Receiving Sunshine

A feasibility study on imported green hydrogen as a feedstock for current and future hydrogen markets in the hinterland of the Port of Rotterdam

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Preface

Ever since I started my bachelors, I have felt the urgency of understanding and exploring different disciplines. It allowed me to attend courses ranging from international relations, to entrepreneurship and finance, to power- and energy engineering. Seeking the complete horizon instead of just a picture of how to understand the world. Occasionally, this made people think it was due to a reality distortion field. In fact it might was.

During the lectures in the MSc Sustainable Energy Technologies and the MSc Industrial Ecology it became clear the world would only need a small area somewhere in the Sahara to harvest enough energy to power the world. To some it might be hard to believe, the real challenge is how to transport this tremendous renewable resource. Being confronted with the sheer size of the fossil fuel imports in Rotterdam and the resulting climate impact it causes, the link was made: shipping sunshine.

It would not have been possible without the support from both the Port of Rotterdam as well as my supervisors at the TU Delft and Leiden University. I am grateful they embarked with me on this journey of exploring a part of the horizon that has not been explored yet. A special thank you to Ankie Janssen, Randolf Weterings, Dr. E.G.M. Kleijn and Prof. Dr. A.J.M van Wijk, who had confidence in setting up this research. Besides, I would like thank my family and friends who sparked my motivation even further.

Abstract

Due to the abundance of solar energy resources in Oman and the participation in the joint venture of the Port of Rotterdam in the Port of Sohar, importing green hydrogen in the Port of Rotterdam has been suggested. In part one of this two-part research (Shipping Sunshine) two green hydrogen import prices were calculated based on a 100 [GW] solar pv system. The first price of 1.97 [$€\cdot kg^{-1}$] hydrogen received at the Port of Rotterdam considers current costs. The second price of 1.47 [$€\cdot kg^{-1}$] considers a 50% decline in solar pv module and electrolyzer capital expenditure costs. However, supply and demand of green hydrogen have to be created simultaneously.

This second part will identify which hydrogen markets in the hinterland of the Port of Rotterdam are feasible from a techno-economic perspective given both import prices and an ETS price of 25 and 80 [$€\cdot t^{-1}$] respectively. Besides, it will evaluate the carbon emission abatement cost in these markets. A new methodology is proposed, using hydrogen parity prices to create a level playing field in comparing these markets as well as synthetic fuel costs. Furthermore, the existing supportive policies will be included. Lastly, the required prices in these markets are compared to current market prices.

At a green hydrogen import price of 1.47 [$€\cdot kg^{-1}$] and an ETS price of 80 [$€\cdot t^{-1}$], the following hydrogen markets are feasible: mobility, steel industry, natural gas blending, low temperature heat, natural gas power plants, SMR substitution and harbor tugs. The marginal abatement cost ranges from minus 350 [$€\cdot tCO2^{-1}$] to 460 [$€\cdot tCO2^{-1}$]. Future research could focus on the sensitivity of these hydrogen markets when other techno-economic parameters change, thereby affecting the parity price of these specific hydrogen markets. Besides, future research could identify the future volume of the studied hydrogen markets.

Keywords Green hydrogen, Techno-economic analysis, Renewable energies, Water electrolysis, Green hydrogen economy

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Nomenclature

List of abbreviations

Symbol	Description
AEC	Alkaline electrolyzer
ATR	Autothermal reforming
BF-BOF	Blast furnace - basic oxygen furnace
CCUS	Carbon capture, utilisation and storage
DEI+	Demonstratie Energie- en Klimaatinnovatieregeling (Demonstration Energy- and Climate Innovation Policy)
DME	Dimethyl ether
DRI	Direct reduction iron
EAF	Electric arc furnace
EF	Emission factor
EU ETS	European Union Emissions Trading System
FT	Fischer-Tropsch
GHG	Greenhouse gas
GO	Guarantee of origin
H-DR	Hydrogen direct reduction
HFO	Heavy fuel oil
HHV	Higher heating value
HSMGO	High sulfur marine gasoil
IMO	International maritime organization
LH2	Liquid hydrogen
LHV	Lower heating value
LNG	Liquefied natural gas
MACC	Marginal abatement cost curve
MGO	Marine gasoil
MTG	Methanol to gasoline
NG grid	Natural gas grid
NG PP	Natural gas power plant
OMEn	Polyoxymethylene dimethyl ethers
PEMEC	Proton exchange membrane electrolyzer
PEMFC	Proton exchange membrane fuel cell
PoR	Port of Rotterdam
PoS	Port of Sohar
PTL	Power to liquid
RED-2	Renewable energy directive 2
SDE+	Stimulering Duurzame Energieproductie (Stimulus renewable energy production)
SMR	Steam methane reforming
TEA	Techno-economic analysis
TEU	Twenty-foot equivalent unit
TRL	Technology readiness level
TTW	Tank-to-wheel
ULSFO	Ultra low sulfur fuel oil

VLSFO	Very low sulfur fuel oil
WTP	Willingness to pay
WTW	Well-to-wheel

List of roman symbols

Symbol	Description	Units
$Annuity$	Annuity	[-]
$CAPEX$	Capital expenditure	[€]
$E_{HHV_{kWh}}$	Higher heating value hydrogen	$[\mathrm{kWh} \cdot \mathrm{kg}^{-1}]$
E_{HHVNG}	Higher heating value natural gas	$[\mathrm{MJ} \cdot \mathrm{Nm3}^{-1}]$
E_{HHV}	Higher heating value hydrogen	$[\mathrm{MJ} \cdot \mathrm{kg}^{-1}]$
V_{gas}	Gas volume consumed annually	$[\mathrm{Nm3} \cdot \mathrm{year}^{-1}]$
E_{LHV}	Lower heating value hydrogen	$[\mathrm{MJ} \cdot \mathrm{kg}^{-1}]$
$fixOPEX$	Fixed operational expenditure	[€]
FLH	Full load hours	[hours]
HBE	Hernieuwbare brandstof eenheid (Renewable fuel unit)	[-]
$LCOH$	Levelized cost of hydrogen	[€$\cdot\mathrm{kg}^{-1}$]
OM	Operation and maintenance	[%]
$OPEX$	Operational expenditure	[€]
P_{ETS}	ETS price	[€$\cdot\mathrm{t}^{-1}$]
tLs	Tonne liquid steel	[t]
$varOPEX$	Variable operational expenditure	[€]
$WACC$	Weighted average cost of capital	[%]

1 Introduction

Overtime, the world has seen major development in its primary energy consumption. Generally, the global energy consumption increased with an ever changing contribution of primary energy sources. The distribution of these natural resources however does not coincide with the demand in different regions throughout the world (IEA, 2019). With international shipping developing, international trade links emerged where some countries became importers and other countries became exporters. The marginal benefit for both the importing and exporting country increases when they engage in international energy trade.

The Port of Rotterdam (henceforth PoR), has the ambition to lower its GHG (greenhouse gas) emissions by as much as 50% in 2025 and 100% in 2050 (Samadi et al., 2017). This ambition does however not apply to the intrinsic emissions of the transshipment of either bulk products (e.g. coal) or other products. As an example, the intrinsic carbon impact of crude oil that is received in the PoR, processed in its refineries to for instance kerosene and transported to Schiphol Airport is not included in national emission statistics. Considering the sheer size of the energy flows going through the PoR, lowering the carbon impact of these flows becomes vital for staying relevant given European emission reduction ambitions. The PoR holds a lever to influence these up- and downstream flows (Samadi et al., 2017).

With the advent of record low solar and wind electricity prices, induced by an abundance of renewable resources in some parts of the world in combination with declining investment costs in renewables (e.g. solar pv, wind turbines etc.) new trade links could emerge. Hydrogen could play a key role in this development as an energy carrier, transporting energy from regions with plentiful renewable resources. Due to the capital intensive nature of renewables, with intrinsically low marginal costs, the capacity factor (the fraction of time a unit is working on full load) becomes increasingly important. As a consequence, importing energy carriers from these regions becomes vital for the PoR for two reasons: importing could be cheaper than domestic production, to maintain its strategic position as an energy port.

Given the favourable solar conditions in Oman as well as the strategic stake in the Port of Sohar (PoS), importing green hydrogen in the PoR from the Port of Sohar (PoS) has been suggested (Wijk, 2019; Van Den Bosch et al., 2011). Essential is that demand and supply of hydrogen are developed simultaneously since there is no global market for hydrogen yet (IEA, 2019). Similar to the liquefied natural gas (LNG) business, developing hydrogen supply should therefore coincide with developing hydrogen demand.

Aim and research questions: This master thesis is the second part in a two-part research project on the techno-economic feasibility of a green hydrogen supply chain from the PoS towards the PoR. In the first part the aim was to evaluate the green hydrogen supply chain itself by means of a cost model. In this second part, the aim will be to identify which hydrogen markets in the hinterland of the PoR are feasible from a techno-economic perspective as well as a GHG reduction perspective. Starting point is the assumption that hydrogen is received at a terminal in the PoR against a certain price per kilogram. Subsequently, the aim is to identify the most interesting hydrogen market.

Hence the following main research question is defined: *Which hydrogen markets in the hinterland of the Port of Rotterdam are techno-economically feasible for imported hydrogen from Sohar (Oman) and what would be the associated marginal carbon abatement costs currently?*

The following sub-questions will be taken into account consecutively, where margin is defined as the gap between the current market price and the parity price specific to each market.

- Which existing and future hydrogen markets could be considered?
- Which of these hydrogen markets is feasible from a techno-economic perspective?
- How do these hydrogen markets compare in terms of margin and carbon abatement cost?

The report has the following structure. In Chapter 2, the literature review will be conducted where the current and future hydrogen markets will be identified and evaluated. Afterwards, in Chapter 3 the research approach will be covered, where every hydrogen market will have a different sub-methodology. Subsequently, Chapter 4 will asses the techno-economic feasibility of both current and future hydrogen markets in the hinterland of the PoR. Finally, Chapter 5 covers the discussion. Lastly, the conclusion as well as the recommendations will be given in Chapter 6. In Appendix A, the synthetic fuel assumptions are listed.

2 Literature review

In this Chapter the literature review will be addressed. As mentioned in Chapter 1, a port authority could have substantial influence on the sustainability of the up- and downstream flows that flow through the port area towards the hinterland of the port. First, Section 2.1 is devoted to hydrogen from a generic perspective. Second, technological transitions will be introduced in Section 2.2 where the different regimes relevant to hydrogen markets are elaborated upon. Third, the current energy flows through the PoR are introduced. Fourth, in Section 2.4 and 2.5 a literature review is conducted on current and future hydrogen markets.

2.1 Hydrogen

Even though it has been introduced in part one already, it is important to distinguish all types of hydrogen. There exist three different types of hydrogen: grey, blue and green hydrogen. The main difference between these three types of hydrogen is the following. Grey hydrogen is fossil fuel based (typically natural gas or coal) and emitting CO_2. Blue hydrogen is also based on fossil fuels, it is an end-of-the-pipeline solution that captures only a fraction of the CO_2 emitted. The CO_2 could either be used or stored via carbon capture utilisation and storage (CCUS). Lastly, green hydrogen is produced with renewable resources, typically renewable electricity or biogas. The hydrogen assumed to be imported in this research only encompasses green hydrogen, which has the lowest emission factor of the three types (IEA, 2019).

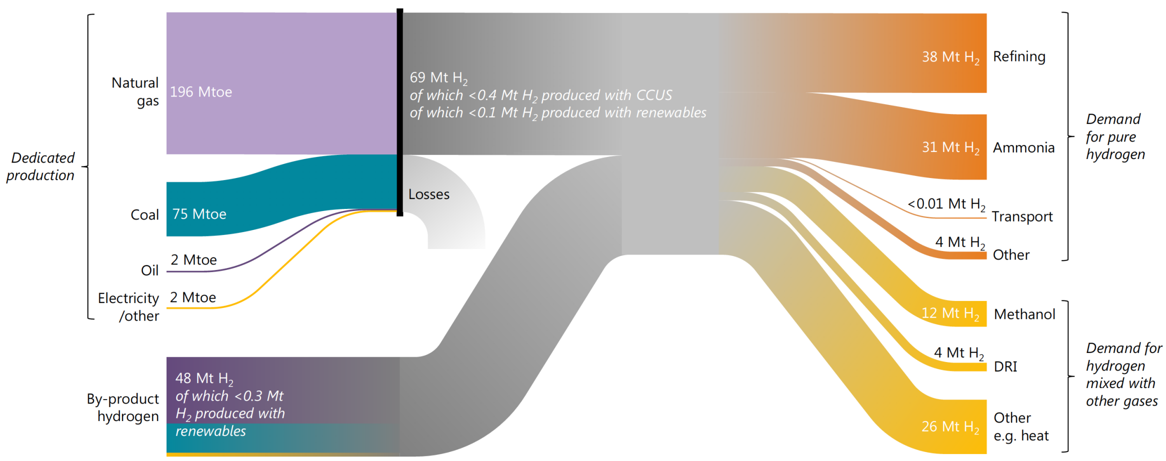

Figure 1: Sankey of the global hydrogen production and consumption in 2019 (IEA, 2019).

At the moment, the two main hydrogen production routes are production from natural gas using SMR (steam methane reforming) and ATR (auto thermal reforming) and coal gassification. The main hydrogen markets are refining, ammonia production, other (heat etc.) and methanol production. The global production and consumption is depicted in Figure 1 (IEA, 2019).

In the first part of this two-part analysis, a techno-economic analysis is conducted on a conceptual green hydrogen supply chain with 100 [GW] of solar pv and electrolyzers located on the Fahud Salt Basin and in Sohar (Oman). The hydrogen would be liquefied and subsequently shipped from the Port of Sohar (PoS) to the PoR. Furthermore, the levelized cost of hydrogen ($LCOH$) has been calculated. It was found to be 1.97 [€$\cdot$kg^{-1}] with current costs and no further supply chain optimization. Electrolyzer costs and solar pv module costs were the most dominant cost contributing factors. According to the sensitivity analysis, a 50% cost decline in both the electrolyzer and solar pv module $CAPEX$ resulted in an import price of 1.47 [€$\cdot$kg^{-1}] including shipping. Besides, in this analysis economies of scale have been mostly neglected. Similarly, since current costs are taken into account, no further cost reduction is assumed between the time of analysis and the time when the system would be actually deployed (Roobeek, 2020).

Van Wijk considered both hydrogen production as well as hydrogen demand in Zuid Holland in 2030. In his study, an upper limit of 2.44 [Mt] of hydrogen demand could develop in 2030 (Wijk, 2019). This hydrogen volume is in line with the annual 2.43 [Mt] of hydrogen received in the PoR based on the 100 [GW] solar pv system in Sohar evaluated in part one of this two-part analysis. Most of these demands are based on estimates and scenarios for 2030, it is however unclear what would be needed for these estimates to materialize. In other words, what the pivot points are to open up these markets. Most importantly, these pivot points depend on the price of hydrogen. However, also other factors such as the carbon price and technology costs affect the techno-economic feasibility of switching to green hydrogen import.

2.2 Technological transitions

According to Geels et al. there are multiple aspects that influence whether a technology is able to develop from a niche application to mainstream applications. These are defined as technological transitions. Geels identifies three levels: the technological niche, the regime and the socio-technical landscape. In Figure 2, this technological transition pathway is depicted in more detail. While by no means being exhaustive, some of the landscape and regime developments regarding green hydrogen import will be covered below.

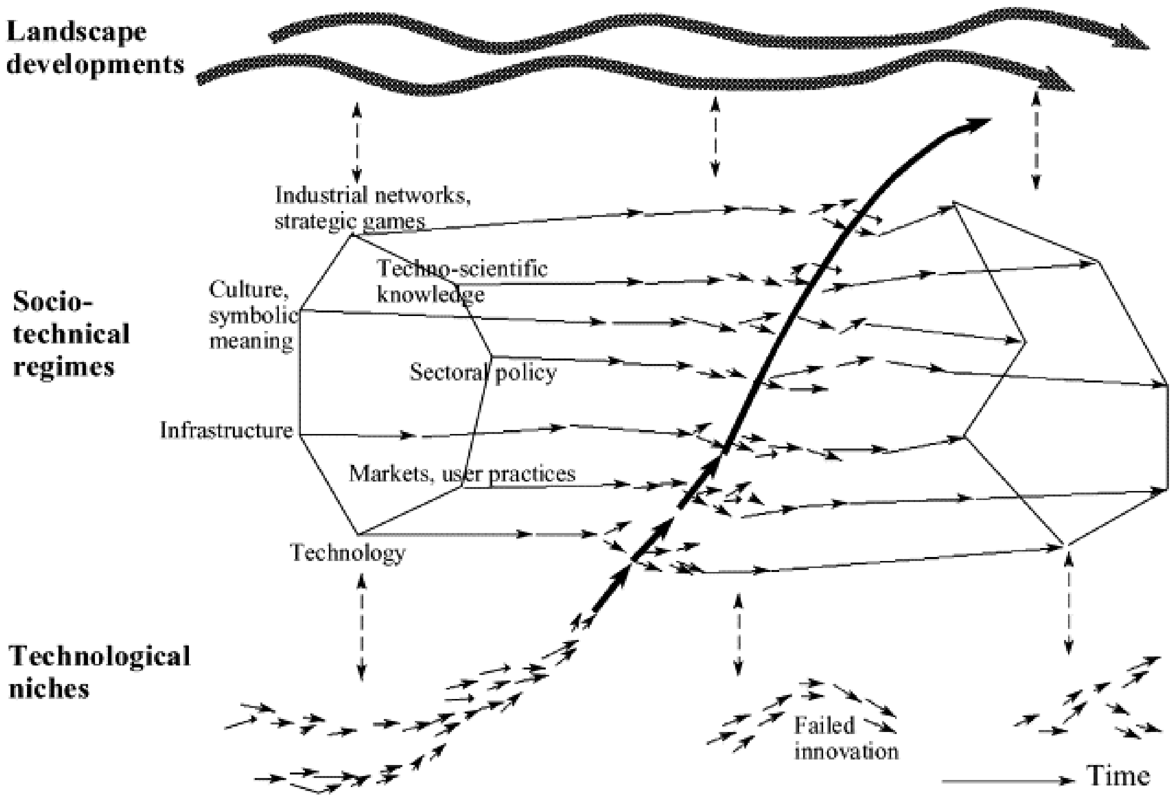

Figure 2: Technological transitions as described by Geels et al. (Geels, 2002).

