plants in development including the Fulcrum Sierra project in the USA. To meet increasing growth for this conversion route, it seems feasible that certain primary feedstocks or intermediates will be produced outside of Europe, close to feedstock source, and could be imported for processing into final SAF products in European facilities.

Other challenges for SAF production

Other challenges not specifically related to the production process of SAF are identified in this section.

(1) Production costs and access to capital for investments

Production costs, as well as reliable information on the investment intensity for SAF production processes, are not yet accurate as a range of cost forecasts are available depending on the information source.

HEFA production costs are estimated to be €0.88/litre, making it the lowest source of SAF in the short term compared to other processes with a lower TRL (ICCT, 2021). Other sources, such as EASA (2019), estimate that the price of SAF produced from used cooking oil to be about €950 to €1,015 per tonne. The costs of fossil fuel-based aviation fuel have, together with other fossil fuels, increased substantially during 2022, and at the time of writing (June 2022) had reached €1,300/tonne, approximately double the cost in summer 2021[9].

For synthetic fuels, production costs are expected to also be significant, although its value is uncertain to date due to their maturity stage. Industry stakeholders, such as aircraft operators and ground equipment owners, require industrial scale demonstration of product performance as evidence of technical maturity. In 2021, the first production facility for CO_2-netural e-kerosene was launched (Clean Energy Wire, 2021) by the non-profit organisation Atmosfair. The facility, located in Germany, uses CO_2 captured from the air and from a biogas plant that uses food waste, and electricity from wind and solar installations to produce green hydrogen. As of 2022, regular operation produces eight barrels of crude paraffin a day, which are refined into synthetic Jet A1 fuel and delivered to Hamburg Airport (atmosfair, 2022). Atmosfair has also been producing synthetic e-kerosene with a plant located in North Germany.

[9] https://www.iata.org/en/publications/economics/fuel-monitor/

Whilst previous comparisons with producing petroleum-based jet fuel have concluded that e.g. HEFA production costs account for twice the production cost, and that other novel conversion processes can cost up to eight times the price of petroleum fuel In comparison[10], clearly with the current rate of change in jet fuel prices these comparisons have shorter and more limited validity. And because further evidence is needed on the price of production of SAF from certain pathways, policy support may still be needed to prove them economically viable and to attract investment.

Other economic-related challenges are the need for economies of scale, as well as the lack of legally binding mandates for fuel suppliers on a percentage of SAF in jet fuels. These mandates would be a mechanism to ensure returns for investments for stakeholders (World Economic Forum, 2021).

(2) Availability and cost of feedstock

SAF producers face three challenges regarding feedstock availability and cost:

- **Restriction on the use of food-based feedstocks**.
- **Competition for feedstock between transport modes**, particularly currently between road transport and the aviation sector. This is expected to increase as more ambitious policy measures to decarbonise the transport sectors are adopted. For example, feedstocks used in the HEFA process are also used for road sector biodiesel production, which has a simpler and less costly production process, and may therefore be a more attractive option for producers. Also, Fischer-Tropsch synthesis pathways, using generic biomass, may have lower cost and abundant feedstock.
- **Lack of feedstock supply chains**. For example, mobilising new biomass supply chains can take longer than 5 years, especially if it concerns feedstocks for which novel incentives have yet to be developed such as cover crops.

(3) Complex and lengthy certification burden

Aviation fuel certification is currently performed by the American Society for Testing and Materials (ASTM). The certification process is considered to be a lengthy and costly process, with the process lasting over three years, and reportedly with costs of $2 million for the first products to be marketed (EPRS, 2020). A number of new products are currently under certification.

4.3 ENERGY INTENSITY OF PRODUCING LOW CARBON FUELS COMPARED TO CONVENTIONAL REFINING – CASE STUDIES OF SYNTHETIC DIESEL FROM THE FISCHER-TROPSCH PROCESS AND METHANOL SYNTHESIS

Comparison of energy intensity between Fischer-Tropsch process and methanol synthesis/refining

Summary:

- The energy intensity of the process of renewably deriving synthetic diesel is shown to be around six to seven times higher than for conventional diesel (with the higher value assuming CO_2 from direct air capture).
- The energy intensity of the process of renewably synthesising methanol is around twice that of conventional methanol synthesis assuming CO_2 captured from flue gases; the energy intensity of the process would be higher if using CO_2 from direct air capture).
- The comparison uses full well-to-tank values from the JEC study (Prussi et al, 2020) which take into account the total energy demand of the production process including the energy consumption needed for CO_2 separation, as well as the energy content of these fuels. The energy content of the feedstock (e.g. of crude oil for conventional fuels) is not included in this.
- Despite the increased energy intensity of production, the synthetic fuel routes nevertheless offer greater than 90-95% reductions in upstream GHG emissions compared to conventional production routes.

Previous work has investigated the renewable electricity requirements to decarbonise transport in Europe, including with electrofuels (Ricardo, 2020). This work concluded that decarbonising light duty road transport will be best without e-fuels (i.e. through electrification), and that to decarbonise shipping and aviation will require significantly more renewable electricity to produce the required levels of e-fuels by 2050. Clearly the amount of energy needed to produce fuels is important in itself, particularly in an economy with limited

[10] In comparison to fuel prices at the time the report was written (2019).

resources. And, for those sectors where electrical propulsion is not practical and renewable electricity is cheap and plentiful, this might be justified.

As an example of the energy requirements of producing fuels, this section aims to compare the energy intensity of the Fischer-Tropsch process and methanol synthesis produced from renewable electricity and CO_2 against their corresponding conventional fossil-based equivalents.

Text Box 4-1 Methanol synthesis and Fischer-Tropsch

Gasification and steam reforming have been used historically to produce syngas from coal and gas respectively. The syngas, which comprises both carbon monoxide and carbon dioxide, as well as hydrogen, provides the feed for the synthesis of methanol as well as for the Fischer-Tropsch process, over different catalysts. The low carbon synthetic fuels that could be produced through these processes will rely on 'green' sources of the syngas constituents, rather than the gasification or steam reforming processes.

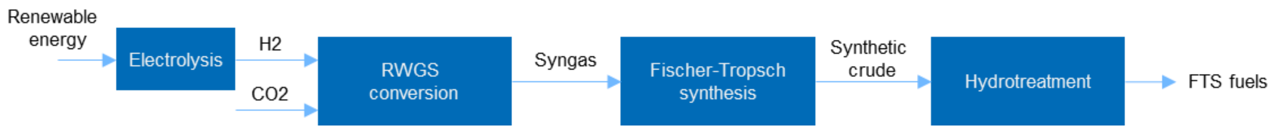
For the purpose of this comparison, the following definitions are used:

- The **energy intensity** (MJ of energy input / MJ of energy in the product) is the quantity of energy input to the production process per unit of chemical energy in the fuel output.
- The **net calorific value** or lower heating value (MJ per tonne of the product) is the amount of heat released from complete combustion of a specified quantity and it is a measure of a fuel's energy density.
- The **energy demand** is the amount of energy that an average plant requires to produce a specific product. It has been derived from the energy intensity multiplied by the net calorific value.

Fischer-Tropsch process

Fischer-Tropsch synthesised fuels are drop-in fuels (e.g. diesel and kerosene) with almost the same chemical composition as fossil fuels but with lower sulphur and aromatic content and usually higher cetane numbers (diesel). In Fischer-Tropsch synthesis, syngas produced from renewable electricity-based hydrogen and CO_2 is used for the production of various synthetic fuels, as detailed in Appendix A, and summarised in Figure 4-2.

Figure 4-2 Fischer-Tropsch synthesis



Source: Ricardo

The simplified reaction sequence is the following:

1. Electrolysis: $2\,H_2O \rightarrow 2\,H_2 + O_2$
2. Reverse water gas shift (RWGS) conversion: $CO_2 + H_2 \rightarrow CO + H_2O$
3. Fischer-Tropsch synthesis: $nCO + (2n+1)\,H_2 \rightarrow C_nH_{2n+2} + nH_2O$
4. Upgrading (hydrotreatment)

The overall conversion efficiency on an energy basis is the product of the individual conversion efficiencies of the main process steps. The overall energy conversion efficiency (from syngas to ready-for-delivery product) is typically in the range of 40-65% on an energy basis. Efficient utilisation of by-products like steam and heat can increase the overall energy efficiency of the plant by up to 5-10%, when integrated with district heating or with combined heat and power production (DECHEMA, 2017). The JEC[11] Well-to-Wheel study (Prussi et al, 2020) has calculated the energy consumption per unit (energy) of synthetic diesel produced from renewable electricity-powered high temperature electrolysis and Fischer-Tropsch synthesis process using CO_2 from flue gases or direct air capture (DAC)[12]. Their energy intensity estimate is 1.55 MJ per MJ of fuel for the entire well-

[11] The JEC consortium is a long-standing collaboration among the European Commission's Joint Research Centre (EC-JRC), EUCAR (the European council for Automotive Research and development) and Concawe (the scientific body of the European Refiners' Association for environment, health and safety in refining and distribution).

[12] Referred to as pathways RESD2a and RESD2d respectively.

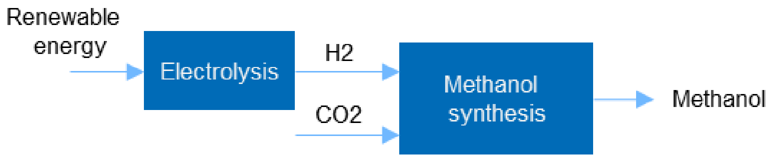
to-tank[13] stage of the pathway assuming CO_2 captured from flue gases, and a higher value of 1.83 MJ per MJ of fuel assuming DAC. The majority of the energy demand is required for the electrolysis.

Methanol synthesis

Methanol is both an important industrial chemical and a fuel. It can also be readily converted into products such as gasoline in the methanol-to-gasoline process or olefins in the methanol-to-olefins process. There are currently different processes available for methanol synthesis. At present, most methanol comes from the catalytic conversion of synthesis gas (syngas) that is usually generated by steam reforming of natural gas. However, the syngas can also be obtained from renewable sources. As an alternative route to using syngas, methanol can also be produced by directly hydrogenating pure CO_2 with hydrogen.

The latter process, which we focus on here, involves hydrogen production via electrolysis, CO_2 absorption from flue gases (e.g. from a refinery process/combustion source), and then methanol synthesis according to the reaction $CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$. In this case, reaction and conversion rates are lower than when syngas is used as feedstock. In addition, methanol synthesis from pure CO_2 is a challenging reaction due to increased water formation[14]. A simplified process scheme is included in Figure 4-3.

Figure 4-3 Methanol synthesis from CO_2 and H_2



Source: Ricardo

This production pathway has been assessed in the JEC Well-to-Tank study (pathway REME1a), and the energy intensity estimated for the entire upstream well to tank phase is 1.29 MJ / MJ of fuel (assuming CO_2 is from flue gases). Whilst the total energy demand for producing methanol from CO_2 and H_2 is higher than for the conventional syngas route, the difference is less pronounced when the feedstock is included in the fossil process to obtain methanol.

Comparison of well-to-tank energy intensity with conventional fuels

Table 4-5 compares the well-to-tank[15] energy intensity for synthetic fuels described above with their equivalents from conventional refining processes. The **upstream energy intensity of renewably deriving synthetic diesel is around six to seven times higher than for conventional diesel**, and the **energy intensity of renewably synthesising methanol around twice[16] that of conventional methanol synthesis**. Despite the increased energy intensity of production, the synthetic fuel routes nevertheless offer greater than 90-95% reductions in upstream GHG emissions compared to their like-for-like conventional (fossil) equivalents. The comparison however, particularly for methanol, is not straightforward, as – for example in the maritime sector – the use of green methanol would not in the long term replace existing (grey) methanol but would rather displace conventional heavy fuel oil for instance.

For transparency, the processes included in each of the production pathways mentioned in Table 4-5 are elaborated in Table 4-6 (also taken from the JEC report (Prussi et al, 2020)).

[13] Well-to-tank includes production and conditioning at source, transformation at source, transportation to market, transformation near market, conditioning and distribution. It excludes use of the fuel (e.g., combustion), which is referred to as 'tank-to-wheel' for road transport.

[14] In the absence of CO, water is produced both as the by-product of CO_2 hydrogenation and by the reverse-water gas shift.

[15] The approach taken here for 'well-to-tank' is a comparison of the energy intensities of the production processes, and excludes the energy content of the feedstock, i.e. taking the approach of the discipline of 'Net Energy Analysis' (NEA). The alternative approach of 'Cumulative Energy Demand' – not taken here – would take into account the energy content of the crude itself.

[16] Around twice the energy intensity assuming CO_2 captured from flue gases. If DAC was used, the energy intensity would increase further, perhaps to between two to three times the energy intensity of methanol derived from steam methane reforming of natural gas.

Table 4-5 Comparison of well-to-tank energy intensity between selected synthetic fuels and fossil fuels (data from JEC (Prussi et al, 2020))

Fuel/Pathway	Total energy demand (MJ/kg)	Net calorific value (MJ/kg)	Energy intensity ($MJ_{process}/MJ_{product}$)	Well-to-tank GHG emissions (g CO_2eq/MJ)	Source
Synthetic fuels					
Synthetic **diesel** from Fischer-Tropsch synthesis using renewable electricity powered electrolysis	68.2	44.0	1.55 (CO_2 captured from flue gases) 1.83 (CO_2 from DAC)	0.8	JEC pathways RESD2a, RESD2d
Methanol from synthesis (renewable, $CO_2 + H_2$)	25.7	19.9	1.29 (CO_2 captured from flue gases)	1.8	JEC pathway REME1a
Fossil fuels					
Diesel from crude refining	11.2	43.1	0.26	18.9	JEC pathway COD1
Methanol from synthesis (natural gas)[17]	12.1 – 13.7	19.9	0.61 – 0.69	24.3 – 31.6	JEC pathways GPME1b, GRME1

In conclusion, the synthetic fuel production processes have a higher unit energy consumption than comparable fossil-origin fuels. Low-carbon processes are not as energy efficient in this sense, although given the need to transition to sources other than fossil fuels for the purpose of decarbonisation, they offer advantages in terms of their GHG footprint. Therefore, even when accounting for a higher energy demand, the synthesis of liquid fuels from hydrogen using renewable CO_2 as the carbon source and additional renewable electricity would allow sustainable fuel production with the potential to reduce CO_2 emissions in the energy and the transport sectors. Furthermore, an added potential benefit is the opportunity to act as chemical energy storage for renewable electricity (Nieminen, Laari, & Koiranen, 2019).

[17] The range here represents the two alternative pathways in JEC, of Piped natural gas (4000 km) to methanol, synthesis plant in EU (GPME1b), and Remote natural gas to methanol, synthesis plant near gas field (GRME1).

Table 4-6 Details of the processes included in each of the five production pathway stages (from JEC (Prussi et al, 2020))

Fuel (pathway)	Production and conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning and distribution
Synthetic diesel (RESD2a / RESD2d)	Wind power	None	High voltage electricity distribution	High temperature electrolysis CO_2 absorption from flue gases / DAC CO_2 liquefaction H_2 compression Fischer-Tropsch synthesis, RWGS, upgrading *(all electricity from wind)*	Distribution (20% barge, 20% rail, 60% pipeline) Fuel depot Local distribution (road) Dispensing at retail site
Green methanol (REME1a)	Wind power	None	High and medium voltage electricity distribution	High temperature electrolysis CO_2 absorption from flue gases Methanol synthesis *(all electricity from wind)*	Distribution (13% road, 32% sea-going product tanker, 51% inland/coastal tanker, 4% rail) Fuel depot Local distribution (road) Dispensing at retail site
Diesel (COD1)	Crude oil production (average for range of crudes) including dewatering and gas separation processes, and flaring	None	Crude oil transport by ship	Crude refining, marginal diesel	Distribution (20% barge, 20% rail, 60% pipeline) Fuel depot Local distribution (road) Dispensing at retail site
Methanol (GPME1b)	Natural gas extraction and processing	None	Natural gas pipeline, with compressors fuelled by natural gas. Includes methane losses.	Natural gas to methanol synthesis plant	Distribution (rail, road) Dispensing at retail site
Methanol (GRME1)	Natural gas extraction and processing	Natural gas to methanol synthesis plant Methanol depot	Methanol carrier by sea Methanol depot	None	Distribution (rail, road) Dispensing at retail site

4.4 COST COMPETITIVENESS OF E-FUELS

This section provides an analysis on the cost competitiveness of e-fuels, including information on the investment and timeframe requirements for this transformation to be able to achieve the Paris Agreement goals, as well as on the main cost drivers of these fuels.

What are the possibilities for Direct Air Capture (DAC) units to source carbon for the production of synthetic hydrocarbons?

- DAC is not yet commercially deployed at large industrial scale. Currently, there are 19 DAC plants operating worldwide, all of which are small scale (IEA, Nov 2021). Demonstration and subsequent technology refinement at large scale will be needed for DAC to be used for producing synthetic fuels.
- IEA report (Nov 2021) one large-scale plant (1 million tonnes CO_2/year) is currently under construction and due to come online in 2024. The IEA's net zero scenario projections estimate that DAC capacity will reach 85 million tonnes in 2030 and more than ten times this by 2050. With this capacity expansion, commensurate cost reductions would be foreseen too, making the technology suitable for the production of synthetic hydrocarbons over these timescales.
- However, even when considering a potential fast growth scale-up for this technology, the forecast levelised cost of carbon is still higher than the cost of carbon capture from other sources (Ricardo, 2022). Therefore, DAC CO_2 will need policy support to be able to compete economically with other CO_2 sources. Furthermore, DAC technology is energy intensive, so the additional renewable electricity generation capacity required to meet its energy requirements must also be taken into account.

What will be the investment needs and the timeframe for changes to the existing refineries?

- Fuels Europe estimate an investment of €400 to 650 billion for the development low carbon fuels that could contribute to achieving EU 2050 climate neutrality objectives, citing first-of-a-kind industrial plants possibly starting operations by 2025 at the latest.

What is the cost competitiveness of these plants compared to the e-fuels imports from places with more constant and higher solar and wind energy potential?

- The green hydrogen required for the production of e-fuels could be generated by installing renewable energy sources on-site or imported from other regions, outside or inside the EU. However, due to the potential space constraints on/near site, importing green hydrogen is a potential alternative.
- Regions with larger renewable energy potential are considered as cost-effective options from which this green hydrogen could be imported. This is primarily due to lower green hydrogen production costs, which could be achieved through a combination of abundant renewable energy, affordable transportation costs (e.g., less than 10% total costs), and economies of scale. Economies of scale are considered to be a key driver, as large investments are likely to be made where large resources are available. Additionally, the energy density of the fuel imported is a significant cost parameter.

4.4.1 Factors affecting the costs of e-fuels

This section introduces the drivers for the production costs of e-fuels. These include the conversion technology itself, the costs for renewable energy generation and the utilisation rate for conversion plants, as well as others that are common to any industrial activity, e.g. the need for economies of scale.

