IDENTIFICATION OF OPTIMAL PATHWAYS FOR DEEP DECARBONIZATION OF HIGH TEMPERATURE INDUSTRY

The Dutch oil refinery industry as case study

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MSc. Thesis

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Abstract

Within this study, three deployment pathways for greenhouse gas emission reduction in the Dutch petroleum refinery sector were identified and assessed based on a quantitative techno-economic and qualitative strategic analysis of decarbonization measures. The approach of this study distinguishes itself from previous studies by incorporating petroleum output scenarios and the assessment of synergies between decarbonization options at the level of core processes of oil refineries. High temperature industrial decarbonization measures such as energy efficiency measures, carbon capture and storage, fuel switching, and electrification were studied. It was found that promising combinations of decarbonization measures and the optimal capacities for oil refineries depend heavily on key processing technologies, (future) plant configuration, fuel and feedstock, energy prices and policy.

External market changes that lead to a refinery activity reduction can cause a write-off of decarbonization assets and hereby influence the risks associated with a decarbonization measure. For this reason, a refinery model was created which facilitated detailed emission estimation at different output levels. Three scenarios developed by the International Energy Agency (IEA) were used to assess future petroleum output levels, enabling to distinguish between regret and no-regret investment decisions.

Besides continuous energy efficiency improvement it was found that carbon capture and storage must be implemented to reach short term emissions reduction targets. Electrification (boilers, electric naphtha crackers, electrolysis) show potential in the medium to long-term. It was found that sustainably produced hydrogen will be required to retain a stable output product if demands and chemical feedstocks increase.

The best economic performing pathway is one in which all fuel steams are transformed into blue hydrogen through pre-combustion carbon capture and storage: the blue hydrogen pathway, 11.1 MtCO_2/y can be avoided, at a cost of 61.5 €/tCO_2. When focusing on minimizing refinery adaptations and impact on the refining processes, the minimal impact pathway was identified, which performs second best, 10.3 MtCO_2/y can be avoided at a cost of 68 €/tCO_2. Due to an increased natural gas consumption within the blue hydrogen, a third pathway was identified with the premise to use zero natural gas: the natural gas independency pathway. Despite an increased strategic performance, this pathway has relatively high cost of avoided CO_2, 217.6 €/tCO_2.

Contents

Definitions

Table 1 - Defining decarbonization.

Decarbonization	Reduction of atmospheric carbon dioxide emissions
Decarbonization measures	Option, route or strategy for decarbonization
Decarbonization pathway	Combination of decarbonization measures for deep decarbonization over time
Decarbonization deployment pathway	Decarbonization pathway including combinations, interactions, strategy, and risks of decarbonization measures

Nomenclature

α: annuity factor (-)
ADU: atmospheric distillation unit
ATR: autothermal reforming
BIG: biomass gasification
C_a: CO_2 avoidance costs (€/tCO_2)
CCS: carbon capture and ctorage
CHP: combined heat and power plant
CO_2: carbon dioxide
COP21: conference of parties
CR: catalytic reforming
CWT: carbon weighted ton
DAO: deasphalted oil
EEM: energy efficiency measures
EF: emission factor (kgCO_2/GJ)
EU: european union
FCC: fluid catalytic cracking
GE: geothermal energy
GHG: greenhouse gas
H_2: hydrogen
HC: hydrocracking
HFO: heavy fuel oil
HP: heat pump
HTHP: high temperature heat pump
HVAC: heating, ventilation, and air conditioning
HF: hydrofluoric acid
HT: hydrotreater
I: upfrond investment costs (€)
IEA: international energy agency
IS: industrial symbiosis
kb/d: thousand barrels per day
LGO: light gas oil
LPG: liquified petroleum gas
LT: technological life time
MACC: marginal abatement cost curve
MG/G: middle distillates/gasoline ratio
MVR: mechanical vapor recompression
NCI: nelson complexity index
NG: natural gas
NO_x: nitrogen oxides
O&M: operation and maintenance
P2H: power to heat
PoR: port of rotterdam
PPC: process plant costs
RFG: refinery fuel gas
SMR: steam methane reformer
TCR: total capital requirement (€)
TES: techno-economic and strategic
TP: throughput
TRL: technology readiness level
UK: united kindom
VDU: vacuum distillation unit
VGO: vacuum gas oil
VHTHP: very high temperature heat pump
VR: vacuum residue
WH: waste heat

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1. Introduction

At the 21st session of the Conference of Parties (COP21) in Paris it was agreed to limit global temperature rise to 2°C compared to pre-industrial levels. Achieving a maximum of 2°C global temperature rise with a probability of 66% requires net carbon dioxide (CO_2) emissions to be zero by 2060-2075 (Rogelj et al., 2015). Driven by climate change, depletion of fossil fuels, energy security, and emission reduction targets issued by the European Commission (EC), CO_2 emissions in the European Union (EU) have declined with 22% from 5.7 $GtCO_2$ in 1990 to 4.4 $GtCO_2$ in 2016 (PBL, 2018; EU, 2018). However, in 2017, global energy markets took a step backwards in terms of transitioning towards a low carbon energy system: growth in energy demand, coal consumption and carbon emissions all increased (BP, 2019). From 1990 to 2010, emissions from the EU oil refinery sector have increased with 18% because of increased demand for transportation fuels, especially due to the greater demand for lighter distillated, cleaner fuels, and heavier crude oil (Johansson, 2013). Furthermore, global energy outlooks project that the use of transportation fuels will continue to grow because of population growth and industrialization of developing countries (IEA, 2018).

With 10% of the global total energy demand, the chemical and petrochemical industry contributes the most to the world-wide industrial energy demand (Griffin et al., 2018). Specifically, the petroleum refining industry is by its nature part of the fossil fuel chain and emits significant amounts of CO_2 due to several energy-intensive activities requiring heat, steam and electricity to operate (Johansson, 2013; Concawe, 2012). Globally, refineries emit approximately 4% (1 $GtCO_2$/y) of the total CO_2 emissions (Kuramochi et al., 2012; van Straelen et al., 2010). European refineries emit 7.6% (132 $MtCO_2$/y in 2016) of the EU industrial emissions (E-PRTR, 2019[1]) and if the emissions from the use of refinery products (scope[2] 3) are added, it is estimated that the sectors' emissions are as much as five to six times higher (Shell, 2018; Johansson, 2013.

1.1 Status

To maintain its license to operate, the refinery industry must explore and invest in measures that reduce its CO_2 footprint and ensure a secure decarbonized product supply (CIEP, 2018). Several studies have been performed that assess CO_2 abatement measures within high temperature (HT) industry such as energy efficiency measures (EEM) (Yáñez et al., 2018; Dijkstra, 2017), carbon capture and storage (CCS) (Kuramochi et al., 2012; Turkenburg et al., 2016), fuel switching (VNPI, 2018; DNV-GL 2018), deployment of biomass both as feedstock and fuel (BIG) (Johansson, 2012; Johansson, 2013), electrification on the basis of power to heat technologies (P2H) (Lux research, 2018; Lechtenböhmer at al., 2016), the use of renewable energy sources (Taibi et al., 2012), and the transformation of petroleum refineries into biorefineries (CIEP, 2018; TOTAL, 2015). Besides individual measures, the decarbonization potential for different portfolios of measures have been studied as well (Fais et al., 2016). However, none of these studies assessed the decarbonization potential of a combined portfolio of measures and provided insights into implementation strategies and associated investment costs (Berghout et al., 2019). For this reason, Berghout et al. (2019) developed a method to assess the decarbonization potentials and strategies of a combination of decarbonization measures and deployment strategies. However, P2H, alternative fuels, waste heat (WH) and geothermal energy (GE) were excluded in the identified decarbonization pathways. But it is important to assess these alternatives because electrification of heat demand may also significantly reduce the CO_2 footprint (Kranenburg et al., 2016) and has potential synergies with WH, GE and CCS (Siemens, 2019). Besides the technological possibilities, Mazzucato (2018) argues that mobilizing finance for investment in low-carbon energy is a key challenge for climate change mitigation. Nonetheless, investors are integrating sustainability in their investment decision-making process (Revelli, 2017) and Lozano (2018) identified a positive relation between sustainability and access to capital but argues that uncertainty around

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[1] https://prtr.eea.europa.eu/#/industrialactivity

[2] Emissions can be divided into scope 1, 2 and 3. Scope 1 are emitted on site (direct). Scope 2 are related to generation of electricity at an off-site power station. Scope 3 emissions are emissions that occur in the value chain of the reporting company.

the role of new technologies is still one of the key implementation barriers of decarbonization measures. In the above-mentioned analysis of Berghout et al., (2019), the financial risks and opportunities associated with the implementation of decarbonization measures (e.g. investing in lock-in or no regret measures) are not assessed. As a matter of fact, most research on industrial greenhouse gas (GHG) emission abatement has been conducted from a techno-economic, system, and policy perspective. Investors strategy and how investors perceive the viability of sustainable investment are often covered less, especially in the field of high temperature industry. Besides the challenge of initial resource mobilization, the danger exist that financial resources are mobilized in the wrong direction and are lost for the right direction.

1.2 Outlook

The products produced by petroleum refineries are heavily debated, and European policy is promoting the use of biofuels, especially ethanol (Londo, 2007). Consequently, the future of *European* petroleum refineries does not look bright on the long term and many European refineries are projected to close (CIEP, 2018). In the past two decades, the number of European refineries has been declining and is expected to continue to decline with 1% a year (Total, 2019[3]), however, between 1993 and 2007, the average size of refineries *globally* increased[4] by 30% (Purvin and Gertz, 2008). In 2017, global refinery throughput (TP) grew by 2%, European TP by 2.9% and Dutch TP by 0.7% (BP, 2018). As Figure 1 shows, IEA scenarios project the global demand for light petroleum products[5] to grow. Meanwhile, the demand for heavier products[6] are projected to decline. This shift in output mix could have significant financial implications on the refining sector since the average refining margins (yellow dots, Figure 1) are the highest on the heavier products (gasoline, diesel, kerosene). It is uncertain in what way the mix of output products will change, but besides implications on the refineries business model, different output mixes affect the type and volume of CO_2 mitigation necessary[7].

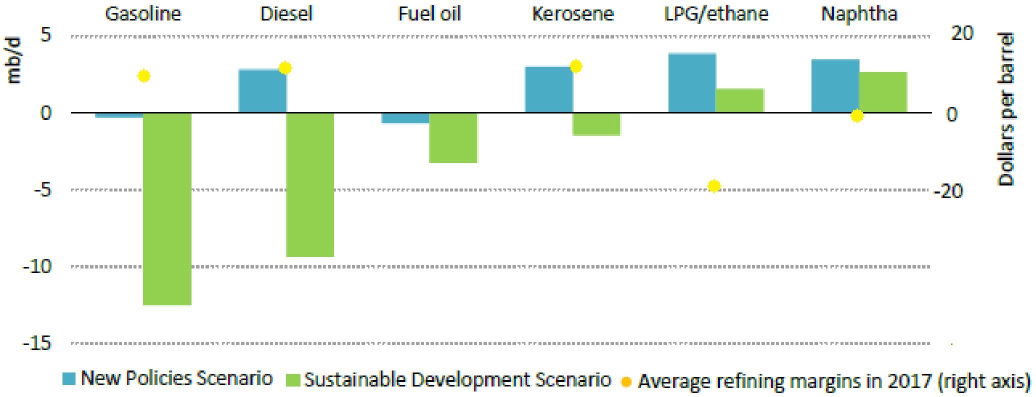

Figure 1 - Average refining margins today and changes in oil product demand by scenario (2017 – 2040) (extracted from WEO, 2018).

1.3 Objective

Navigating the energy transition, to reach the 2050 CO_2 reduction targets whilst staying competitive, comes with many difficult choices and sustainable strategies are required for the implementation of alternatives that reduce the CO_2 emissions of refineries. Such sustainable strategies will involve investments. As many of these are not or not yet economically feasible while there is significant external market pressure on the fossil products of refineries, this strategy needs to be based on smart pathways which are robust for changes in external factors and at the same time offer flexibility. For this reason, the techno-economic and

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[3] Based on interview with TOTAL R&D representative.

[4] Increase is part due to rationalization of smaller capacity and part to the addition of new, larger refineries. For example, refinery capacity in India increased by over 100%. This trend has not been followed in all regions. Russia sees overall capacity and capacity per site decline. Closing of smaller refineries is expected to continue as competition and tightening product qualities force a greater economy of scale. Remaining refineries are expected to upgrade and expand (Purvin & Gertz, 2008).

[5] Within this study, light products, or lighter ends include ethane, LPG and naphtha and are regarded as chemical feedstocks.

[6] Within this study, heavier products, or heavier yields include gasoline and middle distillates (diesel and kerosene) are regarded as fuels.

[7] Based on expert insight.

strategic (TES) performances of the individual and combinations of decarbonization measures were studied to determine:

> ***What is the optimal deployment pathway for deep decarbonization of the oil refining industry**?*

To answer this question, the Dutch refinery sector was used as case study. When considering 2017 scope 1 and 2 emissions, Dutch refineries accounted for 6.3% (12.7 $MtCO_2$/y) of the total Dutch CO_2 emissions (202 $MtCO_{2eq}$) (CBS, 2019[8]; VNPI, 2018). Because of the energy intensive character of oil refining and the pressure to decarbonize energy intense activities, the Dutch refining industry is especially affected by the increasingly stringent environmental legislation (Kranenburg et al., 2016). For this reason, risks associated with decarbonization measures for Dutch oil refineries were studied to assess what decarbonization measure(s) exhibit(s) the lowest regret potential. This was assessed by studying opportunities, interactions and favorable combinations between measures, including aspects such as how different decarbonization measures interact, how they can be combined, to what extent they overlap in abatement potential, policy dynamics, and risks for lock-in or stranded assets due to future market changes.

2. Method

Within this study, existing literature, theory and data was used and combined to quantitatively and qualitatively measure parameters and interactions of decarbonization measures. High performing measures were translated into decarbonization pathways of which the effect was modeled on different oil refining processes and future market changes. To identify optimal decarbonization pathways, 11 steps were followed. These steps were divided in four phases. Figure 2 below summarizes the phases and corresponding steps.

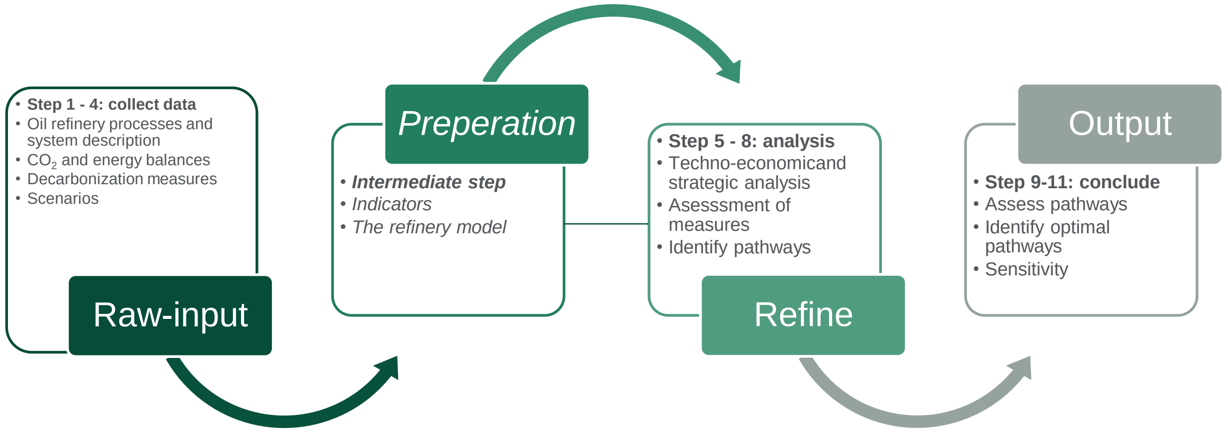

Figure 2 – The four study phases.

2.1 Raw-input phase

The first four steps of this study were dedicated to data collection and organization. First, data regarding the key parameters of the oil refinery processes and projections of baseline developments of the Dutch refinery industry was collected. Next, data regarding the decarbonization measures and scenarios were collected.

1. Creation of energy and CO_2 balance of the Dutch refinery industry.
2. Identification of the core processes in oil refineries. The key parameters related to the refineries energy system and core processes were identified such as: CO_2 emissions ($MtCO_2$/y), capacities

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[8] https://opendata.cbs.nl/statline/#/CBS/nl/dataset/70946NED/table?fromstatweb

(MW_{th}), load factors (%), process energy (PJ/y), thermal requirements (°C), fuel type, electricity demand, and energy infrastructural capabilities (CO_2, hydrogen (H_2)-infrastructure).
3. Inventory of relevant decarbonization measures and their techno-economic and strategic characteristics.
4. Analysis of scenarios to identify smart investment capacity and to determine whether pathways result in a favorable performance.

Table 2 below gives an overview of the main sources that were used during phase one.

Table 2 – Major sources for the input phase.

What	**Key data sources**
Refinery core processes	Treese (2015), Chaudhuri (2011), EC (2015), Worrell (2004)
Refinery energy and CO_2 flows: annual energy consumption, energy intensive processes, scope 1,2,3 emissions, crude throughput rates, fuel consumption	Papers: NAICS (2013), EC (2015), Worrell (2015), Neelis (2008) People: Niels Berghout (IEA), Maarten Neelis (RWS), Eugenia Pocabana (BP), Koen van Leuven (TOTAL), Matthijs Ruitenbeek (DOW), Corné boot (BP), Bart Leenders (Neste), Hans Meerman (RUG), Walter Vermeiren (TOTAL), Marc Zwart (Shell), David Hone (Shell), Bryan Milton (Exxon Mobil). Data: PBL, E-PRTR, abarrelfull, WorldRefiningSurvery2018 Companies: Port of Rotterdam (PoR), TOTAL, BP, Shell, Navigant, Deltalinqs, TNO, Neste, Exxon Mobil
Inventory of measures	EC (2015), Berenschot (2018), Kalavasta (2018), PBL (2018), Rebelgroup (2018), VEMW (2018), Navigant (2018) People: Mark Reissig (Siemens), Mark Schenkel, Paul Noothout, Kornelis Blok, Martin Junginger, Niels Berghout. Companies: Dow Chemicals, BP, BASF, Total, ExxonMobil, Neste
Scenarios	CIEP (2018), DNV-GL (2018), VNPI (2018), Wuppertal (2017), CIEP (2016), WEO (2018)

2.2 Preparation phase

To successfully carry out the refining phase, a preparation phase was implemented. This preparation phase describes an assessment and evaluating mechanism based on criteria, parameters and indicators. Literature, interviews and discussions with experts led to the creation of the indicators presented in this subsection. To assess measure performance, three fundamental criteria were identified: (1) technical, (2) economic, and (3) strategic. These criteria facilitate a dynamic assessment process with the objective to rank the relative performances of different pathways. The technical and economic criteria was measured using only one quantitative indicator for both. However, the strategic performance was assessed qualitatively.

2.2.1 Assessing technical performance

The fundamental indicator for the assessment of the technic performance of decarbonization measures is annually avoided CO_2 emissions (in tCO_2/y). This indicator was calculated using Equation 1 below.

$$\Delta CO2_a = \Delta CO2_{Offsite} + \Delta CO2_{Onsite} \qquad \textit{(Equation 1)}$$

In which:

- $\Delta CO2_a$ = Total annually avoided scope 1 and scope 2 CO_2 emissions (in tCO_2/y)
- $\Delta CO2_{Offsite}$ = Total annually avoided scope 2 CO_2 emissions (in tCO_2/y)
- $\Delta CO2_{Onsite}$ = Total annually avoided scope 1 CO_2 emissions (in tCO_2/y)

Scope 1 (onsite) and scope 2 (offsite) emissions were continuously separated. A list of emission factors (EF) per fuel can be found in Appendix 1b. Scope 3 emissions are excluded because these are not within the primary scope of this study. However, emissions of petroleum refinery products could be an interesting parameter for further research to analyze the impact of potential what-if events (e.g. policy/demand changes/biorefineries) that interact with and change the way scope 3 emissions are produced, handled and framed. In Appendix 5, two options are discussed related to scope 3 decarbonization.

2.2.1.1 The refinery model

To assess technical performance of decarbonization measures, a refinery model was created and used to calculate the amount of CO_2 that is emitted at the different refinery parts and elements according to a specific output. The refinery model was created by combining two different approaches. First, to get an in-depth understanding of the CO_2 allocation to the specific refinery process units, the "CO_2 Weighted Tonne" (CWT) method was used to allocate CO_2 emissions to specific process units according to its TP activity. Using 2017 TP data, baseline emissions at the core process units were calculated. Subsequently, the emissions were compared to output (in PJ petroleum products), giving insight in the relation between TP, output and emissions at a certain year. Detailed description of the CWT method and results can be found in Appendix 2.

The CWT approach has one disadvantage: it considers a refinery purely in terms of process units. Hydrogen (H_2), electricity, steam and fuel consumption (in PJ), that are produced and consumed either onsite or offsite are not threated individually. Secondly, it does not discriminate between refinery elements (e.g. boilers, combined heat and power plant (CHP), pump systems, process cooling, heating ventilation and air-conditioning (HVAC), lightning etc.). Regarding the goal of this study, this complicates the assessment of decarbonization measures with different technical characteristics and limitations. To overcome this limitation, the refinery model examines the refinery as an interrelated system which composes out of 'parts': generation, operation, support, hydrogen manufacturing unit (HMU). Each part has his own elements. All elements have their own steam, fuel, electricity and hydrogen consumption levels. This refinery model allowed a top down analysis scrutinizing energy flows within the refinery system. Detailed description of how the model is created and used is presented in Appendix 3.

2.2.2 Assessing economic performance

To assess the economic performance of measures, one indicator was used: annually CO_2 avoidance cost (C_a) in €/tCO_2/y. This indicator was calculated using Equation 2 below.

$$C_a = \frac{\Delta E_e * P_e + \Delta E_f * P_f + \alpha * I + \Delta C_{O\&M}}{\Delta GHG_a} \qquad \textit{(Equation 2)}$$

In which $\Delta E_{e,f}$ are the net change of annual electricity (in GJ$_e$/y) and fuel (in GJ$_f$/y) consumption. Depending on the specific refinery configuration, ΔE_f refers to the sum of the different types of fuels that are used within petroleum refineries. Fossil fuels (petroleum coke, refinery fuel gas (RFG), natural gas (NG)) and alternative fuels (H_2) were studied. $P_{e,f}$ are projected 2025 industrial prices of electricity (in €/GJ$_e$) and fuel (in €/GJ$_f$). $\Delta C_{O\&M}$ is the net change in operation and maintenance (O&M) costs (in €/y). Investment (*I)* are the upfront investment costs (in €), including additional infrastructure costs. *I* is used to calculate the total capital requirement (TCR). TCR is derived by multiplying process plant costs (PPC) with common percentages for the other cost components. To annualize the investment costs, *I* is multiplied with the annuity factor (α), see Equation 3 below.

$$\alpha = \frac{r}{1-(1+r)^{-LT}} \qquad \textit{(Equation 3)}$$

In which *r* is the real discount rate (%) and LT is economic lifetime (years) of the decarbonization measure.

All techno-economic input parameters that were used during this study can be found in Appendix 1.

An in-depth description of the measures, their specific economic input parameters, and ranges used for sensitivity analysis can be found in section 4.

2.2.3 Assessing strategic performance

For identifying the decarbonization pathways, this study included risks and opportunities associated with a certain decarbonization measure. The goal of the strategical assessment is to provide a systematic overview of the risks and opportunities associated with a decarbonization measure indicating whether investment opportunities outweigh risks or vice versa. To *assess* the strategic performances of measures, four strategic indicators were created based on interviews with high temperature industry representatives. The strategic indicators adhere to four underlying requirements: (1) indicators may not overlap with techno-economic indicators, (2) indicators should be specific for the refining sector, (3) indicators are from a refinery investment decision makers perspective, and (4) indicators must relate to opportunities and risks.

- *Technological maturity*: known technologies are preferred over the unknown. Technology readiness level (TRL) is measure for technological novelty. Measures how adequate a new technology fits in the current system. This indicator involves matters such as amount of complementary technologies, technological synergies, technological controllability, flexibility, and security of energy supply. A low score indicates high risk; a high score indicates low risk.
- *Operational reliability*: by focusing on flexibility, operational reliability measures the capabilities of the technology within an oil refinery now and in the future. A maximum continuous, independent and safe operation is preferred. Technological failures, maintenance hook-ups, and dependency on macroeconomic events are undesirable.
- *The X-factor*: certain technologies are perceived as more appealing to others, for this reason this indicator focusses on the public opinion towards a specific measure. This involves public support, policy support, policy consistency and external integration.
- *Emerging markets*: this indicator focusses on future potential success of a measure and considers future proofing, market dynamics, future growth potential, the degree in which the measure disrupts incumbent routines, processes and markets. This involves knowledge diffusion, horizontally integration of (existing) knowledge, new business opportunities and matches with current competences.

To *evaluate* which measure/pathway offers many risks or opportunities, the strategic performance of measures is assessed based these indicators. Interviews with refining industry representatives were used for indicator creation, fine-tuning and scoring, reflecting the decision makers perception of the viability of a certain sustainable investment.

2.3 Refining phase

The refining phase consists out of steps 5-8 and is divided into two parts. The first part (step 5 and 6) involve a techno-economic and strategic (TES) assessment and analysis of the *measures* that were identified during the input phase. The prepared indicators are quantitatively and qualitatively scored to assess the TES performances of the measures.

5. TES assessment of decarbonization *measures* according to described indicators.
6. Analysis of TES performance of measures. Interactions among promising decarbonization measures are identified. Interactions can be synergies, scale benefits, overlap in abatement potential, technological lock-in or path dependencies.

The second part focusses on the TES analysis of the *pathways*. This involves similar steps as in part one but than for combinations of measures.

7. Identification of decarbonization pathways consisting of a combination of potential decarbonization measures with positive and negative interactions. Negative interactions (risks) can be used to demonstrate regret pathways.
8. Identification of risks and opportunities of decarbonization *pathways* from the perspective of the decision maker. Risks and opportunities are used to determine the strategic performance.

2.4 Output phase

The final phase of this study consists of the last three steps (9-11) during which the selected decarbonization pathways with respect to their TES performances are assessed on the Dutch petroleum refining sector.