The landscape developments are described by Geels as the broader material context in society. It is heterogenous in nature and consists of among others: the material context of society including the physical infrastructures, oil-price developments, the political landscape, cultural values, but also environmental problems. In other words, it is exogenous to a technology. The landscape could put pressure on the underlying regimes, creating a window of opportunity for technological niches to emerge and enter the regime level.

As mentioned before, natural gas is the dominant resource for hydrogen production, of which the production is covered by European Union Emission Trading System (EU ETS). Therefore, the natural gas price as well as the ETS price are two important landscape developments that influence the relative attractiveness of importing green hydrogen. Therefore, these prices are depicted in Figures 3 and 4. In Figure 3, the natural gas transaction price is depicted for three different markets by annual consumption. Generally, a lower natural gas price increases pressure since importing green hydrogen would become less favourable in comparison to producing hydrogen from natural gas, given other developments are at a constant level. Vice versa, a higher ETS price would make green hydrogen more attractive for current and future hydrogen markets where the current technology is covered by ETS.

In turn, various forces exist at the regime level that influence the likelihood of adopting a new technology. Among others, technology factors, policies, existing industrial networks and infrastructures altogether influence a niche becoming mainstream. Sometimes this process does not work out right and the window of opportunity is missed (Geels, 2002).

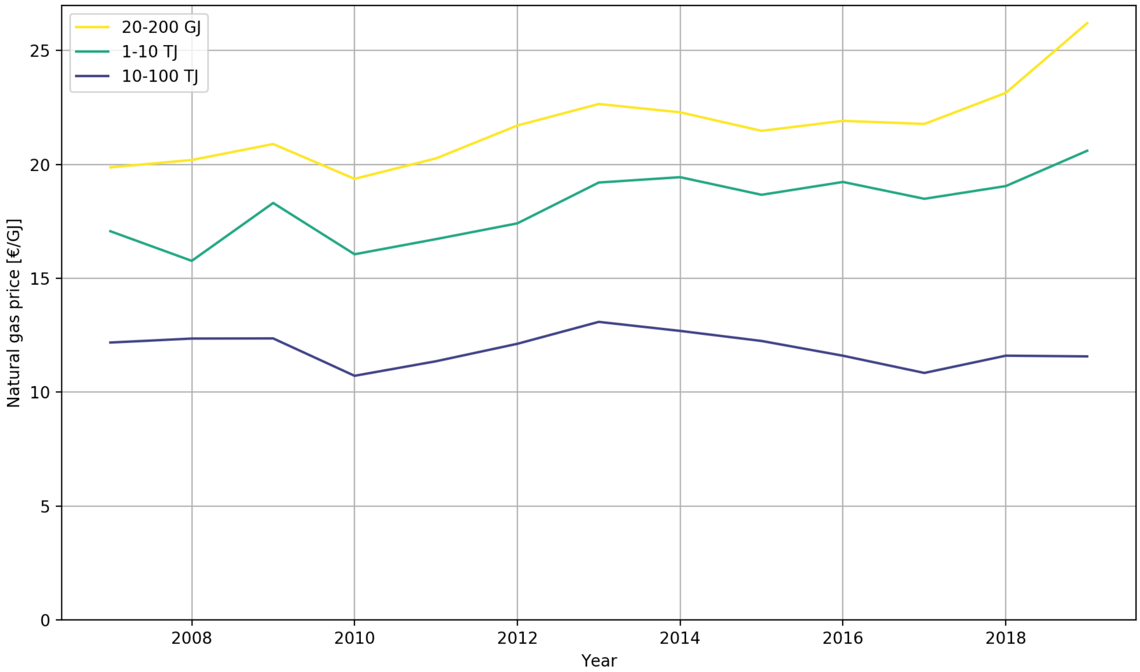

Figure 3: Historical natural gas transaction price including the distribution costs for three different consumer categories: 20-200 [GJ], 1-10 [TJ] and 10-100 [TJ]. Data ranges from 2007 until 2019 (CBS, 2020).

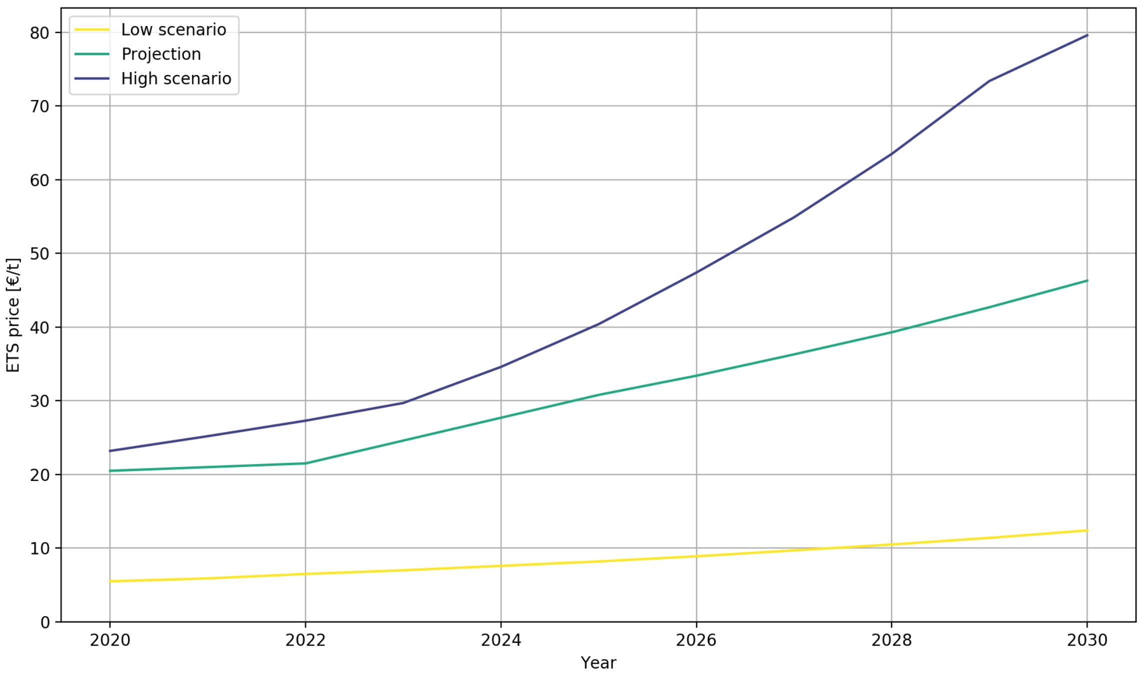

Figure 4: Projection of the ETS price for three different scenarios: low, projection and high. Data ranges from 2020 until 2030 (Brink, 2018).

For green hydrogen import, supportive policies regarding guarantee of origin and standardization are key as they enable green hydrogen import to be considered sustainable thereby allowing green hydrogen to be distinguished from grey hydrogen. The definition of green hydrogen varies to a large extent and there is no global standard yet. The main global standardization initiatives for green hydrogen are listed in Table 1 and are adapted from Abad et al. (Abad & Dodds, 2020). Some of these bodies are still working on a standard, others have already a guarantee of origin (GO) system in development. Besides, the policy objectives of the initiatives are mostly focused on CO_2 reduction. Most initiatives for standardization are based on a comparison with the baseline SMR emissions. In adddition, some policies are technology neutral (no further distinction between renewable and non-renewable hydrogen). Lastly, also the system boundaries are different in terms of a point of production or point of use system.

Since the only EU wide proposal is developed by CertifHy, their approach will be elaborated upon. In Figure 5, the hydrogen categorization system by CertifHy is provided. In order for hydrogen to be considered green, at least 60% reduction in GHG emissions is required in comparison to the base emissions of SMR. Besides, green hydrogen and low carbon hydrogen are differentiated based on inputs being renewable. The emissions are evaluated at the point of production, ignoring the embedded emissions in capital expenditure ($CAPEX$) goods and further downstream transportation. Furthermore, the system proposed is a book and claim system, similar to the system for GO currently existing for electricity. In this way transactional costs are minimized. Under the new Renewable Energy Directive 2 (RED-2), the GHG reduction has to be 70% with a threshold of 24.5 [$\mathrm{gCO2e} \cdot \mathrm{MJH2}^{-1}$] (Parliament, 2018; Abad & Dodds, 2020). However, either case is based on the well-to-tank emissions. For international green hydrogen trade to commence, it is argued that international standardization regarding GO certificates is needed.

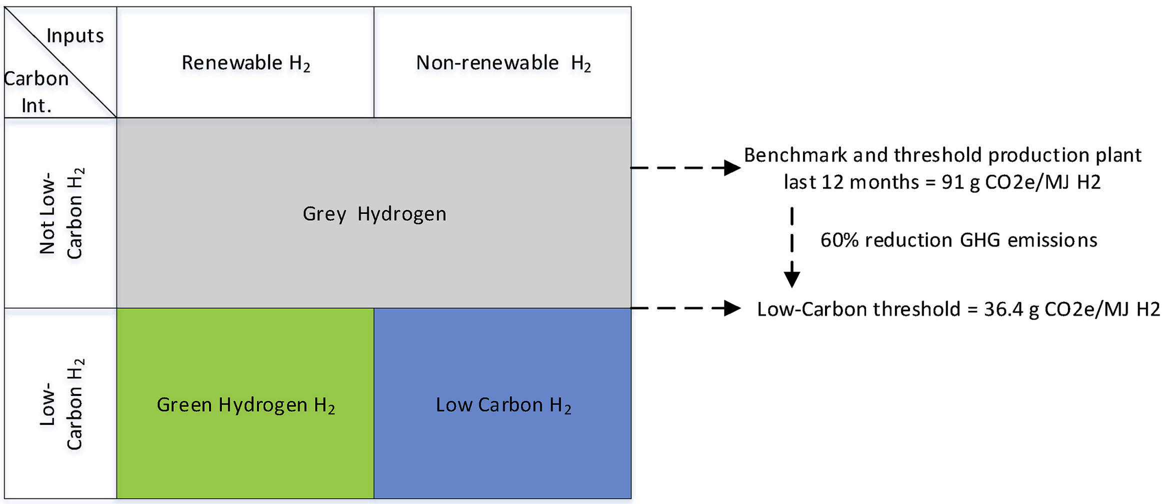

Figure 5: Categorization of green hydrogen according to the carbon intensity and inputs (Abad & Dodds, 2020).

The policy regime in the Netherlands shows that green hydrogen import could be valuable in a Northwest-European context. It gives a clear idea about the required policy framework under consideration. There is an already existing subsidy scheme: DEI+ (Demonstratie

Energie- en Klimaatinnovatieregeling) for demonstration projects, subsidy for exploitation projects and the SDE+ scheme. While only the latter is substantiated by a subsidy for domestic green hydrogen production by means of electrolyzers up to 2,000 full load hours (FLH) (Ministerie van Economische Zaken en Klimaat, 2020). How green hydrogen import fits in is yet unclear.

There is however ongoing research for implementing for instance a mandatory virtual blending in the natural gas grid, where 2% volume percentage requires very few adaptations to the existing natural gas grid. In addition, hydrogen as a feedstock for synthetic fuels is currently evaluated in mobility. In the Netherlands, the ambition for aviation is to have 14% in 2030 and 100% renewable fuel in 2050 (Ministerie van Economische Zaken en Klimaat, 2020).

From the perspective of the framework by Geels, there are multiple aspects to take into account for green hydrogen import to become viable (Geels, 2002). As a consequence, evaluating what role green hydrogen import would play in the nearby future is not only hard to predict but also highly dependent on the set of socio-technical regimes present in the system. Nevertheless, it is clear that there will exist opportunities for green hydrogen import, especially in higher margin markets.

Table 1: Comparison existing standardization initiatives (Abad & Dodds, 2020).

Body (Country)	**Type**	**Main Policy Objective**	**Baseline GHG threshold**	**Qualification level**	**Qualifying processes**	**System boundary**
AFHYPACa(FR)	GO scheme (working group proposal)	Renewable energy source	None	Must be 100% renewable	Any renewable pathway	Point of production
BEISb (UK)	Standard Consultation (abandoned)	Reduction of CO2emissions	Never determined	To be determined.	Any (technology neutral)	Point of production
California Low Carbon Fuel Standard	Regulation (active)	Reduction of air quality and CO2emissions. Third of vehicle hydrogen produced from renewable energy.	WTW emissions from new gasoline vehicles	30% lower GHG and 50% lower NOXemissions (on WTW per mile basis) for fuel cell electric vehicles	Renewable electrolysis, catalytic cracking of SMR of biomethane or thermochemical conversion of biomass, including MSW.	Point of use
CEN/CENELEC CLS JCT 6 WG1/WG2 (International)	International Standard (in preparation)	Terminology, GO, interfaces, OM, safety, training, education	Adopted from CertifHy	Adopted from CertifHy	Adopted from CertifHy	Adopted from CertifHy
CertifHy (EU wide)	GO scheme (testing)	Renewable energy source/GHG emissions	Hydrogen produced via SMR of natural gas	At least 60% lower than SMR (36.4 gCO2e/MJ H2)	Any renewable pathway meeting the threshold with 99.5% purity	Point of production
TÜV SÜD (DE)	National Standard (active)	Reduction of CO2emissions	Hydrogen from SMR of natural gas	35–75% emissions reduction below baseline (83.8-89.7 gCO2e/MJ)	Renewable electrolysis; biomethane SMR; pyro-reforming of glycerine	Point of use

2.3 Energy flows Port of Rotterdam

When considering which hydrogen markets currently exist, it is important to consider the technology currently employed in these current hydrogen markets as well as the ETS price. For future hydrogen markets on the other hand, it would be important to know which energy markets exist in the hinterland of the PoR that could be substituted by hydrogen as an energy carrier, as well as future hydrogen markets that have yet to emerge.

Therefore, the current energy balance of the PoR is depicted in Figure 6. The Figure is derived from data about the current energy throughput through the port area. Where previous Figures constructed by the PoR separated an energy balance overseas and an energy balance based on flows coming from and directed towards the hinterland, Figure 6 actually considers inputs (on the left-hand side) to the PoR and outputs (the right-hand side) from the PoR. In order to construct this energy balance, a virtual gas grid port, electricity grid port and heat grid port is created as if these stages are separated completely from the hinterland.

Some inputs are simply transshipped without further alteration (e.g. biomass). Other inputs follow a more sophisticated pathway (sea crude oil), by first being stored in tank storage (tank crude oil), secondly being refined (industry), thirdly being stored (e.g. tank oil product) and fourthly being shipped towards the hinterland via pipelines, shipped again overseas (sea oil product export) or employed as bunker fuel (bunker).

Probably the most important message from Figure 6 is the dominance of fossil fuels. For instance, the energy content of biomass is 11 [PJ] and dwarfed by comparison to sea crude oil input of 4,230 [PJ]. At the same time, it is an opportunity for green hydrogen imports to substitute and supplement these energy flows. Among others, hydrogen could for instance replace a large fraction of the crude oil imports by being used as a building block for synthetic fuel production. In 2018, 2,180 [PJ] of crude oil is refined in the PoR. A variety of products is produced: 5% gasoil, 29% diesel, 15% kerosene, 11% gasoline and 18% chemical feedstocks. In addition, other smaller product categories are produced (Melieste, 2019).

Another example would be coal imports associated with the steel industry that could be partly substituted by green hydrogen imports when green hydrogen would be used as a reducing agent instead (Vogl et al., 2018). The total coal imports in the PoR amount 690 [PJ], of which about 45% is cokes coal. Hence, given the lower heating value of cokes coal, about 330 [PJ] of cokes coal could be substituted by green hydrogen import given green hydrogen would be imported at a competitive price (Melieste, 2019). Finally, also other imports could be substituted by green hydrogen import such as for example feedstocks for electricity production. Obviously, referring to the framework of Geels, it is not only the green hydrogen import price that will make these markets tip towards green hydrogen import.

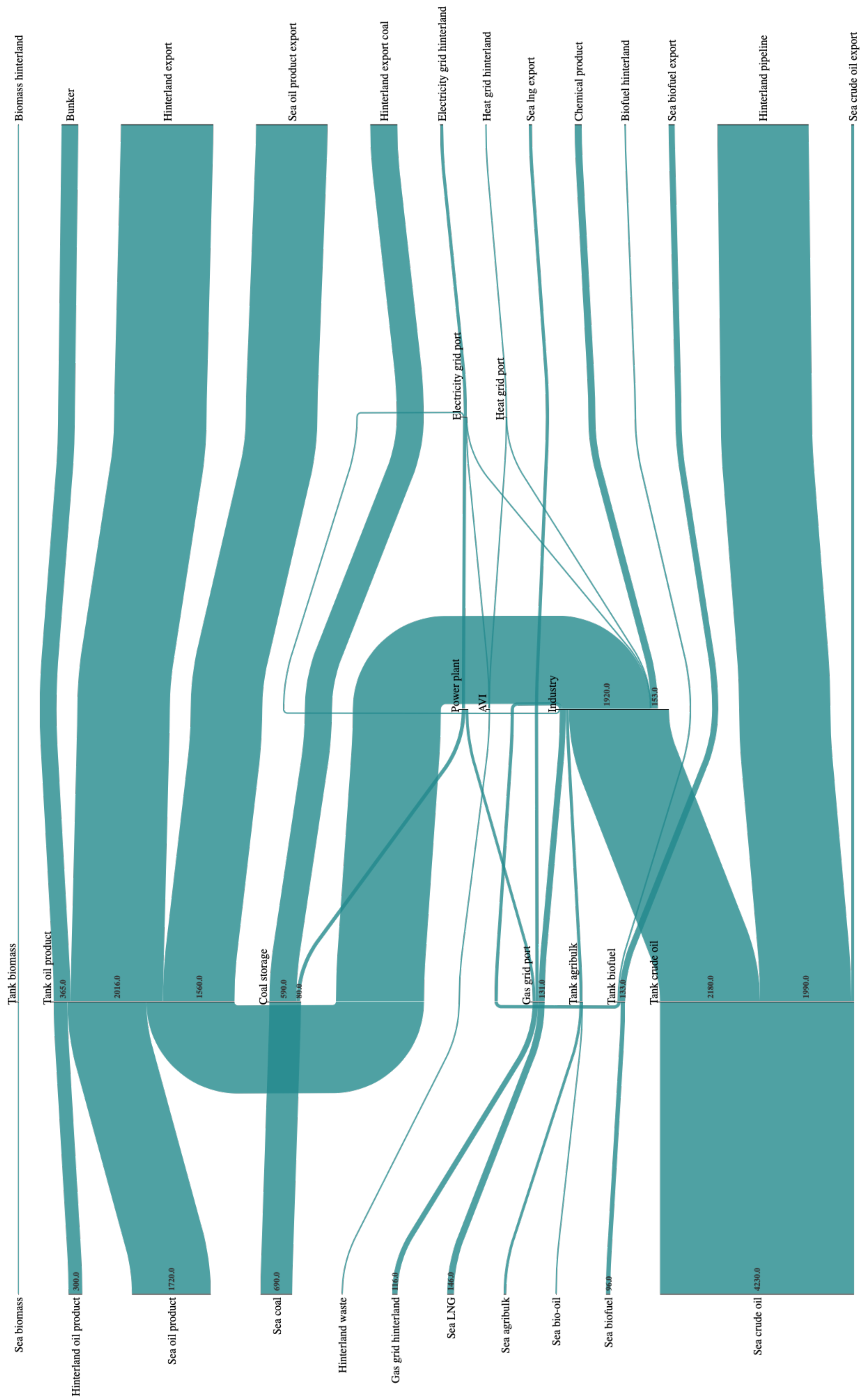

Figure 6: Sankey of the energy flows through the Port of Rotterdam based on their lower heating value (LHV). Adapted from Melieste (Melieste, 2019).