The main cost drivers are:

- **Costs of renewable energy**: the energy cost and efficiency of the process are major drivers of the costs of e-fuels: they account for up to two thirds (~60%) of the total e-fuel costs, when including the cost of electrolysers. Although unit renewable electricity generation costs are predicted to decrease, they will still account for a major share of total costs in 2050 (Agora, 2018). One of the reasons for this remaining major share of costs is the process efficiency: around 67% for the water electrolysis and 80% for conversion processes, such as Fischer-Tropsch synthesis or methanol synthesis.
- **Technology development**: the level of development (TRL) of the different technologies and conversion pathways has a large influence on the cost of the process. For example, as the technology matures, the cost of producing e-methanol is expected to drop to €0.2-0.3/kWh in 2050, down from €0.4-0.5/kWh in 2015 (Concawe, 2020).

- **Utilisation rate for conversion plants**: the utilisation rate of conversion plants is a substantial cost driver, as high-loads are needed to operate e-fuel production plants in a cost-effective manner (Concawe, 2020). Agora (2018) suggest that 3,000 to 4,000 full load hours per year are needed for cost efficient e-fuel plant operation. Concawe's (2020) analysis of Agora (2018) suggests that the impact of increasing the utilisation from 2,000 to 8,000 full load hours a year could reduce the costs of synthesised methane by €0.15/kWh (up to 75%) (Concawe, 2020). However, due to intermittency, there is some scepticism whether 4,000 hours of full-load operation for an e-fuel process plant is manageable from an operational point of view solely using PV electricity, but either combined PV and wind farms or strategically sited wind farms could provide for 4,000 full load hours per year (Agora, 2018).

Other factors impacting the production cost of e-fuels include:

- **Economies of scale**: once the technologies reach commercial maturity, the scaling up of their capacities when rolled out would be expected to lead to cost reductions. The extent of these future cost reductions are difficult to predict, though projections are available in some literature (e.g. (Agora, 2018), (ICCT, 2021), and further literature identified in Concawe (2020)).
- **Carbon feedstock**: the source of the CO_2 used for the process affects the overall fuel cost, as well as affecting GHG emissions. Making use of carbon captured from industry processes is typically less expensive, owing to larger volumes available at higher concentrations from waste streams, with estimates of around €30 per tonne of CO_2 (Concawe, 2020). Direct Air Capture (DAC) costs, on the other hand, are typically higher due to lower feedstock concentrations, estimated to be €145 per tonne of CO_2 in 2030 in Agora (2018), though much broader ranges are summarised in Concawe (2020). However, because the technology is not yet fully established, the cost of DAC is predicted to decline significantly until 2030 as the technology matures, reaching approximately €90 per tonne of CO_2. As the market further develops for CO_2 feedstocks, other novel technologies are being developed. For example, the IEA (2021) in their latest technology perspective indicates that a organic chemicals production paths are testing and validating the CO_2 capture from industrial waste gases as a feedstock source, with projects proven at commercial scale (e.g. urea, salicylic acid and cyclic carbonates), and others as demonstration projects (e.g. methanol, formic acid, polycarbonates).

Text Box 4-2 European CO_2 availability from point-source and Direct Air Capture (DAC) (Ricardo, 2022)

European CO_2 availability from point-sources and Direct Air Capture (DAC)

Significant investment will be required in the coming years to introduce DAC projects to the European pipeline to scale up to the potential 2030 demands. However, forecasting the long-term scale-up of a novel technology such as DAC is highly uncertain since the pace at which the technology is developed plays a significant role. In addition, other factors must be considered, and, in this case, it is anticipated that the future regulatory and policy landscape will have a significant impact on its development.

The study evaluated two scenarios: one with a low DAC requirement and the other with a high DAC requirement. In both cases, a high rate of scale-up from DAC is required, with the highest rates of growth required in the first 10 years. For low and high demands, the scenarios required annual growth rates of 37% and 59% from 2025 to 2030, rising to 63% and 54% from 2025 to 2030, respectively. However, even when taking into account the scale-up for DAC technology, its estimated levelized cost of carbon (LCOC) is still higher than the cost of carbon capture from other sources. Therefore, DAC CO_2 is unlikely to compete economically with other sources of CO_2 without significant policy support. Furthermore, DAC technology is energy intensive, so the additional renewable electricity generation capacity required to meet its energy requirements must also be considered for this estimation.

Nowadays, large-scale engineered negative emission technologies, such as DAC, do not have sufficient financial support to incentivise their deployment and operation. As a result, CO_2 infrastructure is expected to be developed in industrial clusters, although its focus is predicted to be directed towards storage, instead of utilisation, in an effort to mitigate emissions.

4.4.2 Investment needs and timeframe for changes to existing refineries

Considerations for refiners when making investments

As refineries produce products other than fuels, a direct investment comparison with green field plants manufacturing synthetic fuels is not appropriate. These other products may include asphalt, chemical feedstocks, or solvents. Non-fuel production share can account from 20 to 40% of the product portfolio volume in a refinery (Concawe, 2019) but revenues can be larger. These other products can justify maintaining operation of the existing refineries through increasing their crude oil to chemicals conversion units. Therefore, the changes for existing refineries to produce low carbon fuels depend not only on the strategy of each company, but their existing assets and product slate, the investment needs and the estimated time frame for these changes to be implemented.

Plant investment is a significant factor in determining the production cost of alternative fuels (Concawe, 2020) (European Commission, 2017), and the particular conversion technology clearly has a significant bearing on this. As noted in the previous section, costs of techniques reduce with development of the technology, as well as through achieving economies of scale. Other elements to be considered when analysing investment requirements for the development of these plants are the Capex reduction opportunities when incorporating new units in existing sites, the feedstock influence on investment requirements, and the availability of renewable energy at an affordable price (see Appendix D).

The investment cycles for developing new technologies vary widely by industry and may span two to three decades for new industrial processes and manufacturing techniques. Economic stakeholders therefore need long-term planning security to invest in the development and market introduction of new, innovative technologies.

Aggregate investment costs for Europe as a whole

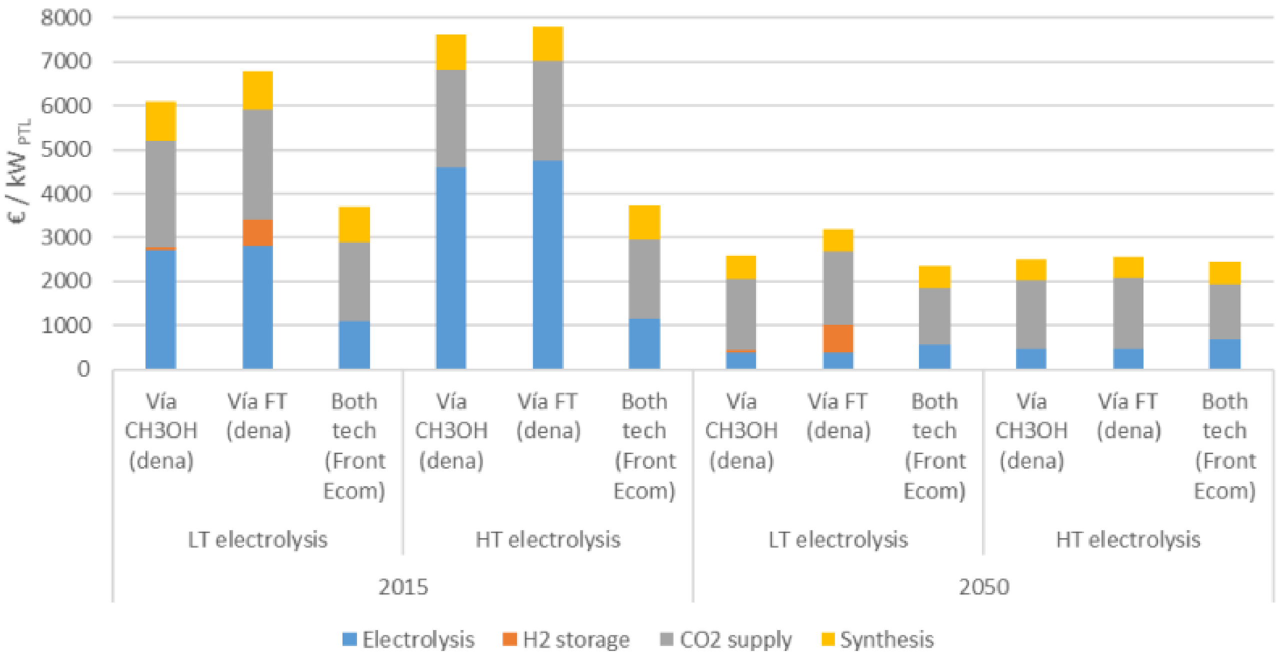
The cost associated with the development of e-fuels conversion plants are mainly driven by initial investment costs and utilisation rates (Agora, 2018). Dena (2018) studied which regulatory frameworks and investments an integrated energy transition would require and estimated the cumulated investment for e-fuels for the whole of Europe in different scenarios of GHG targets and transport demand and considering e-fuels imports from countries with low electricity generation costs.[18] The estimates range from €4,000 billion to €10,000 billion across the scenarios; these include the renewable electricity plants needed, the local infrastructure deployment (such as EV chargers) as well as e-fuel plants (as well as investments for replacing end-of-life plants). Fuels Europe (2021) on the other hand, with a different set of assumptions, estimate a total investment of €400 to 650 billion by 2050 for the development low carbon fuels that could contribute to achieving EU 2050 climate neutrality objectives (i.e. consistent with the Commission's Clean Planet For All 1.5°C scenario), citing first-of-a-kind industrial plants possibly starting operations by 2025 at the latest.

Capital costs for e-fuel installations

Figure 4-4 presents different estimations of the total Capex for e-fuel installations expressed per kW capacity. As shown, Capex for e-fuels technologies is expected to decrease in the coming years. Specifically, from 2015 to 2050, total Capex for e-fuels production plants is expected to drop from €4,000-8,000/kW (depending on the sources used for H_2 and CO_2) to €2,500-3,000/kW (Concawe, 2020). Whilst electrolysis represents around half of the total investment for e-fuels plants today, it is expected that this investment will fall to below 25% of total Capex by 2050, where CO_2 capture and supply becomes the main driver of total investment due to electrolysis prices forecast to decrease the most in the coming years The assumed process for CO_2 capture in the sources used to generate Figure 4-4 is direct air capture. The Capex for synthesis, which is currently around €1000/kW, is expected to drop by half to ~€500/kW by 2050.

[18] The high demand scenario is the one that achieves climate targets, including a reduction of 95% of GHG emissions by 2050, while the low demand scenario is the one that achieves a reduction of GHG emissions of 80%.

Figure 4-4 Comparison of total Capex in 2015 and projections for 2050 for e-fuels via different process routes from different literature sources



Source: (Concawe, 2020). *LT: Low temperature; HT: high temperature electrolysis.*

It is important to highlight that Capex for power generation is not included in the Capex costs shown in Figure 4-4.[19] Therefore, investing in additional power generation could increase the cost of e-fuel production and hence prices.

Capex for biofuels and e-fuels: Table 4-7 provides estimates of Capex for biofuels and renewable fuels of non-biological origin (RFNBOs) technologies (Concawe, 2021). As shown in this table, Capex for thermochemical conversion routes (gasification, pyrolysis or HTL) and RFNBOs are estimated to span wide ranges (€610-900 million for thermochemical conversion routes plants and €400-650 million for e-fuel plants). Given the capacities, thermochemical conversion plants have a higher Capex intensity than RFNBOs plants, ranging from €4-6million/ktoe per year for the former and between €2-3.3million/ktoe for the latter. The costs quoted are current and future costs; they do not assume any cost reductions due to technology development, i.e. these can be interpreted as upper bound costs which would be reduced by learning effects. Although the capex intensities are very different, one should not conclude that this means the more Capex-intensive projects are unlikely to proceed for two reasons: 1) opex costs are not quoted here, and (2) feedstock availability could be a constraint.

Table 4-7 Estimated Capex for new built plants

Bases (per plant)	Capacity (output) – industrial scale (Mtoe/y)	Capex (€million)	Capex intensity (€million/ktoe/y)
New-built HVO plant	0.5	275	0.55
Biomass-to-liquid plants (lignocellulosic)	0.15	610 – 900	4.0 – 6.0
e-fuels	0.2	400 – 650	2.0 – 3.3

Note: due to the cap on food-crop based biofuels, as well as used cooking oil and animal fat, no investment on additional capacity is envisaged towards 2050, increasing utilisation rate of existing plants when required.

Source: (Concawe, 2021)

[19] The IEA indicate Capex costs of utility scale solar in 2019 in 6 emerging economies was $600-1300/kW, with prices having dropped by nearly 50% since 2015. https://prod.iea.org/data-and-statistics/charts/capital-costs-of-utility-scale-solar-pv-in-selected-emerging-economies

Timeframe for investments

An overarching driver for the timescale of investments is implied through the Paris Agreement – though this does not bring obligations directly on operators to make investments – to keep the global temperature increase to "well below 2°C" and drive efforts to limit it even further to 1.5ºC. But rather the spirit of the Agreement provides the impetus, as well as being an underlying driver for regional policy developments in the EU which is more directly encouraging investment.

Table 4-8 shows an estimation from Fuels Europe (2021) in their 'Clean Fuels for All' publication on how timing for investments across different fuel processes in the present decade would change up to 2050. The estimates represent a potential pathway to achieve climate neutrality for the fuels sector in the EU, i.e. in alignment with the ambition of the European Commission for the bloc to be climate neutral by 2050. By 2030 this represents an investment of €30-€40 billion yielding up to 30 Mtoe of low carbon fuels, and then reaching €400 to €650 billion by 2050 for a yield of up to 150 Mtoe of these fuels.

Table 4-8 Timeframe and investment requirements for low carbon fuels development in the EU

Fuel / novel process	Production capacity in 2020 (Mtoe)	Scenario for production capacity in 2030 (Mtoe)	Investment by 2030 (€ billion)
First generation biofuels	14	15 (by increasing utilisation)	-
HVO	5	10 (approx. 10 new plants)	2.5 – 3
Lignocellulosic residues and waste	-	4 (approx. 27 new plants, with 1st-of-a-kind plants from 2023)	25
e-fuels	-	1 (approx. 5 new plants, with 1st-of-a-kind plants from 2025)	3.3
CCS in refineries, and green hydrogen	-	- (2022: 1st-of-a-kind expected)	6 – 7

Note: 1st-of-a-kind refers to the first plants at an industrial scale for specific technologies.

Source: (Concawe, 2021)

In the case of first-generation biofuels, FuelsEurope (2021) does not foresee further investments in new plants but does foresee a small increase in production through optimising utilisation. First-generation production processes are claimed to be robust and economically feasible, however, further improvements are likely as they gain operational experience, such as the introduction of new and/or alternative feedstocks.

Europe is a world leader in HVO/HEFA production technologies, with several commercial size plants currently in production. The EU27 has a biodiesel production capacity over 21 million tonnes (Eurostat, 2022) with fewer than 190 production facilities in operation. The current HVO production potentials in the EU rely on a small number of plants (14), accounting for a production of approximately 5 million tonnes per year capacity, including the so-called co-processing facilities. However, HVO from vegetable oil and residue/waste feedstock needs a total investment of approximately €2.7 billion to be able to reach a 10 Mtoe objective. This is assuming the development of ten new plants within 5 years and with a production capacity of 0.5 Mtoe each.

For lignocellulosic residues- and waste-based biofuels, commercial size plants have already been constructed in Europe, US and Brazil. However, in 2019, no commercial scale plants appeared to be in operation. Regular and reliable production for these processes is yet to be proven. Therefore, between 2026 and 2030, an average of five (5) plants per year are estimated to be built, leading to a 0.15 Mtoe/year per unit (Concawe, 2021). This would result in a total investment of €25 billion to be able to reach the objective of 4 Mtoe and considering the development of 27 new plants.

Regarding RFNBOs, a first of a kind plant is expected by year 2025 and average expansion of two plants per year is expected until 2030, leading to a 0.2 Mtoe/year per unit. This would result in a total investment of €3.3 billion to be able to reach the objective of 1 Mtoe and considering the development of five new plants. It is noted that the scale up will need to increase faster than this rate in order to reach the latest EU objectives in 'Fit for 55'.

4.4.3 Alternative to production in Europe: importing low carbon fuels

The fuel market will remain very large in Europe, and this will foster numerous opportunities for fuel trade. However, there is currently no developed e-fuels trading market for imports and/or exports of these fuels with the European Union. In this context and due to e-fuels being mainly based on green hydrogen and CO_2 and due to the lack of information on an e-fuel trading market, the analysis for this section is based on an extrapolation of the hydrogen trading market.

Policy support for green hydrogen imports into the EU

The 'Hydrogen and Decarbonised Gas Package' released in December 2021, as noted in Section 2, aims to create a hydrogen market with infrastructure including interconnectors, where hydrogen can be cost-effectively imported from areas where it can be produced more cheaply from renewables Existing natural gas networks can be repurposed partially for transporting hydrogen, with significant cost savings compared to new-build infrastructure.

Therefore, there is high potential to scale up the production of renewable and low-carbon gases, which account for less than 5% of the gas market today. However, the Impact Assessment underpinning the European policy proposal has shown that entry tariffs are a significant barrier to the entry of renewable and low-carbon gases into the system. The EC is proposing discounts of 75% on these entry tariffs for low carbon fuels. The Commission is also proposing to eliminate cross-border tariffs for renewable and low-carbon gases to exploit the most promising production spots.

To facilitate trading and supplying hydrogen across borders, a European Network of Network Operators for Hydrogen will be established. Certification rules for low-carbon gas and its derivatives will complement the certification schemes for renewable fuels and will apply both to imported and domestic production to ensure a level-playing field.

Transport options for hydrogen

Since the costs of hydrogen production vary significantly between regions, long-distance transmission and international trading in hydrogen can be considered attractive. There are two possible modes for transporting hydrogen:

- **Long-distance pipelines:** The most cost-efficient option for green hydrogen imports is considered to be by pipeline. This is similar to current imports of natural gas to Europe (e.g. from Algeria or Russia). Current hydrogen transport options from neighbouring regions using pipelines include North Africa, Ukraine, Norway and potentially the Middle East – where the potential for low-cost renewable energy is abundant– to complement domestic hydrogen production and to support the diversification of European supply. Pipelines are expected to outperform other alternatives, such as shipping, in terms of lifecycle cost, however, require greater upfront capital investment. Long-distance pipeline transport costs are estimated at €0.1-0.16/kg/1000km (European Hydrogen Backbone, 2021), representing 10-15% of production cost. Importing hydrogen by pipeline presents a viable strategy to complement domestic EU-27 production.
- **Hydrogen shipping:** Shipping remains as a viable option, with the first liquid hydrogen tanker delivering a shipload from Australia to Japan in early 2022, demonstrating proof of concept for transporting as liquid hydrogen. Due to hydrogen's very low volumetric density, transport of hydrogen favours pressurised or preferably liquified hydrogen. Due to the energy cost of liquifying, as well as its still relatively low energy density, alternatives to this include transporting as ammonia (which is much denser and hence more compact) and using liquid organic hydrogen carriers (LOHC). The advantages of distribution by tanker are improved flexibility of varying supply routes to account for global trends or geo-political disruption, lower upfront investment and a shorter timeframe to implement. For shipping hydrogen to become economically feasible, infrastructure needs to be scaled up to reach similar levels to that of liquified natural gas (LNG) which today is now transported worldwide (Hydrogen Council, 2020).