9. Assessment of selected decarbonization pathways with respect to its TES performance.
10. Identification of optimal decarbonization pathways that show favorable TES performance and interactions for the different scenarios based on the marginal abatement cost curve (MACC) and technical potential until 2050.
11. Sensitivity analysis to evaluate the impact of the techno-economic parameters.

3. Petroleum refining

Petroleum refining is a complex industry in which natural occurring hydrocarbons are converted into useful products such as transportation fuels, combustion fuels, raw materials for the petro- and chemical industry, specialty products, and energy as a by-product in the form of heat and power (EC, 2015). The refining process involves a range of steps such as distillation, cracking, reforming, and treating. These processes are explained in section 3.1. A refinery is the term for all these different process units together, including supporting units and facilities (EC, 2015). There are no typical refineries. The configurations and processes in a refinery depend on several factors such as the crude feed composition, the product demand, local regulations and economics (DNV, 2010). Most of the processes that take place at a refinery are highly reliant on process heating and steam energy (NCAIS, 2013), this in combination with the large refining throughput (TP) quantities, made petroleum refining one of the most energy-intensive industries (EC, 2015). The energy intensive character of refineries in combination with environmental concerns and compliances has led to an increased attention of the environmental performance of oil refineries. In section 3.2, the general refinery's energy system is covered. Next, the Dutch refineries and their energy system are explained in section 3.3.

3.1 Refinery core processes

Naturally occurring crude oil, also known as petroleum, is a liquid mixture of hydrocarbons of varying shape and length, with several impurities such as sulphur and nitrogen. In an oil refinery plant, crude oil is converted into usable petroleum products. The major refining processes in modern refineries are shown in Table 3 below. In all refineries, crude oil is first desalted (dissolved brine is removed by washing) to prevent corrosion and minimize fouling of process units and heat exchangers (Treese, 2015; Worrell, 2004) after which it enters the distillation unit where the desalted crude is split into three main fractions according to their boiling ranges.

Table 3 – Overview major refining units and products (EC, 2015; Fahim, 2010).

Physical separation	**Chemical conversion**	
	Catalytic	***Thermal***
Distillation (atmospheric and vacuum) *(Table 4)*	Reforming *(Reformate, H_2)*	Coking *(delayed/flexi) (Kero/Naphtha Heating oil/diesel HFO Coke/bitumen)*
Solvent deasphalting *(desalted crude oil)*	Hydrotreating *(Gasoline, Kerosene (Kero) /naphtha, heating oil/diesel)*	Visbreaking *Liquified petroleum gas (LPG), Gasoline, Kerosene/Naphtha Heating oil/diesel, HFO*
Solvent extraction and dewaxing *(waxes, white oils, extracts, bright stock)*	Hydrocracking *(Gasoline, Kero/naphtha, heating oil/diesel, Heavy fuel oil (HFO))*	
	Fluid catalytic cracking *(Liquified petroleum gas (LPG), Gasoline, Kero/Naphtha, Heating oil/diesel, HFO)*	
	Alkylation - reversed cracking (*Gasoline)*	
	Isomerization (*Gasoline)*	

**The products between brackets are output products*

3.1.1 Physical separation processes

Crude distillation (CDU)

There are two primary CDUs: atmospheric and vacuum crude oil distillation unit (A/VDU). At the ADU, a two-stage heating process is used to heat the crude oil. First, waste heat and hot product streams are used to heat the crude to 290°C. Next, a gas fired furnace is used to heat the crude to about 400°C after which the crude is fed into the distillation column where the lighter fractions of the crude oil vaporize, and the heavier ones remain as liquid. The vaporized fractions move up the vertical distillation column. Usually there are around 30-50 trays within the column that collect liquid and allow gases to move higher up the column. The temperature in the column decreases with increasing height; at certain heights the temperature will be such that a certain fraction condenses. This means that the liquids in each of the trays are different and removed from the column as different products. The heavier fractions that remained as liquid (atmospheric residue) are fed to the VDU where the feed is heated up to 400°C, partially vaporized (30 - 70% w/w) and flashed into the vacuum column at a pressure between 30 and 100 mbar (EU, 2015). The different product streams leaving the distillation columns are shown in Table 4 below.

Table 4 – Crude distillation products (based on Fahim, 2010; EU, 2015; and McKinsey energy insights, 2019[9]).

Unit	*Product*	*Yield (wt%)*	*True boiling temperature (°C)*
Atmospheric distillation (ADU)	RFG (C1 – C2)	0.10	-
	LPG (C3 – C4)	0.69	-
	Light straight-run naphtha (C5 – C6)	3.47	32-82
	Heavy straight-run naphtha (C7 – C9)	10.17	82-193
	Kerosene (C9 – C12)	15.32	193-271
	Atmospheric gasoil, LGO (C14 – C20)	12.10	271-321
	Heavy gas oil, Atmospheric residue (C>15)	21.10	321-427
Vacuum Distillation (VDU)	Vacuum gas oil (VGO, bunker fuels)	16.80	427-566
	Vacuum residue - VR, Coke/bitumen (>C30)	20.30	+566

Solvent deasphalthing

Deasphalting is an extraction process used to remove the asphaltene from the vacuum residue to prepare a suitable feedstock for the catalytic conversion units (Treese, 2015) or to be used as feedstock for the lube oil plant. Liquid propane or propane-butane mixes at moderate temperature and pressure (37 - 40 bar and 40 – 70 °C) is usually used as solvents after which the asphaltene precipitates (EU, 2015). The deasphalted oil (DAO) has low sulphur and metal contents since these are removed with asphaltene. This oil is also called “bright stock”.

Solvent extraction and dewaxing

In these processes, deasphalted lube oil feedstock from heavy vacuum distillates leaving the VDU are treated by a solvent, which can dissolve the aromatic components. In the solvent extraction unit, the solvent is removed and the product (raffinate) enters the solvent dewaxing unit where it is dewaxed. In the solvent dewaxing unit, the raffinate is dissolved in a solvent and the solution is gradually chilled, during which high molecular weight paraffin (wax) is crystallized, and the remaining solution is filtered (Fahim, 2010). The extracted and dewaxed resulting oil is called “lube oil”.

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[9] https://www.mckinseyenergyinsights.com/resources/refinery-reference-desk/

3.1.2 Chemical catalytic conversion processes

Hydrotreating (HT)

After distillation and prior to catalytic reforming and/or hydrocracking, the A/VDU feed enters the HT unit. A HT reactor consumes H_2 and is one of the major processes for the cleaning of petroleum fractions from impurities. Energy is used to heat the feed stream and to power the transport of the flows (Worrell, 2004). In a HT reactor, the feed stream is mixed with H_2 and heated at a temperature between 260°C and 430°C to remove unwanted contaminants using catalysts (Dragomir et al., 2010; Fahim, 2010; Worrell, 2004). These are unwanted because they form pollution during the production of fuels and lubricants, have a negative effect on the equipment, catalysis and the quality of the finished product (RHDHV, 2015; Cheremisinoff, 2009). The catalyst is selected to suit the degree of hydrotreating and type of impurity. There are different purposes of HT, for example:

- To remove sulfur: hydrodesulfurization. Catalysts such as cobalt and molybdenum oxides are commonly used to help the H_2 react with sulfur and nitrogen to form H_2 sulfide (H_2S) and ammonia.
- To remove nitrogen, oxy-compounds, chloro-compounds and metals.
- To improve the burning characteristics of distillates such as kerosene.
- To improve product quality (e.g. color, odor, acid nature).
- To improve the quality of pyrolysis gasoline.

Catalytic reforming (CR)

In this process, platinum is used to reform the desulfurized heavy naphtha fraction leaving the HT units into aromatics (such as BTX) or high-octane gasoline (Chaudhuri, 2011; Fahim, 2010). In this unit, naphtha is preheated by multiple heat exchangers and heated in a pipe-still heater to a temperature of 350°C in the presence of H_2 over a platinum catalyst packed bed reactor. The product leaving the CR, reformate, is used for blending of different refinery products (e.g. gasoline blend stock) (EU, 2015; Worrell, 2004). Since the platinum catalyst is easily poisoned, the naphtha must be preheated before reforming. This takes place in the catalytic H_2 pretreatment reactor where the naphtha stream of 90 – 140°C is desulfurized and then sent to a platinum CR unit. The CR also produces H_2, which is sent back to the HT unit.

Catalytic hydrocracking (HC)

Catalytic cracking of C-C bonds in the presence of H_2 is called hydrocracking. This involves high pressure and temperature cracking of the higher molecular weight fractions such as atmospheric and vacuum residues (Chaudhuri, 2011). To get light products, the input streams are cracked in the presence of H_2 (RHDHV, 2015; Fahim, 2010). In this case, two catalysts are used: a zeolite catalyst for the cracking function during which unsaturated derivatives are formed and alumina for the hydrogenation function to form saturated derivatives (Fahim, 2010). The main products are naphtha, jet fuel and diesel oil (Worrell, 2004). The feed is heated to 350 – 410°C using multiple heat exchangers which withdraw heat from different product streams (RHDHV, 2015). Specification of a modern advanced hydrocracker (ExxonMobil) can be found in Table 5 below.

Table 5 – Specifications of ExxonMobil's most recent advanced hydrocracker (RHDHV, 2015).

Component	*Installed capacity (MW)*	*Energy consumption (TJ/y)*	*Emissions (ktCO$_2$/y)*
Process furnaces	24	760	45
Heat exchangers	12	380	25
Pumping, compressors, coolers	22	700	90
Total	58	1840	160

Fluid catalytic cracking (FCC)

Being the most important and widely used conversion process in refineries, the FCC is the main player to produce high-octane gasoline, diesel and fuel oil (Fahim, 2010; Worrell, 2004). The catalyst is a zeolite base for the cracking function. The main feed to the FCC is VGO and the main product is gasoline. In the reactor, the preheated feed (260 - 425°C) is cracked at 480 - 540°C to smaller chains (Chaudhuri, 2011; Worrell, 2004). Depending on the feed and reactor conditions, different products are produced. During the process, coke (excess carbon) is deposited on the catalysts which are simultaneously regenerated for reuse. Regeneration of catalyst takes place by burning off the coke to CO and/or CO_2. As a result, CO_2 is formed as a byproduct. Since the cracking reactions are endothermic and regeneration is exothermic, there is an opportunity for thermal integration (Worrell, 2004). Globally, FCC is one of the largest catalytic processes and small process efficiency gains has a large absolute effect on GHG emissions (Vogt, 2015). Consequently, FCCs are rapidly developing into the next generation FCC, which can better separate and recover high value chemicals alongside the increase of improved quality gasoline production, thereby reducing emissions and energy input (DNV-GL Energy, 2018).

Alkylation

Reverse cracking, or alkylation, is the process in which isobutane reacts with low molecular weight olefins (C3-C5) such as butylene (C4) to produce a gasoline range alkylate which are used in jet fuels, butane liquids, LPG, and tar-like by-products (EC, 2015; Worrell, 2004). The feedstock, isobutane, is produced by the HC, FCC, CR, and CDU units. The olefin feedstock is produced by the FCC and coker (explained in section 3.1.3) units (EU, 2015). The process takes place at low temperature (4 - 45°C) and at the presence of strong acids. The catalysts are either sulphuric acid (H_2SO_4), which operates at 4 - 15°C or hydrofluoric acid (HF), which operates at 25 - 45°C. The hydrocarbons and acid react in liquid phase.

Isomerization

Isomerization of light naphtha is the process in which light hydrocarbons (C4 - C6) are separated and transformed into a branched product with the same carbon number. One main advantage of separating hexane (C6) before it enters the CR, is that this prevents the formation of benzene which produces carcinogenic products on combustion with gasoline. The main catalyst in this case is a Pt-Zeolite base.

3.1.3 Thermal chemical conversion processes

Coking

Coking is a thermal cracking process used to reduce the production of low-value residual fuel oils and transform them into transportation fuels (EC, 2015). These processes are considered as upgrading processes for vacuum residues from the VDU. In this thermal process, most of the coke is gasified into fuel gas using steam and air. The preheated vacuum residue feed is sprayed into the reactor, there it is thermally cracked at 510-540°C. The burning of fuel gas by air will provide the heat required for thermal cracking.

Visbreaking

This is a mild thermal cracking process used to break large hydrocarbon molecules into smaller lighter molecules. The residue is either broken in the ‘coil or furnace cracking’ (coil visbreaker) at higher furnace outlet temperatures (470 – 500°C) and reaction times from one to three minutes or within the soaker cracking (soaker visbreaker) using lower furnace outlet temperatures (430 – 440°C) with longer reaction times. The product yields and properties are similar from both processes. The products are gases, gasoline, gasoil and the unconverted residue. The unit is called Visbreaker because the viscosity of the vacuum residue is reduced significantly (EC, 2015).

3.2 Energy system and conversion technologies

Energy consumption has always been a major cost element for refinery operators and currently accounts for around 60% of operating costs of UK refineries (UKPIA, 2017). Refineries need heat and electricity to operate (Concawe, 2012). Currently, all the heat and electricity necessary for the refinery processes comes from fuel (gaseous and/or liquid) combustion systems. Furnaces, boilers and combined heat power (CHP) plants are used to produce heat, steam and electricity. Heating furnaces play an important role in modern oil-refining as they are responsible for 63% of the total energy consumption and 52% of the emissions into the atmosphere (own calculation[10]). In the furnaces, heat from combustion is directly released to the process stream. Most furnaces can combust both oil and gas, providing flexibility in the fuel system. In the boilers, steam is produced which is used somewhere else in the refinery. The boilers are responsible for 12% of the total energy consumption and 15% of the emissions into the atmosphere (own calculation[11]). Furnaces and boilers achieve thermal efficiencies of over 85% and in the case when waste heat is used, the thermal efficiency can be up to 93%. The CHP plant consumes around 15% of the total energy requirement and 12% of the total emissions (own calculation[12]).

3.2.1 Fuels and fuel systems

Within petroleum refineries, energy commodities are used both for feedstock as for energy for steam and power production or for the firing of furnaces. A part of the refinery output cannot be sold and is used as input energy. This means that during the production of petroleum output products, another type fuel is created. This fuel, termed refinery fuel gas[13] (RFG), is a leftover stream mixture of methane, ethane, ethylene and H_2, occasionally with some C3, C4, N_2 and H_2S traces which are not economically recoverable for the use as a feedstock or for sale as products (Chaudhuri, 2011; Treese, 2015). Burning it eliminates the need to dispose it as a waste product while energy can be recovered. In most cases, the RFG production is not high enough to entirely heat the furnaces, boilers and CHP. For this reason, the RFG stream is blended with NG to cover the remaining energy demand (see Appendix 1f). A single source of RFG can be burned locally in the unit where it is generated, or it is sent to one or more refinery fuel headers to be combined with other fuel gas streams. Using RFG as a main combustion fuel instead of NG has several consequences:

- Due to relatively high fuel-sulphur content, higher sulphur oxides emissions are produced. To meet environmental regulations, RFG must be treated to reduce its sulphur content before combustion, or the sulphur oxides must be scrubbed out of the resulting flue gas.
- Due to the higher flame temperatures of RFG, more NO_x is produced.
- Due to a higher carbon content RFG has a higher[14] EF (emission factor) compared to NG: 66.7 vs 56.1 $kgCO_2/GJ$ (Vreuls, 2004).

3.3 Petroleum refining in the Netherlands

Dutch refineries are facing severe competition within Western Europe (van den Bergh, 2016). However, due to the large oil storage capacity of the ports of Rotterdam (PoR) and Amsterdam, the Netherlands has become a major transit and product trading center for oil products in Europe (BP, 2018; VNPI, 2015). As a result, the Dutch refinery industry is relatively large and active. In the Netherlands there are six refineries with different specifications and configuration. In literature, four different types of refineries have been classified based on the degree of facility complexity. From least to most complex, these are termed: (1) topping, (2) hydro skimming, (3) cracking, and (4) full conversion refineries (Britannica, 2019[15]; Treese, 2015). Topping refineries are designed to prepare feedstocks for the petrochemical industry and produce industrial fuels. When HT and reforming units are added, it becomes a more flexible hydro skimming facility

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[10] Dutch petroleum refinery industry based on 2017 activity. Values are in line with literature sources stating that furnaces are responsible for more than 50% of the total energy consumption and emissions into the atmosphere (EC, 2015).

[11] Dutch petroleum refinery industry based on 2017 activity. Values are in line with other sources stating that boilers are responsible for 10-20% of the refinery energy requirements (EC, 2015).

[12] Dutch petroleum refinery industry based on 2017 activity. Values are in line with other sources stating that the CHP is responsible for 10-20% of the refinery energy requirements (EC, 2015).

[13] Different names are used interchangeably such as refinery gas, refinery waste gas or off-gas. This study used RFG.

[14] Other sources were found that indicate lower EF (EC, 2015). Within this study, 66.7 $kgCO_2/GJ$ was used. See Appendix 1b.

[15] https://www.britannica.com/technology/petroleum-refining/Refinery-plant-and-facilities#ref624137

which can produce desulfurized distillate fuels and high-octane gasolines. When adding cracking process units, the facility can process heavy atmospheric residue and convert it into more valuable products. The most complex type of refinery is the full conversion refinery which is the most flexible, has the greatest possibility in crude refining to make the maximum number of high-value products and minimum by-products (Treese, 2015). Refinery configuration and the degree of complexity influences the refineries energy system, energy consumption pattern, CO_2 emissions and ability to refine varying quality crude oil. Complex refineries can process lower quality crude, making it derive the benefits of purchasing lower quality, often discounted crude oils (VNPI, 2015). The Dutch refineries that are scope of this study are introduced in Table 6 below.

Table 6 - Overview Dutch refineries and specifications.

Refinery / description	**Key specifications in 2017**
Shell Pernis: a coastal refinery integrated with Moerdijk chemical site. Has a world scale steam cracker with significant feedstock flexibility. Integration facilitates upgrading of refinery by product streams (e.g. hydrowax) and further processing of steam cracker backflows (CIEP, 2016). Already captures and utilizes 0.3 $MtCO_2$/y from facility to nearby greenhouses[16].	Type: full conversion (Wanders, 2017). TP of 404 kb/d (ADU) and 440 kb/d (VDU) (worldwide refinery survey, 2018). CO_2 emissions of 3.8 Mt/y (E-PRTR, 2019). Nelson complexity index[17] of 7.7 (VNPI, 2015).
ExxonMobil: a coastal refinery, integrated with Exxon's world scale aromatics plant in the Botlek area. The refinery is an important source of sulphur-free naphtha and H_2 for the aromatics plant. Excess refinery gas is used by the nearby Air Products plant to produce H_2, which is supplied to the Exxon aromatics plant (CIEP, 2016). In 2019 operational advanced hydrocracker improved refinery process efficiency with 5%[18].	Type: full conversion (Wanders, 2017). TP of 191 kb/d (ADU) (worldwide refining survey, 2018) CO_2 emissions of 2.1 Mt/y (E-PRTR, 2019). Nelson complexity index of 9.3 (VNPI, 2015).
BP Rotterdam: a coastal standalone refinery with a relatively simple configuration and limited downstream integration. But, with large size and considerable flexibility (CIEP, 2016). Large fluid catalytic cracker (FCC) and high gasoline yield. Currently deciding whether to invest in a hydrocracker[19].	Type: full conversion (Wanders, 2017). TP of 367 kb/d (ADU) (worldwide refining survey, 2018) CO_2 emissions of 2.1 Mt/y (E-PRTR, 2019). Nelson complexity index of 5.4 (VNPI, 2015).
Zeeland refinery: a standalone coastal refinery with beneficial configuration (i.e. outsized hydrocracker) and some downstream integration (CIEP, 2019). WH is delivered to nearby industry (Total, 2019). Owned by Total (55%) and Lukoil (45%) (abarrelfull).	Type: cracking (assumption) TP of 166 kb/d (ADU) (worldwide refining survey, 2018) CO_2 emissions of 1.6 Mt/y (E-PRTR, 2019) Nelson complexity index of 11.5 (VNPI, 2015)
Gunvor and Vitol are both coastal refineries with a simple configuration. Within this study, no individual attention is given to these refineries. Some sources indicate that Vitol is closed, others refer to Smid & Hollander Raffinaderij with a TP of 10 kb/d. Other sources neglect a sixth Dutch refinery.	Type: topping (assumption) TP Gunvor of 84 kb/d (ADU), Vitol no data (worldwide refining survey, 2018) CO_2 emissions: Gunvor of 0.42 Mt/y, Vitol of 0.12 Mt/y (estimation based on previous years of E-PRTR data)

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[16] Based on interview with technology manager Shell Pernis on 28/5/2019.

[17] Nelson complexity Index (NCI) is a measure used to compare the secondary conversion capacity of a petroleum refinery with the primary distillation capacity (Reliance, 1998). The goal is to provide construction costs based upon a refinery's current distillation and upgrading capacity (VNPI, 2015). The more complex, the higher the upgrading costs.

[18] Based on presentation given by Exxon Mobil representative on 27/5/2019.

[19] Based on interview with BP representative on 5/6/2019.

4.3.1 Dutch refinery activity

Figure 3 below gives an overview of the Dutch refinery core process units that are present (x-axis) and the 2017 activity levels (TP) through these units (y-axis) in thousand barrels per day (kb/d). A detailed overview of the TP data used within this study can be found in Appendix 1d.

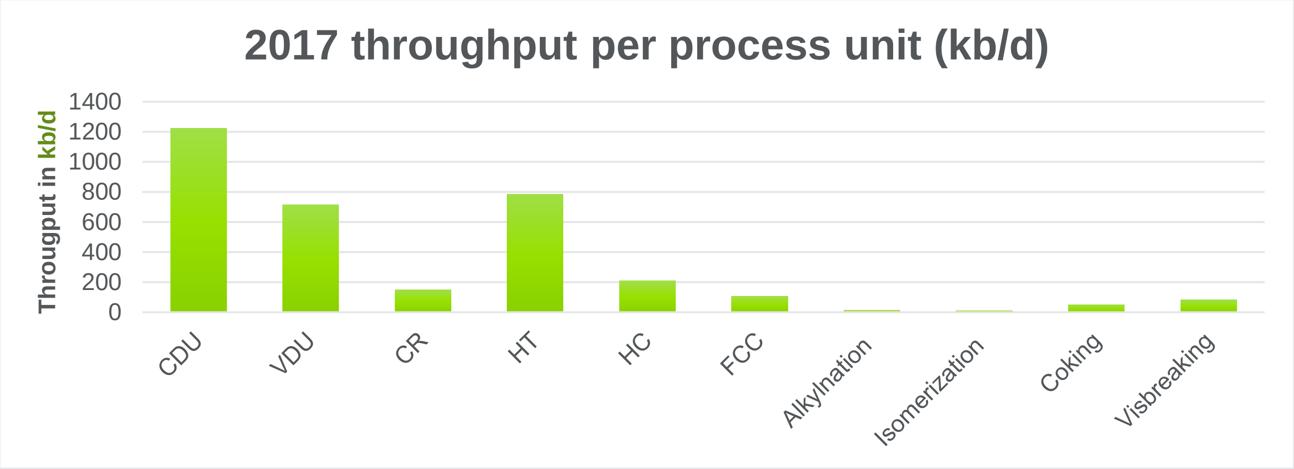


Figure 3 – Dutch refinery configuration and 2017 TP (worldwide refining survey, 2018).

3.3.2 Dutch refinery energy demand

To get an impression how energy is consumed at different refining processes, Figure 4 visualizes energy distribution among the specific process units within the Dutch petroleum refineries at 2017 baseline output. Data is based on the 2017 energy balance of the Dutch refinery sector. Within Figure 4, energy use is expressed as primary energy consumption. CHP electricity generation is assumed to be 32%, boiler efficiency is assumed to be 77%. Transmission and distribution losses are included (see Appendix 1b). Steam demand and temperature composition can be found in Appendix 1e. The sum of NG (red) and RFG (blue) represent the total fuel demand, the share in which the two fuels contribute to the total is assumed to be equal for all process units. How this is calculated can be found in Appendix 1f.

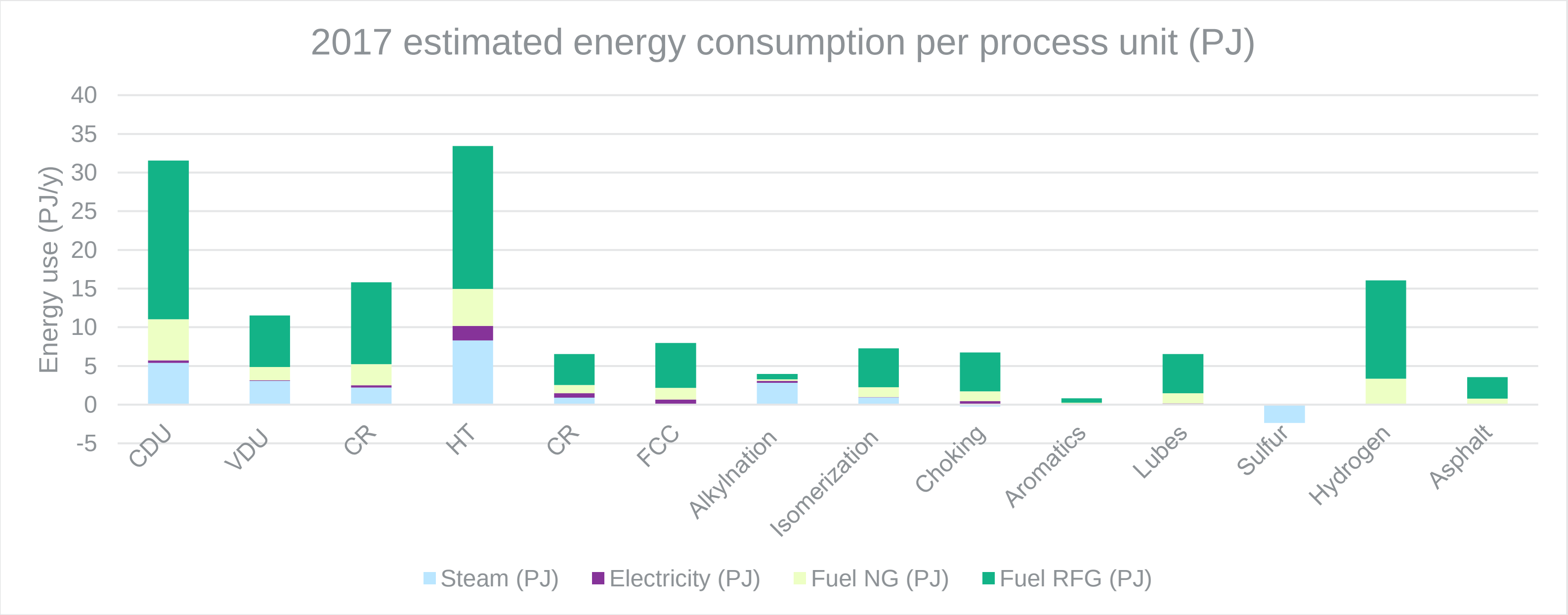


Figure 4 – Distribution of energy demand per process unit (based on Worrell (2004), CBS (2019) and worldwide refining survey (2018)).