2.4 Current hydrogen markets

When identifying hydrogen demands, current hydrogen markets are important to consider. Besides, the following Sections provide insight into where and how hydrogen is being used within the PoR already today.

2.4.1 Production & consumption Port of Rotterdam

Generally, hydrogen is produced with dedicated production as well as by-product production, and both occur in the PoR. Hydrogen is already produced in the Port of Rotterdam by means SMR and ATR. SMR plants produce hydrogen by a chemical reaction between light fuels (e.g. methane, biogas) and steam to create syngas (a mixture between hydrogen and carbon-monoxide). The syngas is further reacting with steam to produce CO_2 and hydrogen. For every kilogram of hydrogen, a typical SMR plant produces 9.01 [kg] CO_2 (Collodi et al., 2017). ATR on the other hand, uses either oxygen or steam to react with methane to produce syngas. An advantage is that the heat is created within the reactor, therefore higher CO_2 recovery rates could be achieved with ATR. The ratio between hydrogen and carbon-monoxide could be varied (IEA, 2019).

Within the PoR, both ATR and SMR plants are operational. Besides, also hydrogen from by-product streams is produced from the chemical industry as well as the refineries. The hydrogen is consumed in three different industries: fossil fuels, chemicals and biofuels. An illustration of both the production and consumption of hydrogen within the PoR is provided in Figure 7. All the numbers are in [PJ] LHV. By-product SMR means applying SMR to the residual gasses within the refinery. Observing Figures 6 and 7 shows that the current role hydrogen takes in the PoR (about 40 [PJ]) is marginal. At the same time, it illustrates the vast potential of green hydrogen in case green hydrogen would only partially substitute these energy flows.

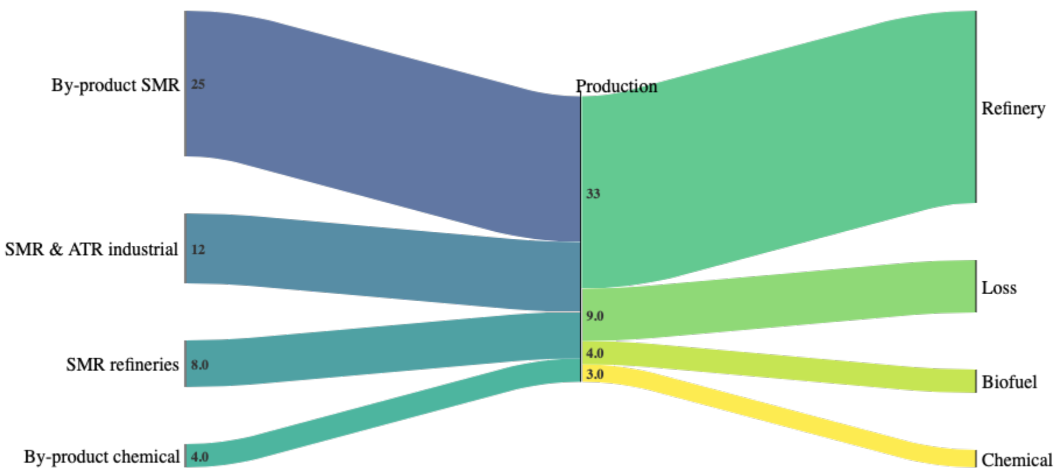

Figure 7: Sankey of the hydrogen flows through the Port of Rotterdam in LHV [PJ]. Adapted from Melieste (Melieste, 2019).

2.4.2 Refineries

Traditionally, hydrogen is used in refineries for hydrotreating as well as hydrocracking. The former process removes impurities (mostly sulfur), that are naturally occurring in fossil fuels. The latter process involves breaking down residual oil into more valuable final products that are typically lighter (IEA, 2019).

Within the PoR area, refineries use 33 [PJ] of hydrogen that partly comes from merchant suppliers as well as dedicated on-site production facilities. In addition, also residual gasses are a feedstock for hydrogen production within the PoR. When assuming by-product hydrogen is still to be used in the PoR with tighter emission policies, only dedicated hydrogen production with SMR and ATR would be substituted. Hence, with an assumed SMR efficiency of 75%, 15 [PJ] of hydrogen could be replaced with green hydrogen. Using the LHV of hydrogen, a total of 0.13 [Mt] would be needed with the current hydrogen demand.

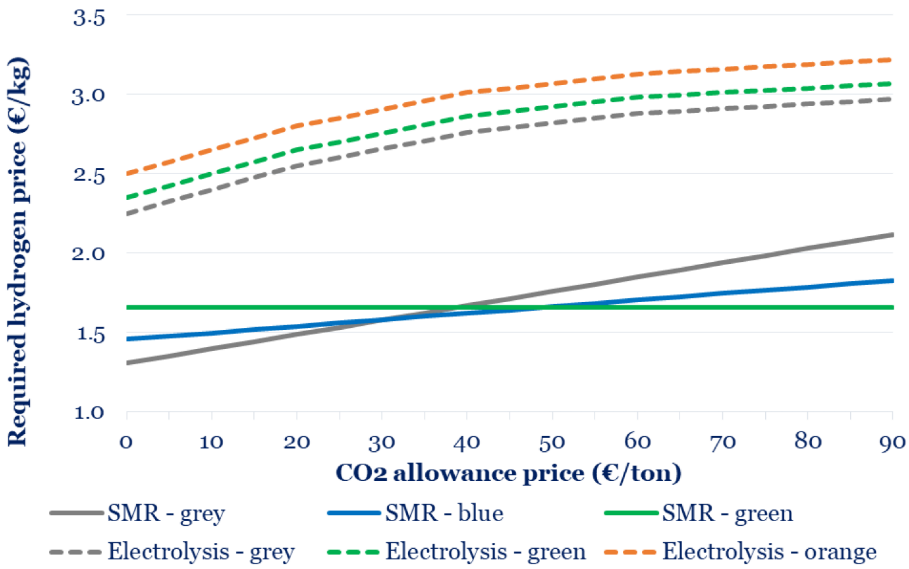

Figure 8: Carbon price plotted against the production cost of grey, blue, green and orange hydrogen in the Netherlands. The CO_2 allowance price has the most profound impact on SMR-grey, since the full 9.01 [$kgCO2 \cdot kgH2^{-1}$] is emitted. The effect is less visible with SMR-blue, since 4.12 [$kgCO2 \cdot kgH2^{-1}$] is still emitted. Also the the electrolysis based hydrogen production is influenced by the carbon allowance price, though less pronounced. This is due to marginal price setting electricity production emits CO_2 in case no renewable electricity is available (Mulder et al., 2019).

However, as mentioned before the dedicated hydrogen production consumes natural gas. A total of 20 [PJ] natural gas is consumed within the PoR to produce grey hydrogen (LHV). The production cost of hydrogen largely depend on the natural gas price as well as the carbon price. In Figure 8, the production cost of hydrogen with various sources is depicted. In this Figure, SMR-grey is understood as conventional SMR hydrogen with CO_2 emissions covered by the ETS rights. SMR-blue is similar to SMR-grey except for the emissions being partially captured and stored, which therefore includes storage costs. SMR-green utilizes green gas as a feedstock. Finally, grey electrolysis is based on the average grid emission factor, electrolysis green takes into account green electricity certificates and electrolysis orange includes Dutch green electricity certificates (Mulder et al., 2019). The price of green electricity certificates in this study is put at 2 [€·MWh^{-1}] and 5 [€·MWh^{-1}] for green electricity produced in the Netherlands. Lastly, the natural gas price considered is 20 [€·MWh^{-1}]. Further assumptions could be found in the study by Mulder et al. (Mulder et al., 2019).

Even though the $CAPEX$ of the electrolyzer is considerably higher than the study by Roobeek, each type of electrolysis is more expensive in comparison to importing hydrogen from Oman already with current cost factors. Alternatively and more importantly, all the electrolysis based hydrogen production costs are above the price found in the study by Roobeek (Mulder et al., 2019; Roobeek, 2020). Nevertheless, Figure 8 could be used as a reference for grey hydrogen production costs as well as the sensitivity of grey hydrogen production costs to the carbon allowance price.

2.5 Future hydrogen markets

From the perspective of the PoR future hydrogen markets could either substitute existing energy markets, or add to the existing portfolio of activities within the port area itself. Therefore, this Section identifies future hydrogen markets as well as the conditions for each market to reach a tipping point. Three factors are crucial for green hydrogen markets to emerge: the current energy markets within the hinterland of the PoR, the right regulations by means of for instance a carbon price and finally the techno-economic factors to be considered for hydrogen introduction in those markets.

2.5.1 Natural gas subsitution

Hydrogen could replace a relatively large fraction of existing natural gas markets. For instance, hydrogen could partly be harnessed in existing natural gas power plants by up to 30% of the fuel input (Wijk, 2019). It is obvious the natural gas price is a key determinant for the feasibility of hydrogen to be used in power plants. In addition, also the carbon price is an important factor. However, it is not straightforward to make a reasonable comparison since the volumetric energy density of gaseous hydrogen is lower in comparison to the volumetric energy density of natural gas in the Netherlands. The differences are listed in Table 2.

Table 2: Comparison hydrogen and methane (Goldmeer, 2018; Zijlema, 2016; Vlijmen, 2000).

	LHV [MJ/kg]	HHV [MJ/kg]	LHV [MJ/Nm3]	HHV [MJ/Nm3]	Emission factor [kg/Nm3]
Hydrogen	120	142	10.8	13.0	0
Methane	50	55	35.8	39.8	1.97

The difference in volumetric energy density between methane and hydrogen has the following consequence. When opting for blending hydrogen on a 5% volumetric basis, only 0.65% of hydrogen is actually blended on a heat basis. As a consequence, CO_2 emissions are reduced by only 1.5%. This relation is illustrated by means of Figure 9. It clearly shows the non-linear relation between CO_2 and the increase in volumetric fraction of hydrogen.

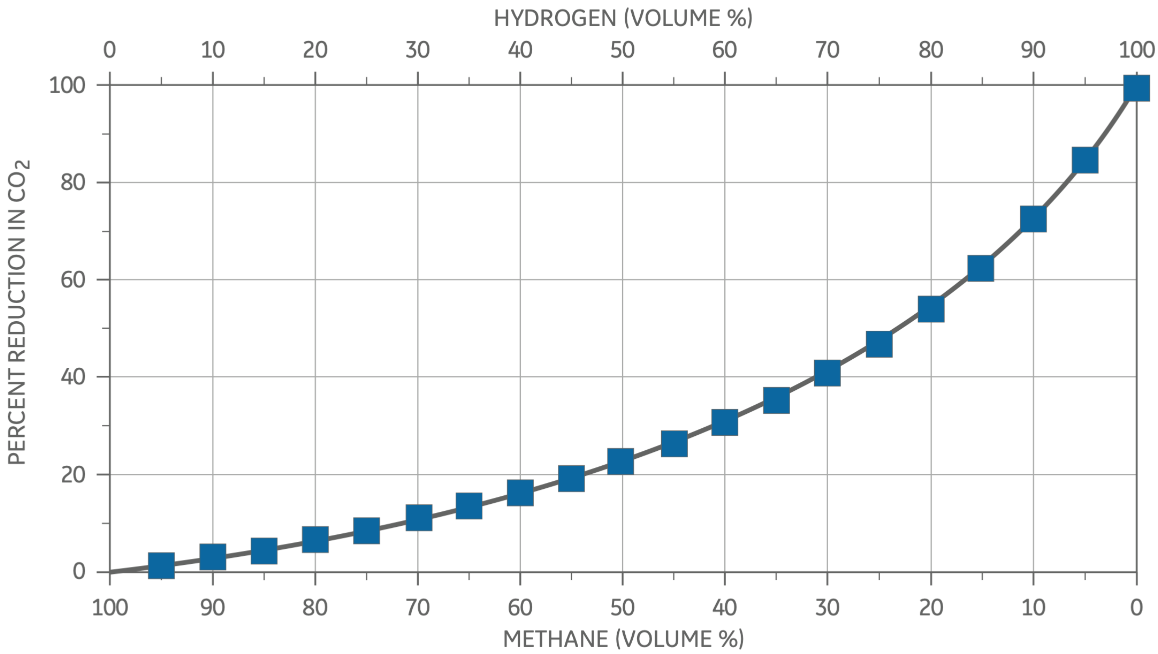

Figure 9: The reduction in CO_2 emissions when blending methane with hydrogen (Goldmeer, 2018).

To illustrate how this volume percentage of hydrogen translates to a reduction in GHG emissions, the efficiency of the turbine should be taken into account as well. For example, a 288 [MW] 9F.04 General Electric turbine has a combined cycle efficiency of 60.4% that solely operates on a 95% methane 5% hydrogen volume blend. The emission per [GJ] methane is 54.9 [$kgCO2 \cdot GJ^{-1}$]. Hence, using the efficiency and the conversion to [kWh], the emission factor for electricity for this turbine would be 0.326 [$kgCO2 \cdot kWh^{-1}$]. As a result of 5% hydrogen blending, the emission would diminish to 0.321 [$kgCO2 \cdot kWh^{-1}$].

It should be noted that natural gas does not entirely exist of methane. In fact, the LHV of natural gas is 31.65 [$MJ \cdot Nm3^{-1}$] and the HHV is 35.17 [$MJ \cdot Nm3^{-1}$] in the Netherlands (Vlijmen, 2000). Even though natural gas substitution with hydrogen seems to be similar for different markets, in fact it is not. When the imported green hydrogen would be employed in power plants for instance and the green hydrogen would be considered green under the new renewable energy directive, the ETS price would not be incurred and therefore it would become relatively more attractive to employ green hydrogen in this market. On the other hand, when hydrogen would be blended into the natural gas grid in the Netherlands, the ETS price does not apply to this market and therefore does not increase the relative value of green hydrogen in comparison to natural gas. The reason is that employing natural gas over green hydrogen also entails the cost of buying ETS rights in certain markets.

2.5.2 Bunkering

In order to understand how a market for hydrogen could develop in bunker fuels, it is important to understand the market characteristics. Traditionally, the bunker market has been dominated by fuels that have a high sulfur content. The market consisted mostly of two main fuel types: heavy fuel oil (HFO) and marine gasoil (MGO). The main difference is that the HFO is mostly residual oil that has to be heated, whereas MGO is pure distillate and does not have to be heated (Billing & Fitzgibbon, 2020; CIMAC, 2018).

However, with emission control zones and tighter global sulfur emissions, new variants of bunker fuels were created. In Figure 10, the trend of the global and emission control sulfur cap is visible. In 2000, the global emission limits of sulfur in shipping fuels was limited to 4.5%. At the time, the emission control zones located at the west- and east coast of the US and Northwest-Europe, already had a limit of 1.5%. While the sulfur content of shipping fuels in the emission control zones already was capped at 0.1% in 2015, the global cap on sulfur content of shipping fuels became tighter as well and is 0.5% from 2020 onwards. Besides, the east coast of China introduced an emission control zone as well where ships built after January 2020 had to comply with a 0.1% limit in fuel sulfur content as well (CIMAC, 2019). At the same time, limits on nitrogen oxide emissions also became more stringent in the emission control zones in Europe as well as the US.

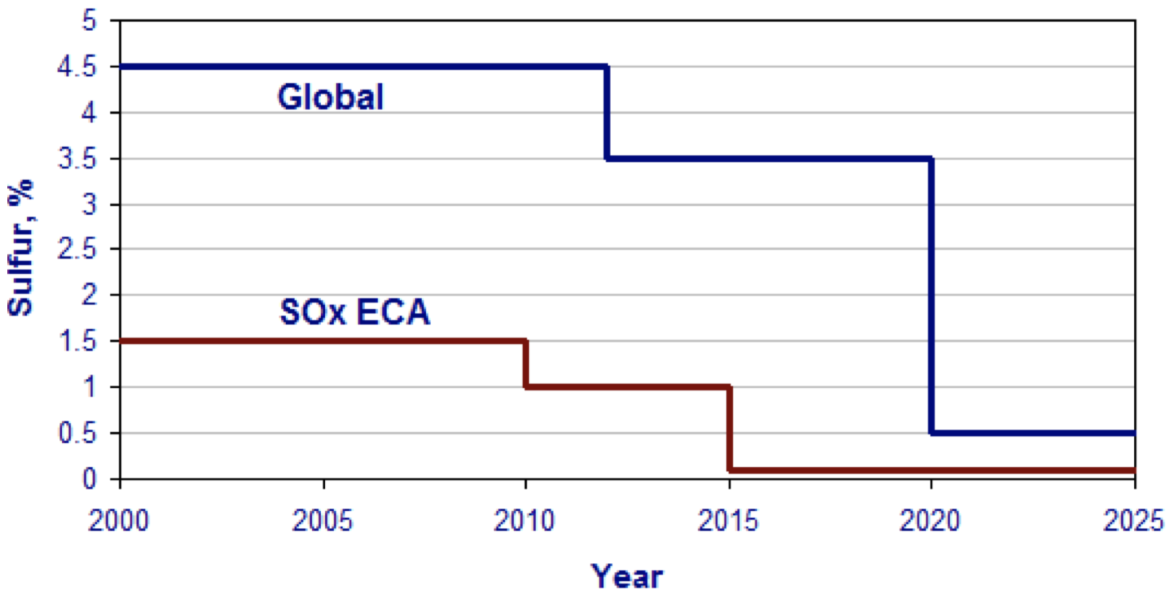

Figure 10: Sulfur content in shipping fuels (CIMAC, 2018).

