Report

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Refinery 2050: Conceptual Assessment.

Exploring opportunities and challenges for the EU refining industry to transition towards a low-CO_2 intensive economy

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ABSTRACT

This report is the second in a series of publications that explore opportunities and challenges for EU refineries to integrate technologies and feedstocks that would reduce the fossil carbon intensity of petroleum products.

The first Concawe report (*Low Carbon Pathways: CO_2 reduction technologies in the EU refining system. 2030/2050)* explored opportunities to invest in new technologies to reduce the CO_2 emissions from refineries in the short and then medium term. *The current report* goes beyond this approach by exploring the potential to substitute crude oil with bio-feedstocks and the use of renewable electricity. Sustainable vegetable oils, lignocellulosic biomass and e-fuels have been selected as initial examples of key low carbon feedstocks in this conceptual assessment.

As the starting point, this reports defines two potential **2050 demand scenarios** followed by the description of the conversion pathways required for the integration of the selected low-carbon feedstocks within a *notional* mid-range European refinery.

Then, the results of the modelling exercise are presented, moving from mostly **oil based cases**, where the EU refineries meet the 2050 demand in the most plausible CO_2 efficient manner consistent with the first report mentioned above, to the progressive integration of low-carbon feedstocks illustrated by two series of cases:

- ***Limited penetration cases*** (individual pathways): where the implications of the production of 1 Mt/a liquid products from each of the selected low carbon feedstocks are described.
- ***Maximum low carbon feedstock* cases** (Combined pathways): Based on the different nature of the feeds explored, this report moves further in the analysis by looking at the combination of different low carbon feedstocks. This second series of cases illustrate a hypothetical situation where these alternative feedstock would provide the bulk of the total intake to the refineries. These cases highlight the need for multiple pathways in order to meet the demand effectively without impacting on the European import/export balance.

In all the cases modelled, the implications in terms of feedstock supply, key processing requirements such as hydrogen and electricity and the impact such changes have on the CO_2 emissions intensity both at refinery level and for the end products in Europe are initially assessed and quantified. Potential impacts and synergies with the existing assets, as crude oil is progressively replaced, are also investigated.

With this report, Concawe aim to provide a better understanding of the implications and framework conditions that would be required, showing how the challenges for such a transformation go beyond the battery limits of the refining system. A joint effort integrating multiple actors would be essential to achieve an effective and sustainable transition.

Finally, this conceptual assessment is not intended to be a roadmap for the whole refining industry. The low-carbon feedstocks explored are selected examples. Multiple additional pathways/feedstocks could be also integrated within the EU refining system subject to the location of the sites and individual company strategies.

KEYWORDS

Refinery, refining, pathways, Vision 2050, low carbon fuels, CO_2, vegetable oil, waste, e-fuels, biofuels, climate change.

INTERNET

This report is available as an Adobe pdf file on the Concawe website (www.concawe.eu).

Note. The appendixes of this *Refinery 2050* report (Concawe 9/19A) can be found with the following link:

report no. 9/19A

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Appendixes

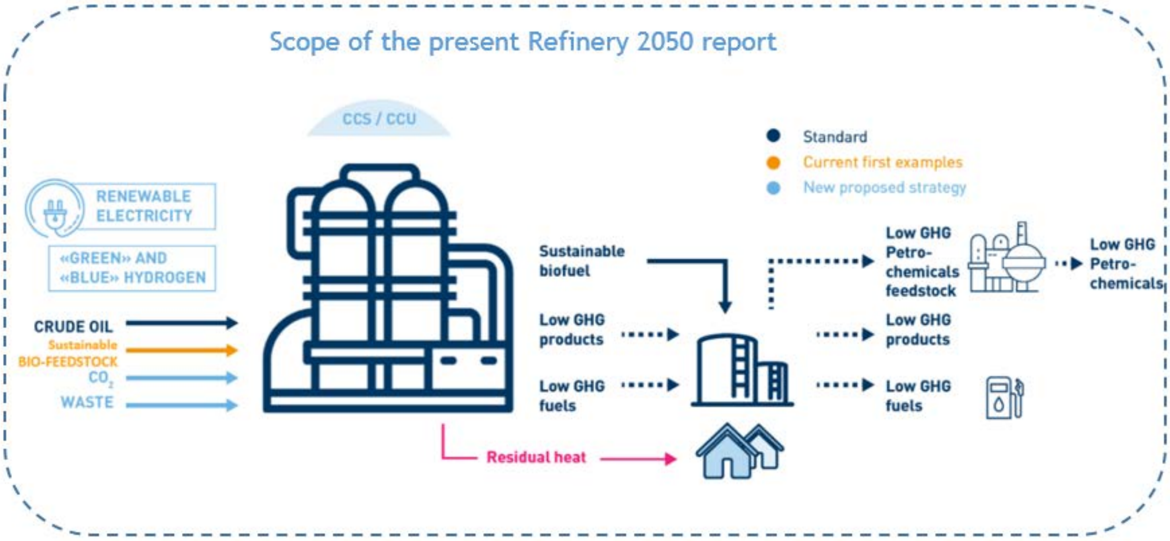
(Separate Concawe report *9/19A*)

1. SUMMARY

1.1. REFINERY 2050: OBJECTIVE AND SCOPE.

The present report is part of a series of publications under the Concawe Low Fossil Carbon Pathways programme aiming at exploring the potential of different technologies to effectively contribute to the EU decarbonisation goals. It focusses on the **transition of the refining industry within a low-CO_2 intensive economy** and explores the technical implications to effectively deploy FuelsEurope's **Vision 2050** [FE 2018] concept for the refining industry across Europe.

Figure 1.1-1 Vision 2050 of the refining system as an energy hub within an industrial cluster



This assessment also integrates the results of a previous Concawe report *CO_2 reduction technologies. Opportunities within the EU refining system (2030-2050) [Concawe 2019]* (Step 1). The earlier report explored the potential of different technologies and operational measures to achieve CO_2 emissions intensity reduction within the refinery site, looking at the 2030 and 2050 horizons; Energy efficiency, use of low fossil carbon energy sources (including electrification and green hydrogen) and CO_2 capture (and storage).

Building on this step 1, the current analysis expands the scope described above by taking into account two demand scenarios for 2050 and exploring the **potential introduction and processing of low fossil carbon feedstocks**[1] **in European refineries** (Step 2) with the objective of producing lower fossil carbon fuels. Through selected examples of key low fossil carbon technologies, it investigates the potential synergies with the existing assets as crude oil is progressively replaced and the implications in terms of feedstock supply, key processing requirements such as hydrogen and electricity and CO_2 emissions intensity both at refinery level and for the end products.

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[1] The term *Low (fossil) carbon* feedstocks refers to feedstocks which produce hydrocarbon fuels /chemicals that are chemically similar to current fuels, but which originate from renewable or non-fossil sources and, therefore, with lower CO_2 intensity factors.

The present conceptual assessment:

- seeks to explore the **suitability of existing refineries for processing low fossil carbon feeds**, the extent of adaptation that would be needed, and the scale **of supply of low fossil carbon feedstocks** that would be required to achieve material substitution of existing fossil fuels,
- includes a preliminary estimate of the associated CAPEX which is not a detailed economic assessment,
- does not aim to provide a comprehensive assessment of all such options nor is it intended to rank or recommend specific pathways,
- is not intended to be a roadmap. For reasons of simplicity, the low fossil carbon feedstocks explored are selected examples and multiple other additional feedstocks and conversion pathways could also be considered. Factors such as the location of the sites, accessibility to resources, the current refining scheme or other opportunities and/or constrains will determine the potential adoption of different alternatives in each of the EU individual refineries.

1.2. LOW FOSSIL CARBON FEEDSTOCK PATHWAYS EXPLORED IN THIS REPORT

This study investigates the potential for substantial replacement of crude oil by three main categories of selected low fossil carbon feedstocks (lipids, lignocellulosic biomass and e-fuels). **Four main processing pathways** were studied:

- Lipids hydrotreatment,
- Gasification of lignocellulosic biomass, such as wood, followed by Fischer-Tropsch synthesis and hydrocracking,
- Hydrotreatment-hydrocracking of pyrolysis- or hydrothermal liquefaction oils made from lignocellulosic/woody biomass,
- E-fuels production from captured CO_2 and electrolytic hydrogen made into syngas by “reverse water gas shift” and then into hydrocarbons by Fischer-Tropsch synthesis with subsequent hydrocracking to produce suitable boiling range fuels.

There are related pathways which could use different refinery process technology (e.g. fluid catalytic cracking as opposed to hydrocracking) or different feedstock preparation (e.g. hydrothermal liquefaction of woody biomass instead of fast pyrolysis). These have not been included in the detailed modelling, but might ultimately prove to be of interest, for example if they offer local advantages for logistics or product slate (e.g. balance between jet and diesel, or production of chemical feedstocks such as olefins and aromatics).

Pathway scalability has been considered at two-levels:

- What might be achieved at an individual production facility?

  For “stand-alone” operations, facility scale is often a compromise between economy of scale and size limits set by process technology and logistics. For “refinery-based” operations, there may be additional constraints linked to the capacity of existing equipment.

- What might be achieved at EU industry level (Refining system)?

  Firstly, this depends on the number of facilities which could be built and operated when potential locations may be subject to technical, commercial and regulatory barriers. Secondly, it depends on the availability of raw materials to feed those facilities – both in terms of local production and potential for imports.

Table 1.2-1 Summary of selected pathways explored in the report

	Lipid route	**Lignocellulosic biomass (Gasification & FT route)**	**Lignocellulosic biomass (Pyrolysis route)**	**e-fuels**
Illustrative pathway	Commercial lipid hydrotreatment has recently become well-established with a few stand-alone operations of up to 1 million tonnes/a.	Biomass-to-Liquids (BTL). Gasification of woody biomass, followed by Fischer-Tropsch (FT) synthesis and hydrocracking	*Fast-pyrolysis* or *hydro-thermal liquefaction of lignocellulosic biomass or* wastes, followed by hydrotreating to remove oxygen	e-fuel from FT synthesis/hydrocracking of syngas derived from CO_2 capture and + electrolytic H_2 using renewable electricity
Product	Primarily paraffinic diesel and jet	Primarily paraffinic diesel & jet, possibly with co-products such as chemical naphtha or wax	Mix of bio gasoline and bio-diesel (relatively aromatic).	Primarily paraffinic diesel & jet, possibly with co-products such as chemical naphtha or wax
Feedstock	Typical feeds today: vegetables oil animal fats or cooking oil; future expansion likely to rely on microbioal/algal oils	Lignocellulosic biomass including wood and residues from forestry, waste-wood from industry, agricultural residues (straw and stover) an energy-crops. Potentially, municipal waste as well.		Captured CO_2 & renewable electricity
Synergy with refining assets	**Very high** Lipid co-processing with fossil gas-oil (5% up to 30% in suitable units with technology stretch). Potential for hydroprocessing refinery units to be adapted as dedicated lipids hydrotreater units (100%). Simplification by integration with refinery utilities especially H_2 and LPG handling (Significant capital saving)	**Moderate** New gasification/FT system, Raw FT product is converted to fuel by co-processing in refinery hydrocracker or by transformation of refinery unit to 100% bio-feed. Integration with refinery utilities especially power and LPG handling	**Significant** Pyrolysis oil made "in-field" simplifies biomass logistics. Pyrolysis oil is deoxygenated /upgraded to fuels by co-processing in refinery unit. Raw oil may need treatment in new stabilizer. Potential for unit transformation to 100% bio-feed. Integration with utilities especially H_2 (from co-processing to dedicated units).	**Moderate** New electrolysers and FT system. Raw FT product is converted to fuel by co-processing in refinery hydrocracker or by transformation of refinery unit to 100% bio-feed. Refinery can use its own CO_2 emissions as feed for integrated e-fuel plants.

Table 1.2-1 Summary of selected pathways explored in the report (Cont.)

	Lipid route	**Lignocellulosic biomass (Gasification & FT route)**	**Lignocellulosic biomass (Pyrolysis route)**	**e-fuels**
Technology & supply-chain readiness	Existing conversion technology and conventional supply-chain. Future expansion requires development of new algae technology + establishment of a significant new agricultural industry	Conversion technologies have been commercialised separately in other sectors (power, natural gas) but have not been demonstrated at scale as an integrated process. A few forestry supply chains exist at >1 Mt/a scale, but significant replication would be needed	Pyrolysis technologies have been demonstrated in a few small commercial operations, mainly in heat/power sector. Upgrading to transport fuel is still at developmental scale; refinery trials have been inconclusive. A few forestry/waste supply chains have been established (power sector), but would need significant replication.	Conversion technologies have been commercialised separately in other sectors (power, natural gas) but at very different scales. Integrated process still at pilot-scale. Potential for CO_2 utilisation at sites without CO_2 storage options or logistics.
External requirements	**High** (Sustainable feedstock availability).	**Very high** (Low-carbon electricity)		

Note: it was considered that feedstocks of biomass origin (wood, lipids, etc) have a residual fossil carbon content accrued during production, processing and transport (see **Section 6.2.9** for details).

1.3. MODELLING

The modelling exercise is based on a Concawe-based refinery simulation tool **(RafXL)**. This was used to explore fossil fuel cases (**Section 7**) as well as some examples of the deployment of these low fossil carbon feedstocks (**Section 8**) in a *notional mid-range* refinery (160,000 bbl/d of crude oil intake assumed as the starting point throughput – current demand - and process unit capacities of other process units consistent with the European average refinery configuration. This is a hypothetical refinery used for illustration and is not intended to represent a "typical" refinery).

The low fossil carbon feedstock pathways are characterized in terms of mass balance (product yields), utilities requirements and basic product properties. Implementation of these pathways is explored through two separate cases: **limited case** (assessing the implications of the production of 1 Mt/a liquid products - **Section 8.1**) and **maximum case** (where the maximum uptake of low fossil carbon feedstocks is determined by the demand scenarios - **Section 8.2**).

The implications of the explored pathways for a notional refinery can be summarized as follows:

1. **Fossil based cases (Section 7):**
   - Reduction of demand for hydrocarbon fuels at the 2030 and 2050 horizons will lead to extensive adaptation of the EU refining industry. While some existing processing capacity will be underutilised, extra capacity will be required for crucial processes in particular hydrocracking and hydrogen production. This coupled with industry restructuring and replacement of ageing plants is likely to result in a significant call for new investment in crucial process units.

- After improving internal energy efficiency, substitution of gas by imported low- carbon electricity and CO_2 capture are the two main routes towards lower total refinery emissions. Reductions of up to 75% may be achievable by 2050 vs the 2030 reference case, provided ample supplies of affordable low-carbon electricity materialise and the right conditions exist for successful implementation of CO_2 capture at scale. Large scale electrification of refinery energy, either directly or via electrolytic hydrogen, could lead to very large electricity demand.

2. **Limited low fossil carbon feedstock cases (Section 8.1)**
    - In a first series of cases, after decreasing the throughput of the notional refinery to meet the 2050 demand scenario, the remaining crude oil intake was reduced by just under a quarter. The shortfall (about 1 Mt/a) being provided by one of the alternative feedstocks under consideration.
    - In these "limited penetration" cases, existing installations would generally be able to accommodate the new feedstocks by adaptation of process plants and other facilities. Additional investment would still be needed for front end processing of raw feedstock, supplement insufficient capacities of crucial processes (mostly hydrocracking and hydrogen production) and adapt infrastructure for electricity import.
    - Fossil emissions from the refinery site would not be substantially reduced unless the bio-feedstocks and imported electricity achieved an almost totally fossil-carbon-free footprint.
    - Production of e-fuels at this scale would require massive amount of imported electricity with attendant infrastructure.
    - The "Well-to-Tank" fossil CO_2 intensity of middle distillates could be reduced by about 25% vs the 2030 reference case.

3. **Maximum low fossil carbon feedstock cases (Section 8.2)**
    - A second series of cases illustrated a hypothetical extreme situation where alternative feedstocks provided the bulk of the intake, the residual crude oil intake being determined by the need to satisfy the demand for bitumen.
    - Even in these extreme cases, a reasonable balance could be maintained between products, with surpluses and deficits within historical limits, although blending products to the required commercial grade quality would likely be a challenge.
    - With the exception of hydrocrackers/hydrotreaters and hydrogen production units, most existing refinery process units would become heavily underutilised or even obsolete. Front end processing of alternative feedstocks would become the primary activity of the "refineries".
    - Fossil related CO_2 emissions from the refinery site would not be substantially reduced unless the bio-feedstocks and imported electricity achieved an almost totally fossil carbon-free footprint.
    - The massive amount of electricity required to produce e-fuels at this scale would have to be imported and would only be climate advantageous if the electricity supply was renewable.
    - The "Well-to-Tank" fossil CO_2 intensity of the main fuels could be reduced by about 75% vs the 2030 reference case.

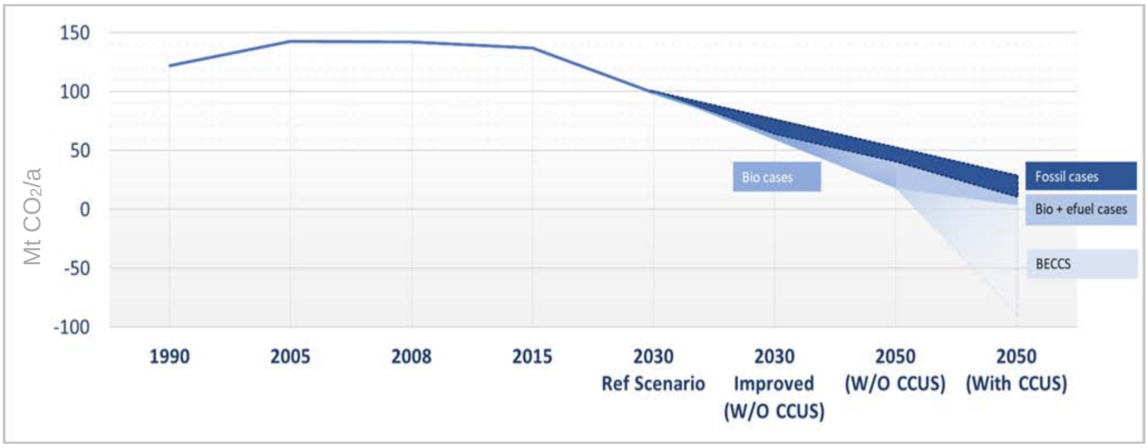
Although some elements of the alternative feedstock pathways are well-established, most are not commercially proven, at least the scale envisaged here. Capital cost data is therefore scarce and often of a preliminary nature. Within these limitations, the **estimated capital investment** for a notional 160 kbbl/d refinery could range between 1 and 10 G€ for the limited penetration cases and between 6 and 15 G€ for the extreme cases.

When the **EU-wide scale** is considered:

- The implications in terms of sustainable feedstock availability are magnified: the notional-refinery cases described above could imply supply of up to 8 Mt/a biomass or 5 Mt/a lipids to a single site. If applied to the whole industry up to 200 Mt/a of lipids or 300 Mt/a of wood would be required. This amount of feedstock is within the range of the maximum potential availability defined by EU COM when great efforts in R&D are pursued (see **Appendix 3, Chapter 2**).
- Large scale production of e-fuels would imply electrical consumption equivalent to a possibly up to a third of total EU consumption today. For this to be climate advantageous, it should be from renewable/low carbon emissions sources (solar, wind, hydropower & nuclear).
- A combination of reduced demand, electrification and CO_2 capture could reduce the EU-wide industry fossil CO_2 emissions from 120 Mt/a to about 30 Mt/a. Outside CO_2 capture, use of alternative feeds have the potential to further reduce CO_2 emissions within the refinery (e.g. As the refinery fuel gas contains some of the biogenic carbon). Fossil-based CO_2 emissions at refinery sites would still be sizeable unless those feeds had a fully renewable carbon footprint (**Section 6.2.9** for details).
- A combination of reduced demand, electrification and CO_2 capture at the refinery could reduce the EU-wide total emissions from main fuel products from about 1400 Mt/a to about 900 Mt/a in the fossil cases and down to 200 Mt/a with alternative feeds.
- The low fossil carbon feedstock cases multiply the external requirements in terms of electricity and hydrogen with respect to the fossil-based cases (~x4 in the lipids and biomass cases up to ~x10 in the cases when e-fuel production routes are also considered).
- Introducing alternative feedstocks in the refinery environment at the scale discussed above would require investment in brand new plants for the front-end processing of these feedstocks, extensive modifications and revamping of existing plants for further processing and treating of the raw products, and extensive adaptation of ancillary facilities such as import terminals, tankage etc. An attempt to estimate the CAPEX associated to the new processes has been included and shows capital investment up to 15 G€ for the extreme cases. However, it is important to note that the present report is a conceptual assessment and further implications in terms of the level of investment required across the whole refining system have not been assessed in detail.

The figure below shows potential evolution of the CO_2 emissions at EU refinery sites resulting from the combination of measures identified in the present report:

Figure 1.3-1 EU-wide CO_2 emissions at refinery sites (Direct fossil emissions, Mt CO_2/a)



It illustrates that, compared to the 1990 level, **the CO_2 emissions from EU refinery sites could be reduced by 50% to 90%.** When *Carbon Capture and Storage* solutions are combined with biomass feedstocks in BECCS schemes, net **negative emissions** could be achieved (compatible with the EU long-term strategy - *A Clean Planet for all*). This can occur when a sizeable proportion of the original biomass is burned during the process of producing biofuels and the (biogenic) CO_2 thus produced is captured and stored rather than being returned to the atmosphere. Overall, more CO_2 is withdrawn from the atmosphere (through the combination of biomass growth and CO_2 capture and storage (CCS)) than emitted from both the manufacturing process and the eventual combustion of the fuel.

2. INTRODUCTION

2.1. BACKGROUND: CONCAWE LOW CARBON PATHWAYS

In December 2015, COP21 in Paris made an important step to address the risks posed by climate change and to keep the global temperature increase to “well below 2°C” and drive efforts to limit it even further to 1.5 degrees. To achieve these goals, the EU is exploring different mid-century scenarios leading to an EU low-carbon economy by 2050.

To support the EU low emissions strategy, Concawe is exploring a cross-sectorial *Low Carbon Pathways* (LCP) programme, identifying opportunities and challenges for different low-carbon technologies and feedstocks to achieve a significant reduction of the CO_2 emissions associated with both the manufacturing and use of refined products in Europe in the medium (2030) and longer-term (2050).

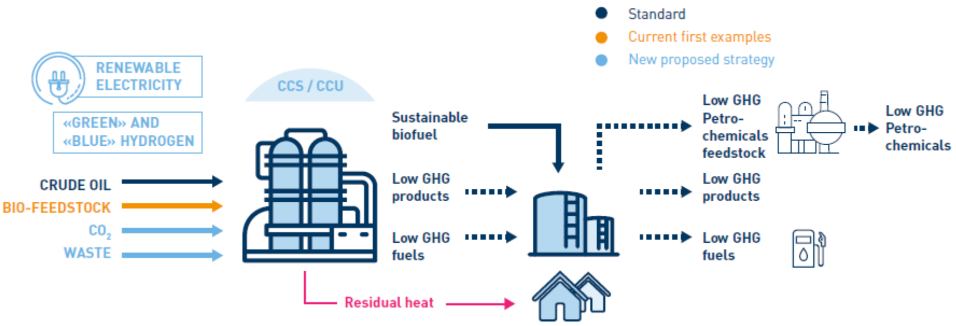
The initial Working plan exploring opportunities from the production phase (Well-To-Tank) to the final use (Tank-To-Wheel) was published in 2018 [Concawe LCP 2018] and since then, a series of reports has already been published and more will follow articulated around two main areas:

a) **Refining Technologies**: from maximizing CO_2 savings to the Refinery 2050 concept.

These Concawe refining-related series of reports focus on the transition of the European refining industry and products towards a low-CO_2 intensive economy and explores the technical implications of the deployment of the Vision 2050 [FE 2018] across the EU refining system contributing effectively to the EU decarbonisation goals.

Some of the technologies identified will be addressed in specific related studies including, among others, energy efficiency, use of low-carbon energy sources (electrification, green hydrogen), CO_2 capture and storage or usage (CCS/U) as well as the implications of the progressive replacement of crude oil by "low-carbon" feedstocks (e.g. advanced bio-feedstocks, e-fuels).

Figure 2.1-1 Vision 2050 of the refining system as an energy hub within an industrial cluster



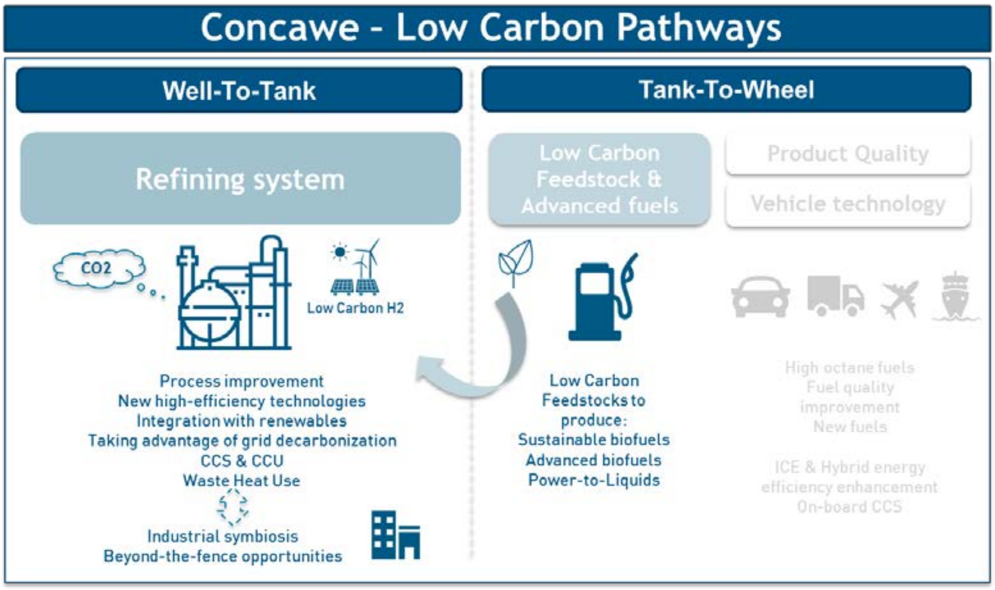
External factors such as the required availability of low-CO_2 electricity, hydrogen or low-carbon feedstocks together with the effective deployment of R&D programs are also investigated as key enablers to boost the effective deployment of the technologies identified.

b) Role of low carbon intensity fuels in the EU transport sector

Through specific deep dives on passenger cars, heavy duty, marine and aviation sectors, other joint research projects are being conducted to provide better scientific understanding on the role of low-carbon fuels across different transport sectors. The potential impact in terms of CO_2 savings (Well-To-Wheels and Life-Cycle Analysis), cost and additional external requirements and infrastructure will be included as part of our joint work which will be conducted through specific programmes with relevant and specialized partners and contractors.

The following figure summarizes the initial technology areas being explored as part of our Low Carbon Pathways programme and highlights the scope of the present report focused on exploring opportunities and challenges for the EU refining industry to transition towards a low-CO_2 intensive economy in 2050 considering the progressive replacement of crude oil as the main feedstock. The following section provides further insights regarding its purpose and scope.

Figure 2.1-2 Concawe – Low Carbon Pathways programme. Scope.



It is important to note that none of our Concawe LCP related works are intended to be a roadmap for the whole EU refining and transport industries. Different factors coupled with local and structural constraints will determine individual companies’ preferred route to contribute to EU goals to mitigate climate change.

2.2. REFINERY 2050: THE CONCEPT

Key messages

- This report explores opportunities and challenges for the EU refining system to progressively integrate different low-carbon feedstocks in a mid-century demand scenario. Through a conceptual modelling exercise, some initial figures have been calculated regarding the potential implications in terms of utilization and synergies with existing refinery assets as well as electricity, hydrogen and feedstock requirements. It also provides a first estimate of the capital cost that would be required.
- This conceptual assessment is not intended to be a roadmap for the EU refining industry but an initial analysis to better inform the technical discussions regarding the role of the sector in a low-CO_2 EU economy.

As part of the Concawe Low Carbon Pathways programme the present *Refinery 2050* report focusses on the transition of the refining industry towards a low-CO_2 intensive economy and explores the technical implications to effectively deploy the Vision 2050 [FE 2018] concept for the refining industry across Europe.

It integrates the results of the previous Concawe *CO_2 reduction technologies. Opportunities within the EU refining system (2030-2050)* report [Concawe 2019] (step 1) focused on the potential of different technologies and operational measures to achieve CO_2 emissions intensity reduction within the refinery site within the 2030 and 2050 horizons. Building on this step 1, this analysis expands the scope described above by exploring the potential introduction and **processing of low fossil carbon feedstocks in European refineries** (step 2) with the objective of producing lower fossil carbon fuels taking into account demand scenarios for 2050. Through selected examples of key low fossil carbon technologies, it investigates the potential synergies with the existing assets as crude oil is progressively replaced and the implications in terms of feedstock supply, key processing requirements such as hydrogen and electricity and CO_2 emissions intensity both at refinery level and for the end products.

It provides a preliminary estimate of the associated costs for the whole European industry.

Table 2.2-1 and **Figure 2.1-2** further illustrate this two-step approach and the complementary nature of the two refinery-related Concawe Low Fossil Carbon Pathways reports.

Table 2.2-1 Low Fossil Carbon pathways: two-step approach

Approach	**Step 1** ***CO_2 reduction technologies* report** **(Concawe 8/2019 report)**	**Step 2** ***Refinery 2050* report** **(*Beyond CO_2 efficiency*)**
Scope: **(CO_2 savings)**	Refinery battery limits (Scope 1 and 2 – Direct and indirect emissions)	Expand scope from refinery battery limits to the final use of products (Scope 1, 2 and a look into Scope 3).
Technologies	Technologies to CO_2 emissions across the EU refining system.	Technologies which reduce the CO_2 emissions of the refinery (identified in Step 1) **+ Low fossil carbon feedstock** (co-located or co-processed within the refinery).
Timeframe	What could be realistically achievable by 2030. A look into wide deployment towards 2050.	A look into the 2050 timeframe (potential progressive deployment from 2030 onwards)
Demand	Based on a 2030 demand scenario [WoodMac 2018].No change in the activity level of the sector / product yields from 2030 onwards.	Exploring different routes and 2050 demand scenarios impacting both the activity level of the sector and product yields.
Feedstock	Crude oil	Crude oil progressively replaced by low fossil carbon feedstocks (e.g. bio-feedstocks + e-fuel liquids).

3. DEMAND SCENARIOS 2050

Key messages

- Aligned with our Low Fossil Carbon Pathways' *Concawe report [Concawe 2019]*, Woodmac data provided to Concawe have been used to define the 2030 demand scenario (updated 2030 projects included in a previous Concawe 1/13R report [Concawe 2013]).
- In the 2050 timeframe, two different demand scenarios have been explored with changes in the distribution of refining products. These scenarios:
    - Have been initially inspired by the IEA scenarios (*WEO 2017*) and adapted to include Concawe's view on specific issues, including different levels of vehicle efficiency improvements and of electrification of passenger cars, heating oil and heavy fuel oil demand reductions.
    - Define the basis for the modelling exercise aiming to explore the resilience of the refining scheme to these changes as crude oil is progressively replaced by alternative low carbon feedstocks.
    - Provide the basis for the scale and range of both feedstock and external requirements (e.g. electricity) at EU level.
- The 2050 scenarios lead to a reduction in the refining throughput ranging from ~-20**%** (*Scenario 1*) to ~**-35%** (*Scenario 2*) versus the 2030 baseline. *Scenario 2* is used as the main reference in the study as an ambitious long-term scenario in terms of greenhouse gas (GHG) reduction.

3.1. KEY DRIVERS:

Over the next few decades demand for liquid fuels and other refinery products from today's EU refineries is expected to change significantly in volume and mix. The nature and rate of changes will be affected by many factors, including the actual EU CO_2 emissions reduction targets and the potential evolution of legislation in different transport and industrial sectors. At the 2050 horizon, the main drivers are likely to be:

- <u>Increasing demand for petrochemicals products:</u> As widely accepted by different analysts [IEA, Wood Mackenzie] the demand for petrochemical products is forecasted to increase significantly in Europe by 2050. However, further development of circular economy principles is expected to boost resource efficiency in downstream activities, reducing the demand for raw materials and petrochemical feedstocks in the 2040-2050 period. In this period, potential increase in import from lower (feed and energy) cost regions may also have a significant impact (not explicitly addressed in this report).

- <u>Electrification of transport</u>: Different studies portray long-term scenarios for Europe where mass penetration of renewable electricity-driven powertrains are considered as the main pathway to reduce CO_2 emissions in transport.
    - Whereas sectors such as aviation and marine will remain mostly reliant on liquid fuels (with an expected increase in demand in the period 2030-2050), electrification would have a major impact in other sectors such as light duty vehicles.

  - In the light duty passenger vehicle sector, the pressure of CO_2 emissions – related legislation (the current "Tank-To-Wheel" legislation sets a target to reduce the average CO_2 emissions in new sales) will encourage further fuel efficiency improvements in conventional powertrains and the progressive uptake of a range of electricity-driven powertrains. Electric powertrains range from full Battery Electric Vehicles (BEVs), Plug-in Hybrid Electric Vehicles (PHEVs) or self-charging Hybrids (HVs). The net effect of more fuel efficient conventional powertrains combined with the different levels of electrification will lead to a significant reduction of demand for liquid road fuels in light duty passenger vehicles by 2050 [Ricardo 2018].
  - In the heavy duty vehicle sector, despite the expected increase in activity, the demand for final fuels and the associated CO_2 emissions are expected to be reduced significantly by the mid-century. **Energy efficiency** improvements are likely to include the range of hybrid/ electric powertrains as well as *electrified road systems*. Additionally, other **energy carriers** such as renewable fuels or hydrogen in conventional engines or in Fuel Cell vehicles (FCHV) are being developed. Finally, potential changes in the **usage** itself including automated/driverless trucks or improved logistics systems leading to *cargo optimization* may also play a role.