4. Decarbonization measures

This section explores the measures that can be implemented to decarbonize the refinery key parts and elements. Determination the refinery elements that are targeted per measure and the associated decarbonization potentials calculated using the refinery model is explained in Appendix 3.

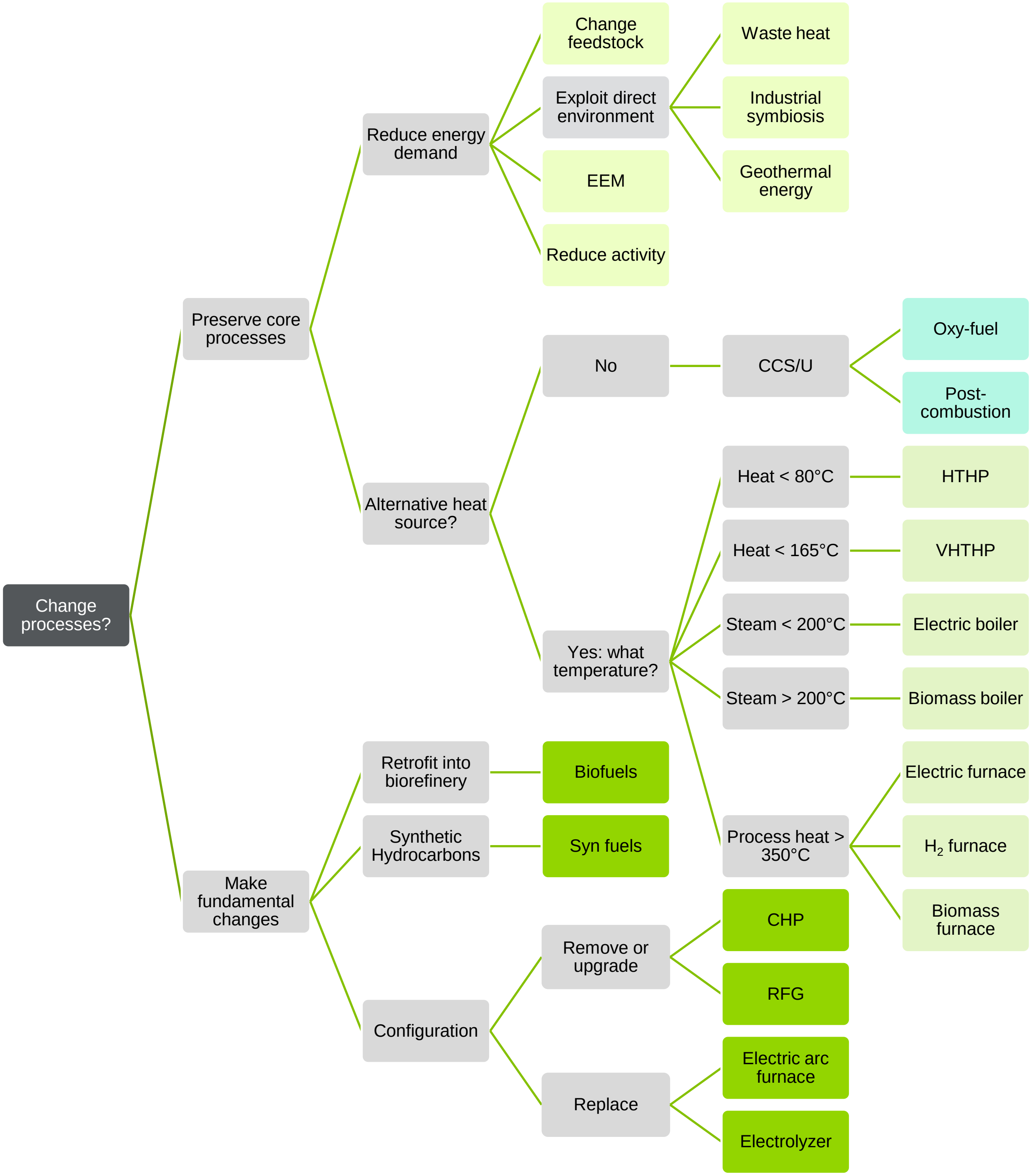
4.1 Identification & classification of available measures

Presented in Table 7 below, four fundamental decarbonization strategies were identified: (1) Improve, (2) Ex-post cure, (3) Ex-ante adjust, and (4) Rethink & change. These strategies include different decarbonization measures and are structured according to their impact on the refinery system. The first two strategies primarily aim to avoid CO_2 emissions whilst the core refining processes and energy systems remain unaltered. The other two strategies decarbonize the system by changing the fuel or by modifying the processes. The identified decarbonization measures are visualized on Figure 5 on the next page. For deciding whether a measure is appropriate to decarbonize a specific refinery part or element, process characteristics (e.g. FCC process emissions, catalysts optimization, (steam) temperature requirements) have been used as key criteria. The decarbonization potential depends on the current refinery configuration, activity, and capacity. Not all measures presented in Table 7 and Figure 5 have been assessed due to time constrains and data limitations. The measures that have been assessed including the techno-economic input data that was used within this study is described in the next subsections. An overview of the techno-economic calculations including intermediate steps can be found in Appendix 6. Complementary descriptions of the individual measures can be found in Appendix 4.

Table 7 – Overview of decarbonization strategies, associated measures and relative impact.

Impact	**Strategy**	**Measures**
Minimal	Improve: *reduce CO_2 emissions but continue business as usual by focusing on lowering energy demand.*	• Implement energy efficiency measures (EEM) • Reduce activity by lowering throughout (TP) • Decrease middle distillates/gasoline (MG/G) ratio • Implement geothermal energy (GE) • Intensify and optimize use of waste heat (WH) • Integrate with other industry; industrial symbiosis (IS)
Minor	Ex-post cure: *lower CO_2 emissions but keep existing processes and energy sources by focus on afterwards treatment of CO_2 emissions that have been formed.*	• Apply post-combustion CCS technology (POST) • Apply oxy-fuel combustion CCS technology (OXY)
Major	Ex-ante adjust: *prevent CO_2 formation from combustion but keep existing refinery processes by changing energy source or carrier*.	• Electrify low heat demand using high/very high temperature heat pumps (HTHP/VHTHP) • Electrify low/middle temperature steam production by implementing electric boilers • Install biomass or H_2 boilers for high temperature steam production • Electrify high temperature process heat such as cracking processes using electric furnaces • Apply pre-combustion CCS technology (PRE) • Retrofit current combustion furnace into a H_2 (blue/green) or biomass furnace
Maximum	Rethink & Change: *lower CO_2 with different processes, inputs and output products.*	• Change HMU; replacement of SMR with an electrolyzer to make H_2 • Remove CHP • Retrofit petroleum refinery into a biorefinery (biofuels and bio feedstock) • Change structure of energy flows by integration of endo- and exo-thermal processes • Prepare refinery for synthetic fuel production • Implement hybrid systems (e.g. H_2-electric boilers)

Figure 5 – Arrangement of identified decarbonization measures.



4.2 Techno-economic performances of assessed decarbonization measures

The decarbonization measures that were assessed within this study are explained in the next subsections.

4.2.1 Improve

Measures within this strategy aim to avoid CO_2 emissions by reducing the fossil fuel input with minimal consequences on the refinery system. Energy efficiency measure (EEM), waste heat (WH), and geothermal energy (GE) have been assessed. Berghout et al., 2019 identified an overview EEM for petroleum refineries in general, these have been used within this study (see Appendix 4d).

Waste heat for cooling

Depending whether the heat is being used directly at the same or at a lower temperature level or whether it is transformed to another form of energy or to a higher temperature level, technologies that can use WH from industry can be categorized as passive (heat exchangers, thermal energy storages) or active (sorption chillers, mechanically driven heat pumps, organic Rankine cycles). The active applications can be subcategorized into three types: to provide heat (WHTH), cold (WHTC) or electricity (WHTP). WHTH and WHTC are considered heat transformation technologies as they modify the inlet temperature (Bruckner, 2015). Because the refineries indicated that most of their WH streams are to a large extent already optimized and *many WH solutions are part of EEM*, it was decided to not assess WHTP and WHTH, but to expend the existing EEM identified by Berghout (2019) with WHTC for the specific refinery element dedicated to cooling. It is assumed that WHTC can fully decarbonize this element. It is assumed that high pressure steam produced by the SMR is used as heat source. In theory, 30 GJ_{th}/tH_2 would become available at the SMR, when losses are considered it is assumed that 83% of this can be recovered (Berghout et al., 2019), which is more than enough for cooling. The techno-economic parameters of WHTC used in this study are based on general WH technologies (see Table 8). The low-high values are used for the sensitivity analysis.

Table 8 - Techno-economic parameters WHTC.

Waste heat for cooling	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Process cooling [a]	Assumption
Capacity	MW (low – used - high)	8 – 23.25 - 45	Navigant, 2019
Full load hours	Hours/y (used - high)	8000 [b] - 8760	Navigant, 2019
Technological life time	Years (low – used – high)	12 – 18 - 25	Navigant, 2019
Investment	M€/MW (low – used – high)	0.4 – 0.73 – 1.2	Navigant, 2019; Assumption
Energy costs [c]	€//MWh (low – used - high)	0 – 0.5 – 1	Navigant, 2019
Other O&M	% of investment (low – used – high)	1 – 3 – 5	Navigant, 2019
CO_2 avoided	-$ktCO_2$/y (used)	9 [d]	Flow model
C_a	€/tCO_2 (average)	-80 [e]	Appendix 6b

[a] At baseline output levels, energy demand of this element is 0.12 PJ_{fuel}. It is assumed that WHTC fully replaces current gas fired cooling equipment with 90% efficiency. Emissions generated by the overall RFG:NG fuel ratio are therefore reduced 100%.

[b] 8000h/y has been used [expert opinion]: 8760 is regarded unrealistic.

[c] Low amounts of green electricity is used for cooling equipment.

[d] Adds 0.1% to EEM ST CO_2 avoidance potential.

[e] Ca of EEM ST increases proportionally: from -153 €/tCO_2 to -152 €/tCO_2.

Geothermal energy

Heat from the earth's crust can also be used to generate heat and/or steam. Geothermal energy (GE) replaces the fuel steam 1:1 and offers therefore a promising and sustainable alternative for heating buildings, greenhouses and for applications in industry. Integration of GE with heat pump (HP) systems and CHP plants could also provide heating suitable for energy intensive industry and is expected to be developed during the next 10 years (EGEC, 2014). HP/CHP integrated GE systems have not been assessed within this study. However, because of the diverse potential applications of GE and the geological expertise of oil companies, it was decided to include GE within the analysis. It is assumed that GE can reach temperatures up to 150°C[20]. It is assumed that the temperature demand of the facility HVAC[21]

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[20] Some sources indicate higher temperatures, up to 200°C can be reached (VNCI, 2018).

[21] Heating ventilation and air-conditioning.

element does not exceed this and can therefore fully be decarbonized using GE. Implementation of GE at other refinery elements has not been investigated. The techno-economic parameters used to assess GE are presented in Table 9 below. The low-high values are used for the sensitivity analysis.

Table 9 - Techno-economic parameters Ultra Deep GE.

Ultra-deep geothermal	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Facility HVAC [a]	Assumption
Capacity	MW (used)	17	PBL, 2019
Full load hours	Hours/y (used)	7000	Assumption
Technological life time	Years (used)	30	PBL, 2019
Investment	M€/MW (used)	2.51	PBL, 2019
Energy costs	€/GJ (used)	273.6	PBL, 2019
Other O&M	M€/MW/y (used)	0,107	PBL, 2019
CO_2 avoided	-ktCO_2/y (used)	36	Flow model
C_a	€/tCO_2 (average)	92.3	Appendix 6b

[a] At baseline output levels, energy demand of this element is 0.49PJ_{fuel}. It is assumed that GE fully reduces combustion emissions generated by the fuel stream.

4.2.2 Ex-post cure

This strategy aims to decarbonize the refinery system after the formation of CO_2 due to fossil fuel utilization. Measures of which the techno-economic performance is assesses, are oxy-fuel and post-combustion CCS at process heaters, boilers, and CHP. Despite that a part of an oxy-fuel combustion CCS system takes place before the CO_2 is formed (air purification), it is classified as an ex-post cure strategy. Regarding the FCC process heaters, oxy-firing and post-combustion are the only alternatives for CO_2 capture because the fuel is coke deposited on the surface of the catalysis and CO_2 is formed when the coke is burned off in the regenerator. Other process heaters can also be decarbonized ex-ante (explained in section 4.2.3). Post and oxy-fuel combustion CCS have not been selected as an option to decarbonize the HMU part of the refinery, because of potential financial advantages of pre-combustion CCS. For example, pre-combustion CCS can benefit from economies of scale when applied at the HMU.

For oxy-combustion CCS, it is assumed that existing burners are retrofitted. This has two benefits. Firstly, modifying old burners is cheaper than installing new systems. Secondly, retrofitted oxy-fuel combustion burners can operate either in air or oxygen combustion modes which increases flexibility. Burner test studies have found no performance issues when RFGs are combusted in process heaters under oxy-firing conditions (Miracca, 2015 – CO2 capture project). The techno-economic parameters used to assess post-combustion CCS are shown in Table 10 and for oxy-fuel combustion CCS in Table 11. The low-high values are used for the sensitvity analysis.

Table 10 - Techno-economic parameters and performance post-combustion CCS.

Post-CCS	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Furnaces, CHP, FCC [a], Boilers [b]	Assumption; CO2 Project, 2015
Full load hours	Hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	20 – 25 – 30	Navigant, 2019; Berghout, 2019
CO_2 capture ratio	% (low – used - high)	85 – 86 - 89	Berghout, 2019; CO2 Project, 2015
Investment	€/tCO_2 avoided (low – used – high)	50 – 83 - 100	Navigant, 2019; Berghout, 2019; assumption
Energy costs	€/tCO_2 avoided (low – used – high)	10 – 19 – 35	Navigant, 2019
Other O&M	% of investment (low – used – high)	1 – 2- 4	Navigant, 2019
CO_2 avoided	-MtCO_2/y (total)	7.77	Flow model, CWT calculation
C_a [c]	€/tCO_2 (min, average, max)	95 – 99 – 107	Appendix 6b

[a] For the FCC, a high CO_2 capture ratio (89%) is used because it is assumed that the CO_2 concentration in flue gasses is higher.

[b] Higher C_a for boilers due to economies of scale at CHP (CO_2 capture project p141).

[c] Includes connection, transport and storage costs (see Appendix 1a).

Table 11 - Techno-economic parameters and performance oxy-fuel combustion CCS.

Oxy-CCS	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Boilers [a], FCC [b], all furnaces, CHP	Assumption; CO2 Project, 2015
Full load hours	hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	20 – 25 – 30	Navigant, 2019; Berghout, 2019
CO_2 capture ratio	% (low - used - high)	87 – 89 – 90	Berghout, 2019; Navigant, 2019; CO2 Project, 2015
Investment	€/tCO_2 avoided (low – used – high)	20 – 50 – 100	Navigant, 2019; Berghout, 2019
Energy costs	€/tCO_2 avoided (low – used – high)	3 – 11 – 20	Navigant, 2019; Berghout, 2019
Other O&M	% of investment (low – used – high)	1 – 4 – 5	Navigant, 2019; Berghout, 2019
CO_2 avoided	-MtCO_2/y (total)	7.99	Flow model, CWT calculation
C_a [c]	€/tCO_2 (min, average, max)	88 – 93 – 103	Appendix 6b

[a] C_a boilers is assumed to be the same as at the CHP. However, oxy-firing remains a more viable option for systems with boilers, which operate at a positive pressure in the firebox.
[b] For the FCC an CO_2 capture ratio of 90% is used due to higher concentration of CO_2.
[c] Includes connection, transport and storage costs (see Appendix 1a).

Post-combustion CCS mainly relies on fuel for steam and oxy-fuel combustion CCS relies on electric power. The differences in cost between the energy sources may differ in location and time and may therefore play an important role in selecting the lowest cost CCS technology. To study these effects, refineries must be analyzed individually (e.g. RFG production ratios).

4.2.3 Ex-ante adjust

This strategy aims to avoid the production of CO_2 emissions from fossil fuel combustion, but do not radically alter the processes themselves.

Mechanical vapour recompression (MVR)

For low temperature, heat pumps (HP) can be implemented to prevent fossil fuel combustion emissions. However, it was found that the integration of HP systems within refineries is very complex because heat streams will be used differently and hereby potentially alter the processes and system configuration radically. This leads to extreme high uncertainty on investment costs. Secondly, HPs are limited in their temperature reach (assumed max 165°C can be reached) which is often below the refinery process heating temperature demands (> 400°C). For this reason, it was decided to include one type of HP technology, MVR, to decarbonize 'machine drive' and 'other process uses' elements of the operation part because it is already applied within industry (BlueTerra, 2015). The techno-economic parameters used to assess MVR are presented in Table 12 below. The low-high values are used for the sensitivity analysis.

Table 12 - Techno-economic parameters and performance MVR.

MVR	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Machine drive/other process uses	Assumption
Capacity	MW (low – used – high)	4/10 – 11 – 10/20	Navigant, 2019
Full load hours	hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	12 – 18 - 25	Navigant, 2019
Efficiency	% (used)	180	Assumption
Investment [a]	M €/MW_{output} (low – used – high)	0.1 – 0.113 – 0.15	Navigant, 2019
Energy costs	€/MWh (low – used – high)	16 – 22.25 – 30	Navigant, 2019
Other O&M	% of investment (low – used – high)	1 – 3 - 5	Navigant, 2019
CO_2 avoided [b]	-ktCO_2/y (used)	292	Flow model
C_a	€/tCO_2 (average)	165	Appendix 6b

[a] Likely to be higher [expert opinion]: heat flows will be used differently, making implementation much more complex and hereby greatly increasing uncertainty on investment costs.
[b] See Appendix 3c, Table 35.

Electric boilers

Electric boilers offer a 1:1 replacement of fossil fuels. Currently, fossil fuel boilers that produce steam below 200°C can be electrified (see footnote a, Table 13). Technological development is needed to generate hotter steam using electric boilers[22]. Due to the implementation timeframe of this study it is assumed that at the time of implementation (2030 - 2050), electric boilers have been further developed and that it is technically possible to electrify steam production up to 400°C. Electric boilers work according to the resistance heating principle where heat is generated if an electric current is running through a wire with high electrical resistance and current TRL is 9. Hybrid systems that combine a combustion boiler with an electric boiler were not studied. However, hybrid systems that use electricity during off-peak hours could be an attractive alternative because of the potential to enhance grid stability. The techno-economic parameters used to assess electric boilers are presented in Table 13 below. The low-high values are used for the sensitivity analysis.

Table 13 - Techno-economic parameters and performance electric boilers.

Electric boilers	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Steam (boiler/CHP)	Assumption
Capacity	MW (low – used – high)	10 – 15 – 30	Navigant, 2019
Full load hours	hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	10 – 16 – 30	Navigant, 2019
Efficiency	% (used)	100%	Assumption
Investment	M €/MW$_{output}$ (low – used – high)	0.1 – 0.26 – 0.5	Navigant, 2019
Energy costs	€/MWh (low – used – high)	55 – 64 – 70	Navigant, 2019
Other O&M	% of investment (low – used – high)	1 – 2 – 3	Navigant, 2019
CO_2 avoided	-MtCO_2/y (low – used) [a]	0.36 - 2.19	Flow model
C_a	€/tCO_2 (average, w/o and with interaction [b])	302 - 179	Appendix 6b

[a] The 'low' range gives decarbonization potential up to 200°C. Some sources indicate that it is technically possible to produce 350°C (VNCI, 2018). Due to the poor data availability of steam temperatures (large temperature ranges), it was assumed that all PJs within the range of 100°C - 400°C can be decarbonized.

[b] With interaction represent the costs when 100% NG is replaced by electricity (no free RFGs). This is used within the NG-Independency pathway (see section 4.3).

Electric furnaces

High temperature process heat such as cracking processes can be electrified using electric furnaces. An electric furnace also works according to the resistance heating principle. Despite that the application within high temperature industry is relatively new (TRL of 5-7), it was decided to include it in the analysis to explore its technical potential. Current implementation barriers are related to the lack of materials that that can withstand low voltages, high amperes and high temperatures (BASF, 2019b). The techno-economic parameters used to assess electric furnaces are presented in Table 14 below. The low-high values are used for the sensitivity analysis.

Table 14 - Techno-economic parameters and performance electric furnaces.

Electric furnaces	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	HC, Visbreaker, Coker	Assumption; VNCI, 2019
Capacity	MW (low – used – high)	5 – 7.5 – 10	Navigant, 2019
Full load hours	hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	10 – 15 – 20	Navigant, 2019
Efficiency	% (used)	100%	Assumption
Investment	€/tCO_2 (low – used – high)	20 – 25 - 30	Navigant, 2019
Energy costs	€/MWh (used)	38	Navigant, 2019
Other O&M	% of investment (low – used – high)	0.5 – 1.6 – 3	Navigant, 2019
CO_2 avoided	-MtCO_2/y (low - used) [a]	0.6 - 1.7	CWT calculation
C_a	€/tCO_2 (w/o and with interaction [b])	533 - 410	Appendix 6b

[a] It is assumed that all cracking activity can be electrified. Includes Visbreaker, coker and HC. Low values is HC only potential.

[b] With interaction represent the costs when 100% NG is replaced by electricity (no free RFGs). This is used within the NG-Independency pathway (see section 4.3).

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[22] Based on expert opinion.

Pre-combustion CCS – Blue H_2

Pre-combustion CCS is classified as an ex-ante adjust measure, because it involves a fuel change from NG/RFG to H_2. The techno-economic parameters used to assess pre-combustion CCS are presented in Table 15 below. The low-high values are used for the sensitivity analysis.

Table 15 - Techno-economic parameters and performance pre-combustion CCS.

Pre-CCS	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	RFG, HMU, Process units (except FCC), boilers, CHP	Assumption; CO2 Project, 2015
Full load hours	Hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	20 – 25 – 30	Navigant, 2019; Berghout, 2019
CO_2 capture ratio	% (low – used - high)	90 – 93 - 95	- Berghout, 2019; CO2 Project, 2015
Investment	€/tCO_2 avoided (low – used – high)	10 – 25 – 40	Navigant, 2019
Energy costs	€/tCO_2 avoided (low – used – high)	3 – 10.3 – 25	Navigant, 2019
Other O&M	% of investment (low – used – high)	1 – 3 – 4	Navigant, 2019
CO_2 avoided	-MtCO_2/y (total [a], RFG, HMU)	8.79 – 4.78 – 2.36	Flow model
C_a [c]	€/tCO_2 (average [b], RFG, HMU)	93 – 77 – 71	Appendix 6b

[a] CO_2 avoidance potential if applied on HMU, all furnaces (except FCC), CHP and boilers.

[b] Turns out higher because C_a pre-combustion CCS on furnaces is 108 €/tCO_2 and CHP 137 €/tCO_2.

[c] Includes connection, transport and storage costs (see Appendix 1a).

Hydrogen combustion (green)

The refinery can also buy external produced green H_2 to replace the currently used fossil fuels. The techno-economic parameters used to assess H_2 combustion are shown in Table 16 below. Centralized and large scale 2025 green H_2 production and prices are assumed. The high-low values are used for the sensitivity analysis.

Table 16 - Hydrogen combustion.

Hydrogen combustion	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	Generation, Process-units (except FCC), Non-process	Assumption
Full load hours	Hours/y (used)	8000	Assumption
Technological life time	Years (low – used – high)	20 – 25 - 30	Navigant, 2019
Efficiency	% (low – used - high)	90	Navigant, 2019
Investment [a]	M €/MW (low – used – high)	0.12 – 0.26 – 0.5	Navigant, 2019
Energy costs	€/GJ (low – used – high)	20.9 – 27.7 – 34.5	Blok, 2017
Other O&M	€/MW/y (low – used – high)	10000 – 26250 - 60000	Navigant, 2019
CO_2 avoided	-MtCO_2/y (used)	8.81 [b]	Flow model
C_a	€/tCO_2 (w/o and with interaction)	434 - 336	Appendix 6b

[a] Assumed that this includes retrofitting of burner and additional adjustments (safety, air inlet).

[b] Fuel switch of all combustion-like refinery parts, excluding HMU (produces H_2) and FCC (explained in section 4.2.2).

4.2.4 Rethink and change

Measures within this strategy aim to *lower CO_2 through implementing different processes, input and output products.* Replacement of the HMU with an electrolyzer has been assessed. The techno-economic parameters that were used to assess electrolyzers are presented in Table 17 below. The low-high values are used for the sensitivity analysis.

Table 17 - Techno-economic parameters electrolyzers.

Electrolyzer	**Unit (range)**	**Value(s)**	**Source**
Target	Emission point source	HMU	Navigant, 2019
Capacity	MW (low – used – high)	1 – 100 – 1000	Navigant, 2019; assumption
Full load hours	hours/y (used)	8000	Assumption
Technological life time	Years (used)	10 [a]	Assumption
Efficiency	% (used)	67	Agora, 2018
Investment	M€/MW_{output} (low – used – high)	0.3 – 0.7 – 1.3	Navigant, 2019
Energy costs [b]	€/MWh (low- used - high) [c]	30 – 47 – 70	Navigant, 2019; Blok, 2017
Other O&M	% of investment/y (low – used – high)	2 – 3 – 5	Navigant, 2019
CO_2 avoided [d]	-$MtCO_2$/y (used)	2.55	Flow model
C_a	€/tCO_2 (w/o and with interaction)	614 - 553	Appendix 6b

[a] High lifetime is used. Lower lifetimes (3 – 7y) are found in literature and strongly depends on electrolyzer type: ALK (7 - 10y), PEM (3 - 7y) (Junginger, 2020).
[b] Based on SDE++ method, which uses a long-term average electricity price of 47€/MWh_e (ECN, 2017). Assumed to be green electricity.
[c] Markets usually estimate energy costs higher than the average SDE++, possible because of risk management.
[d] For achieving max potential, massive amounts of RE are needed. Whether this is realistic or not is not considered.

