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CO_2 reduction technologies. Opportunities within the EU refining system (2030/2050).

Qualitative & Quantitative assessment for the production of conventional fossil fuels (Scope 1 & 2)

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Qualitative & Quantitative assessment for the production of conventional fossil fuels (Scope 1 & 2)

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ABSTRACT

This report describes the work being conducted by Concawe with the objective to explore a range of *Low Carbon Pathways* with the potential to reduce the CO_2 emissions associated with the production of refined oil products. This document demonstrates that the effective deployment of different technologies has the potential to achieve a significant reduction of the CO_2 emissions associated with oil refining by 2050.

The gradual decarbonisation of the EU electricity grid will offer new ways to integrate low-carbon electricity into the production system, while CO_2 Capture technology will enable refineries to make CO_2 available for either storage (CCS) or use (CCU) thereby integrating the EU refining system into a circular economy. External factors such as future energy prices together with more effective R&D programs will play a role in boosting the deployment of the key technologies identified.

It is important to note that this works is not intended to be a roadmap for the whole EU refining industry. Factors such as the CO_2 efficiency of existing facilities coupled with local and structural constraints will determine individual refineries' preferred route to contribute to mitigation of climate change. Whilst this report details opportunities to improve the CO_2 efficiency of the EU Refining system, other studies are underway which examine the potential for integrating different, non-petroleum derived feedstocks and their implications in a future picture of the *Refinery 2050*.

KEYWORDS

Refineries, CO_2, GHG reduction, energy, efficiency, Clima.

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SUMMARY

Oil refining is an inherently energy intensive activity. Refineries meet their energy needs principally by burning hydrocarbon by-products of low commercial value, thereby producing CO_2.

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**. As their contribution, the European Union defined their Nationally Determined Contribution and agreed on a binding target for the EU and its Member States of at least 40% domestic reduction in greenhouse gases (GHG) emissions by 2030 compared to 1990. To achieve these goals, the EU is exploring different mid-century scenarios for a low-carbon economy by 2050. To support the EU low emissions strategy, Concawe is exploring cross-sectorial Low Carbon Pathways where the EU refining industry collaborates with existing and emerging industries in an integrative way to substantially reduce the CO_2 emissions associated with the manufacturing and use of hydrocarbon intermediate and final products, thereby continuing to provide value to the EU economy in the coming decades.

This study was undertaken in this context with purpose of:

- Establishing the current status of EU refineries in terms of energy intensity and CO_2 emissions intensity including a brief historical perspective and a comparison with the situation in other world regions,
- Exploring the future of low CO_2 technologies when deployed across the whole EU refining system towards 2030 and further to 2050, and to describe plausible CO_2 intensity reduction pathways by addressing the following questions:
    - What can realistically be achieved through continued gradual improvement?
    - What is the potential for significant new technologies to enable CO_2 intensity step-changes?
    - What is the potential for hitherto untapped synergies with other sectors?
    - What could be the impact of changes to both the quality and quantity of demand for EU petroleum products?

For the purposes of this study, the demand scenario (quality and quantity) was fixed implying a constant intrinsic energy intensity. The study therefore concentrated on the impact of energy efficiency and CO_2 intensity reduction measures.

According to the GHG Protocol, this assessment addresses the refining CO_2 emissions covered under *Scope 1* (Direct emissions) and *Scope 2* (Indirect emissions from production of purchased energy such as electricity). Other indirect emissions associated with the final use of refining products (*Scope 3*) are excluded from the scope of this analysis and will be addressed in upcoming reports *(Low Carbon Pathways* programme).

EU refineries will continue to seek energy efficiency improvement and CO_2 emissions reductions through a combination of operational measures and targeted investments, taking advantage of technology developments and of external opportunities. The combination of options practically available will be to a large extent unique to each site, dictated by different factors such as existing configuration or location.

A bottom-up approach, looking at each of the 80 refineries currently in operation in the EU, would be impractical and would raise confidentiality issues. Instead, this study adopted a top-down approach, identifying which emission-reduction technologies and external opportunities might be available to EU refiners and what impact they might have at the 2030 and 2050 horizon on the CO_2 intensity of the whole EU refining sector. Relevant information was collected from literature and through consultations with experts from technology providers and Concawe Member Companies.

In this context, it is worthy of note that this report pictures a sound reference 2030 case including product demand forecast with focus on what the CO_2 reduction technologies could deliver in the medium/long term. It is not intended to reflect potential changes in demand onwards (from 2030 towards 2050) keeping the demand fixed in that period. Different scenarios exploring the potential evolution of demand from 2030 to 2050 and investigating the role of alternative low-carbon feedstocks to oil will be further assessed in another complementary Concawe report (*Refinery 2050 report*) belonging to the same Concawe's *Low Carbon Pathways* series of publications.

Opportunities to implement CO_2 reduction technologies in the EU Refining System

A variety of options were identified which were clustered into 3 main categories:

Table 1. Summary of CO_2 reduction opportunities identified (Examples)

A. **Energy Efficiency (EE)**	
Refinery **process efficiency**	○ **Continuous improvement** through implementation of a combination of measures and small projects involving some capital expenditure. Examples include catalyst improvements and hardware improvements such as new motors, heat-exchangers, etc. **This includes Energy Management** Systems combining equipment (e.g. energy measurement and control systems) with strategic planning, organisation and culture. ○ **Major capital projects:** Larger efficiency improvements reflecting changes to the technical configuration of individual refineries (e.g. extensive revamps of existing facilities, new process plants). ○ Inter-unit heat integration
Increased recovery of refinery **low-grade heat** for export and electricity production	
B. **Use of Low Carbon Energy sources (LCE)**	
Benefit from **decarbonisation of the** gas and electricity **grid**	
Reduction of **liquid fuel** burning	
Improved **recovery of Hydrogen and LPG** from fuel gas	

B. Use of Low Carbon Energy sources (LCE) (Cont.)	
Increased use of **imported low-carbon electricity**	**General electrification**: Increased use of electricity for general operations a/o rotating machines
	Generation: Partial replacement of own generation by imported low-carbon electricity.
	Substitution of fired boilers and heaters by electric heaters
	Electrolysis: Production of hydrogen with electrolysers using imported renewable electricity
C. CO_2 capture (CC)	
Capture (and storage) of a portion of the refinery CO_2 emissions.	

Results: Potential reduction of CO_2 emissions / energy savings and refinery capex

a) *Basis*

Different rates of deployment of technology, energy prices and the degree of decarbonisation of the electricity grid were explored for both time horizons, 2030 and 2050.

The starting point for the 2030 horizon (2030 reference case “Median”) was based on actual and detailed refinery data prorated until 2030 including factors such as product demand forecasts and known changes to the configuration of the EU refinery population. This was incorporated into a model which could integrate all options in a systematic and consistent way and arrive at a range of plausible CO_2-intensity reduction figures for the whole EU refining sector.

The potential of each option was scrutinised in some detail, considering:

- The underlying technologies, their current and future state of development,
- The internal and external factors (practical and financial) that might favour or constraint the adoption of such measures.

On this basis, assumptions were made to assess the impact of each option in a “Median” case exploring different sensitivities (“*High*” and “*Low*”) for each of the 2030 and 2050 horizons with, for each:

- a set of energy and CO_2 prices, consistent with authoritative studies.
- a maximum rate of uptake for certain options, consistent with the economic environment what we considered practical and plausible at the time horizon.

In addition to this, in the 2050 "*Median*" and "*High*" cases, we have illustrated three alternative routes to achieve deep decarbonisation namely electric boilers and heaters (Max-e), electrolytic hydrogen (Max-h) or CCS (Max-c) with different implications in terms of both the use of electricity and the technologies applied to achieve significant CO_2 reductions.

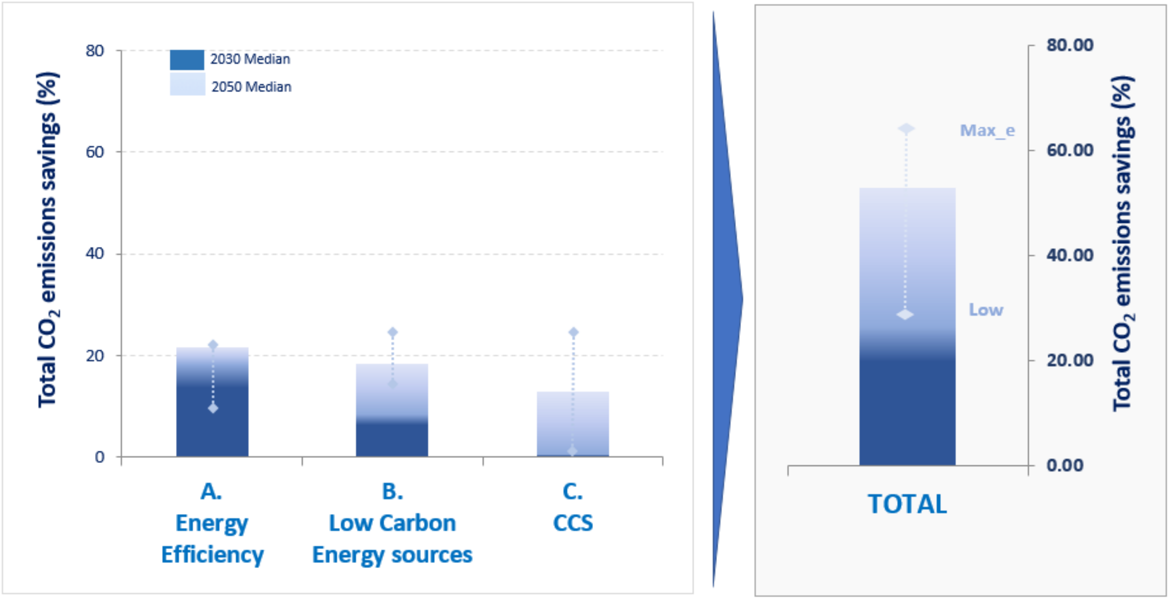
b) Results: CO_2 savings and refinery associated CAPEX

Starting from a 2030 reference case ("*Median*") based on actual refinery data, the results are expressed in terms of four indicators:

1. The degree of **CO_2 emissions reduction** compared to the 2030 reference case
2. The degree of **energy consumption reduction** compared to the 2030 reference case,
3. The **Capital Expenditure** to be incurred by refineries,
4. The implied **CO_2 abatement cost.**

Figure 1 shows the cumulative total emissions savings (i.e. including emissions from production of imported electricity and hydrogen production) and the associated refinery capex for the main opportunities identified above. Each column shows the cumulated potential for a specific category for the 2030 horizon with increasing deployment towards the 2050 horizon:

Figure 1. Cumulative total emission savings



Note: Electrification may account for up to ~23% of the CO_2 reduction in the 2050 High electrification sensitivity case. This incurs significant additional capex outside the refinery not included in the scope of this assessment.

Assuming that the EU refining activity is maintained at the 2030 level[1], when all options are exercised in the **Median scenario** the total EU **refinery CO_2 emissions (direct and indirect)** can potentially be reduced, from a technical point of view, by approximately **25 % by 2030 and 52% by 2050**, compared to the 2030 reference case (for which a CO_2 reduction of approximatively 5% as compared to 2008 is estimated).

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[1] Total CO_2 emissions in the 2030 Reference case: ~125 Mt CO_2/a

This is equivalent to annual total CO_2 emissions savings of 33 Mt (2030) to 65 Mt (2050) with the potential to increase up to 78 Mt by 2050 in the High uptake sensitivity cases (equivalent to a 62% reduction by 2050 in the Max_e scenario).

The basic assumption for the 2050 horizon is that the maximum level of realistic deployment will be achieved for each identified opportunity at the EU level, assuming no change in the demand versus 2030 and, therefore, without changes in the throughput (activity level) of the sector. The degree to which the available options will be deployed will depend on several factors such as external market conditions, evolution of energy and CO_2 prices and future regulatory framework. These factors will influence technology improvements and the effective commercial viability and deployment of the opportunities identified. The combination of options practically available will be, to a large extent, unique to each site, dictated by several factors such as existing energy efficiency performance or location.

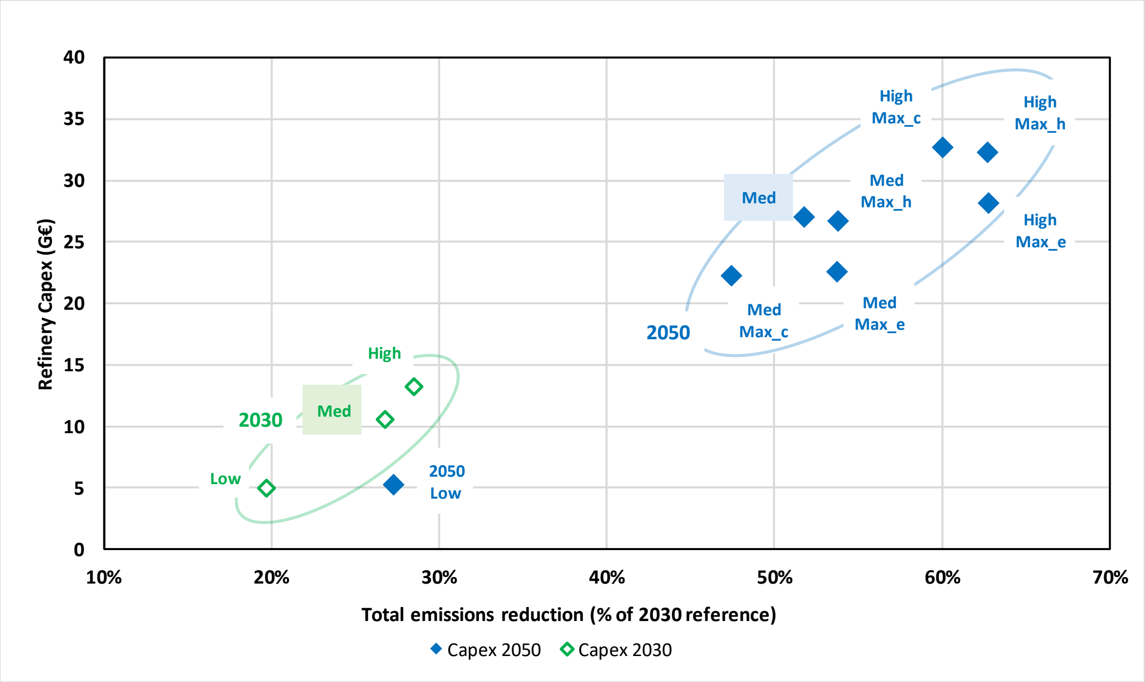
A more detailed analysis of the main opportunities in terms of CO_2 savings identified (*Median Scenario*) shows that:

- By the 2030 horizon, the bulk of the savings will stem from process energy efficiency and a series of other step changes associated to internal improvement measures. Low carbon energy sources and CCS only start to make a significant impact in the 2050 horizon.
- Underlying **energy efficiency** improvements of up to ~17% by 2030 and 22% by 2050 may be achieved from the 2008 level. This is equivalent to an annual improvement of about 0.6% per year on average for the whole period to 2050, slightly above the average for the past 25 years but in line with more recent data. Note that a portion of these improvements have already been achieved today as the rate of improvement between 2008 and 2014 was ~5% relative to the 2008 average [Solomon 2016] closing partially the gap identified in the present study.
- Successful implementation of **CO_2 capture** (and storage or usage) appears crucial to reducing EU refineries emissions. Based on the findings of a recent detailed study taking into account state-of-the-art technologies and a number of factors specific to refineries (large number of relatively small sources with various level of CO_2 concentration), the maximum potential CO_2 that could be captured across a refining site has been limited to 70% of the total CO_2 available. Within this limitation, effective deployment of CCS across the whole industry sector could increase total 2050 emission savings from ~40% to 52% (up to 62% in the 2050 Max_e case).
- Effective large-scale deployment of **renewable electricity in Europe** at an **affordable price** for industrial users may open a number of routes for large emission-savings by substitution of fossil energy by electricity. These routes could reduce EU refinery emissions by up to 18% by 2050. This would, however, bring the total **electricity consumption of the sector close to 130 TWh/a**, which could represent as much as ~4% of the electricity currently generated in Europe.
- Recovery of **low-grade heat** can make a small contribution through either internal production of electricity or export to e.g. district heating schemes.

Based on these results, the Well-to-Tank CO_2 intensity of the refining activity can be substantially reduced by 2050 if these technologies are deployed across the industry. However, major investment efforts are required within and outside the refineries.

Figure 2 shows that the **capex required** to achieve this potential savings for the whole EU refining system is **estimated** at ***minimum*** **~30,000 M€ (2050 Median Scenario).** This estimated cost only refers to the generic cost of the different technologies and opportunities identified within the battery limits of the refinery. It does not include fixed opex, which would account for 25 to 40% of the total annual fixed costs, being highest for cases involving CO_2 capture. The actual cost of implementation would be determined by the specific conditions of each individual asset.

Figure 2. Refinery capex and total emission reduction

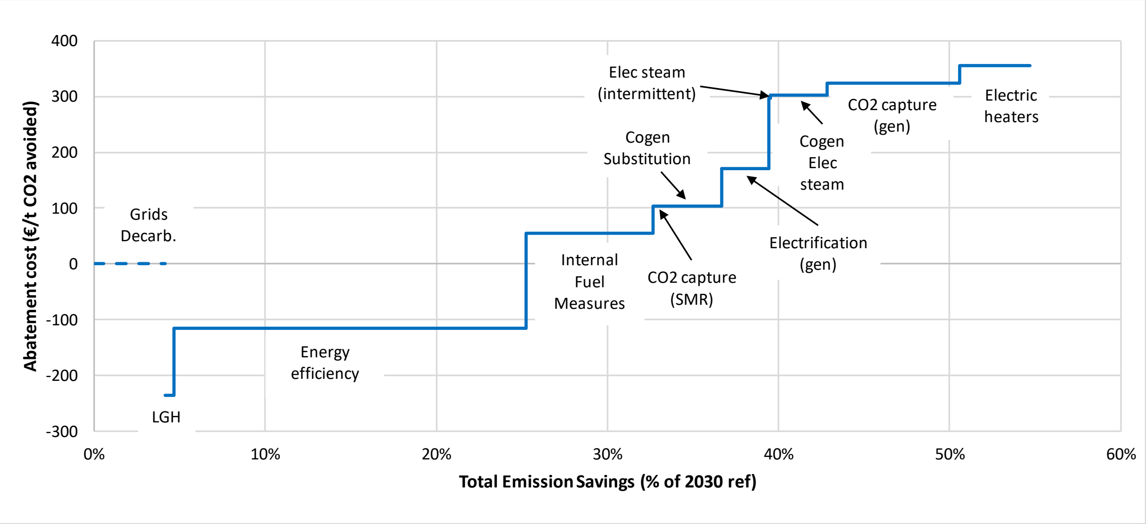


Code. Max_Hydrogen (Max_h), Maximum Electrification (Max_e), Maximum CCS (Max_c)
Note: "Med" cases are highlighted as the main cases explored in the report

c) *Results: Abatement cost*

The abatement cost of a particular option is determined partly by the capex and fixed opex required to implement it but, overwhelmingly, by the assumed energy prices. Therefore, there is no single CO_2 abatement cost per technology and as an example, the figure below plots the abatement cost of each measure, ranked from low to high, versus the cumulative CO_2 emissions savings for the 2050 "Median" case:

Figure 3. CO_2 abatement cost curve
(Energy prices and potential CO_2 savings as defined in the 2050 Median case)



Internal measures and process efficiency improvements show close to zero or negative abatement costs, a direct consequence of the assumptions made regarding the energy prices, the historical profitability of the underlying investments and the pay-back time threshold assumed for such projects, and the discount rate (@15% capital charge) used for consistency between all shown technologies.

The attractiveness of electrification options is directly related to the relative price of gas and electricity, hence low, mostly negative, abatement costs in the “Median” and “Low” cases. Intermittent use of electricity for steam generation is never very favourable because of the high capex involved for a low rate of utilization and similarly, electrolytic hydrogen would only make sense if implemented on a continuous basis. Phasing out CHPs in favour of imported electricity only becomes potentially attractive beyond 2030 and CHP substitution has relatively low cost even in the “Median” cases because of the capex credit involved in not replacing existing plants. This is mostly directly driven by the relative prices assumptions of electricity and gas.

When applied to concentrated CO_2 sources (such as H_2 production in *Steam Methane Reforming* units), CCS achieves a modest abatement cost but remains expensive for the bulk of refinery emissions. This is, in large part, due to the high extra energy consumption of the process as envisaged today. Further technology development could reduce the costs of CCS implementation and therefore increase the penetration of this technology.

R&D

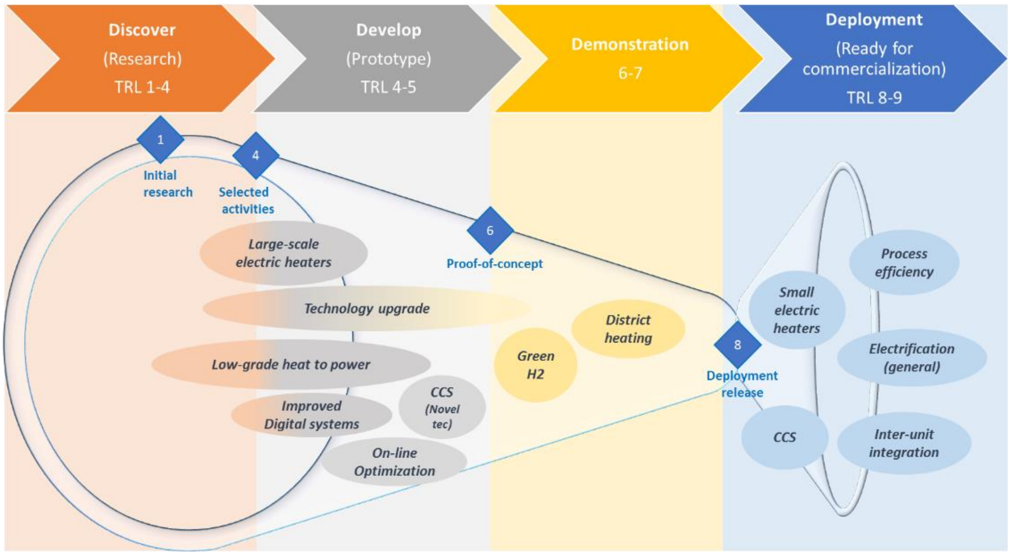
The opportunities to reduce the CO_2 intensity of refinery products identified in this study will require technological development to make the potential a reality at reasonable cost within the time horizons (2030 and 2050).

This study assumes that the refining industry and its technology providers continue to improve conventional refinery process technologies such as separation technologies, catalysts and process additives, and that refiners are able to invest in upgrades which phase-out older technologies. These opportunities are discussed in more detail in **Section 4** and **Appendix 1**.

In addition, this report highlights a number of areas where cross-sectoral and collaborative R&D might accelerate the development and deployment of technologies such as low-grade heat-recovery, electrical process heating, green hydrogen and CCS. Again, these are discussed in more detail in **Section 4** and **Appendix 3**.

Even with such collaborative R&D, refineries will need to attract the investment required to revamp existing or build new plant and the required infrastructure to integrate the developing technologies. This will require a supporting regulatory framework and an economic environment that justifies such investments.

Figure 4. Technology development: Deployment status of various technologies.



A number of the CO_2 intensity reduction opportunities identified in this study will require technological development to make the potential a reality at reasonable cost. This study points out to a number of areas on which R&D might be targeted including specific refinery technologies, generic technologies that could be applied in refineries and external transport and distribution networks for electricity, hydrogen and CO_2.

1. INTRODUCTION

1.1. 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).

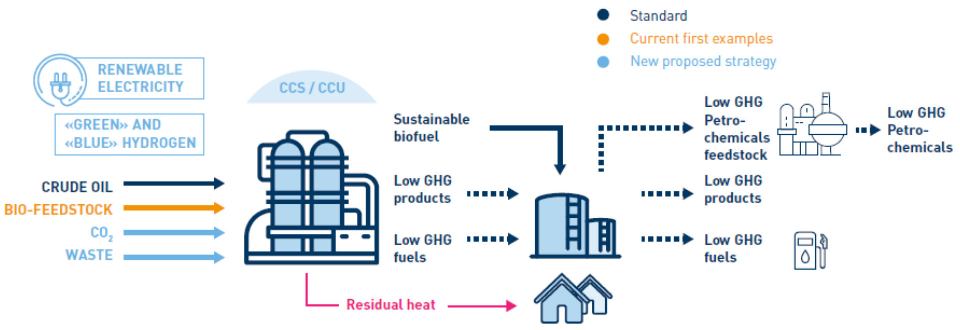
The initial Working plan exploring opportunities from the production phase (Well-To-Tank) to the final use (Tank-To-Wheel) was published in 2018 [Concawe LCP 2018] and since then, a series of reports has already been published and more will follow articulated around two main areas:

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



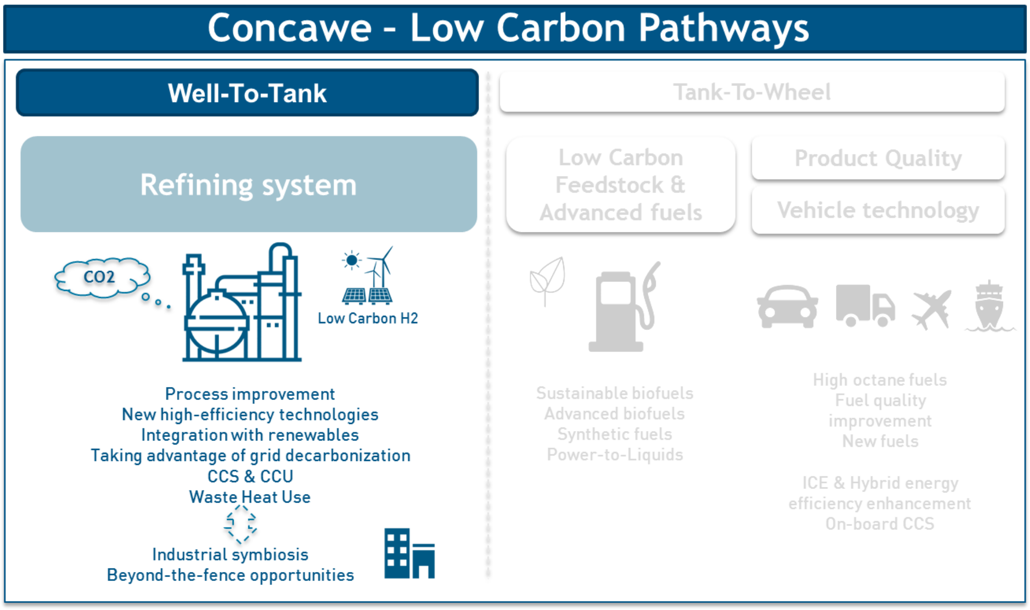
External factors such as the required availability of low-CO_2 electricity, hydrogen or low-carbon feedstocks together with the effective deployment of R&D programs are also investigated as key enablers to boost the effective deployment of the technologies identified.

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 **Figure 1.1-2** 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 opportunities to integrate CO_2 emission reduction technologies within the European Refining System (Well-To-Tank / Scope 1 & 2). The following sections provides further insights regarding its purpose and scope.

Figure 1.1-2 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.

1.2. PURPOSE AND SCOPE OF THIS REPORT

Oil refining is an inherently energy intensive activity. Refineries require energy, in the form of heat and motive power, to transform crude oil into commercial products. They meet their energy needs principally by burning hydrocarbon by-products of low commercial value, thereby producing CO_2. This is supplemented by imported fuels such as natural gas and electricity. Modern refineries also need hydrogen, which is most commonly produced on an industrial scale by decarbonisation of hydrocarbons, releasing CO_2 as a by-product of the chemical reactions involved. Refineries also emit small quantities of other Greenhouse gases such as methane and nitrous oxide but these emissions are insignificant in terms of CO_2-equivalent Global Warming Potential. In this document, “CO_2 intensity” is defined as the amount of CO_2 emitted per unit of refinery activity - a combination of throughput and the amount of upgrading carried out to the crude input.

The purpose of this report is to:

- Establish the current status of EU refineries in terms of energy intensity and CO_2 emissions intensity including a brief historical perspective and a comparison with the situation in other world regions,
- Describe plausible CO_2 intensity reduction pathways of EU refining towards 2030 and further to 2050 by addressing the following questions:
  - What can realistically be achieved through continued gradual improvement?
  - What is the potential for significant new technologies to enable CO_2 intensity step-changes?
  - What is the potential for hitherto untapped synergies with other sectors?
  - What could be the impact of changes to both the quality and quantity of demand for EU petroleum products?

This study considers changes to both direct refining emissions - those emitted within the refinery itself; and to indirect emissions - those emitted outside the refinery, but are related to emissions from production of purchased energy, such as imported electricity or hydrogen, for use in the refinery processes. The emissions from production and delivery of crude to the refinery are not included nor other potential opportunities through crude oil replacement by alternative feedstocks (covered in another report of the series).

1.3. LOWER CARBON ECONOMY: GLOBAL AND EU DRIVES

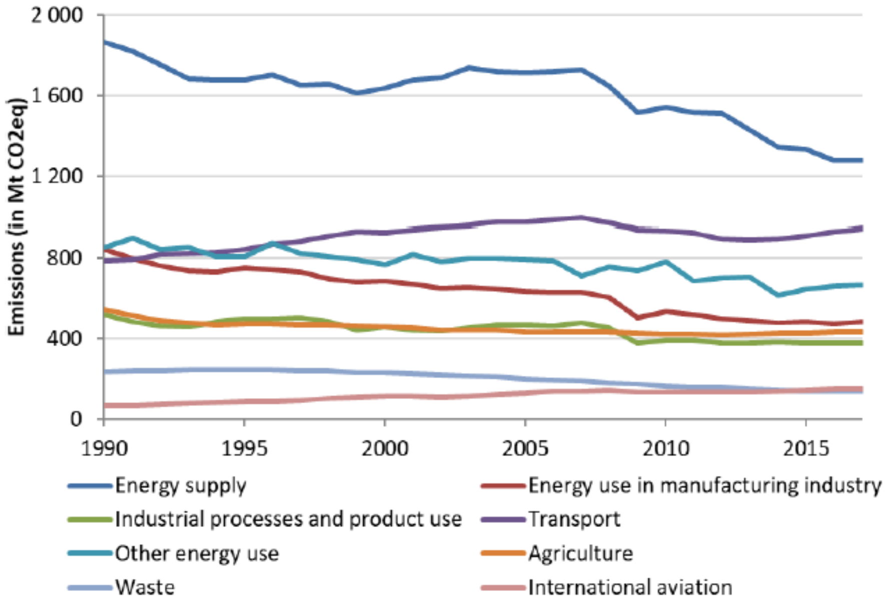
The EU, has recently published its long-term strategic vision for a *prosperous, modern, competitive and climate neutral economy in Europe* [EU 2018, *A Clean Planet for all*] confirming Europe's commitment to lead in global climate action. The *A Clean Planet for all* document provides an assessment in accordance with the Paris Agreement to reduce EU (net) greenhouse gas emissions (GHG) between 80% and 100% by 2050 compared to 1990.

Through six different scenarios, different long-term strategy options are presented with focus on the combination of multiple technologies such as electrification of processes in industry (*ELEC*), hydrogen in targeted applications (H_2) or reducing energy demand via energy efficiency (*EE*) to achieve -80% GHG reduction vs 1990.

Modelling assessments conducted by the EU Commission indicate that the deployment of options such as renewables, including advanced biofuels, energy efficiency or circular economy along with individual options such as electrification, hydrogen and alternative fuels are not sufficient to be aligned to the 1.5°C level of ambition. Therefore, two additional scenarios (1.5 TECH and 1.5 LIFE) explored the cost-efficient combination of different measures coupled with additional mechanisms necessaries to create carbon sinks through maximizing Carbon Capture and Storage (CCS) technologies or natural land based solutions, which could allow the EU to reach GHG neutrality (net-zero emissions) by 2050 and net negative emissions thereafter (See **Appendix 5** for an overview of the eight main scenario building blocks).

The EU has made major reductions in GHG emissions since 1990, reporting CO_2 reduction of 22% by 2017. Industrial activity, contributing about 16% of EU's GDP and 15% of total EU GHG emissions, has also reduced their emissions through the years. In 2015, the Energy Intensive Industry sectors (including refining and chemicals among others) directly emitted ~700 Mt CO_2/y which represents a reduction by more than 30% versus 1990. Energy efficiency investments performed by the industry together with the increased use of recycled and re-used materials are considered as two of the major drivers for this trend [EU 2018].

Figure 1.3-1 EU greenhouse gas emissions by sector 1990 – 2017 [EU 2018]



Source: EEA

Worldwide, although the EU has cut CO_2 emissions, global emissions have increased by ~19%, so that the EU now represents ~ 10% of global CO_2 emissions, versus 19% in 1990 [JRC 2015] [WB 2018]. In the future, according to IEA World Energy Outlook [IEA-WEO 2017] "New Policy Scenario" projections, as EU emissions continue to fall to 2040, global emissions will continue to grow and by 2040 the EU will represent ~8% of global emissions with respect to the other main regions (United States, Japan, China, India, Middle East and Russia).

There are many assumptions about the development of the cost-effective technology needed, about the energy availability and prices and about the necessary CO_2 prices and other policy drivers that are expected to provide the incentives to achieve this goal.

One major assumption is that CCS will be applied to the use of gas for electricity generation, still required to balance the predominant renewable energy sources; and in industry, significant parts of which are difficult to avoid producing CO_2.

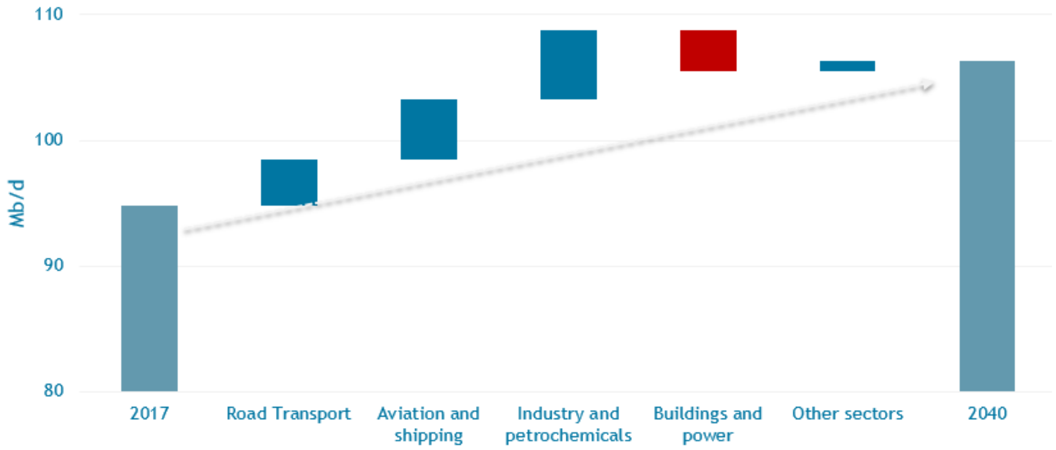
1.4. THE ROLE OF OIL PRODUCTS AND REFINING IN THE ECONOMY

Affordable energy has been a major contributor to economic growth; petroleum products have fuelled global economic growth for more than 100 years, providing transport fuels, heating products, petrochemical and industrial feedstocks, road bitumen, lubricants and many niche special products.

Figure 1.4-1 EU Average refining production (Source: Concawe 2018)

Worldwide, oil currently provides about 1/3rd of global energy and could still account for a similar proportion of a much increased global energy demand to 2040 and beyond. The future energy mix will be more diverse than it is today and, as an example, the International Energy Agency (IEA) pictures a *New Policy Scenario* where, while demand for power generation, buildings and passenger vehicles hints at a peak in oil demand by 2040, this is expected to be largely offset by rising demand from other sectors [IEA-WEO 2018].

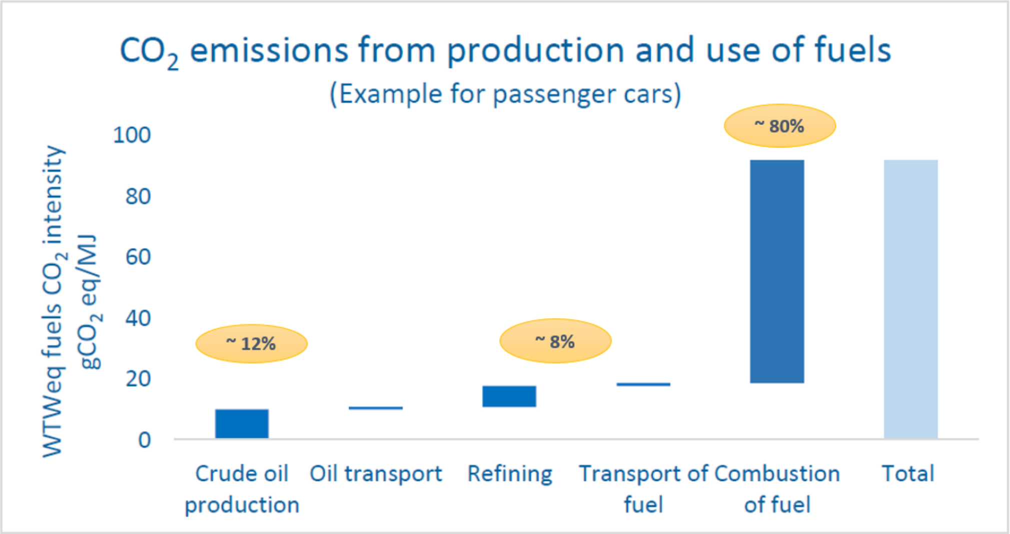
Figure 1.4-2 Global Oil demand by sector in the New Policy Scenario (Source: [IEA-WEO 2018])



In this future energy mix, technological progress is allowing alternative technology-options such as renewables and gas to economically compete with hydrocarbon fuels in electricity production and in some industry, but oil derived fuels will still offer advantages for transport (specially for heavy duty, marine an aviation), chemicals feedstocks and many speciality products where hydrocarbons would continue to be required in the long-term.