- Desulphurisation of marine fuels: The confirmed implementation of the International Maritime Organization (IMO) 0.50 %m/m global sulphur limit as of 1 January 2020 will result in large changes in marine fuel markets. There are different options available to the shipping industry that could be implemented to comply with this sulphur regulation. These range from the installation of on-ship SO_2 scrubbers (gas cleaning systems which would allow the continued use of high sulphur fuel oil (HSFO)), the shift from residual to low sulphur fuel oil (LSFO) and marine gasoil (MGO) or the switch to another type of fuel (e.g. LNG). The way the shipping industry will respond is still quite uncertain and some initial assumptions have been included in the demand scenarios modelled in this report.

- Electrification of industry and phase-out of oil for domestic heating: Gradual decarbonisation of the electricity and (to a more limited extent) the gas grids, will lead to a significant demand reduction for heating oil for domestic and industrial applications and near elimination of demand for heavy fuel oil. Decarbonisation of the gas grid is discussed further in Section 6. The domestic demand for LPG is foreseen to reduce by less than one third vs 2030 levels due to the alternative use of energy sources in domestic use (e.g. natural gas and/or electrification in buildings).

- No major changes in demand nor substitution of other oil products such as bitumen or lubricants were modelled throughout the 2030-2050 period. Nevertheless, we acknowledge that factors such as the lower demand of lubricants from electric vehicles or the potential substitution of mineral oil for synthetic lubricants such as Poly-a-olefin (PAO) may have a potential impact on an additional reduction over crude oil distillation (not considered in detail in this initial conceptual assessment).

3.2. 2030 DEMAND SCENARIO

For 2030, demand projections provided to Concawe by Woodmac have been applied in line with the most recent Concawe CO_2 reduction technologies 2030/2050 report [Concawe 2019]. Compared to today, it features a sharp decrease in gasoline demand (40%) and a modest contraction of middle distillate demand (7%) underpinned by a decrease of road diesel and heating oil partly compensated by an increase of jet fuel (both fossil and bio-based) and distillate marine fuel. Heavy fuel oil demand also decreases markedly through loss of inland fuel oil markets, overall decrease and shift to distillate fuels in the marine bunker market. This scenario also assumes no change in demand for petrochemicals (olefins and aromatics).

3.3. 2050 DEMAND SCENARIOS

Based on the key drivers mentioned above, this report explores **two different 2050 scenarios** considering the evolution of future demand, potential changes in product ratio and the impact of future prices of energy and CO_2 reductions, with reference to a 2030 "base case" scenario.

For 2050 two scenarios have been considered, initially inspired by the IEA scenarios [IEA WEO 2017] and adapted to include Concawe's view on specific issues, including different levels of vehicle efficiency improvements and of electrification of passenger cars, heating oil and heavy fuel oil demand reductions:

1) **Scenario 1** inspired on the IEA "*New Policies*" scenario and the 2016 EU Reference Scenario from the EU Commission. Its main features are (compared to 2030):

    - A ~50% reduction in the demand for road diesel (light and heavy duty) and further loss of heating oil markets, with some upside from increasing jet fuel demand,
    - Constant marine fuel demand but with a large shift to distillate marine fuel demand (linked to the 0.5% sulphur limit) with corresponding disappearance of the low sulphur residual bunker fuel,
    - A small further decrease of inland residual fuel oil,
    - 12% decrease of petrochemical demand,
    - A resulting reduction of crude oil intake by approximately 20% compared to 2030.

2) **Scenario 2** is more aligned to the IEA "*Sustainable Development*" scenario. In addition to scenario 1, it features (compared to 2030):

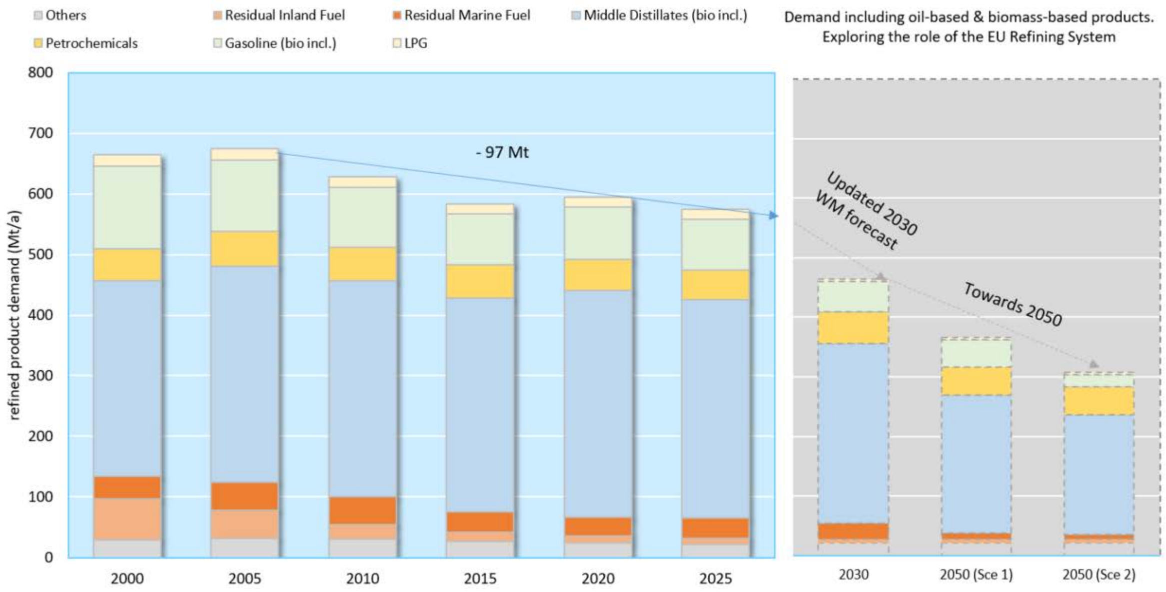
    - A deeper reduction of gasoline demand (60%) exploring a more extreme penetration of alternative powertrains in the light duty segment,
    - A further 10% contraction of road diesel and heating oil demands,
    - 15% increase in jet fuels demand
    - A 25% reduction on total marine fuel demand due to energy efficiency improvement measures coupled with the penetration of alternative energy carriers/technologies.

- No additional changes in petrochemical demand (as Scenario 1).
- A resulting reduction of crude oil intake by approximately 30% compared to 2030.

Scenario 2 is used as the main reference in the study as an ambitious long-term scenario in terms of GHG reduction.

In these scenarios, both the total demand for products and the production yields would be significantly affected. Detailed figures for all three scenarios and actual figures for 2014 are shown in **Table 3.3-2 and Figure 3.3-1**. **Figure 3.3-2** further illustrates changes in the composition of the demand barrel.

Figure 3.3-1 Evolution of total demand for refined products in EU 27+2 (including biofuels and e-fuels)



Note. The demand figures shown above include any bio blending components that may be used. Due to the uncertainty regarding the future blending rates for non-drop in fuels, as a first estimate, it was assumed that ethanol and FAME (possibly from improved processes) will be blended into gasoline and diesel at the following rates:

Table 3.3-1: Biofuels blending rate

%vol	2030	2050
Ethanol in gasoline	20%	25%
FAME in road diesel	10%	15%

Note: Current diesel and gasoline grades: B7 (7%v FAME) and E5 (5%v ethanol)

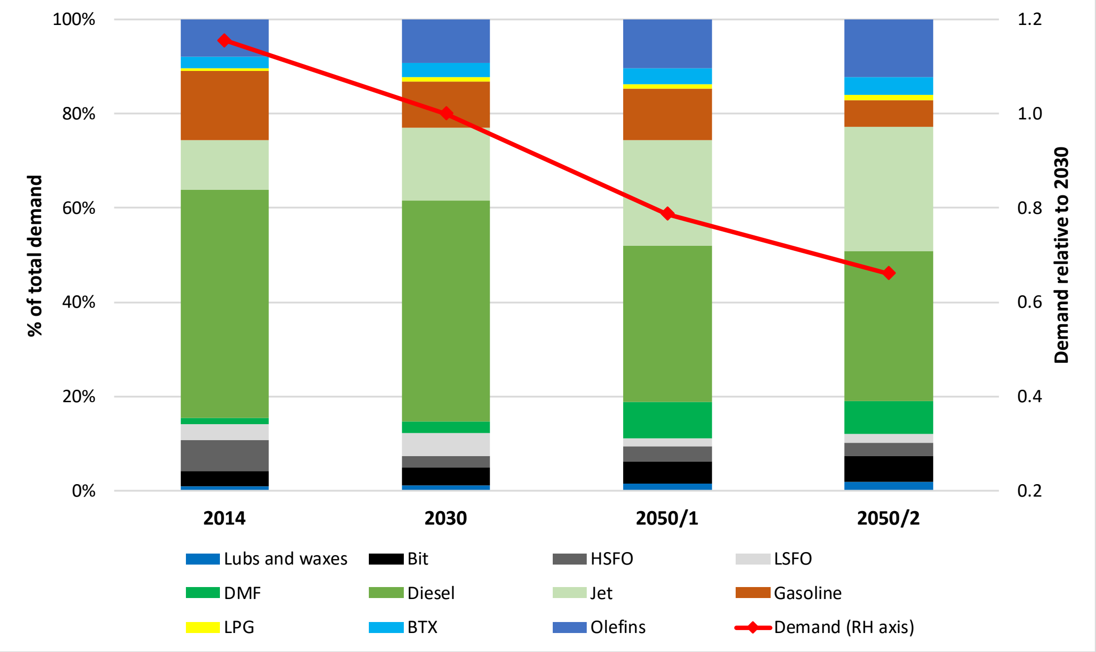
The demand to be satisfied by refineries was therefore reduced proportionally.

Table 3.3-2 Demand scenarios for 2030 and 2050

	Mt/a				Change from 2014 actual			Change from 2030 base case	
	2014	2030	2050		2030	2050		2050	
			1	2		1	2	1	2
All products	**536.6**	**464.5**	**365.7**	**307.1**	**-13%**	**-32%**	**-43%**	**-21%**	**-34%**
LPG	3.0	4.4	3.5	3.1	49%	19%	4%	-20%	-30%
Gasoline	82.5	50.9	45.8	20.3	-38%	-44%	-75%	-10%	-60%
Jet fuel	55.3	67.6	77.7	77.7	*22%*	*40%*		15%	
Gasoils	*268.2*	*233.4*	*153.1*	*123.1*	*-13%*	*-43%*	*-54%*	*-34%*	*-47%*
Road diesel	191.0	165.7	82.9	66.3	-13%	-57%	-65%	-50%	-60%
Other diesels	17.7	16.0	10.7	8.1	-9%	-39%	-54%	-33%	-49%
Heating oil	52.6	40.9	32.7	28.6	-22%	-38%	-46%	-20%	-30%
Distillate marine fuel	7.0	10.8	26.8	20.1	*55%*	*285%*	*189%*	148%	86%
HFO	*52.1*	*32.8*	*16.6*	*13.9*	*-37%*	*-68%*	*-73%*	*-49%*	*-58%*
HFO inland 0.5%S	15.9	6.2	5.9	5.9	-61%	-63%	-63%	-4%	-4%
HFO marine 0.5%S	1.8	16.0	0.0	0.0	806%	-100%		-100%	
HFO marine high S	34.4	10.6	10.6	8.0	-69%	-69%	-77%	0%	-25%
Bitumen	17.0	16.3	16.3	16.3	-4%			0%	
Lubricants	4.8	5.4	5.4	5.4	*13%*			0%	
Petrochemicals	*53.7*	*53.7*	*47.3*	*47.3*	*0%*	*-12%*		*-12%*	
Olefins	40.9	40.9	36.0	36.0	0%	-12%		-12%	
Aromatics	12.8	12.8	11.2	11.2	0%	-12%		-12%	

Note: Figures for LPG demand were adjusted to take into account the imports in Europe for this product (around 13 Mt/a). Total LPG demand is 16 Mton/y in 2015 and 15 Mton/y in 2030.

Figure 3.3-2 Detailed composition of the demand barrel in different scenarios



These scenarios define the basis for the modelling exercise aiming to explore the resilience of the refining scheme to these changes as crude oil is progressively replaced by alternative low fossil carbon feedstocks, providing an initial range in absolute terms of both feedstock and external requirements (e.g. electricity) at EU level.

4. EU REFINERIES CARBON INTENSITY REDUCTION POTENTIAL

Key messages

The current report assumes that the CO_2 efficiency technologies identified deployed to the maximum level estimated possible for the 2050 timeframe: Energy efficiency, use of low fossil carbon energy sources (including renewable electrification and green hydrogen) and CO_2 capture (and storage). This will be the starting point for the modelling exercise (detailed in **Section 6.2**).

In the preceding section (**Section 3**) we developed scenarios to explore how product demand may change in light of improving efficiency and the likely penetration of electrification and alternative powertrains across different transport sectors. In this section we revisit the conclusions from the earlier Concawe *CO_2 reduction technologies* study [Concawe 2019] in which we estimated the potential to reduce the CO_2 emissions through energy efficiency, the use of lower carbon energy sources (including renewable electricity and green hydrogen) and CO_2 capture and storage in context of the 2030 demand outlook.

In this study, all carbon-intensity reduction measures were applied to cases defined by the demand scenarios described in **Section 3:**

- **Energy efficiency** addresses the amount of energy that a refinery uses to produce a range of products from a given crude oil. Although EU refineries have consistently improved their efficiency over the years, continued introduction of more efficient state-of-the-art processes and machinery, improved process monitoring and control and use of modern energy management methods still have the potential to deliver further improvements.
- Refineries use a variety of **energy carriers** mainly internally-produced gas (fuel gas), liquids and solids (coke), imported gas and imported electricity. Substituting liquid fuels with gas can provide a small reduction in carbon intensity. The scope is limited as refineries have already decreased use of liquid fuels for a number of reasons (pollutant emission control and economics). Today liquid fuels account for less than 20% of all fired fuel.

  Use of **solid fuels** is solely linked to specific processes such as Fluid Catalytic Cracking (FCC), flexicoking and coke calcining in which use of coke as fuel is an integral part of the process. The amount of solid fuel burnt is therefore a direct consequence of the type of process in use which, in turn, is dictated by the product demand to be satisfied, the types of crude oil processed and historical investment choices.

  Fuel gas is a by-product of a number of refinery processes. It typically accounts for about 50% of the total refinery energy need. Although it contains a large proportion of methane, its detailed composition as well as logistical considerations make it impractical for export e.g. to the gas grid. Fuel gas must therefore be burned in the refinery and this is a major limitation to the proportion of refinery energy that can be substituted with lower-carbon alternatives. Advances in process and catalyst technology can in time reduce fuel gas production somewhat but scope is limited.
- Over the next decades the average carbon intensity of **EU grid electricity** is expected to become much lower than it is today so that increased use of electricity will be an option to reduce the carbon intensity of refinery operations although ultimately limited by the level of self-generated energy

in the refinery. Introduction of some bio-components into the gas grid is also expected to reduce its carbon intensity although the scale of change will be much less than for electricity.

Table 4-1 Efficiency and GHG Emission Factor for EU "grid" electricity
Assumed in both Concawe's CO_2 reduction technologies and Refinery 2050 reports

		2008	2030	2050
Efficiency	kWh_e/kWh_p	0.37	0.59	0.59
Emission factor (generation + losses to HV)	t CO2/GWh	430	211	40

Electricity is used in today's EU refineries for supplying mechanical energy as well as lighting. Consumption represents about 6% of total energy usage on average but there is a wide range from about 4 to 10% (resulting from choices made when designing the refinery). There is some scope to increase this to substitute higher-carbon forms of energy.

Many refineries produce a large portion of their own electricity with **co-generation** plants which also produce heat. As these reach their end-of-life, it may be attractive not to replace them and import electricity for direct consumption and for producing the heat shortfall in electric steam boilers (the economics of such a move would be highly dependent on the relative forward prices of electricity and gas as well as CO_2). A further option may be to introduce electric process heaters although this would present technological challenges.

- Refineries consume **hydrogen** and this is set to increase over time. Hydrogen is currently almost universally produced from hydrocarbons and water, mostly by Steam Methane Reforming (SMR) and also by gasification of heavier hydrocarbons. These processes release CO_2 which is normally vented to the atmosphere but could be captured and stored. An alternative, not commonly in use today, is water electrolysis. The carbon intensity of hydrogen produced via electrolysis is entirely dependent on the source of electricity. The foreseen decarbonisation of the EU electricity grid would provide a source of "low-carbon" electricity and thus of "low-carbon" hydrogen. In periods of surplus production from renewable sources (solar and/or wind), carbon-free electricity may become available intermittently at a very low price until intermittency is mitigated. Back-up sources of hydrogen or hydrogen storage capacities will offer energy storage solutions to cope with the issue of intermittency and even more important, with the seasonality of green electricity in the future.

  As mentioned above the scope of refinery energy substitution is limited by the need to consume internally-produced fuels so that, in practice, direct electrification and electrolytic hydrogen (replacing natural gas by renewable electricity import) would mutually compete to eliminate imports of fossil refinery fuels (mostly natural gas).

- Finally, the Concawe's *CO_2 reduction technologies* study [Concawe 2019] considered the option of CO_2 capture and storage which can be applied to all combustion gases but is particularly well suited to hydrocarbon-based hydrogen production processes producing a more concentrated CO_2 stream.

  The figures used in this report to account for the CO_2 intensity reduction measures briefly described above are detailed in **Section 6.2**.

5. ALTERNATIVE “LOW CARBON” FEEDSTOCKS AND FUELS PATHWAYS

Key messages

The present conceptual assessment:

- Seeks to explore the suitability of existing refineries for processing low fossil carbon feedstocks, the extent of adaptation that would be needed, and the scale of supply of such feedstocks that would be required to achieve material substitution of existing fossil fuels.
- Does not aim to provide a comprehensive assessment of all such options nor is it intended to rank or recommend specific pathways
- Does not include a detailed economic assessment but does provide a preliminary estimate of the associated CAPEX.

It investigates four illustrative pathways (**Lipids, lignocellulosic biomass and e-fuels**) whilst recognising that additional pathways/feedstocks could be also integrated subject to the location of the sites and the individual company strategy.

Having established the potential for reducing *Scope 1 and 2* emissions from the manufacturing stage (Step 1), the next step towards reducing the fossil carbon intensity of refinery products (Scope 3) would be to introduce low (fossil) carbon feedstocks into the refinery environment (see definition in footnote[2]). There is potentially a very large number of possible combinations of feedstock sources and processing routes. As an example, this study investigates the potential for substantial replacement of crude oil by three main categories of low carbon feedstocks:

- **Lipids** such as vegetable oils, animal fats, waste oils and algal oils,
- Lignocellulosic biomass including agricultural residues, wood and grasses
- **E-fuels** from CO_2 and hydrogen

This study seeks to explore the suitability of existing refineries for processing a range of low fossil carbon feedstocks, the extent of adaptation that would be needed, and the scale of supply of such feedstocks that would be required to achieve material substitution of existing fossil fuels. The study does not explicitly address the long-term for production of finished fuels outside refineries, for example fuels based solely on lignocellulosic ethanol.

Some pathways have been researched to a certain extent, others are more speculative at this stage. This study does not aim to provide a comprehensive assessment of all such options, nor is it intended to rank or recommend specific pathways and it does not include a detailed economic assessment. Rather, it is limited to those sources and routes for which reasonable information and technical data is available and which can be envisaged within the refinery environment.

It further considers the potential synergies associated with processing such feedstocks alongside crude oil in a refinery environment and specifically in the existing EU refineries.

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[2] The term *Low (fossil) carbon* feedstocks refers to feedstocks which produce hydrocarbon fuels /chemicals that are chemically similar to current fuels, but which originate from renewable or non-fossil sources and, therefore, with lower CO_2 intensity factors.

Associated with the selected feedstocks, different main processing pathways were studied in this first assessment:

- **Lipids** hydrotreatment,
- Lignocellulosic biomass:
  - **Gasification** of lignocellulosic biomass (such as wood) followed by Fischer-Tropsch synthesis and hydrocracking,
  - Hydrotreatment-hydrocracking of **pyrolysis** or **hydrothermal liquefaction** oils made from woody biomass,
- **E-Fuels** production from captured CO_2 and electrolytic hydrogen made into syngas by "**reverse water gas shift**" and thence into hydrocarbons by **Fischer-Tropsch synthesis** with subsequent hydrocracking to produce suitable boiling range fuels.

Note: **Other feedstocks** (e.g organic material from municipal solid waste or plastics) might also be available and converted using related technologies (e.g pyrolysis/hydrothermal liquefaction). However, this type of waste materials have not been addressed independently in this conceptual assessment as these often bring case-specific challenges and opportunities. So they have not been included as a separate category in this study; reference is made within the section on lignocellulosic feeds.

In principle, lipids can be used to make a wide range of products including green olefins, gasoline, jet, diesel and lube-base stocks; the same issue arises with syn-gas based technologies, which can make H_2, methanol, gasoline, jet, diesel and lubes. Our analysis has focussed for consistency on a limited set of products from a notional refinery; in reality, we might expect different choices depending on local factors/markets, local regulation/GHG policies, the capability of existing equipment and the willingness to invest in new equipment.

The study does not consider refinery-based fermentation technologies or natural-oil transesterification on the grounds that they offer only limited integration-potential (mainly utilities and logistics). This is not intended to diminish the possible importance of these technologies within the transport fuels supply chain. As discussed in **Section 3**, the study addresses the use of bioethanol (made from sugars, starches or cellulosic feedstocks) or biodiesel as blendstocks through the demand for refinery gasoline and diesel. Advanced bioethanol conversion processes such as "Alcohol-to-Jet" were not considered.

The selected pathways included in this report utilise process technologies that are to an extent established, although the type of feedstock and/or scale envisaged here may significantly deviate from current practical experience. Nevertheless, this allows a broad-brush quantitative assessment.

There are related pathways which could use different refinery process technology (e.g. fluid catalytic cracking as opposed to hydrocracking) or different feedstock preparation (e.g. hydrothermal liquefaction of woody biomass instead of fast pyrolysis). These have not been included in the detailed modelling, but might ultimately prove important, for example if they offer local advantages for logistics or product slate (e.g. balance between jet and diesel, or production of chemical feedstocks such as olefins and aromatics).

In principle, there are **four implementation routes** for each of the representative pathways:

“**Stand-alone**”	where low-carbon fuel production is entirely self-contained (perhaps with access to the electricity grid?)
“**Refinery-integrated**”	where low-carbon fuels are produced in a facility which is integrated with an existing crude oil refinery through shared logistics and utilities.
“**Refinery co-processing**”	where low-carbon feeds are co-processed with (fossil) oil in existing refinery process units.
“**Refinery conversion**”	where an existing refinery unit is adapted to process 100% low-carbon feed.

Most publications about low-carbon fuels technologies only consider “stand-alone” cases where the facilities operate in isolation or in segregated supply-chains. This study uses published descriptions of “stand-alone” technologies then considers how they might be adapted for integration into existing refineries. This might entail co-feeding “low-carbon” and fossil streams into refinery processes, conversion of refinery processes for 100% “low-carbon” streams or construction within a refinery of new units to process “low-carbon” streams. Potential benefits include reductions in capital costs, shared utilities and logistics; details are covered in the sections covering the pathways.

Pathway scalability has been considered at two-levels:

- What might be achieved at an individual production facility?

  For “stand-alone” operations, facility scale is often a compromise between economy of scale and size limits set by process technology and logistics. For “refinery-based” operations, there may be additional constraints linked to the capacity of existing equipment.

- What might be achieved at industry level (EU refining system)?

  Firstly, this depends on the number of facilities which could be built and operated when potential locations may be subject to technical, commercial and regulatory barriers. Secondly, it depends on the availability of raw materials to feed those facilities – both in terms of local production and potential for imports.

5.1. CURRENT SCALE OF REFINERY OPERATION IN THE EU

Key messages

The alternative pathways are explored with reference to integration with a “notional mid-range” refinery with a crude capacity of 160 kbbl/d (~7.5 Mt/a) and process unit capacities of other process units consistent with the European average refinery configuration. This is a hypothetical refinery used for illustration.

The EU refining industry currently comprises 80 “mainstream” refineries which jointly convert approximately 650 Mt/a of crude oil into transport fuels, fuel oil and LPG for heating and power generation, and petrochemicals.

Crude oil is easily transported over large distances by ship or pipelines (and in some regions by rail) so it is easily aggregated. The 10 largest refineries in the EU have crude capacities of 12 to 20 Mt/a and tend to serve both local demand and export markets. 50% of EU refineries are in the range 5 to 10 Mt/a. 20% have capacities under 4 Mt/a and typically operate to meet local demand.

The study aims to highlight the biomass inputs which would correspond to processing “thresholds” in an existing refinery. We therefore consider for this study a “notional mid-range” refinery (See **Section 1.3** consult section 6 for additional details on the average EU capacity for each major processes including petrochemicals).

Specifically, the distillate hydrotreating capacity is about 2 Mt/a typically split up between several separate process units. Hydrocracking is an important consideration, but only about a third of European refineries have hydrocrackers.

As a starting point, the report therefore assumes that the “notional” refinery has a hydrocracking capacity of 1 Mt/a (current EU average).

Note: The present **Section 5** is essentially a series of “*ranging shots*” which were used to guide the subsequent modelling. The refinery modelling work in **Section 6** onwards addresses a wider range of issues and involves a somewhat more rigorous approach. As it will be further explained in the report, the modelling exercise explores some examples of the deployment of these low carbon feedstocks through two different cases: ***limited case*** (assessing the implications of the production of 1 Mt/a liquid products) and a ***maximum case*** (where the maximum uptake of low carbon feedstocks is determined by the amount required to meet the demand scenarios without causing significant imbalances in the whole system).

5.2. LIPIDS HYDROTREATMENT

Key messages

- **Illustrative pathway:** Commercial lipid hydrotreatment based on vegetable oils has established with a few stand-alone operations up to 1 million tonnes/a (Mt/a).
- **Product:** primarily paraffinic distillates (potentially a mix of diesel and jet depending on the degree of hydrocracking).
- **Feedstock:** Typical feeds today include: vegetables oil, animal fats or cooking oil. Future expansion of this pathway probably depends on the development of viable algal oil technology and the establishment of algal farming as a significant new agricultural sector
- **Feedstock availability:** global production of palm oil, soybean oil and rapeseed oil in 2014 was ~ 57, 46 and 26 Mt respectively [FAO 2018b] although this covers all purposes – food, biofuels, oleochemicals. EU production of rapeseed oil in 2014 was ~ 10 Mt. Regarding algae, there Is no current production but according to a report commissioned by DG R&I [Ecorys 2017], the potential availability for the whole EU Bioenergy could range from 41 Mt/a to 367 Mt/a (dry basis) by 2050. This wide range is due to successful development of the current R&I programmes. However, the full potential for algae is not expected to be used because of its high cost compared to other feedstock sources (Further detail can be found in Appendix 3, Chapter 2).
- **Conversion technology:**
    - o *Dedicated lipids hydrotreater units* (or conversion of an existing refinery process unit to 100% lipid feed with a potential impact on capacity losses).
    - o *Lipid co-processing*: Assuming that up to 30% co-processing in technically suitable hydrotreaters may be achievable provided that sustained economic incentives for bio-content have driven process upgrades and technology development.
- **Synergies with existing refining assets**: Very high; use of existing hydrotreating and hydrocracking equipment; utilities including H_2; logistics.

5.2.1. Choice of Example Pathway

Commercial lipid hydrotreatment has recently become well-established with a few stand-alone operations up to 1 million t/a [Neste 2008; Neste 2010]. New 100% lipid hydrotreaters have been co-located at several refineries [Neste 2005; Darling 2011] with shared hydrogen supply, utilities and logistics. Three European refineries [ENI 2015; Total 2015] have either converted, or have announced conversion of refinery hydrotreaters to 100% lipid processing claiming a significant reduction in capital cost [Topsoe 2011] compared with a brand new 100% lipid unit. Several European refineries are co-processing mixtures of 5-10% lipid mixed with fossil gas-oil, but one example is reported to be able to use up to 30%. The product is primarily diesel-range, although some process designs make a mix of diesel and jet depending on the degree of hydrocracking (hydrocracker co-products such as LPG, paraffinic naphtha (for chemicals) or lube-base-oils may be important at some sites, but for simplicity we have focussed on transport fuels). The products are predominantly paraffinic and approved for use in road diesel (EN590) and in jet (ASTM D-7566). Feeds today typically comprise vegetable oils (palm, rapeseed or soy), animal fats or used cooking oils. In principle, algal oils – when they become available at scale – could also be processed this way.

Lipid conversion using FCCs is a valid technical option, but it has had much less attention and development than lipid hydrotreatment; it is more suited to production of C3 & C4 olefins rather than transport fuels.

This study therefore focusses on lipid hydrotreatment as an example of a lipid conversion pathway, but acknowledges that there may be other options such as FCC. Lipid-processing in FCC has been demonstrated at lab-scale, but we are unaware of any commercial trials. Allied technologies (e.g. alkylation, dimerization, oligomerisation) might allow further optimisation of the product slate. The choice between FCC and hydrotreating would probably down to a refinery's specific circumstances.

Lipids routes have certain advantages such as:

- Lipids are mainly energy-rich hydrocarbon liquids which are easily aggregated at logistic nodes (although these support up-to three value chains – biofuels, oleochemicals and food).
- As lipids are hydrocarbons, they are easily blended to make fungible fuels.
- Lipid hydrotreatment technology is easily scaled and can be optimised to maximise diesel production or to provide a balanced mixture of diesel and jet fuel.

However, the chemical composition of lipids differs markedly from similar range hydrocarbons derived from crude-oil (e.g. oxygen-containing vs sulphur-containing) such that considerable re-engineering is required for high levels of lipid processing.

5.2.2. Dedicated Lipid Hydrotreatment

Dedicated purpose-built facilities operating at ~1 Mt/a already exist[3] with investment in the range 0.8 to 1.6 M€ / (kt/a) depending on location and the need for ancillary facilities (e.g. H_2 production; jet fuel and LPG recovery).

An alternative route already made at a handful of crude oil refineries is to convert an existing hydro-processing unit to 100% lipid feed, thus making a considerable capital cost saving (**Figure 5.2.2-1**). The scale is broadly similar to "stand-alone" facilities. The lipid project would involve new lipid storage or reuse /cleaning of existing storage, modification of hydrotreaters and overhaul of key ancillaries such as LPG handling and hydrogen production (the removal of redundant process units and other is not included in the lipid project cost). Lipid processing is quite demanding compared with fossil feeds (e.g. feed pretreatment to remove impurities such as phospholipids, high exotherm, large H_2 consumption, large by-product load on effluent treatment, etc) so the capacity of a converted unit initially would be much less than its original fossil capacity, perhaps only 30-50%. These issues will be site/unit/project specific, but some might be overcome during by technology development, debottlenecking and unit upgrades out to 2050. Additional factors such as investment or feedstock sourcing constrains may determine at which scale this pathway could be effectively deployed. We have not attempted to quantify this, but for the sake of example have **assumed that a converted unit might by 2050 have achieved the same capacity as its 2015 "fossil" predecessors.**

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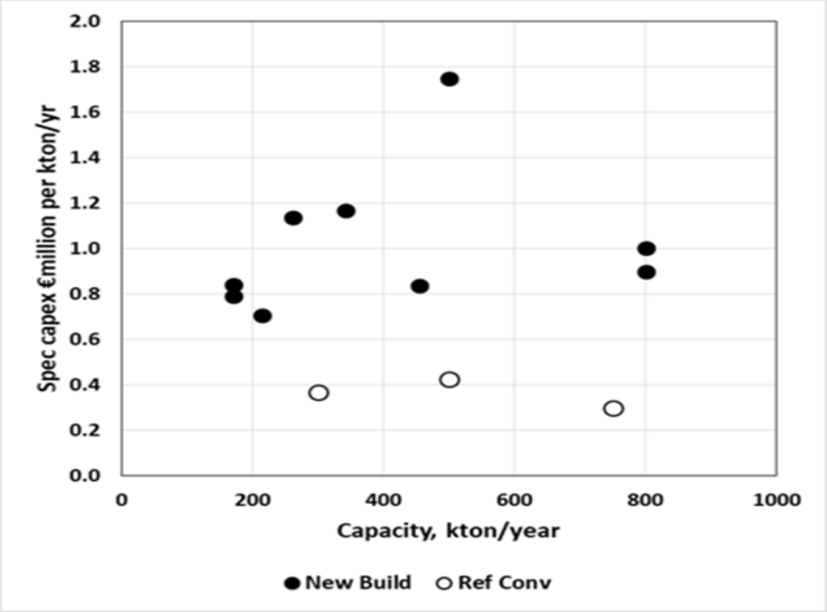
[3] (e.g. [Neste; Diamond Green]

Figure 5.2.2-1 Capital intensity of Lipid Hydrotreatment plants – new build and refinery conversion.
(Source: Neste, ENI, Total and Darling press releases; Concawe members)



Dedicated EU lipid treating capacity today is ~2-3 Mt/a, but - in principle more facilities could be built and more refineries could be converted if demand for hydrotreated lipid product increases, and enough raw-materials are available at an economic price. Logistics will be key; note that all large lipid-HDT facilities built so far have coastal locations with good access to imported oils. This suggests that inland refineries might struggle to access sustainable lipids for large-scale coprocessing or for refinery conversion projects without the development of new supply chains.

5.2.3. Lipid Co-processing in Refineries

Co-processing in refinery diesel hydrotreaters is becoming more common as refiners gain experience and regulators approve co-processing pathways. Co-processing is technically demanding (e.g. increased H_2 consumption) so not all existing hydrotreaters are suitable. Other constraints such as cycle length reduction by catalyst inhibition (CO/ CO_2) or metallurgy may limit co-processing today to about 5-10% of unit feed, although up to 30% has been achieved commercially under special circumstances [Topsoe]. Plant modifications are required (sometimes significant, depending on pressure and the desired proportion of bio material in the feed) as well as installation of lipid storage/pretreatment so investment is very site specific and dependant on the choice of oil (e.g. [IRENA 2016]). The economics depend on a number of factors including the feedstock cost, potential extra value of partially renewable products and possible loss of crude processing margin if hydrotreating capacity becomes a constraint.