Besides the installation of scrubbers aboard of ships that remove these harmful emissions, various new bunker fuel types have emerged ever since. Within the fuel oil domain (fuels that require heating), four types could be distinguished that vary in their sulfur content. High sulfur fuel oil (HSFO) with a sulfur content above 1%, low sulfur fuel oil (LSFO) with a sulfur content below 1%, very low sulfur fuel oil (VLSFO) with a sulfur content below 0.5% and ultra low sulfur fuel oil (ULSFO) with a sulfur content below 0.1%. For MGO fuels, two types could be distinguished: low sulfur marine gasoil (LSMGO) with a sulfur content below 0.1% and high sulfur marine gasoil (HSMGO) with a sulfur content above 0.1%.

While the international limits on sulfur content of bunker fuels became more stringent, the International Maritime Organization also has the ambition to reduce CO_2 emissions from international shipping by 40% in 2030 and by 70% in 2050. Companies anticipated this emission reduction target by investing in LNG infrastructure. However, the marginal CO_2 emission benefits are only about 20% in comparison to conventional marine gasoil (Sharples, 2019). Other sources indicate that from a lifecycle perspective, GHG emissions are only reduced by 8-20% without methane slip through the engine. Assuming 2% methane slip the GHG emissions of LNG, MGO and HFO do not vary substantially (Bengtsson et al., 2011). This would be yet another driver to cleaner bunker fuels in which case the current LNG consumption might not become an effective option anymore (IMO, 2020).

It is expected that the global market for HFO will at first be substituted by MGO and that afterwards VLSFO and LNG will gradually take over this dominance (Billing & Fitzgibbon, 2020). This trend is depicted in Figure 11.

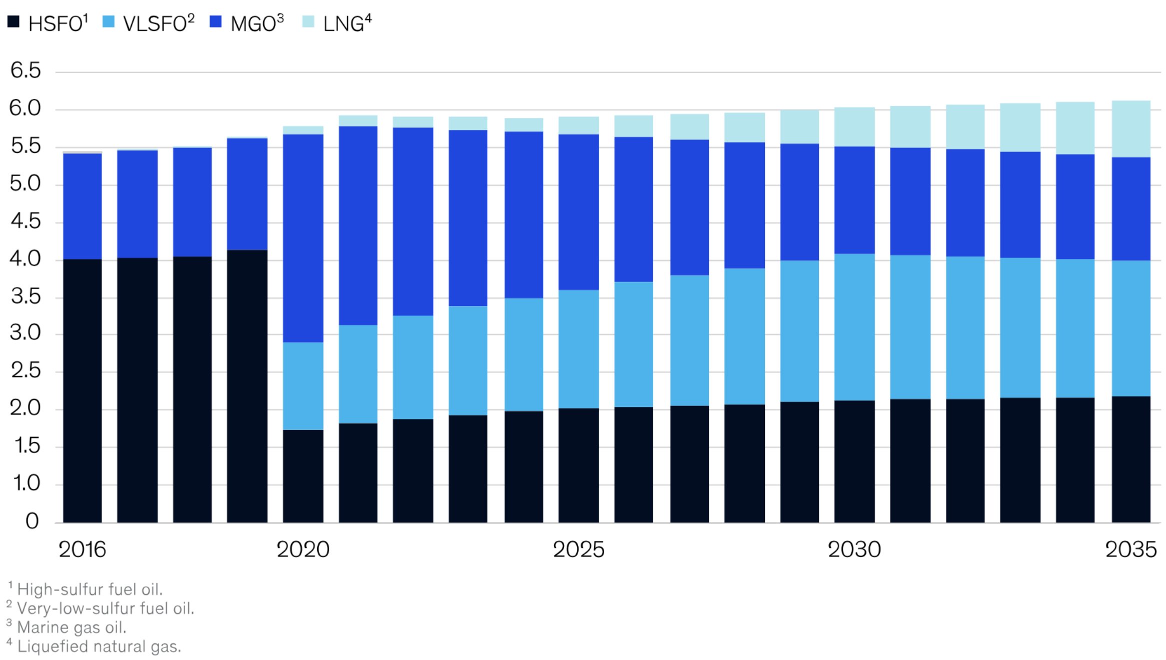

Figure 11: Global demand for bunker fuels (Billing & Fitzgibbon, 2020).

Therefore, when evaluating the competitiveness of hydrogen in bunker markets, LNG and LSMGO were chosen as a point of comparison. The Argonne National Energy Laboratory conducted a study on what the positioning of hydrogen could be for container ships, ferries as well as tug ships. Their first point of comparison are the characteristics of the bunker fuel. These are provided in Table 3, where the tank-to-wheel (TTW) emission factor for LSMGO is found by multiplying the density with the TTW emission factor (CO2emissiefactoren, 2014). The liquid hydrogen (LH2) is shipped following the conceptual supply chain proposed by Roobeek (Roobeek, 2020). The LNG and LSMGO price is the average price in Rotterdam over 2019. Also the well to wheel (WTW) emission factors per [kg] of fuel are provided.

Table 3: Comparison bunker fuels LSMGO, LNG and LH2 in 2019 (Papadias et al., 2019; Ship&Bunker, 2020; Roobeek, 2020; CO2emissiefactoren, 2014).

	Density [kg/m3]	LHV [MJ/kg]	Bunkered price [$/t]	[$/MJ]	TTW CO_2 [kgCO2/kg]
LSMGO	900	42.8	569	0.0133	2.59
LNG	428	48.6	616	0.0144	2.7
LH2	70.8	120	2,170	0.018	0

Obviously, not only the fuel price is relevant for the total cost of ownership. Also the $CAPEX$ and other operational expenditure ($OPEX$) are important. The Argonne National Laboratory compared a container ship with a capacity of 2,100 twenty-foot equivalent (TEU), a passenger ferry and a tug boat with a bollard pull capacity of 55 [t] (the pull ability at zero speed). When comparing the total cost of ownership of each type of ship, the break-even costs (at which costs of liquid hydrogen propulsion is equal) are depicted in Figure 12. The ultimate scenario is assumed for this case, with a $CAPEX$ for fuel cells of 60 [$\$ \cdot kW^{-1}$] (Papadias et al., 2019).

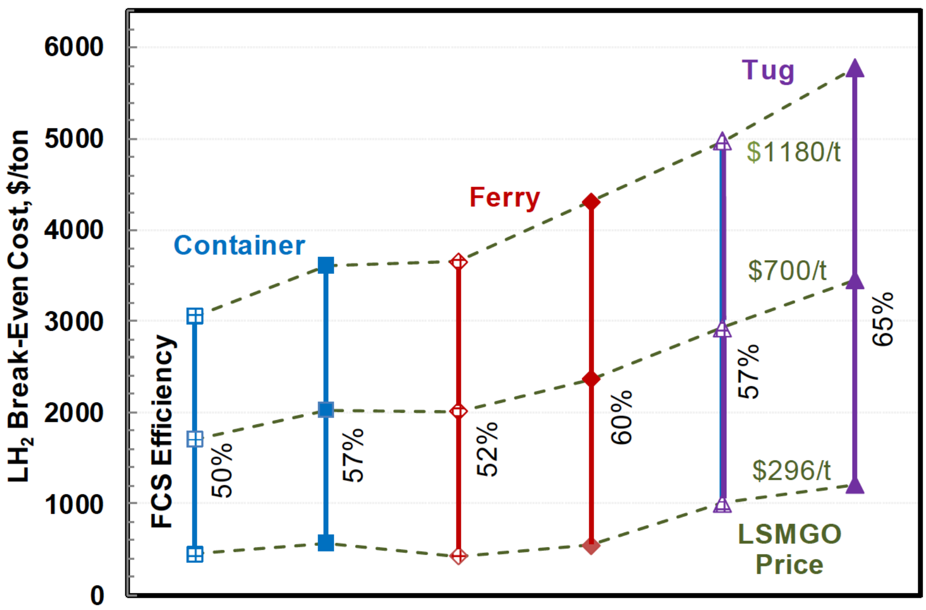

Figure 12: Break-even cost of liquid hydrogen to be competitive with LSMGO for a container ship, ferry as well as a tug boat. Also the fuel cell efficiency is provided on a lower heating value basis (Papadias et al., 2019).

From Figure 12, it becomes clear that the price level of liquid hydrogen varies substantially with either an increasing fuel cell efficiency, or a change in the price of LSMGO. Since the average price of LSMGO was 569 [$\$ \cdot t^{-1}$] in 2019, the parity price of liquid hydrogen could be derived from the Figure (Ship&Bunker, 2020). The fuel cell efficiencies might seem low, other studies indicate similar LHV fuel cell efficiencies. For instance, Bruce et al. assume the current energy efficiency of fuel cells to be 55% on a LHV basis (Bruce et al., 2018).

The first conceptual design of a liquid hydrogen bunker vessel has been proposed already by Mossmaritime, capable of carrying 500 [t] of hydrogen. The ship is depicted in Figure 13 and proved to be technically feasible. According to Mossmaritime, it would be possible to adapt existing LNG terminals and equipment to become feasible for the adaptation of liquid hydrogen (Bøhlerengen, 2019). Further similarities between LNG and LH2 exist.

Figure 13: Liquid hydrogen bunker ship design by Mossmaritime (Bøhlerengen, 2019).

2.5.3 Mobility

When green hydrogen imports would be deployed to be used in mobility, it is important to take into account what the parity price would be. In other words, when green hydrogen would be formally considered green also in transport applications, it would theoretically increase the value of the imported hydrogen since it would be possible to introduce a premium on the product.

Under the RED-2, the overall target for renewable energy consumption has been defined to be 32% by 2030. Besides, a specific goal for road and rail transport is set at 14% renewable energy (H2Platform, 2018). Furthermore, a sub goal was defined for advanced fuels of 7% in 2030 (part of the 14%). E-fuels (synthetic fuels produced with electricity) as well as hydrogen could be counted towards this renewable energy goal for transport as long as the GHG reduction threshold is met. In spite of the EU Commission not being clear about whether the electricity should be renewable (Transport & Environment, 2020). A non-biological transport fuel should have at least 70% lower CO_2 emissions in comparison to the fossil alternative from January 2021 (EU Science Hub, 2018).

In the Netherlands, the market for sustainable transport fuels is regulated by means of hernieuwbare brandstof eenheden (HBE) that are used to account for every [GJ] of renewable energy added to the Dutch transport market. These units are only traded within the Netherlands. Three types of HBE are distinguished on the basis of what type of feedstock is used: advanced, conventional and other (NEA, 2020). At the moment, the typical price of these HBE tokens is about 8 to 9 [$€ \cdot GJ^{-1}$] (Leguijt et al., 2018).

However, green hydrogen is not yet included in the HBE certification system. From January 2021, this would become possible under the RED-2 and the CertifHy certificate system under development to guarantee the origin of green hydrogen (H2Platform, 2018).

In case hydrogen would be used without further HBE certificate, it is common practice to take the average parity price of gasoline and diesel as the future hydrogen price. Accordingly, when the diesel price is assumed to be 1.7 [$€\cdot l^{-1}$] with a consumption of 2.95 [$l \cdot 100km^{-1}$] and the gasoline price is 1.8 [$€\cdot l^{-1}$] with a consumption of 3.5 [$l \cdot 100km^{-1}$], the hydrogen sales price for mobility would be 5.4 [$€\cdot kg^{-1}$]. It does not include distribution costs to the fuelling station nor value added tax. Furthermore, the hydrogen consumption is assumed to be 0.54 [$kg \cdot 100km^{-1}$] in that particular case (Michalski et al., 2017; Albes & Ball, 2014). It should be noted that the diesel and gasoline prices in the Netherlands are much lower currently.

2.5.4 Steel industry

Currently, the global steel production is dominated by two production processes. Both processes are depicted in Figure 14. About 90% of the world steel production is based on the first process that is called the blast furnace-basic oxygen furnace (BF-BOF) (IEA, 2019). On this route, coal is used to produce cokes that act as a reducing agent on the iron ore. During the production CO_2 is produced. The second main process is direct reduction of iron- electric arc furnace (DRI-EAF). It comprises about 7% of the world steel production (IEA, 2019). The main difference is that it uses hydrogen as a reducing agent instead.

Hybrit, an initiative by SSAB, LKAB and Vattenfall is currently testing the feasibility of this production route in Sweden and indicated that it would be around 20 to 30% more expensive than the conventional process for making steel (HYBRIT, 2018). However, this is highly dependent on the price of electricity and hence the price of hydrogen that would be produced with electrolysis. Accordingly, the carbon allowance price under the European Emission Trading System (ETS) also has a significant influence.

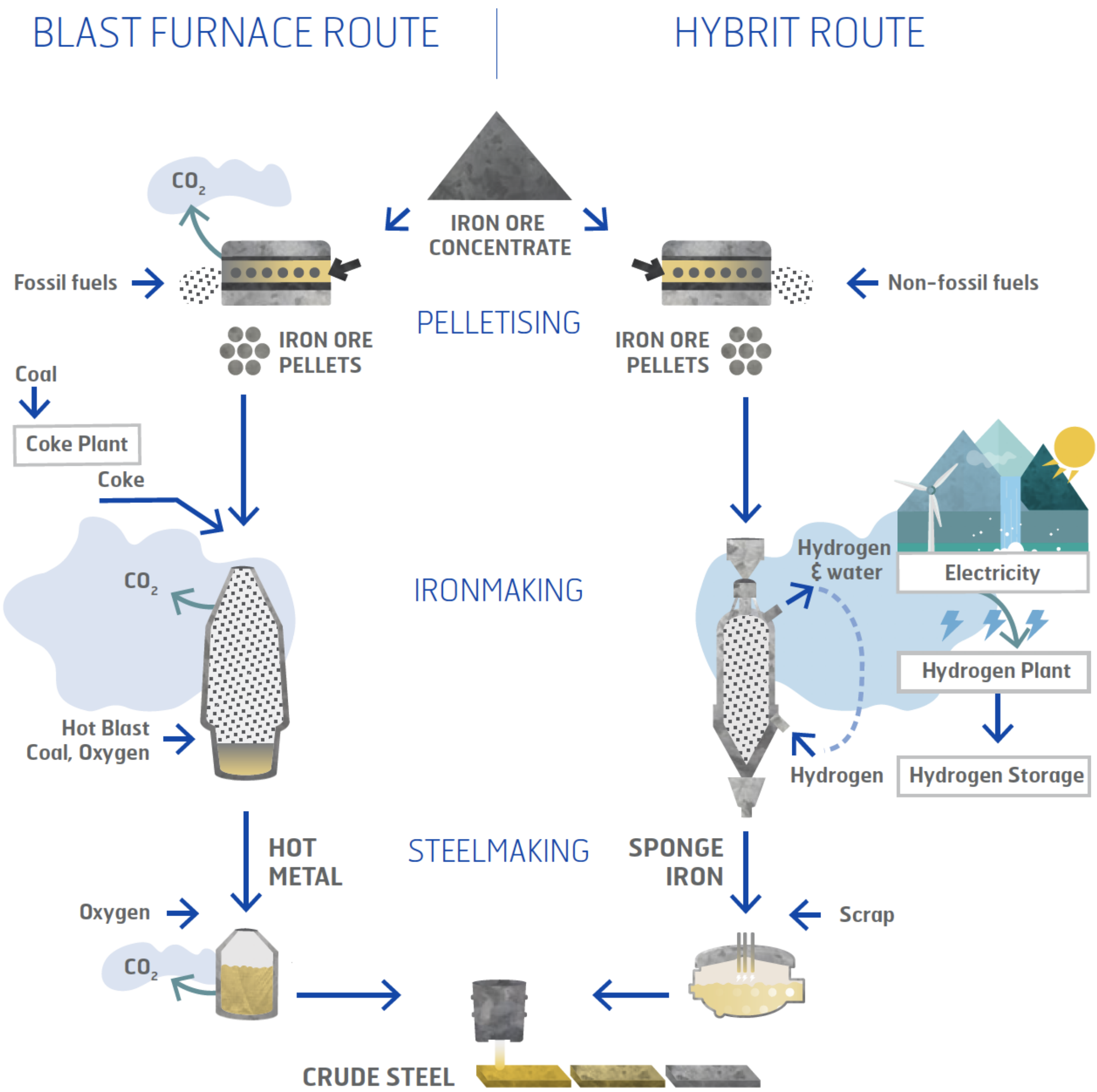

Figure 14: Two main steel production processes using a different reducing agent (HYBRIT, 2018).

Vogl et al. have researched exactly at what price the DRI-EAF process is competitive with a conventional blast furnace. They evaluated at what ETS price and electricity price the DRI-EAF process could compete with the BF-BOF process. Even though the assumptions regarding $CAPEX$ for electrolyzers is different from the study conducted by Roobeek, the parity price for electricity could be derived by finding the linear relation between the electricity price and the price of hydrogen used in the study by Vogl et al. In this way, the assumptions for $CAPEX$ of the electrolyzer are bypassed. At a price level of 1.97 [€·kg^{-1}], a price of 31.6 [€·MWh^{-1}] is found to be congruent to the system proposed by Vogl, using a 1.1 [USD/EUR] conversion rate (Vogl et al., 2018; Roobeek, 2020).