When looking in more detail to the transport sector, combustion of hydrocarbon fuels is the main source of CO_2 when both the production and use of fuels is considered (Well-to-Wheel cycle) accounting for about ~80% of CO_2 emissions from oil.

Figure 1.4-3 "Well-to-Wheels" emissions from passenger cars (Source: Concawe based on JEC v4 and own data [Concawe LCP 2018])



Specifications for petroleum products are increasingly strict, demanding sophisticated refining; in particular, EU road transport fuels are sulphur free, allowing advanced vehicle technologies to improve fuel economy and reduce tail pipe emissions. In this context, refining is responsible for about 8% of the total CO_2 intensity of the current EU fossil-based fuels (the rest includes crude oil production and transport). Reducing the emissions incurred during the refining process as much as reasonably possible remains important in order to reduce the total CO_2 intensity of both fuels and refining products. Whereas other Concawe's Low Carbon Pathways related reports tackle different opportunities to reduce CO_2 emissions along the whole Well-to-Wheels value chain, the present report examines how refineries can reduce their energy consumption and CO_2 emissions, through the use of advanced technology, focused on cutting waste and CO_2 reduction measures while keeping the same levels of activity.

2. CO_2 INTENSITY OF TODAY'S EU REFINERIES

2.1. WHY DOES A REFINERY EMIT CO_2?

The purpose of oil refineries is to manufacture a range of petroleum products, including transport fuels (gasoline, diesel fuel, jet fuel, and marine fuel), heating and industrial fuels, chemical feedstocks, lubricants base-stocks and asphalts that are fit for the market in both quantity and quality. The raw materials are mostly crude oils supplemented by other natural or semi processed hydrocarbon mixtures.

Both feedstocks and products are composed of a range of hydrocarbons (with small quantities of other elements such as sulphur and nitrogen) and the overall operation can be seen as the rearrangement of carbon and hydrogen atoms to obtain final products with the desired characteristics.

In practice the manufacturing process involves three main types of activity: namely physical separation of hydrocarbon fractions, treatment of individual fractions to remove undesirable compounds (e.g. sulphur) and modification of molecular structure (mainly cracking large molecules into smaller ones).

All such activities require energy. Refineries supply the bulk of their energy requirement by burning a portion of their hydrocarbon intake thereby generating CO_2. Where extra hydrogen is required, it is most commonly obtained by decarbonisation of light hydrocarbons which produces additional “chemical” CO_2.

There are 4 essential factors governing the CO_2 intensity of a particular refinery:

- Feedstock and Product slate,
- Complexity,
- Energy efficiency,
- Fuel carbon content.

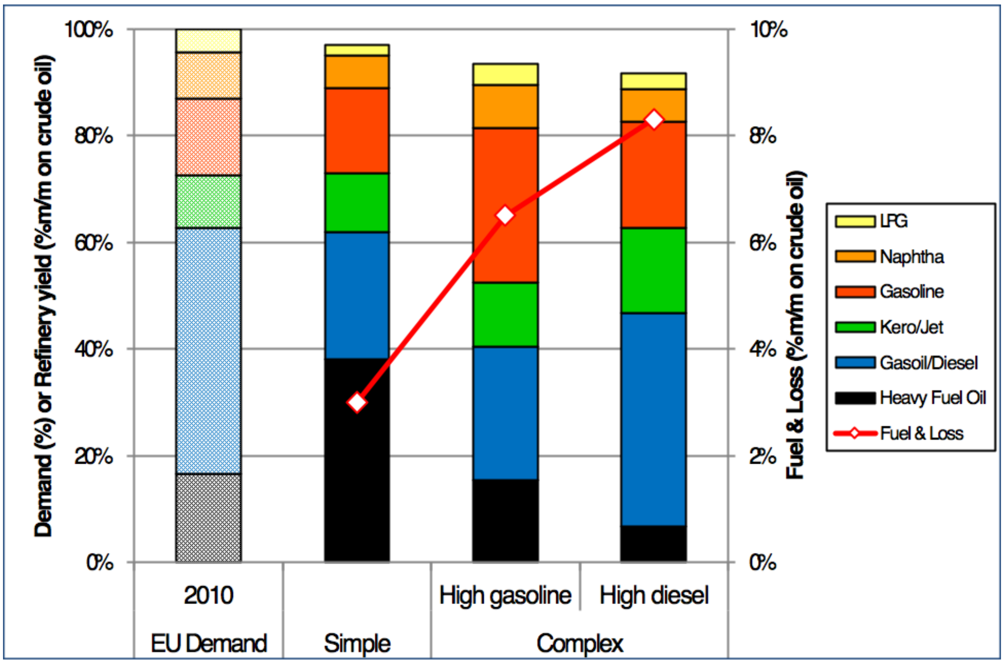
2.2. THE CONTEXT OF PRODUCT DEMAND AND QUALITY

Over time the final applications of petroleum products have become more sophisticated, requiring more stringent specifications related to safety, performance, and pollutant emissions. Sulphur, a naturally occurring component of all crude oils, has been particularly targeted in relation to sulphur oxides emissions abatement as well as vehicle pollutant emission control technologies. This has led to substantial reductions of sulphur content across the product spectrum resulting in an increase in the overall sulphur removal from crude oil in EU refineries from about 35% in 1992 to over 60% in 2010 [Concawe 3/12]. The impact of changing product demand on the energy consumption of and emissions from refining is addressed further in **Section 3** (Note that “Overall sulphur removal” is defined as the total mass of sulphur removed from various intermediate streams during the refining process and recovered as elemental sulphur, divided by the total mass of sulphur contained in the crude oil feed to the refinery, expressed as a percentage.

2.3. COMPLEXITY AND EFFICIENCY: THE TWO KEYS TO REFINERY ENERGY INTENSITY

The first major key to energy intensity is refinery complexity or configuration i.e. the combination of processes operated by a given refinery which, to a large extent, determines which crude oils can be processed and the type, yield and quality of the different refined products that can be manufactured. **Figure 2.3-1** illustrates that, as a general rule, the more "conversion" of heavy streams into light products is carried out and the cleaner the finished products, the higher the energy intensity. A simple refinery performing only distillation and treating and no conversion may consume 3-4% of the energy content of its intake. In a very complex refinery with several conversion units, extensive treatment etc., this figure is typically 7-8%. A complex refinery will therefore consume more energy than a simple refinery with the same crude throughput. Individual refineries may have different configurations, and the overall level of complexity of refineries within a given geographic region is determined by market demand, by regulatory constraints and by the practical and economic crude oil supply available.

Figure 2.3-1 Typical product yield and energy intensity for refineries of different complexity
(Source: [Concawe 3/12])



The fact that simple refineries, compared to complex ones, consume a smaller percentage of their energy input does not imply that they perform these functions in a more or less efficient manner; there are highly energy efficient refineries across the range of complexity.

Beside, complex refineries make more of valuable fractions than simple refineries (less heavy fuel oil versus more gasoline, diesel and jet). Often, the unconverted oil from simple refineries is sold on to more complex refineries. Therefore, complex refineries are important both for profitability and meeting demands.

The market developments discussed in **Section 3** have had major consequences for EU refineries:

- Refineries have steadily become more complex, incorporating more process units dedicated to treating and to conversion of heavy fractions into lighter ones.
- Additional processing for either treatment or conversion has increased the inherent energy intensity of the overall process.
- The hydrogen to carbon ratio of the combined refinery products has increased significantly beyond that of the combined feedstocks, requiring a net addition of hydrogen and/or removal of carbon in the form of coke.

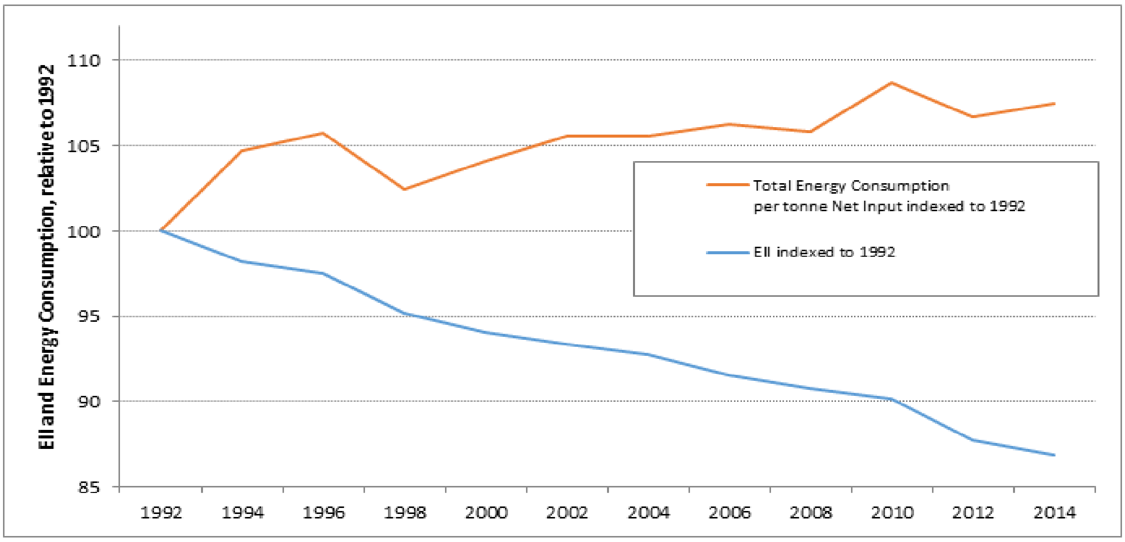
As EU refiners adapted to the large middle distillate to gasoline demand ratio that has developed over the last two decades, hydrocracking has become more prevalent, with corresponding increase in hydrogen demand, as has coking. At the same time utilisation of existing Fluid Catalytic Crackers (FCC) and catalytic reforming plants has slowly decreased.

Beyond the complexity of a refinery, the second major key determining its energy intensity is its intrinsic “energy efficiency”. Measuring efficiency implies that an energy performance metric can be established, allowing comparison over time and between different refineries. Because refineries are all different in terms of complexity and processing/production capability, simplistic metrics such as energy per unit of throughput or products do not provide a suitable comparative platform.

Over many years, and in cooperation with the refining industry worldwide, Solomon Associates have developed their “Energy Intensity Index” or EII® which takes into account complexity to focus on measuring and comparing energy performance. **Figure 2.3-2** shows the evolution over time of the total energy consumption of a consistent group of EU refineries and of their combined EII®.

Note: EII® is an index (dimensionless) representing the ratio of the actual energy used by a refinery divided by a standard energy. Both numerator and denominator are expressed in primary energy terms (i.e. electricity consumption is divided by a standard generation efficiency factor), and relate to the refinery operations proper. As a result, the actual energy consumption of the refinery site has to be corrected to add energy imports and subtract energy exports. Each generic type of process unit used in refineries has been assigned a standard energy factor determined by SA from an analysis of their extensive refinery database. The standard energy of a refinery for a given period is the sum product of the individual factors by the throughputs of the process units operated by the particular refinery during that period. This approach effectively normalizes for size and complexity so that the EII® of a given refinery over time or the EIIs of different refineries can be validly compared. The lower the index, the higher the refinery’s energy efficiency.)

Figure 2.3-2 EU refineries energy consumption and efficiency trends relative to 1992 (Source: Solomon Associates, reported in [Concawe 3/13])



As a result of increased refinery complexity (and some increase in throughput) to support tighter product specifications (most notably lower sulphur contents) and shifting market demand, individual EU refineries have been gradually using more energy.

EU refineries have, however, conducted their operations more efficiently, improving their efficiency by 13% over the last 22 years. By 2010 this represented an annual saving over the 1992 efficiency level of some 60 ktoe (2.5 PJ) on average per refinery or over 4 Mtoe (167 PJ) for the total number of EU refineries. This annual saving is roughly equivalent to the total annual average energy consumption of four large EU refineries.

2.4. REFINERY ENERGY MIX AND ITS IMPACT ON GHG EMISSIONS

2.4.1. Refinery Fuel

Refineries use internally produced fuels to generate most of their energy needs. This is partly historical (there were no or few alternative energy sources available) and also supported by the availability within the refinery of streams for which there are few or no attractive alternative uses. Many refineries also import some energy in the form of gas (mostly natural gas), heat (mostly as steam) and electricity. Some refineries export heat and electricity.

Fuel gas (mainly methane and ethane) is produced in many processes as a by-product of cracking reactions. It is by far the largest component of refinery total fuel, is easy and attractive as a refinery fuel and is in fact similar in composition to natural gas (except for the presence of contaminants like sulphur species).

The majority of refineries worldwide, include a Fluid Catalytic Cracker (FCC), which cracks heavy gasoils producing both lighter products and a coke-like material (about two thirds of EU refineries operate an FCC). The coke is combusted to regenerate catalyst and some of the energy is used to drive the cracking reaction which consumes energy. Because cracking is energy-intensive and concerns a relatively large portion of the crude oil intake, FCC coke represents a significant fraction of refinery fuel.

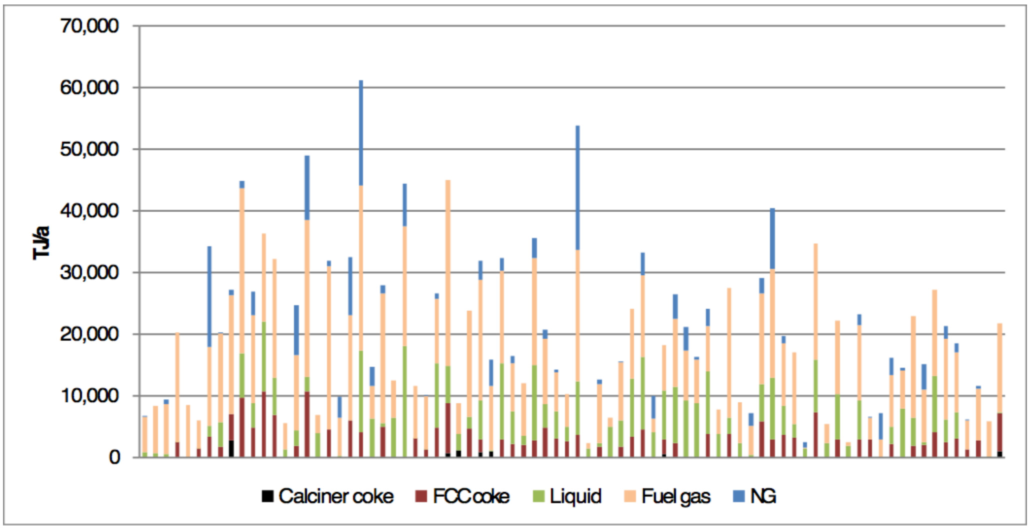
Heavy fuel oil was widely used in the past as refinery fuel but has been in decline largely because of tighter pollutant emissions regulations for SOx and NOx. Some minimal lighter liquid fuels (such as gasoils) are still burnt in some refineries for specific local reasons (e.g. unavailability of natural gas).

Finally, a few EU refineries operate a delayed coker to upgrade heavy residual oils by thermal cracking to produce lighter liquid hydrocarbon fractions and a low-value solid petroleum coke. The raw coke is further calcined to remove and combust volatile matter. At some sites it is further upgraded for smelting or production of anodes for the metallurgical.

The composition of the fuel mix has varied considerably since 1990 where the best estimate indicated that around 57% of the total fuel consumed was internal fuel gas, 28% liquid fuels, 13% coke (process related internal energy carrier described above) and 2% natural gas. In 2008, gas (fuel gas and natural gas) accounted for 65% of the total refinery fuel in Europe, FCC and calciner coke represented about 14%, the balance (21%) being provided by various liquid fuels. Liquid fuel is thought to have been subsequently phased out at a number of refineries. Gaseous fuels typically have CO_2 lower emission per unit of energy.

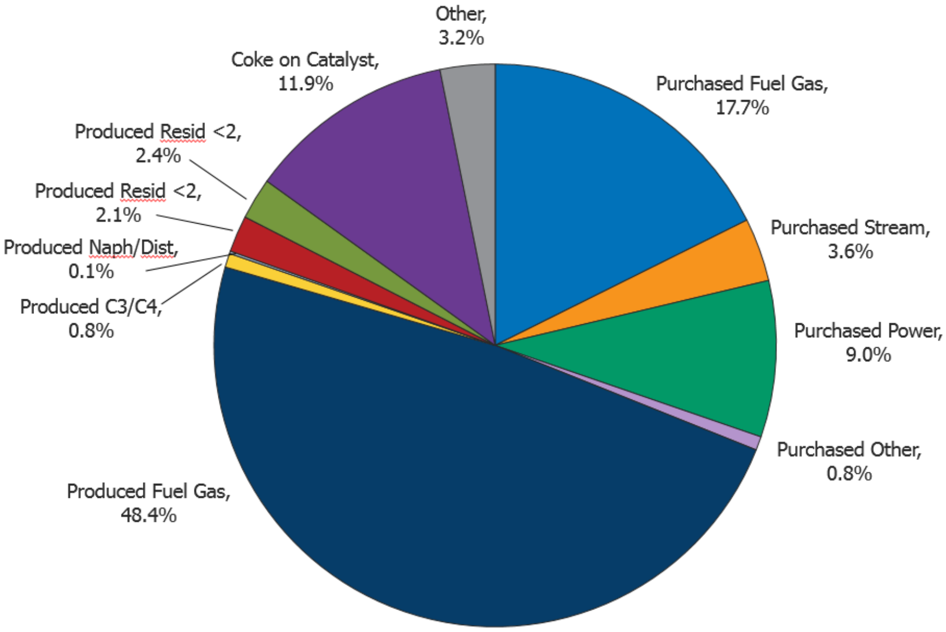
Figure 2.4.1-1 shows the composition of the refinery fuel in 2008 for the 80 mainstream EU refineries in operation today.

Figure 2.4.1-1 Refinery fuel mix in 2008 for 80 mainstream EU refineries (Source: [Concawe BMDB used as the basis for the modelling work - see **Section 4**])



Since then, the fuel mix has changed and in 2016, based on the most recent Solomon data collected for Concawe, the share of fuel gas in the fuel mix has increased, representing ~70% (purchased fuel gas, meaning, natural gas ~17.7%) as an average figure for the EU-28 refineries in operation.

Figure 2.4.1-2 Refinery Energy Consumption by Fuel Type. EU-28 only. Operating year 2016 (Source: [Solomon 2018])



2.4.2. Heat and Electricity

A large proportion of refinery energy needs are distributed as steam. At the same time refineries need electricity. This is a typical scenario for "cogeneration" of heat and power and most refineries have applied this in some form for a long time, within the limits imposed by the utilities balance within each refinery.

The simplest form of cogeneration is the combination of a boiler producing high pressure steam and a backpressure turbine producing electricity and medium pressure steam for further use in process units.

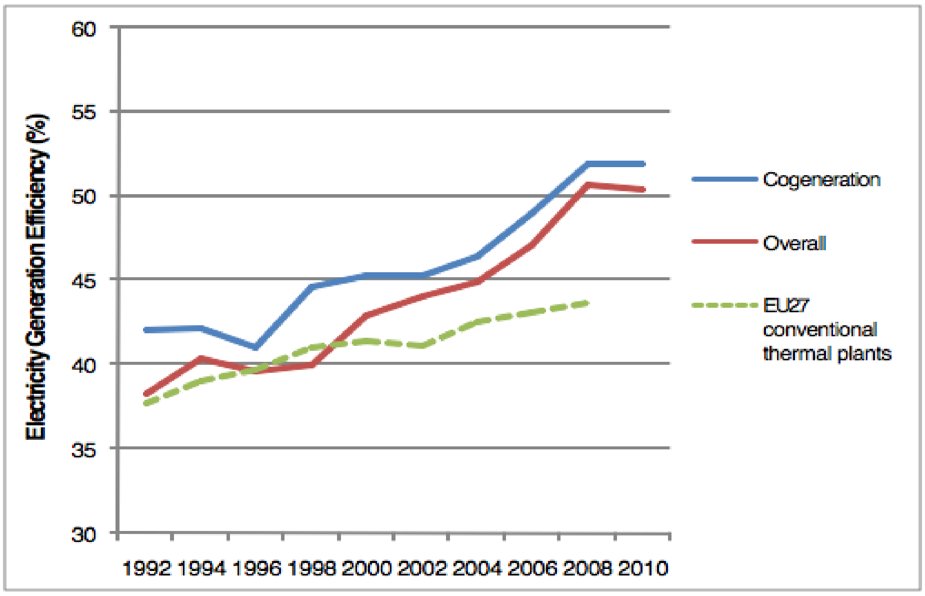
In energy terms, refineries usually require more steam than electricity so that cogeneration to cover only internal needs tends to be limited by the internal electricity demand. The opening up of electricity markets in recent years has provided some refiners with a new opportunity to apply cogeneration, with the possibility to export surplus electricity to the local grid while generating all the refinery steam requirements. The refinery steam demand has now become the main constraint limiting the capacity of cogeneration in refineries.

The most common dedicated cogeneration plants in refineries (also referred to as combined heat and power or CHP plants) consist of a gas turbine (usually natural gas fired) equipped with a heat recovery steam generator and a set of back-pressure steam turbines. Electricity is produced through both the gas turbine and the steam turbines while steam is made available to the refinery processes at the required pressure and temperature levels. Such schemes are highly efficient and have made a decisive contribution to the improvement of the electricity generation efficiency and the overall energy efficiency of EU refineries in recent years.

Data provided by Solomon Associates to Concawe [Concawe 3/12] shows that the share of cogeneration in electricity generation in EU refineries has grown from 76% to 92% over the period 1992-2010, while the total cogeneration capacity has increased by 125%. (Note that the refinery energy surveys conducted by Solomon Associates use the term "cogeneration" to cover all electricity production schemes, including CHP, that also produce useful heat. This includes boiler and steam turbine combinations where steam is "extracted" at an intermediate pressure level, but excludes steam turbines in which the steam is fully condensed.)

As a result, the average efficiency of electricity generation in EU refineries is substantially higher than the EU average efficiency of electricity production from conventional thermal plants. This is illustrated in **Figure 2.4.2-1** which shows the general increase in electricity generation efficiency over time in the Solomon trend group of EU refineries. The overall generation efficiency is very close to the cogeneration efficiency, showing that cogeneration is by far the most common mode of electricity generation.

Figure 2.4.2-1 Electricity generation efficiency trend in EU refineries (Source: [Concawe 3/12])



Refinery electricity generating efficiency increased from 42% in 2009 to 52% by 2015, with an average carbon emission factor of ~330 kg CO_2/GWh [Concawe 3/12; Concawe BMDB]. The EU grid average for 2008 was ~400 kg CO_2/GWh. This difference in carbon emission factors corresponds to 1200 t/a CO_2 when applied to a 17500 GWh electricity generation in EU refineries [Concawe 3/12, Figure 19].

However, physical and financial considerations continue to limit the number of opportunities for new, economically viable cogeneration projects. The tariff structure for purchased fuel and exported electricity is of particular importance for cogeneration investment decisions.

The majority of EU refineries still import some (or all) of their electricity needs. This may be driven by price considerations, by the need to provide a secure and reliable source of electrical power, or by the relatively small scale of potential internal power generation requirements that would not be practical or sufficiently economic to justify investment in a facility.

In most cases electricity is imported from the local grid although in some refineries the CHP plant is operated as a separate legal entity supplying both electricity and steam to several consumers (process industry, petrochemicals etc.).

Electricity imports represent 6 to 7% of total refinery energy, a figure that has slowly increased over the years, although this percentage varies a great deal between individual refineries.

About half of all EU refineries exchange heat with the outside, mostly as import and overwhelmingly in the form of steam. Large imports are likely to denote cases where the refinery is supplied by a CHP plant physically or administratively separate from the refinery. Heat exports are as a rule to neighboring and/or associated complexes such as petrochemical plants.

Refineries generally have a high rate of heat recovery, and only discharge low temperature streams that do not have any practical use (there could potentially be a practical use (e.g. Organic Rankin Cycle) but not economically attractive today). In a small number of cases a set of favourable circumstances (local climate, refinery location in relation to urbanised areas) has made it feasible to export such low-grade heat for e.g. urban heating. Beyond the physical issues, this requires, however, a high degree of cooperation between industry and local planners and decision makers and long-term commitments for all parties in order to arrive at a practically feasible scheme with acceptable economics.

2.5. HYDROGEN PRODUCTION

At the scale required for a refinery, the most economic and technically reliable way of producing hydrogen is by decarbonisation of hydrocarbons via steam reforming or partial oxidation. The so-called “SMR” process (steam methane reforming) is the most common, using natural gas as feedstock. A small number of refineries operate a so-called “POX” unit (partial oxidation) which involves gasification of a heavy oil feedstock followed by conversion of the synthesis gas into hydrogen. The carbon in the feedstock is released as CO_2. Part of the feedstock is burnt to supply the considerable energy required to split stable hydrocarbon and water molecules releasing more CO_2. Overall hydrogen production is highly CO_2-intensive. Steam methane reforming, which is the most favourable case, typically releases about 10 t of CO_2 per t of hydrogen. About half of this is “chemical” CO_2 which cannot be avoided short of using an entirely different source of hydrogen (see further discussion in **Section 5**).

Hydrogen is mostly produced on-site as part of the refinery. In recent years, however, third party operators have built and operated large hydrogen plants serving refineries as well as other customers so that a portion of the total hydrogen requirement of EU refineries is effectively imported. In such cases the corresponding CO_2 emissions become “indirect” as they are actually incurred outside the refinery.

Some hydrogen plant configurations also produce steam for the refinery, in addition to the hydrogen.

2.6. EU REFINERIES CO_2 EMISSIONS

The vast majority of "direct" refinery GHG emissions stem from burning of hydrocarbon fuels (including coke in FCC process) and production of hydrogen on the refinery site. Small amounts of methane are also emitted stemming from fugitive emissions in the gas system and water treatment plants. Even when converted to CO_2 equivalent these are very small and have to a large extent already been minimised in most EU refineries.

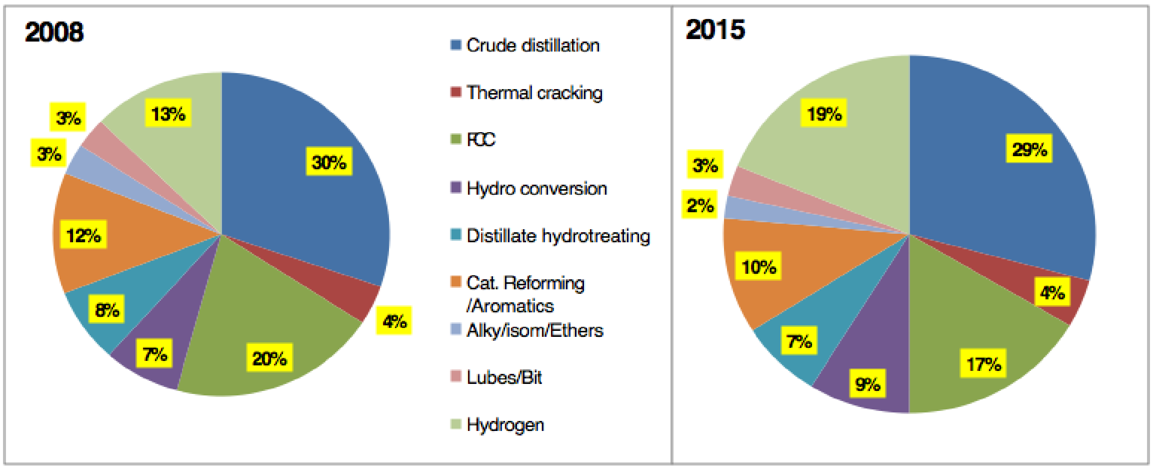
Most of the energy and raw material imports into a refinery are also associated with CO_2 emissions: the crude itself, hydrogen imports and electricity are examples of emissions not under the direct control of refiners and sometimes difficult to estimate. Although this report focuses on emissions within the direct control of the refinery, we also consider options for reducing the total emissions related to refinery operation, whether incurred on or off site.

Refinery CO_2 emissions can be apportioned between refinery processes. **Figure 2.6-1** shows the overall distribution estimated by Concawe for 2008 and 2015. (These are aggregate values - the distribution would be different for each individual refinery depending on the actual units installed e.g. some sites have no FCC or no hydroconversion units).

The largest single carbon emitters today are Crude Distillation (29% including atmospheric and vacuum), FCC (17%) and Hydrogen Production (19%). The FCC share has decreased since 2008 while hydrogen increased markedly. Hydrogen is produced to feed hydrotreaters and hydroconversion units the total of which accounts for 35% of all emissions (from 28% in 2008) forming in effect the largest contributing group.

The "hydrogen" contribution is the notional CO_2 emissions associated with the production of "on-purpose" hydrogen required (whether imported or produced onsite) together with that already produced by catalytic reforming. It includes both energy-related and chemistry-related emissions. For a given refinery the relative size of the contribution depends on the type and capacity of the hydrotreating technology in use, particularly whether it has highly hydrogen-consuming processes such as hydrocracking or heavy-oil desulphurisation.

Figure 2.6-1 Estimated CO_2 Emissions from European refineries by process group (Source: Concawe based on Solomon data)

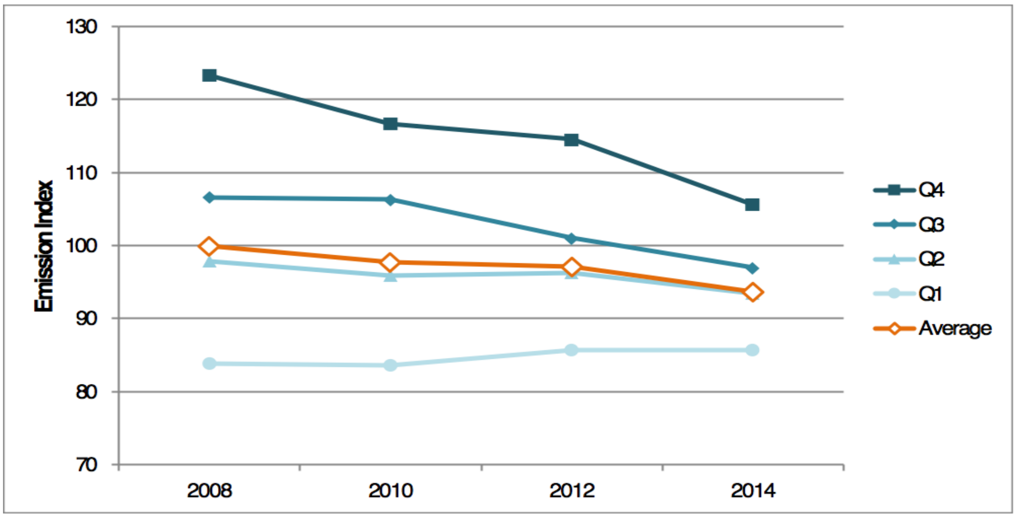


For most other non-hydrotreating processes, the CO_2 emissions are mainly associated with process energy, of which ca 70-80% is heat. In some cases, the heat input is associated with a change in the physical state of matter - the CDU/VDU requires heat to vaporise crude oil fractions; most units require heat to raise feedstock up to reaction temperature. Cracking and reforming involve endothermic chemical reactions that absorb heat. The remaining 20-30% of the energy is used as (a) motive power for pumps and compressors, typically using HP/MP-steam or electricity, (b) MP steam for processes, e.g. for “stripping” solids or liquids of volatile impurities, (c) LP steam for heating pipes and storage tanks, and (d) ancillaries such as control systems, lighting.

For heat and electricity, the historical efficiency improvement illustrated in **Figure 2.4.2-1** can be traced to the installation of large CHP plants. These are gas fired and therefore fairly carbon efficient, more or less on a par with the average EU power grid. It can therefore be surmised that the energy performance improvement translated into similar improvement in CO_2 emissions.

Figure 2.6-2 shows the recent evolution of the CO_2 emission index developed jointly by Solomon Associates and Concawe for the purpose of compliance with the EU-ETS legislation, indexed from a reference of 100 for the EU refining sector average in 2008 for the purpose of illustrating recent evolution. The CO_2 emission index reflects a refinery’s actual CO_2 emissions relative to the calculated emissions of the different process units at a standard level of performance: it is a way of “normalising” refineries which have different configurations to reflect the efficiency of their emissions performance. There has been a marked performance improvement over the 6-year period, the average dropping by 6%. Lower performers are improving faster than higher ones while the first quartile performance has more or less remained the same.

Figure 2.6-2 Recent CO_2 emission performance of EU refineries, relative to 2008 EU average
(Source: Concawe, based on data from Solomon Associates)



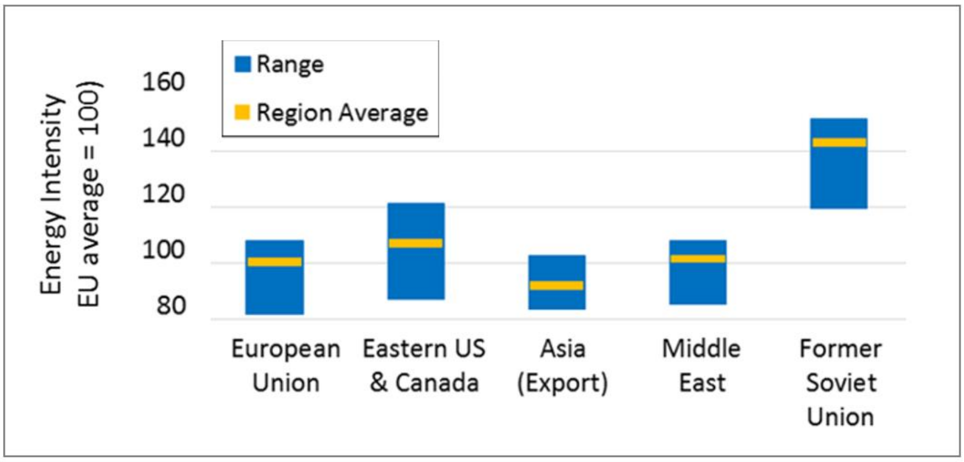
Note. The data collected by Solomon is reported periodically as a “trend-group” of refineries; It therefore excludes the effect of refinery closures).

2.7. HOW DOES THE EU COMPARE WITH OTHER REGIONS?

EU refining has always faced high energy costs, in some cases supplemented by energy taxes and more recently by CO_2 costs. Some EU countries also agree energy performance standards with their refiners (e.g. The Netherlands). Since energy can equate to more than 50% of operating costs, EU refineries are amongst the most efficient in the world. **Figure 2.7-1** represents EII across global regions and shows an EU refinery average only bettered by the new super scale Asian export refineries and the best in the EU being the most efficient in the world. The progression shown in **Figure 2.3-2** suggests that the EU has continued to improve its average performance and will probably at least have held its competitive position vs the best of other regions (**Figure 2.7-1**). Two conclusions can be drawn from this:

- EU refineries have invested in energy efficiency and are as well operated as the best in the world
- Product from EU refining can be considered to have an "energy footprint" which is amongst the lowest in the world.

Figure 2.7-1 Refinery energy performance in different World Regions (Source: Solomon 2008)



Note. Range per region indicates the variability of EII in different world regions

3. THE POTENTIAL IMPACTS OF EU MARKET DEMAND TRENDS ON REFINING CO_2 INTENSITY

3.1. OVERALL REFINED PRODUCT DEMAND

The primary purpose of this report is to comment on the potential evolution of the energy and CO_2 emissions intensity of the EU refining sector, looking at technological advances that if implemented could reduce energy consumption and emissions. Although the EU is not completely homogenous, as a whole it is a mature market; economic growth is likely to continue its recent trend of being accompanied by negative energy and emissions growth; In terms of **final energy consumption**, DG ENERGY predict a **slow decline in demand over long-term through** efficiency gains and substitution [EU Ref 2016_1] **and EU demand for refined oil products** is also likely to decline overall but at a slower pace than the one considered in the DG CLIMA Long term-strategy in 2050 (See **Appendix 5**).

Whilst technological advances which economically reduce oil demand are likely to be the key factor driving this, EU policy ambitions (presented in the recent *A Clean Planet for all* document mentioned in **Section 1**) or regulatory measures to tackle the climate or environmental effects of using oil products, both alone and as part of global action, will undoubtedly have a strong impact.

The **EU demand outlook for refined oil products** will have a significant effect on how the EU refining sector will develop over the next 30+ years, both in overall size and in configuration. Many demand factors will influence how many of today's EU refineries, with what configuration, remain in service to meet future EU demand; although it is not the role of this report to project detailed demand outlooks for EU product, it is appropriate to comment on some of these factors in order to illustrate some of the uncertainties facing the industry.

These factors include the quantity and quality of the refined product "slate" or barrel; refining economics and capital demands; technology advances within the refining industry, its customers and in competition/replacements for oil product; and the strength of global competition - both to supply EU customers and for EU to export any surplus product. It also includes macroeconomic drivers e.g. GDP, income or taxes, political factors e.g. diesel ban and technological factor like motor technology and efficiency.

Overall demand for oil products in EU is expected to decline to 2050, but there are wide disparities in statistics and projections (e.g. EU oil product demand in 2015 for energy use was 550 Mt according to EU statistics; and 590 Mt according to FuelsEurope, but including other non-energy products).

Concawe internal work [Concawe 1/13R], initially estimated 2030 demand to 535 Mt; More recent projections suggest significantly lower figures, in the region of 500 Mt/a (see **Table 5.1-1**). This decreasing trend is likely to continue towards 2050 although the rate of decrease will depend on the combination of different factors which are explored in the next report in this series (*Refinery 2050*).