4.3 Analysis of measures

The results of the techno-economic assessment of the decarbonization measures is presented in Figure 6 below. In Figure 6, the light green bars indicate the max CO_2 avoidance potential of total electrification, EEM, several CCS options and fuel switching to H_2. All other green bars indicate baseline CO_2 avoidance potential and the associated costs (black windows) per individual measure, as well its specific point source. Concerning CCS, it was found that the costs of CCS for all the potential CO_2 sources can differ widely per process unit[23]. However, cost data available in literature and used in this analysis focusses on applying CCS on the easy point sources, hence these figures neglect the extra costs associated with more complex CO_2 sources, such as those with a higher technical difficulty to access. For this reason, the C_a associated with achieving full CO_2 avoidance potential are expected to fall on the right side of the black windows, corresponding to the more conservative cost estimate.

In general, it was found that all electric-based measures applicable for petroleum refineries have a relatively low economic performance compared to other industrial applications. The reason for this is that petroleum refineries produce and consume RFG without costs. When replacing RFG energy with green electric energy, C_a of the electric measure increases significantly, even though electric measures have higher efficiencies and reduce overall energy demand. The effect of the assumption that RFG can be sold at or has to be bought for the NG price on C_a of electric measures is shown by the red circles in Figure 6. Additionally, it can be concluded that the technologies with low TRL levels (mostly electrification measures) have large uncertainties with respect to CO_2 avoidance potential and C_a compared to the more mature measures (such as CCS). Despite the fuel cost disadvantage and uncertainty regarding their ability to achieve the required temperature levels, electric boilers perform well on flexibility, maturity, C_a, and CO_2 avoided compared to other electric measures. Electrolyzers and electric crackers are very expensive, and HPs are characterized by a large uncertainty on implementation costs, because it is unknown in what way the heat streams will change, which increases implementation complexity significantly.

Economically, pre-combustion CCS on the HMU is the best performing CCS option. The reason for this that the HMU produces a pure steam of CO_2 as a byproduct. Because CO_2 separation is already an inherent part of the HMU, adding pre-combustion CCS would simply require additional CO_2 compression, dewatering units and pipeline transport.

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[23] Based on expert opinion.

Even though electrolysis has the worst economic performance, it is regarded as a high potential measure due to large development interest (ITM-Power & Shell, 2018)[24]. Economically speaking, long-term investment cost reduction is expected, through factors related to manufacturing (scale benefits) and incremental innovation (Junginger, 2020). Most importantly, from a technical perspective, it has the potential to fully decarbonize the system (see max potential hydrogen).

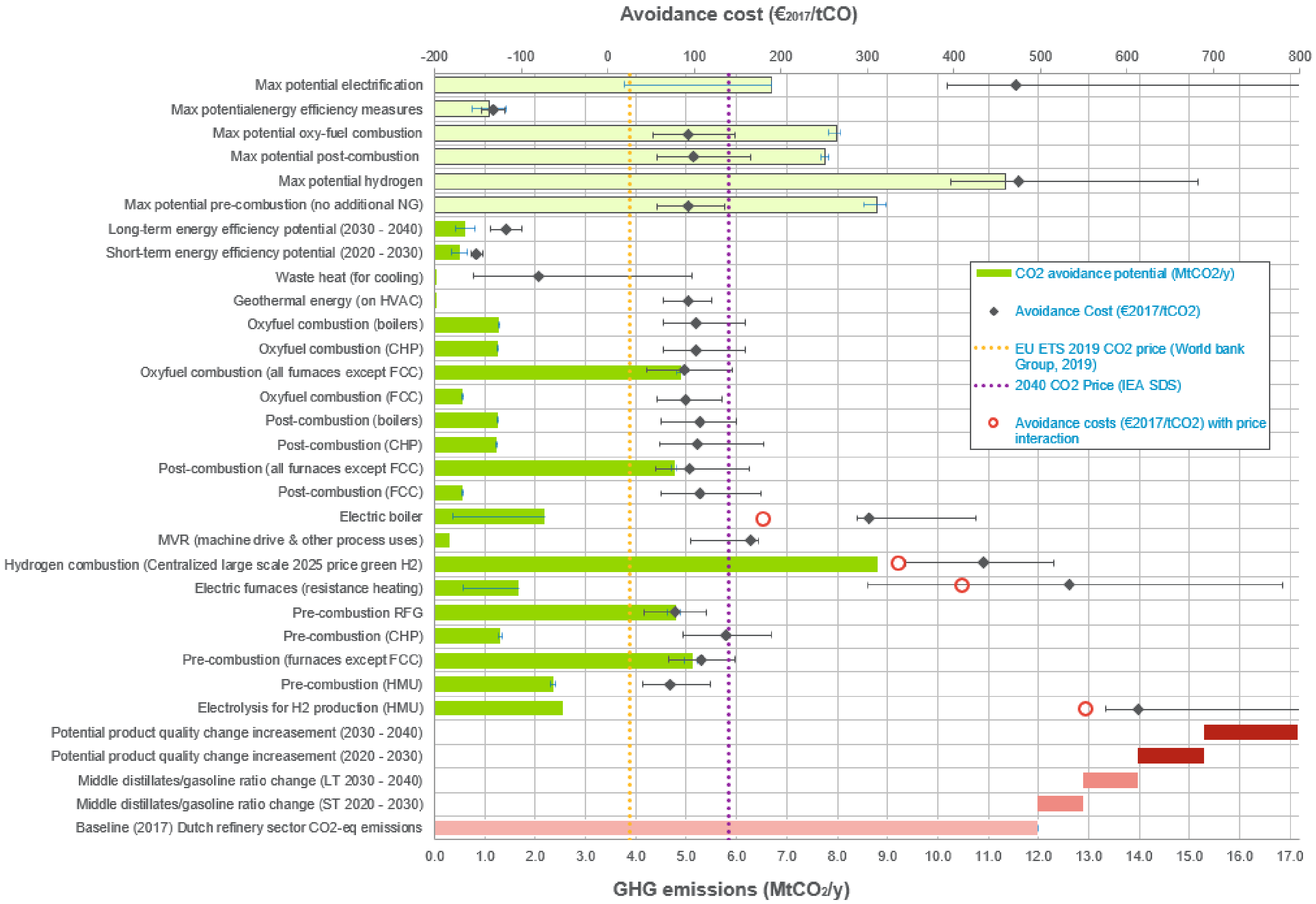

Figure 6 – Overview results techno-economic analysis of decarbonization measures.

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[24] Indication of high interest of refineries in electrolysis technology:
* http://www.itm-power.com/news-item/worlds-largest-hydrogen-electrolysis-in-shells-rhineland-refinery
*https://www.bp.com/nl_nl/netherlands/home/nieuws/persberichten/bp-nouryon-en-havenbedrijf-rotterdam-werken-samen-aan-studie-naar-groene-waterstof.html

5. Results

Based on the refinery model (Figure 7, next page), the techno-economic assessment of measures (Figure 6, section 4.3), the decarbonization strategies (Table 7, section 4), and interviews with experts, three decarbonization pathways were identified (section 5.1).

To assess the impact of future developments on the identified pathways and on the refinery system, two decarbonization targets/goals were formulated. The first goal was to reduce 2030 CO_2 levels by 50% compared to 2017, and the second goal was to have a fully decarbonized system by 2050. These goals were used to assess pathways, as well as to determine the capacity (amount) of measures that are needed to meet these goals. Based on three IEA world energy outlook scenarios (see Appendix 7), 2030 and 2050 Dutch refining activity and output was projected for the Netherlands. Next, the refinery model was used to calculate associated emission changes and to assess the technical performance of pathways, using the projected future output levels. This was done for generation, operation (including all the specific process units), support, and HMU. The outcome of this analysis quantifies CO_2 avoidance potentials, as well as the investments in decarbonization capacities required to achieve the 2030 and 2050 emission reduction targets while simultaneously minimizing the risk associated with stranded assets.

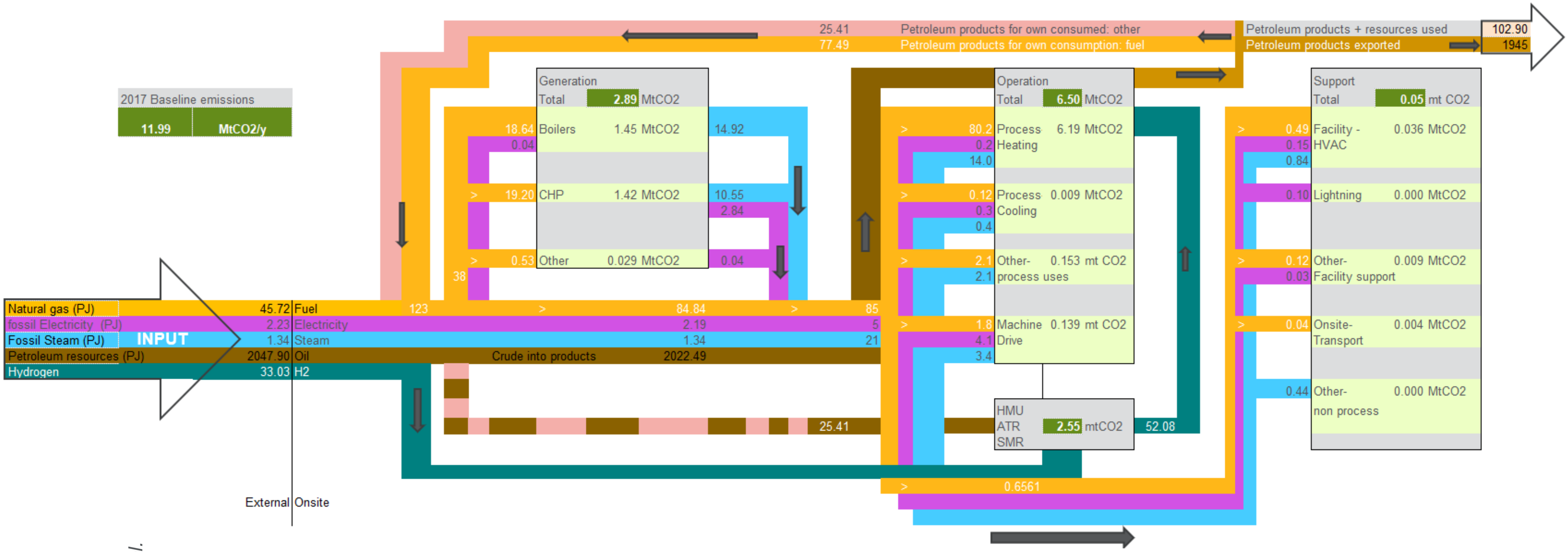

Figure 7 - The Refinery Model.

5.1 Decarbonization pathways

Three pathways have been identified. The first pathway focusses on the measures within the improve and ex-post cure strategies, with the purpose to have minimal impact on the refinery system. The second pathway focusses on the improve and ex-ante adjust strategies with increased impact on the refinery system. The final pathway has maximum impact on the refinery system and combines favorable measures within the improve, ex-ante adjust and rethink strategies.

5.1.1 Minimal impact

Based on techno-economic performance, technological maturity, and the impact of measures on the refinery system, a minimal impact pathway was identified. Within this pathway, baseline emissions are 12 $MtCO_2$/y. EEM will be implemented first. Consequently, fewer emissions reduction can be achieved through CCS (interaction), and when considering CO_2 capture ratios, CO_2 avoided of this pathway is found to be 10.3 $MtCO_2$/y at a cost of 68 €/tCO_2 avoided. Costs reductions through technological learning were not included in the C_a calculation.

Pre-combustion CCS, utilizing a CO_2 capture ratio of 93%, was selected to decarbonize the HMU part of the refinery because it is the lowest cost option. Pre-combustion CCS is not an option for the FCC due to technical constraints. To decarbonize the FCC, it was found that oxy-fuel combustion CCS is cost competitive with post-combustion CCS. C_a for the two techniques are comparable, but oxy-fuel CCS[25] is preferred because oxy-firing provides more flexibility to the operation of the FCC unit, and requires a smaller plot area close to the unit, hence reducing potential issues regarding the refinery layout. The use of high purity oxygen (99.5%) increases the cost of air separation, however it requires less purification of the captured CO_2 for compression and transportation, resulting in a lower C_a.

For all other units, post-combustion CCS was selected due to its "end-of-pipe" characteristic and because it is the most mature technology, which requires minimal unit adaptations. A post-combustion CCS capture ratio of 86% was used. Techno-economic performance of the pathway is presented in Figure 8.

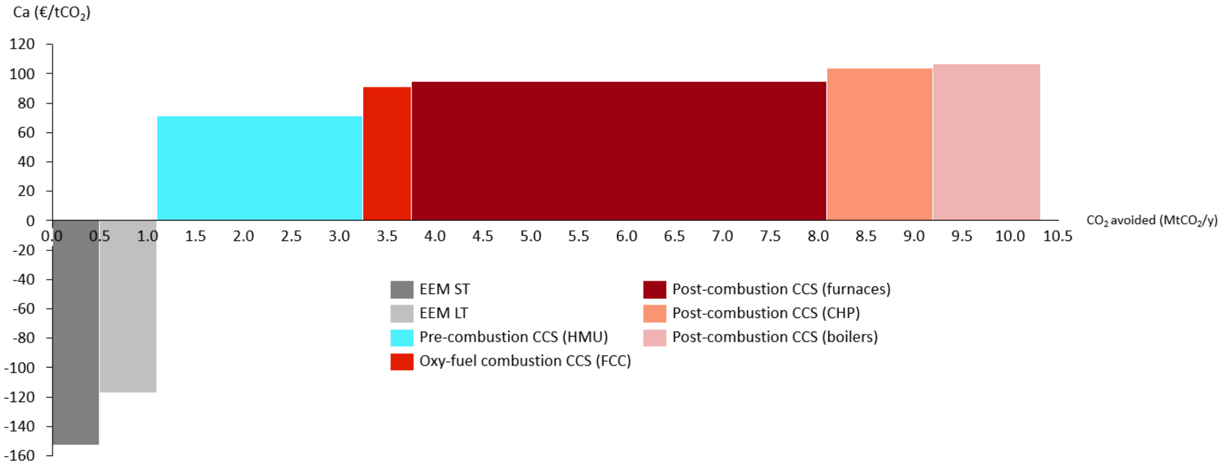

Figure 8 – MACC Minimal impact pathway.

5.1.2 Blue H_2

Despite the low cost and beneficial characteristics of the minimal impact pathway aiming to avoid major short-term refinery adaptations, which are often disliked by refinery operators, there are several disadvantages related to the minimal impact pathway. For instance, many refineries are space constrained. However, oxy-fuel and post-combustion CCS measures require additional equipment (absorbers/regenerator) which may not be able to be placed close to the CO_2 sources. Secondly, when implementing oxy-fuel or post-combustion CCS, the current system requires upgrading and retrofit

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[25] The high range oxy-fuel capture ratio (90%) was used for the FCC unit due high assumed CO_2 concentration.

investments, aggravating lock-in of the refinery on fossil fuels. Consequently, the decarbonized refinery becomes less flexible to be transformed in the future, for instance, into a hydrogen or electrification-based energy system. For these reasons, a second pathway was identified which fully focusses on pre-combustion CCS, i.e. blue hydrogen combustion (see Figure 9). Several beneficial aspects were identified for this pathway. First, for refineries with space constraints, pre-combustion CCS has the advantage that all the H_2 and CCS equipment can be placed away from the refinery processes, and the H_2 fuel can be distributed using the existing fuel infrastructure. Secondly, new large scale H_2 production pathways, such as autothermal reforming (ATR), and large-scale pre-combustion CCS installations may have significant economies of scale and efficiency advantages (CO_2 capture project, 2015 – Kuuskraa p32). Thirdly, NG and RFGs can still be used and when potential hydrogen production cost developments lead to low H_2 prices, the refinery can be easily adapted (e.g. substitute NG with external H_2).

Within the blue H_2 pathway, all fuel streams will be transformed into H_2[26] which is used to fuel the furnaces, boilers and CHP. The FCC will not be decarbonized by H_2, because this unit requires oxy-fuel or post-combustion CCS[27]. The HMU part of the refinery will increase significantly in size. One drawback is that PJ_{fuel} demand rises with 25% due to SMR efficiency[28] losses. Consequently, baseline CO_2 emissions increase. To compensate for the conversion losses, an additional 41 PJ of NG must be imported, leading to an additional 2.3 $MtCO_2/y$[29]. New baseline emissions become 14.3 $MtCO_2/y$. It is assumed that EEM are implemented first and also effect the additional CO_2 emissions. A pre-combustion CO_2 capture ratio of 93% was used. CO_2 avoided within the blue hydrogen pathway becomes 11.1 $MtCO_2/y$ at a cost of 61.5 €/tCO_2 avoided. Potential cost reductions due to technological learning were not included.

The HMU can be decarbonized financially most attractively, 2.15 $MtCO_2$ at 71 €/tCO_2[30]. As zero fuel costs are assumed, the second lowest cost option is the RFG stream, 4.4 $MtCO_2$ at 77 €/tCO_2. The baseline NG input (45 PJ) rises with 41 PJ_{NG}. For the combined NG CO_2 emissions (3.6 $MtCO_2$) pre-combustion CCS is costs 91 €/tCO_2 avoided[31]. The FCC emissions (0.63 $MtCO_2/y$) were deducted[32] from this stream because it is the most expensive CCS option.

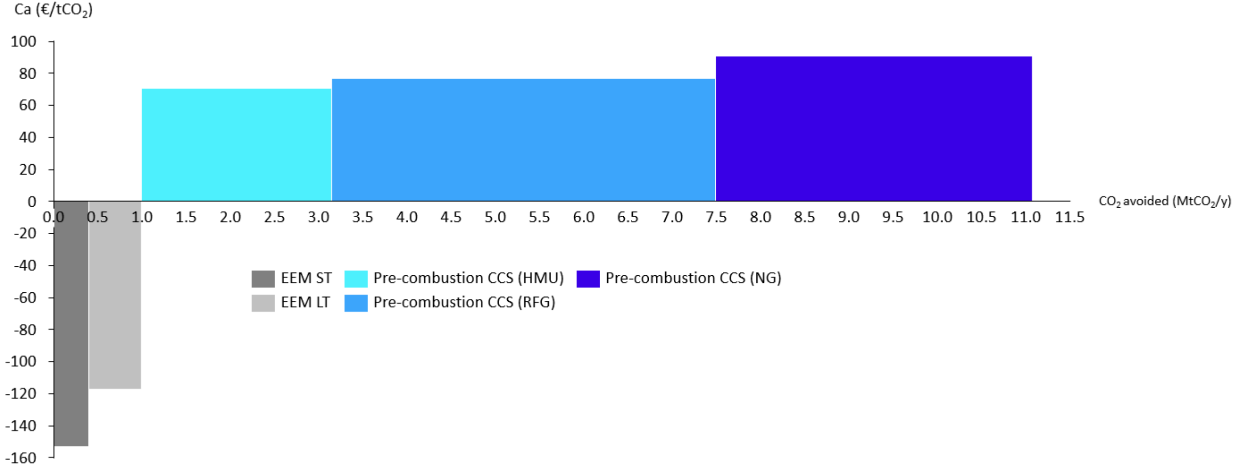

Figure 9 – MACC Blue H_2 pathway.

5.1.3 NG-independency

Based on interviews with refinery representatives, it was found that refineries place great value on control and simplicity. Despite that the blue hydrogen pathway is relatively simple and enables refineries to be in

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[26] Property differences of H_2 (vs NG) are not considered. However, H_2 burns and ignites faster. No significant burner modifications are assumed to be required (Lowe, 2011). However, additional flame control systems might be necessary which can increase costs related to safety assurance.

[27] Theoretically H_2 could be combusted in the FCC. However, it was decided not to study this effect on the CO_2 avoidance, because it is unknown what the exact CO_2 process emissions of the FCC unit are.

[28] Based on an SMR efficiency of 75%, it is assumed that the HMU can transform 1 PJ NG into 0.75 PJ pf H_2 (Peng, 2012; Andersen, 2011).

[29] The current fuel stream (RFG and NG; 123 PJ) will be fully replaced with 123 PJ_{H2}. A large part of this H_2 (58 PJ) originates from RFG (77 PJ) and 34.3 PJ_{H2} originates from NG (45.7 PJ). The remaining H_2 demand (31 PJ) will be produced using additionally imported NG (41 PJ).

[30] A lower C_a is presumable (as low as € 20/tCO_2 [expert opinion] for RFG) due to large scaling benefits.

[31] Based on 2025 industrial energy prices, an NG price of €10/GJ was used. See appendix 1.

[32] It is assumed that the FCC will fully combust NG in the new situation. FCC RFG scrubber installation is likely to need reconfiguration. Effects on CO_2 emissions when 100% NG is combusted in the FCC in the new situation have been neglected such as the lower EF of NG.

control of their own fuel and energy generation (e.g. H_2 from the RFGs), one drawback is that the external NG input significantly increases because the need to compensate for the efficiency losses due to additional H_2 production. As a result, the refinery becomes more dependent on external NG.

Based on the blue H_2 pathway and the strategical indicators, a third pathway was identified: the NG-independency pathway, presented in Figure 10. The premise of this pathway is to use zero NG because the Netherlands has the ambition to significantly reduce the nations reliance on NG. The energy deficit is compensated by electrification. It is assumed that electrification measures are 100% efficient, consequently, 65 PJ_{NG} must be electrified. EEM are implemented first, which reduces the CO_2 that can be avoided of all other measures. CO_2 that is avoided within the NG-independence pathway is 11.5 $MtCO_2$/y at 217.6 €/tCO_2 avoided.

Because it is assumed that RFG are costless, price interactions strongly reduce C_a of electrification measures because additional NG expenditures are prevented. Electric boilers are deployed for steam production, electric crackers for all cracking activity, electrolyzers for hydrogen manufacturing and MVR for machine drive due to its good C_a performance. All electricity used is assumed to be green[33]. Regarding the process heating element, it is assumed that all cracking activity[34] (HC, Coker, and Visbreaking, except FCC) can be electrified using electric furnaces, referred to as electric crackers. Regarding onsite steam generation, it is assumed that steam between 100°C and 400°C can be electrified, despite reaching temperatures over 200°C[35] is currently viewed as very technically ambitious. Electrifying steam demand up to 400°C, replaces 33.9 PJ_{fuel} with 30.5 PJ_e, hence reducing emissions with 2 $MtCO_2$/y. Distribution losses are accounted for. As this replaces steam produced both by the boilers and the CHP, rearrangement of these refinery elements is likely to be inevitable which amplifies investment uncertainty. Implications associated with this effect were outside the scope of this analysis. 3 PJ of high temperature (>400°C) steam and 3 PJ_e will still be produced by the CHP, which combusts H_2 from RFG. It was found that electric crackers have the potential to avoid 1.52 $MtCO_2$/y, which equals 27% of all furnace emissions. Electric crackers replace 21.8 PJ_{fuel} with 19.7 PJ_e.

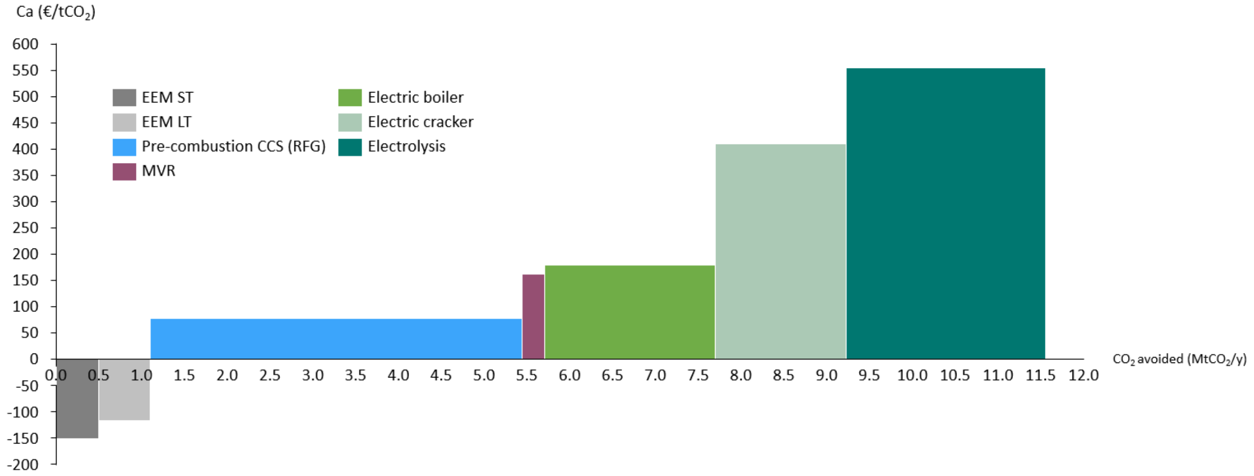

Figure 10 - MACC NG-Independency pathway.

The NG-independency pathway explores a situation in which the refinery is decarbonized while energy flows are re-structured using different energy carriers, including (green) electricity. It was assumed that a refinery element can either be fuel or electricity based. However, in reality, it is likely to comprise hybrid systems such as hybrid boilers. This has not been studied. Secondly, electrification is likely to require major system reconfigurations. In what extent and what the impact of this will be on the refinery is unclear and needs further research. Costs reductions of high temperature electric heating technologies are not considered; however, 33% cost reductions are expected for electrolyzers in the 2040-2050 period (based on Navigant insight).

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[33] Projected 2025 green electricity prices (22 €/GJ). Based on low-carbon power systems for Western Europe with varying shares of variable renewable electricity and fossil power plant CCS using hourly power system simulation software (Brouwer et al., 2016).

[34] Negative error bar of CO_2 avoided electric cracker in Figure 6 shows technical potential when only implementing electric naphtha crackers.

[35] Negative error bar of CO_2 avoided electric boiler in Figure 6 shows technical potential when electrifying steam production until 200°C.

5.2 Future refining activity and emissions

Petroleum product markets increasingly demanded sophisticated products as well as increasing volumes of lighter fractions, while markets for heavier oils were decreasing. Refineries continuously adapt to these changes, becoming more complex in the process. As part of the energy transition, it is expected that a significant part of EU and Dutch refining output will disappear due to a reduced demand for transportation fuels such as gasoline and diesel. The Dutch refineries and their future perspectives are summarized in Table 18 below (green indicates a good position, blue uncertain and gray poor).