Regions and costs for hydrogen trading with the EU

The main drivers for considering regions outside the EU to import green hydrogen from are proximity and abundance of renewable resources, as well as the production costs for the green hydrogen to be imported. In this context, imports of solar PV-powered hydrogen produced in northern Africa (e.g. Morocco and Algeria) and hydrogen from solar-PV and onshore wind in Ukraine could be attractive options for the European Union.

Production costs for green hydrogen are expected to decrease in the coming years, mainly due to lower Capex, as technologies mature, and also due to the production cost of renewable electricity to manufacture green hydrogen. Table 4-9 depicts how hydrogen production costs could evolve in the coming years, while remaining lower at locations with higher mean solar irradiation and with North Africa reaching production costs below €1/kg by 2050. These production costs exclude the cost of shipping the hydrogen to the EU.

Table 4-9 Forecasts of green hydrogen production costs (€/kg) to 2030, 2040 and 2050

Region	2030	2040	2050
Europe average	1.7 - 3.0	1.4 - 2.4	1.3 - 1.9
North Africa	1.4 - 2.3	1.0 - 1.6	0.9 - 1.5

Source: Ricardo with inputs from European Hydrogen Backbone (2021) *and Hydrogen Council* (2020)

Challenges related to green hydrogen imports

In the short term, pipeline imports of green hydrogen will remain modest as these neighbouring regions focus on electrifying and meeting the needs of their own growing economies, reducing any potential concerns or risks associated with green hydrogen imports from this region.

The main concerns related to green hydrogen imports from North Africa include:

- **Fuel supply price volatility**, as a result of recent lessons learned from geopolitical crises impacting fossil fuel supplies to the EU. This could potentially affect other regions considered for imports.
- **Regional freshwater availability** must be taken into account as a concern. Local water supplies might be limited and should not be diverted for electrolysis when needed elsewhere; in the absence of supply, desalination plants are an option but at higher cost and environmental footprint. Where needed, costs of desalination facilities, as a possible source for freshwater, need to be taken into account in the full delivery price of hydrogen from North Africa.

5. CASE STUDIES: NEAR-TERM PLANS OF FIVE EUROPEAN OIL MAJORS RELATED TO BIOFUELS AND HYDROGEN

How much are Repsol, Eni, Total, BP and Shell investing in new/existing refineries to produce biofuels, advanced biofuels and E-fuels?

Summary: The companies profiled have made significant investments into alternative fuels, much of it related to their existing refining portfolios. Advanced biofuels have been the most typical route for diversification, leveraging the existing liquid fuels storage, processing and logistics infrastructure. Hydrogen is more nascent but an area where many of the firms analysed have made at least some initial investment.

5.1 INTRODUCTION TO THE CASE STUDIES AS CONTEXT AND BACKGROUND

The outlook for EU demand for refined oil products will have a considerable impact on how the EU refining sector evolves in size and configuration over the coming years. There are several different options for the refining industry for this transition. The strategies and near-term plans of five European oil majors (refiners) – Shell, BP, TotalEnergies, Eni and Repsol – related to investments in biofuels and hydrogen are described in this section.[20]

The companies covered in this section are large International Oil Companies, and although their roots date back to national government ownership they have since changed their structures. Several decades ago, European refining was largely the preserve of International Oil Companies and domestic National Oil Companies. International Oil Companies, firms such as ExxonMobil, BP, Shell, Total ran multi-national portfolios of refineries. National oil companies such as MOL, ENI, PKN Orlen ran their countries' refining infrastructure. The trend of divestment away from refining began among the international oil companies many years ago as higher returns on capital could be found upstream (oil and gas extraction). Asian Oil Companies, traders, specialised refiners, and financial organisations bought assets from these firms and the footprint of the majors in Europe shrunk, but with typically larger, integrated and more complex facilities being retained (e.g. Essar, Petro Plus or Petrolneos).

More recent years have seen the larger energy companies face increasing pressure to respond to the requirements of the energy transition and move away from reliance on fossil fuel production and refining. Almost all majors and national oil companies have made investments into alternative energy in some form. Biofuels and hydrogen have been the most popular, likely as the physical product allowed some overlaps with their infrastructure and skillset. Some have also diversified into renewable electricity and other energy forms less closely associated with their roots.

In the biofuels sector, feedstock demand is driven by European and national legislation, which is typically moving away from crop-based sources towards waste feedstocks. Beyond used cooking oil and tallow, there are several options, but most have relatively limited global availability, such as palm oil mill effluent (POME), tall oil pitch and spent bleaching earth oil[21].

Although crop-based biofuels are capped, limiting the potential growth of crop feedstocks such as vegetable oils, both European and national legislation differentiate between the various types based on the risk to land-use change. Several Member States have phased out palm and soy oil on sustainability grounds, meaning there are better prospects for vegetable oils considered more sustainable, such as rapeseed and sunflower oils. Growth may be limited by the crop-caps that remain in place, however there is the potential to replace the market share of palm and soy in certain countries, leading to short to medium term growth.

The investment decisions made by European refiners may be a useful indication as to the overall industry direction over the next decades, and their experiences a pointer to a successful model of re-direction of refining infrastructure in Europe.

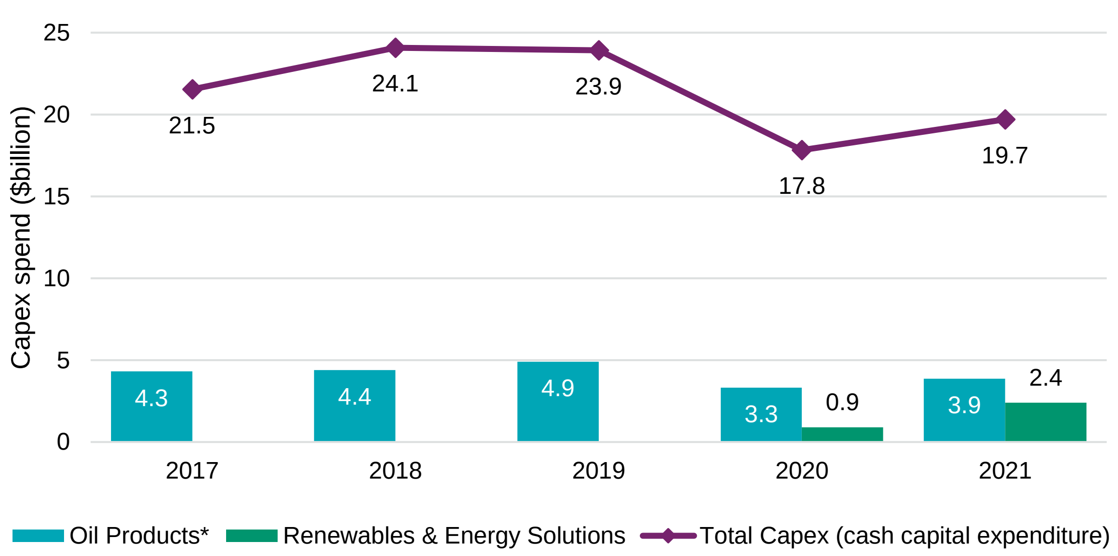
[20] We note, however, that there are also other industrial players, not coming from the mineral oil and gas sector, that are investing in low carbon fuels production processes, such as Air Liquide and Nippon gases, which have experience in capturing and cleaning CO_2 (La Verdad, 2022), and Yara, an ammonia production plant operator.

[21] A waste output from degumming and bleaching crude palm oil.

5.2 SHELL

Shell's global oil products Capex spend, which includes refining, in 2021 was around $3.9 billion – 20% of total Capex spend[22]. The company's investment in the refining sector has been holding steadily at around 20% for the last few years (Figure 5-1). Shell's 'growth sector' Capex of renewables and energy solutions, and marketing is expected to grow from around 20% of total Capex today (12% excluding marketing) to a target of 35% beyond 2025. Figure 5-1, as with other figures in this chapter, shows as bars the trend in capital expenditure on conventional refining and renewables, and, as a line, the total company capital expenditure (which includes capital expenditure in all sectors of the company globally and could, for example, include Capex spend on upstream projects, and low carbon energy projects, among other items). To note that, for each of the companies the definitions vary in their reporting on e.g. 'renewables'.

Figure 5-1 Shell's oil products segment Capex (includes refining)



** Includes refining*
Source: Shell (2021), *Argus*

Shell is transforming its 14 European refineries into 5 energy and chemicals parks; by 2030, it hopes to produce 45% traditional fuels and 55% low carbon fuels – including biofuels for road transport and aviation fuels, and hydrogen.

Shell's first Energy and Chemicals Park was announced last year – based in Rheinland, Germany. It is home to Europe's largest proton exchange membrane (PEM) hydrogen electrolyser and plans are underway to expand its capacity from 10MW to 100MW. Shell currently produces 1,300 t/y of green hydrogen from this electrolyser. The plant is set to produce sustainable aviation fuel (SAF) using renewable power and biomass in the future. A plan for liquefied renewable natural gas (bio-LNG) is also in development. Shell plans to shift its Rheinland refinery away from crude oil and towards low or zero carbon products from 2025.

A consortium including Shell is investing in a €500 million project to add synthetic fuels to the product slate at Germany's largest refinery, Miro Karlsruhe, located in Karlsruhe, Baden-Württemberg with crude capacity of 320,000 b/d. The project targets 50,000 tonnes of synthetic fuel per year which represents ~1% of its annual petrol production volume.

5.2.1 Biofuels

More recently Shell has announced its Energy and Chemicals Park in Rotterdam, the Netherlands. Shell made a final investment decision to build an 820,000 t/y biofuels facility in Rotterdam, targeting a 2024 start date. The facility will produce SAF and renewable diesel made from waste (used cooking oil, waste animal fat and other industrial and agricultural residual products). The waste feedstock will be supplemented by certified

[22] Overall capital yearly expenditure (fixed costs investments in equipment, etc.)

sustainable vegetable oils (but not virgin palm oil). Shell has stated that SAF may make up more than 50% of production.

5.2.2 Hydrogen

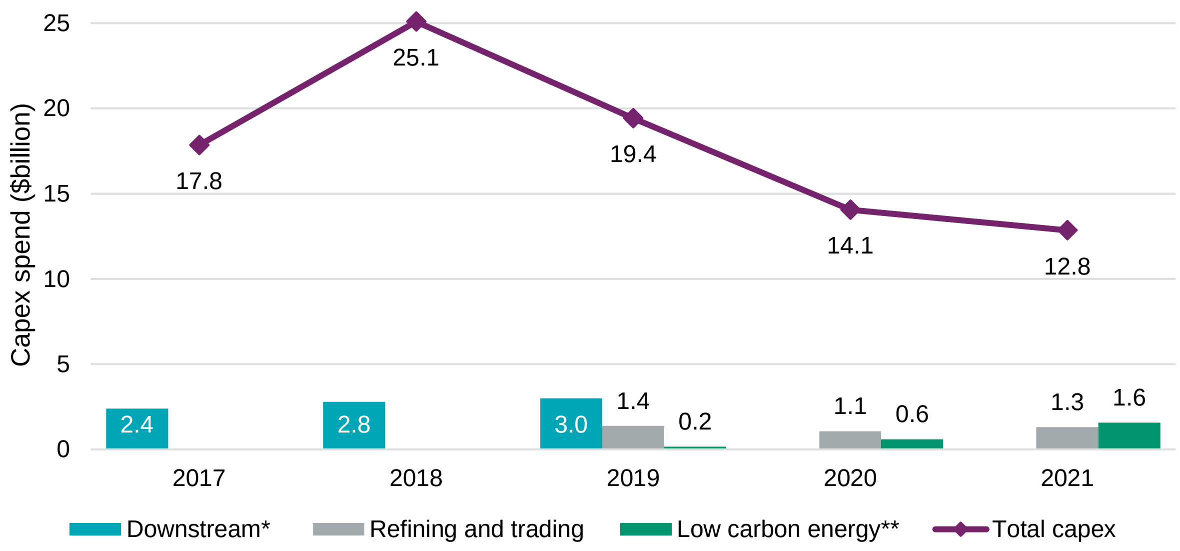
A new green hydrogen plant is also planned with a target start-up date of 2023, expected to produce 50-80,000 kg of green hydrogen per day. It will be powered by renewable energy from an offshore windfarm currently under development. The hydrogen will initially be used to decarbonise Shell's nearby refinery in Pernis and support the industrial use of hydrogen in the heavy transport industry.

Shell and QatarEnergy have agreed to join forces to pursue investments in blue and green hydrogen projects in the UK. The project will target "integrated and scalable opportunities" and may include low carbon fuels and technologies. It is unclear at this point if the project will target blue or green ammonia or a combination of both.

5.3 BP

BP's Capex spend on 'refining and trading' was $1.3 billion, which accounts for approximately 10% of its total Capex in 2021 (Figure 5-2). In the same year, the company spent almost $1.6 billion on 'low carbon energy' Capex, which includes renewables and hydrogen, or when including EV infrastructure (as total 'new energies'), $2.2 billion in 2021. This latter value is projected by BP to increase to $3-4 billion per year by 2025 and $5 billion per year by 2030 (BP, 2021).

Figure 5-2 BP's downstream/refining and trading(1) segment Capex



(1) Reported as downstream in 2017-2019 and as refining and trading in 2019-2021
** Downstream includes manufacturing and marketing of fuels, lubricants, and petrochemicals.*
*** Renewables and hydrogen.*

Source: BP[23] (2021), Argus

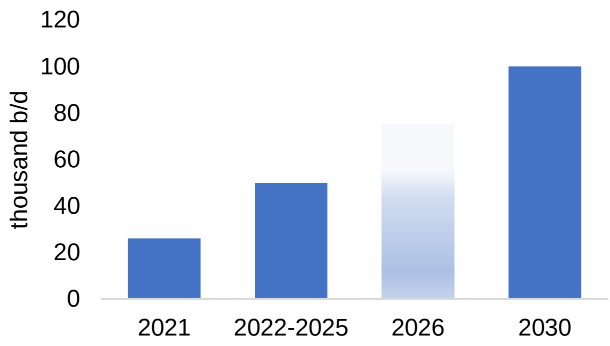
5.3.1 Biofuels

Globally, BP produces 5,000 b/d of biofuels at three of their refineries through bio co-processing. On top of the co-processing, BP has 20,000 b/d capacity of dedicated biorefining. The company aims to approximately double its current bioenergy production of 25,000 b/d by 2025, and doubling that again to 2030 to reach over 100,000 b/d. The company plans to invest globally in five major biofuels projects: three adjacent to existing refineries and up to two conversions of existing refineries (their announcement does not specify whether these are in Europe). This focus on leveraging existing infrastructure, logistics, scale and customer relationships is

[23] BP changed the way they report their segments; up to 2018 they reported it as downstream. Downstream describes a stage in fuel production after crude oil enters a refinery. In 2020 and 2021 they changed the segment to refining and trading (so took out marketing, etc). In 2019 they reported both, but the two are not directly comparable.

expected to create capital-efficient growth. Figure 5-3 depicts BP's announced plans for bioenergy (biofuels and biogas) production.

Figure 5-3 BP's bioenergy (biofuels and biogas) production growth forecast



Source: BP (2021)*, Argus*

5.3.2 Hydrogen

BP is building an electrolyser unit at the Lingen refinery powered by offshore wind. Expansion plans are underway to increase green hydrogen capacity from the expected 50MW in 2022 to 100MW in 2024 – an equivalent of one tonne of green hydrogen per hour. The produced amount will be equivalent to around 20% of the hydrogen that is currently produced from natural gas by the steam methane reformer at Lingen.

The Get H2 project is an open cross-section consortium that aims to link up the energy, industry and potentially the transport and heating sectors along the entire value chain, including the first 135 kilometres of the Germany-wide hydrogen infrastructure, from Lingen to Gelsenkirchen. Get H2 will feature a 100-MW electrolyser plant that converts renewable electricity into green hydrogen and a repurposed natural gas pipelines to transport the hydrogen for use in refineries and in the future also to other sectors. The planned operation start date for the project is 2023.

BP is investing in H2-Fifty - a 250-MW renewable energy plant with capacity to produce up to 45,000 tonnes of green hydrogen per year. The hydrogen will be used in BP's largest European refinery in Rotterdam for desulphurization, replacing the 'grey hydrogen'. A final investment decision is expected in 2023.

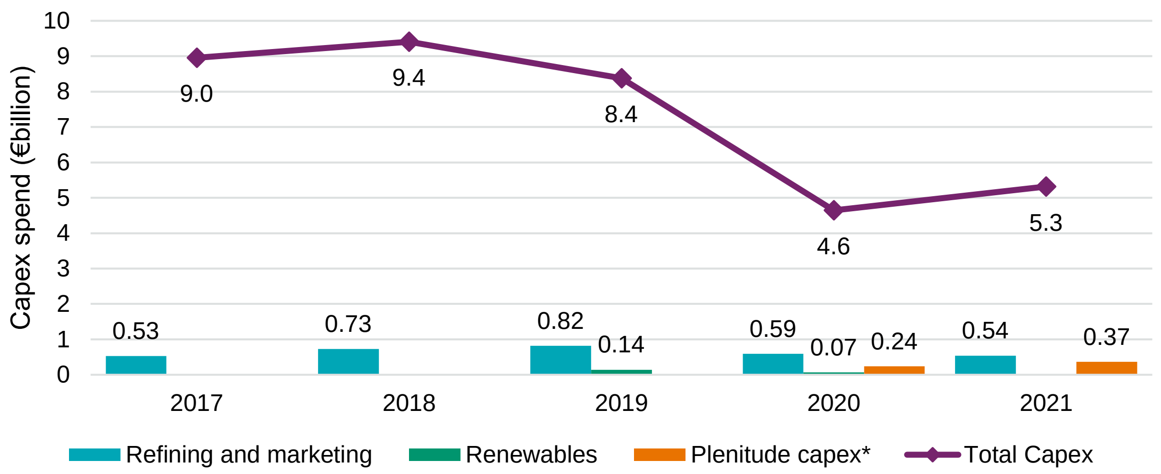
BP and its partners plan to develop a 20MW electrolyser powered by renewable energy located at BP's Castellon refinery, with further expansion capacity of up to 115MW, which would make it the largest green hydrogen project in Spain. The plant, a €90 million investment, would replace current natural gas-based hydrogen production and thus reduce the refinery's emissions by up to 24,000 tonnes of CO2 per year and commence operations as early as 2023.

In the UK and the Netherlands, BP is investing in several hydrogen projects that are not specifically related to their refineries, but all include a hydrogen component in them and some focus on other renewable energy aspects as well. They include H-Vision, NZT, NEP, HyGreen, H2Teesside and Aberdeen Hydrogen Hub.

5.4 ENI

Eni's refining and marketing Capex spend was €0.5 billion in 2021, or 10% of total Capex spend. Figure 5-4 is a depiction of Eni's Refining and Marketing capital expenditure between 2017 and 2021. The company spent €1.9 billion on Energy Evolution, which includes Gas and Power Retail, Renewables, Power, Refining and Marketing and Chemicals. Eni has designated €7.9 billion to this sector over the next four years, averaging nearly €2 billion per year, through to 2025 (ENI, 2022). The company's 'Plenitude' business reportedly spent $0.37 billion capex in 2021, representing 7% of total Capex spend; their annual report describes this Capex was "*for initiatives relating to gas and power marketing in the retail business and renewables activities*".