We have assumed that up to **30% co-processing may be achievable** in some units by 2050 provided that sustained economic incentives for bio-content have driven process upgrades and technology development. Although hydrocracking units may have some technical advantages for co-processing (high H_2 pressure, good heat-removal), they are rarely used today because the economic value of converting heavy fossil streams outweighs the value of the renewable content. If this economic paradigm is different in 2050, then co-processing in hydrocrackers might also apply. The next section (**5.2.4.**) therefore considered a progressive expansion of lipid processing from low-level co-processing through to wholesale conversion of hydrotreatment (HDT) or hydrocracker (HC) units for dedicated lipid processing.

The capital cost for co-processing is hard to estimate because it will be dominated by feed storage and handling e.g. contaminant removal. Today, the "contaminants" in raw lipids often have value in other industries and are recovered early in the supply chain leaving the refinery to import relatively clean feed. If technologies such as algal oils come into play, it seems likely that the same would be true. We have no information about the full site-specific costs (eg storage tanks and pipework; upgrades to off-gas handling). The capex for feed pre-treatment alone would be €0.05 per kt/a. The full cost might exceed this by a factor of 5.

5.2.4. Potential Expansion of Lipid Processing in Refineries

Lipid hydrotreatment uses technology which is very similar to conventional refinery technology, and the hydrocarbon product is almost interchangeable with fossil distillates. Lipid hydrotreatment therefore has a high level of synergy with the refining industry as it can to some extent make use of existing process facilities, and might enable growth of this pathway at a lower capital cost then would be incurred if brand-new "greenfield" facilities were required.

The technology is commercially demonstrated and still has scope for improvement such as co-processing level and product quality. For our notional 160 kbbl/day hydrocracking refinery, the steps might be:

(a) **Blending** – limited by the availability of 3rd party renewable product,
(b) **Co-processing** – initially at low level, but with the possibility of higher levels if technology improves,
(c) **Process unit conversion** – initially at low capacity, but with the possibility of subsequent debottlenecking/expansion/technology improvement.

As an illustration, it is useful at this stage to make some semi-quantitative estimates about the impact of different levels of integration. We therefore consider a "notional" or "hypothetical" 160kbbl/day crude oil refinery with European-average configuration. Note that this refinery has both FCC and hydrocracker conversion units, whereas only about 1/5 of current European refineries have both FCC and hydrocracker. Almost half have FCC but no hydrocracker, with about 1 in 6 having a hydrocracker and no FCC. The notional refinery therefore should not be taken as representing the industry as a whole, nor any particular class of refinery. It does however indicate the relative scale of renewable fuel production resulting from specific integration options. Some semi-quantitative examples are shown in **Table 5.2.4-1**; the detailed effects of a smaller number of integration opt-ins is covered in **Section 6**.

With crude-oil alone, the notional refinery makes 3.4 Mt/a of diesel and heating oil, but could blend renewable imports if available. In the "co-processing" example, there would be loss of fossil hydrotreating capacity which may be addressed by re-optimisation. The second "transformation" example represents a case where a hydrocracker is withdrawn from fossil service and converted to 100% lipid feed. This would allow the refiner to claim that the diesel is renewable but the loss of fossil conversion capability may have a major impact on fossil crude processing. The notional refinery still has some conversion capability because of the FCC unit, but there might still be a need to change the crude diet and/or make a major reduction in crude throughput.

Whilst we explore the potential to use lipids as a source for a full range of hydrocarbons, e.g. for petrochemical feedstock, gasoline blending as well as kerosene and diesel, this is not necessarily how an optimised Notional refinery would operate. Economics and thermodynamics would suggest that lipids are best kept as kerosene and diesel substitutes, with other substitutes such as e-fuels from hydrogen and CO_2 used for lighter hydrocarbons.

Table 5.2.4-1 Illustrative options for integration of Notional Refinery with Lipid HDT
(For reference: the notional 160 kbbl/day crude oil refinery would have capacities in the order of ~2 Mt/a diesel hydrotreating and ~1 Mt/a hydrocracking)

TYPE OF OPERATION	**Co-processing** lipid and fossil in existing diesel hydrotreater		**Transformation** of existing hydrocracker to 100% lipid feeds	
	5% co-feed	30% co-feed	@ 50% of base capacity	@ 100% of base capacity
Low-C Diesel, Mt/a	0.1	0.6	0.5	1.0
Lipid Feed, Mt/a	0.1	0.7	0.6	1.3
Implications for refinery	Moderate reduction in fossil diesel production + slight loss of crude capacity; demand for “on-purpose H_2” increased 25 to 100%; re-optimisation of existing fossil units		Major reduction in fossil diesel production; major loss of crude capacity with closure of many fossil process units; demand for “on-purpose H_2” increased x2 to x4	

Note: Lipid conversion: co-processing = 83%; hydrocracker = 81%

5.2.5. Large-scale Lipid Supply (EU wide)

The section above describes as an extreme case the major refinery transformation into a notional lipid hydrotreating and conversion facility consuming in the order of 1 Mt/a of lipids. By way of example, this section considers what would happen if this was replicated across the whole EU refinery industry. Lipid demand might be as much as 80 Mt/although production of diesel from hydrotreated-lipids (~25-30 Mt/a of diesel) might only represent ~1/3 of 2050 EU production of fossil diesel in demand Scenario 2. To put the lipid demand in context, global production of palm oil, soybean oil and rapeseed oil in 2014 was ~ 57, 46 and 26 Mt respectively [FAO 2018b] although this covers all purposes – food, biofuels, oleochemicals. EU production of rapeseed oil in 2014 was ~ 10 Mt. To use lipids as a large-scale resource for diesel production would require sizeable additional sources of lipids. This study is not intended to address the agricultural and sustainability issues of these feedstocks, but these figures provide some context for the massive scale of additional agriculture resources which would be required for a crop-based system.

In addition to agriculture (dedicated crops) and use of waste lipids sources, a possible solution would be a move towards non-crop sources including algal oils which are claimed to have high productivity compared with conventional agriculture. Algae are simple plant-like organisms which may contain 10 to 50% lipids on a dry basis; like plants, they get their energy from sunlight and carbon from CO_2. The main commercial application today is aimed at speciality products such as food additives.

Algal oil production concepts include:

- **open-ponds**, commonly shallow lagoons with a slow circulation of biomass to simplify harvesting. Development issues are construction of km^2 size ponds, water management (e.g. water supply; evaporation), nutrient management, and bio-containment (protecting the algae from invasion as well as avoiding release of algae into the wider environment.)
- **photobioreactors**, generally vast banks of transparent tubes which provide containment (of water and organisms). Development issues include scalability and construction of the photoreactor banks, nutrient management.

Different studies [JRC 2015, BP 2014, Exxon 2019] show that current algal technology for energy products might yield 5 to 15 t/ha/a of lipid. Estimates of long-term potential yields are in the range 30-90 t/ha/a of lipid. This compares with a global average of ~0.5 t/ha/a for soybean-oil and 3 to 5 t/ha/a for palm oil [BP 2014].

As an example, we might assume that algal oil production could be commercialised at large-scale with a productivity of 50 t/ha/a. A lipids facility processing 1 Mt/a would need the output of 20,000 ha of land (200 km^2; roughly the area of the city of Brussels). By extension, production of 75-150 Mt/a for the fuels industry would require 1.5 to 3 million hectares of new “lipid agriculture”. EU agriculture [Eurostats 2018] currently occupies ~179 million ha of which 60% is arable including 57 million ha cereals and 12 million ha of “industrial crops”. Again, this study cannot address the feasibility of developing and scaling a new agricultural sector, but sheds light on the scale of the undertaking.

According to a study commissioned by DG R&I [Ecorys 2017] algae availability for the whole EU Bioenergy system potentially ranges from 41 Mt/a by 2050 base scenario to 367 Mt/a (dry basis) by 2050 high scenario. This wide range is due to the potential availability (regional constrains) and the successful development of the current R&I programmes to bring the production cost for algae down to competitive levels[4]. However, DG R&I states that the full potential for algae is not expected to be used because of its high cost compared to other feedstock sources. (Further detail can be found in **Appendix 3, Chapter 2**).

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[4] *The availability of commercially available aquatic biomass is considered insignificant for 2020, but biomass available from this sector could rapidly increase to 38 million t in 2030 and 344 million t in 2050. Only 12 out of the 28 EU Member States are identified as being able to provide the EU market with significant amounts of aquatic biomass. Out of these, only six are considered to be able to provide quantities close or more than 10 million t (dry)microalgae and macroalgae combined per year. Spain is estimated to have the most significant potential, as the theoretical availability of Spanish algae is found to be almost 3 times larger than for the other EU Member States. While biomass from microalgae could represent a significant feedstock by 2050, such biomass could only be supplied at very high prices. Even if R&I measures are able to reduce costs below €637/t by 2050 for microalgae and €131/dry t for macroalgae, these supply costs would still be much higher than the costs of other biomass feedstock available from the other sectors, and this feedstock will very likely not be competitive with others”*

5.3. LIGNOCELLULOSIC BIOMASS: GASIFICATION WITH FISCHER-TROPSCH AND PYROLYSIS ROUTES.

Lignocellulosic biomass is characterised by chemical components such as cellulose, hemicellulose and lignin. It is one of the most abundant forms of biomass, including wood and residues from forestry, waste-wood from industry, agricultural residues such as straw and stover, and energy-crops such as willow or miscanthus. Most forms are fibrous are hard to convert through chemical and biochemical processes without severe pre-treatments. Various conversion pathways are being developed including:

- Lignocellulosic ethanol, which involves physical/chemical pre-treatment followed by fermentation of derived carbohydrates
- Conversion to synthesis-gas (CO/H_2) by **gasification**, followed by chemical conversion to liquid product such as methanol or hydrocarbons
- Direct thermochemical conversion by **pyrolysis** or hydrothermal liquefaction (HTL), usually followed by further chemical processing.

The lignocellulosic ethanol pathway has only limited scope for refinery integration, mainly via utilities and logistics, so despite the potential penetration of higher ethanol blending rates in the future (e.g gasoline blending), a major ethanol pathway is not expected to offer additional opportunities to match the whole demand of refining products so no ad-hoc ethanol pathway has been included in this first conceptual assessment. Gasification is covered here in **Section 5.3.2**; pyrolysis/liquefaction are covered in **Section 5.3.3**.

5.3.1. Lignocellulosic biomass supply

The net calorific value of woody materials is relatively low leading to high transport and storage costs – plant size is therefore a compromise between the economy of scale of the BTL plant and the cost of aggregating biomass (e.g. [ECN 2006, RENEW 2006]). Large, sustainable forestry plantations today may yield a few Mt/a of timber generally processed near-by to minimise transport costs. Some coal-fired power stations are now using quite substantial quantities of biomass, but again transport is a key factor; for example, the power station at Drax (UK) co-fires over 3 Mt/a of woodchips, mainly imported from the US and Eastern Europe through a new port in Hull [Drax 2017]. Gasification normally requires the biomass to be pre-processed e.g. shredding or grinding; from the example in the power industry, we assume this is feasible at a scale over 1 Mt/a.

Local factors such as land availability, transport links and permitting could have a significant impact on the feasibility and scale of BTL, both “stand-alone” and “refinery-based”. The woodchip supply chain is already developing in some areas, but some locations would have to develop new local biomass supply chains. For example, the use of crop residues or energy crops might require pre-processing technologies such as torrefaction or pyrolysis to increase energy density and reduce transport costs; this is the basis of the very large BTL plant cited in the RENEW study. We have not analysed this specifically, but have assumed – at the level of detail required for this study – that decentralised pre-processing could be implemented if required to support very large centralised conversion. It is not clear whether existing crude oil logistics (port; pipeline, rail) would benefit or hinder a refinery which wished to establish a new biomass supply chain, so we have not included this in the assessment.

Biomass supply today focuses mainly on forestry, primarily because of cost and ease of logistics. According to a report commissioned by DG R&I [Ecorys 2017] the potential EU sustainable availability by 2050 of agricultural feedstocks (crop residues and energy crops) for all uses is in the range 219-238 Mt/a (dry basis), and forestry feedstocks (woody biomass as logs, chips, residues) for all uses is in the range 286-389 (dry basis). (Further detail can be found in **Appendix 3, Chapter 2**). We therefore assume that supply-chains could be established up to several Mt/a, although the logistic costs would depend on location.

Municipal waste (MSW) is also being considered as feedstock for gasification/FT plants (e.g. [Fulcrum 2018, BA 2017]). Many EU countries already have waste-to-power plants [CEWEP 2018], for example Germany has ~ 120 plants consuming ~25 Mt/a of waste; capacity varies from 50 to 700 kt/a of waste. The energy density of MSW is very low, typically 8-11 MJ/kg [WEC 2016] so these supply chains are generally small compared with the reference BTL plant. Loss of scale would generally be detrimental to economics, but MSW conversion may attract additional sources of value such as avoidance of landfill taxes. According to [Ecorys 2017], waste availability for the whole EU Bioenergy system potentially ranges from 92 Mt/a for a 2050 base scenario to 107 Mt/a for a 2050 high R&I Ecorys' scenario (dry basis). (Further detail can be found in **Appendix 3, Chapter 2**).

5.3.2. Gasification and Fischer-Tropsch route

Key messages

- **Illustrative pathway: *Biomass-to-Liquids*** (BTL). Refinery-based gasification of lignocellulosic biomass, followed by Fischer-Tropsch (FT) synthesis and hydrocracking.
- **Product:** high quality distillates; by-product chemical feeds such as naphtha and wax.
- **Feedstock:** Lignocellulosic biomass including wood and residues from forestry, waste-wood from industry, agricultural residues (straw and stover) and energy-crops. Option to use other feeds in niche areas e.g. municipal solid waste.
- **Feedstock availability:** According to a report commissioned by DG R&I [Ecorys 2017] the potential EU sustainable availability by 2050 of agricultural feedstocks (crop residues and energy crops) for all uses is in the range 219-238 Mt/a (dry basis), and forestry feedstocks (woody biomass as logs, chips, residues) for all uses is in the range 286-389 (dry basis). Waste availability for the whole EU Bioenergy system potentially ranges from 92 Mt/a for a 2050 base scenario to 107 Mt/a for a 2050 high R&I Ecorys' scenario (dry basis). (Further detail can be found in Appendix 3, Chapter 2).
- **Conversion Technology:**
    - Gasification of raw biomass such as wood chips or pre-processed biomass such as torrefied wood or pyrolysis oil resembles technology in power sector.
    - Syngas processing followed by FT synthesis resembles technology used from coal and natural gas conversion. Upgrading of raw FT product ("wax") to meet the demand for different lighter products resembles refinery hydrocracking, providing options from **low-level co-processing to** complete *Hydrocracker* transformation. Second option using FCC for upgrading may be more suited to integrated fuels/chemicals production.

Key messages (Cont)

- **Synergies with existing refining assets**: **Moderate.** Use of refinery hydrocracker for co-processing or unit transformation; utilities including heat, power and H_2; co-product handling e.g. LPG; blending & logistics. Due to the poor cold properties of diesel and kerosene fractions, additional isomerization capability may be required.
- **Technology & Supply-chain readiness:** Most technical elements are known commercially in other applications, but no commercial experience with an integrated BTL system. A few examples in power sector of individual biomass supply chains suitable scale, but wider adoption would require significant expansion of forestry and/or agricultural residues sectors.
- **External requirements**: Potential competition for feedstocks from power sector.

5.3.2.1. Choice of Example Pathway

The gasification pathway builds on technologies already commercialised for production of methanol, diesel and jet from natural gas and coal, although the different raw materials may influence the choice of gasification technology [E4Tech 2009] and synthesis gas cleaning. Synthesis gas conversion to methanol is very well established in the chemicals industry, but has little synergy with refined fuels. (In some regions, % levels of methanol are sometimes blended into gasoline subject to restrictions such as vapour pressure and materials compatibility. Synthesis gas conversion to liquid hydrocarbons using Fischer-Tropsch (FT) synthesis and hydrocracking is well known for conversion of coal or natural gas into-liquid fuels in locations with limited access to crude oil or crude-oil products but other technologies may be further developed in the future optimizing this conversion pathway. Other potential syngas products which are out-of-scope for study include ethanol, mixed alcohols (C1-C4), aromatics (via methanol), hydrogen, ammonia (via H_2) and CO-derived chemicals such as acetic acid and oxo-alcohols.

"***Biomass-to-liquids***" (BTL) using FT technology is viewed as one of the key technologies for low-carbon fuels production but as yet there has been no successful commercial demonstration of an integrated BTL unit, even though most of the components have been used separately at scale. Development projects are still in play e.g. BioTFuel [Total 2018].

One approach for the oil industry might be to co-gasify wood in existing gasifiers designed for fossil feeds such as residual oils or coal [SASOL 2006]. Only a handful of European refineries have gasifiers which are for power or hydrogen production, not FT-synthesis. This seems to be a niche route, so will not be discussed here in detail.

In most BTL flow-schemes, the "raw" FT product is a wax which may contain hydrocarbons larger than C_{25}, compared with diesel which is typically C_{10} to C_{20}. The raw wax can become an alternative source for high quality lubes and waxes[5] and it can be also cracked to obtain the correct carbon-number range. So refinery integration of BTL to produce also lighted products could stem from an existing cracking unit such as a refinery hydrocracker or FCC [De Klerk 2011, Dupain 2006]. Roughly 1/3 of European refineries have hydrocrackers whereas roughly 2/3 have FCC, but hydrocracking would be preferable because it gives better liquid yields from FT wax compared with the higher severity FCC process. A refinery-based BTL facility could also make use of existing refinery light-ends recovery, utilities and

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[5] Shell's HC unit in Qatar as an example of regular FT-wax plants in operation

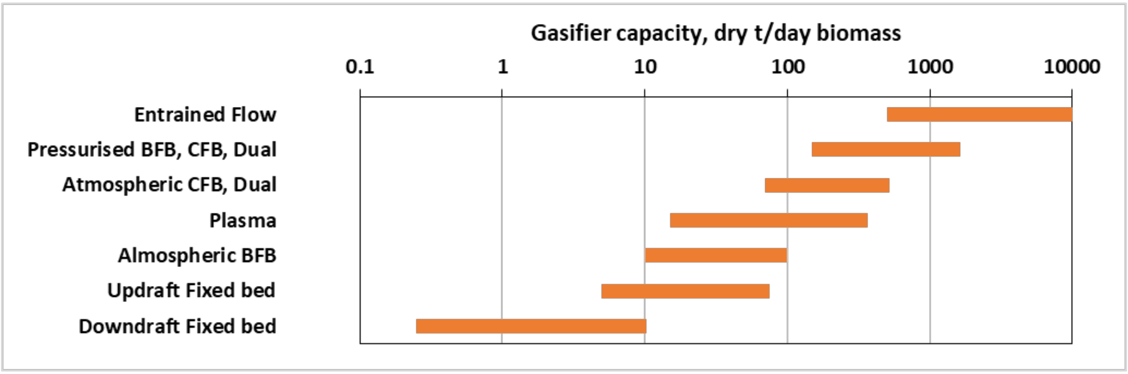
product blending. It would however still require a considerable amount of new equipment (biomass handling, gasifier, syngas treatment, FT reactor).

This study therefore acknowledges that there are several options for pathways based on gasification of lignocellulosic feeds, but uses a specific pathway as an example: refinery-based gasification of woody biomass, followed by FT synthesis and hydrocracking.

5.3.2.2. Biomass Gasification and co-gasification

Biomass gasification appears to be feasible at scales up to ~10 kt/day per train [E4Tech 2009, IRENA 2012] although such large scales have not been demonstrated yet. A BTL plant would also need tar conversion and syngas processing (e.g. cleaning; reverse-water gas shift). We therefore have assumed that biomass gasification using new equipment could technically be feasible at scales between 300 to ~3000 kt/a (or more if multiple several gasifier trains were used).

Figure 5.3.2.2-1 Gasifier capacity – impact of gasifier type
Source: [E4Tech 2009]



A handful of EU refineries (6) already have gasifiers, generally to convert residual oils to syngas for production of hydrogen, power or methanol. Purely as an indication of scale, the largest refinery-based gasifier (Sarrach) consumes ~1Mt/a of residue. In principle, a residue gasifier could be modified to allow co-feeding of ground biomass or a “liquefied” bio-feed such as biomass pyrolysis oil, although this has yet to be demonstrated at scale. By way of example, co-feeding 5% biomass to a 1 Mt/a gasifier would represent ~50 kt/a of biomass and perhaps 25kt/a of liquid product, which is small. Co-feeding say 50% biomass would have a more material impact, but represents a greater technological and economic challenge. Making use of existing gasifiers for biomass co-feed to make liquid fuels would require significant modification both for the bio-feed and for product manufacture, and the small number of existing units would make it a niche pathway.

In principle, a co-fed gasifier could provide an interesting synergy between renewable feeds and crude oil remaining, particularly if the heavy fuel oil market continues to decline (e.g. in response to shipping SOx and GHG emissions. It is however economically complex so, for the sake of simplicity, this study focuses purely on biomass gasification.

5.3.2.3. Refinery Integration - FT synthesis and FT wax cracking

Although not yet applied commercially for BTL, Fischer-Tropsch Technology has been deployed at scale in coal- and gas-to-liquids plants. The FT reaction is very exothermic consequently the reactor must be able to handle large heat flux, which limits the capacity of individual FT reactors to roughly 500 to 2000 t/day depending on technology [Axens 2008]. Some large GTL plants therefore have multiple trains of Fischer-Tropsch reactors (e.g. [Shell 2018]). Recent developments are attempting to improve heat-management in FT reactors using highly-integrated modular reactors; so far, these have only been demonstrated at small-scale [Velocys 2017]. Wax upgrading by hydrocracking also has been demonstrated commercially for coal- and gas-to-liquids facilities of several Mt/a. Based on this, the conversion technology does not seem to be a limit in the scale of BTL plants although it might need to be multi-train.

FT reactor technology is very different from most refinery processes, so would probably entail construction of new units. However, there might be synergies via utilities and infrastructure. The heat released by FT reactors is normally recovered as HP steam used to provide process energy and power for the plant, plus by-product low-carbon electricity. By way of example, a 300 kt/a BTL plant might provide ~100 MW of by-product “low-carbon” energy which could be used partly to run its utilities and partly to generate low-carbon electricity for export. By way of reference, a notional 160 kbbl/day refinery today might require 50-80 MW-e. The surplus low-carbon energy supplied by a large BTL could be a useful contribution to refinery decarbonisation.

Wax conversion provides the main synergy with an existing refinery. FT-wax has been considered as feed for both refinery hydrocracking and FCC units [De Klerk 2011], but this study focusses on the refinery VGO hydrocracker. **Table 5.3.2.3-1** below provides some examples of potential integration based on the hydrocracker in the notional 160 kbbl/day refinery from the previous section. Similar to **Section 5.2** on lipids, this table is a simple indicative estimate; the detailed integration and impact on refinery yields has been modelled in **Section 6**.

The first example involves co-feeding FT-wax to the hydrocracker on the assumption that process conditions and catalyst could be re-optimised to compensate for the change in feed quality. Co-feed at 10% is taken as being representative of conventional technology, with 30% for stretch technology. If the economic case for renewable fuel becomes more compelling, complete conversion to 100% FT wax feed could be envisaged even if this requires improved technology and equipment upgrades; this concept resembles the “*HCK Transformation*” example in Section 5.2 concerning lipids.

Table 5.3.2.3-1 Illustrative options for integration of Notional Refinery with BTL
(Note: a notional 160 kbbl/day crude oil refinery would make ~3.4 Mt/a of fossil diesel)

TYPE OF OPERATION	Co-processing BTL wax and fossil VGO in existing hydrocracker		Transformation of existing hydrocracker to 100% FT Wax
	10% co-feed	30% co-feed	@ 100% of base capacity
Renewable Diesel, Mt/a	0.1	0.3	0.7
Woody Biomass, Mt/a	0.6	1.8	4.2
Implications for refinery	Slight loss of crude capacity and diesel production; re-optimisation of existing process units		Major loss of diesel production from crude with closure of many existing process units

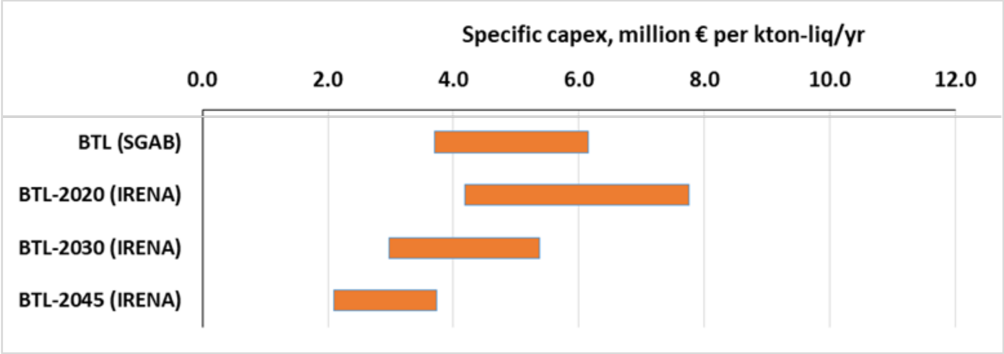
Assumptions: FT-wax yield = 22% of biomass; Diesel yield = 75% of FT wax.

This table shows that the co-fed options have scales which are consistent with potential BTL facilities and possible supply chains. The hydrocracker transformation concept is probably at the upper end of potential technology/supply chains. Due to the poor cold properties of diesel and kerosene fractions of raw FT product, additional isomerization capability may be required through HCK catalyst development or new isomerisation/dewaxing processes.

In principle, the FT wax might also be imported from a separate BTL facility, although this would have little synergy with an existing refinery. It would also require long-range transport of FT-wax which is solid at ambient temperature. In principle this is not a road-block, but it might entail special logistics similar to conventional waxes, asphalts or heavy oils.

No commercial-scale BTL plant has been built, so this section uses data from studies or proposed projects. These generally refer to commercial BTL plants up to 100 kt/a of products [JRC 2009, E4Tech 2009, ECN 2006], although some studies envisage plants up to 1 Mt/a [e.g. RENEW 2006]. Capital cost intensities have been estimated from published studies [IRENA 2016, SGAB 2018] and information provided confidentially to Concawe. For this study, we have assumed 4 to 6 M€/(kt/a) for stand-alone BTL with a conversion efficiency of 0.22 t of liquid products per t of dry wood.

Figure 5.3.2.3-1 Capital Intensities of BTL plants from 3rd party studies (Derived from SGAB 2017, SGAB-2018, IRENA 2018]



We have estimated the cost of a refinery integrated plant by deducting the costs of relevant sub-systems from the cost of a stand-alone BTL plant. The wax-conversion section of a stand-alone BTL plant probably represents 10-15% of the total capital cost[6]. This might not seem a large percentage saving, however this fraction would be applied to a very expensive project; a stand-alone BTL facility making ~1 Mt/a of product would probably cost over 5 G€, so the saving from refinery integration could be ~0.5 G€.

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[6] [Calculation based on ECN2006, NETL 2013, IRENA 2012].

5.3.3. Lignocellulosic biomass: Pyrolysis route

Key messages

- **Illustrative pathway:** *Fast-pyrolysis* or *hydro-thermal liquefaction (HTL) of lignocellulosic biomass such as wood*, followed by hydrotreatment/hydrocracking to produce hydrocarbon fuels. Might be operated as distributed pyrolysis followed by centralised hydrotreatment, or as integrated pyrolysis/hydrotreatment where biomass and hydrogen are available.
- **Product:** Final product is a mix of renewable-gasoline and diesel; fully hydrocarbon but may be moderately aromatic.
- **Feedstock:** Wood and forestry residue, municipal waste, straw, stover and green biomass. Raw pyrolysis oil is the bio-feedstock to the refinery; might be imported or made on site.
- **Feedstock availability:** According to a report commissioned by DG R&I [Ecorys 2017] the potential EU sustainable availability by 2050 of agricultural feedstocks (crop residues and energy crops) for all uses is in the range 219-238 Mt/a (dry basis), and forestry feedstocks (woody biomass as logs, chips, residues) for all uses is in the range 286-389 (dry basis). Waste availability for the whole EU Bioenergy system potentially ranges from 92 Mt/a for a 2050 base scenario to 107 Mt/a for a 2050 high R&I Ecorys' scenario (dry basis). (Further detail can be found in Appendix 3, Chapter 2).
- **Conversion technology:** Raw pyrolysis oil need extensive hydrotreatment to remove oxygen and optimize the product distribution. Low-grade oils may need a dedicated stabilizer hydrotreater to prevent operational problems farther downstream when "finishing" the fuel in refinery hydrotreating or hydrocracker units. Options from low-level co-processing through to unit transformation to 100% renewable duty.
- Technical & Supply-chain readiness: Raw pyrolysis oil is being developed as a fuel for renewable heat & power; a few small commercial examples & regulatory action eg development of pyrolysis oil standards. Advanced technologies intended to make products with lower oxygen content as drop-in fuels have been demonstrated at lab-scale with some commercial demos planned. Trials on refinery co-processing have been problematic so additional R&D required.
- **Synergies with existing refining assets**: Moderate to good. Like BTL can make use of existing refinery hydrotreater/hydrocracker, utilities and logistics but less investment required in upstream equipment.
- **External requirements**: Very high hydrogen consumption compared with refined products

5.3.3.1. Choice of Example Pathway

The gasification pathways rely on the conversion of feedstocks into simple gaseous molecules containing a single carbon atom. There are however other thermochemical pathways where the primary conversion process leads to a multi-carbon product. The best developed processes in this area involve "fast pyrolysis" where biomass is heated rapidly in the absence of oxygen resulting in a "pyrolysis-oil" which superficially resembles crude oil. This is a high severity process (e.g. >450^{o}C) which has been applied to a wide range of feedstocks including wood and forestry residues, municipal waste, straw, stover and "green" biomass. The technology is simpler than gasification and has simpler utility requirements making it suitable for distributed rather than centralised operation, which may help supply chains based on low energy content feeds. Pyrolysis oils are used as an alternative to fossil fuel oil for power and heat, although as yet there are relatively few commercial operations. This is however encouraging the adoption of standard specifications e.g. ASTM D-7544, EN 1690-2017.

Emerging technologies include advanced pyrolysis process which use catalysts or co-fed hydrogen, and related technologies such as *hydrothermal liquefaction* (HTL, where biomass is treated using water at high temperature and pressure). We have chosen to focus on fast-pyrolysis of woody-biomass because it parallels the earlier section on gasification of woody biomass, and has been researched quite widely for heat, power and transport applications.

5.3.3.2. Pyrolysis Oil Production from Woody Biomass

A handful of small fast pyrolysis plants have been operated commercially since the 1990s mainly to supply “bio fuel oil” to users with specially adapted furnaces or motor-generators. Engineering design issues and biomass supply may constrain scalability; more recent plants are in the range 20-50 kt/a (e.g. [Envergent 2009/2010/2016, Empyro 2014, Metso 2012]). These operations generally involve local consumption of the bio-oil, although pyrolysis also would be suitable for decentralised production of “bio-crude” (with transport by dedicated tanker or pipeline).

The products of fast pyrolysis include the pyrolysis-oil (generally a mixture of oxygenated organics such as phenols, aromatic esters, aromatic aldehydes and light organic acids), water, non-condensable gases (CO, CO_2, H_2) and solid char. The detailed distribution depends on feed type and pyrolyser technology. Process energy is provided by burning non-condensable gases and some of the char, with excess char either being exported (“Biochar”) or used for export power generation.

Fast pyrolysis oil made from woody biomass generally has a high oxygen content (>40%) leading to low calorific value and poor physical properties. Raw pyrolysis oil is not compatible with fossil fuel oils; its use for power-generation or heating generally involves a segregated operation although co-firing trials have been made using segregated burners e.g. Harculo Power Station [BTG 2019].

HTL development is less advanced than fast-pyrolysis, with commercial projects only recently announced e.g. Licella [Licella 2018]. HTL has both technical advantages and disadvantages relative to fast-pyrolysis; key factors are its suitability for high-moisture feeds and the reduced oxygen content of the product (~15-20% vs 40-50%).

Advanced pyrolysis processes are intended to make products with lower oxygen content, hence superior fuel properties. These include:

(a) post-treatment using integrated hydrotreatment (e.g. [NREL 2006/2010])

(b) catalytic pyrolysis (e.g. [Kior – no longer in business])

(c) catalytic pyrolysis with hydrogen (e.g. [CRC-IH2 2012]).

The intention of these developments has been to make “drop-in” products for direct blending into conventional road fuels, but they also result in greater process complexity and utility requirements e.g. access to hydrogen. Economy of scale is therefore important; design studies for “stand-alone” facilities suggest 200-400 kt/a of product. These technologies have been demonstrated at large-pilot scale, including claims that the products are suitable for blending. As yet no commercial plant has been constructed.

There are no clear-cut benefits of integrating any of the primary conversion or advanced pyrolysis processes in a refinery other than shared utilities and product logistics. This report therefore focuses on the use at refineries of “conventional” fast pyrolysis oils which might also be relevant to the power/heating sectors.

5.3.3.3. Refinery Integration - upgrading fast-pyrolysis oil to transport fuels

Conventional pyrolysis (main focus of this sub-section) and *hydro-thermal liquefaction (HTL) based oils* oils require extensive hydrotreatment to convert them into transport fuel blendstocks. Different studies have tended to focus on integrated pyrolysis-hydrotreatment, but in principle pyrolysis oil could also be upgraded in refinery hydrotreaters or hydrocrackers (e.g. [PNNL 1996; PNNL 2009]).The use of “raw” pyrolysis oil as a refinery feedstock has attracted significant R&D attention (e.g. [Arbogast 2012/2013/2017; Fogassy 2010; Lappas 2009; Mathieu 2017; Ensyn 2013; deRezende-Pinho 2017; Repsol 2016]).It is not easy; the raw oils have poor thermal stability creating a severe fouling risk, and the high oxygen content risks hot spots and hydrogen starvation in conventional refinery hydrotreating or hydrocracking reactors. Work on dedicated units e.g. [NREL 2016a] has shown that process conditions can differ significantly from those found in refinery process units. One conclusion is that “raw” pyrolysis oils need specialised “stabilisation hydrotreatment” to remove much of the oxygen before they can be used in existing refinery equipment.