Table 18 – Future survival positions Dutch refineries. Based on CIEP (2018) and interviews with refineries.

Refinery	**Comments**
Shell Pernis	Strong position because of integration with the Moerdijk chemicals site and significant feedstock flexibility due to a large-scale steam cracker. Steam cracker integration enables upgrading of refinery by-product streams (e.g. Hydrowax). The Moerdijk chemicals site is also an integral part of the competitive Antwerp-Rotterdam petrochemicals cluster. There is a direct pipe connection to Schiphol airport transporting kerosene.
ExxonMobil	Integration with Exxon's world scale aromatics plant in Rotterdam Botlek, which is an integral part of the competitive Antwerp-Rotterdam petrochemicals cluster, gives the refinery a strong position. The refinery fulfils an especially important role as a source of sulphur-free naphtha and H_2 for the aromatics plant. Excess refinery gas is, for example, used by the nearby Air Products plant to produce H_2, which is again supplied to the Exxon aromatics plant.
BP	A coastal refinery with a relatively simple configuration and limited downstream integration, which despite its size and considerable flexibility could, all else equal, be replaced by imports. Large gasoline output configuration.
Koch, & Q8	A coastal refinery with a simple configuration that could, all else equal, be replaced by imports.
Zeeland	A coastal refinery that despite its beneficial configuration (i.e., an oversized hydrocracker) and some downstream integration, could, all else equal, be replaced by imports.

Changes in markets will trigger changes in output mixes. It is uncertain in what way the mix of output products will change, but different output mixes strongly affect the volume and the structure of the refining industry, and hereby the type and volume of CO_2 mitigation necessary. Investments required to fully decarbonize baseline emissions can potentially result in stranded assets because the market for petroleum products is expected to decline, hence refining activity and associated emissions. For this reason, the consequences of potential external developments[36] on global and EU oil product markets have been modelled to explore future Dutch refinery activity and associated emissions (Figure 11).

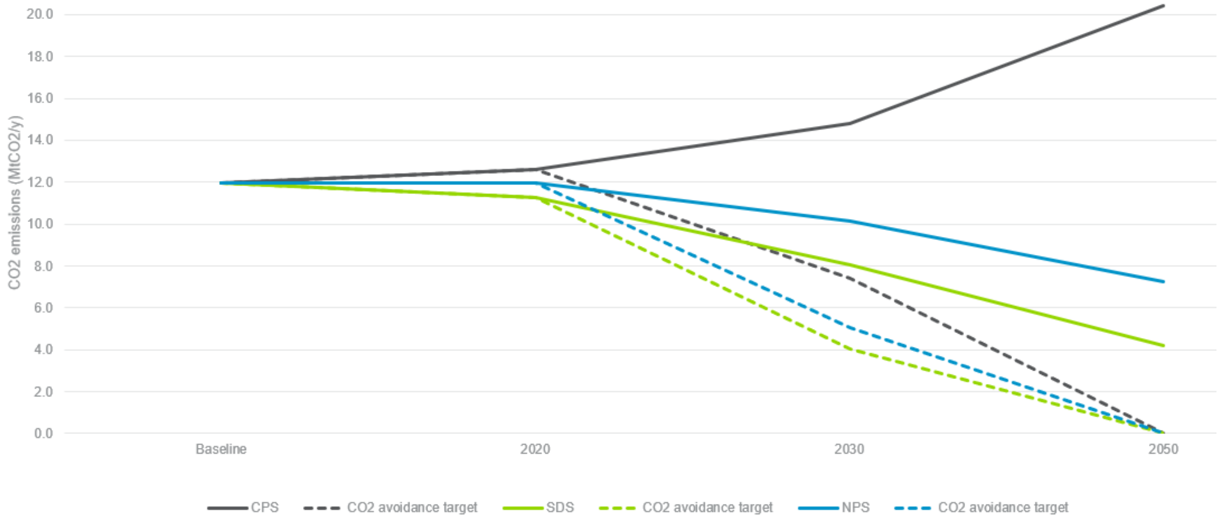

Figure 11 - Projection of future refining emissions and CO_2 that must be avoided to achieve 2030/50 targets per scenario.

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[36] The IEA 'Current Policies Scenario (CPS)', 'New Policies Scenario (NPS)' and the 'Sustainable Development Scenario (SDS)' were used. What this entails and how the specific Dutch refining emissions were calculated is described in Appendix 8

Because the refinery model is unable to calculate effects of output mix changes on refinery activity, The total future refining emissions and the optimal (minimal) proportion of CO_2 mitigation necessary to achieve the 2030/50 targets was determined (dotted lines, Figure 11) based on total output. The CO_2 avoided and total costs associated to achieve the 2050 targets per pathway are presented in Figure 12 below.

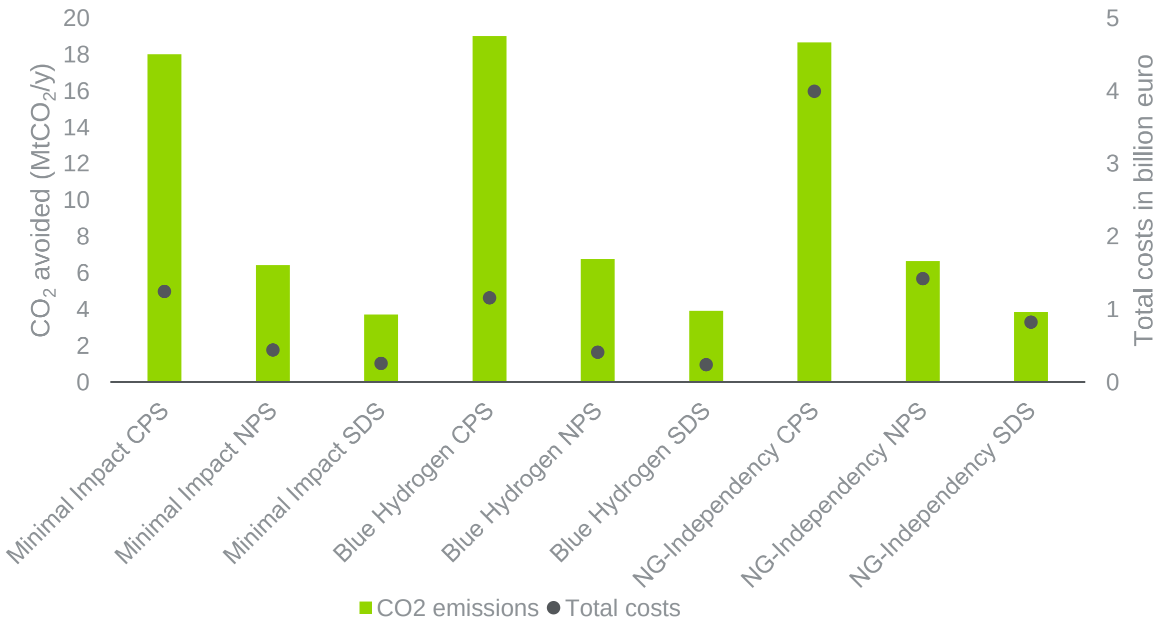

Figure 12 - Techno-economic performance of pathways per scenario.

When announced policies and targets set by government are taken, the NPS explores possible future refinery output and associated emissions. Because the NPS is in the middle of the three scenarios and the decarbonization effort is based on achieving targets, it was decided to analyze the effects of this scenario on the three pathways. This was done in order to indicate in what wat a decline in future demand impacts the type and volume of CO_2 mitigation necessary. Per pathway, two investment waves have been formulated: one to achieve the 2030 and one for the 2050 targets. The figures below show the decarbonization effort necessary per pathway to achieve the reduction targets within the NPS.

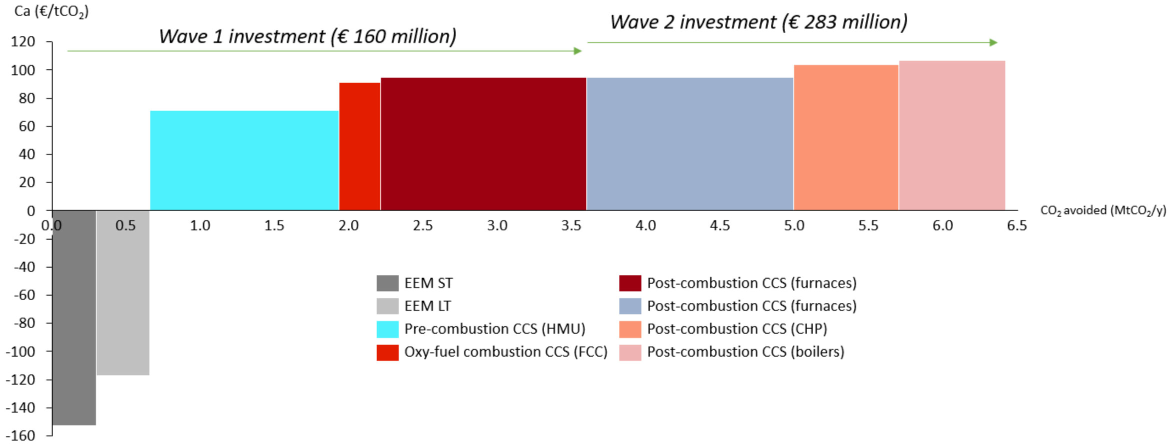

Figure 13 - NPS implications on the minimal impact pathway.

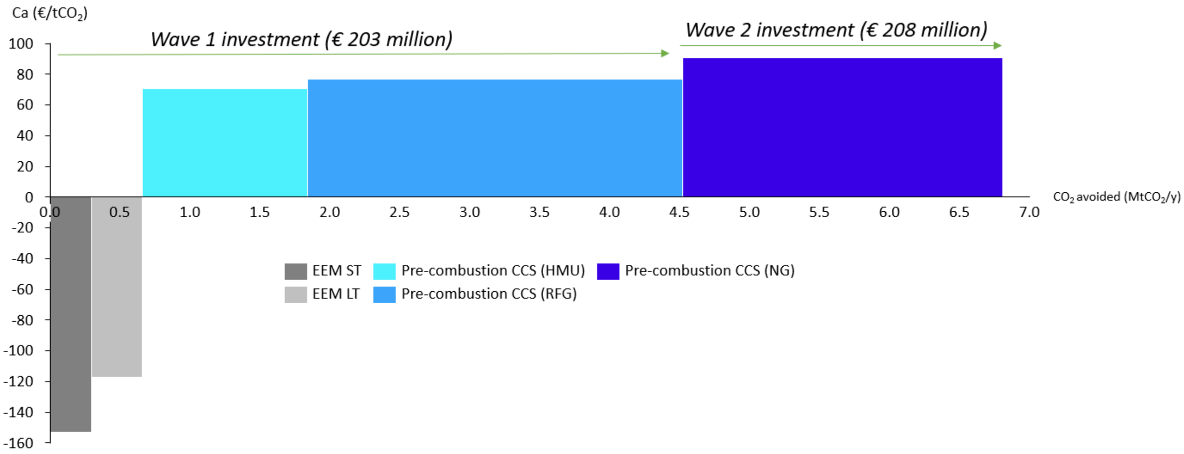

Figure 14 - NPS implications on the blue hydrogen pathway.

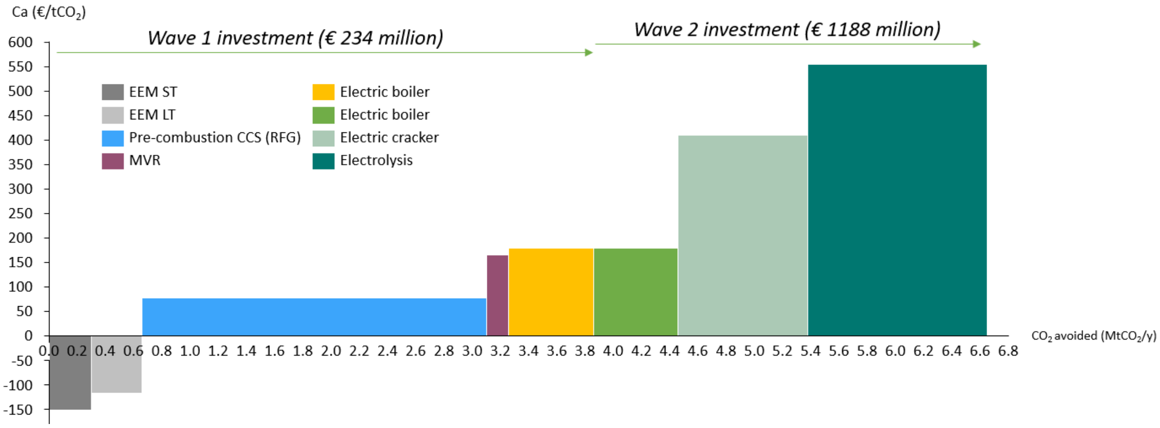

Figure 15 - NPS implications on the NG-independency pathway.

6 Discussion

In section 6.1, the current results are compared with finding of other studies. Next, the context and main limitations of the method and the refinery model on the analysis are described in section 6.2. Finally, suggestions for further research is discussed in section 6.3.

6.1 Comparison with other studies

In general, the CO_2 avoidance costs found within this analysis are similar compared other studies (see Table 19). For electric boilers, furnaces and electrolyzers no much comparable data was available. The CO_2 avoidance costs found for all CCS technologies applied to refinery heaters and boilers are lower than those found by the CO_2 Carbon Project (2009-2015), which focusses on the US refinery industry in the 2004 – 2015 period. A reason for this is that technological development reduced CO_2 avoidance costs. Secondly, the CO_2 avoidance costs found for pre-combustion CCS are lower than the CO_2 avoidance costs compared to a more recent study (Berghout et al., 2019). The reason for this is that within this analysis, the entire Dutch refinery sector was studied, hence increasing economies of scale. Another reason is that zero costs of RFG were assumed within this study, reducing the CO_2 avoidance costs of all CCS measures that focus on the RFG fuel stream within refineries.

Table 19 – Comparison of results with other studies.

Measure	CO_2 avoidance cost (€/tCO_2)	Scope/level
Pre-combustion CCS (average)	56 – 134 (this analysis) 134 – 145 (CO_2 capture project, 2015) 54 – 152 (Berghout et al., 2019) 38 – 117 (Navigant, 2019)	NL Refinery sector US Refinery NL Refinery NL Industry
Post-combustion CCS (average)	57 – 165 (this analysis) 142 – 186 (CO_2 capture project, 2015) 45 – 167 (Berghout et al., 2019) 48 – 142 (Navigant, 2019)	NL Refinery sector US Refinery NL Refinery NL Industry
Oxy-fuel combustion CCS (average)	52 – 147 (this analysis) 322 (CO_2 capture project, 2015) 53 – 152 (Berghout et al., 2019) 58 – 70 (Navigant, 2019)	NL Refinery sector US Refinery NL Refinery NL Industry
EEM (average)	-146 to – 120 (this analysis) -226 to -33 (Berghout et al., 2019)	NL Refinery sector NL refinery
Electric boilers	165 – 302 (this analysis) 102 (PoR, 2019)	NL Refinery sector Industrial cluster
Electric furnace	177 – 658 (this analysis) 302 (Tsinghua University, 2005)	NL Refinery sector China Steel Industry
Electrolysis	494 – 1180 (this analysis)	NL Refinery sector

6.2 Caveats

Due to the complex nature of the refinery sector, as well as data and time limitations, several simplifications and generalization were made in order to complete this analysis. The refinery model analyzes the Dutch refinery industry based on the combined throughput activity of six refineries, effectively translating six dissimilar refineries into one large, uniform refinery representing the entire Dutch refining sector. This has several consequences. First, all Dutch refineries represented in the model automatically become a complex integrated refinery because all parts and elements of the most complex refinery in the Netherlands are incorporated in the model, and represented by a single, uniform refinery. Therefore, the six original refineries efficiencies, fuel demand and composition, steam and electricity consumption patterns and generation methods are described using averages values. However, individual refineries differ greatly among one another, in part due to their intended application, but also to give them competitive flexibility advantages over one another. For example, not all refineries can refine all types of heavy crude, have a CHP or a hydrocracker. Consequently, because all Dutch refineries are regarded as one single refinery, it became difficult to study the actual implications of decarbonization pathways and output composition for individual refineries.

The fundamental structure of the refinery model in terms of elements, parts and energy flows, are based on the US refinery sector. Due to geographic differences, US refineries are usually more self-sufficient compared to the Dutch refineries, which are often located near each other and connected. For example, the refinery model uses twice as much steam compared to the actual Dutch energetic steam use, or about 30 PJ_{steam} versus 14.6 PJ_{steam} (CBS, 2015). It is assumed that the lower energy requirement for Dutch steam is a consequence of the highly integrated nature of the PoR industrial cluster and nearby industries. A major implication of this generalization is that it increases the share of 100-400°C steam demand in the model, hence the estimation of technical potential of electric boilers for refineries that are in industrial clusters.

Based on total output levels, the impact of a wide range of decarbonization measures were assessed for the entire Dutch petroleum refinery sector. Not all identified measures were assessed. For example, the effect of feedstock changes (e.g. bio-based/crude quality) was not studied which would have significant scope 1, 2 and 3 implications. For example, biorefineries require less heat[37], which automatically reduces activity related emissions. Likewise, petroleum products, especially light products, are more easily produced from light crude input and increasing crude feedstock quality could also be regarded as a decarbonization measure. Additionally, industrial symbiosis aiming to increase integration of refineries with the built environment and nearby industries was not assessed either. Although refineries see high potential for such advanced waste heat integration[38] projects, especially the large amount of stakeholders involved in these types of projects is considered to be an important barrier. It may also be challenging to overcome associated technical barriers like refinery adaptations and the need for a consistent heat supply.

A major drawback of the model is that the output is defined as total PJs petroleum output products. Scenarios project that the future output mix of petroleum products are going to change. To study future emissions, it would be ideal if refinery products were connected to activity of specific refinery process units. For this reason, a lot of effort was devoted into connecting specific output products with refinery activity. However, this proved difficult to implement because different products are processed using multiple types of units and using many processes, with a variety of refinery configurations and crude feedstocks. Besides strong interdependency of refinery parts, elements and the feedstock processing possibilities, refineries have economically optimized[39] their configuration. Consequently, refineries they have limited control to decide what products they are going to make without significant negative economic and environmental consequences[40]. For these reasons, it was decided to not model the effect of changing output mixes in a quantitative manner. Instead, scenarios developed by the IEA were used and extrapolated to estimate 2050 output levels.

6.3 Further research

Future output mix is expected to shift towards a higher petrochemical feedstock share. For refiners to satisfy this new demand mix, refineries are likely to require adaptations to more complex configuration to match these output mix changes. As a result, CO_2 emissions from refinery processing units are expected to increase because producing lighter products is more energy intense. In addition to this, an increase in system complexity has financial implications. Another option to respond to output mix changes is to refine lighter crude from which petrochemical feedstock products can more easily be produced, hence reducing process emissions and the need for investments to increase refining capabilities. However, lighter crudes are more expensive, and prices are expected to rise because of the increasing market demand. In this sense, further research that identifies the optimal mix between refinery configuration investments, light feedstock costs, and emission mitigation expenditures is needed.

The refinery model turned out to be a valuable tool for estimating emissions as a function of output levels. However, greater insights will be gained when specific output products can be connected to the activity of

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[37] Based on interview with Neste representative (2/7/2019).

[38] Based on interview with Zeeland refinery representative (8/5/2019).

[39] The refining industry is characterized by long investment cycles, small profit margins and huge processing capacity and activity. Dutch refineries used to earn most of their money from diesel and kerosene and are therefore specialized in producing these products. However, the amount of diesel and kerosene that can be produced from crude is limited: other less valuable products are inevitable produced.

[40] For example, in extreme situations such as war, governments can demand refineries to focus their activities fully on diesel production. Besides the associated extreme costs, this will also be an environmental unfriendly refinery utilization configuration with undesired byproducts and inefficient load curves, and strongly reduce efficiency and increase emissions.

individual process units. Besides estimating future emissions, the economic performances of pathways would strongly improve when expected cost reductions associated with the measures that are within a specific investment period are accounted for. This can be done by studying technology learning curves.

Decision making goes beyond the techno-economic performances of measures (Blok, 2018). For this reason, Blok (2018) proposes that in the development of decarbonization strategies, the techno-economic assessment should be expanded to a set of new procedures that allow for a “socio-political merit order” of decarbonization measures. This has been done within this study by implementing the strategical criteria and the proposed strategical performance indicators. Socio-political opinion towards a certain decarbonization measure could be even more important than its techno-economic performance as demonstrated by current investment of refineries in electrolyzers and not in CCS. Further research into the relative importance of socio-political criteria compared to techno-economic criteria within decarbonization decision making is needed.

7 Conclusion

The goal of this thesis was to identify the optimal deployment pathway for deep decarbonization of the Dutch oil refinery industry. Based on techno-economic and strategic performance of decarbonization measures, three different pathways were identified and assessed. When considering techno-economic performance, the blue hydrogen pathway performs best, 11.1 $MtCO_2$/y avoided, at a cost of 61.5 €/tCO_2, equating to a capital investment of 683 million €. The minimal impact pathway performed second best, 10.3 $MtCO_2$/y, at a cost of 68 €/tCO_2, equating to a capital investment of 700 million €. Finally, the NG-independency pathway performed worst due to the relatively large capital investment required, 2.5 billion €. The cost of avoided CO_2 using this pathway amounted to 217.6 €/tCO_2. However, when strategic performance was considered, several key takeaways observed during this analysis must be considered first:

Refineries that are integrated and flexible have a competitive advantage

Today, refineries in the Netherlands are facing numerous challenges contributing to a challenging business environment, including but not limited to: severe international competition, a declining EU market for oil products, increasingly stricter environmental regulations, the EU-ETS, no CO_2 tax on imported oil products and low EU crude extraction rates. In the US, shale gas has led to an increase in US gasoline production, suppressing profits of gasoline exported to the US from Dutch refineries. For example, BP, a major Dutch gasoline producer suffers, because of this development in the global oil market, and doubts whether to invest in a new hydrocracker to increase flexibility. On the other hand, seeming to ignore this development and banking on flexibility advantages, ExxonMobil just opened a one billion € hydrocracker and has invested around six billion € over the past ten years in the PoR refinery. This has made their refinery extremely flexible, and fully chemical, fuel and lubricant integrated. The flexible refinery can convert different types of crude into different products, increase its potential viability in an uncertain future refinery sector by remaining competitive.

Refineries will produce less fuels and more chemicals in the future

The impact of a changing refinery product mix may be a key factor in decarbonization investment decisions. It is expected that the largest decarbonization achievements will be the result of activity reduction and adaptation of the sector to the changing markets, mostly triggered by the switch to electric vehicles. Scenarios project a decrease of EU refining activity: fuel demand is expected to decline, and demand for petrochemical products is expected to remain stable. Efforts should be prioritized on the processes that produce products for which there is a future market and technologies with versatile applications.

Refineries have free refinery fuel gas (RFG) which must be utilized

During the refining processes, RFGs are produced as a byproduct, which are best utilized as a combustion fuel within the refinery. Transforming RFG into valuable products proves to be difficult and expensive.

Refineries decarbonization decisions are influenced by climate targets, policies and location

To select the specific mix of decarbonization measures, the specific CO_2 reduction targets and associated policies are determinative. For example, for achieving significant short-term emission reduction, policy makers must stimulate the cheapest and lowest impact abatement measures, including the development and financing of a national CCS infrastructure. The location of the refineries, nearby CO_2 storage opportunities, the presence of other carbon intense industry and the Dutch biomass ambitions favor the development of a CCS infrastructure. However, it is important that the policy stimulus does not lead to over investment in CCS, because the system remains locked-in on fossil fuels and low costs of CCS solutions can slow down development of other decarbonization technologies.

Refineries will always need hydrogen

Hydrogen is an important element consumed within refineries and will remain to fulfill a key role in the future of refining. Hydrogen is also needed for the production of chemical products, within bio-refineries and for synthetic fuel production from non-fossil CO_2.

Refineries should not underestimate public opinion

The generally negative societal opinion towards CCS (Fernando, 2013) and the fact that there are hardly any Dutch government parties that unconditionally support CCS (Edmond, 2016) increase the risks associated with engaging in CCS projects. A good example is the cancelation of the Barendrecht project[41] by the Dutch government due to public opposition. Consequently, other decarbonization measures seem to be more appealing, such as indirect electrification. Electrolyzers within refineries are considered a high potential, long-term decarbonization measure. They allow for CO_2 emissions to be avoided all together, are characterized as versatile within emerging markets, have the advantage of increasing grid flexibility and allow refineries to be in control of their own hydrogen production. The first signals are already here: Shell announced the world's largest electrolyzer (10 MW) in one of their refineries, and BP recently announced they have initiated a feasibility study to build a 250 MW electrolyzer at the Rotterdam refinery for green hydrogen production for their hydrotreaters. However, with a CO_2 avoidance cost between 553 – 614 €/tCO_2, it is currently the most expensive decarbonization measure and unlikely to be applied on a scale necessary to meet CO_2 reduction targets outlined in climate agreements. For this reason, blue hydrogen from RFGs, with CO_2 avoidance cost of 71 €/tCO_2, is regarded as the most viable short-term measure. Additionally, this measure has a relatively low impact on the refinery system, and it allows for RFGs to be utilized in a clean way, while paving the way for the adoption of green hydrogen by initiating the development of the required infrastructure and hydrogen ready combustion systems.

Epilogue

The majority and high profitable end-products produced within petroleum refineries are fossil fuels, that emit fossil CO_2 emissions upon combustion, which leads to climate change. It might sound a bit peculiar to decarbonize the industrial processes that transform crude oil into fossil fuels. However, if petroleum refineries would be forced to instantly stop their activity, this will have dramatic consequences regarding energy dependency, security and safety, which is something that must be prevented. Next to the products, the refining activity creates emissions to the atmosphere, water and the soil. With increasingly stricter environmental legislation, targets, and goals, environmental management has become a major factor for refineries. Scenarios project a decrease of EU refining activity, indicating that European petroleum markets are changing. Especially, fuel demand is expected to decline, and chemical feedstock demand is expected to remain stable. In the extent of strategical decarbonization of industry in general, there are industrial processes we should worry about decarbonizing and there are things we should better just abandon doing.

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[41] https://sequestration.mit.edu/tools/projects/barendrecht.html

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Appendix 1 – Input data

The goal of this Appendix is to provide an structured overview including assumptions, discussions and the sources regarding the data that was used to calculate techno-economic performances of measures that were assessed within this study.