In Figure 15, the linear relation is provided between the marginal abatement cost and the electricity price. At the moment there is a global overcapacity in steel production plants. Therefore, only focusing on the brownfield and relining capacity would be prudent. When the carbon price is 68 [€·t^{-1}] and the electricity price 40 [€·MWh^{-1}], the DRI-EAF process would be competitive with the blast furnace at the point of relining (replacing the refractory brickwork). Similarly, the carbon price would need to be 62 [€·t^{-1}] and the electricity price 40 [€·MWh^{-1}] to be competitive for a brownfield investment when 100% ore is used as the feedstock and zero scrap. Due to the linear relation as well as using the linear relation proposed in the previous paragraph, the parity carbon price with a hydrogen price of 1.97 [€·kg^{-1}] would be 49 [€·t^{-1}]. Other sources however indicate that a price level of 2.2 [\$·kg^{-1}] at a steel price of \$310 would already be a tipping point today (BNEF, 2019).

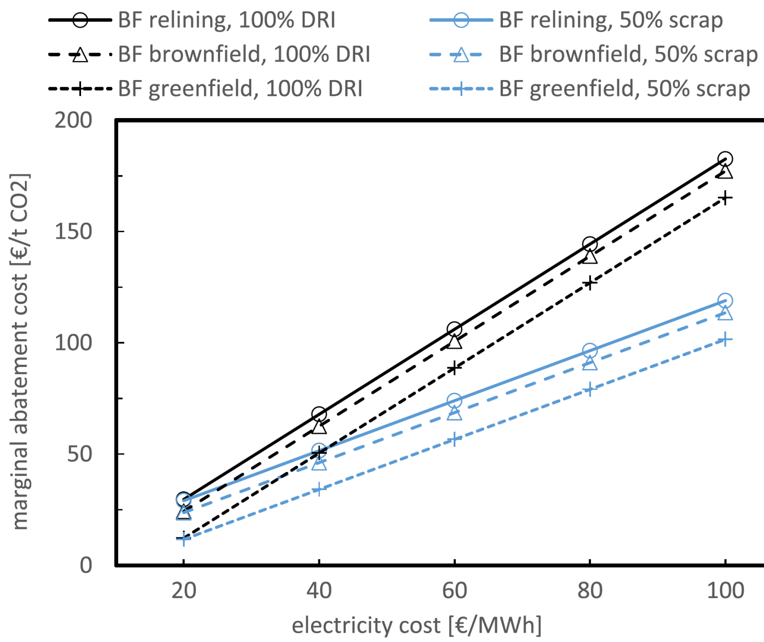

Figure 15: Comparison competitiveness of DRI-EAF versus the traditional BF-BOF process for six different cases (Vogl et al., 2018).

It should be noted that other sensitivities are important to consider here as well. Among others, the price of coking coal for the BF-BOF route assumed in the study by Vogl et al. was 55.7 [€·tLs^{-1}]. Besides the emission intensity of this route was assumed to be 1.870 [$t_{CO2} \cdot tLs^{-1}$]. The H-DRI route only emits 0.053 [$t_{CO2} \cdot tLs^{-1}$] (Vogl et al., 2018).

2.5.5 Synthetic fuels

In case imported hydrogen is to be used, the following is stated in article 30 of the RED-2 (Parliament, 2018):

The obligations laid down in this paragraph shall apply regardless of whether the biofuels, bioliquids, biomass fuels, renewable liquid and gaseous transport fuels of non-biological origin, or recycled carbon fuels are produced within the Union or are imported. Information about the geographic origin and feedstock type of biofuels, bioliquids and biomass fuels per fuel supplier shall be made available to consumers on the websites of operators, suppliers or the relevant competent authorities and shall be updated on an annual basis.

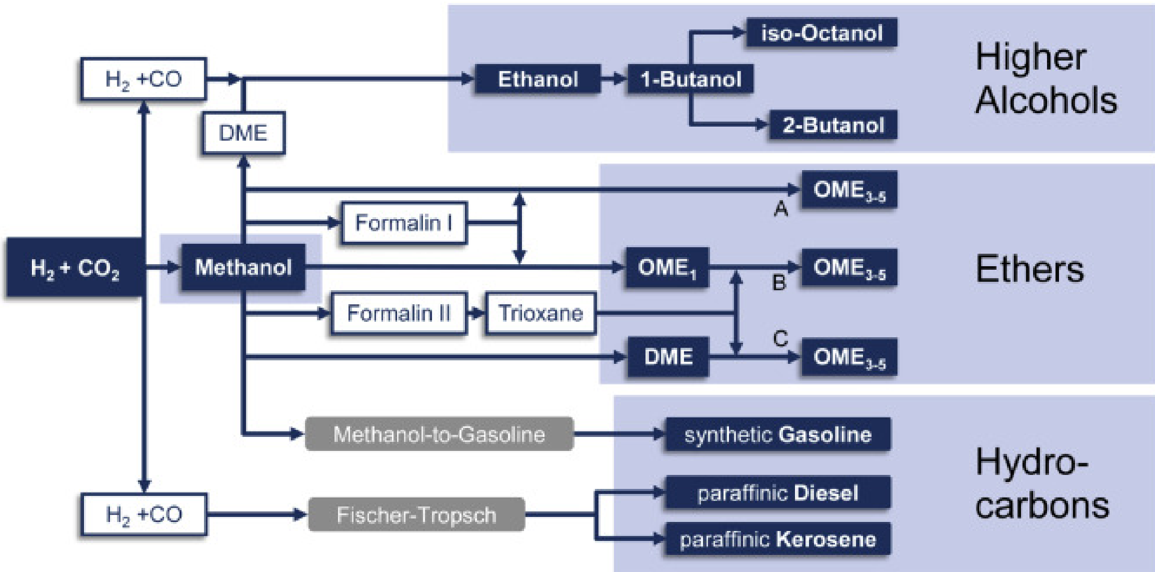

Figure 16: Various synthetic fuel production routes using hydrogen and carbon-dioxide as a feedstock. (Schemme et al., 2020).

When imported green hydrogen would be considered sustainable, it allows for a premium on top of the production cost. Schemme et al. compared various power-to-liquid/power-to-fuel types (PTL) and calculated the contribution of hydrogen to the price of each type of PTL fuel. Accordingly, hydrogen contributed about 58%-83% to the total fuel costs, making it the biggest cost contributing factor. The second biggest cost driver is CO_2. Notwithstanding, there is no further requirement under RED-2 for CO_2 being renewable. As a result, lower cost carbon could be harnessed from fossil sources (Transport & Environment, 2020). Also the technology readiness level (TRL) was identified. The various routes are depicted in Figure 16. Each of these routes has a different technology readiness level, as well as different hydrogen demand (Schemme et al., 2020).

Schemme et al. also identified the required amount of hydrogen for each type of fuel. Besides, the influence of other parameters is verified (e.g. price of CO_2 etc), which are listed in Table 4. The authors used a lower and upper bound for the input price of hydrogen between 3 and 6 [€·kg^{-1}]. A relatively high hydrogen price is taken in this study, since it is assumed that the hydrogen is produced with wind power and also includes the required infrastructure and storage. In this way a stable hydrogen supply is achieved for the chemical plants (Schemme et al., 2020). These additional infrastructure costs on the PoR side of the supply chain are not taken into account in the price found in part one of this two-part study. The CO_2 bounds are derived from CO_2 capture at natural gas plants (lower bound) and coal plants (upper bound). Moreover, each and every type of (synthetic) fuel has its own GHG impact.

Table 4: Synthetic fuel parameters. The $CAPEX$ assumptions could be found in Appendix A (Schemme et al., 2020).

	Unit	Lower bound	Base case	Upper bound
Cost of H2	€/kg	3	4.6	6.00
Cost of CO2	€/kg	0.02	0.07	0.17
CAPEX	–	−30 %	–	+50%
Interest rate	–	0.02	0.08	0.12
Process steam	€/t	16	32	48.00
Cooling water	€/t	−50%	0.1	+50%
Operating electricity	€ct/kWh	4	9.76	14.70

It is important to note that the production costs from Figure 17 are converted into diesel equivalent liters. Taxes are not included in this case, nor a carbon price. A conversion to price per tonne of product could be derived by multiplication of the inverse of the energy content of 35.9 [$MJ \cdot dm^{-3}$] and the specific lower heating value of the synthetic fuel produced. To put the synthetic production cost in perspective, Figure 18 shows the current spot prices of each product. For methanol, ethanol, butanol, gasoline and kerosene prices are derived from ICIS by visual inspection of the average in Rotterdam from March 2019 to January 2020 (ICIS, 2020). The market price of 1-butanol is assumed to be the same as 2-butanol. The diesel price is the latest price of April 2020 (CME Group, 2020).

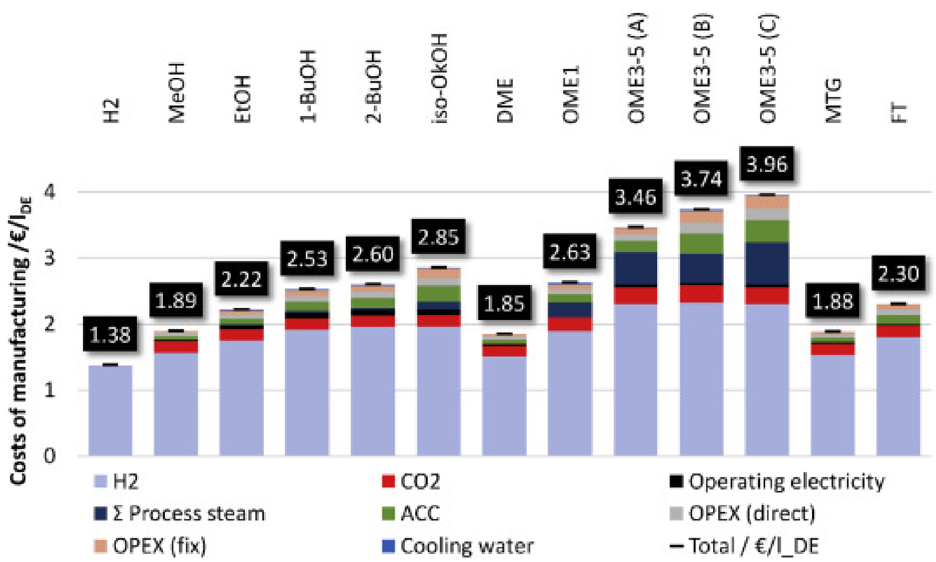

Figure 17: Production cost of various synthetic fuels based on the base case assumptions with everything translated into diesel equivalent liters (Schemme et al., 2020).

Data on market prices of octanol, DME and OME is not readily available. Therefore, taking into account the production pathways of Figure 16, the following is assumed. The market price of octanol is estimated by the ratio between the production cost of butanol over octanol, multiplied with the market price of butanol. A similar approach is taken to estimate the market price of DME and OME. In the latter case, the market price of OME is estimated by the ratio between the production cost of OME over methanol multiplied with the market price of methanol. The market price of DME is estimated by the ratio of the production cost of DME over methanol times the market price of methanol (Schemme et al., 2020). All prices are in USD per metric ton.

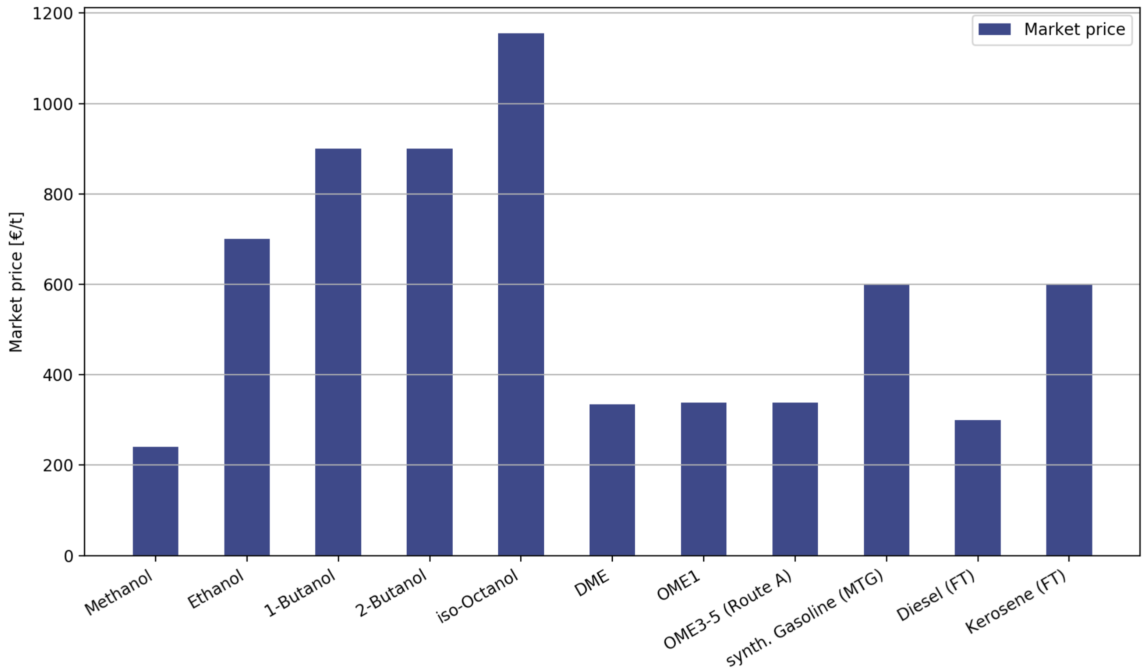

Figure 18: Market prices of the various fuels (ICIS, 2020; CME Group, 2020).

Terwell et al. studied the techno-economic feasibility of PTL fuels as well, while specifically focusing on kerosene production. A similar cost contribution is estimated by the authors and is found to be between n 65%-80%. Several sensitivities are studied: the influence of the electricity price, the crude oil price as well as the scaling and capital costs in new technologies. Under certain circumstances, the price of synthetic kerosene would be competitive according to this study. When the electricity price would be around 0.015 [$€\cdot kWh^{-1}$], which is perceived in the Middle East, synthetic fuel would even be cheaper than its fossil counterpart (Reuters, 2017). Furthermore, also the liquid shipping of green hydrogen was proposed when liquid hydrogen shipping would not add substantial costs in comparison to local fossil kerosene production (Terwel et al., 2019).

2.5.6 Low temperature heat

As part of the Klimaatakkoord (Dutch climate agreement), a total of seven million houses and one million buildings should become gas-free in 2050. In fact already in 2030, 1.5 million existing houses should be transformed to a sustainable alternative to natural gas. This could be achieved in various ways, ranging from district heat networks, heat pumps and possibly also hydrogen (Rijksoverheid, 2019). A profound characteristic of heat pumps is that it is only suitable for low temperature heat and therefore requires a higher degree of insulation. On the contrary, hydrogen is suitable for both low and high temperature heat applications. In this way, it becomes possible for homeowners to adjust the rate of investments in insulation to match their purchasing power. Hybrid approaches are possible as well, where heat pumps are covering the base load heat demand and hydrogen is only employed if there is a peak in heat demand (H2Platform, 2018).

At the moment, there are already projects that evaluate the adaptations needed for a whole city to make their natural gas grid capable of distributing green hydrogen. The required modifications to the grid in Stad aan 't Haringvliet have been identified, as well as the changes needed to the boilers, gas meter and small modifications to the existing infrastructure inside houses. Stedin, the distribution system operator, expects that a new hydrogen boiler would be about 1,500 Euro more expensive in comparison to existing natural gas boilers. Besides, additional costs are incurred to modify the distribution network and also monitoring costs (Stedin, 2019). A drawback of switching to 100% hydrogen is that switching to electric cooking is needed, since hydrogen combustion is colourless. On the other hand, introducing a 20% volume hydrogen blend is not expected to have a significant impact on either modern boilers or on gas stoves. The efficiency of boilers hydrogen boilers is comparable to the efficiency of modern natural gas boilers on a higher heating value basis. A typical efficiency would be in the order of 90% (H2Platform, 2018).

2.5.7 High temperature heat

Similar to green hydrogen for transport applications, when imported green hydrogen would be deployed in either electricity or heating, certain thresholds apply that makes it eligible for subsidies. At least 70% CO_2 reduction should be achieved to be considered from January 2021. This threshold is further increased to 80% after January 2026 (EU Science Hub, 2018). This would introduce a competitive advantage of green hydrogen over the alternative when this legislation would be adopted under the stimulering duurzame energieproductie (SDE+) policies. At the moment this is not yet the case. The techno-economic cost of hydrogen for high temperature heat applications is difficult to estimate due to its high specificity at different market applications. The current price of high temperature heat is about 8 [$€\cdot GJ^{-1}$] (Noothout et al., 2019).

3 Methodology

In this Section the methodology will be explained. The research approach will be provided in Section 3.1. Thereafter, the research method will be covered in Section 3.2. In Section 3.3 the sub-methodology for every hydrogen market will be explained in more detail in order to evaluate the parity prices. Ultimately, the sub-methodologies to assess the marginal CO_2 abatement cost are also provided in that particular Section.

3.1 Research approach

This study will be a case study, where the feasibility of importing hydrogen will be evaluated from an economic and GHG reduction perspective. Where part one of this two-part research addressed what the production cost of hydrogen would be at the receiving end of a supply chain between the PoS and the PoR, with the sensitivity included in the cost factors that have the biggest contribution, this part will reverse the question. It will address what the price of hydrogen would need to be in current and future hydrogen markets to make these markets tip towards green hydrogen import.

Apart from the current hydrogen markets, new hydrogen markets will be identified within current hydrogen markets as well as future hydrogen markets that could emerge in the nearby future. Obviously, various aspects determine the feasibility of supplying hydrogen to these markets. From a techno-economic perspective, it would be preferable to include all factors such as specific $CAPEX$, $OPEX$ as well as the sensitivity of other parameters that are relevant in a techno-economic analysis (Lauer, 2008). Nevertheless, this research will identify the sensitivity of each hydrogen market to the price of imported hydrogen, and in some cases the ETS price or other market specific prices (e.g. LSMGO price).