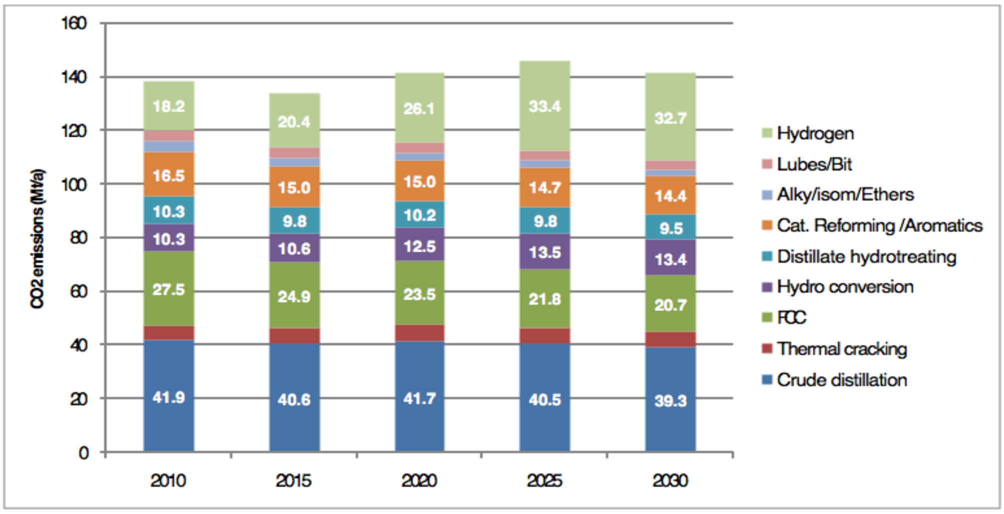
This report is not intended to reflect potential changes in demand when looking into the 2050 timeframe but to **picture a sound reference 2030** case including product demand forecast with focus on what the CO_2 reduction technologies could deliver in the medium/long term (see **Section 5** describing the *Overall methodology*). Different scenarios exploring the potential evolution of demand from 2030 to 2050 and investigating the role of alternative low-carbon feedstocks to oil will be further assessed in another complementary Concawe report (*Refinery 2050 report*) belonging to the Concawe's *Low Carbon Pathways* series of publications.

Whilst changes in demand for any part of the barrel will affect the shape of refinery output, two big trends in transport are identified in the present report likely to have the most significant influence in the 2030 picture: changes in marine fuel oil specifications and IMO CO_2 reduction targets and road and aviation demand.

Concawe concluded that these demand changes will have significant implications for refinery configuration. The ratio of distillate to gasoline demand will continue to rise, and with petrochemical naphtha demand also reducing, no growth in aromatics and increasing difficulties to export surplus gasoline, the European output barrel will become more distillate oriented, which in turn will require refinery configuration changes.

Figure 3.1-1 shows the distribution of emissions between the main process groups. The numbers are very sensitive to the assumptions regarding marine fuels. The case shown is for 80% of the production being desulphurised (20% on-board scrubbers) which the assumption made for this assessment. Total refinery emissions are expected to remain at the current level or increase slightly due to a 20% increase in complexity and in spite of an anticipated 15% reduction on throughput.

Figure 3.1-1 Share of CO_2 emissions between major process groups (Source: [Concawe 1/13R])

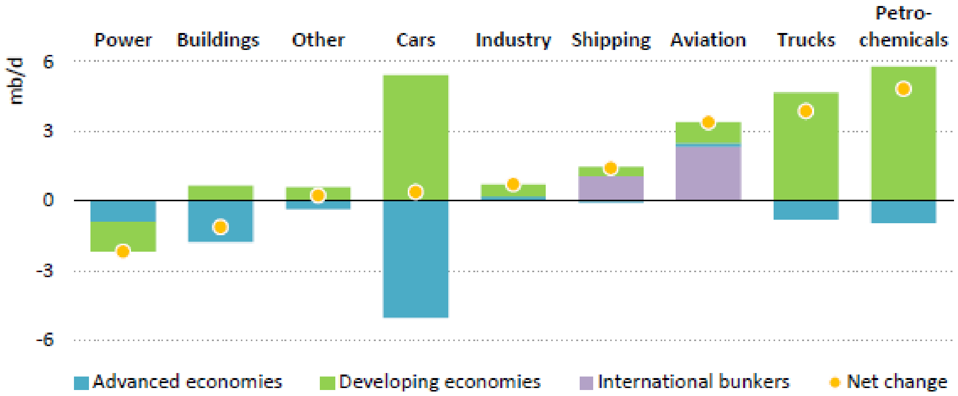


The next sub-sections provide more insights regarding the outlook into different transport sectors and the potential impact for the EU refining systems in terms of demand and potential CO_2 emissions.

3.2. A LOOK INTO THE TRANSPORT SECTOR

In the New Policies Scenario conducted by IEA [IEA-WEO 2018], changes in global demand of current oil-based fuels are mainly driven by the shipping, aviation and trucks:

Figure 3.2-1 Change in global oil demand by sector in the New Policies Scenario, 2017-2040
(Source: [IEA-WEO 2018])



This section qualitatively explores the impact of further developments on **two segments** (marine and road transport) with a high potential to influence on the total CO_2 emissions for the EU refining system: the recent international decisions on Sulphur and CO_2 reduction across the marine sector and the penetration of competing alternative technologies to oil-based fuels in road transport.

3.2.1. Marine fuel oil. Demand and specification changes

As illustrated in **Figure 3.2-1**, demand for marine fuel globally is expected to continue to grow (See Figure 1.4, [IEA-WEO 2018]) and the IEA "*New Policies* Scenario" (NPS) [IEA-WEO 2018] projects a global demand of approximately 6.1 mboe/d in 2040. This is driven by economic growth and the bulk of this growth will be in the non-OECD world.

However, two different **International Marine Organization** (IMO) related decisions are likely to affect significantly the future of this marine industry and the type and quality of the fuels that would be consumed in the short to medium/long term:

3.2.1.1. Short term: IMO regulation to limit sulphur content of marine fuels (0.5 %)

The international specification for marine fuels used in ocean going vessels outside Emission Control Areas (ECAs) is currently 3.5%. Within ECAs around the coast of the USA and Northern Europe, a marine gasoil at maximum 0.1% sulphur has been required since 2015; unless ships invested in "scrubbers" to reduce exhaust gas SO_2 to achieve an equivalent emissions control.

Following a decision made by the **IMO in October 2016**, from 2020 the sulphur content of marine bunkers used in all international shipping will have to be reduced from 3.5% to no more than 0.5%m/m. There are different options available to the shipping industry that could be implemented to comply with this Sulphur regulation ranging from the installation of SO_2 scrubbers onboard (gas cleaning systems which would allow them to use high sulphur fuel oil (HSFO)) to the use of low sulphur fuel oil (LSFO), marine gasoil (MGO) or the switch to another type of fuel (e.g. LNG).

IEA [IEA-WEO 2018] estimates that this regulation will lead to a 2 mb/d drop in HSFO (High Sulphur Fuel Oil) consumption around this time. There is considerable uncertainty on how both ship owners and refiners globally will respond to such a major change both for shipping and for the refining and supply system.

The impact for the EU refining system in terms of their related CO_2 emissions is quite uncertain. An Ensys report claims that CO_2 emissions related to the **refining activity will increase 2-4% globally.**

At EU level, a study by Purvin and Gertz in 2008 (Purvin&Gertz 2008] **estimated EU refining CO_2 increases of 3%** (approximately 5 Mt CO_2/a) for the IMO changes for a 2020 EU heavy bunkers demand of approximately 46 Mt. Concawe [Concawe 1/13R] also projected the increase in CO_2 emissions from EU refining as a result of the 2020 IMO heavy bunkers specification changes at 8MT, close to 6%.

3.2.1.2. Medium/Long term: IMO strategy to reduce greenhouse gas (GHG) emissions from shipping sector by 50% by 2050 (vs 2008 levels).

Worldwide, maritime transport emits around 1000 million tonnes of CO_2 annually and is responsible for about 2.5% of global greenhouse gas emissions (3rd IMO GHG study). Shipping emissions are predicted to increase between 50% and 250% by 2050 – depending on future economic and energy developments. In order to reduce the GHG emissions associated with this sector, IMO has conducted an international strategy with three levels of ambition [IMO 2018]:

1. Carbon intensity of the ship to decline through implementation of further phases of the **energy efficiency design index** (EEDI) for new ships (with the aim to strengthen the energy efficiency design requirements for ships with the percentage improvement for each phase to be determined for each ship type, as appropriate).
2. Carbon intensity of international shipping to decline to reduce CO_2 emissions per transport work, as an average across international shipping, by at least 40% by 2030, pursuing efforts towards 70% by 2050, compared to 2008.
3. **GHG emissions from international shipping to peak and decline** to peak GHG emissions from international shipping as soon as possible and to reduce the total annual GHG emissions by at least 50% by 2050 compared to 2008 whilst pursuing efforts towards phasing them out as called for in the Vision as a point on a pathway of CO_2 emissions reduction consistent with the Paris Agreement temperature goals. This ambitious goal is not yet supported by specific measures and different technologies could be envisaged to contribute.

At EU level, the Commission's 2011 White Paper on transport suggests that the EU's CO_2 emissions from maritime transport should be cut by at least 40% from 2005 levels by 2050, and if feasible by 50%. In 2013, the Commission set out a strategy for progressively integrating maritime emissions into the EU's policy for reducing its domestic greenhouse gas emissions. The strategy consists of 3 consecutive steps:

- Monitoring, reporting and verification of CO_2 emissions from large ships using EU ports
- Greenhouse gas reduction targets for the maritime transport sector
- Further measures, including market-based measures, in the medium to long term.

Following this initiative, large ships over 5,000 gross tonnes loading /unloading cargo/ passengers from 1 January 2018 at EU maritime ports are to monitor and later report their related CO_2 emissions and other relevant information in accordance with their monitoring plan [EU ships, 2018].

Currently, there is a big number of specific measures that could be implemented globally and the impact in terms of changes in formulation of marine fuels or the employment of alternative fuels (LNG, Hydrogen, e-fuels such as synthetic diesel, methanol or ammonia) for the EU refining system is still uncertain. Due to the uncertainty around the final measures that will be adopted by IMO, in the present document, no relevant changes in refining emissions due to this initiative by 2030 have been assumed.

3.2.2. Road fuels. Demand and quality changes

3.2.2.1. Changes in total demand for road transport

Worldwide, [IHS 2018] projects that the number of car sales will continue to grow, but electrification, hybridization and other efficiencies will balance this growth so that oil use in this transport sub-sector (essentially gasoline and diesel) rises to 2020 then flattens. According to Wood Mackenzie [WM 2018], an aggressive electric vehicle penetration forecast leads to 280 million EVs on the road by 2040 with Europe as the region with the highest EV penetration in light vehicles.

In Europe, the new targets to reduce CO_2 emissions for both light and heavy duty in 2030 incentivize energy efficiency improvements in new cars as well as the penetration of the so called zero-*emission* vehicles (*Tank-to-Wheel*) with a significant reduction in demand of refining fuels for this sectors:

The *A Clean Planet for all* documents models a penetration of electric vehicles ranging from less than 10% of the total car stock in 2030 to a massive penetration of this electricity-based technologies in all the 2050 scenarios explored (see **Section 1** and **Appendix 5** for more details regarding the scenarios). In Heavy Duty, electrification is considered likely to penetrate more in the form of hybrid trucks while Internal Combustion Engines (ICE) remain the main powertrain technology even in the most ambitious scenarios:

Figure 3.2.2.1-1 Shares in total cars stock by drivetrain technology in the Baseline and scenarios reaching -80% to net zero emissions by 2050 [EU 2018]

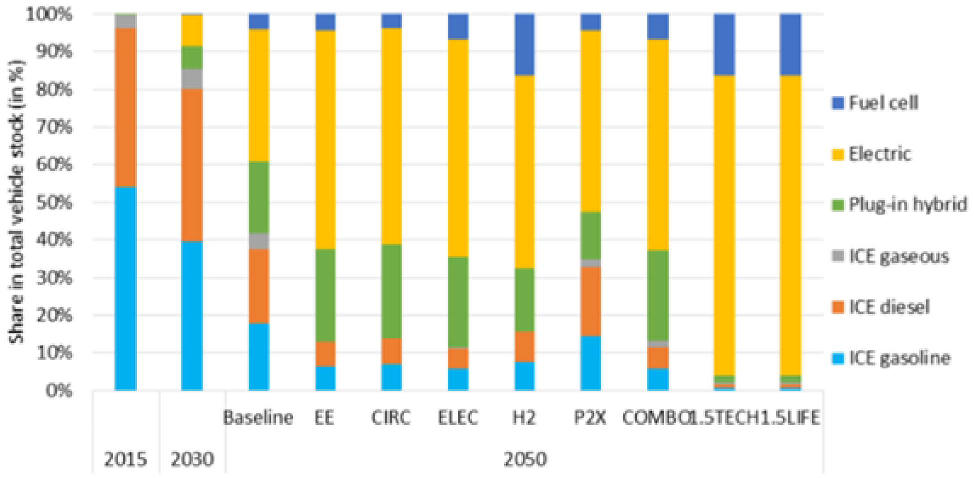
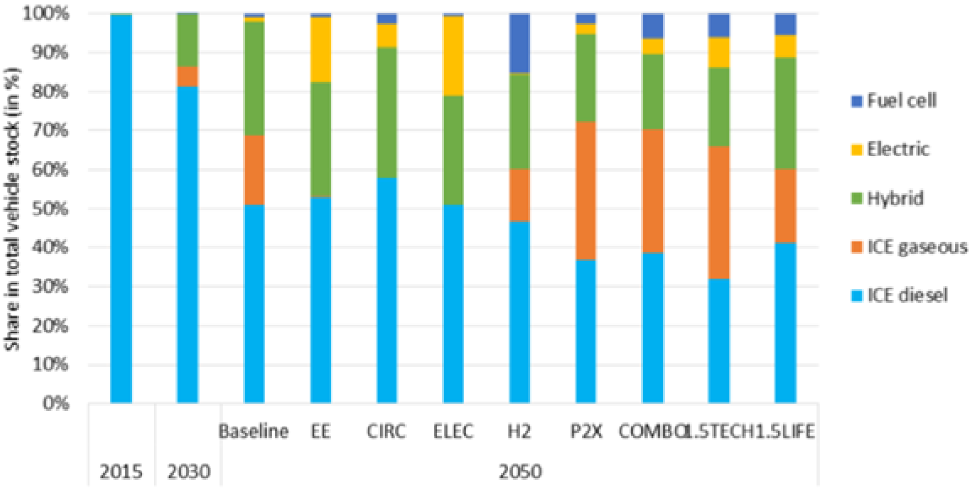


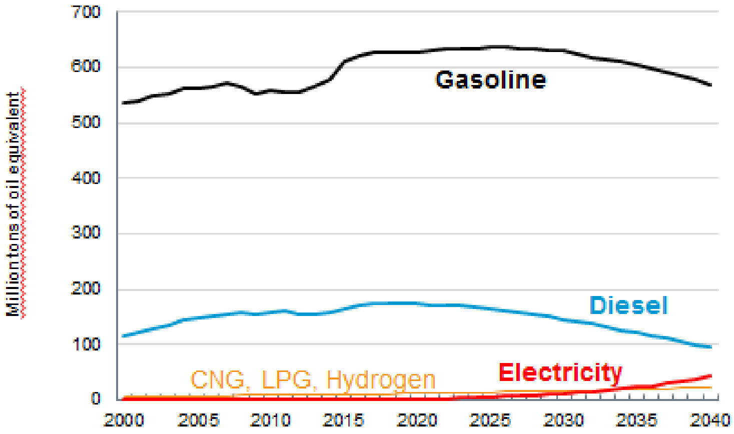
Figure 3.2.2.1-2 Shares in total heavy goods vehicles by drivetrain technology in the Baseline and scenarios reaching -80% to net zero emissions by 2050 [EU 2018]



3.2.2.2. Changes in gasoline vs diesel

Worldwide, although gasoline and diesel demand is set to decline, IHS predicts that they will remain the leading energy source for cars and light-duty vehicles:

Figure 3.2.2.2-1 Global light duty vehicles energy demand (Rivalry scenario) (Source: [IHS 2018])



RTW markets include US, Europe, China and India.
Notes: Ethanol is included in gasoline. CNG = compressed natural gas. LPG = liquified petroleum gas
Source: IHS Markit. Electricity is consumed by LDVs, not demand from power generation.

However, the EU will most likely deviate from this global picture in two marked respects:

- It is a "mature" economy, so vehicle efficiency improvements, and substitution of oil in passenger transport are projected to reduce overall demand in the EU.
- The EU is unique in the world in that diesel demand for cars currently exceeds gasoline demand.

In the EU, the numbers of Diesel cars have grown over the past 30 years, driven by taxation advantages and by regulation on tail pipe CO_2 emissions, which have both encouraged EU manufacturers to develop very high efficiency diesel engines, and consumers to favour diesel powered cars. This trend has started to reverse while gasoline sees a major rebound in new car sales. In 2015, the HGV fleet numbered 15 M vehicles, but accounted for over 30% of fuel used and emissions produced. The HGV demand is anticipated to grow slowly.

As described in the section above on Marine fuels, the reduced sulphur specification is expected to switch a major part of the demand from heavy fuel oil to marine diesel from 2020. LNG may substitute some of the oil demand: the IEA NPS predicts 13% of global marine fuel demand will be LNG by 2040.

The implications for EU refiners are significant: refineries mostly built or upgraded in the 60s and 70s to make a gasoline dominated product slate have had to produce more and more diesel, resulting in a continually increasing ratio of diesel to gasoline, way beyond that normally occurring in crude. This imbalance is significant for EU refiners: a huge market for gasoline in the US has allowed some refiners to retain a more normal gasoline/diesel ratio and sell surplus gasoline to the US; the diesel deficit in Europe is satisfied by imports from Russia, Middle and Far East and USA but at an economic cost to the industry.

4. OPPORTUNITIES TO REDUCE THE CO_2 INTENSITY OF EU REFINERIES - 2030/2050

4.1. TECHNICAL THEMES

Refineries have a number of options to reduce their CO_2 intensity, which can be grouped into three broad areas:

- **Improve** the **efficiency** with which they use energy (both in processes and utilities generation),
- **Lower the carbon footprint of their energy sources** by using lower-carbon fossil energy and/or introducing renewable sources such as biomass ore renewable electricity,
- **Capture the CO_2** they emit for either long-term storage or reuse.

The first area is very much under the control of the refiners and builds on the historical on-going efforts by the refining industry to improve energy efficiency, predominantly driven by the cost of energy and, more recently of CO_2 emissions. It encompasses a wide range of options, each of which play out differently in each refinery. Some improvements can be achieved over time through a combination of operational changes and small targeted projects. Major revamp or extension projects, although not specifically aimed at energy efficiency, also provide opportunities, although they will be justified by separate drivers which may also dictate the potential and timing for implementation. Many refineries will see similar opportunities, although timing, potential energy-saving and cost will depend on each refinery's location, design, history and technology employed.

The last two areas are premised on the industry's potential ability to take advantage of "external opportunities", in particular the anticipated increase in availability of affordable low-carbon electricity and the development of CO_2 collection and storage networks. These external opportunities tend to be linked to new technologies for which accurate performance and capital/operating costs are not available; they are not economic today so the business case relies on hypothetical future regulatory/incentive framework, cost reduction and prices of energy and carbon. There are also uncertainties about (a) "site-potential" i.e. the degree to which a specific refinery could implement a specific option, and (b) "industry potential" i.e. the number of refineries that might have access to the external network or infrastructure supporting that option. Much of this will be outside the direct control of the refining industry and may evolve differently in different locations depending on local legislation, power networks and other infrastructure. This study considers all three aspects (economics; site-potential; industry-potential), aiming to provide an indication of which external options could become significant if particular constraints were overcome, and which would not have a significant impact even if widely implemented.

The number and type of both internal and external measures that can be envisaged is very wide with highly site-specific potential and economics. A "bottom-up" approach, i.e. making a detailed assessment for each refinery would be impractical both in terms of the effort required and the confidentiality issues that it would raise. We have thus adopted a "top-down" approach with generic, industry-level technological and economic data to estimate, for each option, the degree of improvement in a notional refinery, and the likely degree of penetration in the EU industry. This is not an attempt to estimate the actual improvement which could be achieved at each individual refinery, but a holistic attempt to find a plausible global figure covering a diverse set of technologies and refineries.

In addition, the degree to which energy saving technologies are deployed also depends on the level of financial return investors are willing to accept. Where appropriate, we have represented this by a simple Pay Back Time (PBT) threshold (i.e. the maximum PBT that would be acceptable for a project to be undertaken).

The scopes and impacts of individual options are, to an extent, interdependent: as an example, the scope for replacement of fuel fired heaters with electric ones is limited by the refinery gas balance (level of refinery fuel gas production and resulting demand for imported gas), itself a function of the success of energy efficiency measures. As a result, the sequence in which the various measures are deemed to be introduced has some bearing on the overall outcome. The options considered are discussed below in the order in which they have been introduced in the modelling exercise described in **Section 5**. Description of the *quantification parameters* is shown in *italic*.

4.2. DATA SOURCES

Concawe has previously published several reports covering refining trends and the outlook for refining (e.g. Concawe 9/12 and 1/13R). These are based on information provided by member companies and by consultancies such as Solomon Associates and Wood Mackenzie.

In particular, Concawe conducted a detailed review of refining energy and GHG emissions for the purpose of the EU-ETS benchmarking study for the year 2008 [Concawe BMDB]. This database provides a solid historical reference with a focus on the 80 mainstream refineries still in operation today. [Concawe 1/13R] provided a reference case for 2030 in terms of product demand, refinery configuration as well as energy consumption and CO_2 emissions without any specific improvement measures. There is no activity forecast available for 2050.

Additional technical information was obtained from refining literature and by interviews with technology providers and relevant trade associations, then the combined data was reviewed by a number of Concawe Member Companies. This gives a generalised view across the EU refining sector reflecting 80 refineries owned by 30 different companies. It was not a “roll-up” of individual site plans.

We would like to thank the following organisations for their support and input during this study: European Industrial Gas Association, Haldor-Topsoe, KBC, Fluor, Shell Global Solutions, IFP Energies Nouvelles, Siemens.

4.3. PROCESS ENERGY EFFICIENCY

As alluded to above, there is a wide range of options with the potential to improve energy efficiency. It encompasses the large number of different refinery processes and technologies applied in almost 100 different refineries whose circumstances, potential and economics are highly site specific. This section gives an overview of the technological areas to show how they support assumptions made in the final “top down” calculations. There is more detail about refinery technologies in **Appendix 1**.

4.3.1. Energy Management Systems

Energy Management Systems (EMS) combine equipment such as energy measurement and control systems, and “soft” issues” such as strategic planning, organisation and culture. An effective EMS improves both day-to-day management of energy and helps implement operational or low-capex projects which can improve energy performance (e.g. maintenance programmes, exchanger cleaning), and may help identify opportunities linked to process unit optimisation. This type of on-going attention to detail is sometimes viewed as “continuous improvement”. EMS can also help identify energy efficiency improvements linked to major process upgrades, but these are considered in their respective sections.

EMS relies heavily on digital technologies such as advanced process control, process simulation, equipment performance monitoring, predictive analytics, refinery optimisation/scheduling and maintenance management. Faster systems, better storage and improved human interfaces ought to make these tools more effective and easier to use in the future. Technologies such as “machine learning” ought to reduce the reliance on human observation/interpretation, and help embed knowledge within the system.

Case studies [e.g. Gomez-Prado 2016a, US EPA 2015] suggest the move from “no EMS” to ”full EMS” might achieve a 10% energy saving with a payback of <2.5 years; investment might be required for digital equipment, sensors/analysers and associated cabling, staff training and costs of energy specialists. Roughly 40% of EU refineries already have an effective EMS programme [Solomon 2011] in which case they have the benefit of previous on-going energy savings but also the cost of maintaining the system and less opportunity for further low-capex energy savings.

4.3.2. Refinery Process Technology

Process plants are the core of a refinery and use the bulk of its energy. This section looks at trends in the major refinery process technologies in particular (a) which make the biggest contribution to refinery energy intensity, and (b) which have the most scope to improve. This is tempered by the main economic purpose of the refinery – to produce transport fuels as efficiently as possible. Although energy is a major operating cost for each process, the economic optimum for a process unit usually reflects throughput and yield so might not necessarily be the most energy efficient, or offer the best conditions for energy recovery. There is a detailed review of refinery process technology in **Appendix 1**, with a summary provided below.

Table 4.3.2-1 shows the industry-average distribution of refinery energy consumption between the major processes in 2008, and an estimate of the energy distribution for 2030 based on estimates of future demand slate and product quality combined with 2008 process energy intensities. This highlights crude distillation, fluid catalytic cracking (FCC) and hydroprocessing as the major energy consumers. Note that most refineries only have one or two crude distillation units with both atmospheric and vacuum columns and only one FCC unit, but are likely to have several hydrotreating units of markedly different type.

Table 4.3.2-1 Split of EU refinery energy consumption by major process type (source: [Concawe 1/13R])

Process	**2008**	**2030**
Crude Distillation	32%	31%
Thermal Cracking & Coking	4%	5%
Fluid Catalytic Cracking	17%	14%
Hydro-processing	18%	18%
Catalytic Reforming	3%	3%
Hydrogen production	4%	7%
Other	22%	22%

The overall distribution of energy consumption is not expected to change significantly, unless there are breakthroughs which reduce the energy intensity of the key processes. Various organisations have attempted to define the maximum potential for refining energy efficiency e.g. [ICF 2016; US EPA 2015; US DOE 2015]. They all cover much the same process groups, but with slightly different approaches and level of detail.

Figure 3.63 of the ICF report for DG-Energy [ICF 2016]) suggests there is a technical potential to reduce energy intensity by ~25% relative to "business-as-usual by 2030. Of this only about 1/3 was expected to payback within 5 years. It identifies process control, catalysis and process integration as the top three opportunities for energy efficiency improvement.

The US DoE "Energy Bandwidth Study" [US DoE 2015] is particularly useful because it considers both the application of existing technology and the opportunity stemming from R&D. It identifies distillation as the biggest opportunity and suggests 10-15% technical potential to improve through increased deployment of conventional technology and 15-40% technical potential from R&D opportunities. The latter includes "short-term" extensions to existing technology, but also emerging technologies which would be very difficult to apply to large, complex applications such as crude-oil treatment as well as very speculative alternative research concepts. It is not a foregone conclusion that the R&D will actually occur or that it will be successful, or that the new technologies will be economically viable or suitable for retrofit in existing refineries. This suggests that the DoE's assessment for new technologies is very optimistic.

4.3.3. Inter-Unit Heat Integration and Upgrading Low-Grade Heat

Heat-integration operates at two levels: (a) integration within process units was addressed in **Section 4.3.2**, whilst (b) integration between process units is covered here. Refineries routinely use assessment techniques (e.g. Pinch™) to identify bottlenecks and opportunities for heat integration. This can include direct heat exchange between process streams as well as indirect exchange using for example refinery steam or "hot oil" heat transfer systems. A major theme is the feed preheat system for crude units (which are among the largest energy users in most refineries). Other large systems include FCC and hydrocracking units which both have large product fractionators.

Maximising energy efficiency usually involves an economic compromise to take account of operational issues (e.g. avoiding conditions which lead to corrosion and fouling) and retain the desired operating flexibility (e.g. feed-dependent variation of flow-rate through specific exchangers). Case studies in the refining press may identify % level improvements for specific refineries, but this does not mean that all refineries will be able to achieve that degree of improvement (or that the improvement is sustained if the refinery in the case study subsequently has to change its crude slate or operation). There are technologies which can help in this respect e.g. compact heat exchangers for use where plot space is limited or exchangers which operate over a wide range of flow rates. These may need more careful selection and design than conventional exchangers so deployment may benefit from experience, or better monitoring and design tools. Intra-unit heat integration is part of the general trend to achieve "state-of the art" performance but is unlikely to be breakthrough.

In theory, inter-plant integration offers additional energy savings, but is difficult to implement without creating unwanted process inter-dependencies (e.g. where a change of crude to the crude unit might lead to throughput restriction for the cat-reformer). The economic choice for many refiners is often to prioritise operational flexibility by limiting the interdependency between process units; this is one of the areas where digital technologies may bear fruit. It must also be mentioned that many refineries have multiple “operating modes” depending for example on the crude being processed or the particular product grades being made. This leads to widely varying process flowrates and temperatures making it complicated to extract the benefits of inter-plant integration. Other practical issues include availability of plot-space, refinery layout and the need to match turn-around schedules. A good utility system (combined with effective EMS) may help access some of these opportunities, for example by providing additional sources whenever there is a process-heat or –steam imbalance between the integrated units. Technologies such as “hot-oil systems” (where heat is conveyed between process units via a loop containing a specialist heat transfer fluid) have been used in the chemicals industry; these have some advantages where leakage of one process streams into another must be avoided) but requires additional equipment (cost) and has not gained much traction in refining.

Low-grade heat can also be “upgraded” to higher temperature to make it more useful in a refinery; this potentially reduces the need for furnaces, or “fired” heat. Mechanically driven heat-pumps (e.g. vapour-recompression) are currently viewed as suitable for upgrading low-grade heat to perhaps 180ºC thought to account for perhaps 1/3 of heating demand across all industrial sectors [Wolf 2012]. This usually requires electrical power; thus, the economics and carbon benefits depend critically on the price and carbon-intensity of the electrical supply. Various studies [CEFIC 2013, VEMW 2017] see this area as a major plank to decarbonisation – this will be covered in more detail in the section on “electrification” along with low-grade heat for power generation.

Developmental areas include the extension of heat-pump technology to higher temperatures and alternatives to electrical power. For example, a developmental technology [Broadwidth 2016] uses a chemical process to capture heat from low pressure (LP) steam (120-150°C) then reverses the reaction to release ~50% of the energy at higher temperature (up to 200°C). This uplift in temperature might assist process pre-heat thus offsetting fired-heat duty.

Process integration is included in the US DoE report so we have assumed that this is not identifying new energy-saving potential, but instead identifies routes to make it more cost-effective.

4.3.4. Integration with Other Industries

Petrochemical plants offer the main opportunities for integration with refineries. Over 90% of petrochemical feedstock comes from refineries. Plants often share the same site or are geographically close (about one quarter of EU refineries are co-located with a petrochemicals plant [FuelsEurope 2015; PetChem Europe 2017]) involving direct transfer of raw materials and (in some cases) shared utilities such as power, steam, waste-water, logistics or hydrogen. The principle types are:

- Olefins – typically where refinery naphtha feeds a steam cracker producing ethylene, propylene and other light olefins. Other materials may be exchanged e.g. refinery-grade propylene from FCC units and steam cracker pyrolysis oil.

- Aromatics-typically where aromatic-rich refinery product is processed to separate petrochemical feedstocks such as benzene, toluene and xylene; residual material is returned to the refinery for gasoline blending.

Generally, such integration should offer options for incremental energy efficiency measures e.g. shared utilities which gain economy of scale, better optimisation of heat/steam/power. There may however be additional constraints e.g. additional processing needed to make petrochemical quality feeds. In a few cases, there may be additional synergies e.g. a refinery which is co-located with a steam cracker processing ethane/NGLs has a unique option to upgrade C2s from refinery fuel gas.

In practice, however, we believe that most opportunities in this respect have already been exploited. Going forward, there is the possibility that some petrochemical complexes could be shutdown thereby eliminating such synergies. The potential from further integration is limited and would be highly site-dependent and we feel that a generic assessment may lead to erroneous conclusions. We have therefore not attempted to quantify the impact.

4.3.5. Refinery process efficiency: Summary

For this study, Concawe has reviewed refining industry reports, consulted refinery technology companies and sought the views of refining experts within its member companies to assess the efficiency opportunities associated with core refining technologies. This is covered in **Appendix 1**. In general, the findings are similar to other reviews although with some important differences, specific to the EU industry:

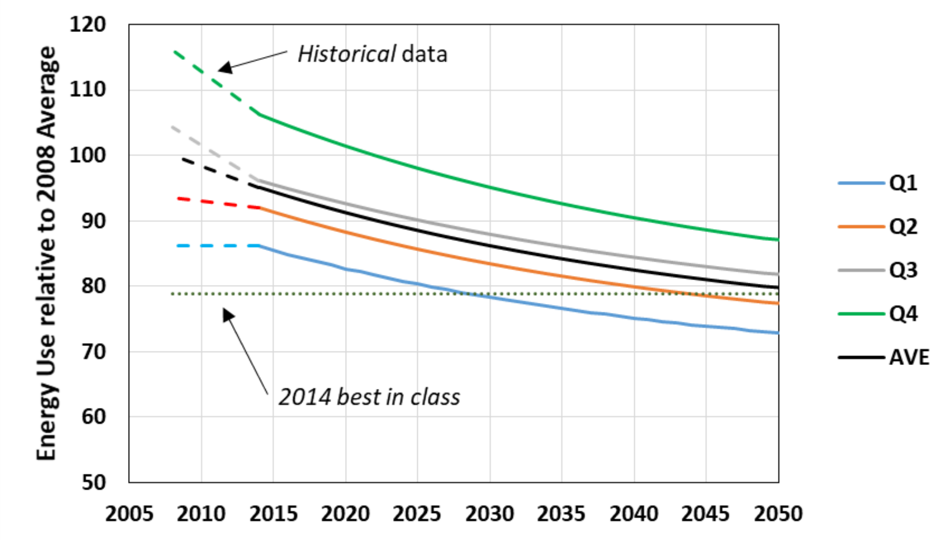
- Crude distillation is an important area with opportunities stemming from process/furnace control, mitigation of fouling using additives or heat-exchanger design, and column design/configuration (e.g. internals and ancillary columns e.g. prefractionation). There is less opportunity for advanced concepts (e.g. progressive distillation, divided-wall technology) than cited elsewhere because these realistically can only be implemented in new distillation units, which will be rare in Europe.
- Improvements in catalyst technology and selection may offer incremental opportunities for energy improvement and hydrogen optimisation, but major improvements are unlikely.
- Power recovery systems (e.g. FCC expanders) are not common in Europe so there may be opportunities for wider deployment, although economics may be challenging.
- There are probably many “small” opportunities for incremental energy savings where wider deployment might result from a greater focus on energy efficiency, clearer demonstration of value or improved technology. Examples include advanced control, rotating equipment and heat integration within individual processes.

Quantification

Process energy efficiency improvements will involve at least ten different technologies applied across nearly one hundred refineries so the number of potential projects is vast. In addition, the specifics of each project, including capex, opex and energy saving, will be highly location dependent. We have therefore developed a "statistical" model to assess the impact of refinery process and energy efficiency improvements. The details of this are covered in **Appendix 2**, but salient points are:

- It includes both low-capex activities (e.g. energy management) and high-capex projects (e.g. process improvements)
- It uses a cost-curve to represent the "technical potential" of the large number of potential improvement activities, then has an economic calculation to assess how much of this curve is realized in the different economic scenarios.
- The model sub-divides the industry into 4 quartiles of energy performance, and makes predictions for each. The highest performing quartile (Q1) is taken to be the pace-setter. For illustration, **Figure 4.3.5-1** shows projections for the 2050 Median case (see definition in **Section 5.1.3**), where savings are relative to industry average reported for 2008. In general terms it shows ~20% improvement over 2008 for a total industry investment approaching €10 billion. To achieve this by 2050, Q1 refineries on average would have to exceed the 2014 "best-in-class" (horizontal dotted line) by about 5%.
- The model was calibrated using data from technical providers, 3rd party technology surveys, Concawe members and from Solomon Associates. We have to acknowledge the high level of uncertainty in these data which leads to uncertainty in the predictions of the order of +/- 25% for both capital investment rate and associated efficiency improvement.

Figure 4.3.5-1 Process Energy Efficiency model - Projections for 2050 Median case



Note that the rate of improvement between 2008 and 2014 was ~5% relative to the 2008 average [Solomon 2016]

4.4. REDUCTION OF THE CARBON FOOTPRINT OF ENERGY SOURCES

4.4.1. Self-Produced Refinery Fuels

Section 2.4 described the current refinery energy mix and its split between self-produced fuels (fuel gas, FCC coke, liquid fuels) and imported energy. **Table 4.4.1-1** shows the characteristics of fuels used for combustion i.e. for process heat and refinery-based steam/electricity production. This section looks at options to reduce the overall carbon-intensity by changing the balance of self-produced fuels and gas. The availability of these options depends on the design and location of individual refineries.

Table 4.4.1-1 Characteristics of Refinery Fuels – EU industry averages 2008 (Source: [Concawe BMDB])

Fuel Type	Carbon Intensity ($kgCO_2/GJ$)	Carbon Content (%m/m)	LHV (MJ/kg)
Imported Gas	55	75.0	50
Refinery Fuel Gas	58	77.5	49
Refinery Liquid Fuel	79	87.8	40.7
FCC Coke	97	93.0	35.3

Liquid fuel (mainly heavy fuel oil) accounted for 21% of EU refinery fuel in 2008 [Concawe BMDB] although there are large variations between refineries. There has been a trend to reduce fuel-oil firing in favour of imported gas and fuel gas, although this has mostly been driven by factors such as operability and local air quality (e.g. EU IPPC/ IED regulation), Some refineries still burn liquid fuel for economic reasons or because they do not have access to imported gas. The trend away from liquid fuel firing is expected to continue, although some sites may find it hard to stop altogether (e.g. if the location has no alternative uses).

Quantification

We have assumed that 80% of the 2008 liquid fuel combustion will be replaced by gas by 2030, then eliminated entirely (or equipped with carbon capture) by 2050. The cost of heater modifications and ancillary costs (e.g. connection to the gas grid) has been assumed to be €0.5 million per 10 MW heater [Member company information]. We further assumed that an average of 25 heaters would be affected per refinery (2000 in EU) or in other words about 400 heaters and 200 M€. Note that the total financial impact for a refiner may also include the differential between the value of the liquid fuel not burnt and the cost of the additional purchased gas. This will be entirely refinery-specific. By 2050 all liquid fuel was assumed to have been substituted.