Appendix 1a – General techno-economic input parameters

For equation 1, 2 and 3 the input parameters shown in the table below were used within the analysis. The values that were used for the sensitivity analysis can be found in section 4 for each individual measure. Since some focus on future costs, Table 20 provides an overview of gas price developments as projected by the IEA.

Table 20 - General techno-economic input parameters used within this study.

Techno-economic input parameters

	Unit	Value	Reference
Real discount rate (*r*)	%	10	Berghout, 2019
Total plant cost (TPC) [a]	%-Investment	130	Van horssen, 2009
Total capital requirement (TCR) [b]	%-TPC	110	Van horssen, 2009
Calorific value natural gas	MJ(LHV)/m³	31.7	Berghout, 2015
Carbon price 2019	$€_{2017}$/tCO$_2$	63	World Bank Group, 2019
Carbon price 2040 SD scenario [c]	$€_{2017}$/tCO$_2$	140	WEO, 2018
Industrial energy prices 2025			
Transport fuels	€/GJ$_{LHV}$	16	Berghout, 2019
Natural gas (NG) [d]	€/GJ$_{LHV}$	10 [e]	Berghout, 2019; IEA, 2018
Green Electricity	€/GJ$_e$	22 [f]	Brouwer, 2016
Refinery Fuel Gas (RFG) [d]	€GJ$_{LHV}$	0	Assumption
Steam (LHV)	€/GJ$_{th}$	12	Berghout, 2019
Green Hydrogen (near term) [d]	€/GJ$_{LHV}$	27.7 [g]	Blok, 2017
Efficiencies			
Industrial combustion furnace efficiency	%	80	Berghout, 2019
Resistance heating	%	99.99	Berenschot, 2017
Max NGCC-CHP (LHV)	%	90	Bolland, 1993
SMR [h]	%	75	Peng, 2012; NREL, 2009
CCS			
Connection costs [i]	$€_{2017}$/tCO$_2$	1	Navigant, 2019
Feed-in-tariff [j]	$€_{2017}$/tCO$_2$	22.5	Navigant, 2019; Assumption
Post capture ratio	%	86	Berghout, 2019; CO2capture project, 2015
Pre capture ratio	%	93	Berghout, 2019; CO2capture project, 2015
Oxy-fuel capture ratio	%	89	Berghout, 2019; CO2capture project, 2015

[a] Comprises equipment and installation costs.

[b] Comprises engineering fees and contingencies costs.

[c] An CO$_2$ price within the most progressive sustainable scenario was used to compare measures with the highest potential CO$_2$ price.

[d] Ranges used for sensitivity analysis: NG: 7 – 13 (IEA, 2017; Berghout, 2019), (RFG: 0 – 10 (assumption), Green H$_2$ (near): 20.9 – 34.5 (Blok, 2017).

[e] A high NG price was used in the analysis. IEA scenarios project NG prices in Europe to be lower (see Table 21). However, the Dutch government has the ambition to significantly reduce the countries NG consumption. For this reason, €10/GJ was chosen for a country with ambitions to reduce NG.

[f] Projected 2025 green electricity prices in a low-carbon based power systems for Western Europe with varying shares of variable renewable electricity and fossil power plant CCS using hourly power system simulation software (Brouwer et al., 2016). Explanation for high prices is that high investments are needed for large scale deployment of low carbon technologies need to be recuperated by investors though an electricity price increase.

[g] An average value of green hydrogen production was used between 38 and 23 $/GJ (full load hours of 3000-5000h/y and el costs of $0.05-0.03/kWh). Currency conversion of 1$ equals €0.91 was used (17/9/2019). In a mass production scenario, prices could be halved.

[h] Assumes that this equals the hydrogen production from NG at the HMU.

[i] Costs to connect the CCS installation on the CO$_2$ backbone.

[j] Yearly costs to feed in CO$_2$ on existing CO$_2$ backbone. Includes transportation costs. Assumed to include storage costs.

Table 21 - IEA NG price projection in Europe per scenario.

European NG price by scenario (€/GJ) [a]

Year	2025	2040
Current policies	7.50	8.93
New Policies	7.41	8.55
Sustainable development	7.12	7.31

[a] IEA prices in $ were converted to €. Currency conversion of 1$ equals €0.91 was used (17/9/2019).

Appendix 1b - Emission factors of fuels

Different fuels have different emission factors (EFs). The EFs used to calculate emission savings (equation 1) are shown in Table 22 below. The EFs used within this study are based on Dutch values which reflect the specific national situation of fuels and emissions.

Table 22 - Emission factors used within this study.

Emission factors (EF)

Fuel	EF (kg CO_2/GJ)	Source
Crude oil	73.3	RVO, 2013
RFG[a]	66.7	RVO, 2013
Refinery feedstocks	73.3	RVO, 2013
Petroleum Coke	100.8	RVO, 2013
LPG	66.7	RVO, 2013
HFO	77.4	RVO, 2013
Naphtha	73.3	RVO, 2013
Benzine	72	RVO, 2013
Kerosene	71.5	RVO, 2013
LFO	74.3	RVO, 2013
Natural gas (NG)	56.1	RVO, 2013

[a] The composition of RFG often changes. Sometimes EF is lower (43 is the lowest value found in EU (2015)). Because the RVO figures are used for national reporting, 66.7 is used within this study as it is assumed to best reflect the Dutch situation.

Appendix 1c – Conversion factors

To converse units of energy, the conversion factors show in Table 23 were used. Other conversion factors used are shown in Table 24.

Table 23 - Energy conversion factors used within this study.

General conversion factors for energy

Convert to:	TJ	Source
From	*multiply by*	
Mbtu	1055.1	IEA WEO, 2018
GWh	3.6	IEA WEO, 2018
Mtoe	41868	IEA WEO, 2018

Table 24 - General mass conversion factors used within this study

General conversion factors

Convert to:	Kt/y	Source
From	*multiply by*	
Barrel/day [a]	0.0498	Qatar petroleum, 2019
MMscfd [b]	0.850	Air Products, 2019

[a] Available data in b/cd was converted to kt/y by multiplication with crude oil conversion factor (0.0498) as defined by Qatar Petroleum (https://qp.com.qa/en/Pages/ConversionFactor.aspx).

[b] Values given in MMscfd were converted to kt/y according to standard oil and gas conversion methodology (it is assumed that 1 scf H_2 equals 0.850 kg H_2 and 1 year has 365 days) http://www.airproducts.com/Products/Gases/gas-facts/conversion-formulas/weight-and-volume-equivalents/hydrogen.aspx

Appendix 1d – Total Dutch refinery sector throughput

Within this study, throughput (TP) is used as refinery activity measure indicator. The values provided in Table 25 are used as input to calculate emissions according to the CWT approach (explained in Appendix 2).

Table 25 - 2017 TP values used within this study used for CWT input (based on worldwide refining survey, 2018)

Unit	TP (b/cd)	TP (kt/y)
ADU	1221868	60849
VDU	714305	35572
Visbreaker	82404	4104
Coker	50500	2515
FCC	106415	5299
CR (Low-pressure)	108660	5411
CR (High-pressure)	41400	2062
Hydrocracking Distillate (Catalytic)	182800	9103
Hydrocracking Residual (Catalytic)	25400	1265
Hydrotreater Naphtha/reformer feed	301864	15033
Hydrotreater Gasoline	9250	461
Hydrotreater Kerosene/jet	216188	10766
Hydrotreater Diesel	193059	9614
Hydrotreater Distillate	14944	744
Other hydrotreating	48314	2406
Alkylation (reversed cracking)	13908	693
Aromatics	25600	1275
Isomerization (C5/C6 feed)	8730	435
Lubes	11600	578
HMU	360 (MMscfd)	310.25

Appendix 1e – Refinery steam temperature and demand composition

To calculate technical potential of electric boilers, insight was required into the temperature composition of the steam that is produced and used within refineries. This was based on a publicly available data provided by the VNPI which focusses on the PoR refineries. See the Table 26 below.

Table 26 – Steam temperature ranges and demand composition Dutch refinery sector (Davidse consultancy, 2012)

Temperature range	< 100°C	100 - 200°C	200 - 400°C	> 400°C	Total
%	0.0%	14.9%	74.6%	10.6%	100%

Appendix 1f – Refinery fuel composition

Fuel composition of the fuel stream in the model was calculated based on large combustion plant data[42] concerning all Dutch refineries and their large combustion plants (LCP) (20 MW+).

Table 27 – Dutch refinery fuel demand and composition in 2017 and ratio used within this study.

Percentage of RFG in refinery fuel stream

Refinery	Shell	Exxon	BP	Zeeland	Gunvor	Koch	Total
Natural gas (TJ)	11734	1258	3271	1789	1333	353	19738
Refinery Fuel Gasses (TJ)	19719	21621	21183	8855	3995	794	76166
% RFG [b]	63%	95%	87%	83%	75%	69%	**79%** [a]

[a] The weighted average ratio calculated is the ratio that is used within this study to describe the refinery sector as a whole.

[b] Only fuel type and amount (TJ) regarding large combustion systems was available. It was assumed that smaller combustion systems combust RFG and NG in the same proportions.

Appendix 1g – CWT factors used

The CWT factors that were used within Appendix 2 are based on Ecofys (2009) that were used within this study are shown in Table 28 and Table 29 below. TP activity was known for several combined processes. However, these processes have multiple sub-processes with different CWTs. For this reason, average CWT factors were calculated to assess 'aromatics' and 'lubes'. Values used within this study are shown in Table 29.

Table 28 - CWT factors.

Refinery Process Heating Unit	CWT factor
ADU	1
VDU	0.85
Visbreaker	1.4
Coker	16.6
FCC	5.5
CR (Low-pressure)	4.95
CR (High-pressure)	4.95
Hydrocracking Distillate (Catalytic)	2.85
Hydrocracking Residual (Catalytic)	3.75
Hydrotreater Naphtha/reformer feed	1.1
Hydrotreater Gasoline	1.1
Hydrotreater Kerosene/jet	0.9
Hydrotreater Diesel	0.9
Hydrotreater Distillate [a]	1.55
Other hydrotreating [b]	0.9
Alkylation (reversed cracking)	7.25
Aromatics [c]	3.42
Isomerization (C5/C6 feed)	2.85
Lubes [c]	3.98
HMU	300

[a] Assumed to be the residual hydrotreater.

[b] Assumed to be the VGO hydrotreater.

[c] See Table 29 below.

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[42] https://www.eea.europa.eu/data-and-maps/data/lcp-7/plant-by-plant-emissions-lcp was used to analyze the types of gas combusted (RFG or NG) and in what amounts (TJ/y).

Table 29 - CWT factor estimates

Unspecified TP's	
Aromatics	**CWT**
Aromatics solvent extraction	5.25
Hydrodealkylation	2.45
TDP/TDA	1.85
Cyclohexane	3
Xylene Isom	1.85
Paraxylene	6.4
Ethylbenzene	1.55
Cumene	5
Average	3.42
Lubes	**CWT**
Solvent extraction	2.1
Solvent dewaxing	4.55
Wax isomerization	1.6
Lube Hydrocracking	2.5
Wax deoiling	12
Lube & Wax Hydrofining	1.15
Average	3.98

Appendix 1h – The US refinery

The Refinery model created and used within this study is based on the US refinery shown in Figure 16 below.

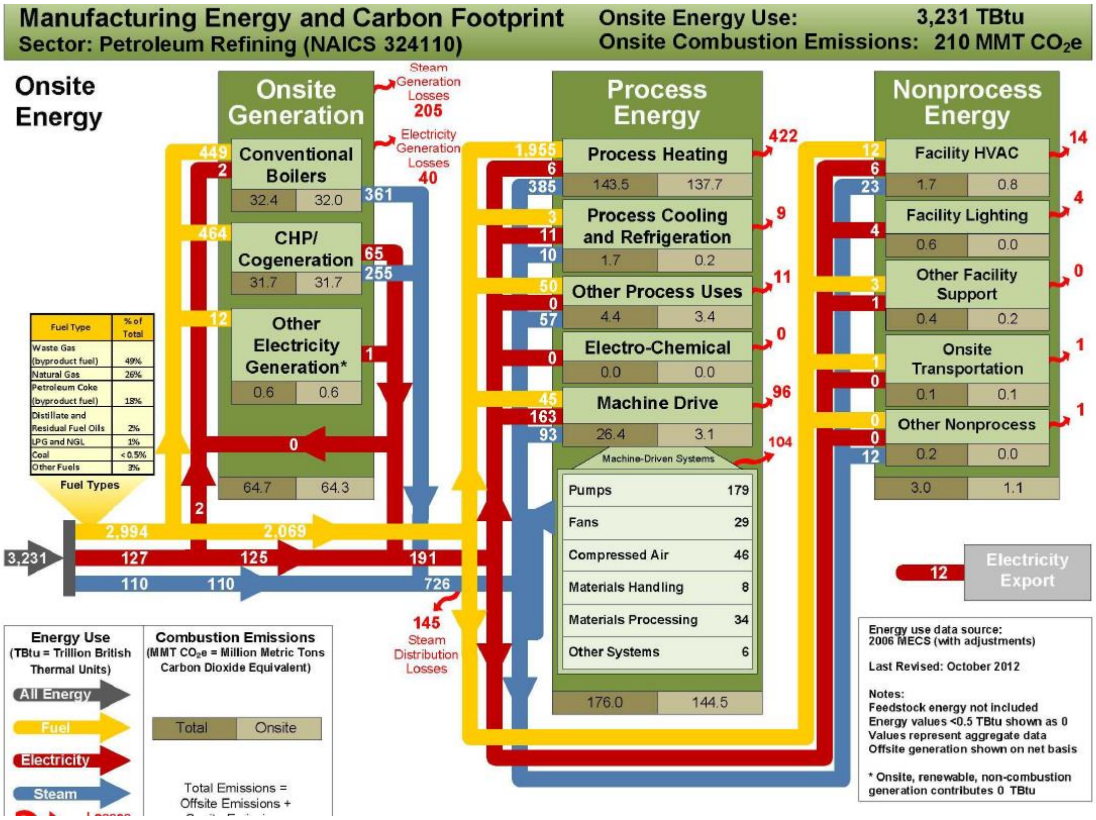

Figure 16 - The US refinery.

Appendix 1i – The refinery model input factors, ratios and constants

The values presented in the Table 30 below are used within the model calculate how much energy goes to an specific refinery part/element. The values are extracted from the US refinery model and converted into factors which were implemented in the refinery model. When the incoming flow (fuel/electricity/steam) is multiplied by the factors, the energy that goes to a specific part/element is calculated.

Table 30 – Total fuel, electricity, and steam use in the US refineries in 2012 (NAICS, 2013).

Fuel Flow Factors	**Value (Tbtu)**	**Name in model**	**Factor**
Fuel not to generation	2069		1.0000
Fuel to process heating (FPH)	1955	FPH	0.9449
Fuel to process cooling (FPC)	3	FPC	0.0014
Fuel to other process uses (FOPU)	50	FOPU	0.0242
Fuel to machine drive (FMD)	45	FMD	0.0217
Fuel to HVAC (FNPEFH)	12	FNPEFH	0.0058
Fuel to other facility support (FNPEOFS)	3	FNPEOFS	0.0014
Fuel to onsite transport (FNPEOT)	1	FNPEOT	0.0005
Electricity Flow Factors	**Value (Tbtu)**	**Name in model**	**Factor**
Electrify total (onsite + offsite)	191		1.0000
Electricity to process heating (EPH)	6	EPH	0.0314
Electricity to process Cooling (EPC)	11	EPC	0.0576
Electricity to machine drive (EMD)	163	EMD	0.8534
Electricity to HVAC (ENPEFH)	6	ENPEFH	0.0314
Electricity to lightning (ENPEFL)	4	ENPEFL	0.0209
Electricity to other facility support (ENPEOFS)	1	ENPEOFS	0.0052
Steam	**Value (Tbtu)**	**Name in model**	**% or factor**
Steam total	726		100%
Steam lost	145		20%
Steam available	581		80%
Steam to process heating (SPH)	385	SPH	0.6627
Steam to process cooling (SPC)	10	SPC	0.0172
Steam to other process uses (SO)	57	SO	0.0981
Steam to machine drive (SMD)	93	SMD	0.1601
Steam to non-process uses (SNPEONP)	12	SNPEONP	0.0207
Steam HVAC (SNPEFHVAC)	23	SNPEFHVAC	0.0396

Appendix 2 – CWT approach

CWT stands for carbon weighted ton and is a method to benchmark environmental performances of refineries. A list of generic process units of refineries was created and an emission factor (the CWT factor) relative to the CDU unit was assigned to each of the generic process units. The CWT factor is a dimensionless factor representing the average CO_2 emission intensity (per ton of TP) relative to the CDU. The CDU is given a CWT factor of 1. The other CWT factors represent their CO_2 emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for combustion, and for average refinery emissions of the process unit. Thus, the refinery in terms of CWT's represent a combination of the TP of the different process units, and therefore the 'activity' of the refinery. The following steps were followed to estimate absolute emission allocation to the specific refinery units relevant for the whole Dutch refining industry:

- Total Dutch refinery process units and 2017 TP was determined using worldwide refining survey data (2018). The CWT-factors *(CWT_i)* of each process unit was determined based on Ecofys (2009). See Appendix 1g. The amount of CWTs of each process unit is determined by multiplying its CWT_i by its intake during a given period. See equation 5 below.

$$CWTprocess = \sum_{i=1}^{N} CWT_i * TP_i \qquad \textit{(Equation 5)}$$

- Once *CWTprocess* is known, the percentage a specific process unit is responsible for the total scope 1 and 2 emissions can be calculated. This indicates its relative environmental impact, including onsite and offsite steam, power and H_2 production. The results of step 1 and 2 are shown in columns 2, 3 and 4 in Table 31 below.

Table 31 – Assessment NL refinery sector in terms of process units, activity and emission distribution according to CWT approach.

Unit	CWT [a]	TP (b/cd)	TP (kt/y) [c]	% CO_2 of total [e]	Absolute CO_2 (kt/y)
ADU	1.0	1221868	60849.0	16%	1919.8
VDU	0.9	714305	35572.4	8%	954.0
Visbreaking	1.4	82404	4103.7	2%	181.3
Coker	16.6	50500 [c]	2514.9	11%	1317.2
FCC	5.5	106415	5299.5	8%	919.6
CR (low-pressure)	5.0	108660	5411.3	7%	845.1
CR (High-pressure)	5.0	41400	2061.7	3%	322.0
Hydrocracking Distillate (Catalytic)	2.9	182800	9103.4	7%	818.6
Hydrocracking Residual (Catalytic)	3.8	25400	1264.9	1%	149.7
Hydrotreater Naphtha	1.1	301864	15032.8	4%	521.7
Hydrotreater Gasoline	1.1	9250	460.7	0%	16.0
Hydrotreater Kerosene	0.9	216188	10766.2	3%	305.7
Hydrotreater Diesel	0.9	193059	9614.3	2%	273.0
Hydrotreater distillate	1.6	14944	744.2	0%	36.4
Other hydrotreating	0.9	48314	2406.0	1%	68.3
Alkylation (reversed cracking)	7.3	13908	692.6	1%	158.4
Aromatics	3.4 [b]	25600	1274.9	1%	137.5
Isomerization (C5/C6 feed)	2.9	8730	434.8	0%	39.1
Lubes	4.0 [b]	11600	577.7	1%	72.6
H_2	300	360[e]	310.25	24%	2550.6
Total [d]				100%	11992

[a] Dimensionless factor representing the average CO2 emission intensity (per ton of TP/product) relative to ADU (Ecofys, 2009). Factors are assumed to be common to all Dutch refineries.
[b] Average number used of major lube and aromatic related process units described by Ecofys (2009). See Appendix 1g.
[c] Sum of all choking activity
[d] CWTprocess is found to be 380104 tCO_2 per kt of crude oil refined per year.
[e] Percentages are calculated by dividing *(CWTi * TPi)* with *CWTprocess*.

- To calculate total refinery sector emissions, the Historic Activity Level (HAL[43]) in units of product was determined using equation 6:

$$HAL_{CWT} = 1.0183 * CWTprocess + 298 + (0.315 * TP_{ADU}) \qquad \text{(Equation 6)}$$

Where:
1.0183, 298, 0.315 are constants defined by the EU (2011) guidance document number 9 on the harmonized free allocation methodology for the EU-ETS post 2012.
TP_i = throughput activity (in kt/y) through process unit *i* in 2017 period as defined for the CWT approach.
TP_{ADU} = throughput of the ADU in 2017 period defined as fresh feed (kt) per year.

- To calculate the total refinery sector emissions, HAL was multiplied with the sector benchmark score: 0.0295 (constant defined by EU (2011), referring to tons CO_2 emitted per tons of unit product produced at EU levels) giving 12 $mtCO_2$ in 2017 (last row and column Table 31).

Accurate emission calculation according to TP requires detailed TP data. For this reason, several sources that provide TP data have been consulted and cross checked. Compared to the data used by and found in other sources (e.g. Port of Rotterdam, a barrel full, Wanders (2017)), the world refining survey 2018 provided the most detailed TP figures on a relatively large amount (20) process units, including the major and most polluting units described in section 3. However, illustrating a refinery in 20 process units remains a strong simplification of a 'real', surely more complex refinery. Actual refinery facilities can have up to 56

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[43] Historic activity level, i.e. the median annual production in the baseline period as determined and verified in the baseline data collection (expressed in units of product). Formula based on EC (2011).

different process units (EC, 2011). As a result, the real emissions are expected to be *higher.* According to 2017 CBS data, the total refinery *scope 1* emissions are in the 10 $MtCO_2$ range. Other sources such as DNV-GL (2018) estimated 2017 *offsite* (electricity, steam and H_2) emissions to be 2.7 $MtCO_2$. The results of the CWT approach, 12 $MtCO_2$, are 6% (0.7 $MtCO_2$) short. This can be explained by the argument that some process units have been neglected. However, the 12 $MtCO_2$ which was calculated, deviates 6% from an DNV-GL (2018) emission estimation. Because the deviation is considered insignificant and based on an estimation, it is assumed that the emission *beak down,* shown in the percentages in Table 31, are a fair estimation of acceptable accuracy to be used to represent the relative *allocation* of emissions per process unit.

Appendix 3 – The refinery model

The refinery model was created and used to calculate CO_2 avoidance potential for all the identified decarbonization measures. The refinery model structure was based on the US refinery sector (NACIS, 2015, see figure Figure 16 appendix 1h). US data was used and translated into the Dutch situation. The main drawback of this approach is that it imposes the US refinery energy system on the Dutch system. In what way, and in what extent the two differ remains unknown. The purpose of the model is to represent the refinery sector in terms of energy and CO_2 flows, depending on output. When it is output-depended, output can be changed, and the refinery model automatically calculates the emissions per refinery part and element at these new output levels. This enables strategical assessment of decarbonization measures based on (future) refining activity, which can support decarbonization strategy and decision making. Detailed description of assumptions and the steps to develop the refinery model are described in this appendix.

Development steps summary:

1. Literature describing the energy use profile (Worrell, 2005; Wuppertal, 2016) and energy balances for the Dutch petroleum refining sector (CBS, 2019) was studied to understand structure and the major energy consuming elements of petroleum refineries.
2. Literature that analyzes the offsite and onsite flows of energy and CO_2 emissions of the US refinery sector (NCIS, 2013) was used to determine the energy flow ratios within the system.
3. Excel was used to create a 'flow model', in US energy flow ratios were used to calculate the Dutch emissions in 2015.
4. In order to validate the model, the numbers calculated by the model (scope 1 emissions of 11.24 $Mt/CO_2/y$) were compared to CBS and NEA emission data (11.14 $MtCO_2$). Due to the insignificant deviation, it is assumed that the model correctly calculates emissions.
5. 2015 Dutch refinery energy consumption (demand) and emissions are linked to 2015 output[44] by using constant ratios, making it dynamic depended on amount of crude that is processed.
6. The 2017 emissions were filled in and output can be calculated. The resulting refinery model (Figure 17 on the next page), has been validated by experts[45].

Appendix 3a – The basics

The model: terminology/structure (Figure 17)

- **Refinery part**: an essential and emission producing block within a refinery. There are 4 refinery parts: 1) Generation, 2) Operation, 3) Support, 4) Hydrogen manufacturing unit (HMU).
- **Refinery element:** each refinery part can consist out of multiple elements (e.g. boilers + CHP + other).

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[44] For validation purposes, different sources and detailed emission data is desired. The 2015 year was used because more recent years did not report emissions for the Vitol refinery. For this reason, CBS petro-output (export) data of 2015 was used (2296.6 PJ).

[45] 1) Maarten Neelis (background in monitoring industrial energy and carbon flows) validated the sources used for model development and US-NL generalization decision was discussed. 2) Carina Oliveira (background chemical engineering and currently working on the Dutch refinery energy balance for the MIDDEN-project at TNO) gave feedback on how the sector was visualized and confirmed the fuel/electricity/steam/emission shares per refinery part to be reasonable assumptions.

- **Export/output:** petroleum products (in PJ/y) that are not used but 'sold' or removed from the system in a certain year.
- **Oil - crude intake:** petroleum resources that enter the refinery system and are transformed at the operation part into usable and saleable petroleum products.
- **Streams**: indicate the flow direction and size of energy. Yellow is fuel (RFG+NG), purple is electricity, blue is heat (steam), dark brown is crude oil, light brown is products, pink is petroleum products own consumption (other), dark blue is hydrogen.