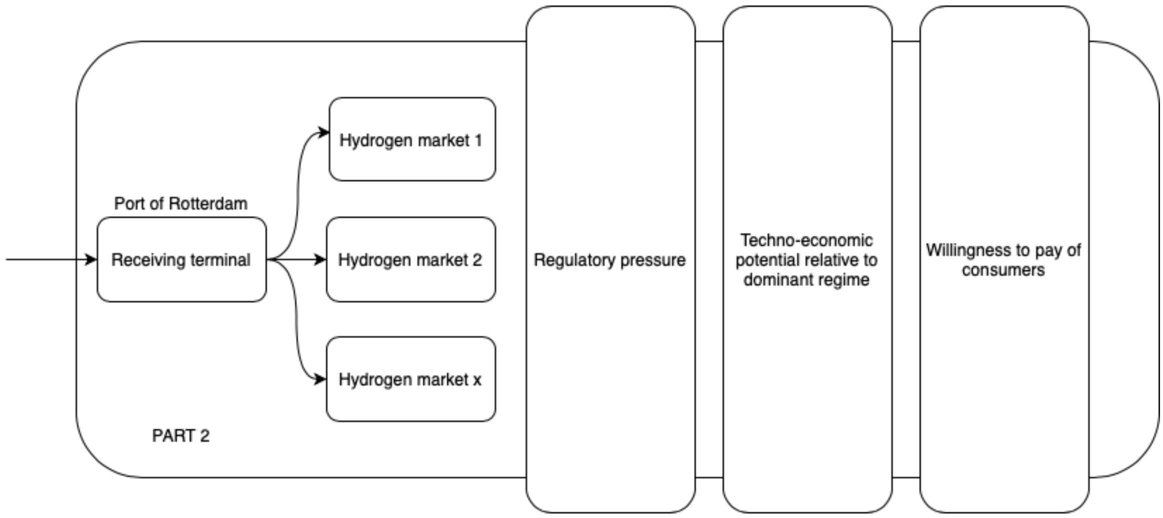

Figure 19: Flowchart of the processes that are considered in part 2.

In Figure 19, a high level overview is provided. Where Geels identified various regimes that have an impact on a niche to become mainstream, in this study a simplified approach is used where three different levels are identified that affect whether hydrogen markets open up (Geels, 2002). First, regulation is important since regulatory pressure supersedes price and the willingness to pay (WTP) of final consumers. For example, when legislation prescribes a certain blend content of renewable fuel in a certain market, hydrogen demands become price takers and have to adopt this new type of fuel. Accordingly, pressure is created on existing energy markets when the ETS price increases or when SDE+ subsidies make some options yet more attractive.

Second, within the solution space individual companies make decisions on what alternative is or is likely to become techno-economically favourable. It depends on the total cost including $CAPEX$, $varOPEX$ and $fixOPEX$. Third, when there still exists a difference in the price needed in a specific market and the green hydrogen import price, this has to be overcome by the WTP of the final consumers. Even though it has to be said that the price paid by the final consumer is often a small fraction of the total price.

3.2 Research method

Every relevant current and future hydrogen market will be identified. Two different price scenarios will be analyzed. The first scenario is based on current green hydrogen production costs in Oman, which is found to be 1.97 [€$\cdot$kg^{-1}] in combination with the average ETS price of 25 [€$\cdot$t^{-1}] in 2019 (Markets Insider, 2020). The second scenario is hydrogen production costs with a 50% cost decline in both solar pv module costs and alkaline electrolyzer $CAPEX$ costs. The latter price is found to be 1.47 [€$\cdot$kg^{-1}] (Roobeek, 2020). Besides, the second scenario will have an ETS price of 80 [€$\cdot$t^{-1}], which is the projected ETS price in the high scenario by PBL in 2030 (Brink, 2018).

These two scenarios will be an input to each relevant hydrogen market. The output differs for each hydrogen market, since not all applications have similar metrics that influence the likelihood of introducing liquid hydrogen to these markets. As an example, in the bunker fuel market LSMGO prices are relevant whereas carbon prices are not relevant since international shipping is not part of ETS. On the other hand, in the steel industry the costs of the main competing technology, the techno-economic cost of the BF-BOF process should be considered as well as the ETS price.

Therefore, the two input hydrogen prices for imported liquid hydrogen from Oman will be taken in order to evaluate the techno-economic tipping point of each relevant hydrogen market. At this tipping point parity is achieved between hydrogen as a feedstock and the conventional alternative. The factors that determine where these parity prices occur are derived from literature. Every hydrogen market requires a different approach, therefore for each market a sub-method is chosen where the new hydrogen price is implemented. These methods will be explained in detail in Section 3.3.

A curve will be constructed that details the difference between the market price and the costs associated with using green hydrogen as a feedstock. Hence, the required relative price decrease will be depicted. This will allow for an understanding of which markets are likely to tip first towards using green hydrogen as a feedstock. In case the relative price is negative, the hydrogen market is theoretically already competitive. On the other hand, when the relative price is positive, it means a further price reduction in green hydrogen is required or alternatively a price decrease in any of the other relevant parameters specific to that particular market.

Finally, a marginal abatement cost curve will be set up. It will detail the price to abate one ton of CO_2 in each market. A negative price indicates that this market is already attractive, while also detailing the gain per ton of CO_2 abatement. On the other hand, a positive value means that a ton of CO_2 abatement actually results in a cost.

3.3 Sub-methodologies

In this Section, the sub-methodologies are elaborated upon. For each hydrogen market a methodology is developed that calculates the parity price specific to that market. This parity price is compared to the actual green hydrogen price found in part one of this two-part research. In addition, the marginal abatement cost is derived specific to that market. For conversion of USD to EUR 1.1 [\$/€] is assumed.

3.3.1 Hydrogen SMR substitution

Perhaps the most obvious application of imported green hydrogen is substitution of the existing SMR facilities. Mulder et al. studied the cost of hydrogen produced by SMR in the Netherlands, and evaluated the influence of the ETS price. The relation between the cost of hydrogen and the ETS price is linear and derived from the study of Mulder et al. (Mulder et al., 2019). In Equation 1 this relation is provided. The slope is derived from Mulder et al. where P_{ETS} is the in [€$\cdot$t^{-1}]. In Equation 2 the relative price is calculated in comparison to the $LCOH$, which is the import price of green hydrogen from the PoS.

$$Par_{SMR}(€/kg) = \frac{2.2 - 1.3}{90} * P_{ETS} + 1.3 \tag{1}$$

$$Relative_{SMR}(-) = \frac{LCOH - Par_{SMR}}{Par_{SMR}} \cdot 100\% \tag{2}$$

In addition, the marginal abatement cost is calculated by using Equation 3. The denominator EF is the CO_2 emission factor and is found to be 0.00901 [tCO2 $\cdot$ kgH2^{-1}] (Collodi et al., 2017).

$$MACC_{SMR}(€/tCO2) = \frac{LCOH - Par_{SMR}}{EF} \tag{3}$$

3.3.2 Hydrogen natural gas substitution

When a future hydrogen market would substitute an existing or future natural gas market, two options exist. The first is hydrogen applied under ETS markets and the second is without. When further $CAPEX$ factors are neglected, the heating value of both hydrogen and natural gas is relevant as well as the associated price. Besides, when imported hydrogen is considered to be green under RED-2 a further cost advantage exist for application in ETS markets.

The parity price of natural gas at an input price of hydrogen is given in Equation 4. The parity price is increased with the ETS price when it is to be used in a power plant (PP), since an increase in the ETS price would make green hydrogen more competitive in comparison to natural gas and therefore the parity price of hydrogen substituting natural gas should be higher (see Equation 5). P_{NG} is the natural gas delivery price per [GJ] for consumers. For households the delivery price of natural gas was 23.2 [€·GJ^{-1}] in 2019 (CBS, 2020). When natural gas is used in a power plant, it will fall under the 10-100 [TJ] category and consequently will have a delivery price of 11.1 [€/GJ] in the Netherlands. In addition, the TTW CO_2 emission factor is 1.79 [kgCO2 $\cdot$ Nm3^{-1}] and the $E_{HHV_{NGNM3}}$ is 35.17 [MJ $\cdot Nm3^{-1}$] for natural gas (Zijlema, 2016). Households are not covered under ETS, so the ETS price should be omitted in that case. The E_{HHV} is the higher heating value of hydrogen in [MJ $\cdot kg^{-1}$] and $E_{HHV_{NGNM3}}$ is the higher heating value of natural gas in [MJ $\cdot Nm3^{-1}$].

$$Par_{NG}(€/kg) = \frac{E_{HHV}}{1000} * P_{NG} \tag{4}$$

$$Par_{PP}(€/kg) = \frac{E_{HHV}}{1000} * P_{NG} + \frac{1.79 * P_{ETS}}{1000} * \frac{E_{HHV}}{E_{HHV_{NGNM3}}} \tag{5}$$

A similar approach is taken to calculate the parity price for LNG. The price of LNG is 5.28 [€·GJ^{-1}] in the Netherlands, which is the average LNG price in February 2020 (Bebeka, 2020). The parity price is calculated by Equation 6. The relation for the relative price difference with the parity price of LNG and the $LCOH$ is given in Equation 7. The latter Equation is also used to calculate the relative price difference between the Par_{PP} and the LCOH as well as the Par_{LNG} and the LCOH.

$$Par_{LNG}(€/kg) = \frac{E_{HHVH2}}{1000} * P_{LNG} \tag{6}$$

$$Relative_{NG}(-) = \frac{LCOH - Par_{NG}}{Par_{NG}} * 100\% \tag{7}$$

The marginal abatement cost is determined for natural gas (NG), LNG and natural gas power plant (NG PP). Equation 8 provides for the right relation for NG, but also for LNG when P_{NG} is replaced with P_{LNG} (both are in [€·GJ^{-1}]). In addition, Equation 9 defines the marginal abatement cost when the ETS price is included as well as the P_{NG} for consumers in the 10-100 [TJ] category. The factor EF is in this case 0.0565 [tCO2 $\cdot$ GJ^{-1}] and is the emission factor of natural gas (Zijlema, 2016).

$$MACC_{NG}(€/tCO2) = \frac{LCOH/E_{HHV}/1000 - P_{NG}}{EF} \tag{8}$$

$$MACC_{NGPP}(€/tCO2) = \frac{LCOH/E_{HHV}/1000 - P_{NG} - EF * P_{ETS}}{EF} \tag{9}$$

3.3.3 Hydrogen in bunkering

Bunkering liquid hydrogen is yet another future hydrogen market. Several factors are important to take into account as mentioned in Section 2.5.2. However, in this research only the LSMGO price is used as an input to approximate the break-even liquid hydrogen price to be competitive in this market. In order to do so, a linear approximation (linear equation) is conducted on the lower half of the spectrum from Figure 12. In this way the fuel cell efficiency is set at 50% for container applications, 52% for ferry applications and 57% for tug boat applications. Equations 10, 11 and 12 provide for these relations. Hence, it is the parity price at which liquid hydrogen becomes competitive at a given LSMGO price. P_{LSMGO} is set at the average LSMGO price in 2019, which is 569 [$\$ \cdot \mathrm{t}^{-1}$]. Since the slope is derived from 12, a conversion to Euro is needed, for which an adjustment is carried with 1.1 [$/€]. Accordingly, it divided by 1000 to convert to [kg] of hydrogen.

$$Par_{Container}(€/kg) = (\frac{1710 - 450}{700 - 296} * P_{LSMGO} - 473)/1000/1.1 \tag{10}$$

$$Par_{Ferry}(€/kg) = (\frac{2010 - 430}{700 - 296} * P_{LSMGO} - 728)/1000/1.1 \tag{11}$$

$$Par_{Tug}(€/kg) = (\frac{2930 - 1010}{700 - 296} * P_{LSMGO} - 397)/1000/1.1 \tag{12}$$

The relative hydrogen price decrease or increase needed is calculated by Equation 13. The parity prices of Equations 10, 11 and 12 are implemented in this Equation.

$$Relative_{Bunkering}(-) = \frac{LCOH - Par_{bunker}}{Par_{bunker}} * 100\% \tag{13}$$

In order to identify the marginal abatement cost of CO_2 for each bunker market, the equivalent LSMGO price is determined based on the LCOH. Equations 10, 11 and 12 are solved for the equivalent LSMGO price, given the hydrogen import price in LCOH. Then, the P_{LSMGO} is subtracted, which is 569 [$\$ \cdot \mathrm{t}^{-1}$], divided by the TTW emission factor (EF) of LSMGO in 2.59 [$\mathrm{tCO2} \cdot \mathrm{t}^{-1}$] (see Equations 14, 15 and 16) (CO2emissiefactoren, 2014).

$$MACC_{Container}(€/tCO2) = \frac{((LCOH * 1.1 * 1000 + 473) * (700 - 296) - P_{LSMGO})/1.1}{(1710 - 450) * EF} \tag{14}$$

$$MACC_{Ferry}(€/tCO2) = \frac{((LCOH * 1.1 * 1000 + 728) * (700 - 296) - P_{LSMGO})/1.1}{(2010 - 430) * EF} \tag{15}$$

$$MACC_{Tug}(€/tCO2) = \frac{((LCOH * 1.1 * 1000 + 397) * (700 - 296) - P_{LSMGO})/1.1}{(2930 - 1010) * EF} \tag{16}$$

3.3.4 Hydrogen in mobility

As mentioned in Section 2.5.3, the expected sales of hydrogen would be 5.4 [€·kg^{-1}] for the mobility market. In addition, also the hydrogen price in combination with a P_{HBE} price of 8 [€·GJ^{-1}] is included. The HBE price is converted to the energy content of one [kg] hydrogen based on the HHV and added to the expected hydrogen sales price (see Equation 17). In Equation 18 the margin is calculated based on the $LCOH$ as well as the expected sales price.

$$Par_{mobility}(€/kg) = 5.4 + \frac{P_{HBE} * E_{HHV}}{1000} \tag{17}$$

$$Relative_{Mobility}(-) = \frac{LCOH - Par_{mobility}}{Par_{mobility}} * 100\% \tag{18}$$

The marginal abatement cost is calculated as follows. Since the average parity price for mobility is based on the average of gasoline and diesel consumption, also the average carbon emission will be taken per 100 [km]. For diesel the consumption is taken to be 2.95 [l·100km^{-1}] and the TTW emission factor at 2.608 [kgCO2·l^{-1}]. For gasoline the consumption is taken to be 3.5 [l·100km^{-1}] and the TTW emission factor at 2.269 [kgCO2·l^{-1}] (Michalski et al., 2017; Albes & Ball, 2014; CO2emissiefactoren, 2014). Hence, the emission factor EF is 7.8 [kgCO2·100km^{-1}], only considering the TTW emissions. Assuming a consumption of 0.54 [kg] hydrogen per 100 [km] with zero emissions, the following marginal abatement cost could be calculated (Albes & Ball, 2014). In Equation 19, the marginal abatement cost for mobility is calculated, using either the $Par_{mobility}$ with or without the HBE margin.

$$MACC_{mobility}(€/tCO2) = \frac{0.54 * (LCOH - Par_{mobility})}{EF} \tag{19}$$

3.3.5 Hydrogen in steel industry

Similar to Vogl et al. hydrogen direct reduction (H-DR) will be compared to brownfield relining and brownfield investment in BF-BOF applications due to the oversupply on the global steel market (Vogl et al., 2018). However, Vogl includes the $CAPEX$ and $OPEX$ of the electrolyzer and the electricity price in order to find the price of hydrogen. In the case of imported hydrogen from Oman, hydrogen obviously is already produced. The relation between the price of hydrogen and the electricity price is linear, which could be exploited. The price of hydrogen varies between 1.43 and 5.17 [€·kg^{-1}] for a price of electricity between 20-100 [€·MWh^{-1}].

Accordingly, from Figure 15 the relation between the electricity price and the marginal abatement cost could be derived. The marginal abatement cost is defined as the minimum carbon price to make the H-DR route competitive with each comparative investment (e.g. investment in brownfield steel production with a 100% ore stream fed to the reactor). However, this could be reversed by asking the question what the required electricity price would be at a given carbon price to make the H-DR route competitive. Again, only relining and brownfield BF-BOF are considered here due to the oversupply on the steel market. Equations 20 and 21 provide for this relation between the ETS price and the electricity price specific to this study. The slope is derived from Figure 15 and given that at an electricity price of 40

[€·MWh^{-1}] an ETS price of 68 [€·t^{-1}] would be required to make H-DR relining competitive with traditional BF (see Equation 20). By inserting these values, the y-intercept could be derived. Similarly, at an electricity price of 40 [€·MWh^{-1}] an ETS price of 62 [€·t^{-1}] would be required to make H-DR brownfield competitive with traditional BF (see Equation 21). Again the y-intercept could be determined. The numerator of 60 is due to the difference between an electricity price of 40 and 100 [€·MWh^{-1}].

$$P_{Electricity_{Relining}}(€/MWh) = \frac{60}{185-68} * P_{ETS} + 5.13 \tag{20}$$

$$P_{Electricity_{Brownfield}}(€/MWh) = \frac{60}{175-62} * P_{ETS} + 7.08 \tag{21}$$

Subsequently, since the hydrogen price is given in the study by Vogl et al., the electricity price allows for a hydrogen price to be derived at which price parity is achieved between the H-DR route and either BF-BOF relining or BF-BOF brownfield. These two relations are provided in Equations 22 and 23. The slope is found by using the hydrogen production costs in the study by Vogl et al., and the y-intercept is derived by plugging a specific value for the hydrogen price of 5.17 [€·kg^{-1}] at an electricity price of 100 [€·MWh^{-1}].

$$Par_{Relining}(€/kg) = \frac{5.17-1.43}{80} * P_{electricity_{Relining}} + 0.495 \tag{22}$$

$$Par_{Brownfield}(€/kg) = \frac{5.17-1.43}{80} * P_{electricity_{Brownfield}} + 0.495 \tag{23}$$

Thereafter, the relative price decline in the actual hydrogen price found in part one of this two-part research could be compared with the parity prices for both relining and brownfield BF-BOF. The relative decrease or increase in the $LCOH$ needed is calculated by means of Equations 24 and 25.

$$Relative_{Relining}(-) = \frac{LCOH - P_{parityH2relining}}{P_{parityH2relining}} * 100\% \tag{24}$$

$$Relative_{Brownfield}(-) = \frac{LCOH - P_{parityH2brownfield}}{P_{parityH2brownfield}} * 100\% \tag{25}$$

Furthermore, the marginal abatement cost could be calculated for both relining and brownfield BF-BOF in comparison to the H-DR route. It is the reverse approach conducted to find the parity prices in 22 and 23. The similar slope is used, instead of solving for the hydrogen price by having the electricity price as an input, the import hydrogen price is used as an input instead ($LCOH$) (see Equation 26). The marginal abatement cost is calculated by using Equations 27 and 28.

$$P_{Elec}(€/tCO2) = \frac{(LCOH - 0.495) * 80}{(5.17-1.43)} \tag{26}$$

$$MACC_{relining}(€/tCO2) = \frac{(P_{Elec} - 5.13) * (185-68)}{60} - P_{ETS} \tag{27}$$

$$MACC_{brownfield}(€/tCO2) = \frac{(P_{Elec} - 7.08) * (175 - 62)}{60} - P_{ETS} \quad (28)$$

Lastly, the price per liquid tonne steel could be approximated as well. This price could be calculated by an approximation given in Equation 29 to estimate the equivalent electricity price used in the study by Vogl et al. and implementing this electricity price in Equation 30.

$$P_{EquivalentElectricity}(€/MWh) = 21.39 * P_{H2} - 10.59 \quad (29)$$

$$P_{HDRsteel}(€/tLs) = \frac{279}{80} P_{electricity} + 291.25 \quad (30)$$

3.3.6 Hydrogen for synthetic fuels

In order to evaluate what the hydrogen price impact will be on the cost of synthetic fuels the following methodology is proposed. The basic framework by Schemme et al. is used with the same assumptions (Schemme et al., 2020). However, instead of the base case cost factors for CO_2 and hydrogen (see Table 4) the specific price for importing green hydrogen from Oman is applied to every synthesis route as well as a specific CO_2 price for the PoR (which is different from the ETS price) (Roobeek, 2020). Besides, the diesel equivalent liters are converted to metric tons to allow for a better comparison to current market prices of the final products.