Figure 5-4 Eni's refining and marketing segment Capex



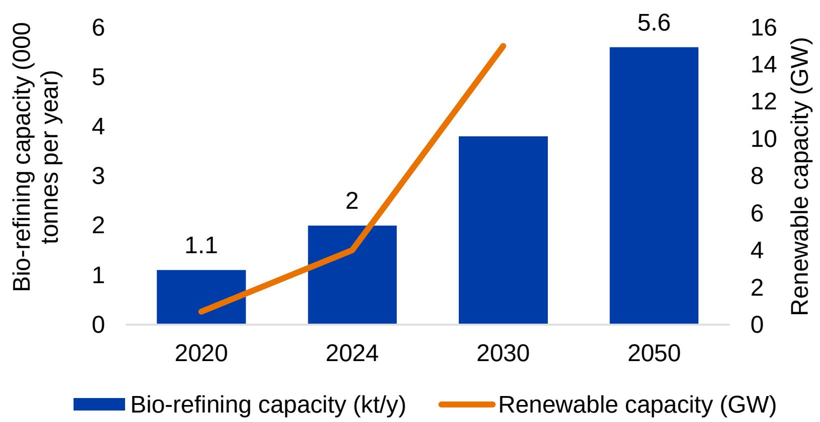
** In 2021 recorded as Plenitude Capex. Plenitude is ENI's renewables business, which combines renewable energy generation, retail customers, electric vehicle charging, and energy services.*

Source: Eni (2022), *Argus*

5.4.1 Biofuels

Eni plans to increase its bio-refining capacity from 1.1 million t/y in 2020 to 2 million t/y in 2024, and further increase it to 5-6 million t/y by 2050. ENI is looking to significantly increase their renewables (wind and solar) capacity from 0.7GW in 2020, to 4GW in 2024 and further to 15GW in 2030. These are shown in Figure 5-5 .

Figure 5-5 Bio refining capacity and renewable capacity growth projections



Source: Eni (2022), *Argus*

Eni has decided to stop producing fuels from 2022 at its Livorno, Italy, refinery. The company is considering converting Livorno into a biorefinery for HVO production and also constructing a waste-to-methanol plant nearby. The conversion would be completed by the third quarter of 2024, and the plant should be operational by the end of that year.

Eni started the production of SAF sourced from waste and residues at its Tartano refinery, in line with the company's strategic decision to move away from palm oil as a feedstock. SAF from the Taranto refinery is currently produced through a 0.5% used cooking oil co-feeding process for conventional plants.

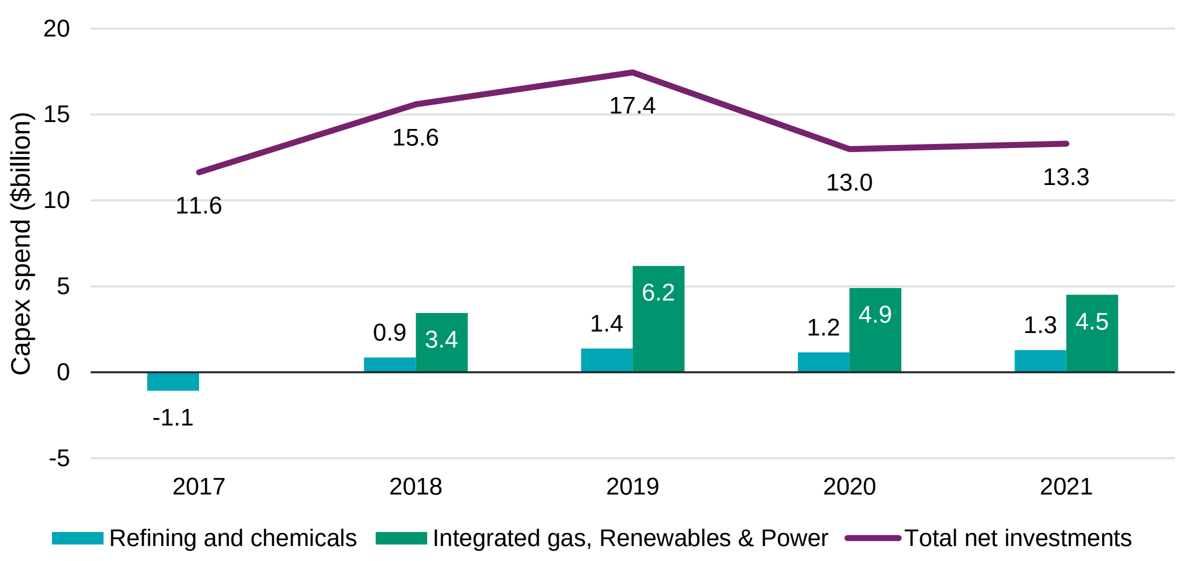
5.4.2 Hydrogen

Eni has partnered with Enel to develop green hydrogen projects near two of Eni's refineries, Pavia and Sicily. The two pilot projects will comprise electrolysers of around 10 MW each, which are expected to start operations by 2022-2023.

5.5 TOTAL ENERGIES

In the race to capture market share of the sustainable fuels demand, Total has chosen biofuels as its target market. The company projects renewable diesel production of nearly 5 million tonnes per year by 2030 and aims to become a market leader in renewable diesel, hoping to reach 15% share of the biofuel market. Figure 5-6 compares the company's Capex spend on refining and chemicals with the reported totals for integrated gas, renewables and power (TotalEnergies, 2021). Of this, TotalEnergies indicate in their 2021 annual report that "*in 2021, TotalEnergies lifted its investments in electricity and renewables to more than $3 billion, or 25% of its net investments*", and in its Sustainability progress report that "*it intends to finance investments of more than $60 billion in renewable power generation capacity by 2030*".

Figure 5-6 Total Energies segment Capex ('refining and chemicals")



** Net investments include organic investments and net acquisitions.*

Source: TotalEnergies (2021), Argus

5.5.1 Biofuels

TotalEnergies plans to produce 2-3 million t/y of hydrotreated vegetable oil (HVO) and sustainable aviation fuel (SAF) by 2025, and a target of 5 million t/y by 2030. The company has a 500,000 t/y HVO plant at La Mede, where it recently began SAF production, and is converting its 93,000 b/d Grandpuits facility into a 400,000 t/y biorefinery that it has scheduled to start up in 2024. This will produce 170,000 t/yr of SAF, 120,000 t/y of biodiesel and 50,000 t/y of naphtha for bioplastics. In 2020, TotalEnergies said it planned to add 300,000 t/y of HVO capacity in Europe from co-processing at existing facilities.

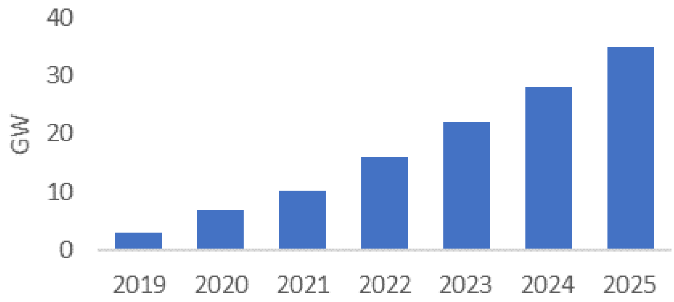
TotalEnergies and Veolia, a French waste and water utility company, have initiated a research project to accelerate the development of advanced biofuels made from microalgae fed by CO_2. The companies will set up a four-year research and testing project to grow microalgae at TotalEnergies La Mede biorefinery, with the long-term goal of producing biofuel. Separately, TotalEnergies will also stop using palm oil at La Mede from 2023. The company is focusing on accelerating development of alternative feedstocks, including fat, oil and grease waste and residues and plant oils like sunflower and rapeseed oil.

TotalEnergies' Antwerp refinery is considering adding coprocessing biofuel units with capacity of 150,000 t/y, processing cooking oil and animal fats, though there is currently no timeline for making a decision about the project.

5.5.2 Hydrogen

TotalEnergies has aggressive targets for renewable energy production. The company is aiming to increase its renewables gross capacity from 10 GW in 2021 to 35 GW in 2025 (Figure 5-7).

Figure 5-7 TotalEnergies Renewable capacity growth projections



Source: TotalEnergies (2021)*, Argus*

Orsted is planning to build a 1GW green hydrogen facility in the Amsterdam-Rotterdam-Antwerp (ARA) refining hub. The project, which will be developed in two phases, is scheduled to be fully completed by 2030. The firm plans to connect the electrolyser to a new 2GW offshore wind farm in the Dutch North Sea and a 45km regional pipeline network from Vlissingen to Ghent. The new production plant could help replace around 20% of the fossil-fuel derived hydrogen produced in ARA, which currently produces around 580,000 tonnes of hydrogen per year. Orsted estimates demand for hydrogen in ARA could increase to around 1 million tonnes — or 10GW of electrolysis — by 2050. The major industrial companies in the region, including Total, support the development of the required regional infrastructure to enable sustainably produced steel, ammonia, ethylene, and fuels in the future.

TotaEnergies and Sunfire are investing in a project that will produce methanol from green hydrogen and highly concentrated CO_2 from refinery production processes at the 235,000 b/d refinery in Leuna.

5.6 REPSOL

Repsol's non-current assets (used in lieu of Capex) in the Industrial sector, which includes refining, petrochemicals, trading and transportation of crude, products, natural gas and LNG, was €8.7 billion, or 28% of total non-current assets (Repsol, 2021).

Repsol shared a vision in February 2021 on how their refineries would be transformed into low carbon refineries (Repsol, 2021). This defined four strategic pathways in the transformation:

- **Energy efficiency**: promotion of energy efficiency both in traditional and new processes and considering energy use and network optimisation, Best Available Techniques and electrification of the processes.
- **Renewable gases**: use of renewable gases for the decarbonisation of sites and as low carbon products for other industries. Processes involved include electrolysis, renewable feedstocks reforming and bio syngas production.
- **Low carbon liquid fuels**: considered key elements to decarbonisation of all transport sectors.
- **CO_2 capture and use (CCU)**: promotion of technologies for net zero and circular economy goals to achieve negative emissions for both processes and products.

The objective is to be able to process alternative feedstocks to generate fuels and materials with a low carbon footprint in the short term. This includes using urban, agricultural, forestry or agri-food industry waste to produce advanced biofuels.

In addition, renewable hydrogen and CO_2 captured in the refineries themselves will be used to make synthetic fuels.

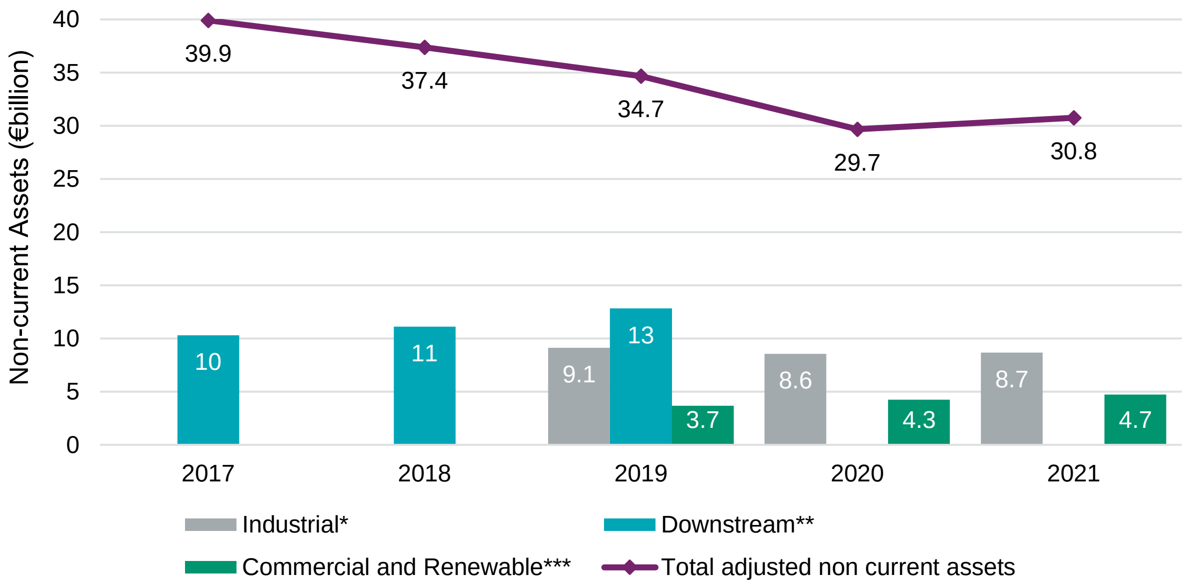
Repsol plans to invest €611 million to develop its 2021-2025 targeted hydrogen production capacity, €273 million of which will be dedicated to the steam reforming of biogas equivalent to 200MW in electrolysis production capacity. Biomethane, which the company currently sources from urban solid waste, is identified as the fastest way to build up green hydrogen capacity for the company and help meet Repsol's targets, which include ramping up production capacity to 1.9GW of electrolysis equivalent from 2025 to 2030. The remaining €338 million of planned capital expenditure to 2025 has been earmarked for electrolysers, with a planned

232MW of capacity at Repsol's three largest refineries in Bilbao, Cartagena and Tarragona, costing an estimated €179 million, and €32 million to be invested in 10MW of electrolysis at the company's planned pilot synthetic fuels plant in Bilbao.

Repsol is investing €60 million in a carbon capture to e-fuel project that involves generation of e-methanol from green hydrogen and CO_2 captured from the company's nearby Petronor refinery in Bilbao. The facility is projected to start operations in 2023. Though no size estimate has been given, it is expected to be one of the largest facilities of its kind in the world.

Repsol forecasted the allocation of capital to low-carbon businesses (e.g. industrial transformation for the production of low carbon fuels, renewable electricity generation, CCUS) for the period 2031-2050 in their annual report, expressing it as a percentage of total company investment (Repsol, 2021). When considering a scenario consistent with the SDS[24] demand, Repsol forecasts an allocation between 55-65% of total Capex for low carbon business for the 2031-2040 period, and between 65-75% for the 2041-2050 period. When a scenario consistent with NZE[25] demand is considered, the figures for the whole 2031-2050 period are higher, with 70-80% of total Capex allocated for low carbon business for the 2031-2040 period and 80-90% for the 2041-2050 period.

Figure 5-8 Repsol segment non-current assets [(1)]



(1) Non-current assets used in lieu of capex.

** Industrial includes refining, petrochemicals, trading and transportation of crude oil, products, natural gas and LNG.*

*** Downstream includes refining, chemicals, commercial businesses – mobility, LPG, lubricants, asphalt and specialisms –, wholesaler and gas trading, and electricity generation and sale.*

**** Commercial and Renewables integrates the businesses of (i) low-carbon power generation and renewable sources, (ii) sale of electricity and gas, (iii) mobility and sale of oil products, and (iv) liquefied petroleum gas (LPG).*

Source: Repsol (2021), Argus

5.6.1 Biofuels

In the refining sector, the company's aim is to produce 2 million tonnes per year of low carbon fuels by 2030, with a target of 1.3 million tonnes per year in 2025, using advanced HVO.

[24] In the SDS (Sustainable Development Scenario), a 90% reduction in the Carbon Intensity Indicator (CII) is expected to be achieved through energy solutions, with the remaining 10% to be achieved through Natural Climate Solutions (NCS) if the technology is not developed as fast as expected.

[25] The Net Zero Emissions (NZE) scenario from the International Energy Agency's (IEA) aims to achieve net zero CO_2 emissions by 2050, with advanced economies reaching net zero emissions ahead of others (IEA, 2021).

Repsol is planning a waste pyrolysis project in Bilbao, which will use 10,000 t/y of urban waste converted to gas. In the later stages, landfill waste capacity will increase to 100,000 tonnes per year. The pyrolysis process involves heating up waste at high temperatures without oxygen until it is transformed into gas. The gas will be used at the Basque refinery to supplement its production processes. The investment for the project is estimated at €20 million.

After the first investment in SAF from waste production coming online in 2021, the company is next targeting bio marine fuel and co-processed HVO in 2022. In 2023, after bringing electrolysis online, Repsol expects to produce advanced non-co-processed SAF, HVO and BioC3, or bio propane derived from biomass as well as bio-naphtha, with advanced bioethanol, e-jet, e-diesel e-naphtha and $bioCH_4$, or butane derived from biomass the following year.

Repsol is planning to build an advanced biofuels plant in Spain at its refinery in Cartagena. The plant's annual production capacity will be approximately 250,000 tonnes of hydrobiodiesel, or HVO, SAF, bio-naphtha, and bio-propane. This will represent an investment of €188 million and production is expected to start in 2023.

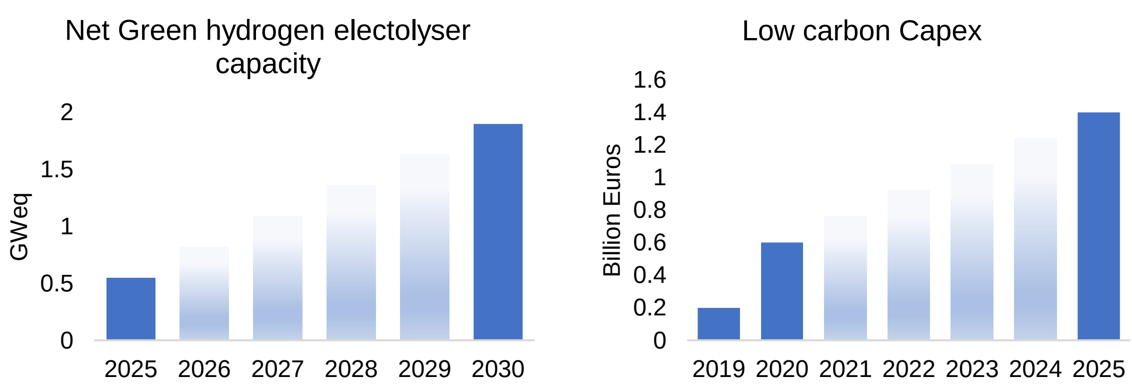
Repsol increased its capacity for production of renewable diesel from waste through the processing at its industrial complex in A Coruna of 500 tonnes of used cooking oil of national origin.

5.6.2 Hydrogen

Repsol's hydrogen strategy is expected to require an additional net investment of €700 million in the development of 1.8GW of wind and photovoltaic (PV) solar generation, with equity stakes in the Spanish projects ranging from 50-100% and a 95% capacity factor for the installed renewables. In the interim, the company plans to increase steam biomethane reforming capacity to 200MW by 2025 and has dedicated €273million of funds for this target.

Repsol has increased its electrolysis capacity target to 1.9GW by 2030 from a previous target of 1.2GW, with an interim target of 552 MW in 2025 at an investment of €611million.

Figure 5-9 Repsol's renewable energy capacity and Capex projections



Source: Repsol (2021), Argus

Repsol will use steam biomethane reforming for around 30% of its targeted 2030 green hydrogen production and will increase its hydrogen production by 60% to 300MW from steam biomethane reforming compared to its previous target. The feedstock for the project is urban solid waste, which can produce 500 MWh of biomethane and be converted to 10 million tonnes of hydrogen.