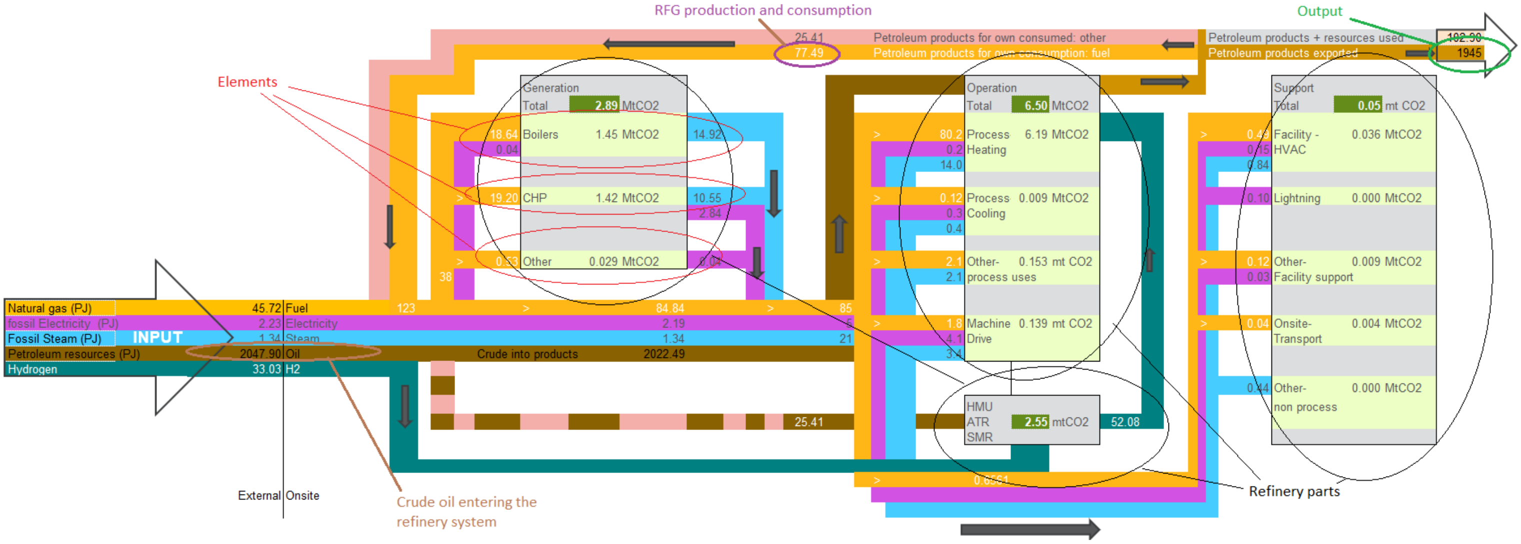

Figure 17 - Snap Shot Refinery system.

General assumption: US refinery sector is the same as the Dutch refinery sector in terms of:

- Presence of refinery parts.
- Presence of elements.
- Relative share (% of total) of emission production per refinery element and part.
- Energy generation ratios (steam/electricity/fuel) at the CHP and boilers.
- External energy input ratios (steam/electricity/fuel).
- Energy (steam/electricity/fuel) distribution ratios towards the refinery elements and parts.
- Steam distribution losses (%).

Assumptions related to fuel and emissions

- Internal fuel generation contains 100% RFGs that are formed during refining activity. Considered a waste product gas, without costs.
- External fuel input contains 100% NG.
- Internal fuel stream contains NG (20.59%) and RFG (79.41%). Composition never changes.
- Total refinery emissions include scope 1 fuel/electricity/steam/H_2 emissions and scope 2 H_2 emissions. Emissions of electricity and steam generation outside the refineries are not included because of the negligible amounts compared to own production (1.34 PJ_{steam} and import vs 21 PJ_{steam} produced)
- Emissions are fully related to output (PJ).

Appendix 3b – Building the model

Transforming the US system into a Dutch system: *determining flow factors. Different amounts of energy (PJ/Tbtu)) and types (electricity/steam/fuel) are needed at the different refinery elements. Flow factors per energy carrier (fuel/electricity/steam) were created to link energy consumption and type to the different refinery elements.*

In order to calculate the amount of steam/electricity and fuel that is used in a specific part/element of the refinery, factors were made. These factors are fully based on the US refinery industry. It was found that the US system uses almost twice as much steam as the Dutch sector[46]. This has been neglected in the analysis. Impact on the results discussed in section 6. Factors are presented in appendix 1i.

Transforming the US system into the Dutch system: *determining emission factors per refinery element.*

Different fuel mixes are combusted at different refinery elements. However, within this study it is assumed that the fuel composition (NG:RFG) is always the same. To compensate for this assumption, an emission factor for all the refinery elements has been implemented. This factor corrects for the different fuel compositions that are emitted per refinery element. The Dutch 2015 emission distribution among the refinery elements is based on the US emission distribution in % per refinery element. Next, the Dutch emissions are divided by the PJ_{fuel} that is used at a specific element. The resulting emission factors are implemented to make emissions per element depended on fuel input. Results are shown in Table 32 below.

Table 32 – Dutch EF's refinery elements.

Process	Baseline energy input (F+E+S)(PJ)	Baseline emissions NL (mt/y)	EMF ($MtCO_2$/PJ)	Formulae	Name in model
Boilers	22.01	1.71	0.08	CO2 emissions boiler / Fuel in	EMF_Boiler
CHP	22.67	1.67	0.07	CO2 emissions CHP / Fuel in	EMF_CHP
Other process uses	0.62	0.03	0.06	CO2 emissions other / Fuel in	EMF_Other
Process heating	94.66	7.31	0.08	CO2 emissions PH / Fuel in	EMF_Heating
Process cooling	0.15	0.01	0.07	CO2 emissions PC/ Fuel in	EMF_Process Cooling
Other process uses	2.42	0.18	0.07	CO2 emissions OPU / Fuel in	EMF_Process Uses
Machine drive	2.18	0.16	0.08	CO2 emissions MD/ Fuel in	EMF_Machine Drive
Facility HVAC	0.58	0.04	0.07	CO2 emissions HVAC/ Fuel in	EMF_Facility Hvac
Other facility support	0.15	0.01	0.07	CO2 emissions OFS/ Fuel in	EMF_Facillity Support
Onsite transport	0.05	0.01	0.11	CO2 emissions OT / Fuel in	EMF_Onsite Transport
Hydrogen production	69.00	3.01	0.04	CO2 emissions H2/Fuel in	EMF_hydrogenproduction

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[46] At 2015 output levels, 25 PJ_{steam} is consumed according to the model. However, CBS states that 14.6 PJ_{steam} is used in 2015.

Linking internal energy demand to output: *to assess the impact of future refining activity changes, energy demand per refinery element was linked to output.*

To make the energy flows towards each refinery element dynamic with output, factors were calculated by dividing baseline output (2296.6 PJ, CBS[47]) by baseline energy demand levels per refinery element. These factors were implemented to calculate fuel demand with a particular output. See Table 33.

Table 33 – Constants used to connect fuel demand with output.

		TP baseline	2296.6
Operation part	**Name in model**	**Factors**	**Baseline (fixed)**
Fuel Process Heating	Nf_PH	24.3	94.7
Electricity Process heating	Ne_PH	12945.5	0.2
Steam process heating	Ns_PH	138.5	16.6
Fuel Process cooling	Nf_PC	158111.0	0.2
Electricity Process cooling	Ne_PC	7061.2	0.3
Steam Process cooling	Ns_PC	5330.7	0.4
Fuel other process uses	Nf_OPU	948.7	2.4
Steam other uses	Ns_OPU	935.2	2.5
Fuel Machine drive	Nf_MD	1054.1	2.2
Electricity machine drive	Ne_MD	476.5	4.8
Steam machine drive	Ns_MD	573.2	4.0
Support part	**Name in model**	**Factors**	**Baseline (fixed)**
Fuel facility HVAC	Nf_FHVAC	3952.7	0.6
Electricity facility HVAC	Ne_FHVAC	12945.5	0.2
Steam facility HVAC	Ns_FHVAC	2317.7	1.0
Electricity facility lightning	Ne_FL	19418.2	0.1
Fuel Other facility support	Nf_FS	15811	0.1
Electricity other facility support	Ne_FS	77672.8	0.03
Fuel onsite transport	Nf_FT	47432.9	0.05
Steam other non-process	Ns_FP	4442.3	0.5

Linking external energy input to output: *to assess the impact of future refining activity changes, energy input was linked to output.* The following factors (Table 34) were used:

Table 34 - Constants used to connect energy input with output.

To link external energy input to output		Using a bassline export value of:	2296.6
Throughput factor of..	**Input (PJ)**	**Name in model**	**Factor**
Fossil Fuel	17.1	Cnst_Fi/O	0.007
Electricity	2.5	Cnst_Ei/O	0.001
Steam	1.5	Cnst_Si/O	0.0006
Petroleum resources intake	2418.1	Cnst_O/I	0.950
NG	53.5	Cnst_NGi/O	0.023
Refinery fuels	91.4	Cnst_Ri/O	0.040
Crude used to generate H_2	30	Cnst_CrudeH2	0.012
Hydrogen external	39	Cnst_Hi/o	0.017

Finding 2017 output and emissions: most recent activity data available was that of the Dutch refinery 2017 TP (worldwide refining survey, 2018). Using these TP data and the CWT approach (See appendix 2), the 2017 emissions were calculated (12 $MtCO_2/y$). Consequently, the 2017 output was calculated (1945 PJ) at the emission levels found using the CWT approach.

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[47] https://opendata.cbs.nl/statline/#/CBS/nl/dataset/83141NED/table?dl=1F612

Appendix 3c – Applying the model

Emissions at the refinery parts and elements: Table 35 gives an overview of the baseline emissions per refinery part and element. This was calculated using the refinery model at estimated 2017 output levels.

Table 35 - Emissions per refinery part and element in 2017.

Baseline CO_2 avoidance potentials

Part	Element	Value ($MtCO_2/y$)
Generation	Boilers	1.446
	CHP	1.417
	Other generation	0.029
	Total	2.89
Process	Process heating	6.194
	Process cooling	0.009
	Other process uses	0.153
	Machine drive	0.139
	Total	6.50
HMU	HMU	2.55
Non-Process	Facility HVAC	0.036
	CO2 Lightning	0.000
	Other facility support	0.009
	Onsite-transport	0.004
	Other non-process	0.000
	Total	0.05
Total	Total	11.99

Zooming in on boilers & CHP: *estimating CO_2 avoidance potential for electric steam production.* Due to technical constraints, electric boilers have steam temperature limitations. For estimating CO_2 avoidance potential, general refinery steam temperature ranges and demand distribution data was used. An overview is shown in Table 36. The percentual composition of heat demand was based on a study into industrial heat demand by Davidse consultancy[48]. The PJ_{steam} (see *total* column, Table 36) was calculated using the refinery model. The losses were calculated by extracting the PJ_{steam} that enter all the individual refinery elements by the PJ_{steam} that is produced by the boilers, CHP and external input. All other PJ values are based on the totals and relative percentages.

Table 36 - steam demand and temperature distribution

Temperature range [a]	< 100°C	100 - 200°C	200 - 400°C	> 400°C	Total
%	0.0%	14.9%	74.6%	10.6%	100%
Boiler (PJ)[b]	0	2.22	11.13	1.58	14.92
CHP (PJ)	0	1.57	7.87	1.12	10.55
External (PJ)	0	0.20	1.00	0.14	1.34
Total (PJ)	0	3.99	20.00	2.84	26.81
Losses (PJ)[c]	0	0.80	3.99	0.57	5.35
Final (PJ)	0	3.20	16.01	2.27	21.46

[a] Data from Davidse consultancy (2015). Note that this only regards refineries located within the PoR. It is assumed that same values apply to the Zeeland refinery.
[b] Energetic values are calculated using own model based in fuel input. It was assumed that PJ input equally correlates with temperature output.
[c] Calculated using model based on NAICS (2013) distribution losses.

Zooming in on process heaters: *calculating emissions for specific refinery process units within the process heater element.* Due to technical constraints and differences between process units, insight was required into the specific emissions per process unit. Using 2017 throughput activity, the emissions from fuel combustion *per process unit* was calculated (see column 4, Table 37) by combining the CWT method

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[48] For more information, see Davidse Consultancy (2015) p5, table 4.3.

(Appendix 2) and the flow model. This can then be used to accurately estimate CO_2 avoidance potential and abatement cost of the selected decarbonization measures.

It was assumed that hydrogen activity and emissions are fully related to the HMU-part of the refinery. This made it possible to make 'hydrogen activity' TP dependent and hydrogen-consumption related emissions (2.6 $MtCO_2$) can be extracted from the total (12 $MtCO_2$). New emissions (9 $MtCO_2$) and its share (in %) of the individual process units were calculated. The next step compares the emissions found using the energy flow model (6.19 $MtCO_2$), which gave emission numbers only for the direct fuel (21% NG, 79% RFG) combustion at the refinery process units. If the remaining emissions (9.6 $MtCO_2$) are divided by the process heating emissions (6.19 $MtCO_2$), a factor was calculated (0.32). Under the assumption that *electricity and steam are equally responsible for activity related emissions for all process units*, this factor can be used to determine the extent in which electricity and steam are responsible for the total emissions from the all the core process units.

Table 37 - Real CO_2 avoidance potentials per process unit.

Emissions per process unit		Emissions 2017 in ktCO2/y	
Unit	**% responsible**	**Including steam and electricity**[a]	**Only fuel**[b]
ADU	16%	1919.8	1305.7
VDU	8%	954.0	648.8
Visbreaker	2%	181.3	123.3
Coker	11%	1317.2	895.8
FCC	8%	919.6	625.5
CR (Low-pressure)	7%	845.1	574.8
CR (High-pressure)	3%	322.0	219.0
Hydrocracking Distillate (Catalytic)	7%	818.6	556.7
Hydrocracking Residual (Catalytic)	1%	149.7	101.8
Hydrotreater Naphtha/reformer feed	4%	521.7	354.8
Hydrotreater Gasoline	0%	16.0	10.9
Hydrotreater Kerosene/jet	3%	305.7	207.9
Hydrotreater Diesel	2%	273.0	185.7
Hydrotreater Distillate	0%	36.4	24.8
Other hydrotreating	1%	68.3	46.5
Alkylation (reversed cracking)	1%	158.4	107.8
Aromatics	1%	137.5	93.5
Isomerization (C5/C6 feed)	0%	39.1	26.6
Lubes	1%	72.6	49.4
HMU	24%	2550.6	EXCLUDED
Total	100%	11992.5	6159.2

[a] See appendix 2 – CWT

[b] 6.16 $MtCO_2/y$ was found using model. The CWT approach values found are 12 $MtCO_2/y$. When extracting H_2 emissions (2.6 $MtCO_2/y$, 9.6 $MtCO_2$ remains. It is assumed that this indicates the whole refinery emissions without hydrogen. It is assumed that the model values, 6.16 $mtCO_2/y$, are only for the process heating element (process heaters). When dividing 6.16 by, 9.6, a factor of 0.68013 was found, which issued to calculate only fuel emissions.

Appendix 4 – Elaboration on measures

Appendix 4a - Energy Efficiency Measures

This study assumes that energy efficiency measures involve all retrofit and replacement measures that can be deployed to reduce the energy demand of the system and thereby lowering CO_2 emissions. The specific measures, CO_2 avoided, and Ca are based on Berghout et al., (2019).

Table 38 - EEM specification.

EEM	CO_2 avoidance potential (%)	Geographical scope	Aggregation level	Economics € 2012/tCO_2	Source
EEM	20-36	NW EU	Refinery	-226 to -33	Berghout (2015)
	20-50	EU	Sector	-150 to – 102	Ecofys (2009)
	20-30	US	Sector	N/A	Worrell (2013)
	8-22	SWE	Refinery	-98 to -27	Holgren (2008)
	10-20	Brazil	Sector	N/A	
	5-20	EU	Sector	N/A	

Short term EEMs:

- Energy management & control (-3%)
- Heat integration distillation units (-3%)
- Motors and pumps (-2.4%)
- Steam distribution systems (-2%)
- Heat integration & waste heat recovery (-2%)
- Fouling mitigation (-1%)
- Improved furnace performance (-1%)
- Hydrogen management & recovery (-0.7%)
- Flaring (-0.5%)

Medium term EEMs:

- Advanced desulphurization (-10%)
- Advanced separation systems (-6.8%)
- Turbine pre-coupling (-2.5%)

Industrial symbiosis

Optimized forms of waste heat and other waste streams are closely related to the industrial symbiosis (IS) concept. IS focusses on finding and utilizing synergies between companies and industries. The term synergies used within this study refer to physical company to company exchanges. Some synergies for oil refineries were identified by Lopes (2013):

- Oil refinery supplies off-spec material to plastic manufacturer
- Bio-treated sludge from oil refinery de-watered and/or dried and sold as fertilizer
- Chemical manufacturer supplies steam to oil refinery
- Sulfur from oil refinery to fertilize industry
- Oil refinery supplies spent-catalysts to be used in cement production industry

IS is expected to have a large potential for the highly integrated refineries with chemical facilities, such as Exxon Mobil Chemical site and Shell Moerdijk. This was not studied because the methodology and scope of this study are unable to assess the techno-economic impact of IS sort decarbonization measures. Also, the due to the complexity of refineries and conflicting actor interest it was decided to not study this concept.

Appendix 4b – CCS

CCS stands for carbon capture and storage, which involves the capture and (underground) storage of CO_2. There are three types of CCS:

1. Pre-combustion. This type of CCS removes the CO_2 from the process gasses from gas like fuels, compresses the CO_2 and feeds it into the CO_2 infrastructure before combustion takes place. One advantage is that this form of CCS has the highest concentration of CO_2 in the gasses, reducing costs for capture. Fuels are transformed into H_2.
2. Post-combustion. Within this type of CCS, the CO_2 is removed from the flue gasses after combustion of the fuel. Compared to pre-combustion, the CO_2 concentration is lower. This increases the energy and capture costs.
3. Oxy-fuel combustion. When chemical waste gasses react with pure oxygen, syngas is produced. This syngas consists out of a mix of H_2, CO and some CO_2. The CO_2 can be captured.

Table 39 - CCS Pre's & con's

Advantages/potential	Challenges	Solutions	Synergies/interaction	Barriers
*Decarbonize the production processes while the existing production processes are kept unchanged (Bataille et al., 2018). * Key long-term advantage: when combined with biomass combustion it allows net-negative emissions. * CO_2 can be used for other processes (e.g. making renewable methanol, ethanol or other compounds)	*Requires large combustion facilities * Energy intensive *Pure steam of CO_2 *CO_2 storage *CO_2 infrastructure	*Oxy-fuel: provides pure CO_2 *Solid Oxide fuel cells	*Electrolysis: O_2 production * SOFC: abundant fuel. produce electricity, operate at a temperature (600-900°C) useful for industrial process heat, produce pure stream of CO_2. Potential to produce methanol.	* Social acceptance barriers to geological CO_2 storage in some countries (Sharp, 2009) * Lock-in fossil fuels

Appendix 4c – Furnaces: utilizing clean fuels

When process heat demand exceeds 350°C, a furnace is required. Regarding decarbonization prioritization, furnaces are also used within biorefineries for hydrotreating, hydrocracking and distillation. Three alternatives to conventional (fossil fired) furnaces have been identified.

With relatively low adaptation of core processes and refinery setup, combustion of clean fuels may offer decarbonized routes to produce high temperature process heat and chemicals. Four potential fuels have been identified to enable long-term and deep decarbonizing of high temperature process heat: (1) H_2, (2) synthetic fuels, (3) biofuels, (4) metal fuels. This study assumes that switching to H_2 as fuel is the most likely option since it is the cheapest and H_2 is already widely used at refineries. Other fuels are not investigated. When combusting H_2, current furnaces and their burners need to be retrofitted because a H_2 flame behaves differently than a natural gas flame. H_2 flames have a faster burning speed which increases the chance of flashback, which is a situation in which the flame retreats into the mixing zone due to a lower gas flow velocity compared to the flame burning velocity and hereby damages equipment (Larfeldt, 2017; Al-Hashimi, 2011). Secondly, higher flame temperatures lead to an increased NO_x production. Also, the radiative heat transfer is much less compared to natural gas flames. This was not investigated. When switching to H_2, a H_2 infrastructure (expansion) is likely to be needed.

Appendix 4d - Electrification

Electrification of heat demand expected to increase, advocating enhanced implementation of electric boilers and electric heat pumps. Industrial electric heating infrastructures (high temperature) and domestic district heating infrastructures (low temperature) are expected to become increasingly important (DNV-GL & CE Delft, 2015). Table two below gives an overview of potential electrical heating technologies suitable for HT industry (Berenschot, 2018; NREL, 2017). Major drawback is that for assessing and estimating electrification potentials, some processes will require radical changes, disrupting the current processes. This would involve pinch analysis and fundamental rebalance efforts of the refining systems. In theory, and from the physics perspective, it is possible to electrify all heat demand. However current assets, infrastructure and configuration would demand extreme adjustments, involving large risks and financial uncertainty.

Table 40 - P2H specs.

Unit operations	Technologies	Category	Emission scope
Process heat (steam, hot water, thermal oil)	Heat pumps Electric boiler/ electrode boiler Hybrid CHP-EB concepts Steam recompression/vapour recompression Resistance heating	Power2heat Power2pressure	1,2
Process heat (baking, melting, casting)	Induction furnace Microwave heating Electric melting Electric arc furnace Plasma heating/ plasma recycling Infrared heating Resistance heating	Power2heat	1,2

Resistance heating: direct electric

When an electrical current is running through a wire with high electrical resistance, heat is generated according Joule’s first law: $Q = I^2Rt$. The electrical heating element that is in a washing machine or dishwasher is based on this law as for the most industrial electrical heating solutions. This is called the Ohm resistor. This can be placed into the oil.

Investment costs for an air heater installation can vary greatly, depending on structural investments such as foundations required for installation. In all cases the electricity connection costs to a utility and onsite should be included and are site specific.

Electric arc furnaces

For chemical cracking, an electric arc furnace has the potential to decarbonize current fossil fueled furnaces. An arc furnace creates an electric arc which generates a plasma beam. This plasma beam can reach very high temperatures needed for cracking. However, plasma cracking technology has a low TRL (< 3) and catalysts and system integration research are required.

Heat pumps

Heat flows naturally from a higher to a lower temperature. However, heat pumps can change this heat flow direction using high quality energy (Siemens AG, 2019). In an industrial heat pump system, electricity (yellow, Figure 18) and low-level heat (blue Figure 18) are used to generate heat at a higher temperature. A source with a constant heat supply is required such as a river or ground water but WH or GE can also be upgraded. Although industrial heat pump systems are a promising technology, the TRL (6-7) is a limiting factor for MW applications (Berenschot, 2018). HPs are more efficient then direct electric systems (Lux Research, 2018).

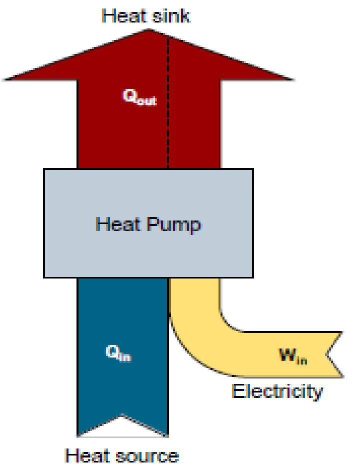

Figure 18 – Schematic overview HP (Siemens, 2019)

Appendix 5 - Scope 3 emissions (extension)

Worldwide policy support aiming to replace fossil fuel consumption with biofuels had led to an increased biofuel production and market expansion in domestic markets. The fastest growing products are bioethanol and biodiesel. Bioethanol production from corn crops is dominated by the US and Brazil and represents 2-3% of the US fuel supply. Rapeseed and sunflower oil biodiesel are largely produced in Germany (75% of total EU and 40% worldwide production).

Bio refineries

Petroleum refineries can be retrofitted into bio-refineries. Within a bio-refinery, process units convert sustainable biomass to marketable products such as chemicals and fuels. Hydrotreaters, hydrocrackers and in some cases ADU and VDU units of petroleum refineries can be used. A disadvantage of biorefining is that sustainably produced biomass- including wood, biogas and biofuels – is not available in enough quantities to replace coal, oil and NG in applications that rely on thermal combustion (Agora, 2018). Since biomass displaces croplands for food production there are strong limitations to expending its production. Land use competition can be avoided by production of biofuels from waste and agricultural residues. However, the growth potential of this class of biofuels (13-19 EJ) is far too limited to cover the energy needs of the transport sector (100-170 EJ) (Agora, 2018). An example of a petroleum refinery that was retrofitted into a bio-refinery is described in Box 1 below.

Box 1 - La Mède (Total).

Total fully converted one of their petroleum refineries into a biorefinery. This refinery stopped its petroleum refining activity and 15-20% of the present process units became useful in the new biorefinery facility. This refinery refines used cooking oils and produces biodiesel and bio aviation gasoline. For the retrofit, the CDU, VDU and FCC became unrequired and were removed from the facility. The two available hydrotreaters got connected. Deoxygenation takes place in two steps: (1) removal of oxygen and (2) minor cracking. A pre-treatment unit to remove impurities from the cooking oils was added.

Total costs: €275 million – Bio oil TP: 500 kt/y.

Figure 19 - La Mède

Synthetic fuels

If produced with renewable power and climate neutral carbon, synthetic fuels have the potential to facilitate deep decarbonization of our current energy system. When synthetic fuels become an important future fuel source, this will have consequences for the petroleum refining sector. Synthetic fuels are energy dense, easily transportable, compatible with existing combustion systems and infrastructure, and can be stored. The disadvantage is that they will always be more expensive than the direct consumption of electricity. The reason for this is that synthetic fuel production is associated with high conversion losses (e.g. electrolysis is 70% efficient and energy is required to produce climate neutral carbon) (Frontier economic, 2018). Reliance on synthetic fuels will also increase the demand for renewable electricity from wind/solar/hydro/geothermal which increases the geographic area occupied by renewable energy systems. Europe will most likely not be able to deliver enough (cheap) renewable power and power import[49] is necessary. For these reasons, synthetic fuels should be used in areas in which the direct and efficient use of electricity is less convenient such as aviation and industrial process heating. Another potential role for synthetic fuels is in the field of long-term electricity storage and climate neutral production of industrial input materials such as naphtha (BASF, 2019a).

Regarding synthetic fuel production within petroleum refineries, it would be financially valuable to have insight in what petroleum process units are also required for synthetic fuel production. In case demand for

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[49] In 2020: Iceland geothermal/hydropower: < 3 ct/kWh$_{el}$. North Africa and middle east PV < 4 ct/kWh$_{el}$. Compared to North and Baltic seas wind offshore of 9 ct/kWh$_{el}$ with possible 2050 prices of 5 ct/kWh$_{el}$. (Frontier economics, 2018).

petroleum-based fuels decline, it might be strategically smart for petroleum refineries to invest in decarbonization measures for process units which are also required for producing synthetic fuels. For this reason, two major synthetic fuel routes have been examined: methanol (Figure 20) and Fischer-Tropsch (Figure 21) synthesis. Methanol conversion and upgrading comprises FCC (olefin synthesis) and hydrotreating. Crude P2L upgrading comprises hydrocracking, isomerization, and distillation. In both cases, CO_2 can originate from fossil CO_2 captured from process heaters, power generation or hydrogen production. Better would be carbon captured from biomass combustion. Ideally, direct air captured CO_2.