First, the clean price of each synthetic route is calculated, without the costs of hydrogen and CO_2. Then, the specific price for the synthetic fuels is calculated with the hydrogen price from the two scenarios in part one of this two-part research. The price of CO_2 of 50 [$€ \cdot t^{-1}$], which is higher than the ETS price since also CO_2 capture costs are incurred, should be included as well (Weterings, 2020). In Equation 31, the relative price decrease needed to make synthetic fuels competitive is given. The emission factor of SMR is again assumed to be 0.0091 [$tCO2 \cdot tH2^{-1}$] (Collodi et al., 2017).

$$Relative_{Synthetic}(-) = \frac{P_{CostSynthetic} - P_{Market}}{P_{Market}} * 100\% \quad (31)$$

Also for the synthetic routes the marginal abatement cost is calculated. For this hydrogen market, it is assumed that the amount of hydrogen required ($Hydrogen_{requirement}$) for each product is the sole contribution to carbon emissions and that the hydrogen would be produced with SMR for comparison (see Equation 32).

$$MACC_{Synthetic}(€/tCO2) = \frac{P_{CostSynthetic} - P_{Market}}{Hydrogen_{requirement} * 0.00901} \quad (32)$$

3.3.7 Hydrogen for low temperature heat

In case hydrogen would be employed in low temperature heat applications for households, the following assumptions are made. First of all, the total additional investment is assumed to be 1,700 [$€ \cdot household^{-1}$]. This includes a 200 [$€ \cdot household^{-1}$] modification to the existing natural gas infrastructure within each house. The average natural gas price paid by consumers is 23.2 [$€ \cdot GJ^{-1}$] and the average natural gas consumption is 1,270 [$Nm3 \cdot year^{-1}$]

in 2019 (Weeda & Niessink, 2020). Furthermore, the WACC is assumed to be 0% because households are considered here. Therefore, the annuity equally distributes costs over the lifetime. Lastly, the efficiency is assumed to be the same for both hydrogen and natural gas heating systems. An overview of the parameters is given in Table 5.

Table 5: Hydrogen for low temperature heat parameters (Weeda & Niessink, 2020; CBS, 2020; Noothout et al., 2019).

$P_{GasConsumer}$	23.2 [€·GJ^{-1}]
Natural gas consumption V_{gas}	1,270 [Nm3 · household^{-1} · year^{-1}]
Efficiency η (HHV)	90 %
Depreciation period boiler	10 [year]
Depreciation period grid	40 [year]
$WACC$	0 %
OM	10 [€·year^{-1}]
$CAPEX$ boiler	1,500 [€·household^{-1}]
$CAPEX$ grid	200 [€·household^{-1}]
Emission factor CO_2 EF	0.06 [t · GJ^{-1}]

In order to find the parity price of low heat hydrogen applications, Equation 33 is used to calculate the hydrogen parity price. The efficiency is not included, since it is assumed to be similar to natural gas boilers. The $E_{HHV_{NG}}$ is assumed to be 35.2 [MJ · Nm3^{-1}].

$$\begin{aligned} Par_{HeatLow}(€/kg) &= P_{GasConsumer} * E_{HHV}/1000 \\ &- \frac{(CAPEX * Annuity + OM) * E_{HHV}}{V_{gas} * E_{HHV_{NG}}} \end{aligned} \tag{33}$$

Also for low temperature heat applications the marginal abatement cost is calculated. In Equation 34, the marginal abatement cost is calculated. The emission factor EF is 0.06 [t · GJ^{-1}].

$$MACC_{HeatLow}(€/tCO2) = \frac{\frac{CAPEX*Annuity+OM+V_{gas}*E_{HHV_{NG}}/E_{HHV}*LCOH}{\eta*V_{gas}*E_{HHV_{NG}}/1000} - \frac{P_{GasConsumer}}{\eta}}{EF} \tag{34}$$

3.3.8 Hydrogen for high temperature heat

Similar to the study conducted by Noothout et al. the $CAPEX$, $fixOPEX$ and $varOPEX$ are listed in Table 6. The average value is taken on a literature basis (Noothout et al., 2019). The annuity is calculated from the $WACC$ of 6% used in the study. The parity price for hydrogen employed in high temperature heat is calculated by using Equation 35. The factor 0.0036 converts the [kWh] to [GJ]. In addition, the CO_2 emission associated with conventional heat production is 0.06 [t · GJ^{-1}]. The associated emission of green hydrogen is assumed to be zero (point of use). Lastly, it should be noted that there exists substantial variety in the estimated costs for hydrogen heat production in both literature and under experts.

Table 6: Hydrogen for high temperature heat parameters (Noothout et al., 2019).

Efficiency η (HHV)	90 %
Depreciation period	10 [year]
$WACC$	6 %
Full load hours (FLH)	7750 [hour $\cdot$ year^{-1}]
OM	17.5 [€$\cdot$kWp^{-1}year^{-1}]
$CAPEX$	140 [€$\cdot$kW^{-1}]
Emission factor CO_2 EF	0.06 [t $\cdot$ GJ^{-1}]
P_{heat} without ETS	6.8 [€$\cdot$GJ^{-1}]

$$\begin{aligned} Par_{HeatHigh}(€/kg) = {} & (P_{heat} + EF * P_{ETS}) * 0.0036 * \eta * E_{HHV_{kWh}} \\ & - \frac{(CAPEX * Annuity + OM) * \eta * E_{HHV_{kWh}}}{FLH} \end{aligned} \tag{35}$$

Evaluating the relative price decrease needed to make imported green hydrogen competitive is provided by Equation 36.

$$Relative_{heat}(-) = \frac{LCOH - P_{ParityH2heat}}{P_{ParityH2heat}} * 100\% \tag{36}$$

Accordingly, also the marginal abatement cost for high temperature heat is determined. It is given in Equation 37, where the heat price P_{heat} is subtracted from the hydrogen based heat price. The difference is divided by the emission factor EF, which is 0.06 [t $\cdot$ GJ^{-1}] in the case of high temperature heat. The marginal abatement cost is reduced with the emission factor EF multiplied with the ETS price, since the ETS price is no longer incurred.

$$MACC_{HeatHigh}(€/tCO2) = \frac{\frac{CAPEX*Annuity+OM+FLH*/\eta/E_{HHV_{kWh}}*LCOH}{FLH*0.0036} - P_{heat} - EF * P_{ETS}}{EF} \tag{37}$$

4 Results

In this Chapter, the results will be covered. First, the regulatory pressure will be addressed in Section 4.1. Afterwards, the techno-economic costs will be covered in Section 4.2. The margin will be identified in Section 4.3 by comparing the parity prices of every hydrogen market to the current market prices. Lastly, the marginal abatement cost curve is provided in Section 4.4.

4.1 Regulatory pressure

From a regulatory perspective, different policy measures influence each hydrogen market. Each of these markets will be touched upon. The interplay of these policies affects the relative attractiveness of employing hydrogen in different markets. Four main policies have been identified that influence this relative attractiveness: European Emission Trading System (EU-ETS), Stimulering Duurzame Energie (SDE+), Hernieuwbare Brandstof Eenheden (HBE) and standards (e.g. blending obligation).

The ETS scheme mostly affects the larger industries where hydrogen is applied. In industry, SMR is the main competitor of imported hydrogen. Both the natural gas price as well as the ETS price are crucially important. A higher ETS price makes current hydrogen markets (e.g. refineries) and future hydrogen markets (e.g. steel industry) yet more attractive for green hydrogen import. However, not all hydrogen markets are covered under the ETS system. As an illustration, ETS increases the likelihood of green hydrogen being used in for instance power plants over hydrogen as a replacement for natural gas at final consumers (households).

The SDE+ regime does not yet cover green hydrogen applications, although proposals are already made to include for instance high temperature heat in this subsidy scheme. More important would be how the SDE+ regime influences the relative attractiveness of imported green hydrogen over domestic green hydrogen production. For example, currently SDE+ already supports green hydrogen production with electrolyzers (Ministerie van Economische Zaken en Klimaat, 2020). In this way imported green hydrogen actually becomes indirectly less attractive.

The HBE scheme in combination with the RED-2 directive would enable imported green hydrogen as a feedstock for mobility from January 2021. The carbon reduction should be at least 70% to be approved under RED-2, and HyCertificates would be needed (H2Platform, 2018). A typical price for HBE would be about 8 [$€\cdot GJ^{-1}$] (Leguijt et al., 2018). This would be a further markup of 0.96 [$€\cdot kg^{-1}$] on green hydrogen, thereby increasing the parity price and improving the margin.

Finally, even though from an economic perspective some hydrogen markets show particularly low parity prices (e.g. LNG), standards could still make these markets tip towards hydrogen. An example would be a fixed percentage of synthetic fuel being added to kerosene. In that particular case, the premium is simply paid and the margin between the conventional fuel type and the synthetic substitute becomes obsolete. The market would be simply created, which should be taken into account when evaluating the relative attractiveness of different hydrogen markets as well as the difference between the parity price and the actual price. This is currently under consideration (Ministerie van Economische Zaken en Klimaat, 2020).

4.2 Techno-economic cost

The absolute parity prices that are needed in the identified hydrogen markets except for the synthetic feedstocks, are given in Figure 20 for an ETS price of 25 [€·t^{-1}] and Figure 21 for an ETS price of 80 [€·t^{-1}]. The $LCOH$ should be at least below the parity price to enable green hydrogen application in each specific market (indicated by the red horizontal lines for the two import prices). A lower parity price indicates that this market is less likely to tip towards green hydrogen. Using hydrogen for high temperature heat is therefore one of the last hydrogen markets that will be targeted. On the other hand, a higher parity price means that this hydrogen market is more likely to tip. For instance, the mobility parity price is 5.4 [€·kg^{-1}], which is based on the average parity price of diesel and gasoline (without the HBE included to be prudent).

Hydrogen in power plants is denoted as NG PP, which not only includes the natural gas price but also the ETS price and assumes a 100% hydrogen content. Furthermore, steel relining, steel brownfield, SMR hydrogen and high temperature heat (denoted as high heat) include the ETS price. Every parity price considers both $OPEX$ as well as $CAPEX$ except for: LNG, NG grid, NG PP, mobility and mobility HBE.

The techno-economic cost of synthetic feedstocks in comparison to current market prices is depicted in Figure 22 for a hydrogen import price of 1.97 [€·kg^{-1}] and a CO_2 price of 50 [€·t^{-1}] (which is again different from the ETS price since capture costs are incurred). It should be noted that this price is the CO_2 price paid for as an input to the synthesis process. Similarly, the techno-economic cost of synthetic feedstocks with a 1.47 [€·kg^{-1}] and a CO_2 price of 50 [€·t^{-1}] is depicted in Figure 23. In either case, all the current market prices are higher than the techno-economic cost of each synthetic feedstock at the previously indicated $LCOH$.

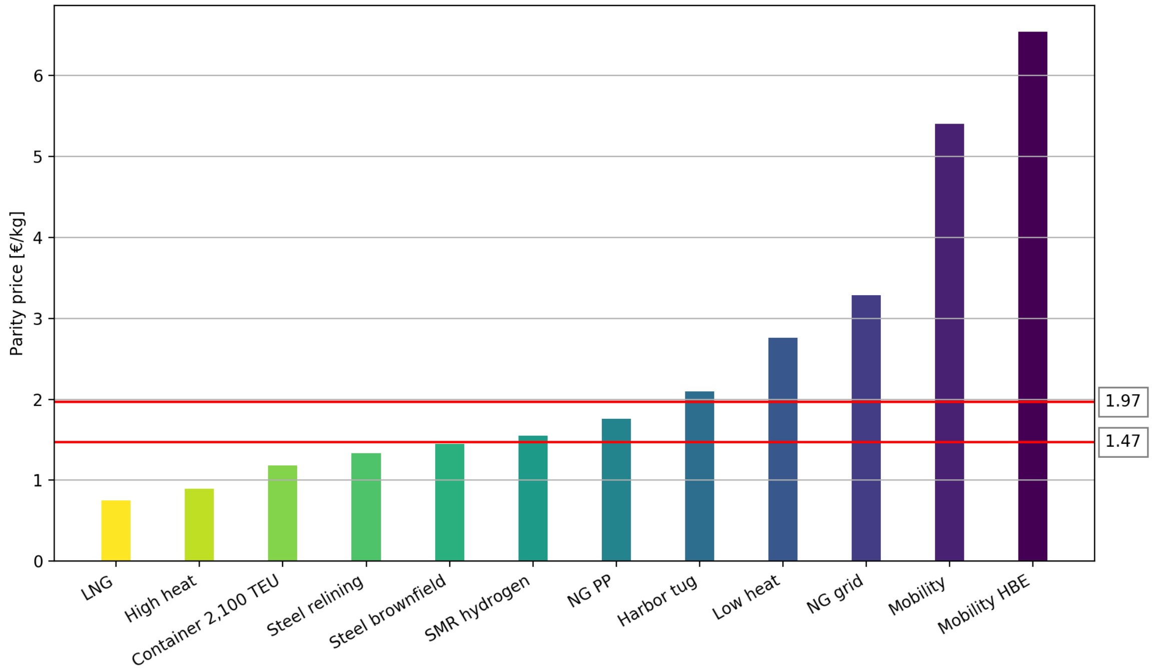

Figure 20: Absolute parity prices hydrogen in different markets at an ETS price of 25 [€·t^{-1}] and a HBE price of 8 [€·GJ^{-1}].

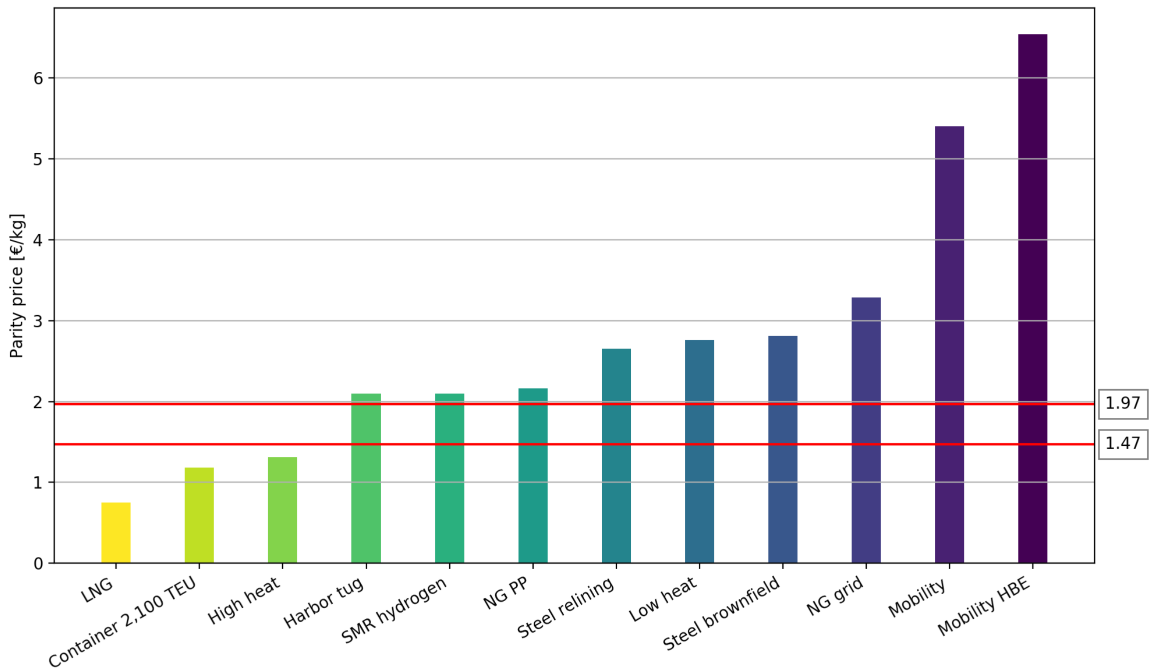

Figure 21: Absolute parity prices hydrogen in different markets at an ETS price of 80 [€·t^{-1}] and a HBE price of 8 [€·GJ^{-1}].