Stabilised pyrolysis oils have an oxygen content similar or lower than lipids (~15%) so we have assumed they can be used in much the same way i.e. co-processing in existing hydrotreating units or conversion of a hydrotreater/hydrocracker to 100% renewable feed. In contrast to lipids – which make paraffinic distillates - the product in this case would be a mix of gasoline and diesel, both of which would be fairly aromatic. There might be some benefits (e.g. good gasoline octane rating) but also some potential disadvantages (e.g. blend limitations particularly with diesel). One might also consider routing conventional pyrolysis oils to a refinery FCC unit. Unfortunately, laboratory and refinery skid-trials have shown this to be problematic ([UOP 2016, NREL 2016b]) and there is considerable uncertainty about the product distribution. In principle this pathway could make use of under-utilised FCC units, but much work is needed before it looks viable. We do not have reliable data so we have not evaluated this sub-pathway any further.

Table 5.3.3.3-1 below provides some examples of potential integration based on the hydrotreating and hydrocracker units in the notional 160 kbbl/day refinery from the earlier sections. Again, this is a simple indicative estimate; the detailed integration and impact on refinery yields has been modelled in **Section 6**.

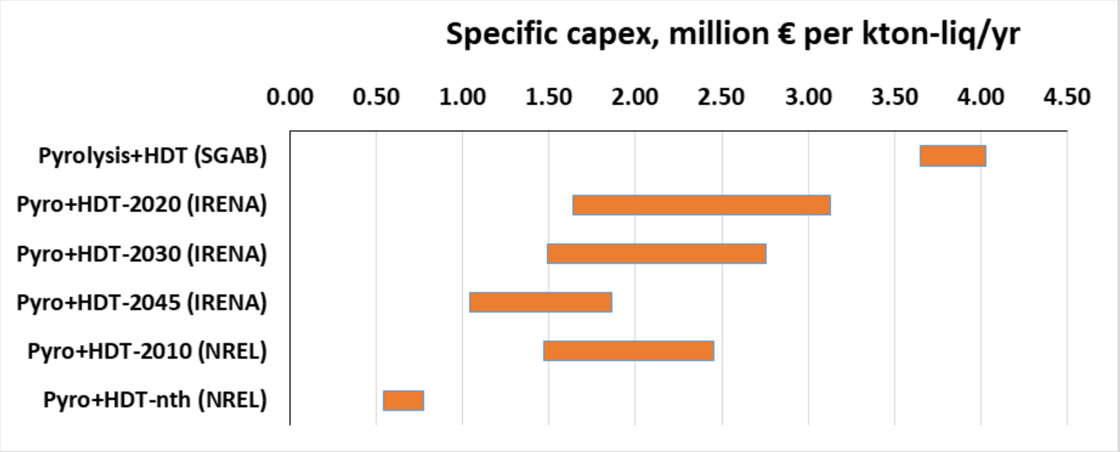
Table 5.3.3.3-1 Illustrative options for integration of Pyrolysis Oil within the notional Refinery (Note: a notional 160 kbbl/day crude oil refinery would make ~3.4 Mt/a of fossil diesel)

TYPE OF OPERATION	Co-processing stabilised pyrolysis oil and fossil VGO in existing hydrotreater		Transformation of existing hydrocracker to 100% stabilised pyrolysis oil	
	5% co-feed	30% co-feed	@ 50% of base capacity	@ 100% of base capacity
Renewable Road Fuels, Mt/a	0.1	0.6	0.5	1.0
Raw Pyrolysis Oil, Mt/a	0.2	1.3	1.1	2.3
Implications for refinery	Slight loss of fossil diesel production and crude capacity; demand for "on-purpose H_2" increased 30% to x2; re-optimisation of existing fossil units		Major loss of fossil diesel and crude capacity with closure of many fossil process units; demand for "on-purpose H_2" increased x2 to x4	

In all examples, the raw pyrolysis oil is first hydrotreated in a new dedicated "pyrolysis oil stabiliser". We have assumed that the stabiliser is installed in the refinery; it could in fact be installed anywhere in the pyrolysis oil supply chain, but locating it at the refinery takes advantage of the existing utilities and H_2 infrastructure. The first example involves co-feeding stabilised pyrolysis oil to the existing diesel hydrotreater; co-feed at 10% is taken as being representative of conventional technology, with 30% for stretch technology (provide that increased offgases, light-ends and effluent can be handled). If the economic case for renewable fuel becomes more compelling, then one might anticipate complete transformation of a process unit from fossil to 100% renewable duty. For consistency with previous cases, we have based this estimate on the conversion of a hydrocracker. The bio-feedstock to the refinery would be raw pyrolysis oil, which might give logistic advantages over solid wood. For reference, the equivalent wood consumption for the in-field pyrolysis plants would be ~0.3 to 1.8 Mt/a for the co-processing options, and 1.6 to 3.2 Mt/a for the transformation examples.

The capital cost of this pathway is not straightforward because investment is split between the "in-field" pyrolysis plant and a refinery-based stabilisation hydrotreater (which would be small, high-pressure and might need specialised metallurgy). **Figure 5.3.3.3-1** shows published estimates for capital intensities for pyrolysis plant with integrated hydrotreatment but no hydrogen production. For an example where the refiner feeds wood to its own pyrolysis unit, with the intermediate pyrolysis oil being stabilised in a new refinery-based hydrotreater, we have assumed net costs are similar to integrated-pyrolysis-HDT (1.5 to 2.5 M€ per kt/a). Where the refinery purchases raw pyrolysis oil for a third party, we have assumed refinery investment of 0.5 to 1.5 M€ per kt/a to cover the new stabilisation hydrotreater and HCK adaptation.

Figure 5.3.3.3-1 Capital Intensity of Integrated Pyrolysis Oil + Hydrotreatment (excluding cost of additional H_2 capacity)
Source: [SGAB 2017, IRENA 2016, NREL 2010]



5.4. E-FUELS DERIVED FROM CAPTURED CO_2 AND ELECTROLYTIC HYDROGEN

Key messages

- **Illustrative pathway:** Production of syngas (CO/H_2 mixture) from captured CO_2 + low-carbon electrolytic H_2 using renewable electricity. Syngas conversion to fuels by FT synthesis and wax-cracking
- **Product:** Mainly high quality renewable jet and distillates.
- **Feedstock:** Renewable electricity and CO_2 either from refinery SMR, refinery fired heaters or imports from 3rd party (potentially including *Direct Air Capture* systems in the long term).
- **Feedstock availability:** LBST/DENA [LBST 2017] suggest that solar and wind electricity allocated to e-fuels could reach ~2000 TWh/a by 2050 (equivalent to around 70 Mt/a of liquids assuming 44% efficiency). The EU long-term strategy *A Clean Planet for all* [EU 2018] estimates that e-fuels could represent from 0 to 28% of the energy demand in transport in 2050 (0-71 Mtoe/y). [Ecorys 2017] has a more conservative view: potential e-fuel production of 10 Mt/a by 2050 in a high scenario (Further detail can be found in Appendix 3, Chapter 3).
- **Conversion technology:** All elements resemble technologies which are used commercially elsewhere, although at very different scales e.g. existing FT technology is deployed at much larger scale than existing electrolysers. Integrated processes have only been demonstrated at pilot scale.
- **Synergies with existing refining assets:** Moderate; electrolyser, syngas production and FT would be new equipment in refinery or stand-alone; refinery-based system could use existing hydrocracker for final fuel finishing either by co-processing or unit transformation. Could be linked to CO_2 capture from an existing refinery e.g. from SMR or fired heaters. This approach includes options for co-processing in existing hydrocracking units, for conversion of refinery-hydrocrackers to dedicated e-fuels or for construction of new hydrocrackers making use of the existing refinery infrastructure. Due to the additional H_2 demand, additional production capacity could also be required depending on the scenarios/cases considered.
- **Technology & Supply-chain readiness:** Integrated technology at large-pilot scale with plans for commercial demos;
- **External requirements**: **Very high.** It needs very large renewable electricity supply, possible with new business model (e.g. for intermittency). Possible benefit if this reduces the need for CO_2 logistics e.g. pipeline from the refinery.
    - Developmental technology currently with higher capital costs (3.5-4 M€/t/d of liquid product) but potential to reduce capital intensity down to 1.1-1.7 M€/t. Future estimate: Total investment of 450-650 M€ for a 400 t/d plant consuming ~350-400 MWe (energy intensive process).

5.4.1. Choice of Example Pathway

Section 5.3 outlined the range of products which can be made from synthesis gas by gasification of coal, biomass and residual oils. A second route to syngas is provided by steam reforming of methane and light hydrocarbons. However, syngas can also be made by blending hydrogen and carbon monoxide. This leads to a "CO_2 capture and utilisation" (CCU) also described as "*e-fuel*" or "*Power-to-Products*".

The e-fuels concept involves the conversion of captured CO_2 into syngas using hydrogen made from water by electrolysis using renewable electricity. The CO_2/H_2 conversion process uses the catalytic "reverse water gas shift" reaction, with final conversion to different products for example using methanol or Fischer-Tropsch technology.

These pathways are considered to be low-carbon if powered using renewable electricity, and are often cited as an option to make use of low-price electricity during periods of surplus renewable power. Options for implementation include both distributed production for local consumption and small-scale centralised production for export e.g. 10-250 t/d of products [LBST 2017; JRC 2018a] with the detailed choice of pathway depending on the scale and application. For example, methanol has been proposed for long/medium-term energy storage as an alternative to pumped hydroelectric, batteries or compressed air energy storage. Note that these facilities would be significantly smaller than existing centralised facilities such as refineries.

This study concerns the potential for refinery integration and consequently will focus on the FT pathway, whilst recognising that methanol also might be used as an alternative transport fuel (Methanol blending is currently limited to 3% in conventional EN228 gasoline, but some regions allow the use of high methanol blends M70-M85 in modified vehicles).

5.4.2. E-fuel Technology

The basic sub-systems for e-fuels - electrolysis, CO_2 capture, CO_2 conversion & product upgrading – are all independently in commercial operation, although not necessarily at similar scales. Some developers are therefore considering new conversion technologies (e.g. CO_2/H_2O co-electrolysis) or new variants of existing technologies (e.g. modular FT synthesis).

Recent electrolyser projects in the range 5-10 MW might produce 2-4 t/day of hydrogen [ITM 2018b]; most of the other systems operate at scales of kt/d. Some integrated e-fuel processes are being demonstrated at small scale [Audi 2015; Sunfire 2017a], but proposed commercial plants are also small in comparison with conventional fuels plants. A recent announcement [Sunfire 2017b] describes a plant with an electrical capacity of 20 MWe leading to ~8 kt/a of products. Recent studies [LBST 2017, ITM 2018a] consider larger plants with a capacity of ~100 MWe which would correspond to ~100 t/d of products (~35 kt/a if operated continuously). For consistency with the other pathways, this section reports liquids production in units of tons, whereas many eFuel studies report liquid fuel production in GJ or kWh or litres[7].

Conversion & upgrading have already been demonstrated on world-scale GTL plants so are unlikely to constrain the upper limit to e-fuels plant capacity. On the other hand, the e-fuel plants cited above are small in relation to commercially demonstrated syngas technology and might be expected to operate intermittently or at partial-load. This may require new “down-scaled” technologies which are still at early stage of development e.g. modular FT [Velocys 2017]. It also increases the uncertainty in the capital costs (and might be expected to increase capital intensity compared with large conventional plant).

E-fuels is a developmental technology, so current capital costs are very high e.g. 3.5-4 M€/(t/d) of liquid products. Note that e-fuels plants might be operated intermittently, so capital intensity is based on instantaneous rather than annualised output. Long-term estimates for the capital intensity of e-fuels plant are in the range 1.1 to 1.7 M€/(t/d) of liquid product [JRC-2018a, LBST-2017]. This suggests total investment of 450-650 M€ for a 400 t/d plant [e.g. JRC-2018a] which would consume ~350-400 MWe. Carbon capture and electrolysis make up

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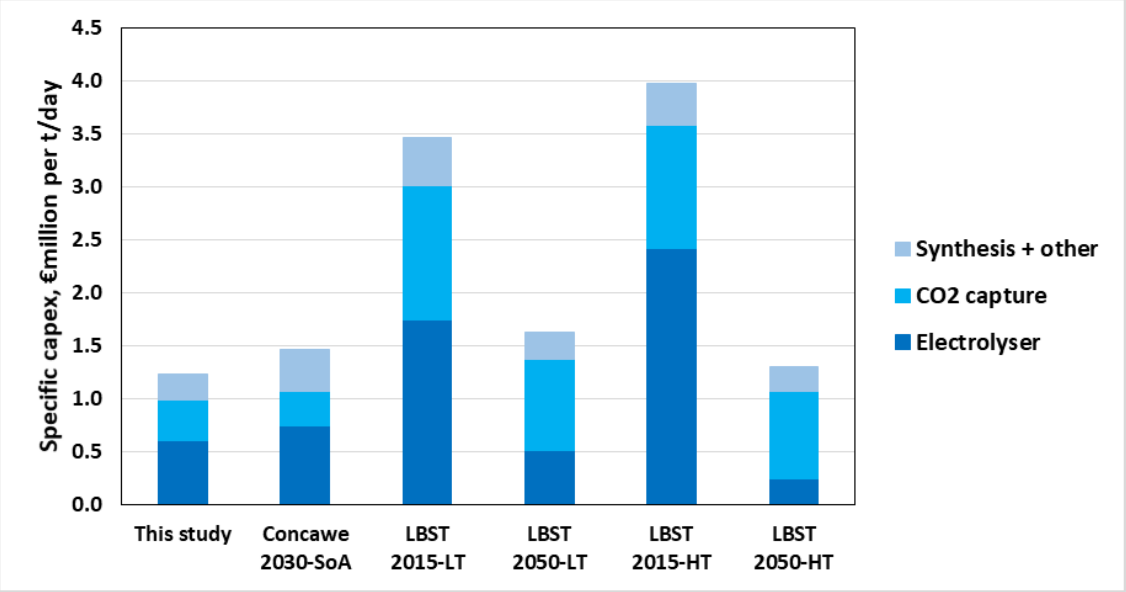
[7] Throughout this section we have assumed that the energy content of the liquid product is 44 GJ/ton-liquids and the density is 0,832 kg/l of diesel equivalent. Source: [LBST 2017].

75-80% of the total capital cost. Based on electrolyser and CO_2 capture costs from [Concawe 2019] and conversion unit costs used elsewhere in this report, this study estimates long-term e-fuel capital costs to be 1.2 to 1.5 M€ per t/d (See **Figure 5.4.2-1** below).

Figure 5.4.2-1 Capital intensity of e-fuel plants
Sources: This study, [Concawe-2018b], [LBST-2017]



Note. The LBST-2018 study assumes that electricity would cost 85 €/MWh in 2015; 110 €/MWh in 2050. LBST shows e-fuels at 130 to 140 €/GJ in 2015; 65 to 75 €/GJ in 2050. This corresponds to 5700-6200 €/t in 2030 falling to 2900-3300 €/t in 2050 (~2,5-2,8 €/l diesel eq). LBST shows the 2050 costs in more detail; it has fossil diesel at 0.55 to 0.6 €/litre (650-750 €/t) with e-fuels at 1.7 to 2.5 €/litre (2100-3000 €/t).

Our own calculations give similar production costs ~2500-3000 €/t (~2,2-2,5 €/l diesel equivalent) for the 2030 and 2050 Scenarios where electricity costs 60-100 €/MWh and represents 70-80% of the total cost of the renewable fuel. Some developers suggest that e-fuels could be operated intermittently to make use of low-cost “surplus” renewable electricity. This certainly reduces the electrical contribution to overall production cost, but capital charges and fixed costs now have to be repaid from a much smaller volume of product. If electricity is “zero-cost” for 10% of the time [Concawe 2019], then the contribution of capital charges and fixed costs would “concentrated” onto 1/10 of the volume of fuel, raising the production cost to > 5000 €/t (~4,4 €/l diesel eq). In comparison, fossil diesel from crude at $60/bbl with a Well-to-Wheel (WtW) GHG charge of 150 €/t would cost < 1000 €/t (< 0,9 €/l). To compete with fossil diesel, an e-fuels plant would have to find additional sources of value, for example sale of “grid stabilisation services”. This is outside the scope of the current study and so has not been explored further.

5.4.3. Refinery Integration of an e-fuels facility

The example pathway for refinery integration involves the use of the raw FT "e-wax" as co-feed to the refinery hydrocracker. The e-fuel facility would then not need its own hydrocracking and product recovery equipment, nor would it need storage or equipment to handle co-products such as LPG. Eliminating the hydrocracker element of the e-fuels project might reduce the capital cost of the e-fuel plant by a few % (Concawe estimate). A second integration option involves the use of the refinery's own CO_2 emissions as feed for the e-fuels plant; we have assumed the refinery does not have a pre-existing CO_2 capture system therefore this element should still be included in the e-fuel investment.

Table 5.4.3-1 shows some illustrative integration options.

The first case shows an e-fuels plant which provides 5% of the feed for the existing refinery hydrocracker. Its power requirement is ~120 MW i.e. roughly the same size as the power-to-gas (P2G) plants being considered by LBTS and ITM. Its CO_2 consumption would be ~1/10 of the refinery's total emissions, perhaps about the scale of small SMR. The second co-processing option (30% of hydrocracker feed) is 6 times larger, would need nearly 1 GW of electricity and would consume about half of the refinery's CO_2. The final case completely fills the refinery HC with "e-wax" but its electricity consumption is really high, almost 2.5 GW and would require CO_2 to be imported from other facilities nearby as part of a potential hub (CO_2 network) or, in the long term, eventually from Direct Air Capture facilities. To put this in context, the world's largest CO_2 capture plant today (on a coal-fired power station in the USA [GCCI 2017] has a single train absorber-regenerator with a capacity of ~1.4 Mt/a of CO_2 say 3800 t/d.

Table 5.4.3-1 Indicative integration of Notional Refinery with e-fuels
For reference: a notional 160 kbbl/day crude oil refinery would make ~9 kt/day of fossil diesel with direct CO_2 emission of ~4.5 kt/day.

TYPE OF OPERATION	Co-processing e-fuel wax and fossil VGO in existing hydrocracker		Transformation of existing hydrocracker to 100% e-fuel Wax
	5% co-feed	30% co-feed	@ 100% of base capacity
Renewable Gasoline + Diesel, t/day (kt/a at 100% utilisation)	120 (44)	715 (260)	2350 (860)
Electrical Input, MW-e	120	730	2430
CO_2 input, t/day (kt/a at 100% utilisation)	430 (160)	2600 (950)	8600 (3140)
Implications for refinery	Slight loss of crude capacity + re-optimisation of existing fossil units		Major loss of crude capacity with closure of many fossil process units

It is worth comparing the electrical demand with the scale of renewable energy facilities. Europe's largest wind-farms [EWEA 2013] have nameplate (peak) capacities in the range 0.5 to 1 GWe (although larger windfarms have been built in China and the USA). World scale solar farms also have nameplate capacities of 0.5 to 1 GW e.g. the 600 MWe Solar Star project in California [IMechE 2016]. Both wind and PV generation vary with conditions leading to capacity factors of 20%-40% [IRENA 2018, Figs 3.9 & 5.11]. This suggest that an e-fuel plant capable of converting roughly half of the refinery's CO_2 emissions and providing enough product for 30% coprocessing in the refinery hydrocracker would require the peak output of what is today a world scale-wind or solar farm, and the combined outputs of several farms to ensure continuous operation.

The previous paragraph is about facility scale, not about industry capability; renewable energy generation is expected to grow considerably in the next few decades. LBST/DENA [LBST 2017] suggest that solar and wind electricity allocated to e-fuels could reach ~2000 TWh/a by 2050. This is equivalent to around 70 Mt/a of liquids assuming 44% efficiency. [Ecorys 2017] has a more conservative view: they estimate a potential e-fuel production of 10 Mt/a by 2050 in a high scenario. (Further detail can be found in **Appendix 3**, **Chapter 3**). A single "refinery-hydrocracker" sized e-Fuel plant would make almost 1 Mt/a at 100% utilisation.

Electrolysis technology and electrical infrastructure are probably the key issues for scaling e-fuel plants to large capacity, with the nature of the electricity supply determining e-fuel production rate. An e-fuel plant using intermittent renewable electricity would have to be colossal if its production was expected to be a significant fraction of refinery output. The production of e-fuel at a scale approaching even a fraction of the existing fossil fuel industry would be hard to image. On the other hand, e-fuel might have an important role to play in some locations as an alternative to energy storage for mitigating renewable intermittency.

5.4.4. Large-scale renewable electricity supply

Data from the European Wind Energy Association (now Wind Europe) suggest that the EU's installed wind capacity was 129 GW in 2014, expected to rise to 192 GW by 2020 (EWEA 2015]. EWEA's central scenario anticipates 320 GW of EU (including UK) wind energy capacity by 2030; this is expected to produce 778 TWh. The EU's solar PV electricity generating capacity is somewhat smaller at ~100 GW at the end of 2016, producing ~90 TWh of electricity [JRC 2018a; Eurostats 2018].

The IEA WEO-NPS [IEA, 2017] cites wind and solar-PV as producing just over 1000 TWh/a in 2040. LBST's e-fuel report [LBST2018, Fig 4.6-4] estimates that the EU's potential for LC-electricity production is 12000 TWh/a, including 4700 to 8500 TWh/a of wind and 1500-2200 TWh/a of Solar-PV. According to LBST and DENA by 2050, max transport electricity for e-fuels could reach ~2000 TWh/a (7691 PJ/a), equivalent to around 80 Mt/a of liquids assuming 44% efficiency. DG R&I Ecorys has a more conservative view: they estimate a potential e-fuel production of 10 Mt/a by 2050 in a high scenario (Further detail can be found in **Appendix 3, Chapter 3).**

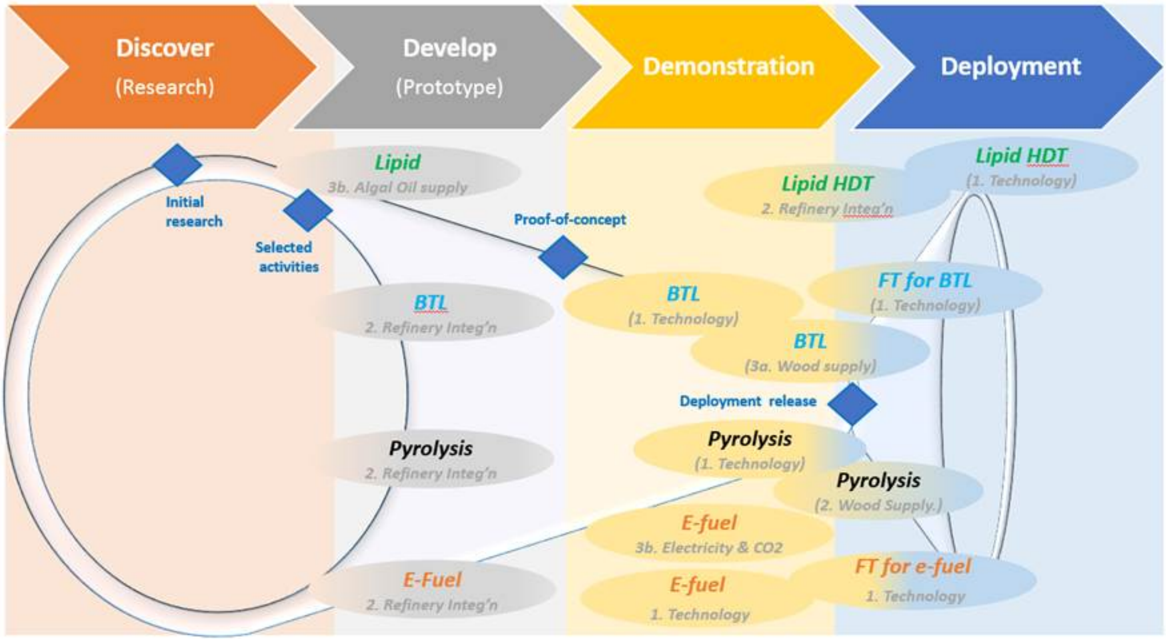
5.5. MAIN PATHWAYS FEATURES AND TECHNOLOGY & SUPPLY READINESS COMPARISON.

Table 5.5-1 and **Table/Figure 5.5-2** give a summary of the illustrative pathways including existing refinery equipment which could be utilised, new equipment which would be required, synergies through product blending and readiness levels for technology and supply chain. Numerical data such as yield structures and capital costs required for detailed system modelling are given in **Section 6**.

Table 5.5-1 Summary of example pathways features

PATHWAY	EXISTING REFINERY EQUIPMENT	NEW REFINERY EQUIPMENT	PRODUCT BLENDING	SYNERGIES with refineries
LIPIDS	Lipid to refinery diesel hydrotreater or hydrocracker	Lipid storage and cleaning; hydrogen production; possible expansion of refinery hydrocracker	High quality bio-jet and bio-distillate	Significant synergies and capex savings. Additional H_2 production could be low-carbon (SMR+CCS; Electro-H_2)
	Lipid to refinery FCC	Lipid storage and cleaning; hydrogen production	Bio-alkylate and low-S FCC gasoline (high octane; good blend stocks)	Significant synergies and capex savings. Co-products include renewable propylene and aromatics feedstocks.
BIOMASS GASIFICATION	FT product to existing hydrocrackers	Biomass handling; Biomass gasifier, syngas cleaning and FT-reactor; possible expansion of refinery hydrocracker	High quality bio-jet and bio-distillate	Moderate synergies regarding product quality and product slate optimisation - still need major investment for gasification & FT. Refinery site also provides space, infrastructure, skills and logistics
BIOMASS PYROLYSIS OIL	Stabilised pyro-oil to existing hydrocrackers	Pyrolysis oil storage and cleaning; Pyrolysis Stabiliser (HP-HDT); Hydrogen production; possible expmnsio of refinery hydrocracker	Acceptable bio-gasoline and bio-distillate (after polishing?)	Significant synergies and moderate capex savings. Additional H_2 production could be low-C (e.g. SMR+CCS; Electro-H_2)
	Raw pyro-oil to existing FCC	Pyrolysis oil storage and cleaning	Uncertain; R&D suggests aromatic gasoline & diesel	Significant synergies and moderate capex savings
E-FUELS	FT product to existing hydrocracker	Electrolyser and power infrastructure; Syngas conditioning and FT reactor; possible expansion of refinery hydrocracker	High quality bio-jet and bio-distillate	Moderate synergies regarding product quality, product slate optimisation and hydrogen management - still need major investment for electrolysers and FT. Refinery site also provides space, infrastructure, skills and logistics

Table/Figure 5.5-2 Technology & Supply chain readiness.



Code (Figure 5.5.-2)	Lipid HDT	BTL	Pyrolysis-Oil HDT	e-fuel
(1) **Conversion Technology**	Licensable technologies from several suppliers. Commercial up to ~1 Mt/a with conventional vegetable oils and fats	Sub-systems demonstrated with fossil feeds at Mt/a scale. Some commercial demo of biomass gasification (for power) but no integrated systems for BTL; BTL may need downscaled conversion technologies which are still at low TRL	Pyrolysis oil production demonstrated at small commercial scale for power-generation or heating; conversion to transport fuel still at low TRL	Conversion sub-systems demonstrated at scale for fossil feeds; integrated systems at large pilot level with small commercial demos being planning; may need downscaled conversion technologies operated with variable throughput - low TRL. CO_2 capture has been demonstrated at scale for flue-gas in power sector.
(2) **Refinery Integration**	Co-processing at low-level widely implemented; 2-3 examples of refinery transformation	Pilot studies only (for GTL)	Pilot work and poor feedback from refinery trials suggests that refinery processing still needs R&D	Pilot studies only (for GTL)
(3a) **Supply-chain**	Existing international trade of veg oils and fats. Commercial facilities operate up to ~1 Mt/a	Large-scale wood (Mt/a) supply demonstrated at niche locations in power sector	Large-scale wood (Mt/a) supply demonstrated at niche locations in power sector	May need new large-scale electricity infrastructure, possible with new business models (Eg. time-based pricing, incentives linked to renewables); would need new CO_2 capture facilities - already demonstrated for flue-gases.
(3b) **Raw material**	Wide adoption at scale would require additional feeds. E.g. Algae oils. Biology is still in R&D; low experience level with construction and operation of large algae farms (e.g. water management).	Commercial today, but would need substantial expansion of supply chain for forestry and/or crop-residues	Commercial today, but would need substantial expansion of supply chain for forestry and/or crop-residues	Special niches, otherwise needs massive expansion of LC electricity generation

6. MODELLING

6.1. MODELLING TOOL: RAFXL

For this work the RafXl refinery simulation tool was used. RafXl is an Excel-based model developed and jointly owned by Concawe and Institut Français du Pétrole. It can be made to represent any refinery configuration. It is entirely user-driven, the only assistance being provided by blending modules which find an optimum solution for each of the major product pools (gasoline, middle distillates, heavy fuel oils). From a user-defined crude oil diet and process plants utilisation, the model works out product yields and qualities, utility consumption and CO_2 emissions both direct (incurred on site) and indirect (embedded in utilities and hydrogen imports). Electricity and hydrogen can be imported and exported.

The model was adapted to meet the specific requirements of this study including processing of alternative (bio) feedstocks and CO_2 capture. The energy required for CO_2 capture was assumed to be, where applicable, waste heat from the Fisher-Tropsch process and/or electrolyser, supplemented by imported electricity.

CO_2 emissions associated with crude oil and alternative feedstocks production and transport were also taken into consideration to estimate the total carbon intensity of refinery operation and of the main products.

The model is fully balanced for total mass but also for carbon, hydrogen, sulphur and where applicable oxygen. It works out the carbon content of each product which make it possible to study the overall CO_2 emissions impact of certain changes including refinery direct and indirect emissions (from imported utilities) and potential combustion emissions of fuel products. It also separately calculates the proportion of renewable carbon both in emitted CO_2 and in carbon locked in products.

Although the model includes inspection properties for all streams and applies simple blending rules, accurate blending of such complex products as gasoline, jet and diesel fuel cannot credibly be done in such a generic study. Blending optimisation has therefore been limited to the main properties viz. sulphur and density with checks to ensure credible levels of RON for gasoline, cetane index for diesel and viscosity for heavy fuels.

6.2. MODELLING STRATEGY AND ASSUMPTIONS

Key messages

- Basis:
  - Refinery simulation tool **(RafXL) calibrated against 2008 data.**
  - Notional refinery simulated (160,000 bbl/d of crude oil intake).
  - Energy efficiency improvement rates of 19 and 22% in 2030 and 2050 respectively (from the 2008 reference), broadly representing the average between the "Median" and "High" cases detailed in the previous Concawe *CO_2 reduction technologies report*.
  - Carbon Capture (and storage) applied in selected cases. Waste heat from FT synthesis provided up to 80% of the capture energy demand (synergy).
- For each case, the capacity of the various process plants was adjusted (allowing extra new capacity where required) to best match the demand for all major products.
- For alternative low fossil carbon feedstocks product yields, utilities requirements and basic product properties were derived from literature data.
- Well-to-combustion fossil CO_2 emissions include:
  - Crude oil production and transport
  - Refining (including distribution although this is small and has been ignored here)
  - Bio-feeds contribution (fossil emissions from production and transport)
  - Combustion of final products (according to their fossil carbon content)
- The modelling exercise explores fossil fuel cases (**Section 7**) as well as examples of the deployment of the low fossil carbon feedstocks through two different separate cases: **limited case** (where the intake of alternative feedstocks in the notional refinery was limited to equivalent of 1 Mt/a liquid products - **Section 8.1**) and a **maximum case** (where alternative feedstocks provided the bulk of the intake, the residual crude oil intake being determined by the need to satisfy the demand for bitumen.- **Section 8.2**).

The main assumptions are described below:

6.2.1. Energy consumption and refinery fuel

RafXl was calibrated against data from the year 2008 used as reference in the previous Concawe study [Concawe 2019] and for which Concawe has a comprehensive data set for all EU refineries. This provided a realistic base level of energy efficiency and of composition of the refinery fuel.

The previous Concawe study assessed the energy efficiency improvement potential for a range of cases, each with different energy and CO_2 prices and return on investment threshold. We used improvement rates of 19 and 22% in 2030 and 2050 respectively (from the 2008 reference), broadly representing the average between the "Median" and "High" cases.

The calibration suggested that RafXl underestimates fuel gas make by 20-25%. Conservatively, gas import was subjected to a lower limit of 30% of the fuel gas make the extra 5% provides for the fact that, for operational flexibility reasons, gas could not be entirely eliminated (this also impacts on the room for increasing the level of electricity import level being constrained by the amount of this remaining gas).

6.2.2. Matching demand

The primary strategy was, for each case, to best match the demand for all major products from a given set of feedstocks by adjusting the capacity of the various process plants, allowing extra new capacity where required. In many cases, a perfect match could not be achieved particularly with regards to gasoline and middle distillate components for which there is currently and historically an imbalance in Europe. We endeavoured to minimise the imbalances and to keep them within historical ranges.

6.2.3. Scale

Although this study is concerned with the whole EU refining industry, the simulations represented a single refinery with a "notional" size today of 160,000 bbl/d of crude oil intake (about 7.5 Mt/a). This is a somewhat arbitrary size but it provides a realistic scale to assess the scale of individual plants and of the supply infrastructure for alternative feedstocks and imported electricity. All the same, most if not all of the options considered could be envisaged in larger as well as smaller refineries, with possible limitations in terms of a/o individual plant size. The total EU industry today has an aggregate crude capacity of 80 such average refineries. As demand decreases over time, so does the notional refinery intake and production. Note that, in reality, rationalisation is likely to occur across the industry so that the average refinery size might remain relatively constant (or even increase) with fewer sites still in operation in the future. Wherever appropriate we also provided figures scaled up to the whole industry assuming that all refineries would operate in a similar way. This is of course unlikely in reality but it is only meant to provide a view of what this would entail in terms of feedstock, hydrogen and electricity.

6.2.4. Electricity and gas supply

Electricity is imported into refineries for general purpose (motors, lighting etc) but also potentially at a much larger scale for heat and electrolytic hydrogen production. Gas is imported as a balancing fuel as well as feedstock for hydrogen production.