FCC coke accounted for ~14% of EU refinery fuels in 2009 [Concawe BMDB]. It is the highest intensive carbon-fuel in the refinery, but is not substitutable by liquid fuel – coke combustion is not just a source of energy, but is required to reactivate the FCC catalyst once it has been deactivated by coke formation. The coke yield of the process is not expected to change significantly, however a reduction in FCC utilisation is foreseen in the years to come (See **Table 4.3.2-1** above and [Concawe 1/13R]). We have assumed that FCC coke production would decrease 28% between 2008 and 2030 leading to a 2 Mt/a CO_2 emissions reduction.

This effect has, however, been incorporated into the 2030 reference case and not shown separately as it is not the result of an efficiency improvement measure but a consequence of the refineries operational requirements.

FCC units provide a key step in the production of transport fuels so it is unlikely that there will be a substantial reduction in FCC coke production without a major change in crude- or product-slate (or without retrofitting FCC units with CCS – **Section 4.5**)

Refinery fuel gas provides nearly half of the energy required by the EU refining system [Concawe BMDB]. It contains methane with C3-C4 hydrocarbons and hydrogen (entrained by hydrotreater purge-streams). It is not made on purpose but arises because refinery processes are not 100% selective. There is little possibility that changes in process chemistry will significantly reduce the production of fuel gas, so its production sets a “floor” level of self-produced energy. There is however a moderate potential to reduce the carbon intensity of the fuel gas by purifying it. The heavier C3+ hydrocarbons can in principle be recovered (e.g. by chilling) and sold as LPG. Recovering hydrogen (e.g. membranes; PSA) would increase the carbon intensity of the fuel gas but this would be more than compensated by the avoidance of hydrogen manufacturing emissions.

Quantification

Starting from a fuel gas composition inferred from the 2008 actual average fuel gas emission factor [Concawe BMDB], we have assumed a 50% reduction of both C3+ and hydrogen by 2030. The reduced fuel gas production, increased energy use and extra hydrogen availability were taken into account. The associated capex is 2€/GJ-FG (see e.g. [McIntush 2016]). No further improvement was deemed possible.

4.4.2. Flaring

Refinery flares are required as a safe means for disposing of (potentially hazardous) hydrocarbons during emergencies, upsets, start-up/shut-down or major changes in plant operation. Flare gas recovery technologies allow some of this gas to be recovered and placed in the refinery fuel system. The main issues are intermittency and low delivery pressure so deployment often requires modification to the flare itself, gas compression (e.g. liquid-ring system), liquid recovery and associated pipe work. Installation of flare-gas recovery may be required for environmental compliance. Flaring has already been reduced considerably over the years both on economic grounds and in order to comply with emission regulations; it represented 2.2% of total EU refinery emissions in 2008 [Concawe BMDB] but this has declined with the development of more sophisticated systems.

Quantification

We have assumed 80% reduction of gas flaring from the 2008 level by 2030 with near complete elimination (95%) by 2050. The recovered flare gas has been assumed to be used as extra fuel gas, thus reducing natural gas imports. 50% of the savings have been assumed to be achieved without capex. The capex for the balance is consistent with a 5 years PBT at low energy cost.

4.4.3. Low-Grade Heat

Conventional heat integration between refinery units typically is achieved by direct heat-exchange between process streams. Higher temperature streams clearly are most useful for heat-exchange; lower temperature streams may be too cold to be used in this way, but still need cooling e.g. to control distillation systems or cool products for storage. This typically uses air-coolers (~120 - 140ºC), water-coolers (~80ºC) or produces surplus LP steam (~120ºC). The US DoE MECS program [US MECS 2012] estimates that ~30% of refining process energy is discharged in this way.

Some of this low-grade heat is lost from hot pipes and surfaces and is not easily recoverable, but some sources are large enough to be considered for recovery. For examples, some refineries may have > 50 MW of low-grade heat being discharged by air-coolers on the condensers or pump-arounds of large distillation units or FCC fractionators [Bealing 2016; Gomez-Prado 2016b]. This may create an opportunity to use low-grade heat as a source of energy - provided that the sources are easily accessible, have adequate plot-space and can be treated cost-effectively.

The main option today is the export heat for space heating, although there have only been a few successful applications. It requires a suitable geographical location near a major conurbation as well as a high degree of cooperation (both practical and financial) between local authorities and heat network operator. A recent system for 16,000 households is said to have cost ~$18 million including funding from municipal authorities [WR 2016]. For practical reasons, district heating is mainly restricted to Northern latitudes with efficiencies depending on local circumstances (e.g. distance between source and consumer; limitations on supply and return temperatures). It is conceivable that a few such schemes may be developed at certain refineries in the next decades.

Some sources of low-grade heat (e.g. air-coolers, water-coolers or surplus LP steam) may appear as point sources > 50 MW_{th}. Where these are easily accessible and could be treated cost-effectively, the low-grade heat might be upgraded using heat-pumps or used for power generation using technology such as Organic-Rankine-Cycle (ORC) turbines. Current heat pump technology does not have the high temperature uplift needed for large-scale refinery use, so today has limited application e.g. chillers; its longer term potential is addressed in more detail in **Appendix 3** (Electric Heating). This section focusses on ORC purely as an example of low-grade heat recovery; we are not concluding that it is necessarily a preferred option. ORC is a demonstrated technology, although wide deployment might need R&D to reduce capital costs and improve retrofit potential. In principle, ORC is applicable to any refinery with a large source of low-grade heat, however integration costs depend on the physical nature of the source (e.g. height above ground; access around existing equipment) and also has a large plot-space requirement – current ORC installations typically have very large air-cooler banks.

Sources of low-grade heat in refineries typically have relatively low temperatures (80-120ºC) which leads to low thermodynamic (Carnot) efficiency, typically in the range 10-20%. Higher temperature sources would help, but these are better used for refinery process heat integration (**Section 4.1**). We have used a conservative value of 10% for the overall efficiency of such schemes.

The cost of generation is dominated by capital cost of the plant, taken to be in the range 3000-5000 $\$/kW_e$ [Lemmens 2015; Jung 2014; Chen 2016]. Capital costs may fall if this type of technology is deployed widely across all industry sectors. Economics might also improve if heat-storage (such as hot-water reservoirs) could be used to allow power generation to times of peak demand.

Integration with cryogenic energy storage [Highview 2017] might improve efficiency by allowing a much lower discharge temperature for low-grade heat-to-power (although this impairs operating flexibility unless large-scale heat storage is available). Taking the above into account we have assumed a capex of 3000 €/kWh$_e$ at the 2030 horizon, with no further improvement thereafter.

Quantification

The total process energy consumption of the EU refining industry was ~55 GW in 2008 [Concawe BMDB] suggesting ~30% is discharged as low-grade heat from all sources; we have assumed that ~25% of this fraction might ultimately be recoverable, corresponding to 4 GWth of low-grade heat would be available for recovery.

We have assumed that 5% of this could be made available for district-heating by 2030, increasing to 10% in 2050 with 20% heat losses. Notional CO_2 savings were calculated assuming alternative heat generation with gas at 90% efficiency. The capex for refiners would be highly dependent on the contractual arrangements with local authorities; we have assumed an expenditure of 5 M€ per refinery with 10 refineries developing such schemes.

For electricity generation, we have used a conservative conversion efficiency to electricity of 10% with a capex of 3000 €/kWhe at the 2030 horizon and no further improvement thereafter. The proportion of that heat actually converted would be a function of the price of electricity and CO_2, with no uptake when a PBT of 7 years and above is considered, increasing to 100% for the minimum PBT cases (2.3 years, corresponding to the maximum electricity price of 150 €/MWh).

4.4.4. Substitution of refinery energy by low-carbon electricity

The assessment in **Section 4.3** includes efficiency improvements which might be brought about through the use of improved electrical equipment (e.g. motors, transformers, etc) within refineries. This section explores the potential for refineries to reduce carbon emissions through use of lower-carbon electricity, either generated within the refinery or imported from external lower carbon sources via the grid to substitute other existing energy vectors. In both areas, the low-carbon technologies are generic to a range of industry sectors and their development is driven by the wider community, not just the refining industry. Details of electrical equipment, infrastructure and associated costs are provided in **Appendix 3**; the rest of this section focusses on the impact in and around refineries,

Table 4.4.4-1 shows the distribution of refinery energy supply in 2008 and the associated carbon-intensities. Note that these figures are aggregates based on the [Concawe BMDB]; individual refineries vary considerably both in terms of distribution and overall energy intensity. Today, the carbon intensity of grid-electricity is higher than the refinery fuels, but in the future - typically post-2030 - it is anticipated that the increasing level of renewable (see **Section 4.4.4-1**) generators may reduce this sufficiently for refiners to access a lower carbon intensity fuel than they are currently using.

Table 4.4.4-1 Characteristics of Refinery Energy – EU industry average (Source: Concawe BMDB 2008; Electricity – see section 2.4)

Fuel Type	Contribution to Refining Energy Supply (2008)	Carbon Intensity Factor ($kgCO_2/GJ$)
Refinery fuel (2008)		
Self-produced Fuel Gas	49%	58
Self-produced FCC Coke	14%	97
Self-produced Liquid Fuel	13%	79
Imported Gas	13%	55
Imported Steam (2008)	4%	61
Imported Electricity (2008)	7%	119
Imported Electricity (2030)		59
Imported Electricity (2050)		11

This section explores how refineries might access low-carbon electricity and what they might do with it. Technical options for supply include refinery-based and external low-carbon generation. Technical options for use include the use of low carbon electricity instead of fossil fuels for producing steam for processes and motive power, and for refinery process heat. However, we should note that electrification at most could substitute perhaps 30% of average refinery energy demand because they must consume the low-value fuel-gas and FCC coke which are unavoidable by-products of refinery processes. This gap is already tight in some refineries and will become tighter as refineries improve their energy efficiency.

Increasing electricity imports into refineries on a large scale would require extensive additions to- and modifications of- the refinery electrical infrastructure, adding significant costs to such projects.

Quantification

We have assumed investment of 300 k€/MWe to cover new electrical infrastructure; it is applied to all options in this study which require additional electricity import (**Appendix 3**).

4.4.4.1. Sources of Low-Carbon Electricity

Technologies for low-carbon electricity generation include hydroelectric, nuclear, tidal, wind, solar power, and biomass-to-power. The first three are constrained by location, generally are large and have little synergy with refining assets. The last three are more scalable and might potentially be associated with a refinery as some sites may have opportunities in developing and operating renewable production facilities nearby. However, as this section will show, this is expected to remain marginal and refinery-based low-carbon power generation is likely to be limited to niche locations and most refineries would access low-carbon power via distribution grids to which the refinery is connected.

Wind installations in Europe vary from single turbines (perhaps 3 MW onshore) to large arrays with capacity up to 500 MW [EWEA 2015]. The capital cost of onshore wind-power is 1.6 to 1.9 M$/MW, leading to a levelised cost of electricity (LCOE) of 71-117 $/MWh [WEC 2014]. The capacity factor for wind is typically only ~25-30% (24% global average in 2017) [IEA-WEO 2018, WEC 2014] so the combined output of ~60 100 MW windfarms would be needed to cover the refining industry's current electricity imports.

A 100 MW wind farm typically occupies several thousand hectares [NREL 2009] so few EU refineries would have enough available space for such a facility. The Valero McKee refinery in Texas [TEEA 2009, WSJ 2009] has 33 turbines with a net capacity of ~35 MW; the wind farm is ~5 times the area of the refinery. There have been a handful of European refinery-based wind energy projects, but typically at the level of 10-20 MW. Intermittency is a significant issue, so a refinery which uses high levels of wind energy from a dedicated facility would also need a back-up supply for wind-free days.

Solar-PV also provides scalable renewable power generation - from mall rooftop installations of a few kW to large solar farms > 200 MW. Capex for largescale solar-PV is currently ~1.5-2 M$/MW giving a LCOE ~200-400 $/MWh in Northern Europe [WEC 2014] although costs might fall as much as 50% by 2050 [BP 2015]. Again, space and intermittency are issues – a refinery would need a dedicated solar farm occupying perhaps 1 to 3 km^2 to cover its electricity imports but would still need a corresponding back-up supply for use at night. The Indian Oil Corporation is reported to be considering solar-PV, for a refinery in Madhyar Pradesh India, [PVTech 2016]; there may be some niche opportunities in parts of Europe where land and sunlight are suitable.

Concentrated Solar Power (CSP) using focused sunlight to provide heat has been demonstrated for power-generation [NREL-CSP-2018; SciAmer 2016]. In theory, CSP allows energy storage using the heat transfer medium. Options include direct production of steam (e.g. PS10 near Seville, Spain – 10MWe; steam at 45bar, 275°C) or indirect production using molten salts (Crescent Dunes, Nevada, USA – 110 MWe, 565°C). As an alternative to power generation, this technology could be used for direct heating of refinery process streams e.g. crude distillation, but this would be but considerably more location-specific than power generation.

The main biomass-to-power technologies today are anaerobic digestion (AD) and biomass combustion. AD conversion technology is relatively mature (e.g. Europe currently has ~17,000 biogas plants [EBA 2016]) but there may be significant potential for growth in feedstock supply, possibly 3-fold by 2030 [Lukas 2016, IEA-DH2013; ICCT 2016b; Poyri 2012]. However, the low energy content of the feedstock means that logistics may constrain both the location and scale of the plant. The primary AD product is biogas (mix of CH_4 and CO_2) which is usually combusted to generate power, typically 1 MW_e and rarely > 3 MW_e capacity. AD economics are complex with financial support in many parts of Europe [IEA-Biogas 2013]; the generating cost is typically 60-150 $/MWh [IRENA, 2015]. There is little synergy between AD with generation and refining, but there might be an alternative approach where bio-gas is routed into a refinery's fuel-gas system without the need for power generation or for purifying the biogas to pipeline quality.

Biomass combustion also is a mature technology with a variety of configurations from grates to fluid beds to gasifiers. Again, generating scale is often constrained to < 50 MW by the feedstock type (e.g. woodchips; agricultural residues, although pre-treatment (e.g. torrefaction) and special logistics (e.g. barge, rail) may allow capacities > 300 MW. Generating costs depend on feedstock and conversion technology with prices from 60 to 300 $/MWh [IRENA 2015]. Like AD, there is no obvious synergy between refining and biomass-to-power (although bio syngas comprising CO_2+CO+H_2 might be burned in a refinery fuel system instead of being used for power generation).

There are few general synergies between refining and low-carbon power generation although there may be small refinery-based projects where conditions and space are suitable. A few isolated refineries might also make use of these technologies rather than invest in conventional infrastructure. In the main, refineries are expected to access low-carbon electricity via general electricity networks.

4.4.4.2. Intermittency of Renewable Electricity

The Intermittency of wind and solar-PV power generation become an issue once they comprise a significant fraction (typically more than 1/3) of the total electricity supply. The period of intermittency may extend from minutes/hours (changes in wind strength or cloud cover) up to days/weeks (changes in weather) leading to problems with voltage- and frequency- stabilisation as well as supply-demand balancing. Variability may be mitigated by grid expansion, long-range interconnection, bulk energy storage (e.g. pumped hydroelectric), local energy storage (e.g. batteries) or alternative generating capacity with the different technologies having different characteristics regarding cost, power, capacity and response time.

The production cost of electricity is therefore not constant but depends on the degree to which renewable variability has to be mitigated. Some parts of Europe have already experienced this effect with “negative” spot prices for electricity being reported in Germany during 2016; they were however relatively infrequent and short duration. By 2030, most markets might see this effect to some extent [DG Ener 2014], with surplus renewable generation possibly leading to very low electricity prices for short periods (hours; days) which might account overall for 5-20% of the total. There is also an open question whether short-term surpluses also benefit from lower-than-average carbon intensity or simply contribute to the “grid-average.”

Quantification

We have assumed surplus renewable electricity would be available 10% of the time at 10% of the normal grid price.

4.4.4.3. Refinery Use of Low-Carbon Electricity for Steam Production

Refineries experience variations in demand for both power and heat, which historically have been set more by refinery operating schedule than by the availability or cost of energy. Increased generation of renewable energy means that the variations in supply will become more important and may need to be mitigated by consumers varying their demand, and by grid-based mitigation measures. This section firstly explores how refiners could make use of heat (steam) production to vary the electricity imports to respond to the variations in supply (translating into price). It then considers how refiners could use electricity as a means of decarbonisation (which may only become relevant in the 2050 timeframe). Steam production typically accounts for ~3% of refinery fired fuel [Concawe BMDB]. Throughout this section, it is assumed that low-carbon electricity only has a GHG benefit where it backs out fired heat using imported energy (eg natural gas); there is little GHG benefit from backing out fired heat using fuel gas produced as a by-product of refinery processes because it would still have to be used somewhere.

a) Intermittent steam production with surplus renewable electricity

This first area considers how steam demand might be managed so that Low-Carbon electricity could substitute fossil energy during periods of surplus renewables.

As an example, some recent Scandinavian trials have used intermittent Low-Carbon electricity for boilers rated up to 25 MWe to provide pressurized hot water for district heating systems. Electrode boilers also are reported to provide steam at 10’s of bar. Production of high (HP) or medium (MP) pressure steam for refinery use would require high temperatures and pressures, but these technologies make a good stepping stone towards refinery-scale steam production using Low-Carbon electricity – provided that there is sufficient investment in R&D.

Refineries might be able to provide several tens of MW of switchable demand, similar in scale to grid-scale battery storage facilities. Investment would be required in new electric boilers and supporting new electrical infrastructure. The steam produced would effectively be “zero-carbon” and low cost but, because of the limited low-electricity-price time slots, the capital charge would be spread over a much-reduced steam production. For these reasons it may only become attractive in a high-fossil-energy / low-renewable-electricity environment. The concept is probably of less value for refiners than it is for grid operators looking for ways to supplement renewable electricity in the grid.

b) Continuous steam production with low-carbon grid electricity

The second approach would involve refineries using low-carbon electricity on a continuous basis to produce their steam requirements. This could potentially cover the total refinery steam demand and would require installation of new electric steam-boilers and electrical infrastructure. **Figure 4.4.4.3-1** compares the economics of making steam using a gas-fired boiler (horizontal lines), or a hypothetical electrical-boiler operated continuously (solid diagonal lines) or intermittently to utilise low-cost “surplus” renewable electricity (dotted diagonal line). The intermittent case assumes the same capital cost per unit of electrical capacity, so the intermittent operation requires the capital charge to be spread over a much smaller production of steam. The green region shows the range of electricity and gas prices in the 2030 and 2050 Scenarios. Electrical steam production only appears to be economic if low-carbon electricity is less than €100/MWh and gas costs more than €13/GJ. The grid emission factor is expected to fall in the future (**Section 5.2** citing JRC data) so the emission factor for electrically-produced steam would also be expected to fall (**Figure 4.4.4.3-2**).

Figure 4.4.4.3-1 Economics of steam production using electric-boiler vs NG fired-boiler – continuous- and intermittent operation

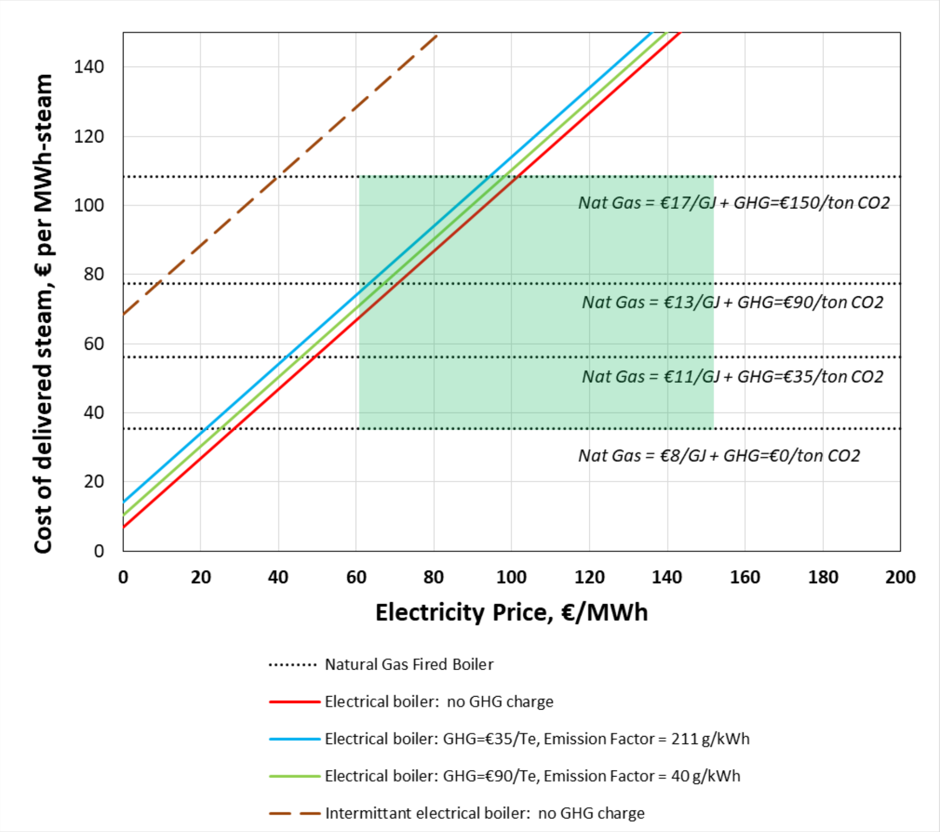
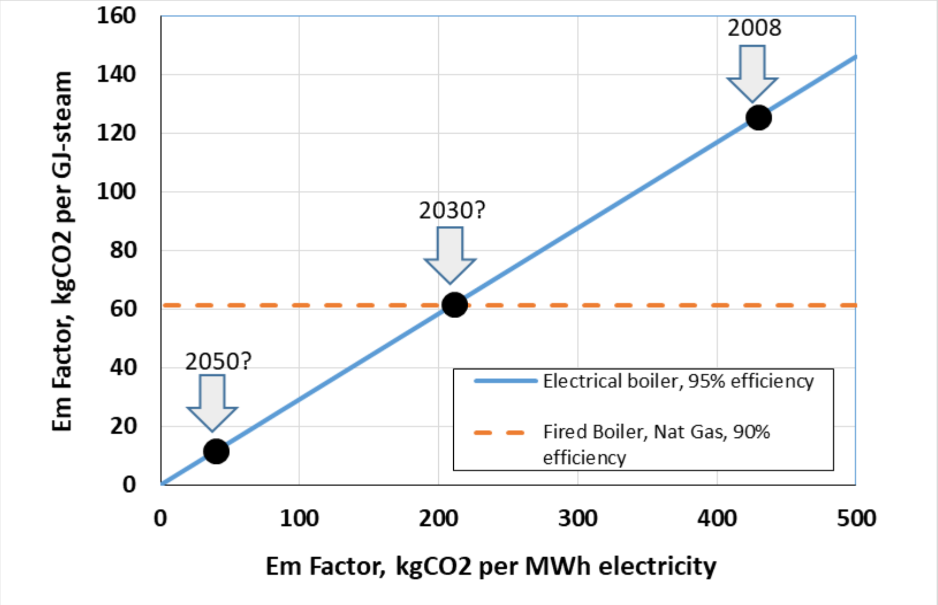


Figure 4.4.4.3-2 Carbon intensities of steam from fossil-fuel or grid electricity

(See **Section 5.2** regarding emission factors for 2008, 2030 & 2050)



Quantification

We have adopted the [Concawe BMDB] steam production figure of 3% of refinery fired fuel. We estimated the associated total project capex at 100 k€/MWe for electric boilers (see e.g. **Appendix 3**).

For intermittent use we have assumed that 25% of the capacity could be converted to electricity by 2030, increasing to 50% by 2050, and that availability of surplus electricity would limit its use to 10% of the time.

For continuous use the uptake would be limited to substitution of gas imports (see also **Section 4.4.4.5**)

4.4.4.4. Refinery Use of Low-Carbon Electricity for Power

There will be some “natural” decarbonisation of refinery electricity imports because the carbon intensity of the grid is expected to fall due to increased renewable generation.

- **Electricity for general purposes**

Refineries use electricity for general purposes, mostly for mechanical energy (motors), lighting etc. (electrical boilers or process heaters are currently not in use in refineries). The proportion relative to total energy use varies greatly, between about 4 and 14% across the EU refinery population (6.5% on average). About 40% of this electricity is imported, generally from the local grid (this is an EU average. Actual figures are refinery specific. Some refineries produce virtually all their electricity internally and some even export electricity. Others rely almost exclusively on imports). The gradual reduction of the carbon intensity of the grid over time will provide for a reduction of the indirect refinery emissions and may also present an incentive for increased use of electricity. Also note that the absolute amount would be offset in line with energy efficiency improvements.

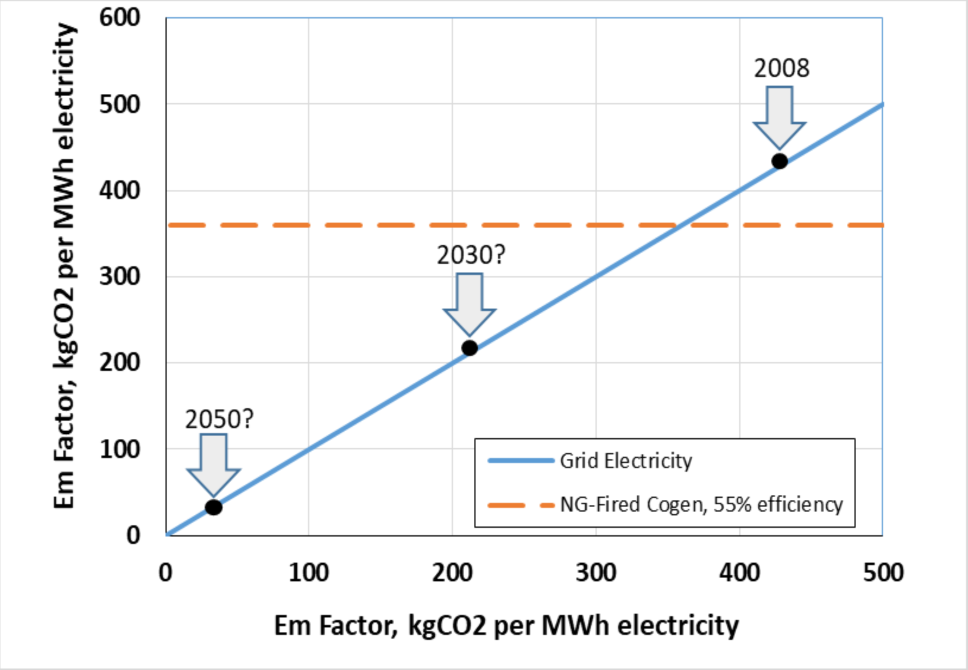
Quantification

We have assumed that the average share of electricity in the total energy used by EU refineries would increase from the historical value of 6.5% to 7.5% in 2030 and 9.5% in 2050.

- **Replacement of Cogeneration Plants (Combined Heat and Power or CHP)**

Fossil-fired power generation in refineries – mainly CHPs – could be replaced by low-carbon electricity imports. There may well be an emission saving before 2030 (**Figure 4.4.4.4-1**) but the economics of closing such plants are unlikely to be favourable over this timescale.

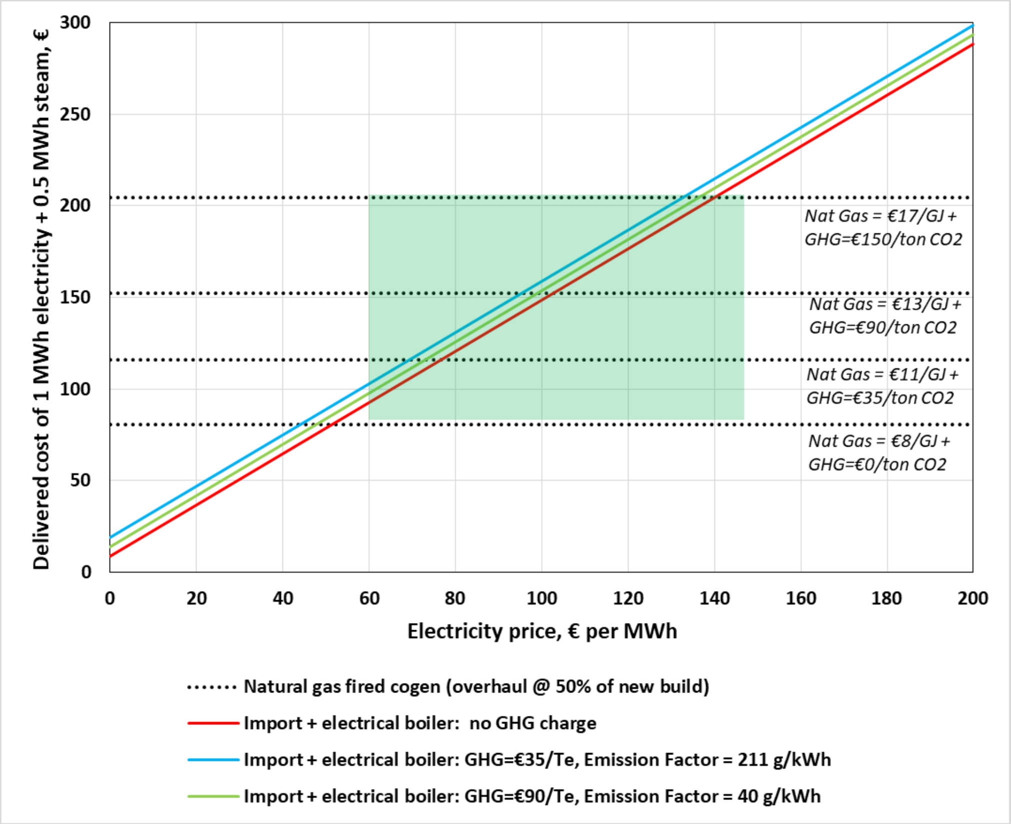
Figure 4.4.4.4-1 Carbon intensities of electrical generation by NG-fired CHP and grid electricity



Many refineries installed CHPs in the period 1990-2010 as part of the refining industry's improvement in energy efficiency. CHPs typically have a technical lifetime of at least 25 years [IEA-CHP 2015, ESMAP-CHP 2009] so there is relatively little incentive for change before 2025-2030. By 2050 though, some CHPs would be >50 years old. The period 2030-2050 raises the question how many CHPs would need a major overhaul or complete replacement, or whether they might be substituted by imported electricity. We have tried therefore to represent a case involving an "end-of-life" CHP which would need substantial replacement (but not to the extent of a completely new unit) in comparison with a new-build electrical system.

Figure 4.4.4.4-2 shows the cost of co-supplying 1 MWh of electrical power and 0.5 MWh of steam using NG-fired CHP (horizontal lines) or imported grid-electricity for power and electrical steam-boilers. The green region shows the range of electricity and gas prices in the 2030 and 2050 Scenarios. Substitution of CHP by imported electricity would be driven primarily by higher prices for gas and carbon; the carbon intensity of grid electricity has less impact because it is expected to fall whilst carbon prices are expected to rise. Substitution is probably not economically viable before 2030, but CHP and electrification would be roughly competitive for a 2050 scenario with gas = €13/GJ, electricity = €100/MWh and CO_2 = €90/ton. Electrification would look more attractive in a 2050 scenario with gas = 17 €/GJ, electricity = 60 €/MWh and CO_2= 150 €/t.

Figure 4.4.4.4-2 Economics of generating power using grid electricity vs gas-fired CHP



Assumptions:
CHP: 0.50 GJ electricity + 0.25 GJ-steam per GJ-natural gas; capex = €2million per MW-e; Electrification: 1 GJ steam per GJ-electricity; capex = €100 per kW-e for electrical steam boiler + €300 per kW-e for switchgear and infrastructure; prices and emission factors from Concawe Scenarios

Cogeneration technology is relatively mature so significant improvement in performance is unlikely, unless emerging technologies such as fuel-cells [EPA-CHP 2015] might be available at refinery scale and acceptable capital costs (e.g. < 1500 €/MWe). High-temperature SOFC & MCFC fuel cells offer improved electrical efficiency; however, the steam temperature/pressure is too low for refinery applications).

If and when CHP plants are shutdown, the shortfall in steam production would have to be met by either conventional boilers (possibly some existing ones) and/or electric boilers.

Quantification

We assumed no CHP replacement in 2030 but for illustrative purposes have assumed 100% in 2050 when the electricity grid will have been substantially decarbonised. Over this period we assume that many existing refinery cogenerations will have reached the end of their working life or else are in need of major overhaul. The capex associated with new electrical infrastructure (300 k€/MWe, see above) is partly offset by a capex saving of 1000 €/MWe for not replacing the CHP plants.
For steam production we assumed a capex of 100 k€/MW for both conventional and electric boilers. In the former case we assume 50% would be existing.

4.4.4.5. Electrical process heaters

Process heat is the largest energy demand in most refineries. Fired burners are mainly gas-fired, delivery high temperatures (e.g. > 350 degC) and operate at duties up to perhaps 200 MW. It is technically more demanding than steam production particularly where process streams are higher boiling, flammable, potentially corrosive and have a propensity for fouling. In principle, electrical heat might replace conventional fired heaters as a source of process energy. This is reviewed in more detail in **Appendix 2**. The concept is quite speculative and barely at the R&D stage at the moment. Compared with fired-heat – where the industry has >100 years' experience – this technology would raise HSSE and operational challenges, particularly for early implementers. It is reasonable to expect that electrical process heaters would be more costly than electrical steam boilers, so it is only likely to be economic when electricity prices are very low and gas prices high.

At face value the technical potential for electric process heating is large, but several factors create severe limitations. Firstly, roughly two-thirds of refinery energy is fuel gas and FCC coke produced as unavoidable by-products of refinery processes (although this percentage might increase if refineries continue to improve their energy efficiency). This limits the total potential substitution to roughly one-third of refinery energy, but perhaps half of this might be taken by cheaper routes to electrification e.g. replacement of steam-drives or electrification of steam production. Secondly, complete replacement of the large process heaters on crude-distillation units is extremely challenging compared with smaller heaters for "clean" feedstocks e.g. isomerization, naphtha reboilers. Applications would therefore seem to be limited to smaller units or for supplementary heat in larger units which continue to be fired with hydrocarbons. These applications only represent a small fraction of a refinery's total process heat demand i.e. just enough to avoid imports of gas.

Quantification

We have assumed that this option would be exercised after all other measures for increasing imported electricity have been implemented. The scope is limited by the need to consume all internally produced fuel gas. Based on limited literature data we have assumed a significantly higher cost of 300 k€/MWe for electric process heaters than for boilers (100 k€/MWe).

4.4.5. Low-Carbon Hydrogen

Section 2.5 outlined current approaches for supplying hydrogen to refineries, primarily steam-methane-reforming (SMR) based on natural gas operated by the refinery or by a 3rd party supplier. It also explained that this is a carbon-intensive process typically releasing about 10 t of CO_2 per t of hydrogen and representing ~17% of refinery CO_2 emissions in 2015. **Section 3** explained that changes in demand slate are likely to increase refinery use of hydrogen perhaps as much as 50% by 2030.

This section explores two options for decarbonising the hydrogen supply – first, the application of CO_2 capture and storage (CCS) to conventional hydrogen production technologies and second, production of electrolytic hydrogen production using low-carbon electricity.

4.4.5.1. Conventional hydrogen production with CO_2 capture and storage

SMR is a mature technology e.g. [Rostrup-Nielsen 2001] where “state-of-the-art” technology has high efficiency (> 85% conversion to H_2 on an energy basis). Many existing refinery units are > 15 years old and are less efficient, although they also co-produce HP steam or electrical power which is used by the refinery. At some sites there may be efficiency improvement opportunities, but these changes are likely to be incremental (thus we have accounted for them as part of the general refinery energy efficiency programme).

We have used SINTEF (2017) as the basis for SMR cost. This gives a capital figure of 223 M€ for a plant capacity of 100 kNm^3/h SMR (71 kt/a hydrogen) hence a capital intensity of 3.1 M€/(kt/a hydrogen). The production cost would be 2.5 €/kg using the assumptions in the 2030 Medium scenario. The base SMR capital is higher than other studies (e.g. [JEC 2008]) probably because it includes ancillary facilities required for a large-scale merchant hydrogen plant operating as an “island” and probably not required for a smaller plant integrated into a refinery. We have used the data from the SINTEF study because it includes estimates for SMR with different degrees of carbon capture.

SMR generally requires the separation of CO_2 and hydrogen from the intermediate product stream, so is often cited as suitable for integration with CCS. This is most effectively done during construction, but, in principle, existing plants might be retrofitted subject to the original technology and the complexity of the refinery location. For example, a post-combustion amine plant for purifying CO_2 to “storage quality” would likely occupy as much space as the original SMR.

Recent process development has been aimed at partly at conventional technology (e.g. autothermal reformers; structured catalyst packings), but there are also new concepts which might offer easier integration with CCS, for example transported-bed/cyclic systems or membrane reactors (e.g. [Spalina 2016]). These are still at an early stage of development and are not generally retrofittable. These concepts are claimed to offer moderate capital-cost savings or efficiency improvements so they might ultimately be an option for new units, but it is not apparent that their benefits would justify the replacement of an operating SMR.

Steam Naphtha Reforming (SNR) is a related process using a light hydrocarbon feed such as LPG or light naphtha. It usually requires additional feed pretreatment and a higher carbon intensity, but otherwise has the same characteristics as SMR. This is rare today, but might become more common if conventional markets for LPG and naphtha decline.

An alternative to SMR/SNR involves gasification or partial-oxidation of heavy feeds such as residues (“Residue POX”). This is mature but relatively uncommon in refineries. A few more units may be installed in relation to marine sulphur emissions but would probably require CCS to be viable. Some efficiency gains may be possible for new designs, mainly in the air separation unit.

A recent study about the cost of retrofitting CO_2 capture to refinery processes [SINTEF 2017] shows that the capture cost and degree of decarbonisation depend on the original technology and integration option. Estimates vary between 38 to 60 €/t CO_2 avoided with capture efficiency varying from 55% to 90% and capex from 40 and 120 M€ for a 100,000 Nm^3/h (220 t/day) SMR unit.