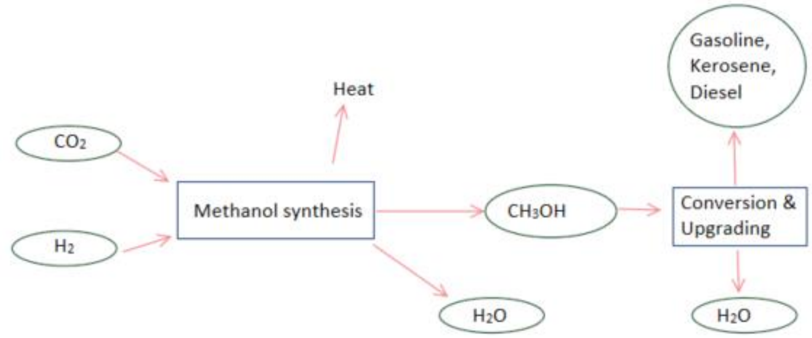


Figure 20 – Methanol synthesis.

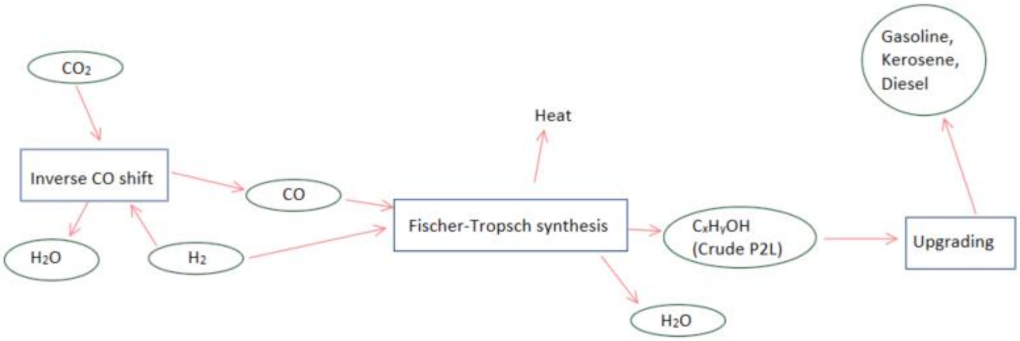


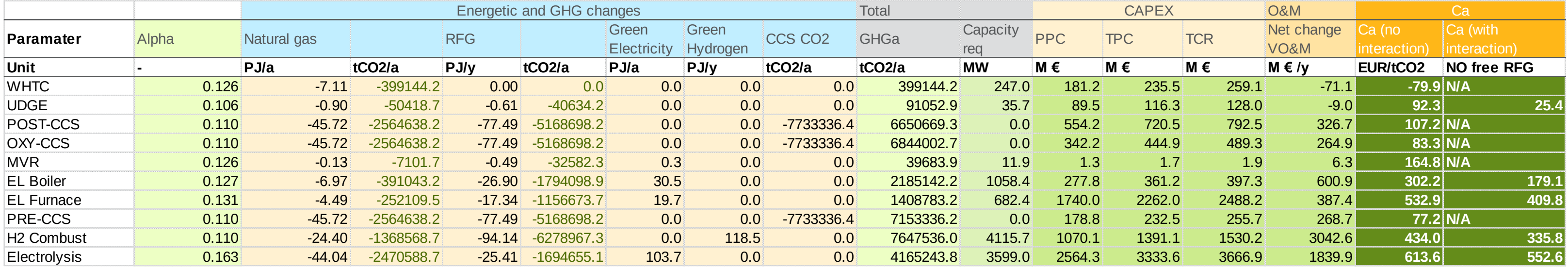
Figure 21 - Fischer-Tropsch synthesis.

For synthetic fuels to become economic viable, two conditions must be fulfilled: (1) high annual full load hours, and (2) cheap renewable power. Many advocate the use of excess renewable power. However, estimated renewable power generation in coming years do not foresee enough power volumes for the operation of synthetic fuel facilities on excess production alone. The production of synthetic fuels is only possible if additional investment is made in renewable energy facilities.

Appendix 6 – CO_2 avoided & C_a

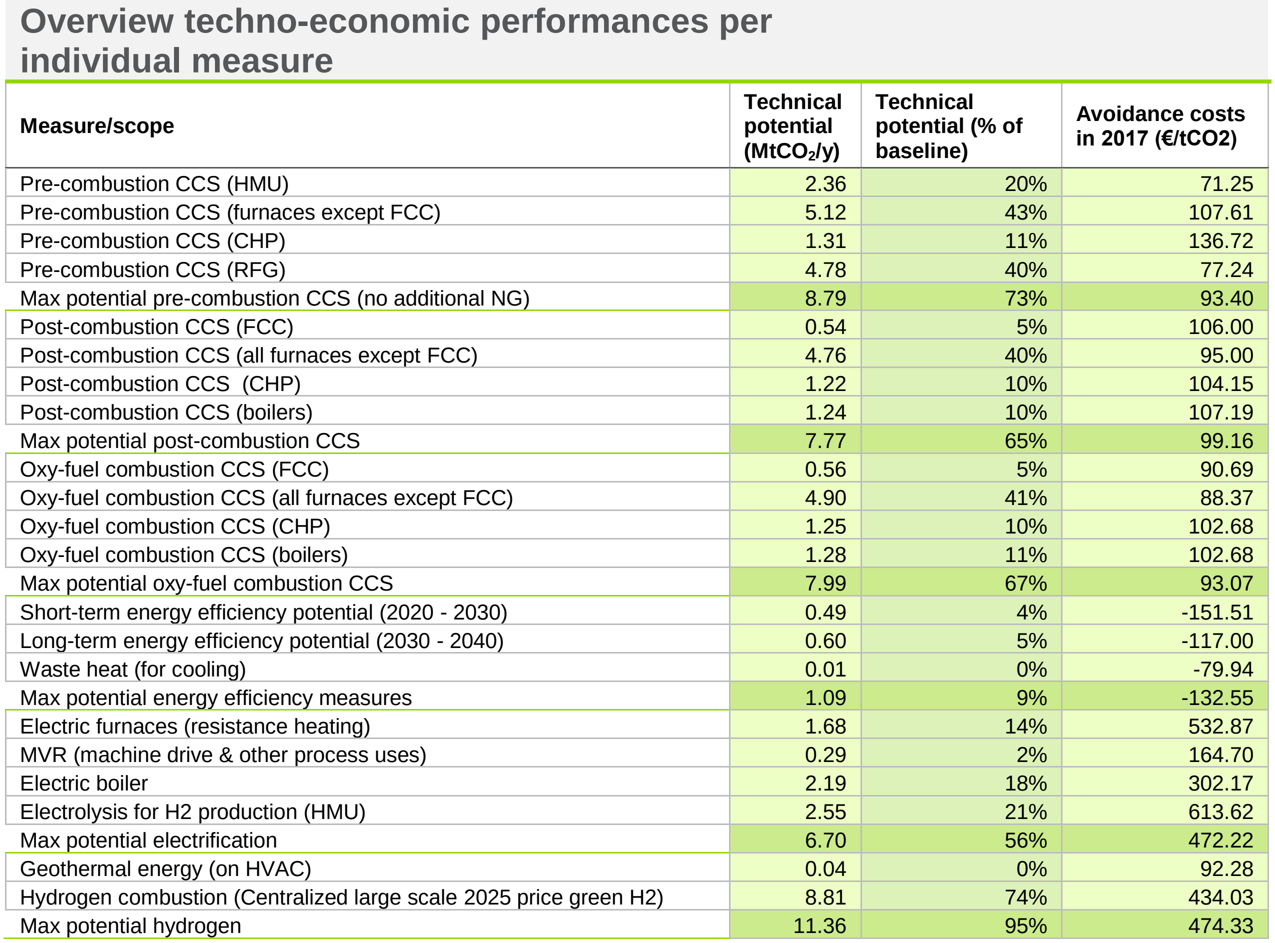
Calculating Ca: an overview of the fuel changes, CO_2 avoided, investment costs and Ca is found in Table 41. These values are all averages. For the sensitivity values, see section 4. A complete overview of CO_2 avoided and Ca per measures can be found in Table 42.

Table 41 - Overview techno-economic input parameters per measure.



		Energetic and GHG changes							Total		CAPEX			O&M	Ca	
Paramater	Alpha	Natural gas		RFG		Green Electricity	Green Hydrogen	CCS CO2	GHGa	Capacity req	PPC	TPC	TCR	Net change VO&M	Ca (no interaction)	Ca (with interaction)
Unit	**-**	**PJ/a**	**tCO2/a**	**PJ/y**	**tCO2/a**	**PJ/a**	**PJ/y**	**tCO2/a**	**tCO2/a**	**MW**	**M €**	**M €**	**M €**	**M € /y**	**EUR/tCO2**	**NO free RFG**
WHTC	0.126	-7.11	-399144.2	0.00	0.0	0.0	0.0	0.0	399144.2	247.0	181.2	235.5	259.1	-71.1	**-79.9**	**N/A**
UDGE	0.106	-0.90	-50418.7	-0.61	-40634.2	0.0	0.0	0.0	91052.9	35.7	89.5	116.3	128.0	-9.0	**92.3**	**25.4**
POST-CCS	0.110	-45.72	-2564638.2	-77.49	-5168698.2	0.0	0.0	-7733336.4	6650669.3	0.0	554.2	720.5	792.5	326.7	**107.2**	**N/A**
OXY-CCS	0.110	-45.72	-2564638.2	-77.49	-5168698.2	0.0	0.0	-7733336.4	6844002.7	0.0	342.2	444.9	489.3	264.9	**83.3**	**N/A**
MVR	0.126	-0.13	-7101.7	-0.49	-32582.3	0.3	0.0	0.0	39683.9	11.9	1.3	1.7	1.9	6.3	**164.8**	**N/A**
EL Boiler	0.127	-6.97	-391043.2	-26.90	-1794098.9	30.5	0.0	0.0	2185142.2	1058.4	277.8	361.2	397.3	600.9	**302.2**	**179.1**
EL Furnace	0.131	-4.49	-252109.5	-17.34	-1156673.7	19.7	0.0	0.0	1408783.2	682.4	1740.0	2262.0	2488.2	387.4	**532.9**	**409.8**
PRE-CCS	0.110	-45.72	-2564638.2	-77.49	-5168698.2	0.0	0.0	-7733336.4	7153336.2	0.0	178.8	232.5	255.7	268.7	**77.2**	**N/A**
H2 Combust	0.110	-24.40	-1368568.7	-94.14	-6278967.3	0.0	118.5	0.0	7647536.0	4115.7	1070.1	1391.1	1530.2	3042.6	**434.0**	**335.8**
Electrolysis	0.163	-44.04	-2470588.7	-25.41	-1694655.1	103.7	0.0	0.0	4165243.8	3599.0	2564.3	3333.6	3666.9	1839.9	**613.6**	**552.6**

Table 42 - Overview CO_2 avoided and Ca per measure.



Overview techno-economic performances per individual measure

Measure/scope	**Technical potential ($MtCO_2$/y)**	**Technical potential (% of baseline)**	**Avoidance costs in 2017 (€/tCO2)**
Pre-combustion CCS (HMU)	2.36	20%	71.25
Pre-combustion CCS (furnaces except FCC)	5.12	43%	107.61
Pre-combustion CCS (CHP)	1.31	11%	136.72
Pre-combustion CCS (RFG)	4.78	40%	77.24
Max potential pre-combustion CCS (no additional NG)	8.79	73%	93.40
Post-combustion CCS (FCC)	0.54	5%	106.00
Post-combustion CCS (all furnaces except FCC)	4.76	40%	95.00
Post-combustion CCS (CHP)	1.22	10%	104.15
Post-combustion CCS (boilers)	1.24	10%	107.19
Max potential post-combustion CCS	7.77	65%	99.16
Oxy-fuel combustion CCS (FCC)	0.56	5%	90.69
Oxy-fuel combustion CCS (all furnaces except FCC)	4.90	41%	88.37
Oxy-fuel combustion CCS (CHP)	1.25	10%	102.68
Oxy-fuel combustion CCS (boilers)	1.28	11%	102.68
Max potential oxy-fuel combustion CCS	7.99	67%	93.07
Short-term energy efficiency potential (2020 - 2030)	0.49	4%	-151.51
Long-term energy efficiency potential (2030 - 2040)	0.60	5%	-117.00
Waste heat (for cooling)	0.01	0%	-79.94
Max potential energy efficiency measures	1.09	9%	-132.55
Electric furnaces (resistance heating)	1.68	14%	532.87
MVR (machine drive & other process uses)	0.29	2%	164.70
Electric boiler	2.19	18%	302.17
Electrolysis for H2 production (HMU)	2.55	21%	613.62
Max potential electrification	6.70	56%	472.22
Geothermal energy (on HVAC)	0.04	0%	92.28
Hydrogen combustion (Centralized large scale 2025 price green H2)	8.81	74%	434.03
Max potential hydrogen	11.36	95%	474.33

Appendix 7 – Scenarios

General assumptions for calculation tables

- It was assumed that RFG production is related to the total PJ
- It was assumed that the Dutch oil refinery sector is a perfect reflection of the EU sector
- It was assumed that the fuels and chemicals reflect total refinery activity
- Chemicals refer to output of petrochemical products/feedstocks such as naphtha. Chemicals include materials such as bitumen, lubricants, waxes.
- It is assumed that fuels refer to transport fuels produced (kero/diesel/gasoline/LPG/LNG)
- IEA data in Mtoe was converted to PJ by multiplying with 41.868

Appendix 7a - Current policies

Within this scenario it is assumed that refinery products and fuels will remain dominant. Consequently, global oil demand rises and will continue to rise with 1.16%/y[50] until 2040. It is assumed that this remains the case until 2050. At the same time, consumers will demand increasingly more sustainable products. Small, noncomplex, and nonintegrated European refineries are expected to be closed due to increasingly importance of scale and flexibility benefits. As a result, remaining refineries will become larger and more complex. It is expected that the EU refining activity increasingly focusses on producing cleaner, higher-grade transport fuels and chemical feedstocks. For this reason, it is assumed that HMU activity will increase with 1.17%/y. All other refinery unit activity will increase with 1.16% per year until 2050. The impact on PJ output and emissions is shown in Table 43 below.

Table 43 - Emission and output projection current policy scenario for Dutch refineries.

Current Policy

Year	2017	2020	2030	2050
Emissions (ktCO2/y)	11992.5	12586.5	14787.5	20412.5
Products exported (PJ)	1934.27	2030.08	2385.08	3292.35

Appendix 7b - New policies

Within this scenario, refinery product demand will decline. The scenario provides an idea of the impact of the most recent policy ambitions on the Dutch petroleum industry. Next to current policies, The scenario also considers the effects of announced policies, as expressed in official targets and plans.

Table 44 - Emission and output projection new policies scenario for Dutch refineries.

New Policies

Year	2017	2020	2030	2050
Emissions (ktCO2/y)	11992.5	11704.0	10135.3	7269.8
Products exported (PJ)	1934.27	1887.7	1634.718447	1172.55

Calculation table:

Table 45 – Calculation table New Policies scenario.

EU oil demand - IEA WEO New Policy Scenario

Year	Fuels (PJ)	Share	Chemicals (PJ)	Share	Total
2017	15156.2	80%	3768.1	20%	18924.3
2018	15062.0	80%	3726.3	20%	18788.3
2019	14967.8	80%	3684.4	20%	18652.2
2020	14873.6	80%	3642.5	20%	18516.1
2021	14779.4	80%	3600.6	20%	18380.1
2022	14685.2	80%	3558.8	20%	18244.0

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[50] Based on 2017 demand (94.8 Mb/y) and IEA projection of 1.1 Mb/y increase (WEO, 2018)

2023	14591.0	81%	3516.9	19%	18107.9			
2024	14496.8	81%	3475.0	19%	17971.8			
2025	14402.6	81%	3433.2	19%	17835.8			
2026	14117.9	81%	3399.7	19%	17517.6			
2027	13833.2	80%	3366.2	20%	17199.4			
2028	13548.5	80%	3332.7	20%	16881.2	% changed compared to baseline		
2029	13263.8	80%	3299.2	20%	16563.0	Fuel	Chemical	Total
2030	12979.1	80%	3265.7	20%	16244.8	-14%	-13%	-14%
2031	12644.1	80%	3223.8	20%	15868.0			
2032	12309.2	79%	3182.0	21%	15491.2			
2033	11974.2	79%	3140.1	21%	15114.3			
2034	11639.3	79%	3098.2	21%	14737.5			
2035	11304.4	79%	3056.4	21%	14360.7			
2036	11086.6	79%	3022.9	21%	14109.5			
2037	10868.9	78%	2989.4	22%	13858.3			
2038	10651.2	78%	2955.9	22%	13607.1			
2039	10433.5	78%	2922.4	22%	13355.9			
2040	10215.8	78%	2888.9	22%	13104.7			
2041	9994.5	78%	2855.1	22%	12849.6			
2042	9773.2	78%	2821.4	22%	12594.6			
2043	9551.9	77%	2787.7	23%	12339.5			
2044	9330.6	77%	2753.9	23%	12084.5			
2045	9109.3	77%	2720.2	23%	11829.4			
2046	8888.0	77%	2686.4	23%	11574.4			
2047	8666.7	77%	2652.7	23%	11319.3			
2048	8445.4	76%	2618.9	24%	11064.3	% changed compared to baseline		
2049	8224.1	76%	2585.2	24%	10809.2	Fuel	Chemical	Total
2050	8002.8	76%	2551.4	24%	**10554.2**	-47%	-32%	-44%

🟩	Linear interpolated between known data points
🟦	Forecasted using exponential smoothing method based on PJ changes 2017-2040 period.
🟧	IEA data (known data point)
🟪	Linear interpolated between known and forecasted energy datapoints
-1.340%	Average yearly change over 2017 - 2050 period

Appendix 7c - Sustainable development

Climate policy interventions result to a global oil demand peak of 97 mb/d in 2020. This implies a grow of 0.8% per year from 2017 to 2020. It is assumed that this global expectation will take place in the EU and NL. It is also assumed that it equally affects the different refinery units. After 2020 different growths are used. IEA projects that by 2040, gasoline and diesel are 40% more efficient than today and 50% of the global car fleet is electric. A quarter of buses are electric and nearly 20% of fuels used by trucks are low or zero carbon. As a result, global demand in road transport in 2040 in this scenario is more than 18 mb/d lower than today (-20%). Demand in aviation fuels is reduced by 0.8 mb/d by 2040 as a result of efficiency improvement and growth in biofuels. The only category that sees growth is petrochemicals. Plastics recycling increases significantly from today's levels which offsets the need for around 1.5 mb/d of oil demand in 2040. However, with few alternatives available, oil use as a petrochemical feedstock grows by 3.3 mb/d in the period to 2040. Shell Pernis and Exxon Mobil are expected to be the two main survivors for the long term and will be retrofitted into refineries that deliver an even higher share of middle distillates for chemical feedstock. Additional HT, HC, VDU and coker investment is necessary to compensate the shutdown of other refineries. Due to the increased demand for bio-based products, refining units that are needed within biorefineries will be given decarbonization priority. Within this scenario, decline rates differ per year and per output product.

EU figures provided by IEA were divided into fuels and chemical feedstock. The data concerned 2020, 2025, 2030 and 2040, the years in between have been linearly interpolated. Based on the fuel shares (%), the 2050 fuel share was forecasted using exponential smoothing method based on the given and interpolated share (fuel-chem) changes over the 2017-2040 period. The reason this was done is that negative values result when forecasting was based on PJ. It is assumed that the market (in PJ) will remain steady after 2040. However, the PJ fuel will keep decreasing. As a result, the PJ of chemical products will increase until 2050.

The result on total output is shown in Table 46 below.

Table 46 - Emission and output projection sustainable development scenario for Dutch refineries.

Sustainable development

Year	2017	2020	2030	2050
Emissions (ktCO2/y)	11992.5	11296.0	8065.8	4218.6
Products exported (PJ)	1934.27	1821.9	1300.9	680.4

Calculation table:

Table 47 - Calculation table sustainable development scenario.

EU oil demand - IEA WEO Sustainable Development Scenario

Year	Fuels (PJ)	Share	Chemicals (PJ)	Share	Total (PJ)
2017	15156.2	80%	3768.1	20%	18924.3
2018	14847.4	80%	3710.6	20%	18558.0
2019	14538.7	80%	3653.0	20%	18191.6
2020	14229.9	80%	3595.4	20%	17825.3
2021	13921.1	80%	3537.8	20%	17459.0
2022	13612.3	80%	3480.3	20%	17092.6
2023	13303.6	80%	3422.7	20%	16726.3
2024	12994.8	79%	3365.1	21%	16359.9
2025	12686.0	79%	3307.6	21%	15993.6
2026	12091.5	79%	3249.0	21%	15340.4
2027	11497.0	78%	3190.3	22%	14687.3
2028	10902.4	78%	3131.7	22%	14034.2
2029	10307.9	77%	3073.1	23%	13381.0
2030	9713.4	76%	3014.5	24%	12727.9
2031	9164.9	76%	2955.9	24%	12120.8
2032	8616.4	75%	2897.3	25%	11513.7
2033	8068.0	74%	2838.7	26%	10906.6
2034	7519.5	73%	2780.0	27%	10299.5
2035	6971.0	72%	2721.4	28%	9692.4
2036	6422.6	71%	2662.8	29%	9085.4
2037	5874.1	69%	2604.2	31%	8478.3
2038	5325.6	68%	2545.6	32%	7871.2
2039	4777.1	66%	2487.0	34%	7264.1
2040	4228.7	64%	2428.3	36%	6657.0
2041	4097.4	62%	2559.7	38%	6657.0
2042	3966.0	60%	2691.0	40%	6657.0
2043	3834.7	58%	2822.3	42%	6657.0
2044	3703.4	56%	2953.6	44%	6657.0
2045	3572.1	54%	3084.9	46%	6657.0
2046	3440.8	52%	3216.2	48%	6657.0
2047	3309.5	50%	3347.5	50%	6657.0
2048	3178.2	48%	3478.8	52%	6657.0
2049	3046.9	46%	3610.2	54%	6657.0

% changed compared to baseline

Fuel	Chemical	Total
-36%	-20%	-33%

% changed compared to baseline

Fuel	Chemical	Total

2050	**2915.5**	44%	**3741.5**	56%	6657.0	-81%	-1%	-65%

🟩	Linear interpolated between known data points
🟦	Forecasted using exponential smoothing method based on share (fuel-chem) changes 2017-2040 period.
🟥	Assumed that during 2040-2050 period total PJ demand remains the same, however, the shares in chemicals and fuels do change.
🟪	Linear interpolated between known and forecasted percentage share datapoints
🟧	IEA data (known data point)
-1.964%	Average yearly change over 2017 - 2050 period

Appendix 8 – Tackling emissions (extension)

Appendix 8a - RFG

Approximately 5.1MtCO_2 are the result of combustion of 77 PJ of RFGs. This makes the RFGs a relatively large and easy and cheap point source to decarbonize, but with limited options because RFGs are an inevitable by-product produced from the refining processes. Consequently, when RFG fuelled boilers are replaced by electric boilers, RFG surpluses will arise, which must be decarbonized alternatively. It was found that alternative RFG decarbonization options turn out to be relatively expensive and complex. Besides this, refinery activity strongly influences the volumes of RFGs produced. For this reason, it is crucial to understand that when less crude is refined, less RFG's are produced, reducing baseline technical potential of 77 PJ (e.g. less CCS capacity required). This is evaluated using scenario analysis presented in section 5.1. Several RFG decarbonization strategies have been identified. The first two options are assessed during this study. Option three is interesting for further research.

1. The RFGs can still be used as a fuel but are CO_2 emissions are avoided through pre/post and/or oxy-fuel CCS. Oxy-fuel CCS is found to be the easiest option for non-integrated refineries with scattered emission sources. Pre-combustion CCS is not applicable for process units that generate process emissions (FCC).
2. The RFG CO_2 emissions can be avoided through pre-combustion CCS, transforming RFGs into blue H_2 using auto thermal reforming (ATR). The blue H_2 is subsequently used as a clean combustion fuel in adjusted boilers and furnaces, as an input for processes consuming H_2 (hydrotreaters) or sold as carbon neutral H_2 to third parties.
3. It is possible to add extra processing units. These units can transform RFGs into valuable products such as LPG, LNG, NG, methanol, ammonia. This does however increase scope 3 emissions.

Appendix 8b - Tackling NG emissions

An estimated 45 PJ of NG is (mixed with RFGs and) combusted in the CHP, boilers and furnaces, making it the second biggest CO_2 source (approx. 2.5 MtCO_2). The decarbonization strategies identified are:

1. NG combustion emissions can be avoided by reducing the baseline energy demand. This can be done by reducing TP, changing crude feedstock (processing premium crude oil), implementation of EEM, and exploitation of the direct natural environment by implementation of GE into the system and WH utilization.
2. CO_2 emissions from NG combustion can be avoided by pre/post and/or oxy-fuel CCS.
3. Electrolysis and green electricity to produce H_2 to be used as combustion fuel.

Appendix 8c - Tackling H_2 emissions

It is estimated that the Dutch refineries consume about 50 PJ of H_2, during the production of this H_2 approximately 2.5 MtCO_2 emissions are generated, making H_2 the shared second biggest emission source. Currently, refineries produce hydrogen from petroleum products (own production, 25.3 PJ, 9 PJ is lost) and external sources, mainly NG (32.8 PJ). The external H_2 is included within the scope of this study. Hydrotreaters and crackers consume H_2 for upgrading and cleaning of products. For example, the hydrotreater uses H_2 to reduce the sulphur content of diesel. Hydrocrackers consume H_2 as they operate in the presence of H_2 to increase product properties. H_2 has two main functions in a hydrocracker: (1) H_2 suppresses the formation of heavy residual materials and (2) H_2 increases the yield of gasoline by reacting with the cracked products. The current H_2 demand is provided by fossil H_2 produced using SMR. Most of the H_2 is produced offsite (Air Liquide) using NG. H_2 is also produced on site using SMR or ATR of RFGs and NG. Two decarbonization options were identified:

1. Electrolysis. Using green electricity to split water into oxygen and H_2. This H_2 can be then be used to replace the current fossil H_2 consumption within hydrotreaters and crackers.
2. Pre-combustion CCS on SMR/ATR units.