Imported electricity and gas were assumed to have the characteristics of the average EU grid [Concawe 2019]. Over time, it is expected that the carbon intensity of the electricity grid will be reduced. We have assumed an average generation efficiency of 59% and an emission factor of 211 / 40 t CO_2/GWh in 2030 and 2050 respectively. The fossil-carbon content of the grid gas is also expected to decrease, albeit to a much smaller extent (this may be achieved with bio-components, synthetic "e-methane" from CO_2 and electricity or spiking with renewably produced hydrogen). We have assumed 10% renewable carbon in the gas grid in 2030, increasing to 20% in 2050. Gas production and transport also entails a carbon intensity for which we used a figure of 16 g/MJ. These figures were taken into consideration to calculate indirect refinery emissions.

6.2.5. Electrification

In RafXl refinery energy can be specified in terms of direct fired fuel, imported heat and imported electricity. Where maximum electrification was targeted this was subjected to two constraints:

- Where applicable, the proportion of electricity on total refinery energy was adjusted in each case to comply with the fuel gas constraint, subject to a maximum of 40% (energy content basis) to account for the uncertainties around the massive electrification of all large process heaters. Conservatively, a residual amount of gas import was allowed.
- As highlighted in **Section 4**, the need to burn all fuel gas produced on site is another constraint for electrification.

6.2.6. Hydrogen production

Wherever allowable within the fuel gas constraint mentioned above, hydrogen was assumed to be produced from grid electricity via electrolysis (70% efficiency) rather than by SMR. The corresponding electricity consumption was included when assessing indirect emissions.

6.2.7. CO_2 capture and waste heat from FT synthesis

In line with the previous Concawe study [Concawe 2019], we have applied CO_2 capture only in 2050 and capped it to 35% of total site emissions. This is an average figure postulating that 50% of actual sites would capture CO_2 at an average rate of 70% of their emissions (a different figure was used in some specific cases as highlighted in the relevant sections).

CO_2 capture entails a significant amount of energy, mainly in the form of heat. Concentrated CO_2 streams a/o from hydrogen plants are more favourable in this respect. We have used figure of 1.1 and 8.1 GJ / t CO_2 for hydrogen plants and combustion installations respectively.

FT synthesis produces a large amount of waste heat which, where applicable, was used for up to 80% of the capture energy demand, the balance being supplied by grid electricity. In cases not involving FT, capture energy was assumed to be grid electricity. The balance of the waste heat was converted into electricity at 30% efficiency and taken into consideration in the overall electricity balance.

6.2.8. Crude oil EU-mix

In the majority of runs the blend of crude oils used for 2030-2050 was:

Table 6.2.8-1 Crude oil mix

Origin	Brent	Nigerian Forcados	Iran light	Ural	Kuwait
Class	Low sulphur		High sulphur		
	38%		63%		
	33%	5%	25%	32%	6%

Note. For the maximum low carbon feedstocks cases, the small amount of crude oil used was assumed to be 100% Kuwait.

6.2.9. Alternative “low carbon” feedstocks

The “low carbon” feedstocks pathways are represented in RafXL using new process sub-models each requiring a mass balance to estimate product yields, utilities requirements and basic product properties to assess blending into finished fuel products. Co-processing has been represented either by including a suitable low-carbon stream into the feedstock pool for RafXL refinery process sub-model, or by considering the low-carbon feed through a separate sub-model, then reducing the effective capacity of the corresponding RafXL refinery process sub-model. Basic yield patterns were obtained from a wide-range of publications (**Section 5 and 12**) then adjusted to give closed mass, carbon, hydrogen and oxygen balances to products which were consistent with RafXL.

Investment for “stand-alone” cases comes from third party public reports [SGAB 2017, IRENA 2016, LBST 2017] and data provided confidentially to Concawe [ZEP, JRC]. Investment for “Refinery Co-processing” has been estimated from additional equipment which would be required to allow co-processing. Investment for “Refinery-integrated” and “Refinery-conversion” cases was estimated by adjusting stand-alone costs to reflect re-use of existing refinery assets/equipment.

All pathways are at an early stage of development, in terms of technology and/or supply chain readiness, so the estimates **in Tables 6.2.9-1 and 6.2.9-2** have had to be based in the main on R&D reports, not on detailed commercial experience. This represents a significant uncertainty in the modelling; for example, capital costs could easily be +/-50%. Other additional mass balances are included in Section 13.4.

Table 6.2.9-1 Mass balance for some example pathways

Pathway	Lipid to HDT	Wood to BTL - HC (2)	Wet Pyro/HTL oil to Ref HDT (3)	e-fuel (FT-wax to HC) (4)
Feeds				
Lipids	-100.0			
Wood		-100.0		
Pyrolysis Oil			-100.0	
CO_2				-100.0
Products				
CO_2	5.1	111.6		
Water	8.2	23.2	48.6	81.8
H_2	-3.2	-	-6.2	-14.1
O_2 or (O_2 in air[1])	0.0	-58.1		
Char		1.3		
Fuel Gas	1.2	0.6	13.0	0.90
C3+C4	5.5	1.4		2.1
Gasoline	1.8	4.3	18.9	6.27
Diesel+Jet	81.4	13.5	25.7	19.8
Heavy FT Liquid	0.0	2.2		3.2

Notes:
In the mass balance presented above, negative values refer to inputs (e.g. liquid feed and hydrogen being consumed in the conversion process). Consequently, all products are identified with positive values.

Notes (Cont.):

[1] As pyrolysers are self-contain plants, the mass balance includes the air required to burn the offgases to generate energy.

[2] In this pathway, hydrogen consumption is balanced with the self-generated one. This means that the produced hydrogen in the Wood-to-BTL process is consumed in the Hydrocracker unit (HC) to obtain the final range of products presented in the table. Wood is imported to the refinery in large quantities.

[3] In opposition to the previous Wood-to-BTL pathway [2], Pyrolysis/HTL plants could be built at small scale and they may offer opportunities to circumvent transport of large quantities of wood to longer distances. To represent this case, this balance considers that the Wood-to-HTL oil step takes place out of the battery limits of the refinery. Therefore, HTL oil is deemed to be imported into the refinery as a main input (instead of the wood itself) and an additional production of H_2 is required. In Section 13.4, an additional mass balance is presented for information and comparative purposes: Wood-to-pyrolysis/HTL, (where wood is imported to the refinery as the main input, instead of the Wood-to-pyrolysis/HTL oil).

[4] In this case, hydrogen is considered as a pure import product to the refinery (instead of electricity as utility). As a reference, the amount of H_2 used in the FT reactor is 0.3-0.4 kg H_2 per kg of product and in the hydrocracking section is <0.01 kg H_2 per kg of product.

In Section 13.4, an additional mass balance is included where all the hydrogen, required for both e-fuels production and its subsequent conversion process in the HC unit, is produced from renewable electricity in electrolysers installed within the battery limits of the refinery. In the mass balance this means that the hydrogen is not presented as an input neither an output and only electricity consumption in considered as an input as an utility). When reported in the mass balance table, this means that electricity is the main input (utility) and, therefore, hydrogen is not included as such in table 6.2.9-1.

Complementing the mass balances (**Table 6.2.9-1**), the specific investment for some selected pathways are also presented in the table below:

Table 6.2.9-2 Specific investment for example pathways

Specific capex	€/kW-liq		M€/kt-liq/a	
	Low	**High**	**Low**	**High**
HVO, co-pro	6	122	0.01	0.20
HVO, ref conv	244	366	0.40	0.60
HVO, stand-alone	488	732	0.80	1.20
Stand-alone BTL, wood feed	2439	3658	4.00	6.00
Refinery BTL, wood feed	2195	3292	3.60	5.40
Refinery Pyro+HDT, wood feed	914	1524	1.50	2.50
Refinery HDT for bio-oil feed	305	914	0.50	1.50
Standalone e-fuel	2300	2700	3.77	4.43
Refinery e-fuel	2260	2670	3.71	4.38

Note: The modelling in this study assumes that ALL plants operate at 85% utilisation & product LHV=44 GJ/t. Alternatively, if e-fuel was assumed to operate intermittently using sporadic« surplus » renewable energy then its utilisation might be limited <25% and a proportionately higher annualised cost would be needed. See **Section 5.4.2.**

Although the carbon embedded in lipids and woody biomass is of bio origin, production and transport entails emissions of some fossil CO_2 as well as other GHGs (e.g. nitrous oxide from agriculture). Based on findings from JEC WTW studies we have assumed that the fossil intensity (as CO_2 equivalent) of lipids and woody biomass represent a maximum of respectively 20% and 10% of their total carbon content (due to the consumption/usage of fossil fuels at the different production /processing /transport stages). Although lipids and biodiesel are of a similar nature, the much lower figure for lipids compared to current biodiesel (see below) is premised on more advanced processes and sources assumed to become available over time. As will be further illustrated in **Section 8** and beyond, this "residual" fossil carbon has a bearing on the final emissions from both refinery sites and combustion of finished products.

Estimation of “Well-to-combustion” emissions for fuel products

The total “Well-to-combustion” product carbon intensity includes emissions from:

- **Crude oil production and transport**

  The figure associated with crude oil production and transport is commonly allocated between all refinery products on a mass basis (the figure used here was 9.7 g CO_2/MJ).

- **Refining**

  Distribution of refinery emissions between products is not straightforward and has been the subject of many discussions which are beyond the scope of this study. A simplistic approach has been followed here for the alternative feedstock cases, allocating all emissions to distillate products on a mass basis to allow us to conduct a comparison in a simple way. A more rigorous allocation, based on a marginal approach, would need to be conducted before considering these values representative ones. For simplicity, note that distribution of final products has been ignored here.

- **Biofuel contribution** (fossil emissions from biofuel production)

  As mentioned in **Section 3**, some ethanol and biodiesel were assumed to be blended into gasoline and diesel (as per **Table 3.3-1)**. Conservatively, we assumed equivalent fossil carbon intensity typical of current production (Well-To-Tank, [JEC WTW v4]), i.e. 25 and 57 g CO_2eq/MJ for ethanol (assumed to be first generation) and biodiesel respectively (the high figure for biodiesel is mostly related to N_2O emissions in agriculture).

- **Combustion**

  Combustion emissions were worked out from the fossil carbon content of each product taking into account the net biogenic carbon content of each product (by tracking the fossil carbon content of each stream through the RafXl model).

6.3. MODELLING OUTPUT

The model produces a large amount of information to describe various aspects of refinery operation and of product output and quality including:

- Feedstock composition and implied EU-wide requirements
- Product output versus demand and resulting import/export requirements
- Product carbon content and overall “Well-to-Combustion” carbon intensity
- Product key properties
- Process plant utilisation (compared to existing plants) and implied individual plant sizes
- Refinery direct and indirect (fossil and renewable) CO_2 emissions

Detailed results are tabulated in **Section 13** including a chart (see **Section 13.1**) describing the **terminology** used to refer to the CO_2 emissions (indirect, direct and fossil / non-fossil related) and analysed in more details in the next sections.

7. REDUCING REFINERY CO_2 EMISSIONS: FOSSIL FEEDS CASES

Key messages

- Reduction of demand for hydrocarbon fuels at the 2030 and 2050 horizons will lead to extensive adaptation of the EU refining industry and much existing processing capacity will be underutilised. Industry restructuring and replacement of ageing plants may result in a potential call for new capacity in crucial process units.
- After improving internal energy efficiency, substitution of gas by imported low-carbon electricity and CO_2 capture are the two main routes towards lower total refinery emissions. Reductions of up to 75% may be achievable by 2050 provided ample supplies of affordable low-carbon electricity materialise and the right conditions exist for successful implementation of CO_2 capture at scale. Large scale electrification of refinery energy, either directly or via electrolytic hydrogen, could lead to very large electricity demand.
- Reducing refinery emissions has, however, only a small effect on the carbon intensity of fuels which is overwhelmingly determined by their fossil carbon content.

Section 4 summarised the findings of [Concawe 2019] detailing possible options to reduce refinery CO_2 emissions (scope 1 and 2). A number of cases were run to illustrate the combined impact of these measures and of the different demand scenarios at the 2030 and 2050 horizons on conventional oil refining operations in Europe.

Table 7-1 Fossil feeds cases

Code	Demand scenario	Description	Crude intake(1) (kt/a)
30 FOS ref	2030	Reference case with no reduction measures from 2008 actual level	6350
30 FOS		2030 reduction measures	
50/1 FOS	2050 / 1	2050 energy efficiency level. Limited electrification, no electrolytic hydrogen	5020
50/2 FOS	2050 / 2		4300
50/2 FOS_e		as 50/2 FOS + maximum electrification and CO2 capture	
50/2 FOS_h		as 50/2 FOS + maximum electrolytic hyd. and CO2 capture	
50/2 FOS_c		as 50/2 FOS + CO2 capture	

(1)In notional 160 kbbl/d refinery, 2030 EU-mix quality

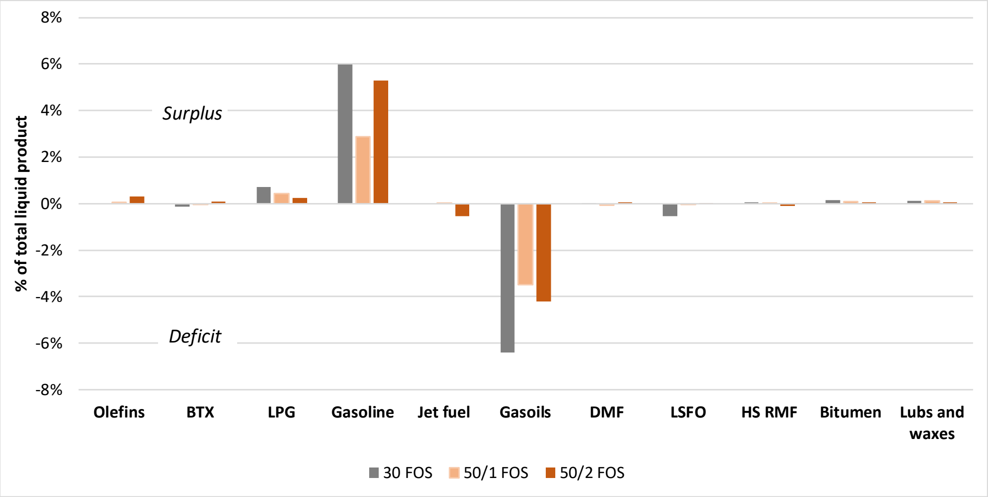
Notes

- **30 FOS ref** is the reference case illustrating how refineries would perform under the 2030 demand scenario if they had not improved since 2008 (this is the reference year for which Concawe have a full and consistent set of data).
- **30 FOS** shows the impact of the CO_2 reduction measures assumed to be achievable by 2030 (additional cases showing the impact of 2050 reduction measures with the 2030 demand scenario are included in **Section 13**).
- **50/1 FOS and 50/2 FOS** respectively relate to the 2050 demand scenario 1 and 2 assuming 2050 level of energy efficiency but limited electrification and no introduction of electrolytic hydrogen.
- **50/2 FOS_e/h/c** illustrate three possible routes to ultimate CO_2 emissions reduction through electrification (including electric heaters but limited to 40% of total refinery energy, see **Section 6.2.5**), electrolytic hydrogen and/or CO_2 capture. In cases involving intense electrification (50/2 FOS_e and _h), availability of low carbon electricity is implied so we have assumed that capture heat would be produced from imported electricity. In 50/2 FOS_c capture heat was assumed to be produced from gas.

7.1. PRODUCTION AND PLANT CAPACITY REQUIREMENTS

Figure 7.1-1 shows the difference between production and demand for 2030 and each of the 2050 scenarios, expressed in % of total liquid product. The figure reflects the familiar imbalance between the gasoline and middle distillates which is a well-known issue in Europe. The deviations are relatively small though and remain within historical bounds (see EU-wide modelled and current figures in **Section 9.2**).

Figure 7.1-1 Production - demand



A reasonable match between production and demand was achieved, with deviations within historical bounds

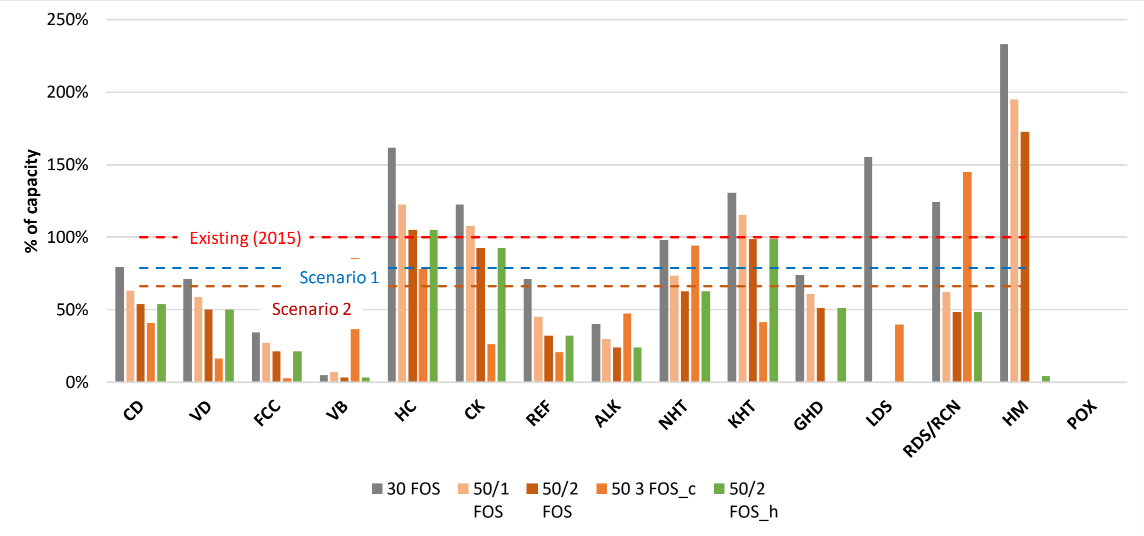
This is achieved with process plants utilisation shown in **Figure 7.1-2** expressed in % of the average existing capacity of each plant type (i.e. the total installed EU capacity divided by 80 refineries). The figure also shows notional "Scenario 1/2" horizontal lines illustrating a potential capacity reduction in line with the demand reduction implied by each scenario (note that, whereas declining demand is likely to trigger capacity reductions, these would, in reality, not be equal across all process units).

The 2030 scenario is in many respects the most challenging because the demand is still relatively high while the demand barrel is evolving towards a larger proportion of middle distillates (partly due to the increasing demand for distillate marine fuels), coupled with a strong demand for low sulphur residual marine fuel. This creates a call for additional capacity in hydrocracking, coking, residue desulphurisation and hydrogen manufacturing. By 2050, demand is lower and existing capacities appear to be generally adequate (the deficit in hydrogen manufacturing reflects to an extent the fact that a significant proportion of hydrogen consumed today is produced outside the refinery jurisdiction). Potential contraction of the industry with falling demand may still result in a need for extra new capacity a/o in hydrocraking, coking and (kero) hydrotreating.

Many plant groups are underutilised in all cases, mainly FCCs and reformers, again reflecting the shift towards middle distillates and the strongly decreasing gasoline demand.

This analysis provides an insight into the likely configuration of future EU refineries. The required new plants capacity is, however, most likely to be much higher than suggested by the simple comparison in **Figure 7.1-2**. Indeed, rationalisation and closures of some sites will result in capacity loss, while many plants may reach their end-of-life and need to be replaced over the next 30 years.

Figure 7.1-2 Process plant utilisation



Demand reduction will free some existing capacity but industry restructuring and replacement of ageing plants may result in a call for new capacity in crucial process units at site level.

Note 1. The dotted lines apply the overall percentage of demand reduction considered in the scenarios 1 & 2 (see **Section 3**) to the existing plant capacities.

Note 2. Reduction of demand for hydrocarbon fuels at the 2030 and 2050 horizons will lead to a transformation of the EU refining industry. Some existing processing capacity will be underutilised or closed, but other process units might switch to processing alternative feeds. The rate at which crude processing declines relative to the growth of alternative feedstocks will determine, among other factors, whether this transformation can be met by existing process units capacity (e.g. HDT/HC) possibly with some replacement of ageing plants or whether some new capacity might also be required.

Process plants abbreviation key

CD	Crude distillation
VD	Vacuum distillation
FCC	Fluid Catalytic Cracking
VB	Visbreaking
HC	Hydrocracking
CK	Coking
REF	Catalytic reforming
ALK	Alkylation
NHT	Naphtha hydrotreating
KHT	Kerosene hydrotreating
GHD	Gasoil hydrodesulphurisation
LDS	Atmospheric residue desulphurisation
RDS/RCN	Vacuum residue desulphurisation / conversion
HM	Hydrogen manufacturing

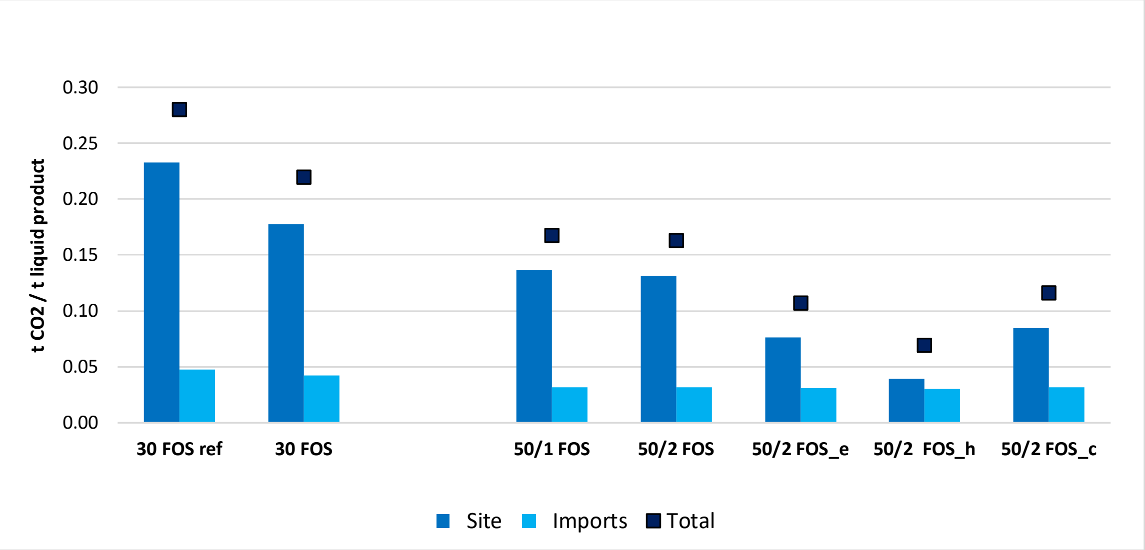
7.2. CO₂ EMISSIONS AND ENERGY

CO_2 emissions incurred on the refinery site (direct) and from imported electricity and gas production (indirect) are shown in **Figure 7.2-1** in relation to total liquid product. Implementation of the reduction measures discussed in **Section 4** lowers total emissions by about 22% in 2030 and up to 75% by 2050 and site emissions by 24 to 83%. Electrification plus CO_2 capture or CO_2 capture on its own offer similar reductions. Note that this is premised on the limited capture scope (70% capture in 50% of all installations). Because of the lower production, absolute reduction would be larger (see **Section 9.3**).

In the *Concawe* CO_2 reduction *technologies* study [Concawe 2019] the maximum achievable proportion of electricity in the total refinery energy was just short of the 40% assumed practical maximum (see **Section 6.2)**. The changes in demand pattern included in this study, change in turn the type of processing applied and the associated fuel gas make, and appear to create additional headroom for electrification. In case 2 FOS_e the proportion was set at 40%. This still left a “surplus” of gas import which could be reduced in case 2 FOS_h by substituting in-house hydrogen with imports thereby further reducing emissions (this case embodies the implied assumption of ample availability of affordable low-carbon imported electricity in this timeframe). CO_2 capture achieves another 15% emission reduction.

It must be noted, however, that the high level and simplified modelling applied here may not represent the fuel gas constraint accurately and may be overoptimistic in this respect.

Figure 7.2-1 CO_2 ***emissions*** from refinery site (direct) and from imports (indirect)



Total emissions reductions of up to 75% may be achievable by 2050 versus the 2030 reference case, provided ample supplies of affordable low-carbon electricity materialise and CO_2 capture can be successfully implemented

Figure 7.2-2/3 respectively show gas and electricity imports, the latter split between processing, CO_2 capture and electrolysis. On an EU-wide basis and if the whole industry followed that route, electricity demand for the 2 FOS_h case would be about 190 TWh/a, about 7% of the total EU-28 electricity demand today.

Note: gas imports in the reference case are much higher than is currently the case in EU refineries. This results from a combination of factors including lower energy efficiency (2008 level), no liquid fuel firing, reduced utilisation of key processes such as FCC and catalytic reformers).

Figure 7.2-2 Gas imports (% of total internal energy)

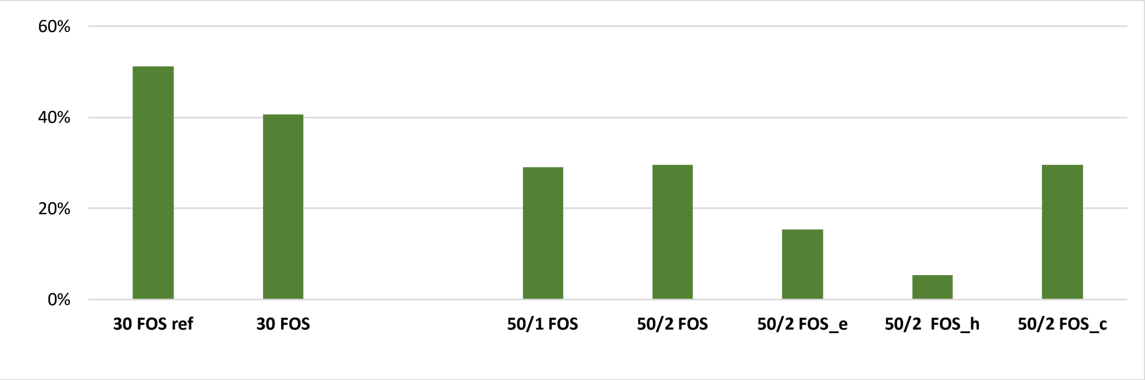
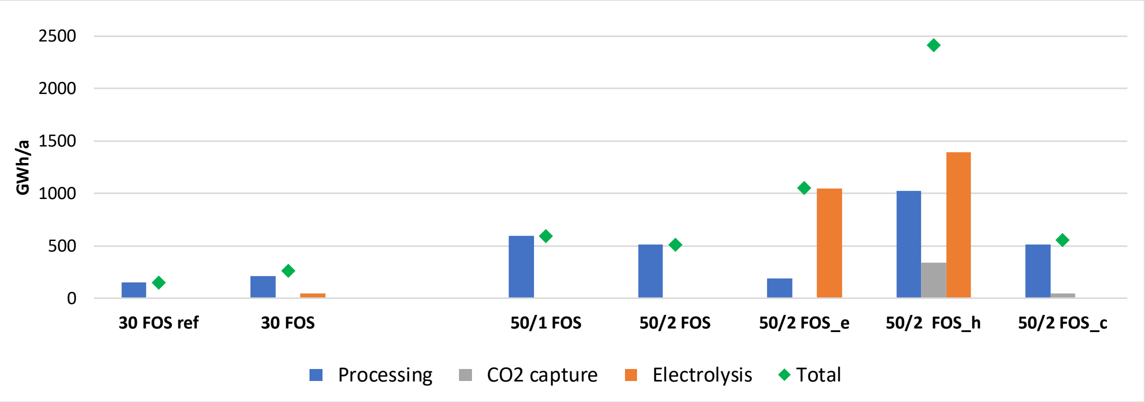


Figure 7.2-3 Electricity imports



Note: EU refineries 2015 total electricity consumption 33,000 GWh (average of about 400 GWh/a per refinery), just over 1/3 being imported.

Electrification of refinery energy, either directly or via electrolytic hydrogen, could lead to very large electricity demand

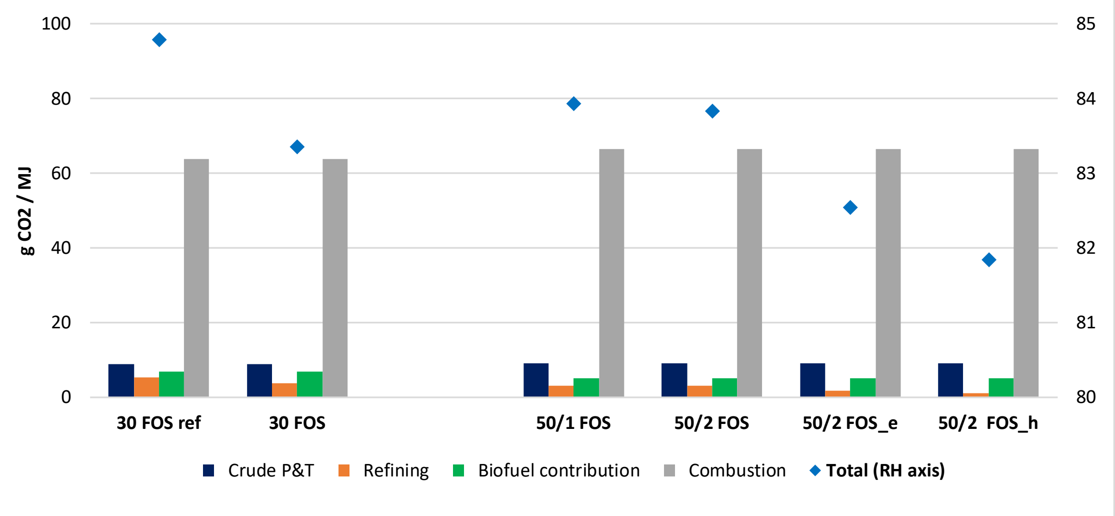
7.3. PRODUCT CARBON INTENSITY

The overall fuel carbon intensity (or so called "footprint") is the total of the emissions incurred during the various production stages and of the potential emissions from the fossil carbon embedded in the finished fuel. It includes:

- Crude oil production and transport
- **Refining** (taking into account non-fossil carbon in refinery fuels e.g. imported gas)
- **Blended biofuels**: fossil contribution from production and transport
- **Combustion in the vehicle**: potential CO_2 from embedded fossil carbon, taking into account bio components.

Figure 7.3-1 shows the corresponding emission factor build-up for diesel. The total figure is overwhelmingly determined by the CO_2 formed during combustion so that the reduction is modest, roughly from 85 to 82 g CO_2/MJ. A similar picture applies for the other main products such as gasoline and jet fuel. In other words, improving the refinery CO_2 efficiency has a small impact on the total footprint of products.

Figure 7.3-1 Diesel CO_2 emission factor



The carbon footprint of fuels is overwhelmingly determined by their fossil carbon content. Reducing refinery emissions has only a small effect

8. REDUCING THE CARBON INTENSITY OF REFINERY PRODUCTS: ALTERNATIVE “LOW FOSSIL CARBON” FEEDSTOCK CASES

Section 5 discussed options that would address the carbon intensity of hydrocarbon fuels by reducing their fossil carbon content (scope 3). This would be achieved by introducing “low carbon” feedstocks into the refinery environment. Three main routes were considered:

- Lipids, i.e. bio oils produced from various sources, could be brought into the refinery environment and hydrotreated / hydrocracked to marketable middle distillates (this is already in use to produce what is commonly known as HVO).
- Woody biomass (actual wood or grasses) could be processed into liquids and subsequently (hydro) treated to marketable products. There are two main routes for this either gasification or synthesis (the “Fischer-Tropsch” of FT route) or some form of pyrolysis. The FT route would lead mainly to middle distillates whereas the pyrolysis route would produce a more balanced product slate.
- Electricity (from low-carbon sources) and CO_2 to produce so-called e-fuels. For this report we have assumed a focus on FT-distillates, whilst acknowledging that local circumstances might lead to a preference for other e-Fuel products such as methanol or gasoline.

The RafXl model was used to simulate a number of cases involving the feedstocks and processes described above with a view to shed some light on:

- The feasibility of introducing such schemes into existing EU refineries,
- The scale that could reasonably be envisaged,
- The resulting match between production and demand,
- The ultimate impact on CO_2 emissions both from production facilities and from product combustion.

In the foregoing, figures for the alternative cases are presented in comparison with the reference case (30 FOS ref) and case 2 FOS_h, the most advanced of the fossil cases.

8.1. LIMITED LOW CARBON FEEDSTOCKS CASES (INDIVIDUAL ASSESSMENT)

Key messages

- In a first series of cases, the remaining crude oil intake required to satisfy 2050 demand was reduced by just under a quarter, the shortfall being provided by one of the alternative feedstocks under consideration. Different cases were modelled exploring the different routes individually to produce around 1 Mt/a of liquid feed (even though this may not be realistic, no combination of alternative feedstocks is considered at this stage, aiming to understand the implications for each of the pathways independently).
- In these "limited penetration" cases, existing installations would generally be able to accommodate the new feedstocks by adaptations of process plants and other facilities. Additional investment would still be needed for front end processing of raw feedstock, supplement insufficient capacities of crucial processes (mostly hydrocracking and hydrogen production) and adapt infrastructure significantly for electricity import.
- Fossil emissions from the refinery site would not be reduced unless the bio-feedstocks and imported electricity achieved an almost totally fossil carbon-free footprint.
- Production of e-fuels at this scale would require massive amount of imported electricity with attendant infrastructure.
- The fossil CO_2 intensity of middle distillates, including the "well-to-tank" production pathway and the potential combustion emissions (see Section 7.3) could be reduced by about 25%.

A first series of runs envisaged limited penetration of such feedstocks, to a level at which the size of individual facilities would be broadly within the range of current commercial experience (where it exists) and existing refinery plants and infrastructure could absorb and treat the new feedstocks and raw products. Within the context of our "notional" refinery, this was set at around 1 Mt/a of liquid feed. In demand scenario 2 this corresponds to substituting about a quarter of the crude oil left after implementing the 2050 demand scenarios by alternative feeds.