4.4.5.2. Electrolytic Hydrogen - Intermittent and Continuous

Electrolysis is being developed for both small-scale (distributed) and large-scale (centralised) hydrogen production. Low-temperature electrolysis (e.g. PEM electrolysers) may suit both applications; high-temperature electrolysis (e.g. solid-oxide electrolysers) are thought to offer better efficiency but might be limited to centralised applications. As yet, there are no facilities which could supply hydrogen at refinery-scale. Estimates from literature for capex, opex and efficiency vary within a wide range (see e.g. [Saur 2011, JEC 2008, IEA-H_2 2015, Ainscough 2014]). Most sources [eg IEA-H_2 2015] assume that the specific capital cost will fall significantly over this period for example due to improved efficiency and operation at higher current densities.

We have used the figures shown in **Table 4.4.5.2-1**

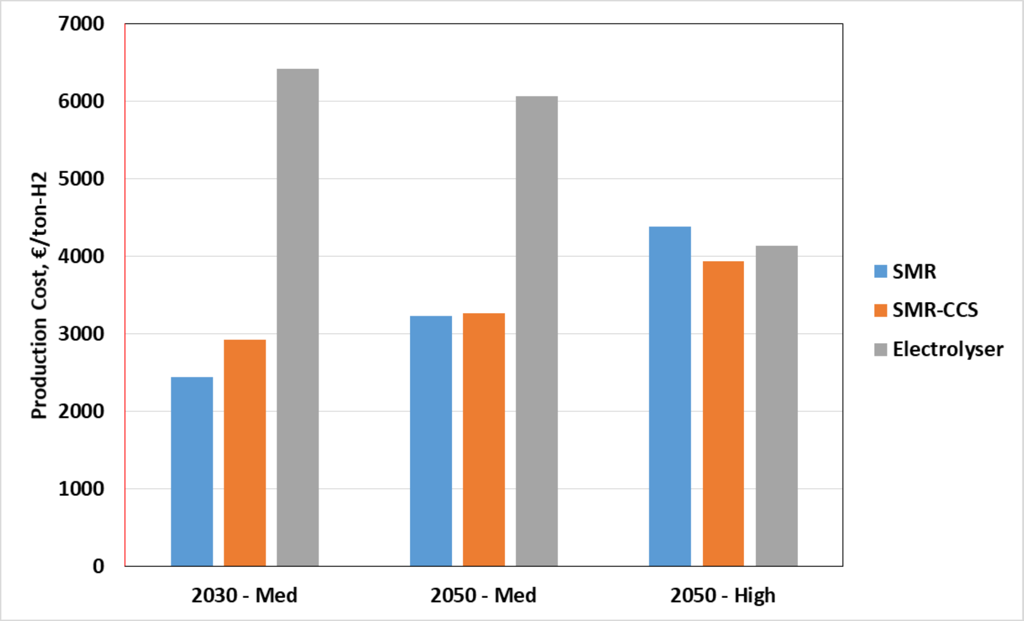
Table 4.4.5.2-1 Efficiency and cost of electrolysers

Case	2030	2050
Efficiency %	70%	75%
Capacity Factor	85%	85%
Initial capex, \$/kW-H_2	1000	650
Fixed opex, % of capex	5%	5%

Note: based on lower heating values

The cost of making hydrogen by electrolysis obviously depends strongly on the price of electricity and for the scenarios used here, electrolysis using “normal” grid electricity would struggle to compete economically with hydrogen from conventional gas-based SMR. **Figure 4.4.5.2-1** compares the potential costs of hydrogen production via SMR (with and without CCS) and electrolysis, suggesting that the latter can only become economic in a very low electricity price scenario.

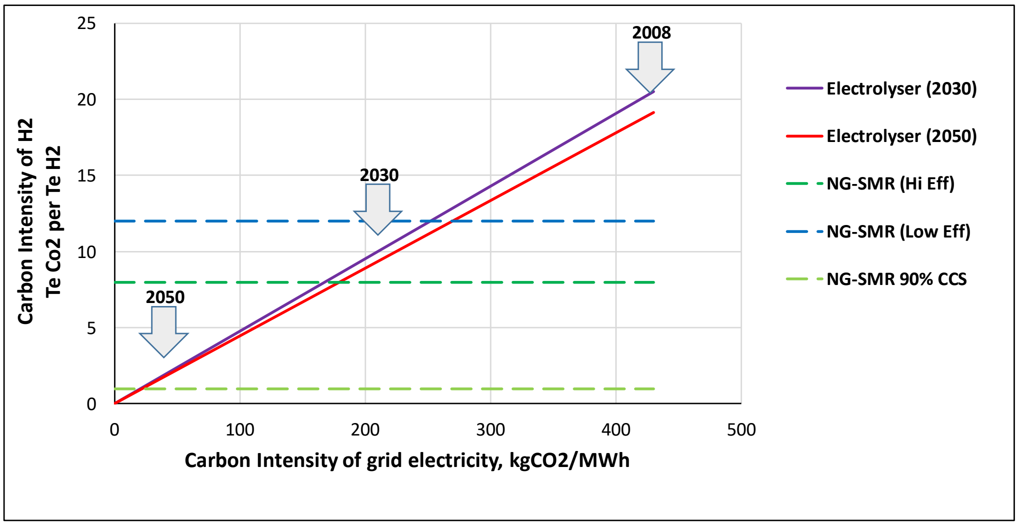
Figure 4.4.5.2-1 Cost of hydrogen production by SMR and electrolysis including CO_2 cost



Note: Assumptions: SMR capital intensity assumed to be 1.8 M€ per kt/a of H_2. SMR-CCS = SMR cost + CCS plant calculated using CCS plant costs from **Table 4.5.1.**

Figure 4.4.5.2-2 compares the carbon intensities (tons CO_2 per ton hydrogen) of the various options at different CO_2 emission-factors for the electricity grid. It suggests that electrolysis using grid-mix electricity would not be carbon efficient compared to standard SMR until about 2030 Even when the grid reaches higher levels of decarbonisation (2050 horizon), it struggles to compete with SMR + CO_2 capture.

Figure 4.4.5.2-2 Carbon intensity of hydrogen production via SMR or electrolysis

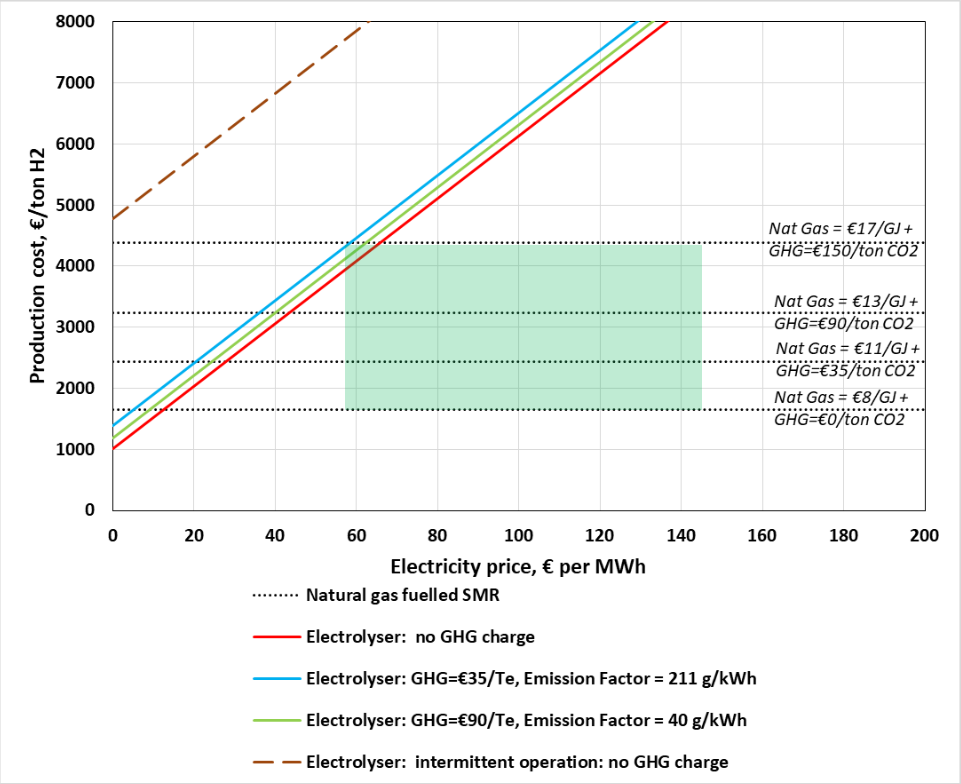


Note that, in 2030, emissions from SMR (no CCS) and electrolysis are virtually the same.

The electricity demand of a “refinery-scale” electrolyser (say 50 t/d H2) is ~100MW$_e$, roughly equivalent to the peak output from a large-scale wind or solar farm. However, these typically have low capacity factors (15-25%) and so a 50 t/d “refinery-dedicated” wind-farm would need energy storage or an alternative source of hydrogen. The capital cost of the electrolysers would also be a more significant factor in the production cost because of the low utilisation.

IEA proposes that intermittent electrolytic hydrogen can be used for “energy storage” by using very low price low-carbon electricity during periods of surplus [IEA-H_2 2015]. This takes advantage of the fast response time of electrolysers allowing them to track the variable output from renewable generation. It would, however, also require somewhere to store the hydrogen (e.g. caverns or in the gas distribution system). This approach is being considered in regions anticipating high renewables on the grid and a shortage of lower-cost energy storage (e.g. pumped hydroelectric; large-scale compressed air energy storage). In principle, refineries also might use intermittent electrolysis as a source of low-carbon hydrogen provided that the varying supply of electrolytic hydrogen could be balanced within the refinery, and that the production price of the hydrogen could be offset by low electricity costs. The capital cost of the facility would depend on its peak capacity, so operation at low utilisation means that capital and fixed costs would have to be reimbursed over a much smaller amount of electrical energy, hence the need for very low electricity prices. **Figure 4.4.5.2-3** shows the trade-off between utilisation and electricity cost for electrolyser operation, suggesting that intermittent operation with very low-price electricity and continuous operation with grid-price electricity (> 60 $/MWh) might well lead to similar production costs. (Note that still this does not necessarily make electrolysis competitive with SMR unless there are other extenuating factors.)

Figure 4.4.5.2-3 Hydrogen production cost - Intermittent vs continuous electrolyser operation



The "price of electricity" is a complex issue. It is represented here as a simple EUR per MWh, but in reality, might encompass other sources of value from grid services such as balancing, voltage- or frequency stabilisation or as an alternative to energy storage. These sometimes are charged according to MW not MWh. If a business case did exist, then implementation would probably not be feasible at refinery-scale. Instead, a smaller scale operation (5-10 t/d H_2) might be powered from the grid or from a small wind- or solar-farm, and the intermittent hydrogen supply might be balanced through turn-down of hydrogen production from the refiner's SMR or catalytic reformer (or turn-up of hydrotreaters). There might also be some natural "buffering" of the refinery hydrogen system as a short-term hydrogen store. The costs and practicalities of running refinery units at reduced utilisation, the storage-capacity of the hydrogen system and all the associated safety implications would have to be considered. This approach might be limited to perhaps 10-25% of refinery "on-purpose" hydrogen demand.

The economic case for refinery-based electrolysers depends critically on the circumstances. It is unlikely to compete with conventional SMR (including GHG charges) or with SMR-CCS except where low-priced electricity is routinely available (e.g. 2050-High Scenario) or where CO_2 storage is not accessible. Intermittent operation does not change the situation even if low-carbon electricity is available at zero cost, or unless other sources of value (e.g. grid stabilization) can be accessed. In cases where intermittent operation is economic, then the low utilisation leads to a very low impact on the refinery's carbon footprint.

Increased availability of low carbon electricity (either intermittently in earlier years or continuously later on) may justify its use to produce a low-carbon footprint hydrogen.

Quantification

Supply of low-cost carbon-free electricity (in times of surplus) is considered to be available 10% of the time. Not all refineries would invest in electrolysers so that only a fraction of the refinery hydrogen production capacity would be concerned (up to 25% by 2030 and up to 50% by 2050).

Continuous production would only be in place by 2050 when the standard grid electricity is substantially decarbonized (2050). We have assumed that it would concern up to an additional 35% of the demand, this figure being also limited by the availability of internal fuels. It could be increased to 50% of the demand if CO_2 capture was introduced at scale (because this would create an additional energy demand).

4.4.5.3. Other Hydrogen Production Technologies

There are several developmental pathways for production of low carbon hydrogen [DECHEMA 2017] including methane pyrolysis, thermal- and photochemical water-splitting. Recent concepts for hydrogen production by methane pyrolysis eliminate carbon as carbon black and have been demonstrated at laboratory and pilot-scale [e.g. Hamilton 2009]. A refinery-scale process would make several tens of kt/a of carbon. Some prospective commercial production might thus displace carbon-black made by other routes (e.g. pyrolysis of residual oils) but widespread adoption would require new outlets (or "sequestration"?) of the carbon product. At best, this looks like it might be a niche opportunity at a few locations.

Hydrogen production by water-splitting is generally at early stage of development, generally being targeted at solar-energy conversion [Sattler 2016]. It might be anticipated to incur constraints similar to solar-electricity as regards space and climate thus is unlikely to be used widely by refineries in the EU.

Bio resources could also be a supply of low-carbon hydrogen.

If any of these pathways emerge, then they might be expected to contribute to the general decarbonisation of imported gas or hydrogen. We have not explicitly included them in this assessment.

4.5. CO_2 CAPTURE AND STORAGE

4.5.1. CO_2 capture in refineries

Individual refineries are relatively large CO_2 emitters (typically several Mt/a) but this is a combination of a number of separate sources. The larger refinery sources of CO_2 are fired heaters, FCC units and hydrogen plants. By power-industry standards, these are quite small – the fired heater of an SMR rarely produces more than 250 kt/a CO_2; an FCC rarely more than 400 kt/a. Process fired heaters are individually relatively small although the flue gases are in some cases, combined and ducted to a common stack. Gas turbines in combined heat and power (CHP) plants and *Integrated Gasification Combined Cycle* (IGCC) units [SARAS, 2008] can also be an important source of CO_2 in certain sites and, thus, suitable candidates for CO_2 capture units. CO_2 concentration also varies a great deal from concentrated streams from hydrogen plants (actual concentration depends on the technology) to low concentration combustion flue gases.

Solvent-based (amine) capture systems are the preferred solutions; most would be retrofits to existing equipment. Capture units may require as much plot-space as conventional refinery units, so many refineries would not have space for the capture units close to the source. Technology development such as chemical looping may be more appropriate for new equipment such as boilers.

The capture process itself consumes energy, mostly in the form of heat to regenerate the solvent. This energy is most likely to be supplied by burning fuel on site (in practice imported gas), although it could also be supplied as imported electricity. In the former case, additional CO_2 will be generated, so that, for a desired target of CO_2 avoidance, more CO_2 will have to be captured than is actually avoided.

CO_2 capture in refineries has been reviewed extensively by Concawe [Concawe 7/11] indicating costs of 80-180 €/t CO_2 mitigated depending on source, scale and technology. A recent update by SINTEF [SINTEF 2017] focussing on retrofitting CO_2 capture to refineries suggests costs of 160-200 per €/t CO_2.

As discussed in **Section 4.4.5.2**, costs are likely to be lower for emissions from hydrogen plants.

4.5.2. CO_2 storage and utilisation

Capturing CO_2 only makes sense if it can subsequently be either reused or safely stored for the long term. Whereas there may be a few niche opportunities for CO_2 reuse, the bulk of captured CO_2 will be stored in suitable geological formations.

Preliminary surveys have identified storage sites in the EU, including depleted oil and gas fields and saline aquifers. The potential capacity could represent up to 100 years of storage at current emissions levels. Public reaction and regulatory issues have affected on-shore storage so by 2015, the EC's "CCS Demonstration Project Network" [CCS-EU 2015] consisted of four onshore and offshore projects: Compostilla (Spain), Don Valley (UK), ROAD (The Netherlands) and Sleipner (Norway).

In Western Europe, the most promising storage structures are in the North Sea. One key condition for CO_2 capture to be a realistic proposition for a given refinery will be reasonably easy transport to a suitable storage. This may involve pipelines and/or shipping. North West Europe coastal refineries are the most realistic candidates possibly together with those in the Rhine corridor. Together, these refineries account for about 35% of total EU refining emissions. There may also be limited local storage opportunities in the Mediterranean basin or inland in Eastern Europe.

Few refineries are large enough sources of CO_2 to justify construction of a dedicated long-range CO_2 transport infrastructure, so "clustering" with other industries is likely to provide the best opportunities to reduce capital and operating costs. The review by Concawe [Concawe 7/11] suggested that CO_2 transport costs are highly scale-dependent. Provided that a refinery could collaborate in a larger scheme (e.g. > 5 Mt/a) then transport costs might be of the order 5-10 €/t CO_2. Projected costs for injection /storage are in the range 1-12 €/t CO_2 stored.

Successful deployment of CCS will also rest on resolving other issues such as long-term storage management and liability and public acceptance. The Gassnova study by the Norwegian Government [Gassnova 2016] includes examples of clustering.

CO_2 Capture and Utilisation (CCU) involving large scale CO_2 conversion to chemicals may offer an alternative to storage which is less sensitive to location. Concepts include the production of chemical intermediates, polymers, inorganics such as cement [OGCI 2017] but scale of utilisation remains an issue. Individual refineries might benefit from CCU, and the products might also offer GHG savings relative to conventional products, but the demand for chemicals is too small to have a significant impact on the refining industry's CO_2 footprint [MacDowell 2016, MacDowell 2017]. In the long term, large-scale CCU might derive from wide-spread availability of low-carbon electricity or hydrogen, or possibly algal technologies, but CCU is too uncertain to be included here.

Quantification

We have assumed no significant impact before 2050 when the total of sites applying the technology could represent up to 50% of refinery emissions. For participating sites, we have assumed that 90% of hydrogen-related emissions would be captured. The balance would bring the total proportion of emissions captured at a given site to 70% (in line with [SINTEF 2017]).

Energy consumption, capex and opex (**Table 4.5.2-1**) were taken from DNV, 2018 for hydrogen-related emissions and SINTEF, 2017 for the balance.

The cost figure for transport and storage is highly uncertain. We have included a notional cost of 15 €/t CO_2 avoided [Concawe 7/11].
Electrolyser capex was based on **Table 4.4.5.2-1**, equivalent to 4.2 and 2.6 €/kg H_2 annual production capacity in 2030 and 2050 respectively. This was considered as refinery investment and as such accounted for in the total capex and opex figures. We considered that 50% of the substituted continuous production (2050 "High" only) would have required new SMR capacity. A corresponding capex credit was included in the abatement cost calculation, with a further credit for the opex saved by not operating the SMRs [JEC 2008].

Table 4.5.2-1 CO_2 Capture parameters

		Hydrogen related	Generic
Capex	€/(t/a CO_2 avoidance capacity)	300	419
Annualized Capex (*) (Capital charge@15% **)	€/t CO_2 avoided	45	63
Opex (***)	€/t CO_2 avoided	12	30
Energy	GJ/t CO_2 avoided	1.1	8.1

Note.
(*) *Capex Capital charge@15%* refers to the annualized CAPEX assuming 15% capital charge divided by annual CO_2 savings (t CO_2/a)
(**) Capital Charge (CC) is defined as the annual revenue (net of opex and expressed as % of capex) before tax necessary to achieve a certain Internal Rate of Return (IRR). Note that the relationship between CC and IRR depends on a number of factors including project life, inflation, tax rate etc. In Western Europe, we are assuming 15% CC corresponds roughly to 8% IRR.
(**) *OPEX* included in the table are non-energy related ones).

5. OVERALL ASSESSMENT METHODOLOGY

5.1. REFERENCE CASE

The Concawe BMDB was used to establish a sound reference case in terms of energy balance as well as plant capacities and production figures for items such as refinery fuel composition and hydrogen which are crucial to emission intensity. The figures were then prorated to a 2030 reference case using data from Concawe, [Concawe 1/13R] including product demand forecasts and known changes to the configuration of the EU refinery population (including closure of some sites). This 2030 reference case assumed, however, **no progress in either energy or CO_2 emissions intensity from the 2008 level**.

The 2030 reference case has been used for both 2030 and 2050 time horizons to explore the potential of the technologies identified in the study isolated from demand forecast (which would be addressed in detail in an on-going Concawe's *Refinery 2050* report).

The crude intake, energy use and GHG emissions of the 80 refineries in operation today in the EU are shown in **Table 5.1-1**, as actual figures for 2008 and as the projection for 2030.

Table 5.1-1 Crude Intake, Energy use and CO_2 emissions for the EU-28 Refinery System

		2008	2030 ref	Change
Crude intake	Mt/a	604	513	-15.0%
Total energy consumed (1)	PJ/a	1735	1648	-5.0%
Total energy spent (2)	PJ/a	1822	1686	-5.0%
Ref fuel production	PJ/a	1624	1543	-5.0%
Direct emissions	Mt CO_2/a	122	116	-4.6%
Total emissions	Mt CO_2/a	131	125	-4.6%

(1) Refinery fuel plus net heat and power imports
(2) Refinery fuel plus net heat and power imports expressed as primary energy

Note. The declining in total EU refining throughput does not translate into a steady decrease in total energy requirement as more energy-intensive processing is required to satisfy the increasing demand for lighter and lower Sulphur products [*Concawe report 1/13R*].

Demand trends are likely to increase the need for hydrogen for hydrotreatment and hydrocracking. In the short term, changes to the marine market will have a large impact on refinery operations and in particular the hydrogen consumption. The 0.5% sulphur specification for marine fuels adopted by the IMO, starting in 2020, can be met in essentially two different ways: either fuel desulphurisation in the refinery or installation of scrubbers on ships. There is considerable uncertainty as to the uptake of the scrubber technology by ship owners as it will be affected by technical as well as financial factors. In line with the recent study by Ensys, [Ensys 2016] we have assumed a scrubber uptake of the equivalent of 20% of the marine fuel demand (although some suggest that this could be larger beyond 2020, allowing for a rebound of high sulphur marine bunker demand). In the reference case the resulting hydrogen demand is assumed to be produced through conventional processes, mostly SMR with some SNR and POX.

These changes are assumed to be fully in place by 2030. Beyond that, no major changes are foreseen that would greatly increase hydrogen consumption relative to intake. **Table 5.1-2** shows the 2008 actual figures and the 2030 projections for the traditional hydrogen production routes (steam reforming of natural gas (SMR), steam reforming of LPG/naphtha (SNR) or partial oxidation of various feedstocks (POX)).

Table 5.1-2 Hydrogen production for EU-80 refineries and associated CO_2 emissions (Source [Concawe report 1/13R])

	2008	2030	Emissions 2030	
			Process	Total
	kt/a		Mt CO_2/a	
Total	1338	2182	15.7	24.1
SMR/SNR (90/10)	1047	1560	8.8	16.0
POX	291	622	6.8	8.0

Note: “Total” CO_2 emissions includes both process and combustion emissions.

With regards to electricity imports, the reference case is based on the 2008 grid emission factors. The reduction of the latter over the years results in a structural decrease of total emissions associated with refinery operation.

5.2. EVOLUTION OF ENERGY SUPPLY NETWORKS

Future estimates need to reflect expected changes in the CO_2 intensity of external networks.

Table 5.2-1 shows the expected evolution of the EU electricity grid. The 2008 figures are historical, with 2030 figures estimated by the JEC consortium in the context of their Well-to-Wheels study. The EU’s 2050 aspiration is for the grid to be substantially decarbonised (90% in 2050 [EU 2016 1]). We have assumed a residual emission factor of 40 t CO_2/GWh (a/o to account for the efficiency of CO_2 capture). The efficiency figure for 2050 is difficult to estimate as it will be heavily impacted by the options exercised to decarbonise the grid. Wind or solar are credited with 100% efficiency but use of CO_2 capture would increase energy use significantly. We have therefore used the same figure as for 2030.

Table 5. 2-1 Efficiency and GHG Emission Factor for EU “grid-average” electricity

		2008	2030	2050
Efficiency	kWh_e/kWh_p	0.37	0.59	0.59
Emission factor (generation + losses to HV)	t CO_2/GWh	430	211	40

The carbon-intensity of the gas supplied via the gas grid may also decease, due for example to increased production of biogenic methane from anaerobic digestion [EBA 2016; Eurostats 2016], of bio-SNG from gasification + methanation [E4Tech 2010] or because of H_2 injection linked to energy storage [IEA-H_2 2015]. For illustration, we have assumed that the carbon-intensity of imported gas falls 10% by 2030, and 20% by 2050.

This potentially affects both combustion and process emissions from hydrogen production (note, however, that other measures such as efficiency improvements and increased use of electricity will reduce and, in some cases, remove the impact of this change).

5.3. MODELLING AND STUDY CASES

5.3.1. Modelling approach

All quantified parameters discussed in **Section 4** were entered into a spreadsheet model representing the combined EU refineries. Starting from the 2030 reference case as per **Section 5.1**, options were introduced in a stepwise manner in the order in which they are discussed in **Section 4** namely:

1. Electricity grid decarbonisation (impact on historical electricity imports)
2. Self-produced fuel measures
    a. Reduction / elimination of liquid fuel burning
    b. Fuel gas purification
3. Improved energy efficiency in process units, including reduction of flaring
4. Use of low-grade heat for export (a/o district heating) and electricity production
5. Increased use of electricity for general purposes (a/o mechanical energy)
6. Intermittent use of low-carbon electricity for steam production
7. Replacement of end-of-life CHP plants by imported (low-carbon) electricity, with option for electric boilers to produce steam deficit
8. Import of “green” hydrogen (intermittent and continuous, the latter limited by internal fuel gas production)
9. Replacement of conventional fired boilers and process heaters by electric heaters (limited by internal fuel gas production)
10. “Greening” of the gas grid
11. CO_2 capture

Points 1 and 10 are effectively “windfalls” from external developments outside the control of refiners.

Point 2 groups changes in the refinery fuel diet that are on-going in most refineries. They have been considered first as they are very likely to be in place across the sector within the time horizon considered. Together with points 4 to 9 they belong to the generic “low carbon footprint energy” theme.

Energy efficiency improvement (point 3) has been a long-term pursuit in all refineries and will continue, albeit at different rates in different refineries, irrespective of other emission reduction measures that might be introduced. Although flaring cannot be eliminated altogether for operational and safety reasons, there is still scope for reduction.

Apart from point 2 and 3, other options may not all be introduced in a given refinery. Certain options are in fact competing against each other (e.g. 8 and 9 for the substitution of gas imports). As alluded to in **Section 4.1**, the scope and impact of each option on CO_2 emissions reduction is, to an extent, a function of its assumed position in the sequence: the emissions that can be saved by improved energy efficiency are in direct relation to the carbon footprint of the energy sources while the higher the energy efficiency, the lower the gas imports and the lower the scope for substitution by electricity.

The results discussed below therefore only give an estimate of the overall potential impact of each option across the sector.

To provide a more straightforward overview we have also grouped the options described above into four broad categories:

- Energy efficiency
- Low (fossil) carbon energy
- Low carbon hydrogen import
- CO_2 capture

5.3.2. Horizons, main case and sensitivity analysis

This study addresses two time horizons: up to 2030, for which current trends and technology outlooks allow for reasonably certain projections; 2030 to 2050, for which both demand outlooks and technology developments are more speculative. For each time horizon we have considered a **"Median" case** (as the main scenario) as well as "Low" and "High" sensitivity cases with, for each:

- a set of energy and CO_2 prices, consistent with authoritative studies such as [IEA-WEO 2017] or [EU 2016 2],
- a maximum rate of uptake for certain options, consistent with the economic environment and what we considered practical and plausible at the time horizon.

Table 5.3.2-1 summarises the main parameters relevant to each case.

It has to be noted that:

- The price structure used for the "Low" cases do not favour electrification, with high electricity, low gas and low CO_2 prices. The "High" cases are at the opposite end of the scale, with potentially attractive economics for electrification.
- In the "Low" cases investment in energy efficiency projects is curtailed by the low 2.5-year PBT threshold (i.e. only projects that have a very high rate of return are allowed). A 5-year PBT threshold, close to what can be considered as standard industry practice, was used in all other cases.
- The 2050 "Median" case achieves limited CO_2 savings describing a scenario with limited electrification, no access to electrolytic hydrogen on a continuous basis and limited CCS penetration. In addition to this, in the 2050 "Median" and "High" cases, we have illustrated three competing routes to deep decarbonisation namely electric boilers and heaters (Max-e), electrolytic hydrogen (Max-h) or CCS (Max-c).
- In both Max_e and Max_h, general purpose electrification and substitution of CHP plants are maximised. The remaining scope for substitution of gas imports is fulfilled by electric heaters in Max_e and imported electrolytic hydrogen in Max_h. In Max_c, no additional electrification is envisaged. CCS is applied to refinery emissions in all cases but the impact is reduced in Max_e and Max_h because of the already reduced site emissions. In these two cases, all capture energy is supplied as additional imported electricity. In Max_c most of the capture energy is supplied as gas.

Table 5.3.2-1 Modelled cases

Time horizon		2030			2050				
Case		Low	Median	High	Low	Median	High		
Prices									
Natural gas	€/GJ	8	11	15	8	13	17		
Electricity	€/MWh	150	98	60	160	100	60		
CO_2[1]	€/t	25	35	75	25	90	150		
Electricity grid EF	t CO_2/GWh	211			40				
Renewables in NG grid	%	10%			20%				
Process energy		As per model described separately (section 4.3.5)							
Pay Back Time threshold	Years	2.5	5.0		2.5	5.0			
CO_2 capture	%[2]	0%			0%	25%	50%		
					Low	Median	Median / High		
Mode[3]							Max el	Max Hy	Max C
Electrification[4]	%[5]	0%		1%	0%		3%		0%
CHP plants									
Substitution	%[6]	0%			100%				0%
Electric boilers option					Where cost-effective				
Electric boilers and heaters	Y/N								
Intermittent[7]		N	Y	Y	Y	Y	Y	Y	N
Continuous[8]		N	N	N	N	N	Y	N	N
Electrolytic hydrogen	%[9]								
Intermittent[10]		0%	0%	25%	0%	50%	0%	50%	0%
Continuous[11]		0%	0%	0%	0%	0%	0%	[12]	0%
Low-grade heat export	%[13]	5%			10%				

[1] Only used as input to the process efficiency model

[2] % of refining capacity applying capture (after application of all other measures). Subject to 90% capture rate in participating sites for hydrogen-related emissions and 70% overall.

[3] Maximum electrification, elecrolytic hydrogen or CCS

[4] General purpose a/o mechanical energy (5-14%, 6.5% average in 2008)

[5] Increase from base case in % of total energy delivered as electricity

[6] % of existing cogeneration capacity taken out of service and replaced by imported electricity and electrically raised steam (39% of total refinery electricity consumption in 2008)

[7] Using intermittent cheap renewable power, limited to utility boilers

[8] Applied to all heaters incuding process. Scope limited by availability of fuel gas

[9] % of total hydrogen demand (1400 kt/a SMR hydrogen in 2030 base case)

[10] Using cheap renewable power 10% of the time

[11] Using average grid power

[12] As limited by FG production

[13] % of total available low-grade heat

6. RESULTS

For each case and each option, the model produced an estimate of

- the **energy and emissions savings** from the reference case (both direct, i.e. related to the refinery site and "total", i.e. including production of imported electricity and hydrogen),
- the associated **capex** and extra **opex** (over and above energy cost),
- the **CO_2 abatement cost**, calculated as:
  - capex (annualised with a 15%/a capital charge), opex and cost of imported energy,
  - minus the value of energy savings plus, where appropriate, a credit for saved capex and opex,
  - divided by the achieved CO_2 emission reduction (either direct or total).

The detailed outcome is shown in **Appendix 1**. The main findings are discussed below.

6.1. PROCESS ENERGY EFFICIENCY

The model described in **Section 5.3.** was applied to the six cases above to estimate the level of process efficiency improvement that could be achieved together with the associated capex and opex (**Table 6.1-1**).

Table 6.1-1 Process energy efficiency improvement

Case		2030			2050		
		Low	Median	High	Low	Median	High
Energy saving	% of ref case	6.9%	17.5%	19.9%	8.6%	21.2%	22.7%
Capex	G€	0.7	6.3	8.7	0.7	8.3	10.5
Opex	G€/a	0.11	0.61	0.93	0.13	0.93	1.19
Annualised[1]	G€/a	0.52	1.30	2.49	0.60	2.32	3.34

[1] at 15%/a capital charge

The model is driven by economics, responding to energy and CO_2 prices and to the allowed payback time (PBT) threshold: a higher PBT allows projects that have a lower rate of return whereas higher energy and CO_2 prices increase the rate of return and therefore reduce the PBT of individual projects allowing more such projects to be undertaken within a given PBT threshold.

6.2. CO_2 EMISSIONS REDUCTION POTENTIAL

Figure 6.2-1 shows the potential reduction in CO_2 emissions both total and direct (at the refinery) for the 2030 and 2050 "Median" cases. The error bars show the range of variability according to the related sensitivity cases.

By 2030 modest gains of 20-29% can be achieved. This can increase up to about 63% by 2050 but successful large-scale electrification and CO_2 capture would be key to achieve such reduction figures. In the "Median" cases direct emission reduction are more or less the same as these cases involve limited electricity imports.

Where the latter are significant, total emission reductions are lower than direct ones because of the emissions incurred for electricity production.

Figure 6.2-2 shows the breakdown of reductions according to the categories of options, for the 2050 sensitivity cases.

The energy efficiency improvements discussed in **Sections 4.3 and 6.1** together with flaring reductions, translate into commensurate emission reductions (note that flaring figures were relatively high in 2008 so that reduction figures are significant. A large proportion of these reductions are believed to have already been achieved today).

Introduction of low-carbon energy provides the next block of reductions. This block includes reduction and eventual elimination of liquid fuel burning and substitution by imported gas which accounts for 5% reduction in 2030 and over 6% in 2050 (note that the base case refers to the situation in 2008 and recent data suggests that this has already been implemented in most EU refineries). The balance is essentially achieved by substitution of fossil fuel by imported electricity.

Low-carbon hydrogen has a more limited impact as it is limited to emissions related to on-site hydrogen production.

CCS deals with the balance of emissions from non-substitutable internally produced fossil fuels burned on-site (within the penetration and efficiency limits specified). The relatively “easy” capture from concentrated CO_2 streams from hydrogen plants represent 10-15% of the total captured emissions.

Eliminating fossil fuel imports by either pure electrification or a combination of electrification and (electrolytic) hydrogen imports yields similar overall reductions. CCS alone appears to be somewhat less effective but this is very contingent on the actual penetration of the technology. The penetration rates of 25% (Median) and 50% (High) are somewhat arbitrary but recognize the fact that not all sites will be in a position to apply the technology due to various constraints, mainly related to availability of suitable storage structures, see **Section 4.5.2**.

Table 6.2-1 further illustrates the variation of direct emissions (incurred on site) and indirect emissions (from production of imported electricity and gas) across the range of cases considered. Although it is tempered by the decreasing CO_2 intensity of imported electricity at the 2050 horizon, large scale use of electricity still results in a substantial increase of the share of indirect emissions.