Between 2024 and 2025 Repsol sees an increase in electrolysis capacity of 232MW at its largest refineries (Bilbao, Cartagena and Tarragona). The planned hub for hydrogen and e-fuels in its refinery in Bilbao (Petronor) and another hub for biogas production, is expected to generate gas from urban waste, contributing to the decarbonisation of the production processes and other products to be produced in the refinery

Repsol and Enagas have secured EU funds to build a plant to produce green hydrogen using photo-electrocatalysis. This development, which originated as a pilot project at Repsol's research lab, has now received funds from the EU's Innovation Fund, which will enable the build of a larger hydrogen production facility at Repsol's Puertollano refinery. The project will facilitate production of approximately 100 kg of hydrogen per day using photovoltaic energy and is slated for operation as early as 2024. The plant's annual capacity is estimated at 200 tonnes of hydrogen.

5.7 SUMMARY

All the companies profiled above have made significant investments into alternative fuels, much of it related to their existing refining portfolios. Advanced biofuels have been the most typical route for diversification, leveraging the existing liquid fuels storage, processing and logistics infrastructure. Hydrogen is more nascent but an area where many of the firms analysed have made at least some initial investment. The announcements made by these companies on the future share of their capital expenditure on renewable and low carbon energy suggest that their focus will be in large or majority part on these new energy pathways. However, for the moment, the share of energy production from fossil sources still dominates.

As a summary of the Capex spend by each of the five companies, Table 5-1 shows total Capex ($), refining Capex ($) and Renewable Capex (%) for 2021 and, for the latter, a forecast for 2025 based on public statements. The table also includes the key biofuel and green hydrogen investments identified.

Table 5-1 Capex spend and share comparison for the five European majors

Parameter	Shell	BP	Eni	Total Energies	Repsol*
Total Capex spend 2021 ($ billion)	19.7	12.8	5.3	13.3	30.8*
Refining Capex spend 2021 ($ billion)**	3.9	1.3	0.5	1.3	8.7*
Renewable Capex share 2021 (%)**	12% 'Renewables & Energy Solutions'	12.5% 'Low carbon energy'	7% Retail (gas and power marketing) and renewables	34% (Gas, renewables & power) 25% (renewables and power)	15%* 'Commercial and renewable'
Renewable Capex share 2025 (%)**	34% 'Renewables & Energy Solutions' and marketing	27% 'Low carbon energy' and EV infrastructure	25%-30% 'Renewables, circular economy, biorefining, sustainable mobility	30%	55-80% in 2031-2040 'low carbon businesses'
Selected biofuel investments	820,000 t/y (Rotterdam, 2024)	Global target of over 5 million t/y 2030	Global target of additional ~4-5 million t/y by 2050	400,000 t/y (Grandpuits) 150,000 t/y (Antwerp)	250,000 t/y (Cartagena, 2023)
Selected green hydrogen investments	18,000 – 27,000 t/y (Pernis, 2023)	1 t/hour (Lingen, 2024) 45,000 t/y (Rotterdam, 2023)	Green hydrogen projects at Pavia and Sicily by 2022-2023	115,000 t/y Orsted project (ARA, 2030)	200 t/y (Spain, 2024)

** Non-current assets in lieu of Capex*

*** Apart from total Capex, refining and renewable capex are classified differently by each company and therefore it is not a like for like comparison among the companies but rather an indicative direction of Capex focus. In addition, some numbers are average of a range reported by the companies. Where Capex was not available other indicators have been used in lieu and are noted herein.*

Note – Exchange rates have been used to convert some of these values, and exchange rate fluctuations may affect such conversions.

6. A JUST TRANSITION FOR REFINERY WORKERS: RE-SKILLING

This section describes how the transition to low carbon fuels production may impact the existing workforce, with consideration to the main areas that will require re-skilling:

- Section 6.1 analyses the characteristics of the workforce in current refineries, including information on the number of people that are currently employed in the sector and the necessary skills.
- Section 6.2 identifies the required skills in the sector to minimise transition impact.
- Section 6.3 analyses the available tools and mechanisms in the EU for this transition.

6.1 WORKFORCE ANALYSIS

How many people work at oil and gas refineries today? And what skills do they need?

Approximately 130,000 people are directly employed by the refining sector in the EU today (FuelsEurope, 2022). European oil and gas refineries in Europe have different workforce sizes corresponding to their complexity and the amount of crude oil they process. The size of the indirect workforce can be ten times that amount.

The skill set is very wide and changes from one workforce category to another. However, the production processes for a transition to e-fuels and green hydrogen products will require similar skills for the majority of direct and indirect workers.

6.1.1 Refinery workforce

A skilled and competent workforce will be essential to manage the increased production of renewable energy. The upskilling of existing refinery workers will be needed to create a strong and effective workforce. Employment in the global energy sector stands at over 58 million, of which 20 million work in renewable energy, with forecasts that this will expand beyond 48 million over the next three decades, if we are to fulfil 1.5 ºC Paris Agreements (IRENA, 2021). Both in the medium and the long term, the relative weight of employment in the fossil fuel industries is expected to decrease while employment in renewables, energy efficiency, energy flexibility and grid are expected to rise. In the EU-28, the number of total jobs in renewable energy reached over 1.5 million in 2018 (European Commission, 2020).

The expected and forecasted trends for different climate policy scenarios suggest how employment in fossil fuel energy activities may decrease in the next decade. According to information from the IEA (2020), for the oil and gas sector as a whole a decrease of less than 10% employment is expected globally over the next decade, as opposed to only downstream refineries which is the focus of this study. The same forecasts from IEA do not foresee disruptive changes and do not forecast a dramatic reduction of employment.

The EU refining industry supports approximately 130,000 employees directly (Eurostat, 2022) and an additional 1.20 million jobs indirectly (FuelsEurope, 2022), including highly skilled technical positions, logistics and marketing. Furthermore, the refining industry supports employment in the engineering, building and infrastructure industries, which all supply services and equipment. The liquid biofuels industry in the EU by comparison is cited to employ ~248,000 people (JRC, 2020).

Table 6-1 provides a simplified characterisation of the oil refinery *direct* workforce. Production operators that work in shifts account for the largest share of workers. There are many workers (accountants, human resource assistants, purchase department clerks, etc) for whom new processes would require very little adjustment to their existing skill sets. The column on the right describes an initial potential impact on skills for each work category considering a transition from conventional refining to producing low carbon fuels - deeper analysis is included in section 6.2 of this document. These employees are used in site retrofits that are done in large engineering works that normally last several years allowing for a well-planned training and re-skilling of employees involved in those changes. The manufacturing plant elements (pipes, valves, instruments, pumps) are similar for the novel fuel production processes and this facilitates the transition.

Table 6-1 Overview of direct workforce in European refineries

Work category	Share (%)	Illustrative example	Background (entry level)	Overview on skills impact from transition
Manufacturing operators (and shift managers)	60%	Control room operator	Large variety (few university diplomas)	Limited impact since plant elements (valves, instruments, tanks) remain similar
Maintenance, safety and laboratory team miscellaneous	20%	Instrument supervisor		
Engineering (managers): production, safety, maintenance	10%	Head of mechanical Maintenance	Engineers, chemist, Computer science	Training required to understand new equipment and new products specifications
Services miscellaneous	8%	Accountants, purchasing expert	Large variety (most university diploma)	Very limited impact of novel processes in skill sets
Services managers	2%	Head of finance	Finance, lawyers	

Source: Ricardo

Table 6-2 provides an overview of the *indirect* labour force associated with European refineries. There is a large variety of professionals providing goods and mainly services to these sites. Estimations indicate that the number of indirect workers generated by these industrial sites are often triple to direct labour force generated (JRC, 2020), though the statistics quoted by Eurostat and Fuels Europe suggests it's 10 times for the refinery sector. Many of these indirect workers categories will require similar skills in a transition because the key elements of the new manufacturing plants will be similar (e.g. pipes, reactors, tanks, pumps, valves). A small share of the Engineering, Procurement and Construction (EPC) firms will need to increase their biobased process capabilities. This means, for example, different engineering approaches to store solid biomass compared to storing liquid crude oil. Nevertheless, some engineering firms already have relevant expertise given they already also design plants for biobased industries such as pulp and paper companies or biomass combustion units.

Table 6-2 Overview of indirect workers in refinery

Category	Illustrative example	Current skills/ background	Skills required for new fuels
Construction company	Civil works company construct/ build structures that host a new distillation tower	Ranging from architect, engineers to field mason builder	Similar to conventional
Engineering and design	Engineering firm designing a new energy efficiency measure (waste heat recovery based in pipes)	Engineers, draftsman, etc.	Generally similar but knowhow on novel biobased processes needed
Maintenance contractors	Subcontracted maintenance team to support during yearly turn around	Engineers to machinist	Similar to conventional
Services	Cleaning company to maintain offices and other buildings	Security, cleaning, lawyers, food and drinks	Identical to conventional
Suppliers/ vendors	Equipment suppliers to provide and sell filters, catalyst, etc.	Engineers, draftsman, etc.	Similar to conventional

Note: Data from the US has been considered, as information at EU-level for refineries has not identified.

Source: Data USA (2019) *and Ricardo*

There are also many induced employments as a consequence of the large economic impact of these industrial sites. This induced employment has larger impact in the surroundings of the industrial sites in most sectors: residential, restaurants, general services, education, etc. These industrial complexes often include chemical sector business units so that the number of workers reported might have significant difference depending on criteria and data source.

6.1.2 Wider trends in labour markets with impacts on refineries

Ageing Workforce

A general trend in European heavy industry labour markets is an increase in the average age of the workforce. This threatens a potential imbalance in the supply of skilled labour compared to the quantity required. This is exacerbated by an increasing demand for employees with more digital skills. The combination of both these elements risk causing a double challenge for the energy industry and may cause a significant talent gap for the sector.

Currently, just 4% of workers in the oil and gas industry are aged between 18-24, while 20% are over 55 (JRC, 2020). This disparity between age cohorts may impact the type and quantity of reskilling required for the industry to have the right skills to meet the challenges and opportunities for the sector in the future. A general trend across the whole EU employment market is that younger cohorts entering the workforce have an overall higher level of education, motivated more by goals such as equality rather than money, move jobs more frequently, are more task oriented and are more digital orientated (JRC, 2020). Equally, the negative environmental and social connotations associated with the oil and gas sector could further discourage career uptake within the oil and gas sector. Since 2006, the number of business-school graduates opting for a career in oil and gas has reduced by 40%, with 62% of 16–19-year-olds labelling the industry as unappealing (Financial Times).

Ultimately, these mismatches of skills among a current workforce that is disproportionately older and male acts as an inhibitor for the transition to a low-carbon energy system within Europe and across the globe. There is high demand for graduates from Science, Technology, Engineering and Mathematics (STEM) subjects, while soft skills such as communication, customer awareness and problem solving continue to be desirable in the energy sector. STEM graduates continue to be proportionally more male, therefore the industry has yet to fully capitalise on the contributions that women can make, which will be essential for a more equitable Just Transition. (Women make up just 30% of the renewable energy workforce (IRENA, 2021)). As part of the solution, many private companies are initiating their own training programmes in collaboration with educational institutions to encourage a wider more balanced uptake of the skills that the industry requires in the transition to net zero.

Globalisation

While globalisation has been a key driver for numerous cost and productivity efficiencies, it has also catalysed outsourcing within manufacturing supply chains, such as the relocation of solar photovoltaic manufacturing capacities from Europe to Asia.

In a Just Transition, greater consideration should be taken to understand the real costs and long-term impacts that outsourcing has upon the existing industries and communities within both the existing places of production and the outsourced country. This includes considering what type of culture this encourages, the impact of global transportation costs, whether it prioritises productivity at the expense of a fair wage and ultimately whether these activities are reinforcing an extractive economy or supporting the transition towards a regenerative future.

Digitalisation

A more digitalised workplace will create efficiencies and new jobs in some areas such as IT and software, while leading to occupations in other areas to become obsolete due to automation substitutes. However, while there is much speculation and concern that digitisation may replace workers all together, it will more likely mean adjustments in how workers carry out existing tasks.

The consequence of increased productivity due to technological advances has been a significant decline in refinery employment across major industrialised countries including France, Germany, the Netherlands, the United Kingdom and the United States (ILO, 1998).

6.2 SKILLS TO MINIMISE TRANSITION IMPACT

What re-skilling would be need in the current workforce to upgrade skills required for the production of e-fuels or hydrogen?

Limited re-skilling might be required for plant operators and manufacturing teams, since gradual uptake of novel processes is expected as a matter of course under business as usual. Licensors will transfer knowhow for common challenges. During the design stages several activities will deliver know-how to manufacturing managers. During the commissioning stage operators and control panel workers will receive training.

Will a completely different profile of workers be required?

It has been identified that several new "service" specialists outside of the production (manufacturing) team will need novel skills, though the majority of positions can be covered by people with similar skill sets. Therefore, only a limited number of new specialist categories will be required such as:

- Carbon cycle managers: to reduce the amount and cost of GHG generated in refineries
- Novel supply chain specialists: purchasing and resolving issues on the acquisition and sustainability of biomass and waste as feedstocks.
- Renewable energy specialists: aiming to minimise the cost of renewable energy acquisition via wide variety of options.
- Biobased process engineers: deep knowledge of biobased processed such as fermentation.
- ESG specialist: corporate team member, close to CEO unit aligning environmental, social and governance (compliance) procedures and tasks.

6.2.1 Impact of novel process in skill sets of refinery workers

The most relevant technical knowhow to develop, design and build fuel manufacturing processes often belongs to third parties that do not operate the refinery sites. These suppliers charge the refineries with an annual variable cost that can be proportional to their production rates. The refinery is largely in charge of operating the units (often following recommendations from licensors) and generally only propose/suggest minor changes to optimise performance. The suppliers provide expertise for conventional fuels processes and are also expected to provide the expertise for novel fuel manufacturing processes. Nevertheless, due to some of the specific changes in techniques, some suppliers may change and very specific devices may be dominated by newcomers to the sector, such as electrolysers to manufacture green hydrogen from renewable electricity.

Refinery manufacturing teams receive training from licensors on new processes or modifications taking place at their sites: this is business as usual for them. For example, in the past, there was a trend to invest in novel processes that converted heavy fractions of crude oil into chemical feedstock.

A limited number of unit operations from novel fuel production processes will be disruptive and might need larger training efforts. These being storage of solid biomass or biobased processes like fermentation. Hydrogen is not a new product in refineries since it has been used for many decades on units to reduce sulphur content or units to crack heavy molecules into more profitable ones.

6.2.2 Decarbonisation transition scenarios for refinery workforce

It can be argued that the oil and gas refineries have, so far, undergone limited transition toward a climate neutral economy. For the range of future decarbonisation paths for refining, Table 6-3 introduces two hypothetical scenarios to consider – these are purely descriptive scenarios at a high level in order to identify a range of possible outcomes for workers; others could be defined. There are uncertainties today on different key factors that will define the pace and severity of refinery transformations. The two scenarios distinguish, in broad terms, on the basis of this pace. For example, national governments could set faster and more ambitious policies to accelerate electromobility and banning combustion engines for road transport sooner than the EU. This faster decarbonisation path is captured in #2-Fast and disruptive changes in European Refineries.

Table 6-3 Overview of potential decarbonisation scenarios and paths for refineries

Scenarios	Conventional fuel demand	Share of stand-alone units outside existing refineries	Market trends for other refinery products	Type of novel processes selected at commercial scale
SC1-Slow and limited change in European Refineries	Slow decrease in demand mainly driven by high overall energy demand and slow penetration of renewables and electrification	Large share of the investments in novel fuel production units taking place in existing refinery sites (synergies with existing assets for storage and logistics)	Chemical sector maintains strong steady growth from previous decades compensating the refinery production losses on conventional fuel production rates	New production units selected by refinery operators based on profitability: have large similarities (equipment elements) with conventional ones
2-Fast and disruptive changes in European Refineries	Fast and significant decrease of conventional fuel driven by polices and successful penetration of electricity for different road transport fleets	Significant share of novel fuel sites located in standalone plants or associated with other industrial sites.	Circular economy and wider policies (such as single use plastics) have a negative impact on final chemical demand	New units selected have completely new technical elements (electrolysers, fermentation)

Source: Ricardo

The impacts of these decarbonisation paths will be different for each one of the workforce categories (introduced in section 6.1). For some of the categories, the re-skilling needed will be low regardless of the scenarios. This is the case of service teams (such as finance or accountants). Many employees in the core manufacturing teams (both operators and managers) will remain with similar skills sets. A limited number of operators and middle managers will need re-skilling. These changes will be slightly higher for faster decarbonisation scenarios as shown in Table 6-2. The key re-skilling and potential recruitment of different specialists are described in Table 6-4 for each of the two 'scenarios'.

Table 6-4 Impacts on workforce depending on transition scenarios

<table>
<tr><th>Work category</th><th>Share (%)</th><th>Scenario 1-Slow and limited change in European Refineries</th><th>Scenario 2-Fast and disruptive changes in European Refineries</th></tr>
<tr><td>Manufacturing operators (and shift managers)</td><td>60%</td><td>Majority will undergo common training on novel processes as per BAU</td><td>Some may move to renewable energy generation. Some may need completely new skill sets (operating biomass treatment or electrolyser)</td></tr>
<tr><td>Maintenance, safety and laboratory team miscellaneous</td><td>20%</td><td rowspan="2">Slow and minor changes in training to manage biomass and waste feedstocks</td><td>New skills for quality control (different from liquid fuels laboratory analysis)</td></tr>
<tr><td>Engineering (managers): production, safety, maintenance</td><td>10%</td><td>Upskilling for many electrical devices: electric boilers, renewable energy generation, electrolysers, etc.</td></tr>
<tr><td>Services miscellaneous</td><td>8%</td><td colspan="2" rowspan="2">Limited/negligible impact of transition regardless of scenarios. A limited sets of new specialists on carbon cycle, renewable energy purchases or biomass/waste supply chains.</td></tr>
<tr><td>Services managers</td><td>2%</td></tr>
</table>

Source: Ricardo

The transition will drive changes in the refinery workforces. We estimate that the proportion of workers requiring significant skills changes might be in the region of 5-10%. Some of these potential newer roles are: carbon cycle manager, to reduce the amount and cost of GHG generated in refineries; novel supply chain specialist, purchasing and resolving issues on the acquisition and of biomass and waste as feedstocks; renewable energy specialist, aiming to minimise the cost of renewable energy acquisition via wide variety of options; biobased process engineer, deep knowledge of bio-based processes such as fermentation; ESG specialist, corporate team member close to CEO unit aligning environmental, social and governance (compliance) procedures and tasks. These are summarised in Table 6-5.