Table 8.1-1 Limited Low-C feedstock cases

Code	Crude intake[1]	Low-C feedstocks[2]			
		Type / processing route	kt/a	Refinery feed	kt/a
L1	3280	Lipids	1000	Lipids, of which	1000
				Co-processing GHT	20%
				Co-processing HC	20%
				Dedicated HT	60%
BFT1		Biomass / FT route	4250	Raw FT liquids	935
BPY1		Biomass / HTL route (pyrolysis)	2250	HTL oil	970
FOE1	3300	90% internally produce CO2	466	e-fuel liquids	1020
		Additional CO2 imported	2700		

Demand as per 2050 / 2 scenario

Refinery emission reduction measures at 2050 level in all cases

(1)In "notional" refinery, 2030 EU-mix quality

(2) To produce around 1 Mt/a liquid feed in "notional" refinery

L1 is a pure lipids case. As discussed in **Section 5.2**, a variety of processing options are available. By way of example we have assumed 20/20/60% processing respectively in gasoil hydrotreater, co-processing in existing hydrocracker and dedicated hydrotreater.

The next two cases use purely biomass. BFT1 uses the gasification / Fischer-Tropsch synthesis / hydrocracking route (see **Section 5.3**). BPY1 assumes import of HTL oil (a form of pyrolysis oil) into the refinery environment for processing mostly into FCCs (see **Section 5.3**). Note that the HTL process is assumed to take place near the biomass production sites and is not taken into consideration in the refinery balances.

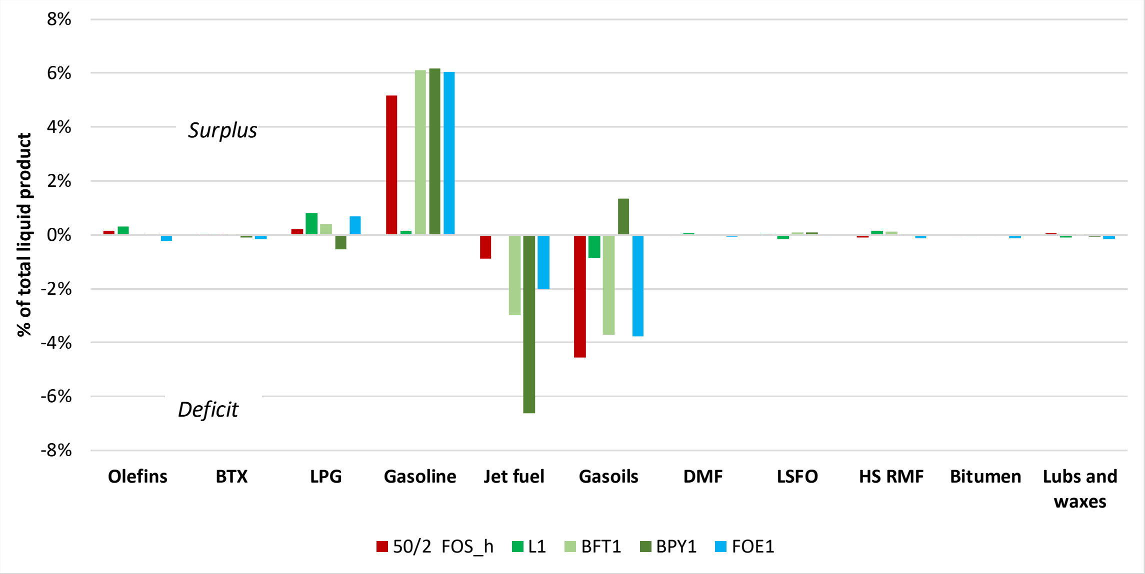
Only a modest amount of e-fuel could be made from the refinery own CO_2 emissions. In order to reach a total alternative fuel amount similar to the previous cases (1 Mt/a), the last case (FOE1) assumes that e-fuels are produced from a combination of captured own CO_2 supplemented by imported CO_2. In this specific case we have assumed maximum own CO_2 capture (90%). This makes the implied assumption that substantial sources of CO_2 could be made available to the refinery (probably from other energy-intensive industries in the locality).

8.1.1. Production and plant capacity requirements

Figure 8.1.1-1 shows the difference between production and demand for the notional refinery. In all cases a reasonable match could be obtained for the main distillate products with EU-wide deficits and surpluses within historical bounds (see EU-wide modelled and current figures in **Section 9.2**).

The lipids case (L1) provides the best match as it conveniently rebalances the gasoline / middle distillate yields. The other cases do not offer any improvement over the purely fossil case but remain more of less within the same bounds.

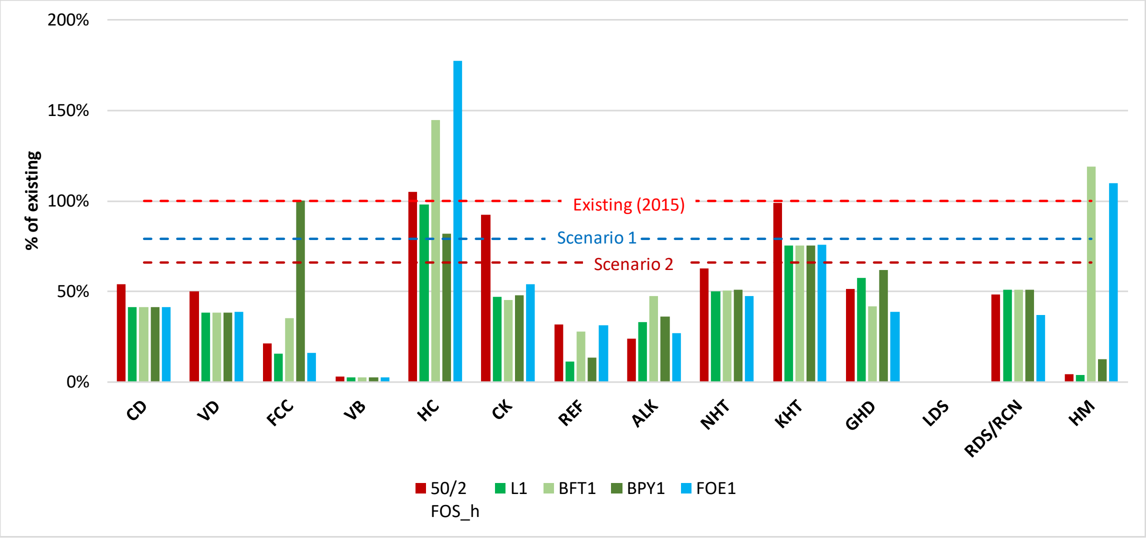
Figure 8.1.1-1 Production – demand



A reasonable match between production and demand was achieved, with deviations within historical bounds

Figure 8.1.1-2 shows process plants utilisation as a proportion of existing average capacities. All plants are utilised at a level well below the average of existing facilities, with the exception of hydrocrackers for BFT1 and FOE1 (required to process the raw FT product) and hydrogen plants (SMRs) in the same two cases. In BPY1, FCC are fully utilised to process HTL oil. The caveat regarding actual new plant capacity requirement expressed in **Section 7.1** is of course also valid here.

Figure 8.1.1-2 Process plant utilisation



Demand reduction and use of alternative feeds will free some existing capacity in the notionale refinery used as example but new processing routes as well as industry restructuring and replacement of ageing plants may call for new capacity in specific process units. BPY1 is the main route modelled as an example of a potential pathway where FCC utilization is maximized.

Utilisation of SMRs is dependent on the refinery fuel gas balance, with priority being given to electrolytic hydrogen import wherever possible (see **Section 6.2**). The sources of hydrogen are further illustrated in **Table 8.1.1-1**.

Table 8.1.1-1 Hydrogen production (kt/a)

Case	50/2 FOS_h	L1	BFT1	BPY1	FOE1
SMR (general purpose)	0.8	0.7	20.5	2.2	18.9
Electrolysis (general purpose)	29.0	59.0	0.0	80.0	0.0
Electrolysis (e-fuels)	0.0	0.0	0.0	0.0	445.2
Total	29.8	59.7	20.5	82.2	464.2

Note: In FOE1 case, hydrogen is considered as an intermediate product within the battery limits of the refinery, produced from renewable electricity.

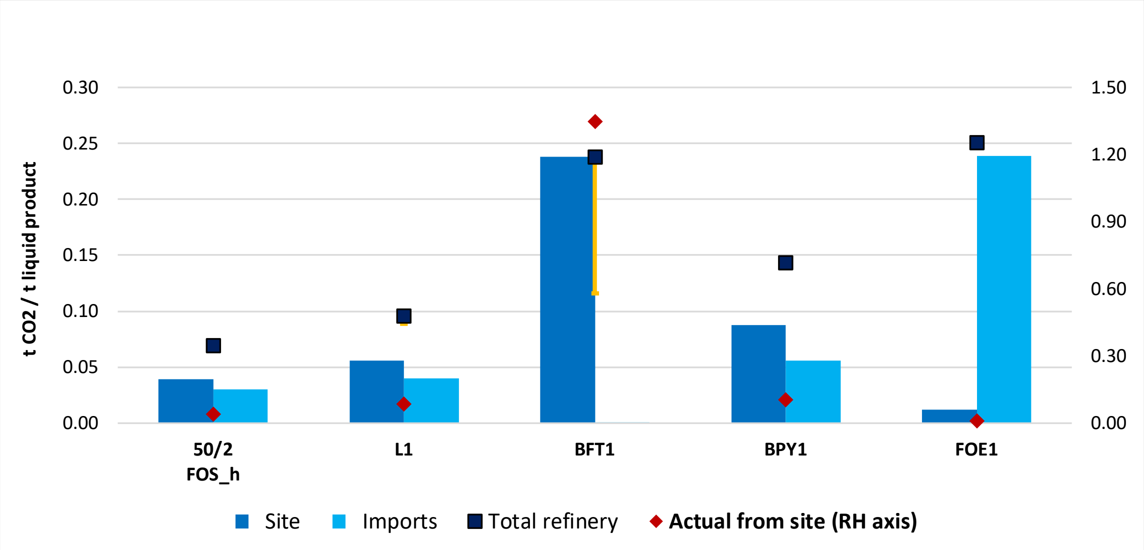
8.1.2. Net fossil CO_2 emissions and energy

The **net fossil CO_2 emissions** incurred at the refinery site (direct) and from imported electricity and gas production (indirect) are shown in **Figure 8.1.2-1**. It also shows the **Actual** emissions from site (including both fossil and biogenic CO_2 emitted as a result of part of the alternative feeds carbon being turned into CO_2 within the refinery as part of the production process). All cases result in higher emissions than the best fossil case. This is because of a combination of factors:

- Bio feedstocks contain oxygen, some of which is recombined during processing with biogenic carbon from the feedstock to form CO_2. When, as assumed here, the bio feedstocks have a partially fossil footprint (see **section 6.2.9**) some of the CO_2 emitted in the conversion of these feedstocks within the refinery is effectively fossil. The error bars show the range of emissions that could be avoided if the bio-feedstocks became fully renewable (the impact is only material for BFT1 because of the large amount of biogenic CO_2 produced when processing the biomass).
- Imported electricity (used massively in FOE1) also has a fossil component. Site emissions are high for BFT1 because of the large amount of biomass (with a partially fossil content) processed, and very low for FOE1 because of the assumed 90% rate of CO_2 capture.

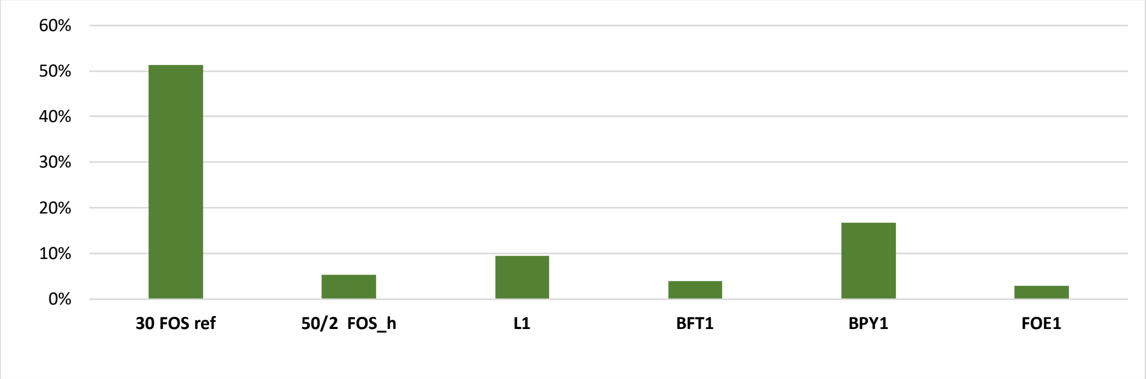
Achieving complete renewability of feedstocks (using renewable energy in the production and transport of those feedstocks) and electricity (importing 100% renewable electricity from the grid) would remove these terms in the alternative feedstock cases considered.

Figure 8.1.2-1 CO_2 emissions from refinery site (direct) and from imports (indirect***)***



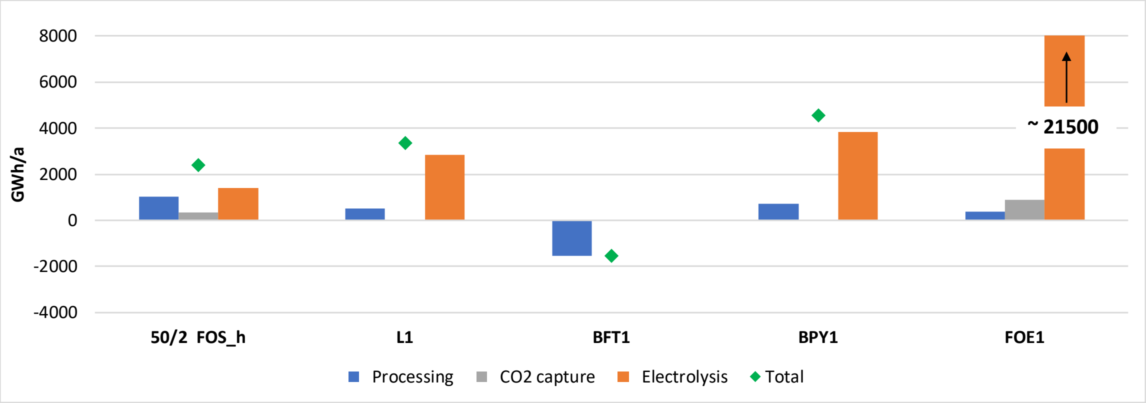
Figures 8.1.2-2/3 respectively show gas and electricity imports, the latter split between processing, CO_2 capture and electrolysis. Gas imports are low in all cases (in BPY1 substitution is limited by the maximum allowed proportion of electricity in refinery energy). In BFT1 electricity is produced from excess heat from the FT plant. E-fuels production consumes large quantities of electricity. Half the EU refineries following the FOE1 case would require about 25% of the entire EU electricity consumption today.

Figure 8.1.2-2 Gas imports
(% of total internal energy)



Compared to the best fossil feed case, use of alternative feeds would not offer further refinery emissions reductions unless substantially complete renewability could be achieved (That means importing renewable electricity from the grid and using renewable energy e.g. in the production and transport stages of the alternative feedstock cases).

Figure 8.1.2-3 Electricity imports



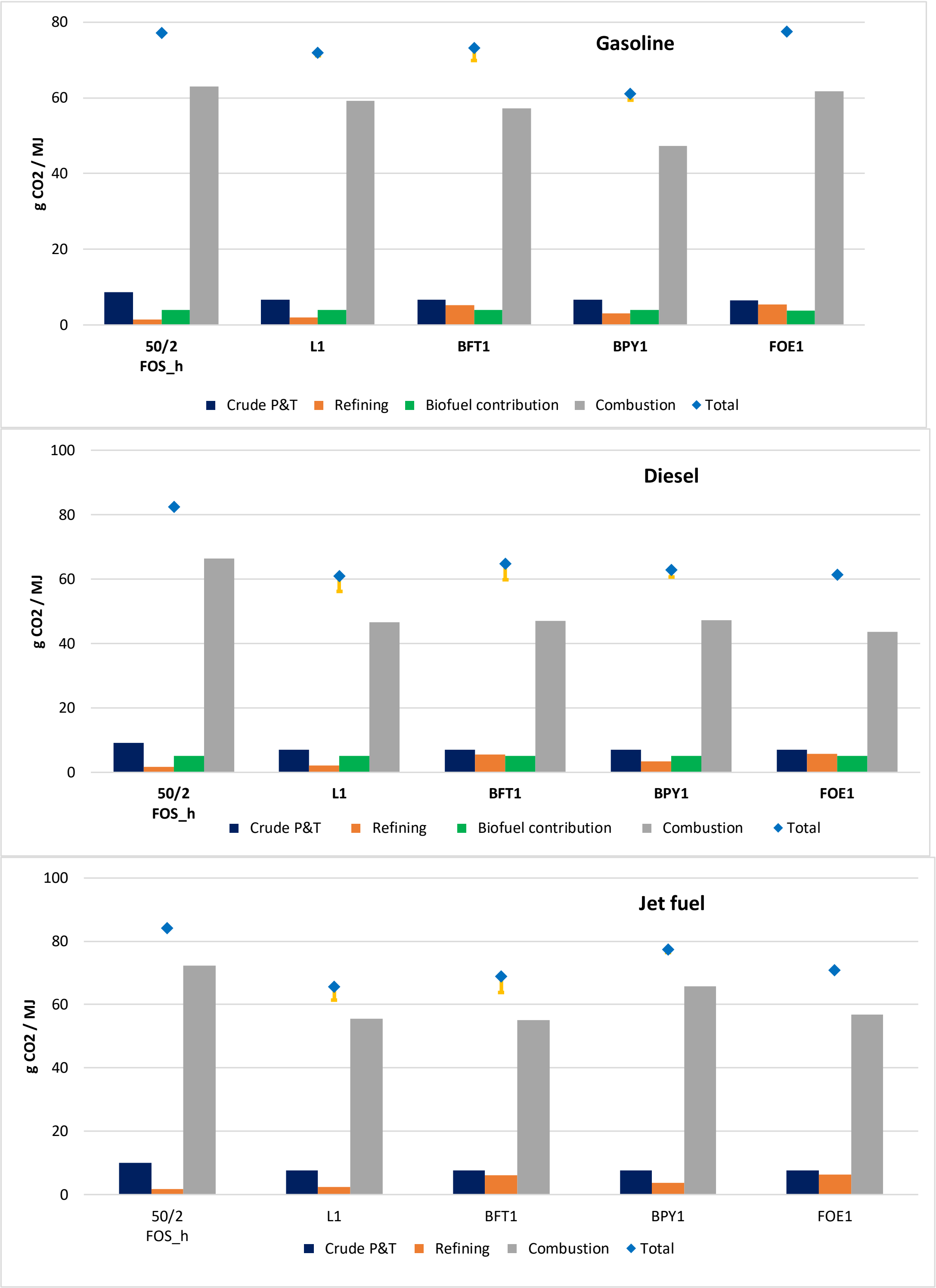
Large scale use of electrolytic hydrogen would lead to high electricity demand

8.1.3. Product carbon footprint

Figure 8.1.3-1 shows the make-up of the overall carbon footprint of the three main fuel groups, gasoline / diesel / jet fuel (see details of make-up in **Section 7.3**). The potential impact of achieving full renewability of the bio-feedstocks (see **section 6.2.9**) is illustrated by the error bars.

L1, BFT1 and FOE1 produce little in the way of low fossil carbon gasoline components and have therefore little impact on the footprint of the gasoline blend. BPY1 would reduce this to about 60 g CO_2/MJ. The impact on diesel and jet fuel is roughly the same for all cases, resulting in an overall (simplified) footprint in the order of 60 g CO_2/MJ for diesel and 70 g CO_2/MJ for jet (no biofuels in jet).

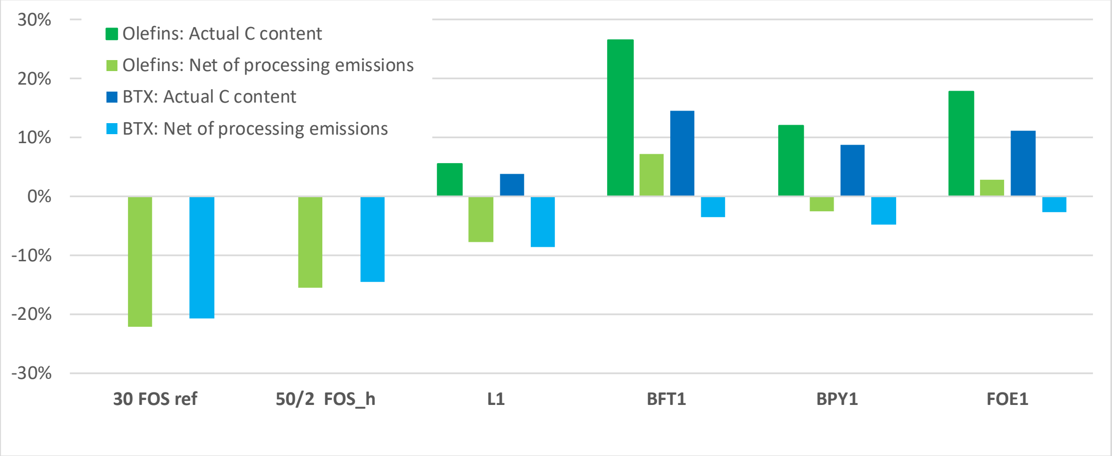
Figure 8.1.3-1 Main fuel products CO_2 emission factor



In the most favourable cases the fossil carbon footprint of main fuels could be reduced by 20-25% vs 2030 reference case.

Petrochemical products also benefit from the renewable carbon intake. **Figure 8.1.3-2** shows the fraction of non-fossil carbon content in olefins and BTX products (both actual content and corrected for processing emissions).

Figure 8.1.3-2 Petrochemicals non-fossil carbon content



8.2. MAX LOW CARBON FEEDSTOCKS CASES (COMBINED PATHWAYS).

Key messages

- A second series of cases illustrated a hypothetical extreme situation where the notional refinery experiences a transformation and the crude oil intake was reduced to the minimum required to satisfy the demand for bitumen and lubricants. Alternative feedstocks are combined in a synergistic way to provide the bulk of the intake.
- Most existing refinery process units would be heavily underutilised or even obsolete (with exception of hydrocrackers/hydrotreaters and hydrogen production units). Front end processing of alternative feedstocks would become the primary activity of the “refineries”.
- Even in these extreme cases, a reasonable balance could be maintained between products, with surpluses and deficits within historical limits, although blending products to the required commercial grade quality would likely be a challenge; Fossil emissions from the refinery site would not be reduced unless the bio-feedstocks and imported electricity achieved an almost totally fossil carbon-free footprint.
- Production of e-fuels at this scale would require massive amount of imported electricity with attendant infrastructure.
- The fossil CO_2 intensity of the main fuels, including the “well-to-tank” production pathway and the potential combustion emissions could be reduced by about 75% (see Section 7.3).

This second set of cases illustrates a hypothetical extreme situation where virtually all crude oil would be replaced by low-C feedstocks as a combination of lipids, biomass and e-fuels. The only oil remaining would be dedicated to the production of bitumen (for which there is, at the moment, no credible alternative).

Table 8.2-1 Max Low-C feedstock cases

Code	Low-C feedstocks				
	Scheme	Type / Processing route	kt/a	Refinery feed	kt/a
LB/ LB_c(1)	Lipids + Biomass	Lipids		Lipids, of which	2910
				Co-processing GHT	15%
				Co-processing HC	15%
				Dedicated HT	46%
				FCC (olefins mode)	23%
		Biomass / FT	3810	Raw FT liquids	838
LBE	As LB plus e-fuels through own CO2 capture (70%) (Capture energy deemed to be supplied by waste heat from the FT process)	Lipids		Lipids, of which	2150
				Co-processing GHT	20%
				Co-processing HC	20%
				Dedicated HT	60%
				FCC (olefins mode)	0%
		Biomass / FT	2800	Raw FT liquids	616
		CO2 capture	2729	e-fuel liquids	879
LBPE	As LBE but limited e-fuels (16% capture) and with biomass 50/50 FT and pyrolysis oil (HTL process)	Lipids		Lipids, of which	2410
				Co-processing GHT	15%
				Co-processing HC	15%
				Dedicated HT	45%
				FCC (olefins mode)	26%
		Biomass	3640	Raw FT liquids	400
				HTL oil	784
		CO2 capture	459	e-fuel liquids	148

In all cases:
Figures relate to "notional" refinery
Demand as per 2050 / scenario 2, crude intake in "notional" refinery 810 kt/a in all cases
Crude intake 810 kt/a (minimum heavy crude to meet bitumen demand)
Refinery emission reduction measures at 2050 level

(1) LB_c includes CO2 capture

Note that:

- In **LB** a combination of lipids and woody biomass is used (LB_c is the same case with CO_2 capture). Lipids are processed with the same options as case L1 (see **Section 8.1**) with, in addition, an FCC mode which allows production of extra olefins. The biomass follows the FT route as in case BFT1.

- **LBE** combines the above two routes with e-fuels, assuming capture of 70% of the considerable amount of CO_2 produced partly by fuel burning but mainly from processing of oxygen-containing feedstocks (roughly 20/80 ratio).

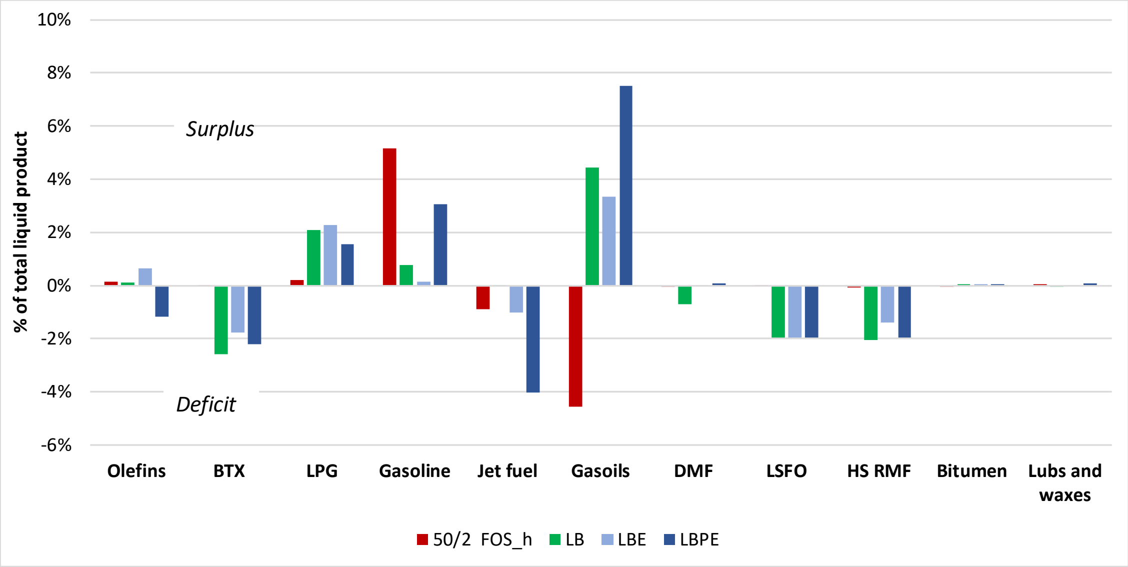
- In **LBPE** the equivalent of 50% of the biomass is imported in the form of HTL oil (note that HTL oil production is not accounted for here). Capture rate is reduced (16%) to obtain a total product slate reasonably similar to the other cases.

It must be pointed out that these are extreme conceptual cases which would take refinery operations very far from what they are now and would need extensive study and work before practical feasibility could be established. In particular the scale of the resources required would be a particular challenge.

8.2.1. Production and plant capacity requirements

Figure 8.2.1-1 shows the difference between production and demand for the notional refinery. In all cases a reasonable match could be obtained for the main distillate products with EU-wide deficits and surpluses within historical bounds although there is now a slight surplus of both gasoline and gasoils (see EU-wide modelled and current figures in **Section 9.2**). The larger imbalances as a proportion of the specific demand are for BTX (only about 50% of demand) and LPG (150% of demand). Note that, by design, these cases do not produce any heavy fuel oil as crude runs are tailored to bitumen and lubricants production only.

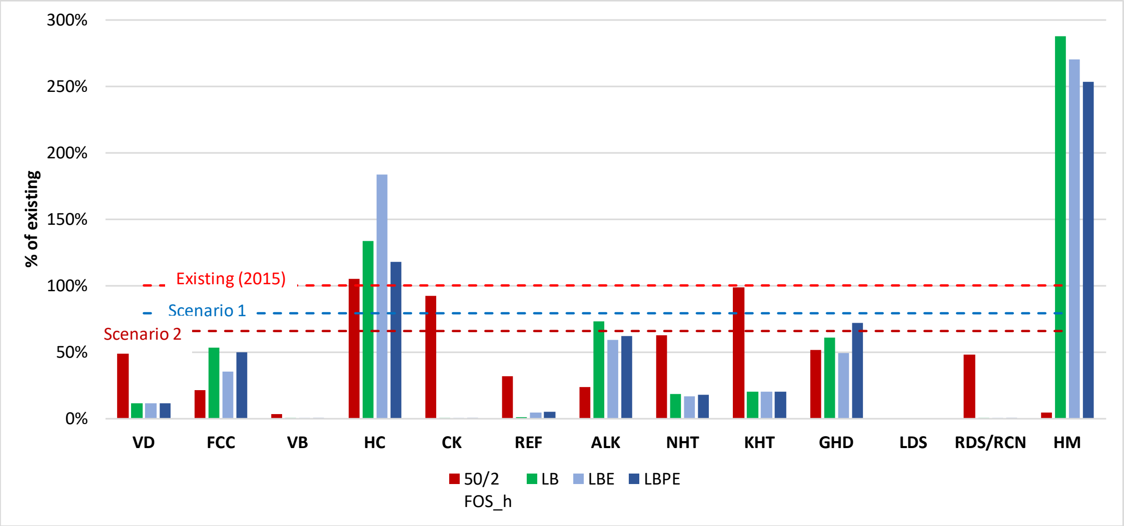
Figure 8.2.1-1 Production - demand



A reasonable match between production and demand was achieved, with deviations within historical bounds. When these pathways are maximized, the gasoil production exceed the demand in order to meet the bitumen/lub-waxes one (modelling criteria followed).

Figure 8.2.1-2 shows process plants utilisation as a proportion of existing average capacities. Here again all plants are utilised at a level below the average of existing facilities, with the exception of hydrocrackers and hydrogen plants (hydrogen plant utilisation remains high as they use up surplus fuel gas). For many units, the rates of utilisation would be below operational limits so probably only a handful of such plants would still be in operation. The caveat regarding actual new plant capacity requirement expressed in **Section 7.1** is of course also valid here.

Figure 8.2.1-2 Process plants utilisation



Utilisation of SMRs is dependent on the refinery fuel gas balance, with priority being given to electrolytic hydrogen import wherever possible (see **Section 6.2**). The sources of hydrogen are further illustrated in **Table 8.1.2-1**.

Table 8.1.2-1 Hydrogen production (kt/a)

Case	50/2 FOS_h	LB	LBE	LBPE
SMR (general purpose)	0.8	54.6	50.6	48.8
Electrolysis (general purpose)	29.0	30.0	14.0	68.0
Electrolysis (e-fuels)	0.0	0.0	383.7	64.5
Total	29.8	84.6	448.3	181.3

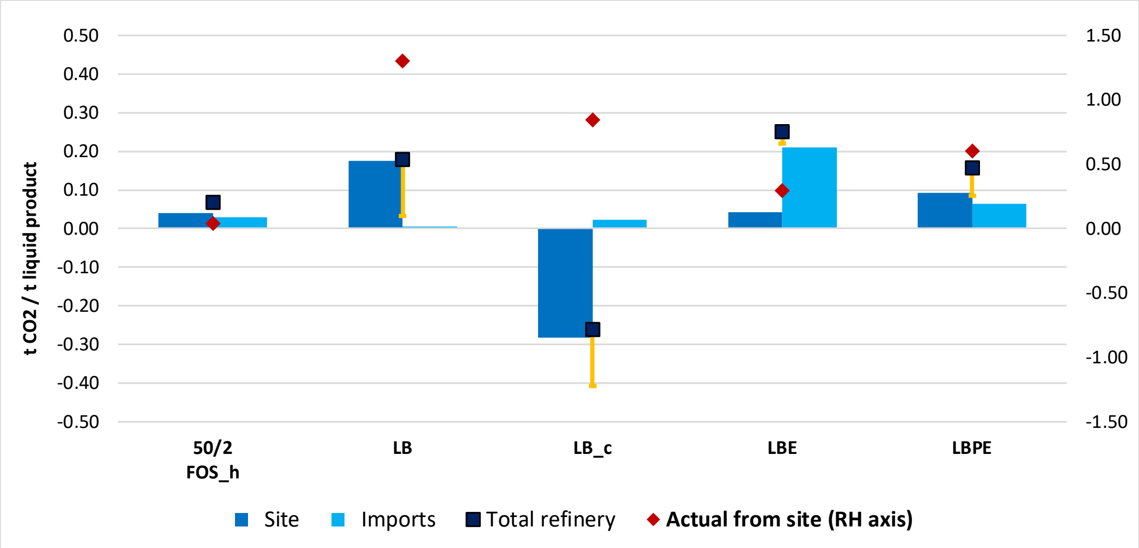
8.2.2. Net fossil CO_2 emissions and energy

The net fossil emissions resulting from refinery operations (from site, i.e. direct and from imports i.e. indirect) are shown in **Figure 8.2.2-1** in relation to total liquid product. It also shows the **Actual** emissions from site (including both fossil and biogenic CO_2 emitted). With the exception of LB_c, all cases result in higher site emissions than the fossil case. This is because of the combination of factors discussed in **Section 8.1.2**. Achieving complete renewability of feedstocks and electricity would remove these terms (see **section 6.2.9**. here again the error bars show the range of emissions that could be avoided if the bio-feedstocks became fully renewable).

In LB_c the introduction of CO_2 capture results in negative net fossil emissions. The actual emissions from the site before capture are very high because, during lipids processing, a proportion of the lipid oxygen content is recombined with carbon to form CO_2 that is effectively biogenic. When this is captured the overall process actually removes CO_2 from the atmosphere (some of the carbon absorbed by the biomass is captured and stored rather than being returned to the atmosphere).