Figure 6.2-1 CO$_2$ emissions reduction overview

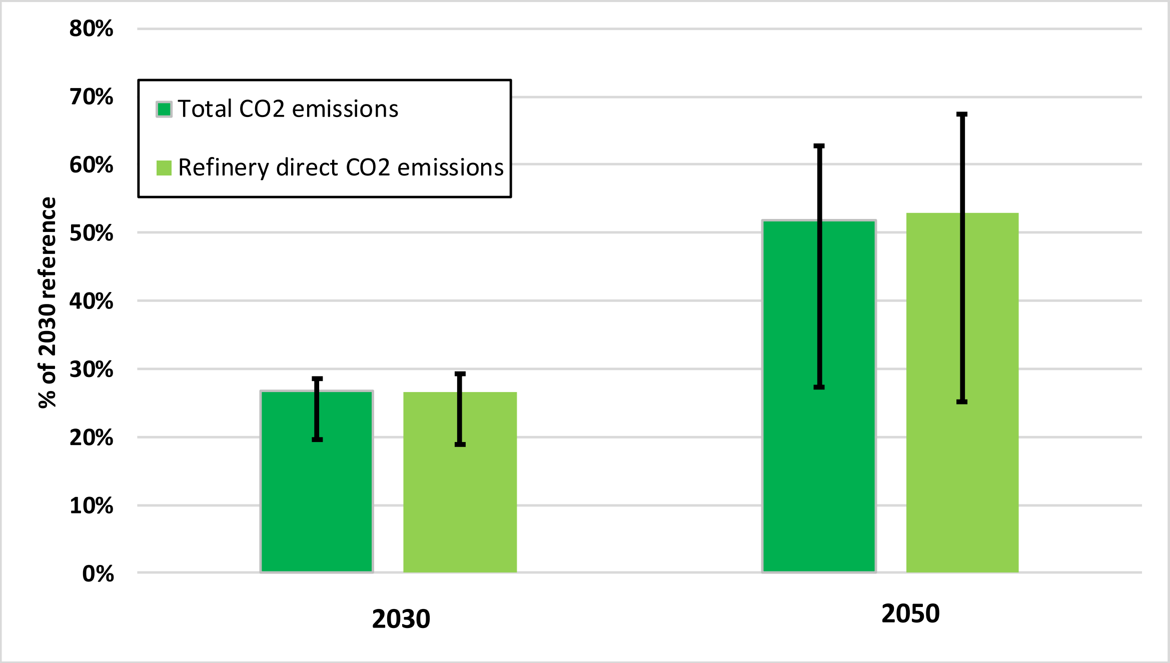


Figure 6.2-2 CO$_2$ emissions reduction: Sensitivity cases

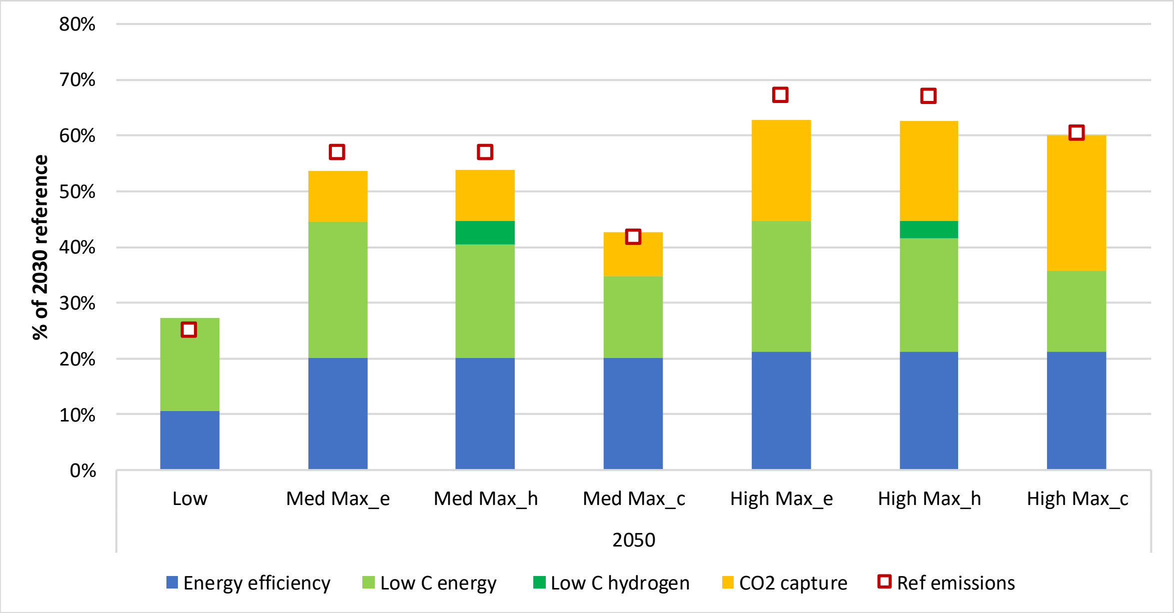


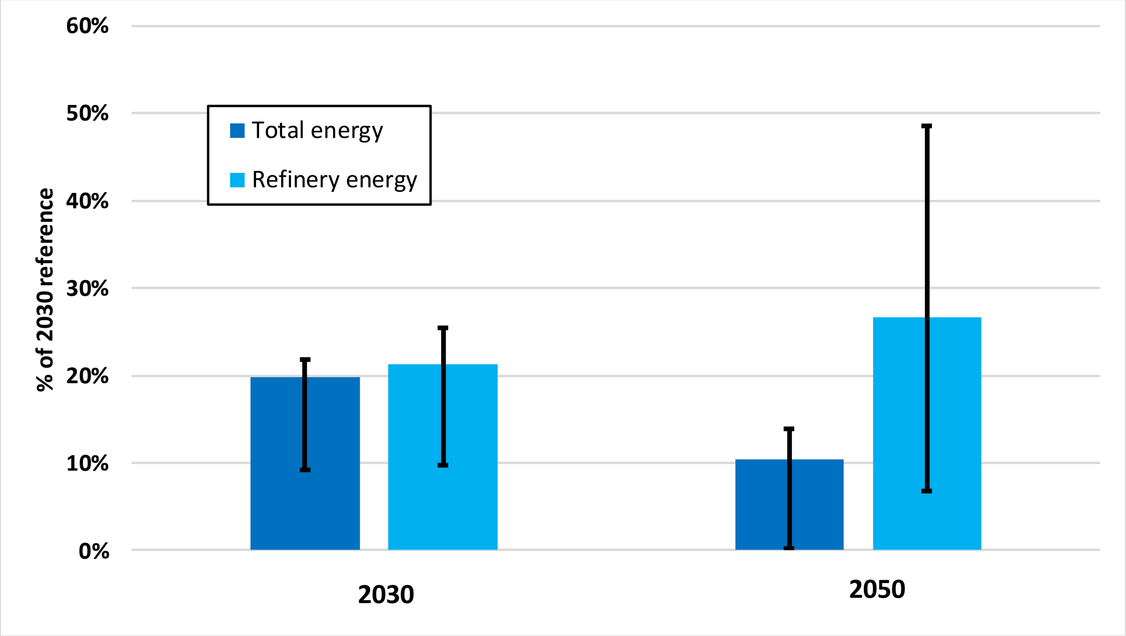
Table 6.2-1 CO$_2$ emissions overview (Mt/a)

Case	2030				2050							
	Ref	Low	Med	High	Low	Med	Med Max_e	Med Max_h	Med Max_c	High Max_e	High Max_h	High Max_c
Total	125.0	101.1	91.5	90.2	96.1	60.3	57.9	57.7	65.8	46.5	46.6	50.0
Refinery (direct)	116.0	94.8	85.2	83.9	91.9	54.7	49.8	49.7	61.6	37.8	38.0	45.2
Imports (indirect)	9.0	6.3	6.3	6.3	4.2	5.6	8.1	8.0	4.2	8.7	8.6	4.8
% of total	7.2%	6.2%	6.9%	7.0%	4.4%	9.3%	14.0%	13.9%	6.4%	18.7%	18.5%	9.6%

6.3. ENERGY CONSUMPTION REDUCTION POTENTIAL

Figure 6.3-1 shows the reduction in energy consumption both total and within the refinery for the 2030 and 2050 "Median" cases. The error bars show the range of variability according to the related sensitivity cases.

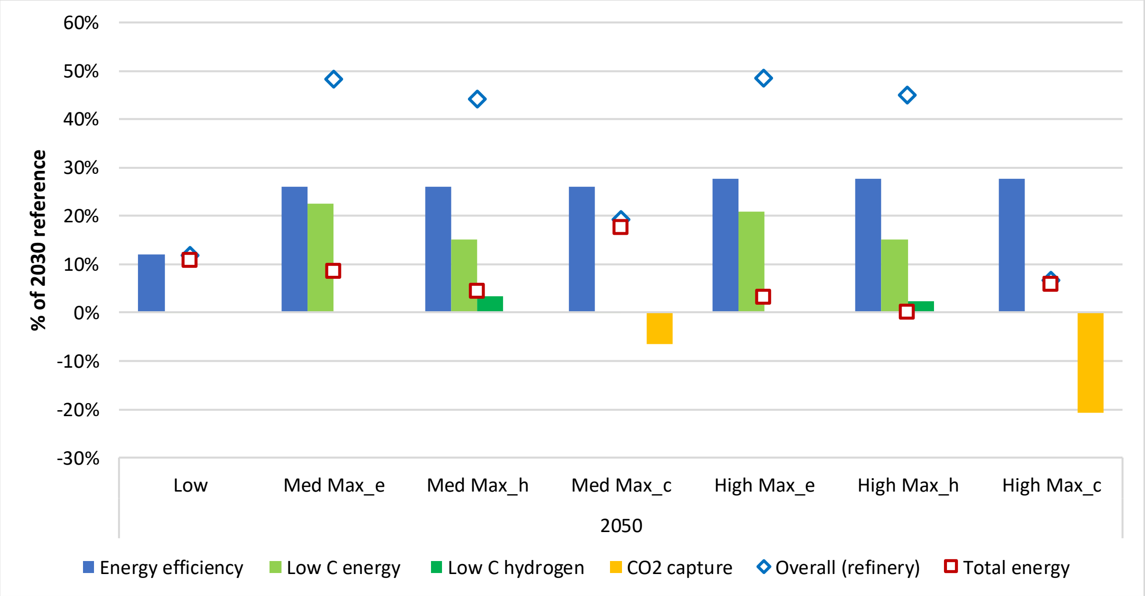
Figure 6.3-1 Energy consumption reduction



Refinery energy consumption is reduced by 10-25% by 2030 and 8-48% by 2050. A portion of these gains are, however, achieved by substituting on site fuel firing by imported electricity. As a consequence, total energy reductions are lower (particularly in 2050) as they take into account the energy consumed for electricity production. Note, however, that these figures are highly dependent on the assumed imported power production efficiency (see **Section 5.2**).

Figure 6.3-2 shows the breakdown of reductions according to the categories of options, for the 2050 sensitivity cases.

Figure 6.3-2 Energy consumption reduction: sensitivity cases



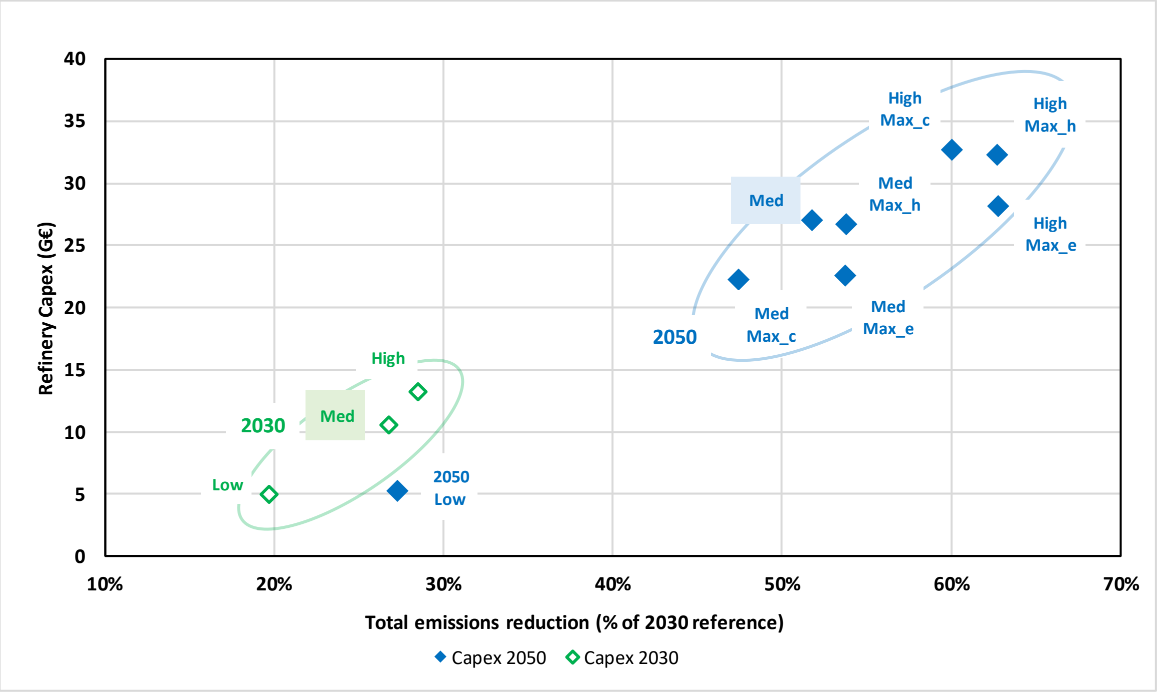
Note: the 4 columns refer to savings in the refinery, the "Overall" figure being the algebraic sum. "Total" energy refers to the net energy saving when taking into account imported electricity production.

Energy efficiency is the main contributor. As discussed above, electrification (including electrolytic hydrogen) is mostly energy substitution and does not translate into effective net savings. In the Max_c cases, the extra energy required by the *CO_2 capture* ***units*** is assumed to be supplied by imported gas accounting for extra refinery energy.

6.4. REFINERY CAPITAL AND OPERATING COSTS

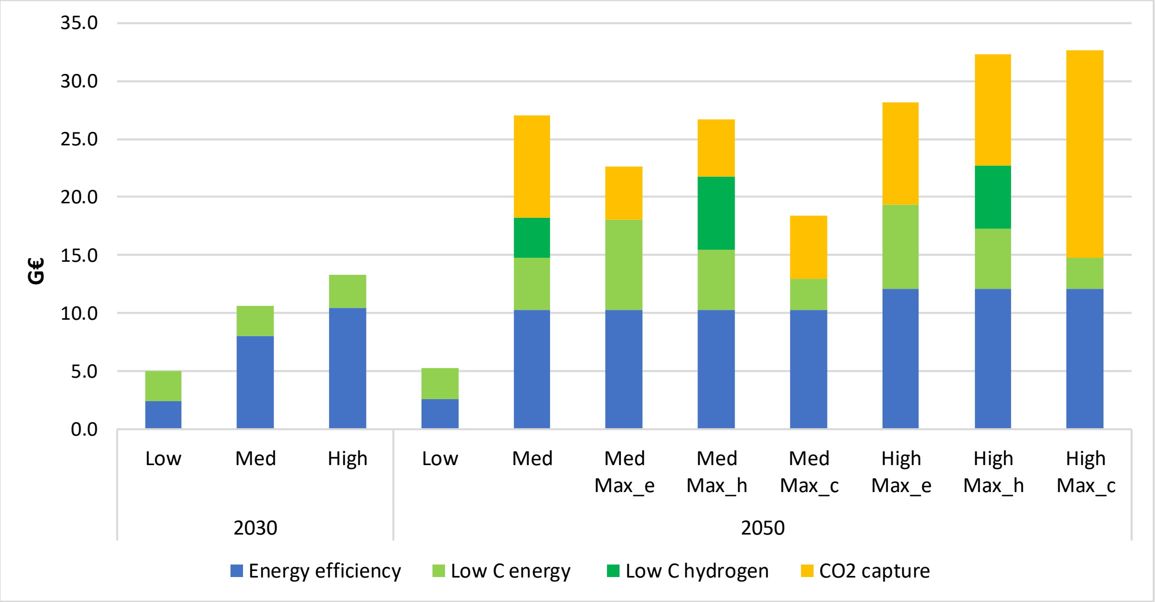
Figure 6.4-1 shows the total refinery capex against the total emission reduction achieved in each case. **Figure 6.4-2** illustrates the breakdown for selected cases.

Figure 6.4-1 Refinery capex and total emission reduction



Code. Max_Hydrogen (Max_h), Maximum Electrification (Max_e), Maximum CCS (Max_c)
Note: “Med” cases are highlighted as the main cases explored in the report

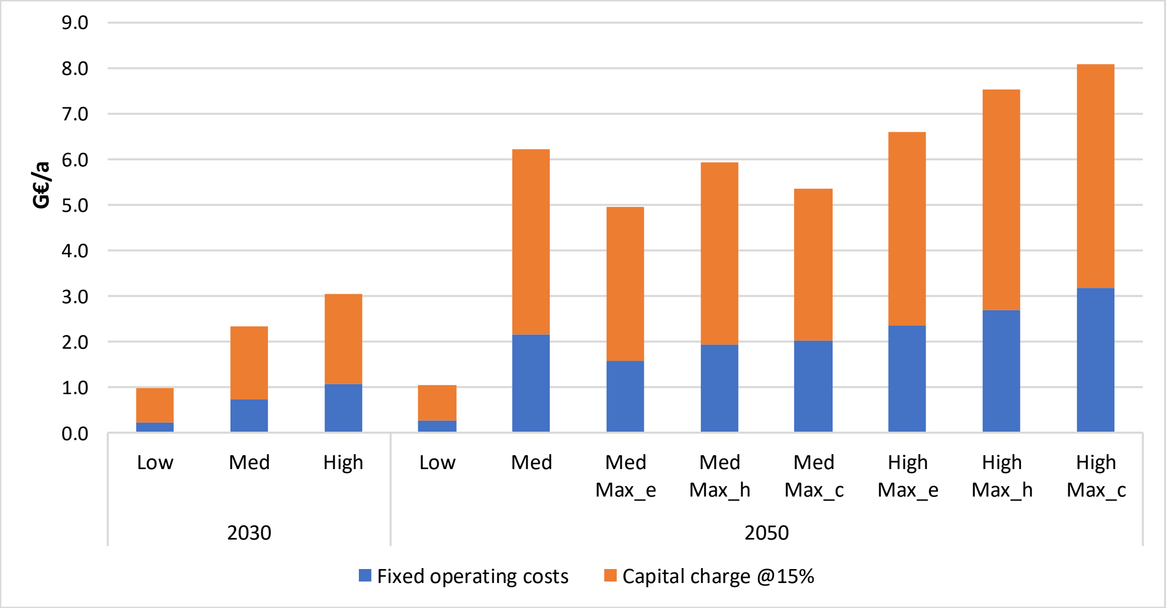
Figure 6.4-2 Refinery capex breakdown



In the 2030 cases (and the 2050 “Low” case), a large proportion of the capex is spent on process energy efficiency improvement. This accounts for a smaller share of the total in 2050 where significantly more investment is required for electrification and, where applicable, electrolytic hydrogen (note that intermittent hydrogen production is very capital intensive as it requires full scale facilities even though it is used only part of the time). CCS is capital intensive, the actual capex being obviously a function of the level of penetration of the technology.

Fixed operating costs account for a substantial proportion of the total annual fixed costs (**Figure 6.4-3**) especially relevant for the cases with significant penetration of new technologies such as electrolytic H_2 or CCS.

Figure 6.4-3 Breakdown of annual fixed costs



6.5. CO_2 ABATEMENT COSTS

The abatement cost of a particular option is determined partly by the capex and fixed opex required to implement it including the impact in terms of energy consumption (or savings).

Therefore, there is no unique single CO_2 abatement cost per technology as assumptions such as the energy prices considered in each scenario heavily affect the results. As an example, **Figure 6.5-1** plots the abatement cost of each measure, ranked from low to high, versus the cumulative CO_2 emissions savings, for the 2050 "Median" case.

Figure 6.5-1 CO$_2$ abatement costs *(Median case)*

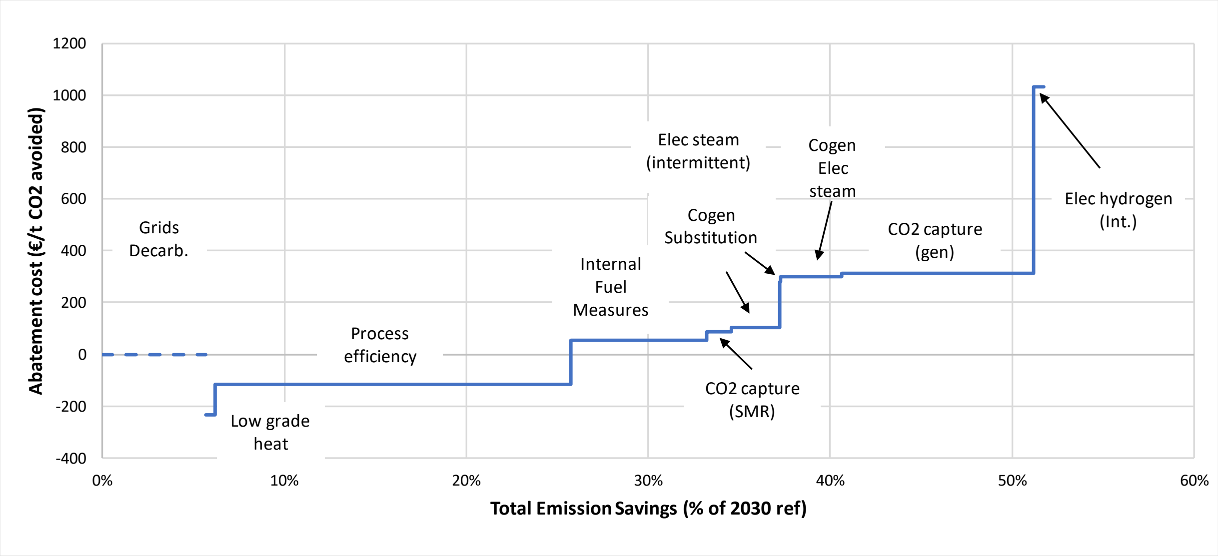
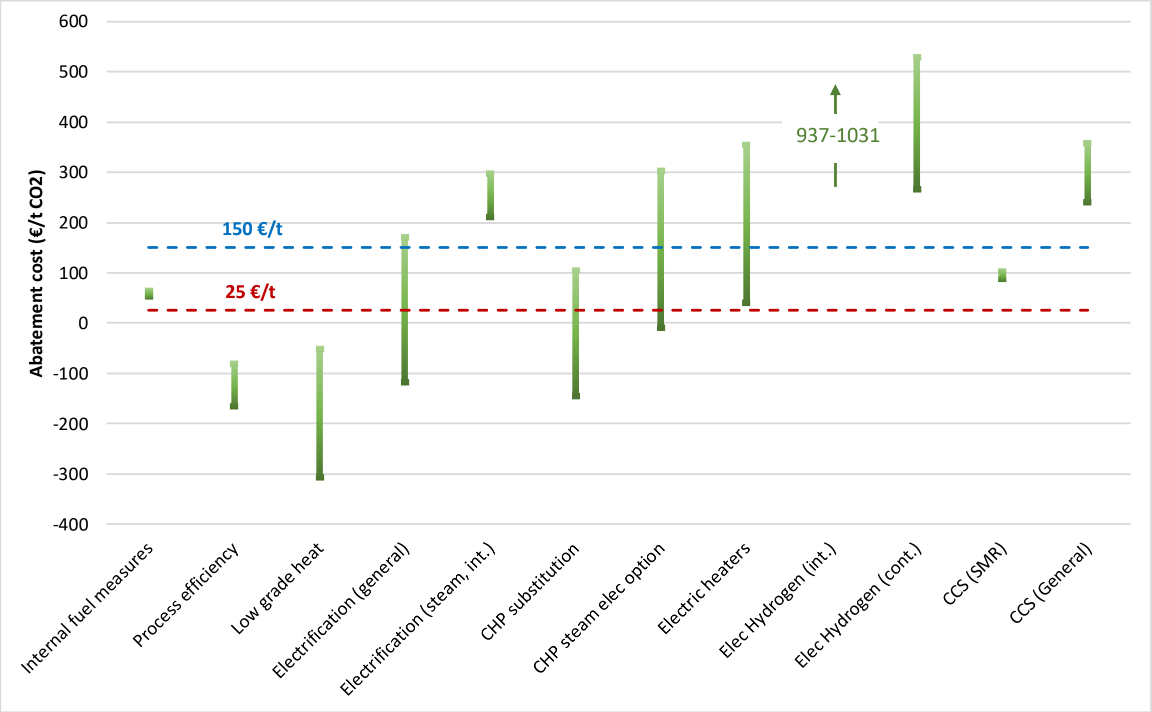


Table 6.5-1 and **Figure 6.5-2** give an overview of the abatement cost for all cases and all options along with the range of CO$_2$ prices as per **Table 5.3.2-1** Some costs are negative, meaning that the corresponding option is economic by itself, irrespective of the price of CO$_2$.

Table 6.5-1 CO$_2$ abatement costs (€/t CO$_2$)

	2030			2050							
	Low	Med	High	Low	Med	Med Max_e	Med Max_h	Med Max_c	High Max_e	High Max_h	High Max_c
Internal fuel measures	63	55	65	53	54	54	54	54	55	55	55
Process efficiency	-81	-95	-141	-84	-116	-116	-116	-116	-166	-166	-166
Low grade heat	-219	-109	-51	-307	-235	-235	-235	-235	-233	-233	-233
Electrification (general)			-117			171	171		-77	-77	
Electrification (steam, int.)					281	297	297		211	211	
CHP substitution					104	83	83		-145	-145	
CHP steam elec option					300	303	303		-10	-10	
Electric heaters						355			40		
Elec Hydrogen (int.)					1031		999			987	
Elec Hydrogen (cont.)							530			266	
CCS											
SMR					87	103	103	93	91	91	93
General					311	324	332	359	240	247	358

Figure 6.5-2 Range of CO_2 abatement costs per option



Note: the horizontal lines indicate the range of CO_2 prices considered in the different cases

Process efficiency has a consistently negative abatement cost. This is a consequence of the choice of the PBT threshold for such projects and of the calibration of the model. The 15% capital charge used for estimating all abatement costs on a consistent basis implies a PBT of 6.5 years for all projects whereas the process efficiency model considers a range of projects with PBTs up to 5 years. As a consequence, the energy savings projects make a better return than embodied by the 15% capital charge, hence the negative cost. The calibration of the efficiency model is based on average historical investment rate / PBT for the whole EU refining system and may be different for specific actors / regions resulting in higher or lower abatement cost.

Abatement costs are also directly influenced by the assumed energy prices (gas and electricity), e.g. low electricity prices can more than compensate the required investment for imports and result in actual savings.

The attractiveness of electrification options is directly related to the relative price of gas and electricity, hence low, mostly negative, abatement costs in the “High” cases and high in the “Median” cases. Intermittent use of electricity for steam generation is never very favourable because of the high capex involved for a low rate of utilisation. CHP substitution has relatively low cost even in the “Median” cases because of the capex credit involved in not replacing existing plants.

Electrolytic hydrogen is expensive due to the large associated capex and would only be economically deployed if implemented on a continuous basis with higher utilisation rates.

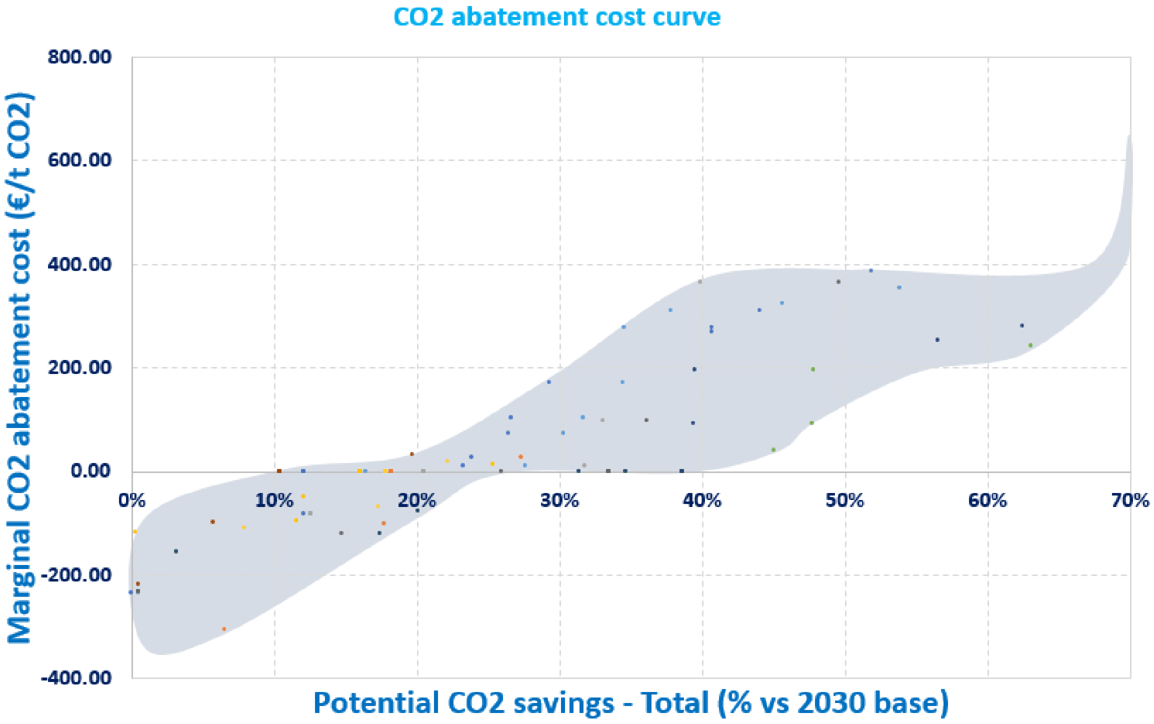
When applied to concentrated CO_2 sources, CCS achieves a modest abatement cost but remains expensive for the bulk of refinery emissions. It is in large part due to the high extra energy consumption of the process as envisaged today. Technology development could further decrease the costs and therefore the penetration potential of CCS.

Note: CCS abatement costs estimated here are significantly higher than quoted in SINTEF, 2017. There are three main reasons for this

- SINTEF assumed a much lower price of natural gas than in this study (6.0 €/t versus up to 17 €/t),
- In this study "CO_2 avoided" refers to the net emission reduction, taking into account the emissions from the additional gas required to power the capture equipment, whereas it referred to CO_2 captured in SINTEF,
- This study accounts for additional cost for transport and storage (15 €/t CO_2 captured).

Figure 6.5-3 below plots the same data as **Figure 6.5-1**, now for all cases (for clarity and illustrative purposes, the envelope of all data points is shown). It illustrates how it becomes increasingly difficult to reach potential savings higher than 20-30% vs 2030 (in terms of CO_2 abatement cost). As the refining system progresses in the curve, less cost-effective technologies remain and the marginal technologies that would be required to reach savings beyond 50-60% see their cost effectiveness reduced in such a way that make their wide implementation unrealistic in all the sensitivity cases explored.

Figure 6.5-3 CO$_2$ abatement cost curve (Main scenarios and Sensitivity cases)



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8. GLOSSARY

CCS	CO_2 Capture & Storage
CCU	CO_2 Capture & Utilisation
CDU	Crude Distillation Unit
Chemical CO_2	CO_2 emitted by carbon-rejecting reactions, not from fuel burning
CHP	Combined Heat and Power plant
CO_2	Carbon dioxide
ETS	Emissions Trading Scheme
EU	European Union
FCC	Fluid Catalytic Cracker
GHG	Greenhouse gases
HDS	Hydrodesulphurisation unit
IEA	International Energy Agency
IMO	International Maritime Organisation
JEC	JRC-EUCAR-CONCAWE consortium
LCOE	Levelised cost of Electricity
LDV	Light Duty Vehicle (i.e. car)
LPG	Liquid Petroleum Gas
LNG	Liquified Natural Gas
MCFC	Molten Carbonate Fuel Cell
NPS	IEA "New Policies Scenario"
NOx	Nitrogen oxides
ORC	Organic Rankine Turbine
PBT	Pay-Back Time, years
POX	Hydrogen plant using Partial Oxidation technology
SMR	Hydrogen plant using Steam-Methane Reforming technology
SNR	Hydrogen plant using Steam-Naphtha Reforming technology
SOFC	Solid Oxide Fuel Cell
SolarPV	Solar Photovoltaic electricity generation
SOx	Sulphur oxides
toe	Tonne of oil equivalent (= 10 Gcal or 41.868 GJ)
VDU	Vacuum Distillation Unit

APPENDIX 1: REFINERY PROCESS TECHNOLOGY

This appendix provides a brief overview of external reports then a summary of Concawe literature reviews and consultation with technology providers and member companies.

A1.1 Process Technology - Third Party Overviews

Various organisations have attempted to define the maximum potential for refining energy efficiency [e.g. ICF 2016; US EPA 2015; US DoE 2015, UK DECC 2015]. Nearly all address improvements to the core refining processes through digital systems (e.g. advanced control, sensors and monitoring), improved catalysts and process additives, improved heat transfer and heat integration, improved hardware and reaction design, and new process technology. The refinery press contains many articles [e.g. Spoor 2006, Spoor 2008, Mertens 2009] about the role of technology in improving refinery energy efficiency and mitigating greenhouse gas emissions.

The ICF report for DG-Energy (Figure 3.6.3 in [ICF 2016]) suggests there is a technical potential to reduce energy intensity by ~25% relative to "business-as-usual by 2030. Of this only ~1/3 was expected to payback within 5 years. It identifies process control, catalysis and process integration as the top three opportunities for energy efficiency improvement.

The US DoE has issued "energy bandwidth" studies in 2006 and 2015. These provide a semi-theoretical assessment of the energy intensity of key refinery processes at three different levels of technology development; these data are provided in **Table A1.1-1**. It suggests that the key technical areas for efficiency improvement are column design/configuration for crude distillation, fouling control, rotating machinery (e.g. compressors) and heat-transfer/heat integration.

Table A.1.1-1 Energy Intensity Data from US DoE Bandwidth Study
(Source: US DoE 2015, Appendix A)

PROCESS	Energy Intensity MMBTU/bbl			% difference between	
	CT	SOA	PM	CT to SOA	SOA to PM
Atmospheric distillation	109	94	57	14%	40%
Vacuum distillation	89	77	54	14%	29%
Fluid catalytic cracking	183	158	133	13%	16%
Hydrocracking	159	139	107	13%	23%
Hydrotreating	81	69	52	15%	24%
Catalytic reforming	264	233	178	12%	23%
Alkylation	247	219	154	11%	30%
Coking	148	132	85	11%	35%
Isomerisation	216	193	122	11%	36%

Key: CT =current typical; SOA = state-of-the-art; PM =practical minimum

For the purpose of this study, the US DoE "Energy Bandwidth Study" [US DoE 2006 & 2015] are useful because they consider both the application of existing technology and the opportunity for future R&D. The 2015 version estimates the energy intensities for nine refining processes at three levels of technology development: "current typical" (CT), "state-of-the-art" (SOA) and "practical minimum" (PM). Firstly, this helps identify the energy savings potentially attainable through capital investments in the best technologies available today, quantified as the difference between CT and SOA. Secondly, it identifies the "R&D opportunity" i.e. the energy saving potentially attainable through deployment of technologies which are still being developed and currently are not commercially available; this can be quantified as the difference between SOA and PM. We should note that this is "technical potential" is (a) not necessarily operationally practical and (b) not necessarily economically viable. It also is based on an assessment of US refineries which are designed for a different product slate, and operate under different regulations and market pressures.

The DoE study also reports a theoretical "thermodynamic minimum" (TM) energy intensity, calculated from scientific principles assuming ideal conditions and perfect processes. However, the DoE notes that this is "unachievable in real-world applications" and has "thermodynamic limitations which impede technology opportunities". This may be interesting from a theoretical perspective, but provides little guidance about what might realistically be anticipated in the future; we have therefore not considered the DoE's TM figures".

The percentage improvement for conventional technology ("Current Typical" to "State-of-Art") is in the range 10-15%. Note that this is the saving per implementation, not the potential saving for the industry as a whole - by definition, some sites already use "state-of-the-art" technology; others may find that "state-of-the art" technology is not economically justifiable. The US DoE report includes "conventional" opportunities such as process control, process optimisation and heat integration, but also cites "unconventional" technologies such as progressive distillation and process-CHP. These have been demonstrated in niche locations, but are only suited to new builds and have not shown wide applicability.

The percentage change for improved process technologies ("State-of-art" to "Practical Minimum", described by the DoE as "R&D Opportunities") are generally larger (15-40%). This includes "short-term" developments which are extensions of existing processes (e.g. heat recovery, inter-unit heat integration, catalyst developments) and so have a good chance of success. It also includes technologies which have been demonstrated for small "clean" applications (e.g. catalytic distillation; membrane separation) but would be very difficult to apply to large, complex applications such as crude-oil treatment. Finally, it includes some very speculative alternative research concepts such as freeze separation of crude and non-H_2 desulphurisation chemistry. It is not a foregone conclusion that the R&D will actually occur or that it will be successful, or that the new technologies will be economically viable or suitable for retrofit in existing refineries. This suggests that the DoE's assessment for new technologies is very optimistic.

A1.2 Process Technology – Detailed Review

A1.2.1 Separation / distillation

Crude and vacuum distillation accounts for ~20% of refinery energy use, so the operation and equipment installed in these units is scrutinised in most refineries. Conventional approaches include operational management of fired-heaters and recycle rates, state-of-the-art column internals, design/control of heat-exchange networks, preflash- and prefractionation-columns and product strippers. Some refineries in Europe have already deployed these technologies, although the commercial drivers may include crude throughput, fractionation quality or crude-slate flexibility as well as energy efficiency.

Fouling has a large impact on crude units, perhaps increasing energy consumption per barrel as much as 10% between cleaning cycles; this may result in lower throughput as opposed to increased energy use. The US DoE (US DoE 2015) claims that elimination of fouling might be equivalent to ~2% improvement in refinery energy, however it is hard to eliminate entirely and may become more significant as the EU crude slate evolves. The science of fouling is complex, and the mechanism of fouling may depend on the crude or crude-blend.

Mitigations for fouling include heat-exchanger design, additives, crude scheduling and desalter operation, however, their effectiveness may be crude/unit specific. This means that hardware options (e.g. "fouling-resistant" heat-exchanger designs) are not applied as widely as might be expected, partly because it is hard to predict their effectiveness, and partly because they can only be installed during turnarounds. Additives which work in some circumstance may fail in others (e.g. different feed, unit design, unit operating conditions) and may have consequences for downstream equipment particularly catalysts. Another approach is regular chemical cleaning of heat-exchanger trains (although this may reduce throughput while a set of exchangers is offline for cleaning.) Fouling is a major topic for the industry, so one might expect to see improvements in the science and technology, and wider/more effective implementation of mitigation technologies enabled by better performance monitoring.

Some approaches cited as energy-efficiency measures for distillation are primarily "new-build" options which only have limited applicability for existing refineries in Europe. These include:

- Multi-column "progressive distillation"– this is claimed [OGJ 1997] to offer >10% improvement in energy efficiency compared with conventional systems. Deployment is probably limited only to new units; only one full progressive distillation unit has been built for crude oil separation. Conventional approaches such as preflash- and prefractionation-columns offer some of the benefit for lower cost e.g. [Bealing 2016; Martinez Valino 2008].
- "Divided Wall Columns" (DWC) and "Highly-integrated Distillation Columns" (HiDiC) – these are mechanically complicated and better suited to fractionation of light products than crude. A handful of refineries are using DWC for smaller-scale applications such as reformate splitting [OGJ 2016; Polovina 2016]. More installations might be expected but the overall impact on refinery energy use is very small.
- Membrane separations are often cited as "low-energy" but current applications are mainly for light gases (or for water purification. Separation of gasoline by membrane was demonstrated in a short refinery trial [Zhao 2004]., but operation was discontinued after a few months. Fouling is a big problem with membranes, so one might expect any future refinery use to be limited to gases or possibly light-ends separation, but not heavy feeds such as crude.

The EU refining industry has the potential to approach "state-of-the-art" for conventional technology, but very limited potential to deploy new separation concepts.