Table 6-5 Refinery jobs profiles with higher impact from transition

Job position	Category	New hire/ upskilling	Description
Carbon cycle manager (decarbonisation leader)	Services managers	Upskilling of industrial emission expert	Reduce GHG emissions from refineries. Reduce cost of ETS. Select investment projects to keep reducing GHGs
Supply chain specialist on circular economy	Services miscellaneous	New hire/ upskilling	Ensure quality, volume and price of novel feedstocks (biomass, organic fraction of waste, plastic waste).
Head of Renewable energy purchase	Services managers	Upskilling energy purchase expert	Ensure availability, stability and best price for renewable electricity supply. Potentially also heat generation via renewables.
Biobased process engineer	Engineering (managers)	Preferred option new hired with pilot plant background	Build and transfer knowledge (to manufacturing, maintenance and engineering) on novel biobased processes
Head of maintenance		Upskilling on new devices	Minimise downtime (maximise availability) and minimise maintenance cost for a larger set of electrical devices and components

Source: Ricardo

6.2.3 Potential actions on capacity building and human resources

Due to the aging workforce mentioned in the previous sections, a greater level of investment into technology skills may be necessary to upskill the existing workforce or greater mechanisms and hiring strategies may have to be reconsidered to encourage and facilitate oil and gas career uptake among a younger generation.

The under representation of women and diversity within the industry is a clear indicator that recruiters could do more to understand the potential barriers for minorities and women in the workforce and actively seek to address this through their recruitment and capacity building.

To re-stimulate career uptake, the industry can take several actions to support graduate attraction and retention of staff. While the COVID-19 pandemic has caused the oil and gas employment sector many negative impacts, it has, through necessity, expanded remote working across all sectors of the business. Recruiters can take advantage of remote working arrangements to tap into a previously inaccessible talent pool of professionals who live much further away from employment locations, internationally and, with the correct training programs in place, graduates who may have not previously considered a career in oil and gas. Although within refineries many roles will still require on-site presence.

Table 6-6 Different actions from Human resources team on refinery decarbonisation

Age range	Human resource aim	HR team strategy	New capabilities
New entries (less than 5-year experience)	Attract	New roles: emission or energy efficiency officer. Accelerate transition from fuels to energy business	Big data: statistics, data visualisation, coding, and programming
	Hire	Facilitate remote work for certain positions. Modern organizational structures	Transferable skills: finance, stakeholder management, public/remote communication skills
20% in 25-35 age	Develop	Promote remote process control Launch collaboration tools	Proficiency in data driven decision making. Deeper

Age range	Human resource aim	HR team strategy	New capabilities
			knowledge on data driven risk analysis and prevention
Median lies in 44-year-old	Grow	Facilitate transition/ growth to (green) energy business. Seed leadership opportunities	Add skills beyond core technical: finance, management, etc.
Employees> 45 y old	Engage	Increase pairing with millennials	Mentoring programs

Source: (Deloitte, 2020)

Greater digital automation should increase the return on investment for employers, on personal development of their employees, given that greater automation and digital skills will allow employees to create more business value and reduce the hours of their working day spent doing administrative tasks (McKinsey & Company).

Equally, Human Resources departments can utilise digital tools and analytics to deliver more personalised development programs, which can support talent retention. New technology will enable smoother interactions, which will be especially important as they make the most of a remote workforce. Equipping Human Resources departments with these tools would significantly impact the pace of change, employee productivity and wellbeing.

6.3 SUPPORT TOOLS AND MECHANISMS

What role can the Just Transition Mechanism of the EU play for refinery operations?

Summary:

- The Just Transition Mechanism mobilises funds to support key territories in Member States to face the socioeconomic challenges associated with the transition towards climate neutrality. The mechanism prioritises social support and economic revitalisation. The allocation of funding has been pre-decided based upon territories, in line with EU policy, and the criteria included industrial regions with high carbon intensities (primarily driven by coal and lignite power production).
- For the funding that has been allocated, it could support refineries in the reskilling of workers, new job creation and transformation of existing carbon intensive activities. This could be through the Just Transition Fund, through the InvestEU 'Just Transition' Scheme, or through the new public sector loan facility, the former being a pre-requisite for the latter two.

Which tools/assistance are available?

There are several EU funds that could provide support to refineries in the transition to net zero. These include:

- **The European Globalization Adjustment Fund for Displaced Workers** (EGF) is a special EU instrument to express EU solidarity with European workers or the self-employed that were displaced due to restructuring, and to help them find new jobs.
- **Horizon Europe** – €95 billion budget for research and innovation to help achieve UN Sustainable Development Goals and tackle climate change.
- **LIFE** Program – private funding to support biodiversity and climate adaptation and energy efficiency investments.
- **Modernisation Fund** – funding allocated to 10 lower income EU Member States to support their transition to net zero.
- **Connecting Europe Facility** (CEF) – CEF budget is allocated to projects that develop environmentally sustainable interconnected transport, energy, and communications networks across Europe. Of this budget, the energy sector could receive €5.35 billion.

The previous chapters have described how the refinery sector might transition towards low carbon fuel production. A 'Just Transition' would mean that this is done in such a way that job creation, job upgrading, social justice and poverty eradication are taken into consideration. Some definitions would also go further to encourage that a Just Transition also addresses the roots of inequality. Widely recognised, a Just Transition to an environmentally and socially sustainable economy is one in which no one is left behind.

The Just Transition Mechanism (JTM) put forward by the European Commission in January 2020, centralises funding opportunities across the public and private sectors to mobilise approximately €55 billion over the period 2021-2017, to support the most vulnerable regions to invest and alleviate the socio-economic impact of the transition to a climate neutral economy (European Commission, 2022). The Just Transition Mechanism is the first holistic attempt from the European Commission to protect vulnerable people and citizens. The plans are to target territories that will incur the worst economic and social impacts from the transition, and plans are be prepared in collaboration with the relevant authorities.

The mechanism will prioritise social support, economic revitalization and comprises three pillars: The Just Transition Fund (JTF), the Just Transition Scheme (JTS) and the public sector loan facility.

The allocation among the Member States from the **Just Transition Fund** (JTF) has been outlined by the Commission according to set rules. The allocation largely focuses on the reduction of carbon output from each Member State's largest emitters and economics sectors related to fossil fuel extraction. The JTF could be utilised to target the upskilling and reskilling of workers in the refinery sector in key carbon intensive regions of Member States. Plants covered by the EU's Emissions Trading System, located in EU regions with a carbon intensity of at least twice the EU average will have a chance of receiving support. The fund allocation from the EU budget for the JTF is €7.5 billion, with an expectation that for each euro invested, Member States will add their contributions for example via their share of the European Regional Development Fund (ERDF) or European Social Fund Plus (ESF+). It is anticipated that, in total, the fund should generate approximately €30 billion of investments.

The **Just Transition Scheme** under the InvestEU is a set aside budget allocated for climate and environment-related investment, specifically for Just Transition projects. The scope for projects supported by the InvestEU is wider than that of the Just Transition fund with projects to develop energy infrastructure, however, there continues to be an allocation of funds to support economic and social diversification. The Just Transition scheme complements the JTM, by opening combining funds from public and private sectors, thus doubling the momentum and encouraging accountability from both the public and private sector to support a just transition.

The **public sector loan facility** is the third pillar. The facility consists of concessional loans to the public sector and should trigger €25-30 billion of investments. It will rely on €1.5 billion from the EU budget and on a European Investment Bank lending of €10 billion (European Commission, 2020). The InvestEU and public sector loan facility are financial streams designed to leverage public and private investment, but supporting projects backed by financial partners. The public sector loan encourages short term action for underfunded public projects, while also setting a precedent for future public private funding partnership, which will be essential for generating the investment required to achieve adequate action towards net zero in the next decade.

Other tools

Other available tools include Horizon Europe funding, which is intended to be used to create jobs, support the implementation of EU policies, and optimize investment impact within the European Research Area. Horizon Europe could support the implementation of future policy changes for refineries. In total it is €95 billion EU budget for research and innovation to help achieve UN Sustainable Development Goals and tackle climate change (European Commission, 2021).

The LIFE Program, or 'LIFE finance' mobilizes private funding through Natural Capital Financing Facility and Private Finance for Energy Efficiency to support biodiversity and climate adaptation and energy efficiency investments.

The Modernisation Fund, with a value currently over €600 million, is derived from revenues from auctioning 2% of 2021-30 allowances of the EU ETS, allocated to 10 lower income EU Member States to support their transition to net zero. Beneficiary members include Bulgaria, Croatia, Czechia, Estonia, Hungary, Latvia, Lithuania, Poland, Romania and Slovakia.

Connecting Europe Facility (CEF) – CEF budget is allocated to projects that develop environmentally sustainable interconnected transport, energy, and communications networks across Europe. Of this budget, the energy sector will receive €5.35 billion for energy infrastructure projects (European Commission, 2022).

7. CONCLUSIONS

Demand and supply trends

As a consequence of the beginning of the transformation shifts encouraged by policy, as well as the impacts of the covid pandemic, demand for refined products is changing, with road fuel demand particularly decreasing principally due to electrification, as well as vehicle efficiency improvements. One projection of the electrification of the car fleet is for a 10-20 fold increase in the EV stock by 2030. Not all demand is declining though – demand is increasing for chemical feedstocks, encouraging the conversion of refineries to integrated petrochemical refining.

Refinery capacity must adjust to this change in demand. This has already been occurring through rationalisation (closures): around 13% of refining capacity in Europe closed over the last decade, leaving a capacity today of around 13.6 million barrels per day. Argus' forecast of road fuel demand is for a decline of 31% between 2021 and 2035. If the demand were to drop more sharply – a scenario was run of a 56% decline – it is estimated that 43% of the remaining refinery capacity would close (or convert).

Transition to low carbon fuels: examples

But it's not just closures to address the change in demand. Many investments in low carbon fuels have begun. This includes conversions to biorefining as well as dedicated plants for green hydrogen and synthetic fuels. Biofuel production in Europe is forecast to more than double between 2020 and 2025 to ~2.6% of fossil-based road fuel production, with examples of refineries being converted into bio-refineries. On green hydrogen projects – which can be used for synthetic fuels or directly as a transport fuel or within refinery processes – some 30 European refineries plan to implement green hydrogen capacity at their existing facilities.

As well as developments at existing sites, nearly 30 investments in new greenfield sites for novel production processes to produce advanced biofuels and e-fuels in Europe have been identified. These projects could produce up to 9.3 million tonnes per year of low-carbon liquid fuels by 2030, and include:

- Advanced biofuel projects with output capacities ranging from 0.1 to 0.75 million tonnes per year.
- Green hydrogen projects to reduce the GHG intensity of manufacturing processes or to combine with captured carbon to produce synthetic fuels with an annual capacity of up to 3.4 million tonnes.
- Waste-to-fuel projects, with a production capacity of up to 0.1 million tonnes per year in output (derived from municipal solid waste).

The report includes further details on these investments.

Transition to low carbon fuels: technology and site considerations

More generally, the report presents an overview of the most relevant low carbon fuels and the available entry points for non-fossil feedstock into a conventional refinery for the production of low carbon fuels. There are different options for the processing of non-fossil feedstocks, including dedicated plants, co-processing and refinery conversion. Overall, there is no clear general preference for investment either in dedicated plants, co-processing plants or refinery conversions for the production of low carbon fuels, as the relative merits differ on a case-by-case basis due to a range of influencing factors. Capital cost considerations include sharing conversion assets, the availability of storage facilities for products, the investments needed on plant utilities, the available fuel transportation infrastructure. Whilst many of these considerations point towards the use of existing refinery assets (i.e. conversion), some potential drawbacks to this approach include the space available and the permitting arrangements.

For the particular case of e-fuels (produced from green hydrogen and CO_2) the feedstocks for these fuels are expected to primarily be obtained from new plants. In this context, there can be advantages to repurposing decommissioned oil refinery sites for sustainable e-fuel production. The synergies are economic in nature, with benefits such as land ownership, access to workforce, opportunity for sharing or reusing fuel storage and handling assets and utilities, and repurposing waste from conventional processes as feedstocks for low carbon fuels production processes. Other factors such as feedstock supply chains can however benefit alternative locations for dedicated plants.

The technical capacity to manufacture e-fuels based on green hydrogen and renewable carbon is not constrained by existing refinery capacity or capabilities, because existing refineries do not provide the input streams nor conversion units to enable this production path. The critical element to de-bottleneck production of e-fuels is the up-front investment for these novel processes.

Cost competitiveness of low carbon fuels

The main cost driver affecting the costs of producing e-fuels are the costs of renewable energy, which are largely driven by the costs of electrolysis. These costs are expected to scale down substantially by 2050 until they are no longer dominant cost components. Further cost drivers are the status of technology development, the utilisation rate for conversion plants, economies of scale and the choice of the carbon feedback.

On the latter point, making use of carbon captured from industry processes (for example, within refinery complexes, is typically much less expensive than processes such as Direct Air Capture, owing to large volumes of product being available at high concentrations from waste streams. Direct Air Capture costs per tonne of CO_2 are around five times the costs of capture from waste streams.

A comparison of the capital costs of new build e-fuels plants with new build HVO plants identifies the e-fuel plant Capex is expected to be 5 times higher than the HVO plant. However, costs may be expected to drop with time with technology maturity. Although the capex intensities are very different, this does not lead to the conclusion that the more Capex-intensive projects are unlikely to proceed for two reasons: 1) operating costs are not quoted here, and (2) feedstock availability could be a constraint.

Energy intensity of producing low carbon fuels

The energy intensity of producing renewably derived synthetic diesel is shown to be around six to seven times higher than for conventional diesel, while the energy intensity of renewably synthesised methanol is at least twice that of conventional methanol synthesis, with the higher values for both processes when assuming CO_2 from Direct Air Capture. Despite the increased energy intensity of production, the synthetic fuel routes nevertheless offer greater than 90-95% reductions in upstream GHG emissions compared to conventional production routes. The comparison used well-to-tank energy intensity values which take into account the energy intensities of the production processes while excluding the energy content of the feedstock, i.e. using the ‘Net Energy Analysis’ (NEA) approach.

Deep dive case studies into five European oil majors’ investments into hydrogen and biofuels

Regarding the strategy of European refiners, significant investments have been made in alternative fuels, much of it related to their existing refining portfolios. Advanced biofuels have been the most typical route for diversification, leveraging the existing liquid fuels storage, processing and logistics infrastructure. Hydrogen is more nascent but an area where many of the firms analysed have made at least some initial investment. The announcements made by these companies on the future share of their capital expenditure on renewable and low carbon energy suggest that their focus will be in large or majority part on these new energy pathways. However, for the moment, the share of energy production from fossil sources still dominates.

Use of renewable energy sources

In addition to the production of low carbon fuels, a wide range of approaches and technologies are required for oil and gas companies to achieve emission reduction efforts for minimising the CO_2 intensity of their production processes, both conventional and novel. These may include energy efficiency improvement, the introduction of renewable energy sources lowering the carbon footprint of their energy sources, capture of CO_2 for long-term storage or reuse as well as the inclusion of renewable fuels in the portfolio of oil and gas industries. Energy efficiency is already under the control of the refiners and builds on on-going efforts. Further emission savings can be achieved through the use of renewable energy sources. There are different alternatives for producing and/or crediting renewable energy sources (e.g., green hydrogen from renewables electricity) for European refineries, including the direct co-location with renewable energy assets, consuming electricity from the grid using a power purchase agreement with a dedicated renewable generation asset, consuming electricity from the grid in hours of low grid carbon intensity or trading renewable energy certificates.

A Just Transition for refinery workers

Finally, the transition from conventional refineries to the future of refineries, including the introduction of low carbon fuels in their portfolios, has the potential to have only a small impact on the existing workforce, with consideration to the main areas that will require upskilling: it is expected that 5-10% of refinery workers will need significant skills changes. Wider trends in European labour markets are predicted to also impact refineries, such as an aging workforce, globalisation, and digitalisation. The EU refining industry currently employs approximately 130,000 workers directly, and an additional 1.2 million jobs indirectly, including highly skilled technical positions, logistics and marketing. Some of the potential newer roles include carbon cycle managers, to reduce the amount and cost of GHG generated in refineries; novel supply chain specialists, purchasing and resolving issues on the acquisition and of biomass and waste as feedstocks; renewable energy specialists, aiming to minimise the cost of renewable energy acquisition via wide variety of options; and bio-based process engineers, with deep knowledge of processes such as fermentation. In the most part, the production processes for a transition to bio and green hydrogen products will continue to require the existing skills for the majority of direct and indirect workers.

As the refinery sector moves towards low carbon production guided by ambitious EU policy objectives for a carbon neutral EU it is clear that investment will be needed. A just transition would mean that this is done in such a way that job creation, job upgrading, social justice and poverty eradication are taken into consideration. There are several EU funds to support the technical and just transition to which refineries may be eligible, as discussed further in this report.

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APPENDICES

Appendix A: Processes and conversion technologies

A.1 Pre-treatment processes for biofuels

This section describes pre-treatment processes. The processes included here convert the compatible feedstocks to a product that can enter a conventional refinery. By this definition, pre-treatment does not include the physical 'pre-processing' of the feedstocks e.g., chip/pellet production, steam explosion etc. The products listed in the following tables are intermediate products and cannot be used as/in fuels without further processing.

Lipid extraction	
Compatible feedstocks	Microalgae
Product(s)	Lipids/oil
Technical description	The microalgal biomass is first concentrated then the lipids are extracted. Multiple methods for the extraction of lipids are available, e.g. (Frontiers, 2015).
Conventional refinery entry point	Hydrotreatment
Other potential processing routes	Transesterification
Indicative/typical fuel products	Biodiesel for diesel blends or upgrading to bio-kerosene
TRL	TRL 5-6. Microalgal biodiesel is seen as a potential substitute for petroleum-based fuels. The various downstream technologies employed in the biodiesel production are still in early stages of development.

Gasification	
Compatible feedstocks	• Lignocellulosic materials e.g., RED II Annex IX A Feedstocks. • Waste plastic.
Products(s)	Syngas. This syngas will require further such as Fischer-Tropsch synthesis, and potentially a purification final stage.
Technical description	The feedstock is reacted at high temperatures (>700 °C) in the presence of a controlled quantity of oxygen or steam. The reaction produces raw syngas, impurities such as CO2 are then removed to give pure syngas. Under optimised conditions the production of syngas can reach up to 85% by mass of the total products (IEA Bioenergy, 2019).
Conventional refinery entry point	Syngas is not currently utilised directly by refineries in the production of fuels. The syngas must be passed to a FT Synthesis step before it can be utilized by a refinery.
Indicative/typical fuel products	Diesel, kerosene and naphtha from FT synthesis.
TRL	TRL 6-8. Gasification is already a well-established technology for large-scale coal applications. Industrial experience of gasification conversion routes for biofuel applications is, on the other hand, at a much earlier stage.

Pyrolysis	
Compatible feedstocks	• Lignocellulosic materials e.g., RED II Annex IX A Feedstocks. • Waste plastic.
Products(s)	Pyrolysis oil
Technical description	The feedstock is reacted at high temperatures in the absence of oxygen. The main product is pyrolysis oil however, combustible gases and biochar are collected as by-products. The pyrolysis oil produced is not miscible with fossil oils due to the presence of a large quantity of oxygenated molecules. It is also corrosive and thermally unstable. Consequently, pyrolysis oil must be upgraded. Two direct routes have been pursued for the upgrading, either as an integrated part of the pyrolysis plants facility, or off-site and then preferably in co-processing with fossil fuels in a fossil refinery.
Conventional refinery entry point	• Hydrotreatment (lignocellulosic feedstock) • Distillation (waste plastic fraction feedstock)
Indicative/typical fuel products	Drop-in hydrocarbon fuels.
TRL	TRL 6-9, depending on the feedstock used (TRL 9 for lignocellulosic and TRL 6 for processes using waste plastic fraction).