In many of the cases, actual emissions from the refinery sites are considerably higher, mostly consisting of biogenic CO_2.

Figure 8.2.2-1 CO$_2$ emissions from refinery site (direct) and from imports (indirect)

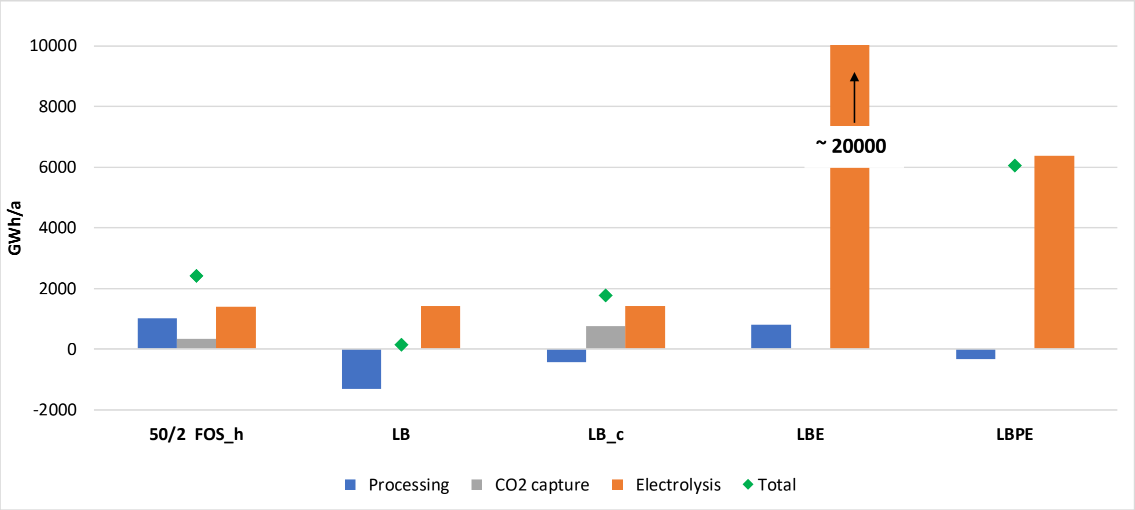


Note. As mentioned in the text above above, the reported CO$_2$ emissions include only fossil emissions (currently under the Emission Trading System) with the exception of the *Actual from site* one which also considers CO$_2$ from biogenic origin.

Use of alternative feeds would not offer further refinery emissions reductions unless complete renewability could be achieved. CO$_2$ capture of partially biogenic CO$_2$ could lead to negative emissions.

Figure 8.2.2-2 shows the balance of electricity imports. The last two cases produce large quantities of e-fuels, relying massively on electricity imports. Half the EU refineries following the LBE case would require about 25% of the entire EU electricity consumption today.

Figure 8.2.2-2 Electricity imports



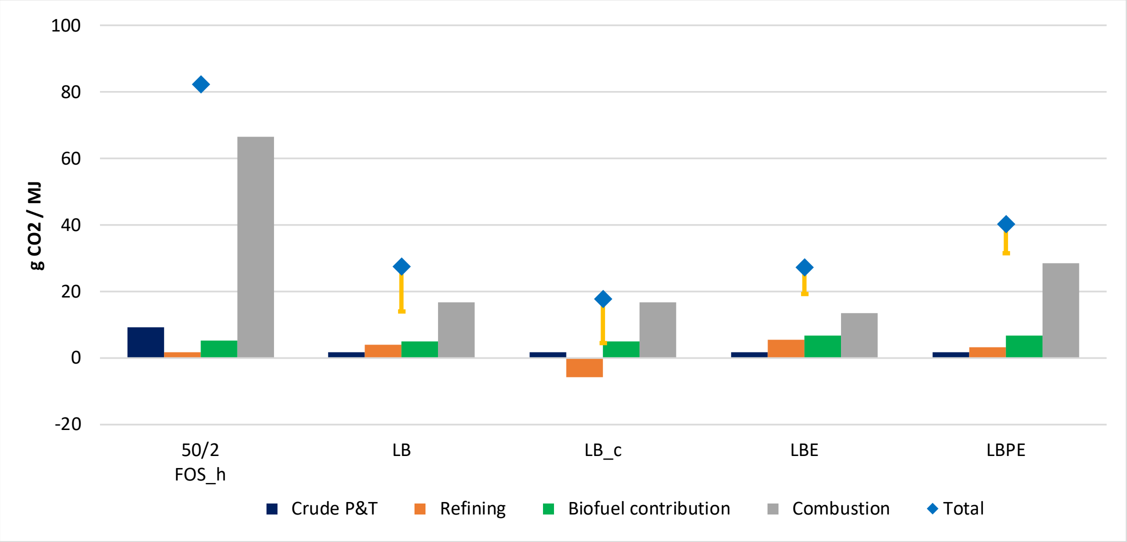
Large scale use of electrolytic hydrogen would lead to extreme electricity demand

8.2.3. Product carbon footprint

Figure 8.2.3-1 shows the make-up of the overall carbon footprint of diesel (see **section 7.3** for details). The potential impact of achieving full renewability of the bio-feedstocks is illustrated by the error bars (see **section 6.2.9**).

These extreme cases could achieve 60 to 80% reduction to levels roughly between 20 and 40 g CO_2/MJ, and even more if the bio-feedstocks became fully renewable. Similar levels of reductions would be achieved for gasoline and jet fuel. LB_c is the most effective because of the underlying negative emissions at the refinery. The difference between LBE and LBPE is mainly due to the lower proportion of e-fuels in the latter case.

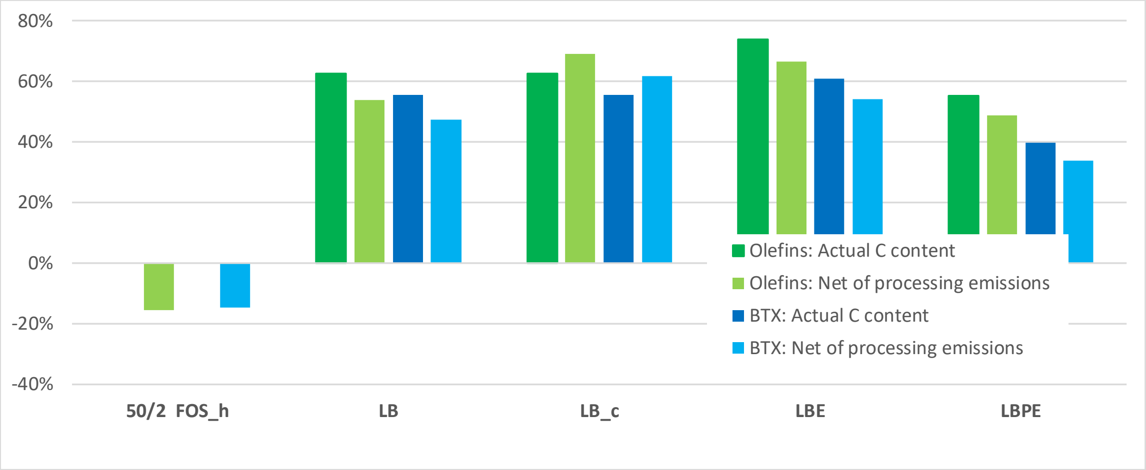
Figure 8.2.3-1 Diesel CO_2 emission factor



Petrochemical products also benefit from the renewable carbon intake. **Figure 8.2.3-2** shows the fraction of non-fossil carbon content in olefins and BTX products (both actual content and corrected for processing emissions). In these extreme cases, up to about 60% non-fossil carbon could be achieved.

In these extreme cases the fossil carbon intensity of main fuels could be reduced by 60-80%, and even more if the bio-feedstocks became fully renewable reducing their WTT CO_2 intensity.

Figure 8.2.3-2 Petrochemicals non-fossil carbon content



8.3. PRODUCT QUALITY IMPLICATIONS

As mentioned above, these alternative cases imply, to different degrees, operation beyond any current experience. With the level of aggregation and the relatively crude modelling applied here, detailed blending issues cannot realistically be addressed, nor can the potential quality of blends be considered against detailed specifications.

Certain properties, such as sulphur, density, viscosity, are easily modelled. With the feedstocks considered here we would not anticipate major issues with these across the product range.

It is likely that marketable diesels and heavy fuel oils could be produced. Jet fuel may be more challenging in view of the demanding specification of this product.

Gasoline blending is more challenging with properties such as octane rating, vapour pressure, boiling range which cannot be accurately assessed at an aggregated level. The make-up of the gasoline blending pool components is very unusual in many of the cases presented here and it is by no means certain that practical gasoline blends could be produced without import of additional components.

9. A LOOK INTO EU-WIDE SCALE

Key messages

- When introducing alternative feedstocks, the main objective would not be to reduce emissions at the refinery site but indeed to reduce the carbon intensity of the final products contributing to a low carbon future in Europe.
- The cases described above could imply supply of up to 8 Mt/a biomass or 5 Mt/a lipids to a single site which would present significant challenges. If applied to the whole industry up to 200 Mt/a of lipids or 300 Mt/a of wood would be required.
- Large scale production of e-fuels would imply electrical consumption equivalent to a significant fraction of total EU consumption today.
- **A combination of reduced demand, electrification and CO_2 capture could reduce the EU-wide industry emissions from 120 Mt/a to about 30 Mt/a. Outside CO_2 capture, use of alternative feeds would still result in sizeable fossil emissions at refinery sites, unless those feeds were fully renewable.**
  - A combination of reduced demand, electrification and CO_2 capture at the refinery could reduce the EU-wide total emissions from main fuel products from about 1400 Mt/a to about 900 Mt/a in the fossil cases and down to 200 Mt/a with alternative feeds.
  - When the 2050 scenarios are compared with CO_2 emissions at 1990 level, the CO_2 reduction savings range from -50% up to -90% (direct emissions). Additional carbon sinks can be created when *Carbon Capture and Storage* solutions are combined with the biomass cases (BECCS) achieving negative emissions compatible with the EU long-term strategy (*A Clean Planet for all*).

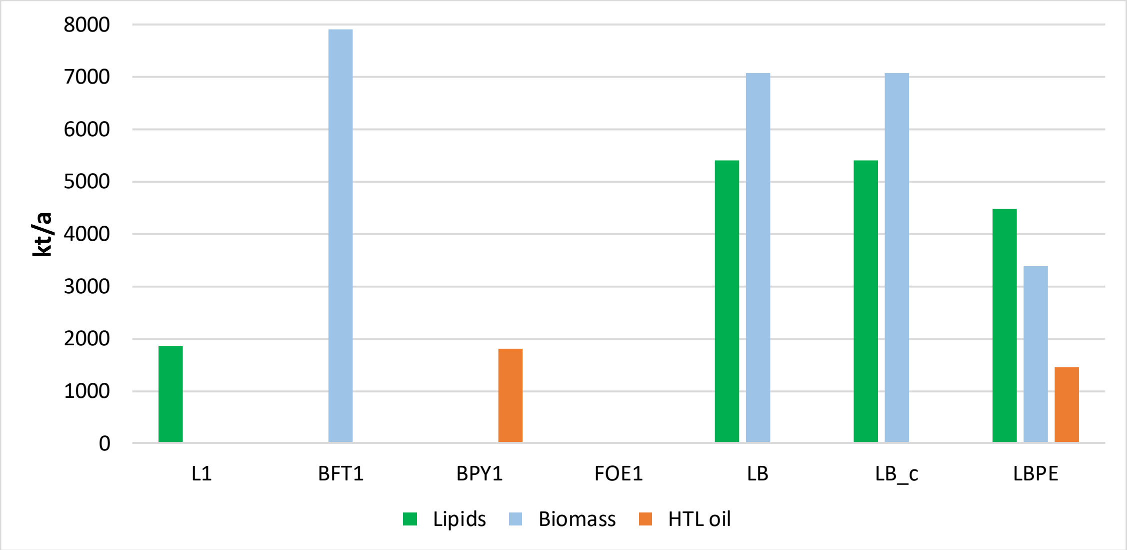
In the two previous sections, results are presented at the scale of the "notional" refinery. Scaling this down with the demand, its intake of 160 kbbl/d today would be reduced to a little more than half that in the 2050 scenario 2. This section examines the implications on a wider basis extrapolating the picture to the whole EU refining system in terms of EU-28 feedstock, product imbalances and CO_2 reduction potential estimating the additional electricity requirements as a sector. The preliminary figures extracted from this work were used as initial inputs to the contribution of the Energy Intensive Industries to the EU long-term strategy.

9.1. REFINERY SCALE AND EU-WIDE ALTERNATIVE FEEDSTOCKS REQUIREMENTS

As already mentioned in **Section 6.2**, rationalisation is likely to occur across the industry in the different 2050 demand scenarios so that the average refinery size might remain relatively constant with fewer sites still in operation in the future. If occurring across the industry, this would leave just over 40 refineries of the size of the initial notional refinery in operation by 2050 from the ~80 ones considered as the starting point.

The scaled-up notional refinery feed requirements for the cases examined in **Section 8.1 and 8.2** would be as shown on **Figure 9.1-1**.

Figure 9.1-1 Feed requirements in scaled-up 160 kbbl/d 2050 refinery



EU-wide, for the remaining refineries of the size of the notional one, supply of up to 8 Mt/a biomass or 5 Mt/a lipids to a single site may be challenging

Supply of up to 8 Mt/a woody biomass to a single site of the 40 that we have considered remaining in 2050 (running at its full 160 kbbl/d capacity) may be problematic and could in all likelihood only be envisaged for coastal locations with good harbouring facilities. The same would apply to lipids at the suggested scale. Some combinations of the different options as illustrated by LBPE may alleviate these feed limitations.

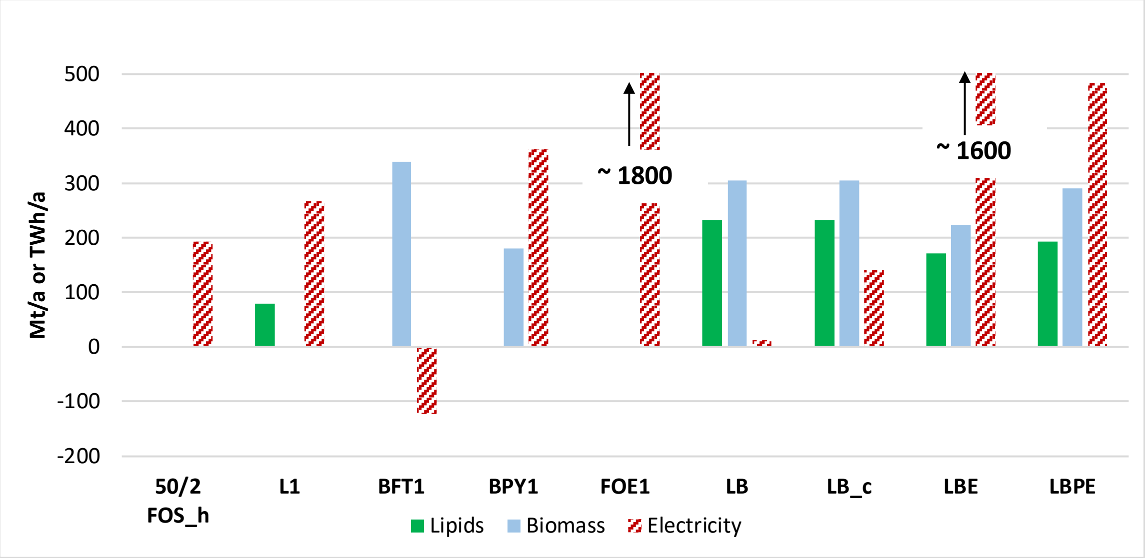
Most of the options explored in this report would require extensive hydrocracking capacity. At about 3.5 Mt/a, the maximum required (case FOE1 and LBE) is just within current experience for a single site, although such large capacity would normally be found in larger refineries (the average hydrocracking to crude capacity ratio is about 25% in Europe compared to a range of 27 to 47% for the study cases).

Dedicated lipid hydrotreaters would also need to be significantly larger than today (existing plants are in the order of 1 Mt/a). Larger single plants or multi-train complexes should, however, be possible in the future.

Although it is most unlikely that all refineries would follow the same route, it is informative to scale up to the whole industry to provide a view of what this would entail in terms of feedstock, hydrogen and electricity.

Figure 9.1-2 shows the alternative feed supplies that would be needed in the different cases. The order of magnitude would be 200 Mt/a for lipids and 300 Mt/a for wood (in combination in minimum oil cases). As already alluded to, electricity needs would be very large, particularly in the e-fuel cases where it could represent in the region of 50% of total EU demand.

Figure 9.1-2 EU-wide alternative feedstock supply requirements



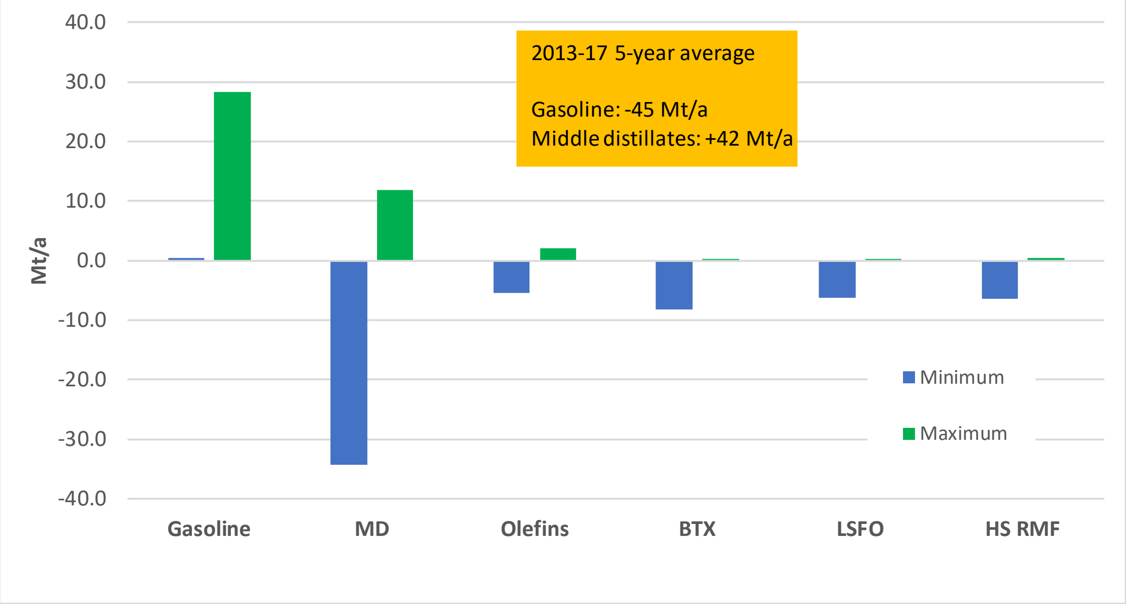
Note. As a reference, net electricity generation in EU-28 ~3100 TWh in 2016 (Source: Eurostat).

Large scale production of e-fuels would imply electrical consumption equivalent to a significant fraction of total EU consumption today

9.2. PRODUCTION-DEMAND IMBALANCES

Figure 9.2-1 shows the maximum surpluses and deficits for the main product group across all study cases that would be implied at the overall EU scale if all refineries operated in a similar way. The 2013-17 5-year average actual figures are also shown for gasoline and middle distillates. The larger deviations are observed in 2030 but remain well within recent historical values.

Figure 9.2-1 EU-wide maximum surpluses and deficits for main product groups



In all cases, EU-wide surpluses and deficits of the main product groups could be kept within historical limits

9.3. CO_2 EMISSIONS

Figures 9.3-1a/b illustrate, for fossil and alternative feed cases respectively, the EU-wide site emissions (direct) and emissions from imports (indirect) CO_2 emissions that would result from full uptake of each pathway at all refinery sites (see **Section 13.1** for details regarding the terminology used to differentiate between the origin/location of the CO_2 emissions).

From a level of about 120 Mt/a in the 2030 base case, total EU-wide refinery emissions could be reduced to a minimum of 26 Mt/a for the fossil cases. Without CCS, emissions for the alternative feed cases would be in 30-60 Mt/a range. The best fossil feed case (2 FOS_h) compares well with the bio-feed alternatives. As previously mentioned, these figures are sensitive to the "renewability" assumptions attached to bio feeds and grid electricity (the error bars show the range of emissions that could be avoided if the bio-feedstocks became fully renewable). Note also that a portion of the reduction stems from the lower demand and resulting production level.

In many of the alternative feed cases, actual emissions from the refinery sites are considerably higher, mostly consisting of biogenic CO_2.

Adoption of CO_2 capture on a large scale could, when combined with bio feedstocks, result in negative fossil emissions i.e. removal of CO_2 from the atmosphere.

Figure 9.3-1a EU-wide refining system direct (site) and indirect (imports) CO_2 emissions. Fossil cases

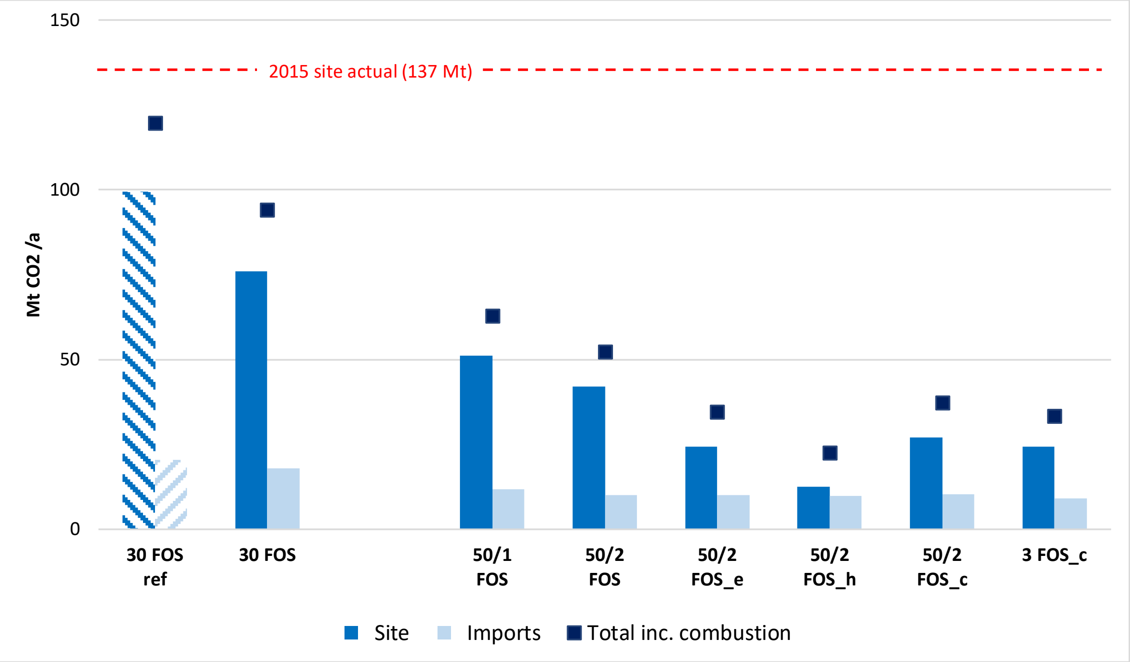
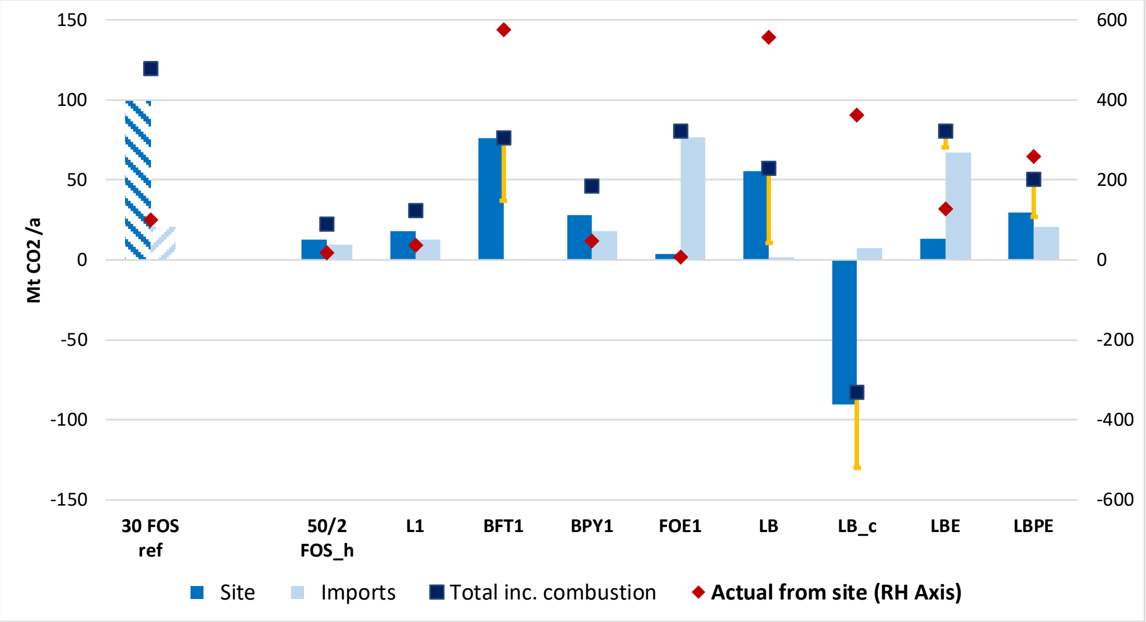


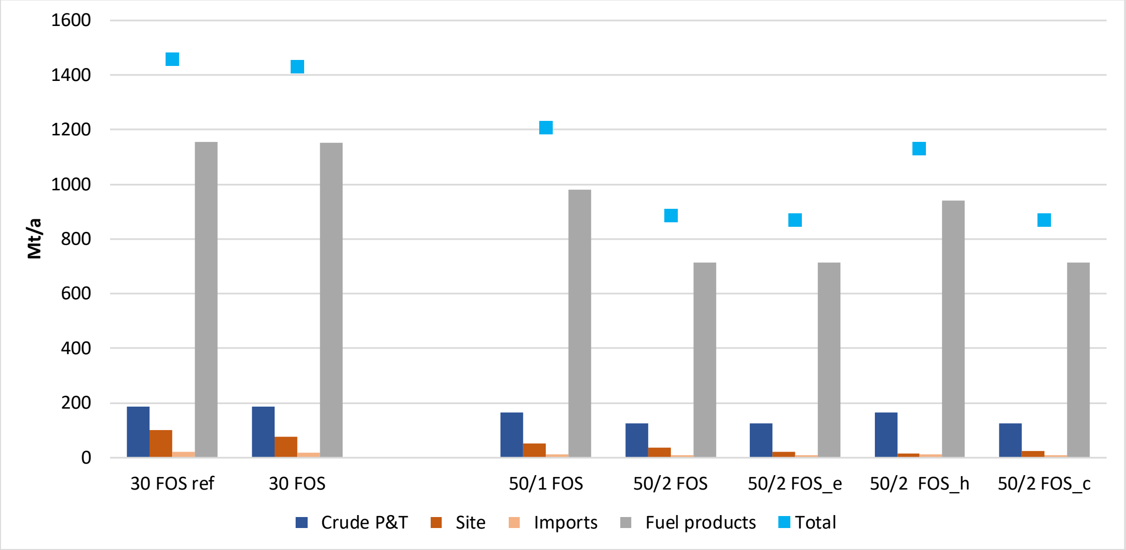
Figure 9.3-1b EU-wide refinery direct (site) and indirect (imports) CO_2 emissions Alternative feed cases



Outside CO_2 capture, use of alternative feeds would still result in sizeable fossil emissions at refinery sites, unless those feeds were fully renewable

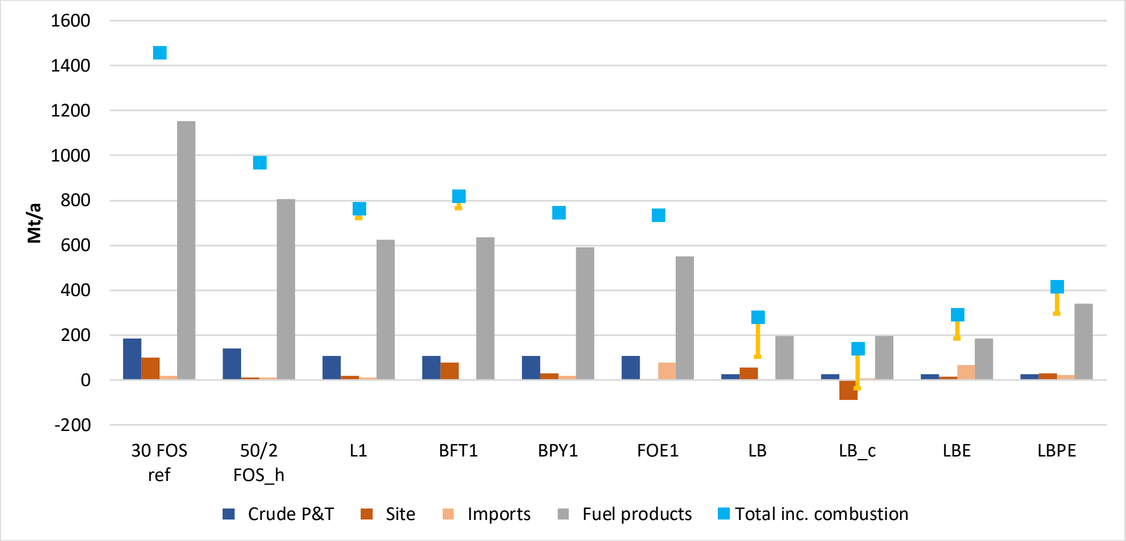
When introducing alternative feedstocks, the main objective would not be to reduce emissions at the refinery site but indeed to reduce the carbon intensity of its products. Figures 9.3-2a/b show the same information now including the crude oil contribution and combustion emissions for all fuel products. Overall fossil emissions, including fuel combustion could be reduced by up to about 80%, and even more should the bio-feedstocks achieve full renewability (note that, on this basis, the LB_c case could be virtually carbon neutral). The actual emissions, which include CO_2 of biogenic origin, remain high but from a climate perspective, these biogenic CO_2 molecules are *sustainable* as they form part of the carbon cycle and we are not releasing additional CO_2 from fossil sources.

Figure 9.3-2a EU-wide CO_2 emissions from refined products (Simplified approach) Fossil cases



A combination of reduced demand, electrification and CO_2 capture at the refinery could reduce the EU-wide total emissions from main fuel products including both production and usage (combustion) from about 1400 Mt/a to about 900 Mt/a

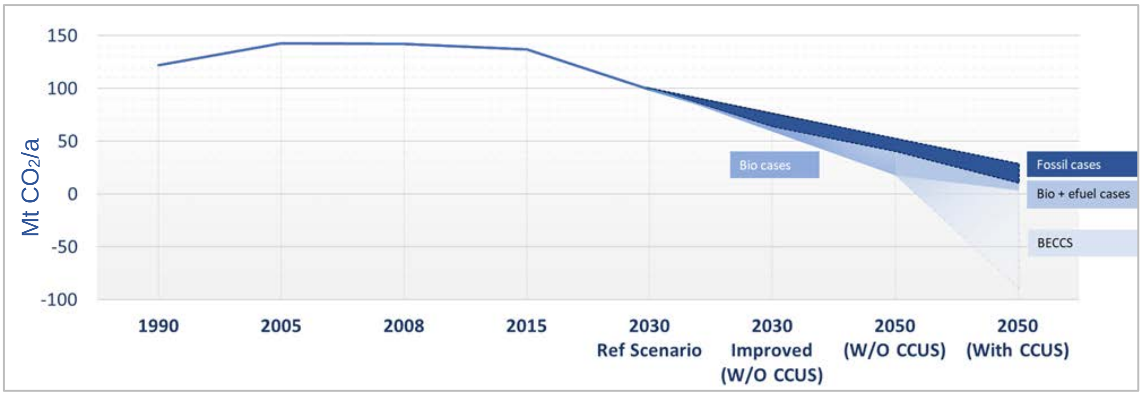
Figure 9.3-2b EU-wide CO_2 emissions from refined products Alternative feeds cases



Reduced demand and introduction of alternative feeds could reduce the EU-wide emissions from main fuel products from about 1400 Mt/a down to 200 Mt/a

As a result of this conceptual assessment, the figure below shows a walk into the potential evolution of the CO_2 emissions associated with the EU refining system along with a summary of the additional requirements in terms of low-carbon feedstocks, electricity and hydrogen. This **long-term vision** is the result of the combination of measures identified along the present report:

Figure 9.3-3 EU-wide refinery emissions (Direct fossil emissions, Mt CO_2/a)



Note: (1) BECCS: Biomass + CCS negative emissions

Table 9.3-1 EU-wide – Summary of key CO_2 savings and external requirements (Selected cases as examples)

2050 Scenario 2	**50/2 FOS_c**	**LB**	**LB_c**	**LBPE**
Description	**Fossil + CCS**	**Lipid+biomass**	**Lipid+biomass+CCS**	**Lip+Bio+efuel**
Emissions Directs (Mt CO_2/a) – EU 28	27	56	-90	13
Emissions Directs/Indir (Mt CO_2/a) – EU 28	37	57	-82	80
Total liquid intake bio+oil (Mt/a)	344	297	364	286
Total crude intake (Mt/a)	344	65	65	65
% oil replacement by bio-feedstocks	0%	78%	82%	77%
Bio-feedstock demand (Mt/a)	0	233	300	221
Lipids (Mt/a)	0	233	233	172
Raw Biomass (Mt/a)	0	304	304	224
E-fuel production (Mt/a)	0	0	0	11.8
Electricity consumption (TWh/a)	54.5	150.1	210.0	547.9
H_2 consumption (Mt/a)	2.4	6.8	6.8	14.5
% CO_2 reduction vs 1990 (Direct)	**78%**	**54%**	**174%**	**89%**
% CO_2 reduction vs 2030 Ref case (Direct)	73%	44%	190%	86%

10. CAPITAL INVESTMENT

Key messages

- The present assessment is not intended to be a detailed study of the capital cost that would be required to deploy the low fossil carbon feedstock pathways at scale but an initial indication of the order of magnitude.
- The capital investment would range between 1 and 10 G€ for the limited penetration cases and between 6 and 15 G€ for the extreme cases for a notional 160 kbbl/d refinery.