A1.2.2 FCC

Fluid Cat Crackers (FCCs) account for ~17% of refining energy consumption, but have a bigger impact on CO_2 emissions because they burn high-carbon fuel (catalytic coke). On the other hand, they also cogenerate HP steam and in some cases electricity. Conventional FCC energy efficiency measures are well known. They include optimisation of dispersion and stripping steam, optimisation or electrification of compressor and blower drives and advanced control.

Production of FCC coke is one of the ways that refineries adjust the carbon/hydrogen ratio of the crude to match the desired carbon/hydrogen ratio of the products. Coke impairs the performance of the catalyst by blocking its pores so must be removed to keep the catalyst in operation. Combusting the coke not only cleans the catalyst, but is an efficient way to provide the process energy to run the unit. Some FCCs, however, produce more than enough coke to satisfy the FCC unit itself and use the surplus heat to produce HP steam. The driver for this is normally high conversion or throughput through the FCC, but in principle operational changes (feed quality, catalyst and process conditions) might allow this to be reduced. The shortfall in steam could be made up using a lower-carbon energy source.

Electricity may be generated from hot FCC flue-gas using a turbo-expander; this might provide up to 20 MW_e on a large FCC [Couch 2010, Sutkino 2010] leading to %level improvements in energy efficiency. These are expensive projects (several tens of $million + site integration costs) with long payback times and historically have not generally been economic. Today about ~10% of EU FCC units are equipped with flue-gas expanders [Concawe BMDB].

R&D aimed at mitigating of FCC CO_2 emissions has led to a semi-commercial trial of an advanced "Oxy-fuelled FCC" concept [de Mello 2015]. The concept facilitates carbon-capture-&-storage by providing a flue-gas with high CO2 content (> 90%). The cost of retrofitting to existing units could exceed $250 million for a typical FCC (CCP data), requiring incentives of > 100 \$/t CO_2. Significant deployment in Europe seems very unlikely much before 2050.

More speculative long-range concepts include:

- New catalysts – most catalyst R&D is aimed at improving stability and catalyst selectivity, including coke formation [Vogt 2015]. This is however optimisation of the existing process - a deep reduction in coke production is unlikely.
- "Cold Cracking" is a laboratory-scale alternative technology using unconventional energies such as microwaves, ionising radiation, photochemistry or ultrasound [NETL 2006]. Progress seems slow; if something viable does ever emerge then it is still at least a decade from commercialisation and would have little relevance to existing FCCs in Europe.

There is probably little relevance to European refineries, even after 2030.

Trends in gasoline demand suggest that the overall value of FCC is likely to decrease in the future, but they remain the main "conversion unit" in many EU refineries and thus a significant contributor to the refinery margin. It seems unlikely that there will be major FCC investments across the industry but their continued operation means that marginal efficiency gains are still likely. A lower net FCC throughput across the industry would in itself reduce the proportion of coke in the refinery fuel mix and have therefore a beneficial effect on CO_2 intensity.

A1.2.3 Hydrocracking and Hydrotreating

Refinery hydrotreatment covers a range of different processes, generally typified by operating pressure:

Low-pressure	< 30 bar	Naphtha and gasoline hydrodesulphurisation
Medium pressure	30-80 bar	Distillate hydrodesulphurisation and dewaxing
High pressure	80-150 bar	Hydrocracking, FCC pretreat

Common features include a packed bed reactor using a catalyst comprising cobalt, nickel or tungsten supported on alumina; hydrogen recycle to maintain adequate hydrogen partial pressure; operating temperature between 270 and 380ºC. In general, it is the high-pressure units which use the most energy (e.g. for make-up and recycle gas compression) and consume the most hydrogen. For example, the hydrogen consumption of a distillate hydrocracker might be ~120 Nm^3 H_2/m^3 compared with 20 Nm^3 H_2/m^3 for naphtha HDT. Energy-use and hydrogen-consumption both contribute to the carbon footprint, so this section concentrates on MP and HP units.

Conventional energy efficient measures include compressor design and operation, choice/design of motor and controller (e.g. variable speed), feed/effluent heat exchange, reactor internals and catalyst bed design for minimise pressure drop. Major design features may include inter-unit integration (e.g. with crude unit) to avoid use of cold feed; high-pressure units may have 2-stage separators and power-recovery turbines. These are hard to justify on energy saving grounds and might only be implemented as part of a major revamp/debottlenecking.

HDT catalysts have to be replaced every 2-5 years, which in principle allows frequent technology upgrades. Over the last 30 years, this has provided a steady improvement in the activity of conventional catalyst (usually employed to achieve longer run lengths hence unit productivity, or to treat more difficult feedstocks) but also the advent of high activity HDS catalysts (albeit with correspondingly high hydrogen consumption). The need for conversion or lower sulphur products generally outweighs any desire to minimise hydrogen consumption.

These development trends are expected to continue [Topsoe 2004; Weitkamp 2012]: improved R&D tools will allow faster and broader testing of ideas, but there is no expectation of a game changing breakthrough. However, it may well be possible to make a better compromise between yield/quality and hydrogen consumption using conventional technology; this might be enabled by digital technologies such as refinery-wide optimisation, process simulation or advanced control. For example, hydrogen consumption might be reduced by avoiding over cracking or by routing streams to avoid "re-hydrotreating" or "over-hydrotreating."

There is also academic interest in new reactor concepts which might be smaller, lower-pressure or more selective. Examples include channel/monolith reactors and heat-exchanger reactors. Once proven, these might well be options for new units post-2025, but replacement of existing HDT units would be hard to justify.

A1.2.4 Low and zero-hydrogen desulphurisation processes

There have been large-scale trials of processes which can remove sulphur-containing hydrocarbons from gasoline with little or no-hydrogen consumption, but these have not deployed commercially to any great extent. Research on adsorbents for low-hydrogen desulphurisation of jet or diesel continues in universities, but there is little experience via commercial-scale trials. There is also continued developer interest in "oxidative desulphurisation" processes which do not use hydrogen, but may require "high-energy" feeds such as ozone or hydrogen-peroxide. These processes lack the versatility and predictability of hydrotreating, and generally do not have such good yields and also compromise product quality. The lack of commercial experience suggests they are not ready to be deployed to help meet marine sulphur regulations. They may find niche applications but are unlikely to have a significant impact on CO_2 emissions from the refining industry.

Researchers have also investigated electro-desulphurisation which would be a disruptive concept for oil refining. R&D activity is low and it is barely beyond "proof-of-concept" using simple model feeds. Even if this was a research priority, it would take several decades to scale up to practical application. It would also need large amounts of "low-carbon" electricity and its implications for product quality are not yet apparent.

A1.2.5 Residue conversion technologies

The main residue conversion technologies are coking and residue hydroconversion. Residue hydrodesulphurisation which are specifically designed to remove sulphur while achieving a modicum of conversion is often included under this heading as it is technologically similar to hydroconversion.

Cokers are relatively rare in Europe (compared with the USA) so they are not major contributors to the industry's overall footprint. The process energy per unit is broadly similar to FCC but is lower-carbon because it is provided by gas or fuel-oil rather than FCC coke. Conventional energy efficiency measures include furnace optimisation, process control, fouling mitigation.

Residue hydrotreaters also are relatively rare but a few residue conversion units may be constructed in support of marine sulphur regulations. These have very high hydrogen consumption driven by conversion level, product quality and the need to suppress fouling. There are several commercialized technologies generally operating at > 100 bar, with different compromises between performance factors. The timeframe for marine sulphur regulations will generally "lock in" conventional residue HDT technology choices for 2030 and beyond. The opportunity for breakthrough "low hydrogen" technologies over this timeframe seems slim, although there will be long term opportunities for efficiency improvement probably in line with historic refining trends.

The remaining option is residue gasification for power, hydrogen (or syngas for petrochemicals use). This is expensive but is suitable for CCS.

A1.2.6 Catalytic Reforming

Catalytic reforming is a high-temperature process which converts low-octane naphtha to high-octane reformate. It is the main source of "octane" in most refineries owing to its high aromatics content. Some refineries also use cat reforming to make aromatics such as benzene, toluene, xylenes and ethyl benzene for the petrochemical feedstock; currently, > 80% of the EU's aromatics feedstock is made in refineries. Falling gasoline demand might lead to a slight reduction in overall cat reformer utilisation.

The process operates at high temperature and relatively low-pressure to drive the endothermic reactions which convert paraffins into aromatics and hydrogen. Hydrogen is recycled to prevent formation of coke on the catalyst, then recovered for use in LP- and MP-HDT units. Only a tiny fraction of the feed is converted to coke, which is removed by combustion to CO_2. This is generally not a significant part of the refinery's carbon foot print. The aromatics content (and octane rating) of the product depends very much on feed quality. Octane rating increases with reactor temperature, but this is generally limited by the design window of the unit.

Conventional energy efficiency measures include furnace design and operation, minimisation of pressure drop, feed-product heat exchange, process control. From an industry perspective, the key factor is unit design. Early catalytic reformers used a fixed-bed reactor, and a high hydrogen partial pressure to minimise coking. Despite this, reactors still had to be shut-down periodically to be regenerated; these were known as "Cyclic" or "Semi-Regen" catalytic reformers. This approach also set a limit on the octane rating and aromatics content. In the early 1970s, reformers with continuous catalyst regeneration (CCR) were introduced. These allowed the catalyst to be regenerated online, so CCR units could operate at lower pressure and higher temperature, thus boosting octane and hydrogen yield. Hydrogen from a cat reformer is a by-product thus is considered to have a lower carbon foot-print compared with hydrogen made on purpose by steam reforming natural gas. Compared with the Semi-Regen and Cyclic designs, a CCR makes more hydrogen per unit of feed thus reducing the amount of SMR hydrogen needed by the refinery. CCR technology thus reduces the overall carbon footprint of hydrogen supply.

CCR technology has tended to replace the earlier technologies for new units, however the longevity of refinery hardware means that many refineries have Cyclic- or Semi-Regen cat reformers built before CCR became proven technology. Although these units have poorer yields and may be costlier to run, these disadvantages generally do not justify replacing them with a CCR. Older units are slowly being replaced, but generally because the hardware has reached the end of its life ("Stay-in-Business" investment.) Operational optimisation may provide a small increase in hydrogen yield but no developments are foreseen within each cat reforming technology that would significantly enhance its hydrogen yields.

A1.2.7 Hydrogen optimisation and recovery

Significant quantities of hydrogen end up in refinery fuel gas which reduces direct CO_2 emissions. As long as hydrogen is produced from hydrocarbons without CCS, the net effect is however to increase overall emissions (10% recovery would reduce overall CO_2 intensity by about 0.5%). Hydrogen management (like EMS) can offer small improvements [Halele 2003; Sayles 2011], for example by identifying excessive HDT purge rates, but significant recovery requires hydrogen recovery technology such as PSA, membranes or cryogenic systems [Klein 2008]. Roughly a quarter of EU refineries already have some-form of hydrogen recovery although some of this may be linked to specific process units rather than fuel-gas in general. Equipment costs may run to several tens of millions, but reports suggest paybacks of more than 5 years in some cases (depending on refinery type e.g. type/pressure/number of hydrotreaters; size of FCC, etc).

A1.2.8 Integration of power generation and process

Some process units can be equipped with power-recovery systems e.g. flue-gas turbo-expanders for FCC systems or let-down turbines on HP hydrotreaters. These are covered in **sections 4.3.5 and 4.4.3**. In principle, a gas turbine based cogeneration system could co-produce process heat instead of steam. There are only a handful of commercial implementations e.g. gas-turbine exhaust has been used as preheat for a steam cracker producing ethylene. Potential applications in refineries would be units with large fired heaters (e.g. crude and vacuum distillation, catalytic reformers, visbreakers, cokers), but this type of application is not particularly suitable for processes where the feed-quality/flow-rate vary from day-to-day. It also would be uneconomic to modify an existing unit just for the energy efficiency gain, and might only be implemented when replacing a furnace at its end of life. Electricity prices would need to be sufficiently high to make this type of technology attractive to overcome the additional process- and operating-complexity.

APPENDIX 2: MODELLING REFINERY ENERGY EFFICIENCY

A2.1 Introduction

Historically EU refineries have steadily improved their energy performance through a combination of “continuous improvement” and “major projects”. The former is assumed to involve collections of small often low-capex projects such as energy management systems, upgrades to unit process control, catalyst optimisation & improvements, minor hardware upgrades such as better heat exchangers. The latter is assumed to entail major capital projects such as extensive revamps of existing facilities, new process plants, major upgrades to the refinery energy system to improve heat integration, installation of new power generation. The information gathered from literature, technology providers and Member Companies suggest that the costs and benefits of implementation is site-specific, often depending on the configuration and incumbent technologies deployed at individual sites. With more than ten technology areas applied to nearly one hundred refineries, the number of potential projects is vast so it is not practical to investigate this using a “bottom-up” methodology. We have therefore developed a “statistical” model to assess the potential of process and refinery energy efficiency improvements.

This approach provides a means to represent the continued deployment of conventional technology across the industry, and for the introduction of advanced technologies in the decades up to 2050. The degree to which this potential is realized depends on economic justification which is scenario-dependent.

A2.2 Model Structure

Concawe does not have historical data for the energy efficiency of each process technology, nor does it have any corresponding investment data – these improvements are often made as part of projects with wider commercial implications. We have assumed that:

- low-capex activities (e.g. energy management, optimisation, operational procedures and minor process upgrades) could provide refineries in the 4th quartile of energy efficiency with the technical potential to reduce their specific energy consumption by 10%. Such projects are viewed as economic but time-dependent - it could take a decade or more to implement (for example because of staff availability and timing of opportunities such as turnarounds). Refineries which already have better energy efficiency are assumed to have a smaller potential to reduce energy use in this way, and it would be harder to capture because they have already addressed the easier opportunities.
- high-capex projects (e.g. process/refinery improvements involving “state-of-the-art” conventional technology and new “advanced” technologies) correspond to 20% of the energy use of 1st and 2nd quartile refineries. 4th quartile sites represent the “baseline” so are assumed to have made no investment in “state-of-the-art” technology to date, but other quartiles are assumed to have pre-invested to meet their current energy performance.

The “statistical” model addresses both continuous improvement and major projects, which it represents as exponentially-decreasing cost-curves, respectively time-based and investment based. Essentially this treats the large number of potential improvement activities as a continuum of projects, where the exponential form means that successive improvements in energy efficiency progressively are harder/more expensive to achieve. The model treats the EU refining industry as 4 quartiles characterised by initial energy performance. All four quartiles are assumed to be on the same “trajectory” with Q4 defining the starting point; Q1, Q2 and Q3 are therefore assumed to have “pre-invested” relative to Q4 in order to achieve their initial advantage in energy performance. The model then uses the cost-curve to find the last increment of energy efficiency improvement which is just about economic based on assumed energy price, carbon price, maximum acceptable payback time (PBT), capital and operating costs. It then estimates the total energy saving and required investment to complete all projects between the starting point and this economic limit (i.e. it aggregates all activities with PBTs better than the selected maximum). At face value, the model would predict that Q4 should invest at a higher rate than Q1 – it has more scope to improve and has not “pre-invested”. This however is not supported by industry data e.g. Q4 sites may be less profitable hence have less money to invest. On that basis, this model assumes that all quartiles invest at the same rate, equal to the investment rate which would allow Q1 to complete all of its economic improvements. Q1 is thus seen as the “pacesetter” for the industry.

A2.3 Key Inputs & Calibration

The model’s key parameters include:

- Maximum possible energy saving through continuous improvement is assumed to be 10% of 2014 Q4 energy use for Q4. The other quartiles (Q1, Q2, Q3) are assumed to have already achieved 75%, 50% and 25% of this at the start of the modelling period. Maximum possible energy saving through major projects is assumed to be 20% of 2014 Q1+Q2 average energy use. This generally is the largest potential contribution to improved energy efficiency, so the degree of “pre-investment” is estimated during calibration. The US DoE “Bandwidth Study” [US DoE 2015] suggested individual process units show a performance gap of 30-40% between “current typical” and “state-of-the-art”. ICF figure 3.63 [ICF, 2016] implies a technical gap of ~25% of industry energy use. We have used a lower figure of 20% because (a) our reference point is overall refinery energy use as opposed to energy use by a few key individual process units, (b) our reference is “state-of-the-art” refineries, taken to be average of Q1+Q2, and (c) most European projects would be upgrades to existing units as opposed to construction of “green-field” refineries.
- Technical, configurational and locational factors prevent refineries from achieving their full technical potential improvement. All quartiles therefore have a technical “floor” set by the need to consume self-produced fuel, assumed to be 65% of 2008 average energy consumption. Lower performing quartiles are also assumed to have a permanent structural disadvantage relative to Q1; this increases progressively to Q4 whose floor is 15% higher than the Q1 minimum energy use. This was estimated simply by assuming 50% of the current gap between Q1 and Q4.

The model was calibrated using data from Concawe [2008 BMDB] and from Solomon Associates. {Solomon 2011]. This provided standardised energy consumption split by quartiles for a consistent set of refineries (“trend group”) for the period 1992 to 2010. The Solomon data also include investment data, but this is highly scattered (and noted by Solomon as potentially unrepresentative). We therefore estimated the average investment rate to be $1.1/edc per year based on the assumptions that each year’s investment would achieve a maximum 5 year payback for projects which saved energy at an average price of $6/GJ. Both the energy price and derived investment rate are broadly consistent with average values reported by Solomon for 1992-2010.

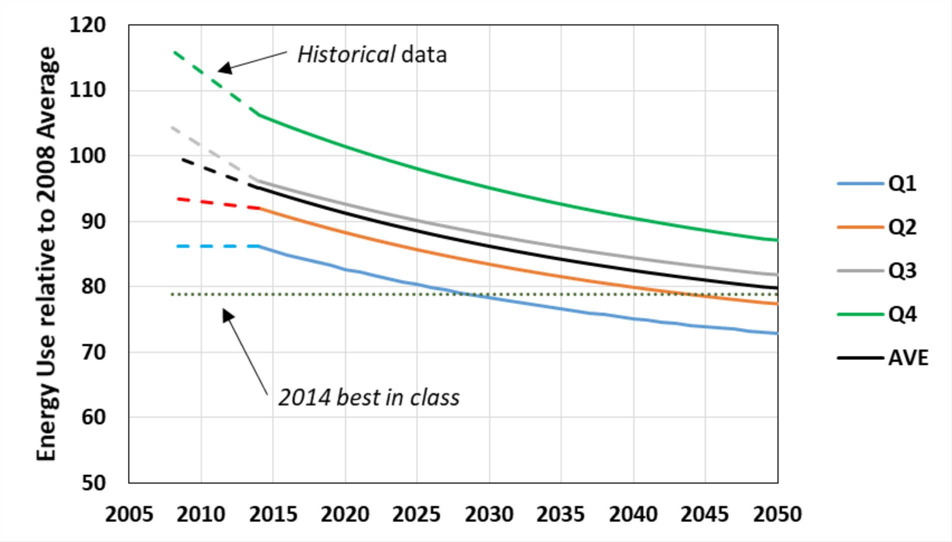
A2.4 Modelling Period

CO_2 calculations were made using a separate model which includes energy efficiency, fuel-switching and flare reduction, deep electrification of power/process-energy, use of renewable H_2 and carbon-capture. This was based on detailed information in the Concawe BMDB which provided data for 2008 only. The energy efficiency model therefore has to cover the period starting in 2008, so it has two stages. For the period 2008-2014, it uses energy intensity data provided to Concawe by Solomon [Solomon 2016], with the statistical model projecting from 2014 to 2030 or 2050 using the cost-curve method outlined above. Note that Solomon 2016 includes uncharacteristically high rates of improvement for Q3 and Q4 between 2010 and 2014.

A2.5 Example Output

For illustration, **Figure A2.5-1** shows projections for the 2050 Median case (see definition in **Section 5.3.2**), where savings are relative to industry average reported for 2008. In general terms it shows a 20% improvement over 2008 for a total industry investment approaching €10 billion. To achieve this by 2050, Q1 refineries on average would have to exceed the 2014 "best-in-class" (horizontal dotted line) by about 5%.

Figure A2.5-1 Predicted Relative Energy Use by Quartile for 2050-Median Case



A2.6 Calibration Sensitivity

The data available for this model is sparse and scattered, so there is considerable uncertainty in the calibration. Tests showed that the most critical factors for calibration are:

- The technical potential for improvement. This was set at 20% for 2010. Because of the reported efficiency improvement between 1992 and 2010, this translates to a technical potential of ~25% in 1992. The uncertainty is easily +/- 5%.
- The energy price assumption used to decide investment during the calibration period 1992-2010. The spot price for energy rose during this period from ~$3/GJ to ~$10/GJ, with an average value of ~$4.5/GJ [BP Stat Review 2016]. We have assumed that projects would be justified using a value higher than spot, so have used $6/GJ for calibration. The investment rate calculation assumes that the longest acceptable payback time in this period was 5 years, broadly consistent with refineries having a "strategic" view of energy efficiency. This leads to an industry average payback time of ~ 3.5 years. Both energy value and payback time are fairly crude assessments, and other values could be chosen (e.g. $10/GJ and max-PBT = 4 years).

The model therefore was run with a range of different calibration values to assess the impact of calibration uncertainty; the predicted capital investment and associated energy improvement both have an uncertainty of ~25% relative.

APPENDIX 3: ELECTRIFICATION OF REFINERY POWER AND HEAT

Today, the refining industry both imports electricity from the grid and generates its own electricity from refinery fuel or imported gas. Self-generation is mainly by CHPs which provide both electricity and heat (mainly as steam), leading to higher-than-average thermal efficiency and lower-than-average carbon intensity compared with most fossil power generation. In the future, increased renewable generation on the grid may lead to a situation where grid-electricity has a lower GHG emission factor than electricity from refinery-based CHP. Where this does occur, the refinery might in principle lower its carbon footprint by stopping self-generation based on imported gas and importing low-carbon electricity instead. This would of course require the imported electricity to be cheap enough to justify the change (Self-generation using refinery-fuel might continue as a means of consuming refinery by-products such as fuel-gas).

As well as power, refineries need steam and process heat which might in principle be provided using imported low-carbon electricity rather than fired-heaters using fossil fuels. Some recent work in Scandinavia involves the use of intermittent renewable electricity to provide hot water for district heating (hence temporarily replacing other sources such as fired boilers.) In principle, the same concept might also be applied to refineries except that the service would be more severe e.g. production of MP/HP steam or for process heat. This is unfamiliar technology which is either developmental or at early stages of R&D. The estimates in this report therefore are somewhat speculative so we are grateful for advice provided by member companies.

A3.1 Refinery infrastructure for electricity distribution

These concepts probably entail a significant expansion of a refinery’s internal electricity distribution system. We assume that the corresponding expansion of the distribution system outside the refinery would be covered by the delivered cost of electricity.

Reports describing the costs of power infrastructure [EIA 2016, ACER 2015] suggest equipment costs of $100k-120k per MWe to cover cabling, transformer and switchgear. The does not include other project costs such as EPC, contingency, owners costs suggesting that the total project costs might be €250k-300k per MWe. The EIA & ACER estimates are for “greenfield” projects; a project within an operating refinery would be more complex to implement so we have assumed infrastructure costs of €300k per MWe.

A3.2 Electrical Production of Steam

We have been unable to obtain any information about the capital cost of large-scale (1-50MWe) electrical boilers for steam production, although large electrical water-heaters (up to 25MWe) have recently come into service for district heating [DEA 2016; DTU 2016]. The Danish Energy Agency [DEA 2016] has published a detailed analysis of equipment costs suggesting a nominal investment of ~€70k per MW for electric boilers >10MWe. Production of HP or MP steam for refinery use would require higher temperatures and pressures than needed for district heating, but pressures up to 500 psig (~35barg) are claimed by some manufactures of electrode steam boilers [e.g. Vapor Power International 2019]. We believe that these current technologies make a good stepping stone for technologies which might be available by 2050 –provided there is a recognised need and investment in R&D. We have used these to provide a “low” ranging shot on capital costs.

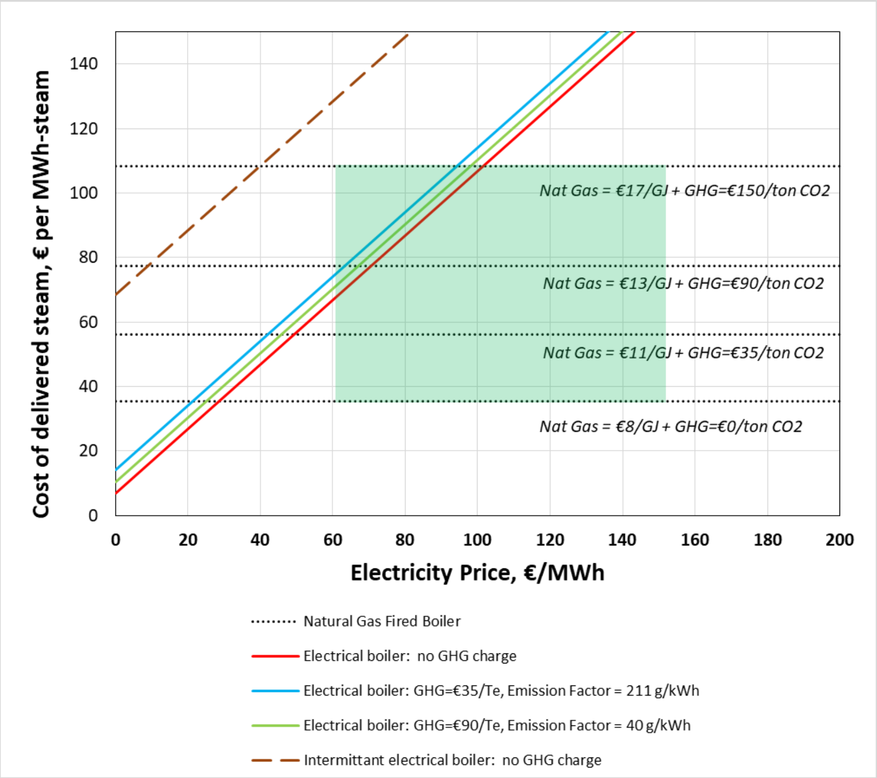
An alternative approach is to assume that the cost of an electric steam boiler would be similar to the equivalent fired system. Published equipment costs for packaged or field-built steam boilers in the range 10-50 MW are in the range $20k-40k per MW USGC-basis [Towler 2013]. Allowing for other costs, contingency and location, the total project investment might be €60k-120k per MW. This is very broadly consistent with other sources (eg IEA 2010 implies a total installed cost of $5 million for 30MW, hence $170k per MW].

We have assumed that an “nth-of-a-kind” electrical boiler providing up to 50 MW of steam would lie between these two estimates, so have used a total project cost of €100k per MWe. Such a project would also require expansion of the refinery electricity system as outlined in the previous section.

Figure A3.2-1 shows the cost of producing steam using a gas fired boiler at different gas- and CO_2 prices (horizontal lines) or a hypothetical electric boiler (diagonal lines). The shaded area represents the range of grid electricity prices used in the 2030 and 2050 Scenarios; the 2017 prices were ~€8-10/GJ for gas and ~€100 per MWh for electricity. The electrical heater costs are closely grouped because of the assumption that high CO_2 prices occur in the future when the grid GHG emission factor might be expected to be lower. The chart shows that electrical steam production is more expensive than fired heat except when gas costs are high and grid electricity costs are low.

Variability of renewables supply to the grid might be expected to create periods of “surplus” where the electricity price might be low, so the dashed diagonal line shows the economics for an intermittently-operated electric boiler with 10% utilisation. This lies above the other lines because the capital cost has to be spread over a smaller amount of steam. It would only be economic with effectively “zero-cost” electricity (and high gas prices).

Figure A3.2-1 Economics of production of steam using natural gas fired boiler and electrical heat – continuous and intermittent operation.



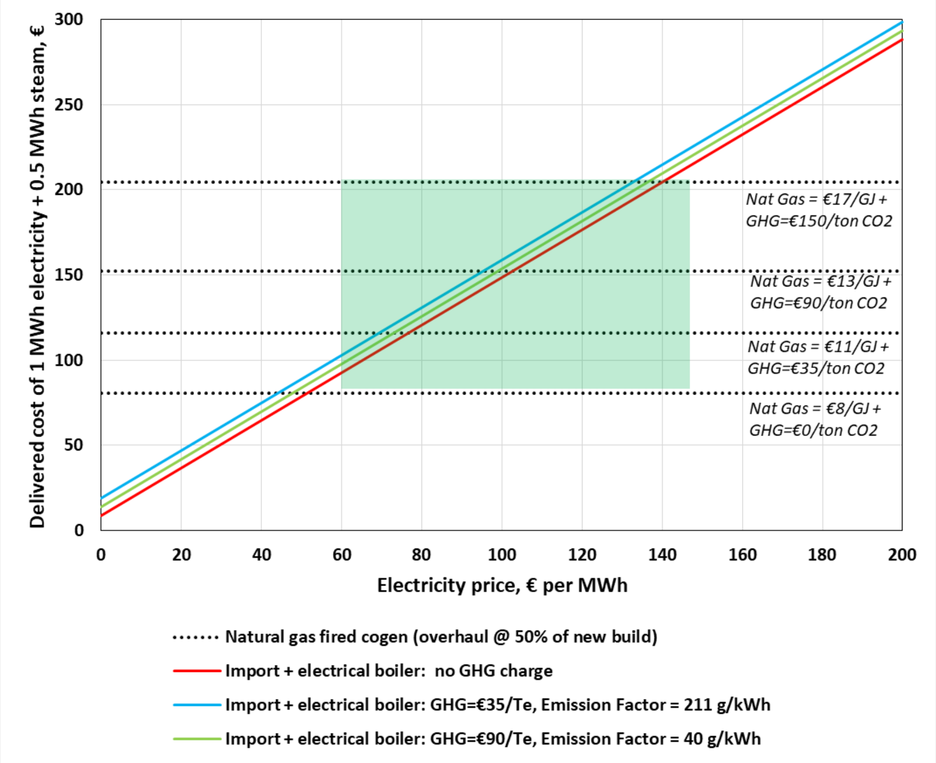
A3.3 Replacement of refinery CHP systems

Installation of CHPs for power production was a key feature of the refining industry’s drive for energy efficiency over the last two decades. By 2030, some of these systems may be due for major overhaul or replacement begging a question whether it might be worth maintaining them at all if grid electricity is (a) lower carbon, (b) low cost. CHPs produce both power and steam so an electrical alternative would require a refinery to (1) upgrade its electrical infrastructure to handle more imported electricity, (2) install additional steam production to compensate for the loss of cogenerated steam. For the sake of argument, we have assumed that the CHP produces 0.5MW-th of steam for each 1MW-e, and that the replacement steam system would use an electric boiler (as described in the previous section).

Concawe/Solomon data shows that installation of CHPs was a major contributor to refinery energy efficiency improvement between 1990 and 2015. By 2030 many of these CHPs will be >25 years old; by 2050, some would be >50 years old. We have tried therefore to represent a case involving an “end-of-life” CHP which would need substantial replacement but not to the extent of a completely new unit. We are therefore trying to compare a substantial rebuild of an existing CHP with a new-build electrical system; we have therefore assumed that CHP option would involve 50% of the capex of a new build CHP, say €1000k/MW-e.

Figure A3.3-1 shows the cost of producing 1 MW of electricity and 0.5 MW of steam using a gas fired CHP at different gas- and CO_2 prices (horizontal lines) or from electricity imports and an electric boiler (diagonal lines). As before, the shaded area represents the range of grid electricity prices used in the 2030 and 2050 Scenarios; the 2017 prices were ~€8-10/GJ for gas and ~€100 per MWh for electricity. The chart shows that the CHP is the more cost-effective option today and for a 2030 scenario with imported gas = €11/GJ, electricity = €98/MWh and CO_2 = €35/ton. The two options would be roughly competitive for a 2050 scenario with gas = €13/GJ, electricity = €100/MWh and CO_2 = €90/ton. Electrification would look the more attractive in a 2050 scenario with gas = 17 €/GJ, electricity = 60 €/MWh and CO_2= 150 €/t.

Figure A3.3-1 Economics of generating power & steam-production from grid electricity vs gas-fired CHP



A3.4 Electrification of Process Heat

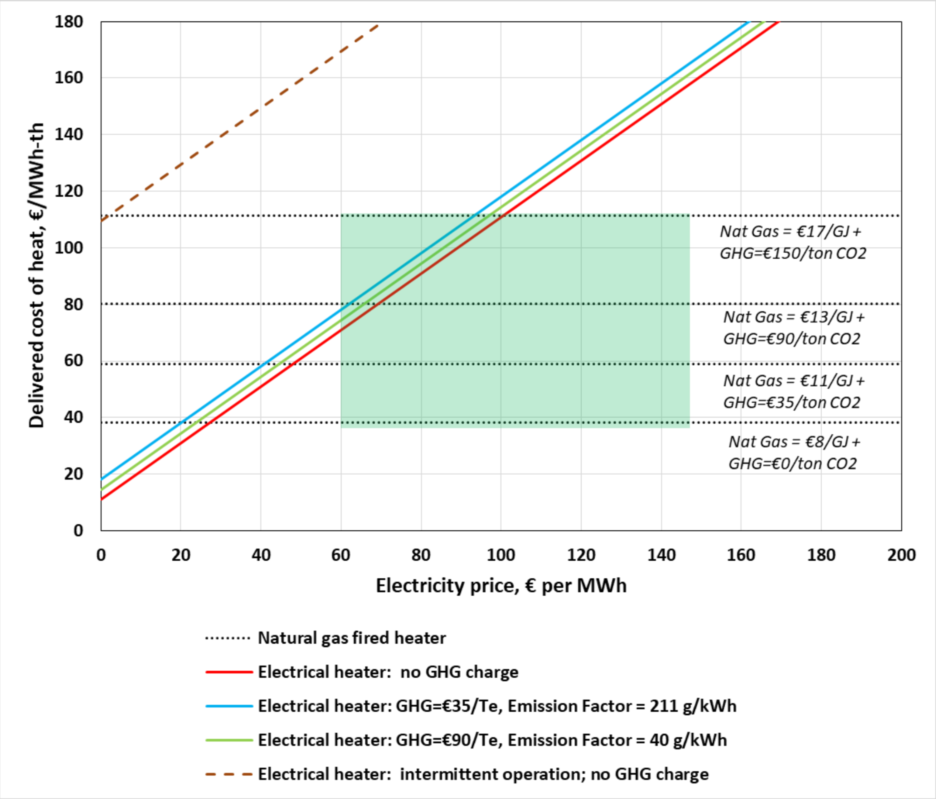
This area is much more speculative that electrical steam production, particularly because of the large scale of some refinery heaters (eg 100-150 MW) and the challenges posed by refinery streams (eg fouling potential). There are few precedents in this area and considerable R&D will be required if anything is to be available in the future. Process heating has important HSSE considerations and we should also note the availability/reliability risks for early-industrial applications. The industry has more than a hundred years' experience of fired heater design and operation.

We were unable to find any hard information about the design and cost of electrical process heaters so have taken guidance from the earlier estimate for electrical steam heating and published data for conventional fired process heaters. Published equipment costs for "field-built" fired heaters in the range 50 to 150MW are in the range $50k-90k per MW [Towler 2013], a paper by Linde [Rentshler 2015] about the capital costs of large furnaces for steam crackers, reformers and refineries suggests an equipment cost of ~$11 million for 616 MMBTU/h (180MW), i.e. roughly $60k per MW broadly in line with Towler. Allowance for other costs, location, contingency would bring the total project investment to €150k-250k per MW for new equipment. However, large-scale electrification of process heating would almost certainly entail significant revamp of existing equipment so costs could well be higher. We have therefore assumed €300k per MWe for electrification of process heat, excluding supply infrastructure.

Figure A3.4-1 shows the cost of producing 1 MW_{th} of process heat using a gas fired heater at different gas- and CO_2 prices (horizontal lines) or a hypothetical electric heater (diagonal lines). As before, the shaded area represents the range of grid electricity prices used in the 2030 and 2050 Scenarios; the 2017 prices were ~€8-10/GJ for gas and ~€100 per MWh for electricity. Fired heaters are already in place on refinery units, but for the sake of argument have compared a new fired heater (€200k/ MW_{th}) and a new electric heater (€300k/ MW_{th})

The chart shows that the gas-fired heater is the more cost-effective option today and for a 2030 scenario (gas = €11/GJ, electricity = €98/MWh, CO_2 = €35/ton) and for a 2050 scenario (gas = €13/GJ, electricity = €100/MWh, CO_2 = €90/ton.) The electrical option would only be competitive for extreme 2030 or 2050 cases with low electricity prices. It is possible that an electric heater uses intermittent "surplus" renewable electricity at a low price. The dashed diagonal line shows the economics for an electric heater with 10% utilisation.

Figure A3.4-1 Economics of replacing fired-process heater by electric process heater



There are some additional issues:

- Scale: It would seem rather unlikely that anyone would build a fully-electric heater for a crude distillation unit in Europe (e.g. 100-200 MW), but a smaller fired heater with an electrical system; examples might be a re-boiler or a small process unit such as isomerisation.
- Auxiliary heaters: Another option might be to retro-fit a “small” electric heater (e.g. 10MW) as supplement to a large-fired heater (e.g. 150 MW). This would be more complicated, but it would provide greater flexibility to use intermittent low-cost electricity
- Replacement of unfired reboilers: This is not a direct replacement of GHG-emitting fired heat, but might play a role in better optimisation of heat around the refinery, ultimately leading to a general reduction in fired-heat.

The small-scale approaches would make the electrification project more manageable project, although downscaling the heater would tend to justify higher cost per MW and would limit the impact on GHG emissions. We have therefore assumed that ultimate penetration might limited to perhaps 10% of the total fired heat (provided that combustion of self-produced fuels is not limiting) and that it only happens in the 2050 High scenario.