Hydrothermal Liquefaction	
Compatible feedstocks	• Lignocellulosic materials e.g., RED II Annex IX A Feedstocks. • Waste plastic.
Products(s)	Biocrude
Technical description	Hydrotreatment liquefaction involves directly liquefying biomass in the presence of water (with or without the use of a catalyst), to convert biomass into a mix of liquid oil (synthetic crude oil) and solid products, under pressure and with a reaction temperature of less than 400 ºC.
Conventional refinery entry point	• Hydrotreatment (lignocellulosic feedstock) • Distillation (waste plastic fraction feedstock)
Indicative/typical fuel products	Drop-in hydrocarbon fuels.
TRL	TRL 5-6 to produce biocrude. TRL 4 for the overall process, including upgrading to the final fuel.

A.2 Conversion technologies for biofuels

This section describes technologies used to convert feedstocks or intermediate products to fuels.

Fermentation	
Compatible feedstocks	Sugar/starch crops.
Products(s)	Alcohol e.g., ethanol, butanol. Hydrocarbons e.g., farnesene
Technical description	Microorganisms are used to biologically convert feedstock into biofuels, such as ethanol and other alcohols. For instance, starch and sugar crops are usually used as feedstocks to produce ethanol via fermentation, during which the simple sugars are fermented into ethanol. The main operational variables affecting ethanol yield and fermentation efficiency are osmotic pressure and the presence and removal of some by-products (toxic to yeasts) of hydrolysis reactions and yeast metabolism.
Conventional refinery entry point	Ethanol has no interaction with conventional refinery processes. Hydrocarbons can be blended with conventional fuels after hydrotreatment.
Indicative/typical fuel products	Ethanol Drop-in hydrocarbon fuels.
TRL	TRL 9. Ethanol production from sugar and starch crops is a well-established technology. TRL 6-8. Ethanol production from cellulosic material is considered the most promising option for future fuel ethanol production. Further optimising the performance of new processes and saccharification/fermentation yields and improving economic and environmental performance (and hence reducing costs) remain critical. TRL 6. Investigations are taking place on butanol production within the EU. TRL 9. Fermentation to hydrocarbons is used commercially to produce a drop-in aviation fuel by Total and Amyris.

Esterification	
Compatible feedstocks	Fatty Acids (Lipids) i.e., Vegetable oil (rapeseed, soybean, palm oil, sunflower oil) or residual/waste oil and fats (used cooking oil, animal fats)
Products(s)	FAME (fatty acid methyl ester)
Technical description	The raw material is processed with methanol and sodium methoxide or potassium hydroxide in a process known as transesterification.
Conventional refinery entry point	Ethanol has no interaction with conventional refinery processes. Hydrocarbons can be blended with conventional fuels after hydrotreatment.
Indicative/typical fuel products	Biodiesel (FAME). Can be blended up to 7 % in standard European road diesel fuel (EN590) or used as pure biodiesel. The blending limits are primarily a result of the FAME molecules containing oxygen.
TRL	TRL 9 (vegetable oil feedstock). In the EU, the industrial production of FAME is a mature technology, with an annual capacity over 21 million tonnes, and just under 190 factories in operation. TRL 8 (residual waste feedstock). Most facilities use vegetable oil feedstocks. However, esterification routes from residual waste and oil and fats are also commercially available. The main barrier for these facilities is the limited availability of waste-based feedstocks in Europe. It is estimated that the EU imports more than 50% of the used cooking oil it requires for this process.

Hydrogenation of Vegetable Oil (HVO)	
Compatible feedstocks	Fatty Acids (Lipids) i.e., Vegetable oils (rapeseed, soybean, palm oil, sunflower oil) or residual/waste oil and fats (used cooking oil, animal fats)
Products(s)	Hydrogenated vegetable oil (HVO), hydroprocessed esters and fatty acids (HEFA)
Technical description	Vegetable oils are processed at high temperatures and pressures with hydrogen and a catalyst. The process can be tailored to produce varying fractions of diesel or kerosene.
Conventional refinery entry point	Hydrogenation.
Indicative/typical fuel products	Drop-in hydrocarbons – specifically diesel or kerosene. These products are not subject to the same blending limits as FAME because they do not contain any oxygen.
TRL	TRL 9. HVO is an established technology and recently new stand-alone units have been built or announced, some of them converting traditional oil-based refineries into HVO-based biorefineries.

A.3 RFNBOs

RFNBOs are fuels produced from materials of non-biological origin – water, renewable electricity and CO_2. Although the tank-to-wheel GHG emissions of biofuels and RFNBOs are comparable, RFNBOs generally have lower (even zero) well-to-tank emissions. This is because according to the renewable energy Directive, RFNBOs must be manufactured using renewable electricity that meets additionality requirements (the definition of RFNBOs does not stipulate the origin of the CO_2 used, so it could be acquired by direct air capture, or from point sources).

CO_2 Hydrogenation	
Compatible feedstocks	CO_2 and H_2 from renewable energy
Products(s)	Methanol
Technical description	CO_2 is reacted with hydrogen in the presence of a catalyst to produce a mixture of methanol and water. The methanol can be recovered by distillation.
Conventional refinery entry point	None.
Indicative/typical fuel products	Methanol
TRL	TRL 4/5. Pilot plants are in operation to determine the feasibility of this process on an industrial scale e.g. by Mitsui Chemicals (Japan) and Carbon Recycling International (Iceland).

Electrolysis	
Compatible feedstocks	Water and renewable energy
Products(s)	Hydrogen
Technical description	There are different hydrogen electrolysis technologies, including: • Alkaline electrolysis (AEC): a 20-40% solution of potassium hydroxide is electrolysed using a nickel catalyst. The process operates at ambient temperatures and between 1-30 bar. • Polymer electrolyte membrane (PEM) electrolysis: pure water is electrolysed using a platinum/ iridium catalyst. The process operates at ambient temperatures between 1-100 bar. • High-temperature solid-oxide electrolysis (SOEC): a regeneratively run solid oxide fuel cell electrolyses water using a ceramic electrolyte. The process operates at high temperatures, typically between 500 and 850°C.
Conventional refinery entry point	Conventional refineries use vast quantities of hydrogen in hydrotreatment steps. Currently this is generated as part of the standard refinery operation. Hydrogen is a key feedstock to produce all RFNBOs.
Indicative/typical fuel products	Diesel, kerosene, e-fuels.
TRL	AEC: TRL 9. AEC is a mature technology. However, production volumes are still low. Cost reductions are expected through increased production volumes. PEM electrolysis: TRL 8. For PEM electrolysis, the first units have been operating successfully for some years, although a full life cycle under operation conditions has not been yet achieved. SOEC: TRL 5. SOEC is a process already offered by companies, such as Sunfire. However, its lack of flexibility compared to low-temperature electrolysis, is a drawback for the development of this process.

Co-Electrolysis	
Compatible feedstocks	CO_2, Water and renewable energy
Products(s)	Syngas
Technical description	CO_2 and water are co-electrolysed in a single step – using a solid oxide electrolyser cell (SOEC) and renewable electricity.
Conventional refinery entry point	None – this process produces syngas which must first be processed by FT-synthesis before it is compatible with refineries.
Indicative/typical fuel products	Diesel, kerosene, e-fuels after FT-synthesis.
TRL	TRL 5-7. The first demonstration of syngas production by co-electrolysis in an industrial environment was performed at the Schwechat Refinery in Austria (FCH JU, 2020). A previous prototype (10 kW DC) was developed by Sunfire in 2019 (Sunfire, 2019).

A.4 Fischer-Tropsch and methanol synthesis

Fischer-Tropsch and methanol synthesis to obtain synthetic fuels are described in this section. For methanol synthesis, two conversion routes are considered, depending on the feedstock used: (a) from syngas (from non-renewable and renewable sources) and from CO_2 and H_2. The fuels obtained by these conversion route can be considered carbon neutral fuels, due to the CO_2 used being acquired by direct air capture, allowing a sustainable fuel production with the potential to reduce CO_2 emissions in the energy and transport sectors.

Fischer-Tropsch synthesis	
Compatible feedstocks	Syngas from readily available natural resources (coal, natural gas, or biomass), or from renewable CO_2 sources, such as the reduction of CO_2 to CO via the reverse water gas shift (RWGS) reaction.
Product(s)	Syncrude, which is then further processed through hydrocracking and distillation (purification steps) processes. In addition to the hydrocarbon products, very small amounts of oxygen-containing hydrocarbons and some light gases (methane, ethane, etc.) are generated (RSC, 2020).
Technical description	Heterogeneous catalytic conversion of syngas to long-chain hydrocarbons and other oxygenated products (Mehariya, et al., 2020) (RSC, 2020). FT processes can be divided into low-temperature (LTFT) and high-temperature Fischer-Tropsch (HTFT), which are operated at temperatures of 200–250 °C and 300–350 °C, respectively (M. Jarvis & Samsatli, 2018). The characteristics of the products obtained, such as the length of the hydrocarbons, are determined by the process parameters.
Conventional refinery entry point	Hydrotreatment, and cracking and product separation.
Indicative/typical fuel products	Drop-in fuels (diesel and kerosene) with almost the same chemical composition as fossil fuels but with lower sulphur and aromatic content.
TRL	TRL 9 (non-renewable feedstock). FT synthesis is fully commercialised and developed at a global scale for non-renewable feedstocks (natural gas and coal). TRL 5-7. Technologies integrating renewable CO2 routes for syngas production. (M. Jarvis & Samsatli, 2018)

Methanol synthesis	
Compatible feedstocks	Syngas from readily available natural resources (coal, natural gas, or biomass), or from renewable CO_2 sources, such as the reduction of CO_2 to CO via de reverse water gas shift (RWGS) reaction. CO_2 and H_2 from renewable sources, followed by hydrogenation of CO_2 as carbon source.
Product(s)	Methanol – used as a final product or a feedstock to further processing.
Technical description	Catalytic conversion of synthesis gas. The syngas (H_2, CO_2 and CO) is converted into methanol on CU/ZnO-based catalysts at temperatures of 200-300ºC and pressures of 50-100 bar. Hydrogenation of CO_2 with H_2 with high selectivity on conventional Cu/ZnO-based catalysts. Reaction rates are lower that with syngas feeds.
Conventional refinery entry point	None
Indicative/typical fuel products	Gasolines – through methanol-to-gasoline Olefins – through methanol-to-olefins Dimethyl ether (DME) and polyoxymethylene ethers (OME) fuels

Appendix B: Measures to reduce GHG emissions from refineries

B.1 Measures to reduce GHG emissions from power generation

These measures aim to lower the carbon footprint of energy sources by introducing renewable sources such as biomass or renewable electricity in the refineries' energy portfolio and/or using lower-carbon fossil energy, as well as reducing fugitive GHG emissions of these processes.

- Use of renewable sources: according to RED II, fuel suppliers must ensure that the share of renewable energy within the final consumption in the transport sector is at least 14% by 2030. Moreover, GHG emissions savings from the use of RFNBOs must be at least 70% from January 2021, compared to emissions from the fossil fuels they seek to replace (with emission factor of 94 gCO_2eq/MJ).

  Therefore, replacement of on-site renewable-power generation with renewable energy sources could significantly reduce GHG emissions. In this sense, the carbon intensity of the electricity employed for hydrogen production would need to be lower than the existing average grid carbon intensity in order to be able to achieve a substantial GHG emission reduction compared to the fossil fuel alternative.

- CO_2 capture in refineries, storage and utilisation: oil and gas refineries emit CO_2 from a variety of processes, and the exhaust units for these emission sources are numerous and dispersed around the plant. Therefore, CO_2 capture technology is only expected to play a limited role in the sector's total decarbonisation as, at a refinery, CO_2 capture and control is expected to be limited – from a cost-efficiency perspective – to the larger CO_2 emitting processing units, such as the Fluid Catalytic Cracking Unit, the fluid coking unit, the hydrogen plant (conventional natural gas-based production), and large boilers or process heaters (EPA, 2010).

  McKinsey (2020) indicate there are already 19 large-scale carbon capture and utilisation / storage facilities in operation and four more under construction. The capacity of plants to capture and store CO_2 now in service and under construction around is 40 Mt CO_{2e} per year. It is expected that by 2050, the total capacity could have increased 200 times.

- Reducing fugitive GHG emissions: refineries can reduce fugitive methane emissions by enhancing leak detection and repair technologies, adding vapour recovery units, or using the best available technologies for these purposes (IEA, 2021). Technology standards are designed to reduce emissions associated with the normal operation of certain equipment, such as compressors. However, there are alternative technologies that can perform the same function as these components, but with lower or zero emissions, as the ones previously mentioned.

B.2 Measures to reduce GHG from heat generation

Measures related to GHG emissions produced during heat generation and, in particular, high temperature heat supply may remain among most challenging transitions in oil and gas refineries. In most plants, process heat is the highest energy demand (significant amounts of energy are converted into heat), as the majority of the (currently gas-fired) burners deliver high temperatures (over 350°C), and operate at capacities of up to 200 MW (EPA, 2010).

- Heat recovery from process heaters (air preheater): even when air pre-heating is already being used in refineries to some extent, energy efficiency increases of between 10 and 15% can be achieved in all types of industrial steam boilers, furnaces, and fired heaters.
- Electrical process heaters: electrical heat might potentially replace traditional combustion heaters, as a source of process energy. However, this concept is still in its early stages of development, and the challenges it poses in terms of health, safety, and the environment as well as operational issues are currently being examined. Electrical process heaters are expected to be more expensive than steam boilers, therefore they are only considered to be cost feasible at this level of development for considerably low electricity prices and extremely high gas prices.
- Inter-unit heat integration and upgrading low-grade heat: Heat-integration operates on two levels: within-process unit integration and between-process-unit integration. Assessment methods are frequently used by refineries to identify bottlenecks and heat integration opportunities. This can include both direct and indirect heat transfer between process streams, such as heat transfer systems for refinery steam or "hot oil." A key subject is the feed preheat system for crude units (which are among the largest energy users in most refineries).

Appendix C: Advanced biofuels and e-fuels projects in Europe

This table reproduces information from Fuels Europe (2022) on a selection of European advanced biofuels and e-fuels projects.

Table C-1 Overview of advanced biofuels and e-fuels projects in Europe

Project	Company	Location	Category	Operational date	Production	Description of the project
Advanced biofuels						
Venice Biorefinery	ENI	Italy	Advanced biofuels	2014	360,000 tonnes per year	Porto Marghera, in Venice, is the first conventional refinery in the world to be converted into a bio-refinery.
MY Renewable Jet Fuel	Neste	Finland	Advanced biofuels	Operational (year not available)	100,000 tonnes per year	The Neste MY Renewable Jet Fuel™, is a sustainable aviation fuel that in neat form and over the lifecycle reduces GHG emissions up to 80% compared to fossil jet fuel and is produced from 100% renewable waste and residue raw materials, such as used cooking oil and animal waste fat.
bp Biojet	bp	Sweden	Advanced biofuels	2017	(No information available)	bp sustainable aviation fuel is called bp Biojet. It is produced from sustainable, renewable feedstocks such as used cooking oil and other wastes.
Bio4A	TotalEnergies, SKYNRG, Cener, ETA, Camelina, JRC	France	Advanced biofuels	2018	(No information available)	The project goal is to produce HEFA (hydro-processed esters and fatty acids) fuel from waste such as used cooking oil. The production is in a novel industrial scale first-of-a-kind demo plant in La Mède bio-refinery, France.
ReOil	OMV	Austria	Advanced biofuels	2018	(No information available)	OMV is developing a feedstock recovery pilot project in its Schwechat refinery that uses plastic waste to produce synthetic crude in a pyrolysis process.
La Mède Refinery	TotalEnergies	France	Advanced biofuels	2018	500,000 tonnes per year	HVO-type biodiesel. The biorefinery was designed to produce biofuels from all types of oils, be they vegetable, used or residual.
Advanced biofuels for deep sea vessels	Varo	Netherlands	Advanced biofuels	2018	(No information available)	Focused on scaling sustainable marine biofuels for the European inland shipping market and recently extend partnership to scale biofuels and to improve access to biofuels for deep sea vessels leaving from Rotterdam.

Project	Company	Location	Category	Operational date	Production	Description of the project
Humber Refinery	Philips66	United Kingdom	Advanced biofuels	2018	3,000 BPD (barrels per day) with plans to expand to 5,000 BPD by 2024	Production of renewable diesel from used cooking oil at Humber began in 2018, with the refinery becoming the first in the UK to convert waste oil into road fuel.
Biozin	Preem	Norway	Advanced biofuels	2018	289,000 tonnes per year	Large-scale production of biofuels with residues from the forest and wood industry. I
Enerfuel	Galp	Portugal	Advanced biofuels	2019	25,000 tonnes per year	FAME (fatty acid methyl ester) biodiesel from 100% residues through the transformation of used cooking oils and waste animal fats.
Gela Biorefinery	ENI	Italy	Advanced biofuels	2019	(No information available)	The plant processes used vegetable oil, frying oil, fats, algae and waste by-products to produce quality biofuel. In March 2021, the new BTU (Biomass Treatment Unit) was launched and tested. It will enable the use of 100% of the biomass not in competition with the food chain, for example, used cooking oils and fats from fish and meat processing in Sicily.
Preem Lysekil Refinery	Preem	Sweden	Advanced biofuels	2019	25,000 tonnes per year	(No additional information available)
Sustainable Aviation Fuel	Repsol	Spain	Advanced biofuels	2020	600,000 tonnes	Repsol produced the Spanish market's first batch of biojet at its Puertollano Industrial Complex. The Company will also develop alternatives aimed at obtaining airplane fuel derived from waste.
Marine Biofuel Oil	ExxonMobil	Netherlands	Advanced biofuels	2020	(No information available)	The marine biofuel oil is a 0.50% sulphur residual-based fuel (VLSFO) processed with a second-generation waste-based FAME component.
St1 Renewable Fuel	St1	Sweden	Advanced biofuels	2023	200,000 tonnes per year	Hydrogenated vegetable oil (HVO) manufacturing unit at the site in Gothenburg, Sweden, with the goal of producing renewable diesel
Preem Gothenburg Refinery	Preem	Sweden	Advanced biofuels	2023	2.4 million tonnes per year	The production capacity for renewable diesel at Sweden's Gothenburg refinery has increased 40% following a redevelopment of the green hydrotreater plant (GHT). The GHT can produce 100% renewable products by processing renewables raw materials such as raw tall oil diesel, residues from the food industry and recycled frying oil.