Introducing alternative feedstocks in the refinery environment at the scale discussed above would require investment in brand new plants for the front-end processing of these feedstocks, extensive modifications and revamping of existing plants for further processing and treating of the raw products, and extensive adaptation of ancillary facilities such as import terminals, tankage etc.

The last two categories of investments would be heavily site-dependent and have to be assessed on a case by case basis. In this study we have only sought to provide a broad-brush estimate of potential capital investment in front-end processing plants.

Capital investment figures are discussed in detail in **Section 5**. We have used the following assumptions:

- For lipids: 40% co-processing, 20% refinery unit conversion, 40% new dedicated plants,
- For the FT route: 50/50 stand-alone and refinery-integrated
- For the pyrolysis route: only cost related to oil processing (pyrolysis assumed to be carried out by third parties).

Electrolytic hydrogen for general purpose was also accounted for at a capital cost of 2.6 M€/(kt/a).

Results at the scale of a notional 160 kbbl/d refinery are shown in **Figure 10-1**. The capital investment would range between 1 and 10 G€ for the limited penetration cases and between 6 and 15 G€ for the extreme cases. To put these costs in perspective, the figure also shows recent cost estimates for new-build grassroots refineries of a similar size in the Far East[8].

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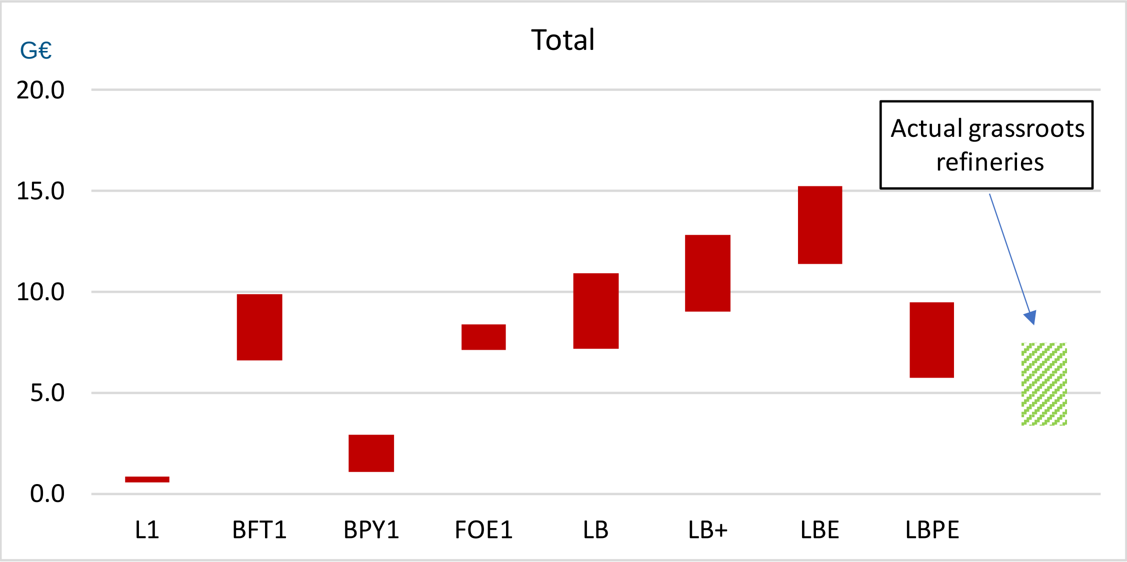
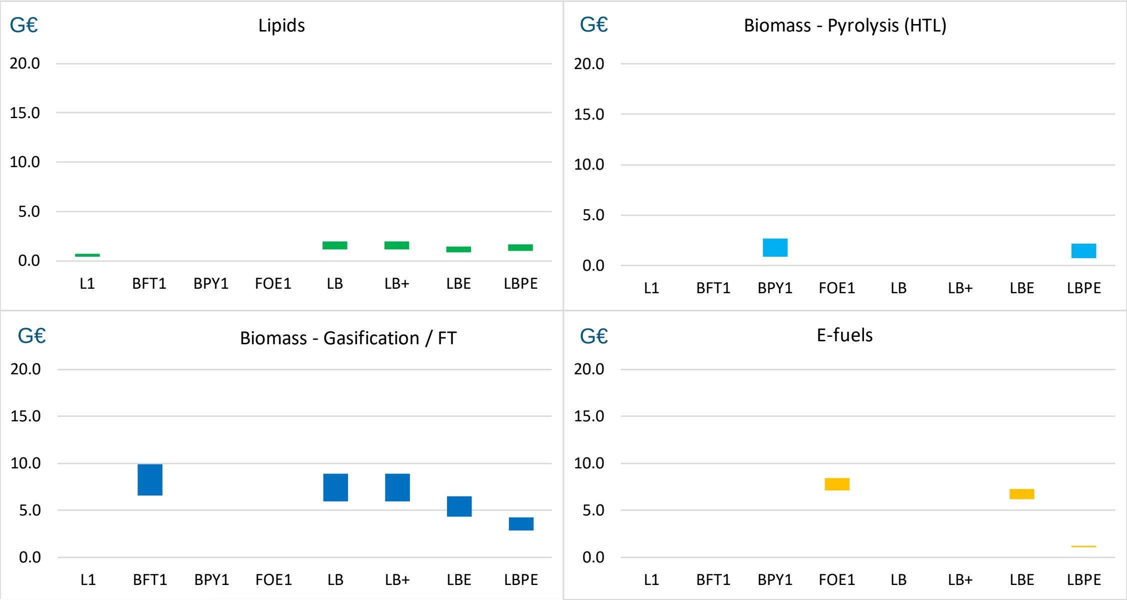
[8] https://oilprice.com/Latest-Energy-News/World-News/China-Built-Brunei-Oil-Refinery-To-Launch-In-2019.html

Figure 10-1 Range of capital investment for a notional 160 kbbl/d refinery (G€)



Details



11. GLOSSARY

AQ	Air Quality
ASTM	American Society for Testing and Materials
BECCS	Biomass and Carbon capture
BEV	Battery Electric Vehicle
BTL	Biomass to Liquid
BTX	Benzene, Toluene, Xylene
CAPEX	Capital Expenditures
CCS	CO_2 Capture & Storage
CCU	CO_2 Capture & Utilisation
CO_2	Carbon dioxide
COM	Commission
EC	Elemental Carbon
EU	European Union
FAME	Fatty acid methyl esters
FCC	Fluid Catalytic Cracker
FCHV	Fuel cell hydrogen vehicle
FQD	Fuels Quality Directive
FT	Fischer Tropsch
GHG	Greenhouse gases
GTL	Gas to Liquids
HCK	Hydrocracker
HCN	Hydrogen Cyanide
HDS	Hydrodesulphurisation unit
HDT	Hydrotreatment unit
HTL	Hydrothermal Liquefaction
HP	High Pressure
HSFO	High Sulfur Fuel Oil
HV	Hybrid vehicle
HVO	Hydrotreated Vegetable Oil
IEA	International Energy Agency
LC	Low Carbon
LCP	Low Carbon Pathways
LPG	Liquid Petroleum Gas
LNG	Liquified Natural Gas
LSFO	Low Sulfur Fuel Oil
MGO	Marine Gasoil
MSW	Municipal Waste
NMVOC	Non-Methane Volatile Organic Compounds
NOx	Nitrogen oxides
P2G	Power to gas
PAH	Polycyclic aromatic hydrocarbon
PAO	Poly-a-olefin
PM	Particulate Matter

PHEV	Plug-in Hybrid Electric Vehicle
RED	Renewable Energy Directive
R&I	Research and Innovations
SCW	Super critical water
SMR	Steam-Methane Reforming
SOx	Sulphur oxides
toe	Tonne of oil equivalent (= 10 Gcal or 41.868 GJ)
TRL	Technology Readiness Level

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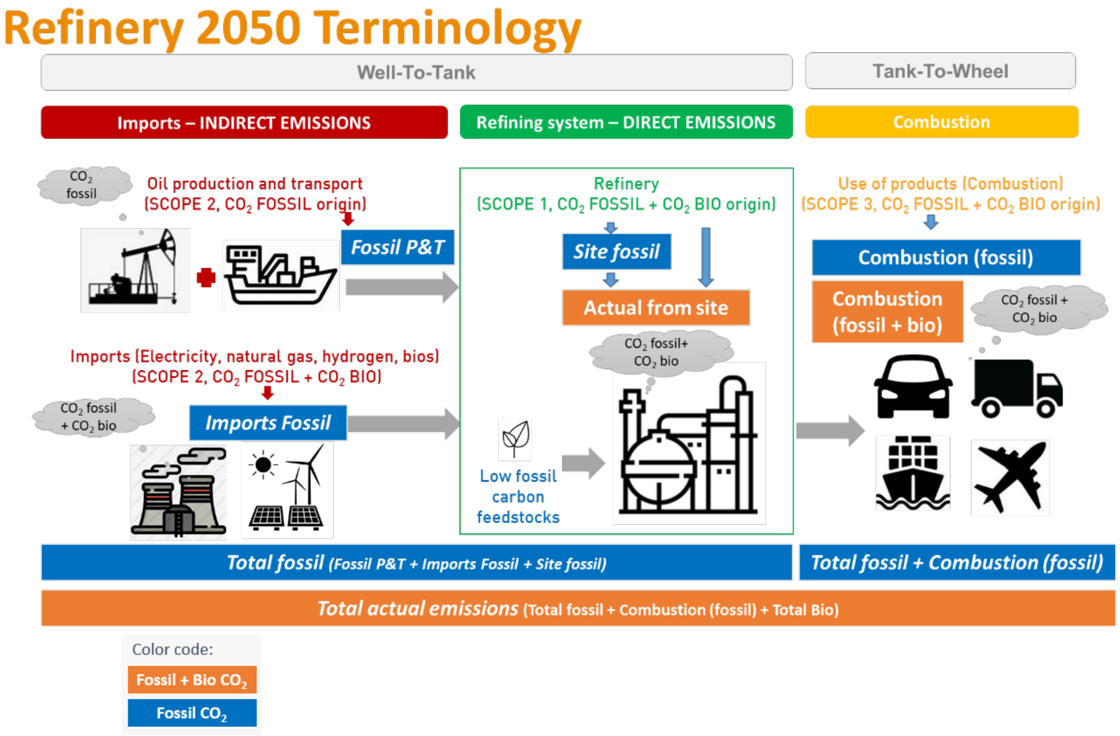
ZEP2017	ZEP data 2017.

13. A DETAILED MODELLING RESULTS

13.1. TERMINOLOGY DESCRIPTION (CO_2 EMISSIONS)



	SCOPE 1	SCOPE 2	SCOPE 3	FOSSIL ORIGIN	BIO ORIGIN
Total actual	x	x	x	x	x
Actual from site (Direct emissions)	x			x	x
Fossil from:					
-Crude P&T		x		x	
-Site Fossil	x			x	
-Imports Fossil		x		x	
-Fuel products			x	x	
Total fossil (Ind.+Dir.emissions)	x	x		x	
Total fossil (including combustion)	x	x	x	x	

13.2. FOSSIL CASES

Code	Demand scenario	Description	Crude intake[1]
30 FOS ref	2030	Reference case with no reduction measures from 2008 actual level	6350
30 FOS		2030 reduction measures	
50/1 FOS	2050 / 1	2050 energy efficiency level. Limited electrification, no electrolytic hydrogen	5020
50/2 FOS	2050 / 2		4300
50/2 FOS_e		as 50/2 FOS + maximum electrification and C	
50/2 FOS_h		as 50/2 FOS + maximum electrolytic hyd. and	
50/2 FOS_c		as 50/2 FOS + CO2 capture	

[1] In notional 160 kbbl/d refinery, 2030 EU-mix quality

Additional cases not discussed in main text

30 FOS 50H	2030	2050 reduction measures	5957
30 FOS 50H_c		2050 reduction measures inc. CO2 capture	

Case		30 FOS ref	30 FOS	30 FOS 50H	30 FOS 50H_c	50/1 FOS	50/2 FOS	50/2 FOS_e	50/2 FOS_h	50/2 FOS_c
Feedstocks	kt/a									
Crude		6350	6350	6350	6350	5020	4300	4300	4300	4300
Lipids		0	0	0	0	0	0	0	0	0
Biomass		0	0	0	0	0	0	0	0	0
Bio FT product										
HTL oil										
CO2 capture (inc. own)		*0*	*0*	*0*	*318*	*0*	*0*	*185*	*178*	*207*
E-FT product										
Gas import as SMR feed		83	81	82	82	67	60	60	2	60
Hydrogen import		0.0	1.0	0.0	0.0	0.0	0.0	0.0	29.0	0.0
Products	kt/a	**5944**	**5946**	**5957**	**5957**	**4681**	**4002**	**4004**	**4002**	**4002**
Olefins		537	537	536	536	480	484	484	484	484
BTX		161	161	161	161	148	151	151	151	151
LPG		233	232	231	231	174	142	142	142	142
Gasoline		935	931	929	929	632	428	428	428	428
Jet		889	888	889	891	1029	998	998	998	998
Diesel (mixed uses)		2348	2346	2331	2327	1354	1063	1063	1063	1063
DMF		146	144	143	145	351	266	265	265	266
LSFO		260	260	295	295	78	79	79	79	79
HS RMF		142	144	138	138	141	101	105	103	101
Bit		224	224	224	224	219	216	216	216	216
Lubs and waxes		69	79	79	79	77	74	74	74	74
Coke		*130*	*130*	*125*	*125*	*116*	*99*	*99*	*99*	*99*
Production-demand	% of total liquid product									
Olefins		0.0%	0.0%	-0.1%	0.0%	0.1%	0.3%	0.1%	0.1%	0.1%
BTX		-0.1%	-0.1%	-0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
LPG		0.7%	0.7%	0.7%	0.0%	0.4%	0.2%	0.2%	0.2%	0.2%
Gasoline		6.1%	6.0%	5.9%	0.0%	2.9%	5.3%	5.1%	5.2%	5.2%
Jet fuel		0.0%	0.0%	0.0%	0.0%	0.0%	-0.5%	-0.9%	-0.9%	-0.9%
Gasoils		-6.3%	-6.4%	-6.7%	0.0%	-3.5%	-4.2%	-4.6%	-4.6%	-4.6%
DMF		0.1%	0.0%	0.0%	0.0%	-0.1%	0.1%	0.0%	0.0%	0.0%
LSFO		-0.5%	-0.5%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
HS RMF		0.0%	0.1%	0.0%	0.0%	0.0%	-0.1%	0.0%	-0.1%	-0.1%
Bitumen		0.2%	0.2%	0.2%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
Lubs and waxes		0.0%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
Production-demand	% of grade demand									
Olefins						0.2%	2.5%	2.5%	2.5%	2.5%
BTX						-1.1%	2.1%	2.1%	2.1%	2.1%
LPG						13.1%	7.4%	7.4%	7.4%	7.4%
Gasoline						26.8%	95.6%	95.6%	95.6%	95.6%
Jet fuel						-0.3%	-2.1%	-2.1%	-2.1%	-2.1%
Gasoils						-11.1%	-13.5%	-13.5%	-13.5%	-13.5%
DMF						-1.3%	1.1%	0.7%	0.7%	1.1%
LSFO						-1.3%	1.9%	1.9%	1.9%	1.9%
HS RMF						-0.3%	-3.8%	-0.2%	-2.1%	-3.8%
Bitumen						1.2%	1.2%	1.2%	1.2%	1.2%
Lubs and waxes						6.5%	3.7%	3.7%	3.7%	3.7%
Plant utilisation	% of existing									
CD		80%	80%	80%	80%	63%	54%	54%	54%	54%
VD		72%	72%	72%	72%	59%	50%	50%	50%	50%
FCC		35%	34%	34%	34%	27%	22%	22%	22%	22%
VB		5%	5%	5%	5%	7%	3%	3%	3%	3%
HC		162%	162%	162%	162%	123%	105%	105%	105%	105%
CK		122%	122%	118%	118%	108%	92%	92%	92%	92%
REF		72%	72%	71%	71%	45%	32%	32%	32%	32%
ALK		41%	40%	40%	40%	30%	24%	24%	24%	24%
NHT		98%	98%	98%	98%	73%	63%	63%	63%	63%
KHT		131%	131%	131%	131%	115%	99%	99%	99%	99%
GHD		74%	74%	74%	74%	61%	51%	51%	51%	51%
LDS		155%	155%	155%	155%	0%	0%	0%	0%	0%
RDS/RCN		124%	124%	124%	124%	62%	48%	48%	48%	48%
HM		239%	233%	238%	238%	195%	173%	173%	5%	173%
POX		0%	0%	0%	0%	0%	0%	0%	0%	0%

Case		30 FOS ref	30 FOS	30 FOS 50H	30 FOS 50H_c	50/1 FOS	50/2 FOS	50/2 FOS_e	50/2 FOS_h	50/2 FOS_c
Energy										
NG import (fuel)	kt/a	194	125.5	122	122	58.9	49.7	21.1	6.6	49.7
	TJ/a	9710	6277	4242	4242	2946	2485	1053	329	2485
	% of inter. energy	51%	41%	32%	32%	29%	30%	15%	5%	30%
Elec import	GWh/a	152	264	756	1155	597	512	1054	2414	559
Processing		152	216	756	756	597	512	186	1022	512
CO2 capture		0	0	0	399	0	0	0	340	47
Electrolysis		0	48	0	0	0	0	1048	1392	0
	% of total energy	7%	11%	29%	29%	29%	29%	40%	40%	29%
Hydrogen	kt/a									
Conventional / Gen. purpose		41.3	40.3	41.0	41.0	33.7	29.8	29.8	0.8	29.8
Electrolytic / Gen. purpose		0.0	1.0	0.0	0.0	0.0	0.0	0.0	29.0	0.0
Electrolytic / efuels		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions	t/kt liq prod									
Actual from site (Fossil + bio)		0.23	0.18	0.15	0.10	0.15	0.15	0.09	0.04	0.10
Fossil from			0.76	0.65	0.43		0.57			
Crude P&T		0.44	0.44	0.43	0.43	0.44	0.44	0.44	0.44	0.44
Site		0.23	0.18	0.15	0.10	0.14	0.13	0.08	0.04	0.08
Imports		0.05	0.04	0.03	0.04	0.03	0.03	0.03	0.03	0.03
Combustion		2.70	2.70	2.70	2.70	2.62	2.52	2.52	2.52	2.52
Total fossil		0.28	0.22	0.18	0.13	0.17	0.16	0.11	0.07	0.12
Total fossil + Combustion (fossil)		3.42	3.35	3.32	3.27	3.23	3.12	3.06	3.02	3.07
Emissions EU-wide	Mt/a	80	refineries							
	Assume	*5340*				*4681*	*4000*			
Total actual (Total fossil + Combustion + Total Bio)		1459	1431	1416	1394	1214	1002	982	967	985
Actual from site (Fossil + bio)		99	76	65	42	66	64	37	18	41
Fossil from		0	326	279	182	0	181	0	0	0
Crude P&T		186	186	185	185	163	140	140	140	140
Site Fossil		99	76	65	42	51	42	24	13	27
Imports Fossil		20	18	14	15	12	10	10	10	10
Combustion		1154	1152	1151	1151	981	804	804	804	804
Total fossil		120	94	79	57	63	52	34	22	37
Total fossil + Combustion (fossil)		1459	1431	1416	1394	1208	996	979	966	981
Main fuels footprint	g/MJ									
Gasoline		78.7	77.3	76.5	65.6	77.7	78.5	77.3	76.6	76.9
Crude P&T		8.5	8.5	8.5	8.5	8.5	8.7	8.6	8.6	8.7
Refining		5.1	3.6	2.8	1.8	2.9	2.9	1.7	1.0	1.8
Biofuel contribution		3.0	3.0	3.0	3.0	3.9	4.0	4.0	4.0	3.5
Combustion		62.2	62.2	62.2	52.3	62.2	63.0	63.0	63.0	63.0
Diesel		85	83	82	56	84	84	83	82	81
Crude P&T		9	9	9	9	9	9	9	9	9
Refining		5	4	3	2	3	3	2	1	2
Biofuel contribution		7.0	7.0	7.0	7.0	5.1	5.1	5.1	5.1	6.8
Combustion		64	64	64	39	67	66	66	66	64
Jet		88	87	85	74	86	86	84	84	85
Crude P&T		10	10	10	10	10	10	10	10	10
Refining		6	4	3	2	3	3	2	1	2
Combustion		72	72	72	61	72	72	72	72	72
Petchem footprint	% non fossil carbon									
Olefins										
Olefins: Actual C content		0%	0%	0%	9%	0%	0%	0%	0%	0%
Olefins: Net of processing emissions		-22%	-20%	-18%	-8%	-19%	-19%	-17%	-16%	-17%
BTX										
BTX: Actual C content		0%	0%	0%	3%	0%	0%	0%	0%	0%
BTX: Net of processing emissions		-21%	-19%	-17%	-15%	-18%	-17%	-16%	-15%	-16%

13.3. ALTERNATIVE FEEDS CASES

Code	Crude intake(1)	Low-C feedstocks(2)			
		Type / processing route	kt/a	Refinery feed	kt/a
L1	3280	Lipids	1000	Lipids, of which	1000
				Co-processing GHT	20%
				Co-processing HC	20%
				Dedicated HT	60%
BFT1		Biomass / FT route	4250	Raw FT liquids	935
BPY1		Biomass / HTL route (pyrolysis)	2250	HTL oil	970
FOE1	3300	90% internally produce CO2 capture	466	e-fuel liquids	1020
		Additional CO2 imported	2700		

Demand as per 2050 / 2 scenario

Refinery emission reduction measures at 2050 level in all cases

(1) In "notional" refinery, 2030 EU-mix quality

(2) To produce around 1 Mt/a liquid feed in "notional" refinery

Code	Low-C feedstocks				
	Scheme	Type / Processing	kt/a	Refinery feed	kt/a
LB/ LB_c(1)	Lipids + Biomass	Lipids		Lipids, of which	2910
				Co-processing GHT	15%
				Co-processing HC	15%
				Dedicated HT	46%
				FCC (olefins mode)	23%
		Biomass / FT	3810	Raw FT liquids	838
LBE	As LB plus e-fuels through own CO2 capture (70%) (Capture energy deemed to be supplied by waste heat from electrolysers)	Lipids		Lipids, of which	2150
				Co-processing GHT	20%
				Co-processing HC	20%
				Dedicated HT	60%
				FCC (olefins mode)	0%
		Biomass / FT	2800	Raw FT liquids	616
		CO2 capture	2729	e-fuel liquids	879
LBPE	As LBE but limited e-fuels (16% capture) and with biomass 50/50 FT and pyrolysis oil (HTL process)	Lipids		Lipids, of which	2410
				Co-processing GHT	15%
				Co-processing HC	15%
				Dedicated HT	45%
				FCC (olefins mode)	26%
		Biomass	3640	Raw FT liquids	400
				HTL oil	784
		CO2 capture	459	e-fuel liquids	148

In all cases:

Figures relate to "notional" refinery

Demand as per 2050 / scenario 2, crude intake in "notional" refinery 810 kt/a in all cases

Crude intake 810 kt/a (minimum heavy crude to meet bitumen demand)

Refinery emission reduction measures at 2050 level

(1) LB_c includes CO2 capture

Case		L1	BFT1	BPY1	FOE1	LB	LB_c	LBE	LBPE
Feedstocks	kt/a								
Crude		3280	3280	3280	3300	810	810	810	810
Lipids		1000	0	0	0	2910	2910	2150	2410
Biomass		0	4250	0	0	3810	3810	2800	3640
Bio FT product		0	935	0	838	0	838	616	400
HTL oil				970					784
CO2 capture (inc. own)		*0*	*0*	*0*	*3166*	*0*	*1814*	*2729*	*459*
E-FT product				0				879	148
Gas import as SMR feed		1	41	4	38	11	15	24	14
Hydrogen import		59.0	0.0	80.0	0.0	30.0	30.0	14.0	68.0
Products	kt/a	**3962**	**3947**	**3960**	**4051**	**3955**	**3955**	**3964**	**3988**
Olefins		485	470	473	475	477	477	498	426
BTX		148	148	143	145	45	45	78	60
LPG		164	148	111	164	215	215	222	194
Gasoline		224	460	463	469	249	249	225	339
Jet		1019	902	758	963	1020	1020	979	860
Diesel (mixed uses)		1195	1083	1282	1107	1405	1405	1361	1525
DMF		265	263	262	267	236	236	265	267
LSFO		71	81	81	79	0	0	0	0
HS RMF		110	109	106	102	24	24	49	27
Bit		213	213	213	214	216	216	216	216
Lubs and waxes		67	71	69	66	69	69	72	74
Coke		*49*	*90*	*50*	*57*	*38*	*38*	*28*	*18*
Production-demand	% of total liquid product								
Olefins		0.3%	-0.1%	0.0%	-0.2%	0.1%	0.1%	0.7%	-1.2%
BTX		0.0%	0.0%	-0.1%	-0.2%	-2.6%	-2.6%	-1.8%	-2.2%
LPG		0.8%	0.4%	-0.6%	0.7%	2.1%	2.1%	2.3%	1.6%
Gasoline		0.1%	6.1%	6.2%	6.0%	0.8%	0.8%	0.2%	3.0%
Jet fuel		0.0%	-3.0%	-6.6%	-2.0%	0.0%	0.0%	-1.0%	-4.0%
Gasoils		-0.9%	-3.7%	1.3%	-3.8%	4.5%	4.5%	3.3%	7.5%
DMF		0.0%	0.0%	0.0%	-0.1%	-0.7%	-0.7%	0.0%	0.1%
LSFO		-0.2%	0.1%	0.1%	0.0%	-2.0%	-2.0%	-2.0%	-2.0%
HS RMF		0.1%	0.1%	0.0%	-0.1%	-2.1%	-2.1%	-1.4%	-2.0%
Bitumen		0.0%	0.0%	0.0%	-0.1%	0.1%	0.1%	0.1%	0.1%
Lubs and waxes		-0.1%	0.0%	-0.1%	-0.2%	0.0%	0.0%	0.0%	0.1%
Production-demand	% of grade demand								
Olefins		2.7%	-0.4%	0.2%	0.5%	0.9%	0.9%	5.5%	-9.8%
BTX		0.7%	0.4%	-3.1%	-1.6%	-69.6%	-69.6%	-47.2%	-59.6%
LPG		23.9%	11.6%	-16.4%	23.8%	62.3%	62.3%	67.7%	46.5%
Gasoline		2.6%	110.2%	111.6%	114.4%	13.8%	13.8%	2.8%	55.1%
Jet fuel		0.0%	-11.6%	-25.6%	-5.5%	0.0%	0.0%	-4.0%	-15.6%
Gasoils		-2.8%	-11.9%	4.3%	-9.9%	14.3%	14.3%	10.7%	24.1%
DMF		0.6%	-0.3%	-0.5%	1.3%	-10.4%	-10.4%	0.4%	1.2%
LSFO		-8.5%	4.4%	4.4%	1.9%	-100.0%	-100.0%	-100.0%	-100.0%
HS RMF		5.4%	4.2%	1.2%	-2.7%	-77.4%	-77.4%	-52.8%	-74.3%
Bitumen		-0.5%	-0.5%	-0.5%	0.1%	0.9%	0.9%	0.9%	0.9%
Lubs and waxes		-5.8%	0.0%	-3.7%	-6.9%	-2.4%	-2.4%	1.1%	4.2%
Plant utilisation	% of existing								
CD		41%	41%	41%	41%	10%	10%	10%	10%
VD		38%	38%	38%	39%	12%	12%	12%	12%
FCC		16%	35%	100%	16%	54%	54%	35%	50%
VB		2%	2%	2%	2%	0%	0%	0%	0%
HC		98%	145%	82%	177%	133%	133%	184%	118%
CK		47%	46%	48%	54%	0%	0%	0%	0%
REF		11%	28%	13%	31%	1%	1%	5%	5%
ALK		33%	47%	36%	27%	73%	73%	59%	62%
NHT		50%	51%	51%	47%	19%	19%	17%	18%
KHT		75%	75%	75%	76%	20%	20%	20%	20%
GHD		58%	42%	62%	39%	61%	61%	49%	72%
LDS		0%	0%	0%	0%	0%	0%	0%	0%
RDS/RCN		51%	51%	51%	37%	0%	0%	0%	0%
HM		4%	119%	12%	110%	288%	288%	270%	254%
POX		0%	0%	0%	0%	0%	-70%	-47%	-60%

Case		L1	BFT1	BPY1	FOE1	LB	LB_c	LBE	LBPE
Energy									
NG import (fuel)	kt/a	9.6	6.5	22.9	4.6	0.8	0.9	0.6	0.8
	TJ/a	481	324	1143	230	40	43	28	41
	% of inter. energy	9%	4%	17%	3%	1%	1%	1%	1%
Elec import	GWh/a	3344	-1536	4545	22739	149	1764	19977	6051
Processing		512	-1536	704	393	-1291	-427	814	-321
CO2 capture		0	0	0	892	0	750	0	0
Electrolysis		2832	0	3840	21455	1440	1440	19163	6371
	% of total energy	29%	29%	40%	29%	29%	29%	29%	29%
Hydrogen	kt/a								
Conventional / Gen. purpose		0.7	20.5	2.2	464.2	54.6	54.6	434.3	113.3
Electrolytic / Gen. purpose		59.0	0.0	80.0	0.0	30.0	30.0	14.0	68.0
Electrolytic / efuels		0.0	0.0	0.0	445.2	0.0	0.0	383.7	64.5
Emissions	t/kt liq prod								
Actual from site (Fossil + bio)		0.09	1.35	0.11	0.01	1.31	0.85	0.30	0.60
Fossil from									
Crude P&T		0.34	0.34	0.34	0.33	0.08	0.08	0.08	0.08
Site		0.06	0.24	0.09	0.01	0.17	-0.28	0.04	0.09
Imports		0.04	0.00	0.06	0.24	0.01	0.02	0.21	0.07
Combustion		1.96	1.99	1.85	1.72	0.61	0.61	0.57	1.07
Total fossil		0.10	0.24	0.14	0.25	0.18	-0.26	0.25	0.16
Total fossil + Combustion (fossil)		2.39	2.56	2.33	2.30	0.88	0.44	0.91	1.31
Emissions EU-wide	Mt/a								
	Assume								
Total actual (Total fossil + Combustion + Total Bio)		935	1330	955	736	1239	1099	968	1044
Actual from site (Fossil + bio)		37	576	46	5	557	363	126	258
Fossil from		0	0	0	0	0	0	0	0
Crude P&T		108	108	108	106	27	27	27	26
Site Fossil		18	76	28	4	56	-90	13	29
Imports Fossil		13	0	18	76	2	7	67	21
Combustion		625	635	591	550	196	196	183	342
Total fossil		31	76	46	80	57	-82	80	50
Total fossil + Combustion (fossil)		763	820	745	736	280	140	290	418
Main fuels footprint	g/MJ								
Gasoline		71	73	60	75	33	23	36	45
Crude P&T		7	7	7	6	2	2	2	2
Refining		2	5	2	3	4	-6	3	2
Biofuel contribution		4	4	4	4	4	4	3	3
Combustion		59	57	47	62	23	23	28	37
Diesel		60	65	62	58	28	17	25	39
Crude P&T		7	7	7	7	2	2	2	2
Refining		2	6	3	3	4	-6	3	2
Biofuel contribution		5.1	5.1	5.1	5.1	5.0	5.0	6.8	6.7
Combustion		47	47	47	44	17	17	13	29
Jet		65	69	76	68	25	14	23	28
Crude P&T		8	8	8	8	2	2	2	2
Refining		2	6	3	3	4	-7	3	3
Combustion		55	55	66	57	19	19	17	24
Petchem footprint	% non fossil carbon								
Olefins									
Olefins: Actual C content		6%	26%	12%	18%	63%	63%	74%	55%
Olefins: Net of processing emissions		-8%	7%	-3%	3%	54%	69%	66%	49%
BTX									
BTX: Actual C content		4%	14%	9%	11%	56%	56%	61%	40%
BTX: Net of processing emissions		-9%	-4%	-5%	-3%	47%	62%	54%	34%

13.4. ADDITIONAL MASS BALANCES

For information and comparison purposes, two extra mass balances for some selected pathways are included in this section:

Table 13.4-1 Additional mass balances for some selected pathways

Pathway	**Dry Wood to Pyro/HTL-HDT (1)**	**e-fuel (FT-wax to HC) (2)**
Feeds		
Lipids		
Wood	**-100.0**	
Pyrolysis Oil		
CO_2		-100.0
Products		
CO_2	**33.6**	
Water	**35.4**	-45.4
H_2	**-4.5**	(5)
O_2 or (O_2 in air[1])	**-12.2**	113.1
Char	**4.9**	
Fuel Gas	**10.4**	0.9
C3+C4		2.1
Gasoline	**13.8**	6.3
Diesel+Jet	**18.7**	19.9
Heavy FT Liquid		3.2

Note: In the mass balance presented above, negative values refer to inputs (e.g. liquid feed and hydrogen being consumed in the conversion process). Consequently, all products are identified with positive values.

(1) Dry Wood-to-Pyrolysis/HTL: this pathway considers that wood is fed into the refinery and, therefore, reported as an input in the mass balance above. Pathway presented for information and comparative purposes versus the other Wood-to-BTL and Pyro/HTL oil to HDT routes modelled in the report (More details in table 6.2.9-1). Regarding the hydrogen balance, this pathway considers the extra import/production of ad-hoc hydrogen for the final refining step and conversion of oil into final products (total hydrogen consumption reported as an input, with a negative value in the table).

(2) This pathway considers that the whole amount of hydrogen (required for both e-fuels production and its subsequent conversion process in the HC unit) is produced from renewable electricity in electrolysers installed within the battery limits of the refinery. This means that electricity consumption in the main input for the hydrogen production – as utility – and, therefore, hydrogen is not been included in the mass balance when reported in table 13.4-1).
It is presented for comparative purposes versus the case presented in the table 6.2.9-1, in the case of considering hydrogen as a pure import product to the refinery (instead of electricity as utility).

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