A3.5. Heat Pumps for upgrading low-grade heat

There are already conventional large-scale heat pumps e.g. 1-5 MW-th for district heating and industrial applications, which can provide heat up to about 140degC. Reports (Danish Energy Agency [DEA 2016] and University of Chalmers [Chalmers 2008]) suggest the installed capital cost is ~€800 per kW-th with COP values of 2-3 (heat-out/electricity-in). There seems to be technical potential to increase scale to few 10s of MW and temp up to perhaps 160 °C so in principle this could use low-grade heat + electricity to provide MP steam. There are some emerging technologies in this area (e.g. Q-Pinch, Bronswerk, thermos-acoustic heat pumps) but public cost-data are not available to this study. A critical issue is whether MP steam is valuable enough to justify this type of project in a refinery. If HP steam is required, then the prospect of viable heat-pump technology seems quite remote.

MP steam service might for example be based on large-scale refinery point sources of low-grade heat (e.g. FCC, CDU air- and water-coolers). These have been considered elsewhere in the report for power-recovery (e.g. ORC turbines) so heat-pumps might well be preferred to ORC in scenarios where the electricity price is low e.g. 2030-H and 2050-H. On the other hand, it is these same scenarios which favour direct electric heating so the choice of heat pumps over electric steam boilers depends (a) on the availability of viable technology, (b) the detailed balance between electrical running costs and capital. On that basis, we have not completed a detailed economic assessment of heat-pumps but note that they may indeed be an option for utilising low-priced low-carbon energy.

There are also related technologies which generally are covered elsewhere in the study:

- Heat-pump-like technologies for distillation units was covered as an “R&D” concepts in the distillation section of “Process Energy Efficiency”
- Chillers (e.g. Lithium Bromide) may be a way of providing moderate cooling using low-grade heat as an energy source. These probably have niche applications (e.g. inlet cooling on FCC air-blowers; light-ends separations; alkylation units) included in process efficiency improvements; we suspect the overall energy efficiency impact is small.

APPENDIX 4: DETAILED CO_2 MODELLING RESULTS

“Low” cases (full details)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	Low											
Total	**150**	***9.7%***	**155**	***9.2%***	**21.9**	***18.8%***	**24.6**	***19.7%***	**5.0**	**0.99**	**-23**	**-20**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	3.1	*2.7%*	5.8	*4.7%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	7.7	*6.6%*	7.7	*6.2%*	2.6	0.47	63	63
Process efficiency	152	*9.9%*	152	*9.0%*	10.4	*8.9%*	10.4	*8.3%*	1.6	0.37	-81	-81
Low-grade heat	0	*0.0%*	5	*0.3%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-219	-219
	2050											
	Low											
Total	**185**	***12.0%***	**185**	***11.0%***	**29.2**	***25.2%***	**34.1**	***27.2%***	**5.3**	**1.06**	**-26**	**-23**
Without CCS												
With CCS												
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	6.6	*5.7%*	11.4	*9.1%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	9.3	*8.0%*	9.3	*7.5%*	2.6	0.5	53	53
Process efficiency	187	*12.1%*	187	*11.1%*	12.7	*10.9%*	12.7	*10.1%*	1.8	0.4	-84	-84
Low-grade heat	0	*0.0%*	1	*0.0%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.2	-307	-307

“Low” cases (summary)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	Low											
Total	**150**	***9.7%***	**155**	***9.2%***	**21.9**	***18.8%***	**24.6**	***19.7%***	**5.0**		**-23**	**-20**
Energy efficiency	152	*9.9%*	157	*9.3%*	11.0	*9.5%*	11.0	*8.8%*	2.4	0.53	-89	-89
Low C energy	-2	*-0.2%*	-2	*-0.1%*	10.8	*9.3%*	13.5	*10.8%*	2.6	0.47	45	36
CO_2 capture												
	2050											
	Low											
Total	**185**	***12.0%***	**185**	***11.0%***	**29.2**	***25.2%***	**34.1**	***27.2%***	**5.3**	**1.06**	**-26**	**-23**
Without CCS												
With CCS												
Energy efficiency	187	*12.1%*	188	*11.1%*	13.3	*11.5%*	13.3	*10.7%*	2.6	0.58	-95	-95
Low C energy	-2	*-0.2%*	-2	*-0.1%*	15.9	*13.7%*	20.7	*16.6%*	2.6	0.48	31	24

“Median” cases (full details)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	Median											
Total	**329**	***21.3%***	**334**	***19.8%***	**30.7**	***26.5%***	**33.5**	***26.8%***	**10.6**	**2.34**	**-49**	**-45**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	2.1	*1.8%*	4.9	*3.9%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	7.7	*6.6%*	7.7	*6.2%*	2.6	0.47	55	55
Process efficiency	331	*21.4%*	331	*19.6%*	20.2	*17.5%*	20.2	*16.2%*	7.2	1.72	-95	-95
Low-grade heat	0	*0.0%*	5	*0.3%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-109	-109
	2050											
	Median											
Total												
Without CCS	**567**	***36.7%***	**331**	***19.6%***	**46.4**	***40.0%***	**49.8**	***39.9%***	**18.2**	**4.01**	**-3**	**-3**
With CCS	**411**	***26.6%***	**175**	***10.4%***	**61.3**	***52.8%***	**64.7**	***51.8%***	**27.1**	**6.24**	**67**	**64**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	2.3	*1.9%*	7.1	*5.7%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	9.3	*8.0%*	9.3	*7.5%*	2.6	0.48	54	54
Process efficiency	401	*26.0%*	401	*23.8%*	24.4	*21.1%*	24.4	*19.6%*	9.4	2.38	-116	-116
Low-grade heat	0	*0.0%*	1	*0.0%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-235	-235
Electrification (steam, int.)	2	*0.1%*	-1	*-0.1%*	0.1	*0.1%*	0.1	*0.1%*	0.3	0.05	281	281
Cogen substitution	68	*4.4%*	-5	*-0.3%*	3.8	*3.3%*	3.3	*2.6%*	0.6	0.04	91	104
Elec steam option	92	*6.0%*	-49	*-2.9%*	5.1	*4.4%*	4.2	*3.3%*	0.9	0.15	246	300
Elec Hydrogen (int.)	6	*0.4%*	-13	*-0.8%*	0.7	*0.6%*	0.7	*0.6%*	3.5	0.8	1031	1031
Capture energy as NG												
CO_2 capture (SMR)	-2	*-0.1%*	-2	*-0.1%*	1.7	*1.4%*	1.7	*1.3%*	0.5	0.12	87	87
CO_2 capture (general)	-154	*-10.0%*	-154	*-9.1%*	13.2	*11.4%*	13.2	*10.6%*	8.3	2.11	311	311
Total	-156	-10.1%	-156	-9.3%	14.9	12.8%	14.9	11.9%	8.8	2.23	286	286
Capex +fixed opex											150	150
Energy											136	136
	Median - Max elec											
Total												
Without CCS	**748**	***48.5%***	**271**	***16.1%***	**54.0**	***46.5%***	**55.7**	***44.6%***	**18.1**	**3.72**	**27**	**27**
With CCS	**748**	***48.5%***	**144**	***8.6%***	**66.2**	***57.1%***	**67.1**	***53.7%***	**22.6**	**4.97**	**72**	**72**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	0.3	*0.3%*	5.2	*4.1%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	9.3	*8.0%*	9.3	*7.5%*	2.6	0.48	54	54
Process efficiency	401	*26.0%*	401	*23.8%*	24.4	*21.1%*	24.4	*19.6%*	9.4	2.38	-116	-116
Low-grade heat	0	*0.0%*	1	*0.0%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-235	-235
Electrification (general)	72	*4.7%*	-13	*-0.8%*	4.0	*3.4%*	3.4	*2.7%*	0.7	0.12	147	171
Electrification (steam, int.)	2	*0.1%*	-1	*-0.1%*	0.1	*0.1%*	0.1	*0.1%*	0.3	0.05	297	297
Cogen substitution	68	*4.4%*	-5	*-0.3%*	3.8	*3.3%*	3.3	*2.6%*	0.6	-0.03	72	83
Elec steam option	92	*6.0%*	-49	*-2.9%*	5.1	*4.4%*	4.1	*3.3%*	0.9	0.15	248	303
Electric heaters	115	*7.5%*	-60	*-3.6%*	6.3	*5.4%*	5.1	*4.1%*	2.6	0.44	290	355
Capture energy as elec												
CO_2 capture (SMR)	0	*0.0%*	-3	*-0.2%*	1.7	*1.5%*	1.7	*1.4%*	0.5	0.13	102	103
CO_2 capture (general)	0	*0.0%*	-123	*-7.3%*	10.5	*9.1%*	9.7	*7.8%*	4.0	1.12	299	324
Total	0	0.0%	-127	-7.5%	12.3	10.6%	11.4	9.1%	4.5	1.25	271	291
Capex +fixed opex											102	109
Energy											169	169
	Median - Max Hydrogen											
Total												
Without CCS	**685**	***44.4%***	**211**	***12.5%***	**54.0**	***46.6%***	**55.9**	***44.7%***	**21.8**	**4.59**	**52**	**50**
With CCS	**685**	***44.4%***	**77**	***4.6%***	**66.2**	***57.1%***	**67.2**	***53.8%***	**26.7**	**5.95**	**96**	**95**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	0.3	*0.3%*	5.2	*4.1%*				
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	9.3	*8.0%*	9.3	*7.5%*	2.6	0.48	54	54
Process efficiency	401	*26.0%*	401	*23.8%*	24.4	*21.1%*	24.4	*19.6%*	9.4	2.38	-116	-116
Low-grade heat	0	*0.0%*	1	*0.0%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-235	-235
Electrification (general)	72	*4.7%*	-13	*-0.8%*	4.0	*3.4%*	3.4	*2.7%*	0.7	0.12	147	171
Electrification (steam, int.)	2	*0.1%*	-1	*-0.1%*	0.1	*0.1%*	0.1	*0.1%*	0.3	0.05	297	297
Cogen substitution	68	*4.4%*	-5	*-0.3%*	3.8	*3.3%*	3.3	*2.6%*	0.6	-0.03	72	83
Elec steam option	92	*6.0%*	-49	*-2.9%*	5.1	*4.4%*	4.1	*3.3%*	0.9	0.15	248	303
Elec Hydrogen (int.)	6	*0.4%*	-13	*-0.8%*	0.7	*0.6%*	0.7	*0.6%*	3.5	0.77	999	999
Elec Hydrogen (cont.)	46	*3.0%*	-106	*-6.3%*	5.6	*4.8%*	4.6	*3.7%*	2.8	0.5	435	530
Capture energy as elec												
CO_2 capture (SMR)	0	*0.0%*	-2	*-0.1%*	1.0	*0.8%*	0.9	*0.8%*	0.3	0.07	102	103
CO2 capture (general)	0	*0.0%*	-133	*-7.9%*	11.3	*9.7%*	10.4	*8.3%*	4.7	1.29	307	332
Total	0	0.0%	-134	-8.0%	12.3	10.6%	11.4	9.1%	5.0	1.36	291	313
Capex +fixed opex											111	120
Energy											180	180
	Median - Max CCS											
Total	**233**	***15.1%***	**233**	***13.8%***	**54.4**	***46.9%***	**59.2**	***47.4%***	**22.3**	**5.38**	**50**	**46**
Without Loop	**299**	***19.4%***	**300**	***17.8%***	**48.6**	***41.9%***	**53.4**	***42.8%***	**18.4**	**4.51**	**15**	**13**
Elec & gas grid decarb.	0	*0.0%*	0	*0.0%*	4.2	*3.6%*	9.0	*7.2%*	0.0			
Internal fuel measures	-2	*-0.2%*	-2	*-0.1%*	9.3	*8.0%*	9.3	*7.5%*	2.6	0.48	54	54
Process efficiency	401	*26.0%*	401	*23.8%*	24.4	*21.1%*	24.4	*19.6%*	9.4	2.38	-116	-116
Low-grade heat	0	*0.0%*	1	*0.0%*	0.7	*0.6%*	0.7	*0.5%*	0.8	0.15	-235	-235
Capture energy as NG												
CO_2 capture (SMR)	-2	*-0.1%*	-2	*-0.1%*	1.8	*1.5%*	1.8	*1.4%*	0.5	0.1	93	93
CO_2 capture (general)	-163	*-10.6%*	-163	*-9.7%*	14.0	*12.1%*	14.0	*11.2%*	8.8	2.2	359	359
Total	-165	-10.7%	-165	-9.8%	15.8	13.6%	15.8	12.6%	9.3	2.4	329	329
Capex +fixed opex											150	150
Energy											178	178
Total without loop	*-99*	-6.4%	*-99*	-5.9%	*10.0*	8.6%	*10.0*	8.0%	*5.5*	*1.5*	*320*	*320*

“Median” cases (summary)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	Median											
Total	**329**	***21.3%***	**334**	***19.8%***	**30.7**	***26.5%***	**33.5**	***26.8%***	**10.6**	**2.339**	**-49**	**-45**
Energy efficiency	331	*21.4%*	336	*20.0%*	20.9	*18.0%*	20.9	*16.7%*	8.0	1.87	-95	-95
Low C energy	-2	*-0.2%*	-2	*-0.1%*	9.8	*8.5%*	12.6	*10.1%*	2.6	0.47	50	39
CO_2 capture												
	2050											
	Median											
Total												
Without CCS	**567**	***36.7%***	**331**	***19.6%***	**46.4**	***40.0%***	**49.8**	***39.9%***	**18.2**	**4.01**	**246**	**300**
With CCS	**411**	***26.6%***	**175**	***10.4%***	**61.3**	***52.8%***	**64.7**	***51.8%***	**27.1**	**6.24**	**1031**	**1031**
Energy efficiency	401	*26.0%*	401	*23.8%*	25.1	*21.7%*	25.1	*20.1%*	10.3	2.53	-119	-119
Low C energy	161	*10.4%*	-57	*-3.4%*	20.6	*17.7%*	24.0	*19.2%*	4.5	0.71	104	89
Low C hydrogen imports	6	*0.4%*	-13	*-0.8%*	0.7	*0.6%*	0.7	*0.6%*	3.5	0.77	1031	1031
CO_2 capture												
Direct	-156	*-10.1%*	-156	*-9.3%*	14.9	*12.8%*	14.9	*11.9%*	8.8	2.23	286	286
	Median - Max elec											
Total												
Without CCS	**748**	***48.5%***	**271**	***16.1%***	**54.0**	***46.5%***	**55.7**	***44.6%***	**18.1**	**3.72**	**27**	**27**
With CCS	**748**	***48.5%***	**144**	***8.6%***	**66.2**	***57.1%***	**67.1**	***53.7%***	**22.6**	**4.97**	**72**	**72**
Energy efficiency	401	*26.0%*	401	*23.8%*	25.1	*21.7%*	25.1	*20.1%*	10.3	2.53	-119	-119
Low C energy	348	*22.5%*	-130	*-7.7%*	28.9	*24.9%*	30.6	*24.5%*	7.8	1.19	155	146
Low C hydrogen imports												
CO_2 capture												
Direct	0	*0.0%*	-127	*-7.5%*	12.3	*10.6%*	11.4	*9.1%*	4.5	1.25	271	291
	Median - Max Hydrogen											
Total												
Without CCS	**685**	***44.4%***	**211**	***12.5%***	**54.0**	***46.6%***	**55.9**	***44.7%***	**21.8**	**13.51**	**52**	**50**
With CCS	**685**	***44.4%***	**77**	***4.6%***	**66.2**	***57.1%***	**67.2**	***53.8%***	**26.7**	**14.87**	**96**	**95**
Energy efficiency	401	*26.0%*	401	*23.8%*	25.1	*21.7%*	25.1	*20.1%*	10.3	2.53	-119	-119
Low C energy	233	*15.1%*	-70	*-4.2%*	22.6	*19.5%*	25.5	*20.4%*	5.2	1.19	197	146
Low C hydrogen imports	52	*3.3%*	-120	*-7.1%*	6.3	*5.4%*	5.3	*4.2%*	6.3	9.79	1780	2117
CO_2 capture												
Direct	0	*0.0%*	-134	*-8.0%*	12.3	*10.6%*	11.4	*9.1%*	5.0	1.36	291	313
	Median - Max CCS											
Total	**233**	***15.1%***	**233**	***13.8%***	**54.4**	***46.9%***	**59.2**	***47.4%***	**22.3**	**5.38**	**50**	**46**
With Loop	**299**	***19.4%***	**300**	***17.8%***	**48.6**	***41.9%***	**53.4**	***42.8%***	**18.4**	**4.51**	**15**	**13**
Energy efficiency	401	*26.0%*	401	*23.8%*	25.1	*21.7%*	25.1	*20.1%*	10.3	2.53	-119	-119
Low C energy	-2	*-0.2%*	-2	*-0.1%*	13.5	*11.7%*	18.4	*14.7%*	2.6	0.48	38	17
Low C hydrogen imports												
CO_2 capture												
Direct	-165	*-10.7%*	-165	*-9.8%*	15.8	*13.6%*	15.8	*12.6%*	9.3	2.37	329	329
Without Loop	*-99*	*-6.4%*	*-99*	*-5.9%*	*10.0*	*8.6%*	*10.0*	*8.0%*	*5.5*	*1.5*	*320*	*320*

“High” cases (full details)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	High											
Total	**393**	**25.4%**	**369**	**21.9%**	**33.9**	**29.2%**	**35.6**	**28.5%**	**13.3**	**3.06**	**-80**	**-77**
Elec & gas grid decarb.	0	0.0%	0	0.0%	1.8	1.5%	4.5	3.6%	0.0			
Internal fuel measures	-2	-0.2%	-2	-0.1%	7.7	6.6%	7.7	6.2%	2.6	0.47	65	65
Process efficiency	371	24.0%	371	22.0%	22.4	19.4%	22.4	18.0%	9.7	2.41	-141	-141
Low-grade heat	0	0.0%	5	0.3%	0.6	0.5%	0.6	0.5%	0.8	0.14	-51	-51
	2050											
	High - Max elec											
Total												
Without CCS	**749**	**48.5%**	**305**	**18.1%**	**54.0**	**46.5%**	**55.9**	**44.8%**	**19.3**	**4.2**	**-84**	**-81**
With CCS	**749**	**48.5%**	**56**	**3.3%**	**78.1**	**67.4%**	**78.4**	**62.8%**	**28.2**	**6.6**	**5**	**5**
Elec & gas grid decarb.	0	0.0%	0	0.0%	0.3	0.3%	5.2	4.1%	0.0			
Internal fuel measures	-2	-0.2%	-2	-0.1%	9.3	8.0%	9.3	7.5%	2.6	0.48	55	55
Process efficiency	426	27.6%	426	25.3%	25.9	22.3%	25.9	20.7%	11.6	2.96	-166	-166
Low-grade heat	0	0.0%	-4	-0.2%	0.6	0.5%	0.6	0.5%	0.5	0.10	-233	-233
Electrification (general)	72	4.7%	-13	-0.8%	4.0	3.4%	3.4	2.7%	0.7	0.12	-66	-77
Electrification (steam, int.)	2	0.1%	-1	-0.1%	0.1	0.1%	0.1	0.1%	0.3	0.05	211	211
Cogen substitution	68	4.4%	-5	-0.3%	3.8	3.3%	3.3	2.6%	0.6	-0.03	-127	-145
Elec steam option	92	6.0%	-49	-2.9%	5.1	4.4%	4.1	3.3%	0.9	0.15	-8	-10
Electric heaters	90	5.8%	-47	-2.8%	4.9	4.2%	4.0	3.2%	2.0	0.34	33	40
Capture energy as elec												
CO_2 capture (SMR)	0	0.0%	-6	-0.4%	3.5	3.0%	3.4	2.7%	1.0	0.25	90	91
CO_2 capture (general)	0	0.0%	-243	-14.4%	20.7	17.8%	19.1	15.3%	7.8	2.20	222	240
Total	0	0.0%	-249	-14.8%	24.2	20.8%	22.5	18.0%	8.8	2.45	203	218
Capex +fixed opex											101	109
Energy											101	101
	High - Max Hydrogen											
Total												
Without CCS	**697**	**45.1%**	**265**	**15.7%**	**53.7**	**46.3%**	**55.9**	**44.7%**	**22.7**	**4.9**	**-58**	**-56**
With CCS	**697**	**45.1%**	**4**	**0.3%**	**77.9**	**67.2%**	**78.3**	**62.7%**	**32.3**	**7.5**	**26**	**26**
Elec & gas grid decarb.	0	0.0%	0	0.0%	0.4	0.3%	5.2	4.2%				
Internal fuel measures	-2	-0.2%	-2	-0.1%	9.3	8.0%	9.3	7.5%	2.6	0.48	55	55
Process efficiency	426	27.6%	426	25.3%	25.9	22.3%	25.9	20.7%	11.6	2.96	-166	-166
Low-grade heat	0	0.0%	-4	-0.2%	0.6	0.5%	0.6	0.5%	0.5	0.10	-233	-233
Electrification (general)	72	4.7%	-13	-0.8%	4.0	3.4%	3.4	2.7%	0.7	0.12	-66	-77
Electrification (steam, int.)	2	0.1%	-1	-0.1%	0.1	0.1%	0.1	0.1%	0.3	0.05	211	211
Cogen substitution	68	4.4%	-5	-0.3%	3.8	3.3%	3.3	2.6%	0.6	-0.03	-127	-145
Elec steam option	92	6.0%	-49	-2.9%	5.1	4.4%	4.1	3.3%	0.9	0.15	-8	-10
Elec Hydrogen (int.)	6	0.4%	-13	-0.8%	0.7	0.6%	0.7	0.6%	3.5	0.77	987	987
Elec Hydrogen (cont.)	32	2.1%	-74	-4.4%	3.9	3.4%	3.2	2.6%	1.9	0.35	218	266
Capture energy as elec												
CO_2 capture (SMR)	0	0.0%	-4	-0.3%	2.3	2.0%	2.3	1.8%	0.7	0.17	90	91
CO2 capture (general)	0	0.0%	-256	-15.2%	21.8	18.8%	20.1	16.1%	8.8	2.45	228	247
Total	0	0.0%	-260	-15.5%	24.2	20.8%	22.4	18.0%	9.5	2.61	214	231
Capex +fixed opex											108	117
Energy											106	106
	High - Max CCS											
Total	**105**	**6.8%**	**102**	**6.0%**	**70.2**	**60.5%**	**75.0**	**60.0%**	**32.7**	**8.09**	**86**	**81**
Without Loop	**231**	**15.0%**	**227**	**13.5%**	**59.2**	**51.1%**	**64.1**	**51.3%**	**25.3**	**6.45**	**39**	**36**
Elec & gas grid decarb.	0	0.0%	0	0.0%	3.9	3.4%	8.8	7.0%	0.0			
Internal fuel measures	-2	-0.2%	-2	-0.1%	9.3	8.0%	9.3	7.5%	2.6	0.5	55	55
Process efficiency	426	27.6%	426	25.3%	25.9	22.3%	25.9	20.7%	11.6	3.0	-166	-166
Low-grade heat	0	0.0%	-4	-0.2%	0.6	0.5%	0.6	0.5%	0.5	0.10	-233	-233
Capture energy as NG												
CO_2 capture (SMR)	-4	-0.3%	-4	-0.3%	3.5	3.0%	3.5	2.8%	1.0	0.3	93	93
CO_2 capture (general)	-314	-20.3%	-314	-18.6%	26.9	23.2%	26.9	21.5%	16.9	4.3	358	358
Total	-318	-20.6%	-318	-18.9%	30.4	26.2%	30.4	24.4%	18.0	4.6	328	328
Capex +fixed opex											150	150
Energy											178	178
Total without loop	*-193*	*-12.5%*	*-193*	*-11.4%*	*19.5*	*16.8%*	*19.5*	*15.6%*	*10.6*	*2.9*	*318*	*318*

“High” cases (summary)

	Energy savings (PJ/a)				Emission savings (Mt CO_2/a)				Capex (G€)	AFC (G€/a)	Abatement cost (€/t CO_2)	
	Refinery fuel		Total$_{pr}$		Direct		Total				Direct	Total
	2030											
	High											
Total	**393**	***25.4%***	**369**	***21.9%***	**33.9**	***29.2%***	**35.6**	***28.5%***	**13.3**	**3.056**	**-80**	**-77**
Energy efficiency	371	*24.0%*	376	*22.3%*	23.1	*19.9%*	23.1	*18.5%*	10.4	2.55	-138	-138
Low C energy	22	*1.4%*	-7	*-0.4%*	10.8	*9.3%*	12.6	*10.0%*	2.8	0.51	43	37
CO_2 capture												
	2050											
	High - Max elec											
Total												
Without CCS	**749**	***48.5%***	**305**	***18.1%***	**54.0**	***46.5%***	**55.9**	***44.8%***	**19.3**	**4.15**	**-84**	**-81**
With CCS	**749**	***48.5%***	**56**	***3.3%***	**78.1**	***67.4%***	**78.4**	***62.8%***	**28.2**	**6.60**	**5**	**5**
Energy efficiency	426	*27.6%*	423	*25.1%*	26.5	*22.9%*	26.5	*21.2%*	12.1	3.05	-167	-167
Low C energy	323	*20.9%*	-117	*-6.9%*	27.5	*23.7%*	29.4	*23.5%*	7.2	1.10	-3	-3
Low C hydrogen imports												
CO_2 capture												
Direct	0	*0.0%*	-249	*-14.8%*	24.2	*20.8%*	22.5	*18.0%*	8.8	2.45	203	218
	High - Max Hydrogen											
Total												
Without CCS	**697**	***45.1%***	**265**	***15.7%***	**53.7**	***46.3%***	**55.9**	***44.7%***	**22.7**	**4.51**	**-58**	**-56**
With CCS	**697**	***45.1%***	**4**	***0.3%***	**77.9**	***67.2%***	**78.3**	***62.7%***	**32.3**	**7.12**	**26**	**26**
Energy efficiency	426	*27.6%*	423	*25.1%*	26.5	*22.9%*	26.5	*21.2%*	12.1	3.1	-167	-167
Low C energy	233	*15.1%*	-70	*-4.2%*	22.6	*19.5%*	25.5	*20.4%*	5.2	0.3	-31	-24
Low C hydrogen imports	38	*2.5%*	-88	*-5.2%*	4.6	*4.0%*	3.9	*3.1%*	5.4	1.1	335	395
CO_2 capture												
Direct	0	*0.0%*	-260	*-15.5%*	24.2	*20.8%*	22.4	*18.0%*	9.5	2.61	214	231
	High - Max CCS											
Total	**105**	***6.8%***	**102**	***6.0%***	**70.2**	***60.5%***	**75.0**	***60.0%***	**32.7**	**8.09**	**86**	**81**
With Loop	**231**	***15.0%***	**227**	***13.5%***	**59.2**	***51.1%***	**64.1**	***51.3%***	**25.3**	**6.45**	**39**	**36**
Energy efficiency	426	*27.6%*	423	*25.1%*	26.5	*22.9%*	26.5	*21.2%*	12.1	3.1	-167	-167
Low C energy	-2	*-0.2%*	-2	*-0.1%*	13.2	*11.4%*	18.1	*14.5%*	2.6	0.5	39	18
Low C hydrogen imports												
CO_2 capture												
Direct	-318	*-20.6%*	-318	*-18.9%*	30.4	*26.2%*	30.4	*24.4%*	18.0	4.6	328	328
Without Loop	*-193*	*-12.5%*	*-193*	*-11.4%*	*19.5*	*16.8%*	*19.5*	*15.6%*	*10.6*	*2.9*	*318*	*318*

APPENDIX 5: EUROPEAN COMMISSION: EU 2016 REFERENCE SCENARIO AND A CLEAN PLANET FOR ALL (OVERVIEW OF MAIN SCENARIO BUILDING BLOCKS).

Figure A5-1 Final Energy consumption by fuel and by sector (1995-2050)
(Source: DG ENERGY, EU Reference Scenario [EU 2016 1])

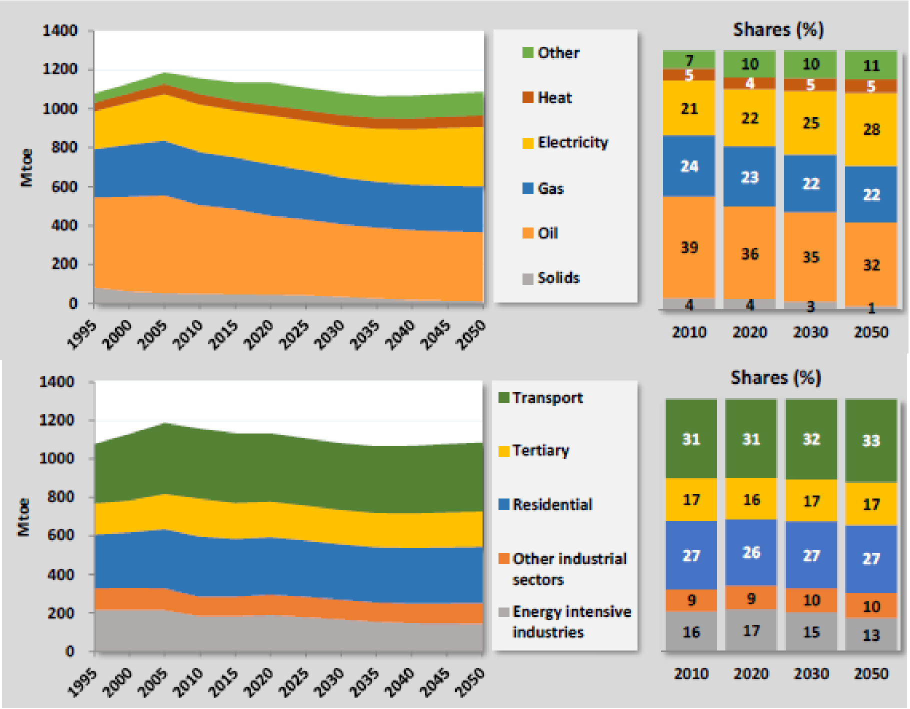
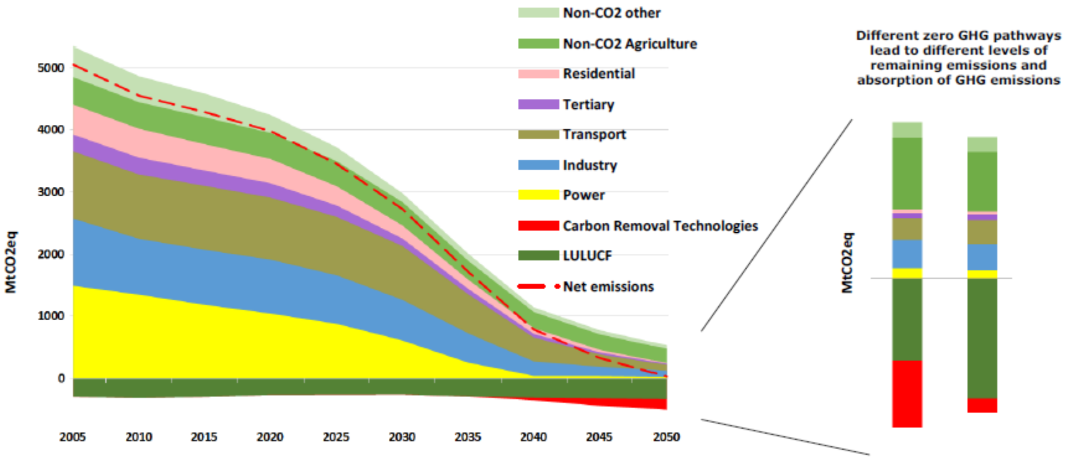


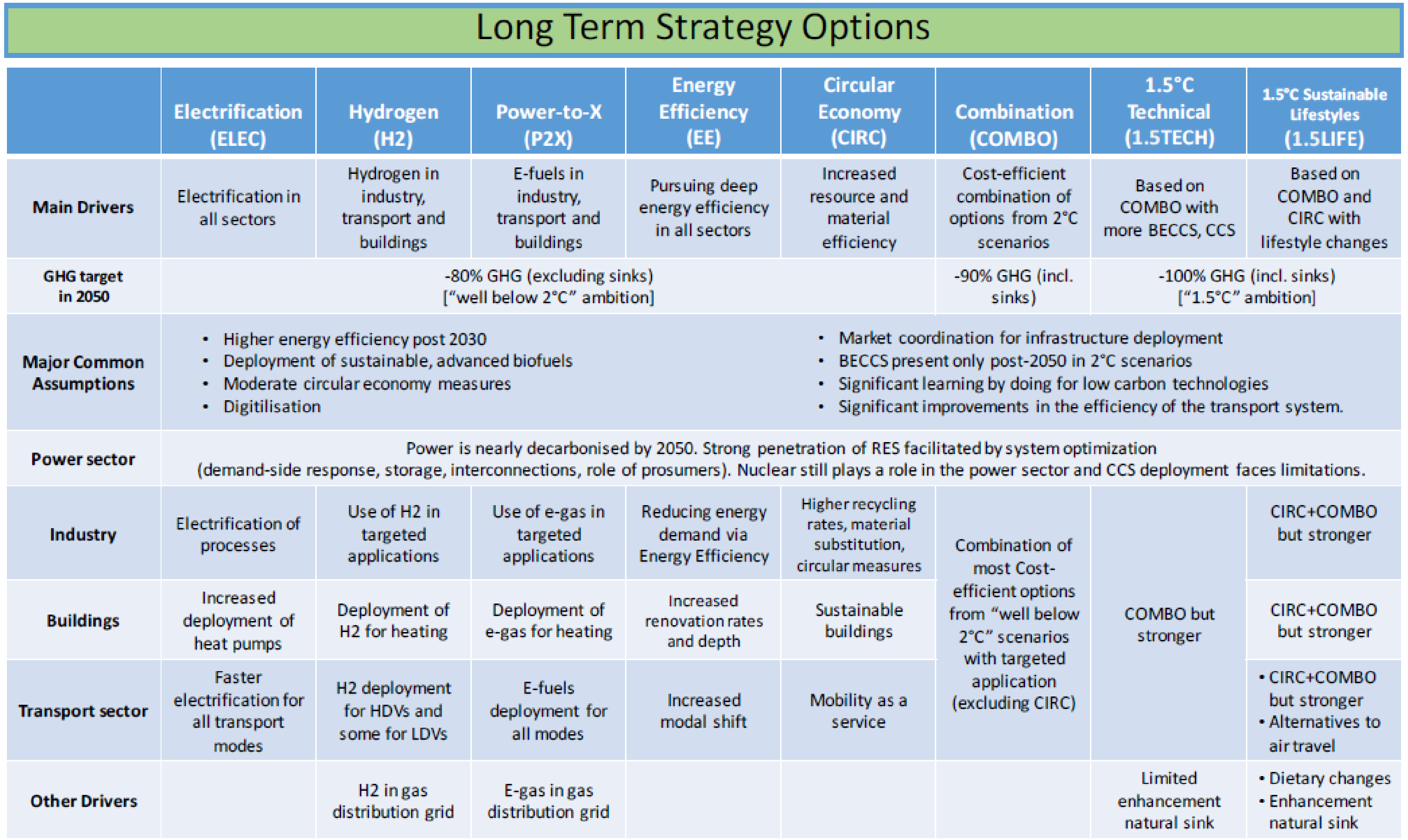
Figure A5-2 GHG emissions trajectory in a 1.5°C scenario
(Source: DG CLIMA, A Clean Planet for all [EU 2018])



Note. Bars represent the emissions and absorptions in 2050 of the 1.5 TECH and 1.5 LIFE scenarios.

In 2050, these scenarios show a deeper reduction in the EU total energy consumption when compared with the EU 2016 Reference scenario cited above.

Figure A5-3 A Clean Planet for all. Overview of main scenario building blocks.



Long Term Strategy Options

	Electrification (ELEC)	Hydrogen (H2)	Power-to-X (P2X)	Energy Efficiency (EE)	Circular Economy (CIRC)	Combination (COMBO)	1.5°C Technical (1.5TECH)	1.5°C Sustainable Lifestyles (1.5LIFE)
Main Drivers	Electrification in all sectors	Hydrogen in industry, transport and buildings	E-fuels in industry, transport and buildings	Pursuing deep energy efficiency in all sectors	Increased resource and material efficiency	Cost-efficient combination of options from 2°C scenarios	Based on COMBO with more BECCS, CCS	Based on COMBO and CIRC with lifestyle changes
GHG target in 2050	-80% GHG (excluding sinks) ["well below 2°C" ambition]					-90% GHG (incl. sinks)	-100% GHG (incl. sinks) ["1.5°C" ambition]	
Major Common Assumptions	• Higher energy efficiency post 2030 • Deployment of sustainable, advanced biofuels • Moderate circular economy measures • Digitilisation				• Market coordination for infrastructure deployment • BECCS present only post-2050 in 2°C scenarios • Significant learning by doing for low carbon technologies • Significant improvements in the efficiency of the transport system.			
Power sector	Power is nearly decarbonised by 2050. Strong penetration of RES facilitated by system optimization (demand-side response, storage, interconnections, role of prosumers). Nuclear still plays a role in the power sector and CCS deployment faces limitations.							
Industry	Electrification of processes	Use of H2 in targeted applications	Use of e-gas in targeted applications	Reducing energy demand via Energy Efficiency	Higher recycling rates, material substitution, circular measures	Combination of most Cost-efficient options from "well below 2°C" scenarios with targeted application (excluding CIRC)	COMBO but stronger	CIRC+COMBO but stronger
Buildings	Increased deployment of heat pumps	Deployment of H2 for heating	Deployment of e-gas for heating	Increased renovation rates and depth	Sustainable buildings			CIRC+COMBO but stronger
Transport sector	Faster electrification for all transport modes	H2 deployment for HDVs and some for LDVs	E-fuels deployment for all modes	Increased modal shift	Mobility as a service			• CIRC+COMBO but stronger • Alternatives to air travel
Other Drivers		H2 in gas distribution grid	E-gas in gas distribution grid				Limited enhancement natural sink	• Dietary changes • Enhancement natural sink

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