Project	Company	Location	Category	Operational date	Production	Description of the project
(No project name)	Repsol	Spain	Advanced biofuels	2023	250,000 tonnes	From this facility, the company will supply advanced biofuels for aircraft, trucks, and cars. The new plant will include the commissioning of a hydrogen plant that will fuel a new hydrotreatment unit equipped with cutting-edge technology.
Sisak bio-refinery	MOL	Croatia	Advanced biofuels	2024	55,000 tonnes per year	The plan is for the biorefinery to produce second-generation (2G) bioethanol, and will use locally grown miscanthus and lignocellulosic biomass, such as cereals and oilseeds, for the raw material.
Litvínov Refinery	PKN ORLEN, Unipetrol, Benzina, UniCRE	Czech Republic	Advanced biofuels	2024	80,000 tonnes per year	Pretreatment and co-processing of used cooking oil and animal fats at existing high-pressure GOHT.
Grandpuits refinery transformation	TotalEnergies	France	Advanced biofuels	2024	400,000 tonnes per year	TotalEnergies will construct a renewable diesel unit, primarily producing for the aviation industry.
Shell Energy and Chemicals Park Rotterdam	Shell	Netherlands	Advanced biofuels	2024	820,000 tonnes per year	Once built, the facility will be among the biggest in Europe to produce sustainable aviation fuel (SAF) and renewable diesel made from waste.
Co-Processing of sustainable biogenic feedstock	OMV Petrom	Romania	Advanced biofuels	2025	200,000 tonnes per year	Via co-processing biogenic feedstock can be processed together with fossil-based raw materials. It is planned to modify existing refinery hydrotreating unit for continuous, full-year introduction of renewable feedstock as co-feed enabling production of high-quality diesel fuel with renewable share and reduced greenhouse gas footprint.
E-fuels						
Blue Crude	Sunfire	Norway	E-fuels	2020	(No information available)	The first commercial plant is producing 8,000 tonnes of the synthetic crude oil substitute e-Crude annually on the basis of 20MW of input power.
P2X Europe	H&R Group and Mabanaft	Germany	E-fuels	2017	(No information available)	The 5MW dynamic electrolysis unit (operational since 2017) will be complemented with a PtL plant, following the founding of the joint venture P2X Europe.

Project	Company	Location	Category	Operational date	Production	Description of the project
Litvínov Refinery	PKN ORLEN, Unipetrol, Benzina, UniCRE	Czech Republic	E-fuels	2022	(No information available)	The aim of the project is to construct photovoltaic power plant with capacity up to 51,9 MWp in neighbourhood of existing refinery. Produced renewable electricity will serve mainly to produce green hydrogen at new electrolyser with capacity 20 MW. The green hydrogen to be utilised for production of mainly automotive and aviation fuels with lower carbon footprint produced in Unipetrol refinery and also to sustain first HRS (7) to be constructed between 2021 – 2024.
Repsol Green Hydrogen	Repsol/Aramco	Spain	E-fuels	2024	(No information available)	The project involves building one of the world's largest plants to manufacture net zero emissions fuels, using CO_2 and green hydrogen generated with renewable energy and building a plant for generation of gas from urban waste which will replace part of the traditional fuels used in Petronor's production process.
Green Hydrogen Raffinerie Heide	Raffinerie Heide	Germany	E-fuels	2024	(No information available)	The refinery wants to turn excess wind power into green hydrogen to replace natural gas and produce synthetic fuels for aviation. The 30 MW green hydrogen project is developed by Raffinerie Heide and a number of partners.

Note: General information provided by Fuels Europe indicates that there are currently, as extracted in June 2022, 29 projects. However, Ricardo has only been able to identify 28 in the map developed by them.

Source: (Fuels Europe, 2022) - *(https://www.cleanfuelsforall.eu/towards-climate-neutrality/)*

Appendix D: Renewable energy sources in refineries

Context

The oil and gas industry operations account for, directly and indirectly, 42% of global GHG emissions and its produced fuels account for another 33% of global emissions (McKinsey&Company, 2020). The Paris Agreement aims to limit global warming below 2ºC and pledges to pursue efforts to limit the increase to 1.5ºC. Therefore, in order to achieve these climate change mitigation targets, the oil and gas sector will need to reduce its emissions by at least 3.4 gigatonnes of CO_{2e} per year by 2050 (including downstream and upstream operations), as per information provided by the same report. This is in comparison to a “business as usual” scenario, defined by the currently planned policies and/or technologies, and corresponds to a 90% decrease in current emissions (McKinsey&Company, 2020).

Several major oil and gas firms have already set their objectives (DNV, 2020) on carbon-neutral production by 2050 or sooner[26], as detailed in section 5 of this document. In order to meet these targets, operators and industry associations in many countries have set medium and long-term targets for decreasing emissions from fuel production. The number and type of both internal and external measures envisaged by each company to reduce emissions are wide with a highly site-specific potential and economics, and will be determined by a variety of factors, including the business strategic plan, the location of their production facilities, their asset mix and the applicable local policies and practices (regulations, carbon pricing, the availability of renewable energy and the central grid’s reliability and closeness). In addition, the extent to which energy-saving technologies are implemented is also determined by the financial return that investors are ready to accept.

A wide range of approaches and technologies are required to achieve emission reduction efforts for minimising their CO_2 intensity. These may include energy efficiency improvement measures (both in utilities and generation), the introduction of renewable energy sources lowering the carbon footprint of their energy sources, capture of CO_2 they emit for long-term storage or reuse, as well as the inclusion of renewable fuels in the portfolio of oil and gas industries (see section 4 and Appendix C). The first area is very much under the control of the refiners and builds on the historical on-going efforts by the refining industry to improve energy efficiency, predominantly driven by the cost of energy and, more recently of CO_2 emissions. It encompasses a wide range of options, each of which play out differently in each refinery. A more detailed description of the measures targeting power generation and heat production is provided in Appendix B of this document. However, the remaining emission savings must be achieved through the development and use of renewable energy sources.

The Renewable Energy Directive 2018/2001 (RED II) requires RFNBOs not only to meet minimum GHG emissions savings but also defines ‘additionality’ with respect to the use of renewable electricity in producing these fuels, meaning that the *increase in demand for electricity in the transport sector beyond the current baseline is met with additional renewable energy generation capacity*. Therefore, new additional renewable capacity needs to be installed to meet this requirement. The impact on land use requirements to generate sufficient renewable electricity for an average size refinery in Europe, assuming a 50-60 MW power need, is very large and it is unlikely that most existing refineries in Europe would have availability as required. Therefore, the installation of renewable energy on-site is expected to remain marginal, with most refineries securing access to renewable energy sources though other alternatives, such as Power Purchase Agreements.

This section aims to describe the possibilities for installing in, and/or crediting renewable energy sources for, European refineries. It is set out as follows:

- Section D.1 assesses the possibilities to install renewable energy sources on site in refineries
- Section D.2 provides an analysis on the impacts in terms of land use for different renewable energy investment options.

[26] Each of the six largest oil and gas companies in Europe — BP, Eni, Equinor, Repsol, Shell and Total — has now made a public commitment to work towards the target of net-zero or near net-zero carbon emissions by 2050.

D.1 Possibilities to install renewable energy sources on site for producing renewable fuels

What are the possibilities to install renewable energy sources on site or co-location?

There are different alternatives for producing and/or crediting renewable energy sources for the oil and gas industry. These options include direct co-location with renewable energy assets, consuming electricity from the grid using a PPA with a dedicated renewable generation asset, consuming electricity from the grid in hours of low grid carbon intensity or trading renewable energy certificates.

Among these alternatives, several European industrial facilities, including refineries, are opting for onsite or adjacent renewable energy generation. When this is not possible or sufficient, PPA appears to be the preferred choice for acquiring low/zero carbon electricity, although costs continue to rise due to high demand for this option from industrial businesses and other economic activities. In general, space constraints at refineries may push operators away from dedicated generation on site.

The possibilities for refineries to make use of renewable electricity include:

- Direct co-location of renewable energy sources on site
- Consuming electricity from the grid using a Power Purchase Agreement (PPA) with a dedicated renewable generation asset
- Trading renewable energy certificates
- Consuming electricity from the grid during periods of low grid carbon intensity

Direct co-location of renewable energy sources on site

Co-location of renewable resources present an opportunity for developers and investors to increase the efficiency of existing infrastructure or production facilities. Direct co-location with renewable generation assets, e.g. wind plus storage, solar plus storage (and EV charging infrastructure) is an option that has been selected by several European refineries.

The main advantages include lower building costs and shorter development timelines, which could benefit stakeholders while also expediting the transition to a renewable energy-powered production.

However, co-location presents some challenges as well. These are mainly related to the following:

- Space: Lack of available space (surface area) available surrounding these sites.
- Variable and limited solar irradiation: Some European countries have low solar irradiation averages for many months of the year, leading to lower electricity yields for similar investments.
- Intermittency: There are periods of lower power production, such as night-time for solar power or during weather-conditioned periods for wind power generation.

The investment made by the TotalEnergies refining group to provide green electricity to all of its industrial facilities in Europe is an example of the approach of co-location. TotalEnergies is investing over €500 million to transform its Grandpuits refinery into a zero-crude platform for biofuels and bioplastics by 2024. The platform is intended to be focused on four new industrial activities: the production of renewable diesel primarily intended for the aviation industry, the production of bioplastics, the recycling of plastics and the operation of two photovoltaic solar power plants (one with capacity of 28MW at Grandpuits, and another with capacity of 24MW at Gargenville) (Total Energies, 2020).

Consuming electricity from the grid using a Power Purchase Agreement (PPA) with a dedicated renewable generation asset

Power Purchase Agreements (PPA) are long-term contracts under which a business agrees to purchase electricity directly from an energy generator. These are typically signed to guarantee corporate consumers a set electricity price and to hedge against market risks, as well as – for renewables – to specify how the renewable energy will meet the energy demand profile of the production plant. The European Commission encourages Member States to facilitate wider access to PPAs beyond large businesses, including SMEs, particularly through the aggregation of end-user demand, in accordance with competition rules.

PPA demand is rapidly increasing, even faster than supply, with 2021 agreements surpassing the 3.5 GW signed in 2020. According to forecasts, European Commercial and Industrial on-site installations could reach a total capacity of 407 GW by 2030 (Wind Europe, 2021).

In this sense, a confluence of factors, including rapidly increasing electricity prices, the easing of COVID-19 pandemic lockdown restrictions and rising carbon prices have led to an increased demand for the construction of additional renewable energy generation capacity (Renewables Now, 2021). As a result, Europe's P25 Index – an aggregation of the lowest 25% of wind and solar PPA offers – raised to approximately €57/MWh in 2021. The increase was primary driven by wind energy, with P25 prices rising 10%, owing in part to significant increases in wind PPA pricing in Germany and the United Kingdom (13% and 16% respectively). In both countries, increasing Capex costs and supply chain constraints have intensified the pressure being created by the European energy crisis.

However, PPA prices have increased 8.6% in the first quarter of 2022 (LevelTen Energy, 2022). This is primarily due to high natural gas prices, which are being fuelled by the war in Ukraine, intensifying the EU's current energy crisis and driving up demand for PPAs, which can be used to secure renewable energy supply while locking in electricity prices.

Trading renewable energy certificates

Renewable energy certificates, also known as green certificates for electricity, officially certify that a certain amount of green electricity was generated. Green certificates represent the environmental value of renewable energy production. These certificates can be traded separately from the energy produced and for accounting purposes the energy used can be treated as being renewable when the certificate is retired.

RED II promotes a substantial increase in the proportion of electricity generated from renewable energy sources across the EU. This can be achieved through different instruments, including through support schemes and/or guarantees of origin certificates. Therefore, it is important to distinguish between green certificates used for support schemes and guarantees of origin:

- Green certificates: 'renewable energy obligation' is a '*support scheme requiring energy producers to include a given share of energy from renewable sources in their production, requiring energy suppliers to include a given share of energy from renewable sources in their supply, or requiring energy consumers to include a given share of energy from renewable sources in their consumption, including schemes under which such requirements may be fulfilled by using green certificates'* (Article 2(6) of RED II).
- Guarantees of origin are issued to show to '*a final customer that a given share or quantity of energy was produced from renewable sources. A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another*' (recital 55 of RED II). Any Guarantees of Origin generated in the context of a PPA should be bundled and cancelled. This will avoid the risk of double counting whereby renewable energy used in RFNBO production would also be counted towards achieving targets for renewables in other sectors.

Regarding support schemes, there is a large set of public funds at European and national levels applicable to decarbonisation efforts. For example, the Innovation Fund (European Commission, 2021) is one the world's largest funding programmes for the demonstration of innovative low-carbon technologies. The EU is investing over €1.1billion into several large-scale projects under this fund. The grants are intended to support breakthrough technologies in different sectors, including energy-intensive industries, hydrogen, carbon capture, use and storage and renewable energy.

Consuming electricity from the grid during periods of low grid carbon intensity

Electricity grid carbon intensity fluctuates as a result of supply and demand. On the supply side, renewable energy will be at its highest throughout the day for solar and will fluctuate for wind renewable energy based on the weather. Forecasts of grid carbon intensity are available, but there is no indication that this option has been selected by European refineries.

However, in the case of green hydrogen supply, there are other practical issues that need to be considered when analysing possibilities for producing RFNBOs. These challenges mainly relate to connecting renewable energy projects to the grid, such as interconnection limits, permitting constraints, and power grid congestion.

Hydrogen generated during periods of oversupply can be used to provide distributed power during periods of undersupply in systems with a high proportion of wind and solar power (European Hydrogen Backbone, 2021). Therefore, connecting electrolysers directly to renewable energy projects via 'dedicated' green hydrogen plants provides advantages that allow these projects to be implemented in situations where traditional grid-connected projects may not be possible or economically viable, or to provide buffers for oversupply, such as in the following situations:

- Additional capacities for wind and solar can be installed in areas where the potential for green hydrogen production is large, and electricity demand is already being covered by wind and solar.
- Hydrogen can provide long term energy storage to balance the electricity grid, as it can be cost-effectively stored for long periods. This storage capacity can improve the economics of renewable projects in areas where grid connection costs would otherwise make projects economically unattractive.
- Hydrogen can be transported cost-efficiently over long distances, especially when large scale existing pipeline infrastructure are repurposed. Therefore, with a high penetration of intermittent renewables, green hydrogen can ease pressure on an electricity grid.

This green hydrogen could be produced domestically and minimise the competition of certain feedstock with food supplies, or it could be imported from European neighbouring regions with renewable resource abundance as discussed in section 4.4.

D.2 Impacts in terms of land use for different renewable energy investment options

What are the impacts in terms of land use?

The land use requirements to generate sufficient renewable electricity for an average size refinery in Europe, assuming a 50 MW power need, are very large. These may range from ~2.5 km^2 for solar (PV) power generation, to 18 km^2 for wind power generation, and most existing refinery installations in Europe would not have available and affordable land for those requirements in the surroundings (unless perhaps offshore for wind). Whilst biomass combustion technologies on site have similar space footprints to existing natural gas fired equipment, there are potentially vast additional land footprints associated with the feedstocks. As a result, it is expected that the installation of renewable energy on-site will remain marginal, with most refineries securing access to renewable energy sources though other alternatives, such as those described in section D.1.

The electricity demand in refineries typically requires several tens of megawatts of electricity supply, typically supplied from integrated natural gas combined cycle gas turbine CHP plants, individual steam turbines, expanders or power recovery turbines. As detailed in previous sections of this report, consumption will grow owing to decarbonisation trends, including the requirements to meet the additionality criteria of RFNBOs. Specifically, between 9% and 30% of the energy consumed by refinery operations could be supplied from the grid in the future (Concawe, 2019).

The renewable electricity investment options for the oil and gas sector as alternatives to the conventional natural gas fired power generation are mainly wind and solar power, as well as biomass-to-power, for developing and operating renewable production facilities nearby at some sites.[27] However, these options have higher total land use requirements than current power generation in refineries. However, installations of renewable electricity on-site are predicted to remain marginal and refinery-based low-carbon power generation is likely to be limited to niche areas, with most refineries gaining access to low-carbon power via distribution grids to which the refinery is connected (Concawe, 2019).

Table D-1 overviews the sources of electricity generation, their levelised costs, land area requirements and a short description of key challenges.

Wind installations in Europe are projected to have a levelised cost of electricity of $55-90/MWh (onshore-offshore respectively) in 2025, though this is assuming low carbon prices. However, intermittency is a relevant drawback, so a refinery would also need a back-up supply for wind-free days. Hence Table D-1 provides indicative area requirements both for 50MW and for 100MW capacities. The latter may be required to address the intermittency / average capacity factors. A wind farm of that capacity would take up approaching 20km^2, hence most EU refineries would not have enough area for such a project, unless for example, a coastal location suitable for offshore windfarms was identified. Nevertheless, there are a few exceptions inside and outside Europe.

[27] Other options, such as hydroelectric, nuclear and tidal are constrained by location, and are generally large and have limited synergy with refining assets.

Table D-1 Overview of investment options to decarbonise the electricity supply of refineries

Alternative electricity source	Levelised electricity costs ($/MWh) in Europe in 2025, assuming carbon price of $30/t$CO_2$	Area requirements (km^2)		Challenges
		For ~50MW	For ~100MW	
Natural gas combined cycle (business as usual)	*71*	*~0.1-0.2*		*GHG emissions*
Wind	55 (onshore) 90 (offshore)	9	18	Alternative sources (PPAs) and/or batteries required to cover low wind periods
Solar-PV	70	1.2	2.5	Alternative sources (PPAs) and/or batteries required to cover nights and low irradiation periods. Area depends on latitude.
Biomass-to-power	60-300	~0.1-0.2		Complex biomass supply chain. Might not be sufficient availability at reasonable cost in every European region. Area excludes feedstock production.

Source: Levelised electricity costs from IEA (2020) *for all except biomass-to-power which is from Concawe* (2019)*. Area requirements for renewable sources computed from unit area requirements given in* (NREL, undated).

There have been a handful of refinery-based wind energy projects, but typically at smaller capacities than those considered indicative in Table D-1:

- The Valero McKee refinery in Texas has 33 turbines with a net capacity of ~35 MW; the wind farm is ~5 times the area of the refinery.
- Orsted and BP are to jointly develop a 50 MW renewable hydrogen project at BP's Lingen refinery. The project, expected to be operational in 2024, would comprise a 50 MW electrolyser capable of generating 9,000 kt/year of hydrogen, 20% of the refinery's current fossil-based hydrogen consumption. The electrolyser is expected to be powered by an Orsted North Sea offshore wind farm.

Solar-PV also provides scalable renewable power generation. Large scale solar-PV has a projected levelised cost of electricity of ~$70/MWh in Europe in 2025. This option also has space and intermittency issues. An average refinery would need a dedicated solar farm occupying ~2.5 km^2 to cover its electricity imports and would still need a corresponding back-up supply for use at night (NREL, 2013). For example, the Sabic petrochemical polycarbonate production site in Cartagena in Spain is developing a 100MW solar PV plant with 263,000 solar panels to achieve 100% self-generated power. The investment is worth €70 million.

Regarding **biomass-to-power**, the main technologies are anaerobic digestion and biomass combustion. Although anaerobic digestion is a mature technology, there may still be significant potential for growth in feedstock supply, potentially tripling by 2030. However, due to the low energy density of the feedstock, logistics may limit both the location and scale of the facility. The main anaerobic digestion product is biogas (CH_4 and CO_2), which is typically combusted to generate power. The levelised cost of electricity is typically $60-300/MWh. There is limited synergy between anaerobic digestion with generation and refining, but there might be an alternative approach where biogas is routed into a refinery's fuel-gas system without the need for power generation or for purifying the biogas to pipeline quality.

Biomass combustion is also a mature technology with numerous technology options ranging from grate- to fluidised bed combustion to gasifiers. The main challenge is establishing a supply chain for affordable and sustainable biomass in order to support large-scale capacities, and the competition of certain feedstocks with food supplies.

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