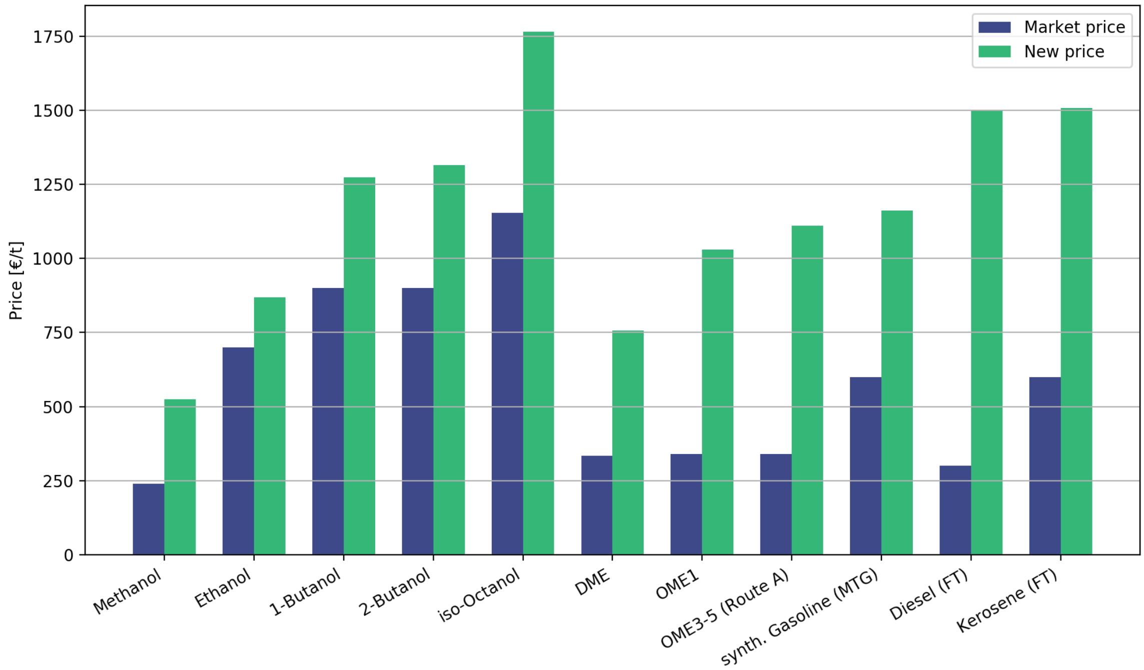

Figure 22: Cost of synthetic fuels with a hydrogen price of 1.97 [€$\cdot$kg^{-1}] and a CO_2 price of 50 [€$\cdot$t^{-1}] in comparison to market prices.

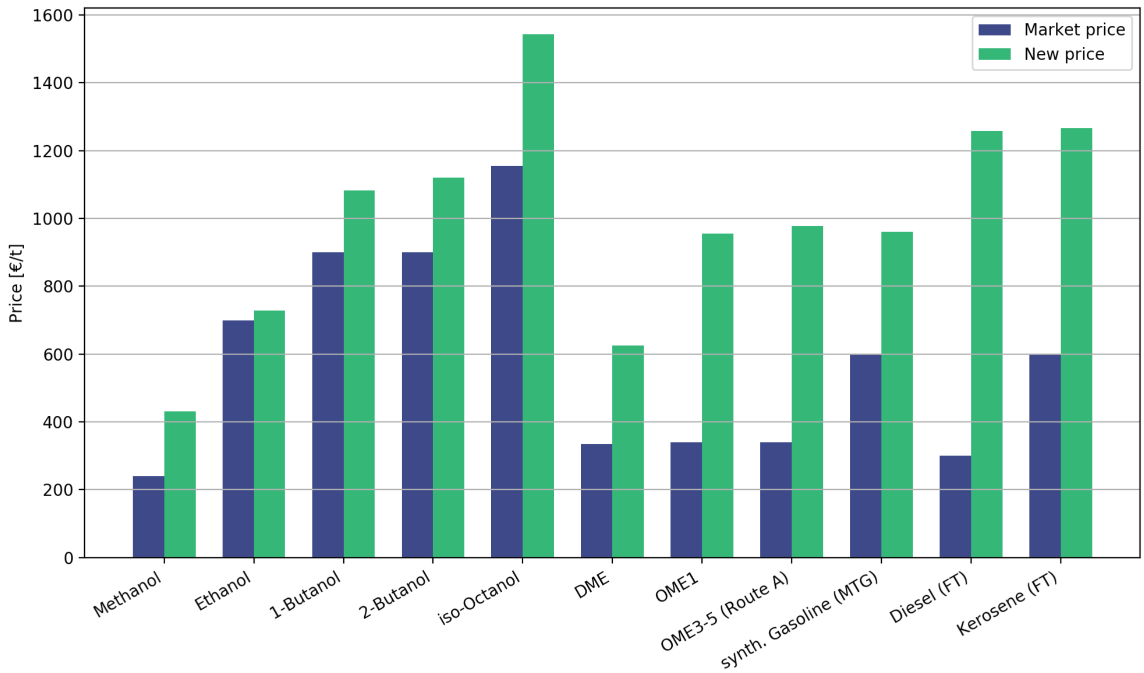

Figure 23: Cost of synthetic fuels with a hydrogen price of 1.47 [€$\cdot$kg^{-1}] and a CO_2 price of 50 [€$\cdot$t^{-1}] in comparison to market prices.

4.3 Willingness-to-pay

The third factor that influences the economic feasibility of hydrogen markets in the hinterland of the PoR is the WTP. In Figure 24, the difference between the market price and the green hydrogen import price used in each market is depicted. It considers the current costs of green hydrogen production in Oman including shipping to Rotterdam, at a price of 1.97 [€$\cdot$kg^{-1}], an ETS price of 25 [€$\cdot$t^{-1}] and a CO_2 price of 50 [€$\cdot$t^{-1}] (higher due to capture costs) for the synthetic fuels. It shows the relative price difference and hence the margin needed to introduce hydrogen to these markets.

A negative margin indicates a hydrogen market that is already attractive for green hydrogen import from Sohar. A positive margin shows that this hydrogen market either needs a premium (hence an increase in the WTP for final consumers), a subsidy, or a further reduction in other cost contributing factors at the market prices that were chosen in this research. Alternatively, a combination of these factors could together overcome the relative price difference between the parity price and the imported green hydrogen from Sohar.

Similarly, in Figure 25 the price difference between the parity price of each hydrogen market and the price of imported green hydrogen given a 50% cost decrease in electrolyzer $CAPEX$ and pv module $CAPEX$ (hence a hydrogen import price of 1.47 [€$\cdot$kg^{-1}]), an ETS price of 80 [€$\cdot$t^{-1}] and a CO_2 price of 50 [€$\cdot$t^{-1}] (higher due to capture costs) for the synthetic fuels. In that case, the difference between the parity price for a specifc hydrogen market and the current market price becomes smaller. Yet, the least attractive hydrogen market is synthetic diesel production, where synthetic diesel is 300% more expensive than the conventional alternative.

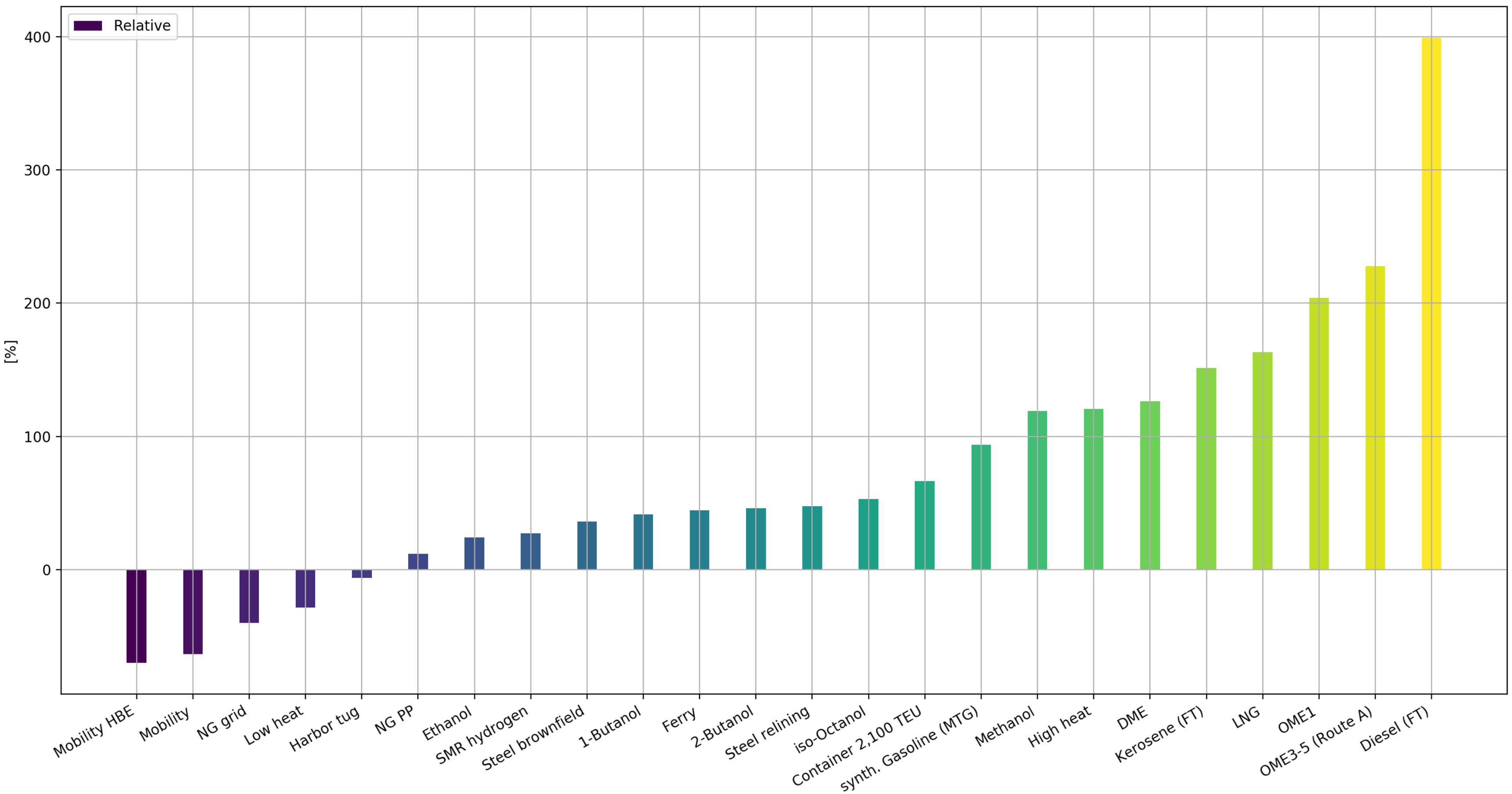

Figure 24: Relative decrease in price needed to become competitive in each specific market at a hydrogen price of of 1.97 [€·kg^{-1}] and an ETS price of 25 [€·t^{-1}]. The negative percentages indicate that these markets are attractive at the input hydrogen price. The positive percentages indicate the markets that are not competitive at the input hydrogen price.

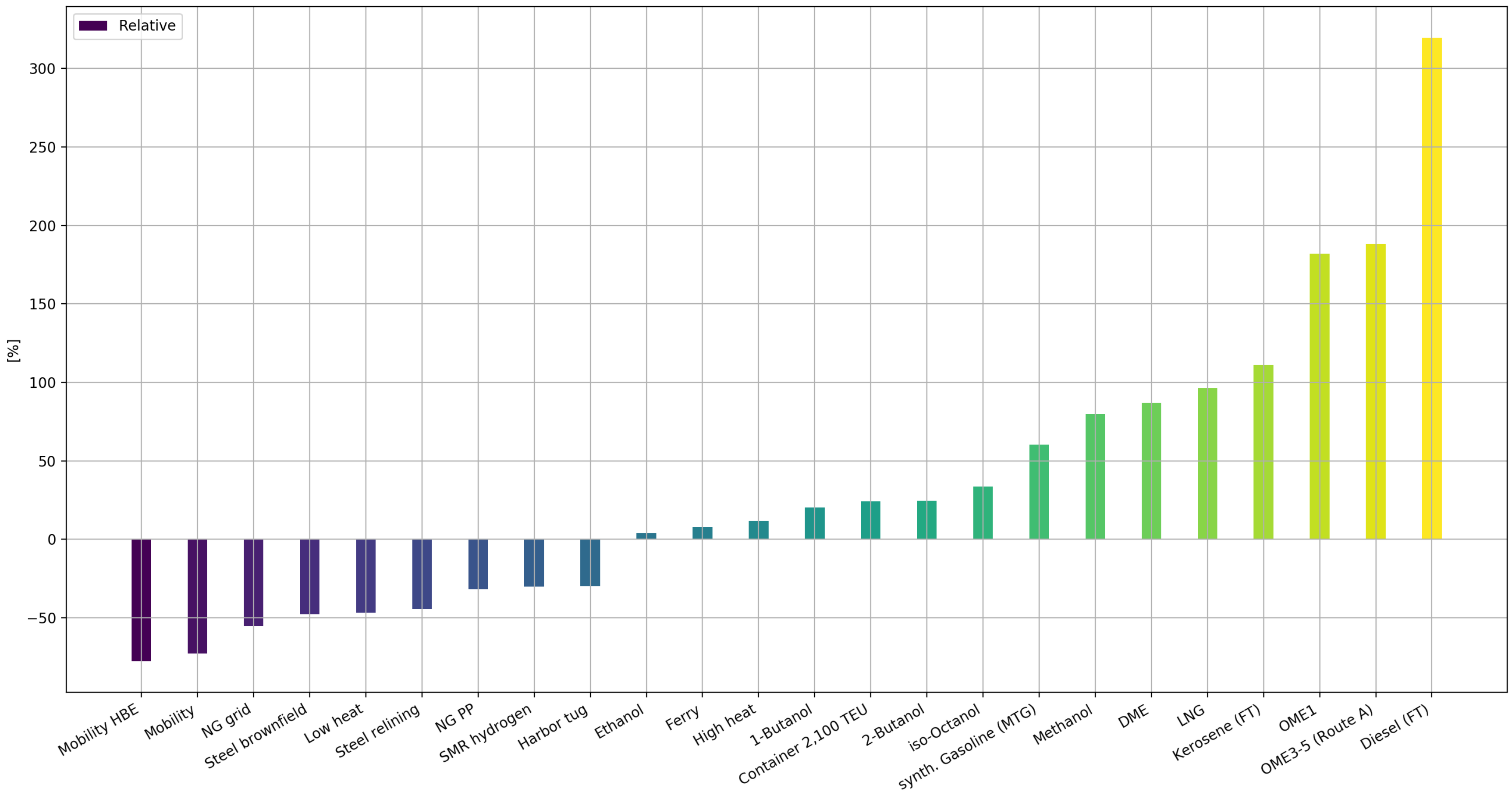

Figure 25: Relative decrease in price needed to become competitive in each specific market at a hydrogen price of 1.47 [€·kg^{-1}] and an ETS price of 80 [€·t^{-1}]. The negative percentages indicate that these markets are attractive at the input hydrogen price. The positive percentages indicate the markets that are not competitive at the input hydrogen price.

4.4 Marginal abatement cost curve

Every hydrogen market considered in this study is also evaluated from a marginal abatement cost perspective. Each market is analyzed using dedicated sub-methodologies. In Figure 26 the result is depicted of the marginal abatement costs when the hydrogen import price is 1.97 [$€\cdot kg^{-1}$] and the ETS price is 25 [$€\cdot t^{-1}$]. It shows a similar result as the relative cost curve in Figure 24. However, in this case the hydrogen markets are compared on the marginal abatement cost of each hydrogen market. Light green indicates the markets that are affected by an ETS price. Hence, the marginal abatement cost is the additional gain (when negative) or cost (when positive) per ton of CO_2.

Accordingly, In Figure 27 the marginal abatement costs are determined for each hydrogen market with a green hydrogen import price of 1.47 [$€\cdot kg^{-1}$] and an ETS price of 80 [$€\cdot t^{-1}$]. Again, the light green markets are markets that include the ETS price. When comparing Figures 26 and 27, it becomes clear that more hydrogen markets become attractive with a negative marginal abatement cost at the lower $LCOH$ and higher ETS price. In addition, also the relative attractiveness of hydrogen markets changes.

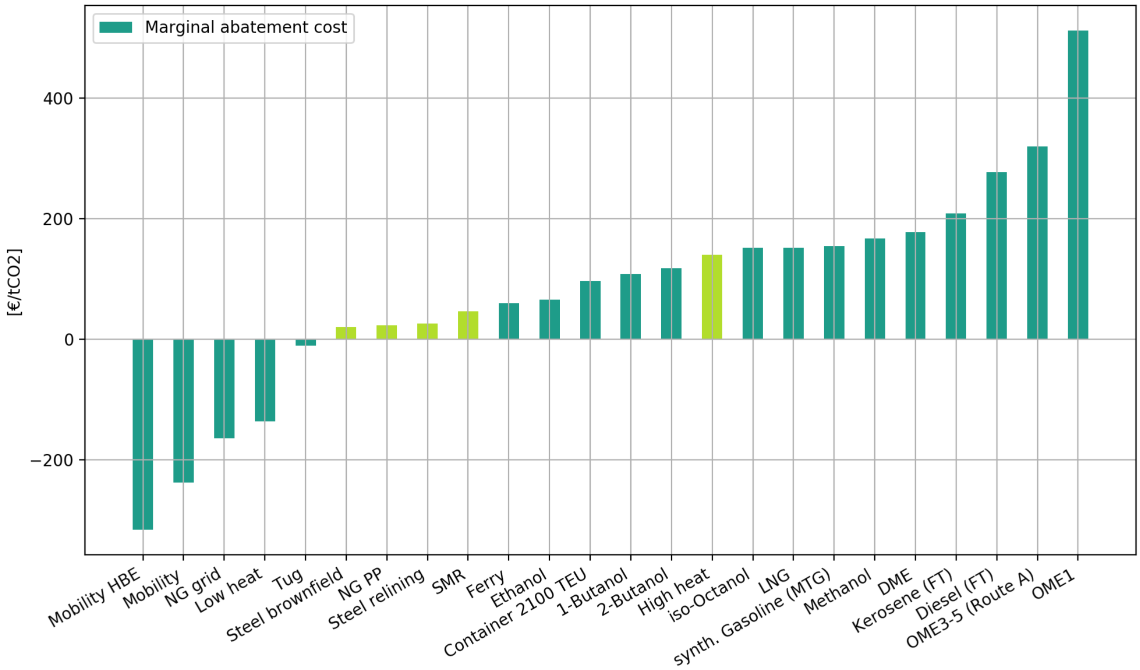

Figure 26: Marginal abatement cost curve for an import hydrogen price of 1.97 [€·kg^{-1}] and an ETS price of 25 [€·t^{-1}]. The light green hydrogen markets have an ETS price included.

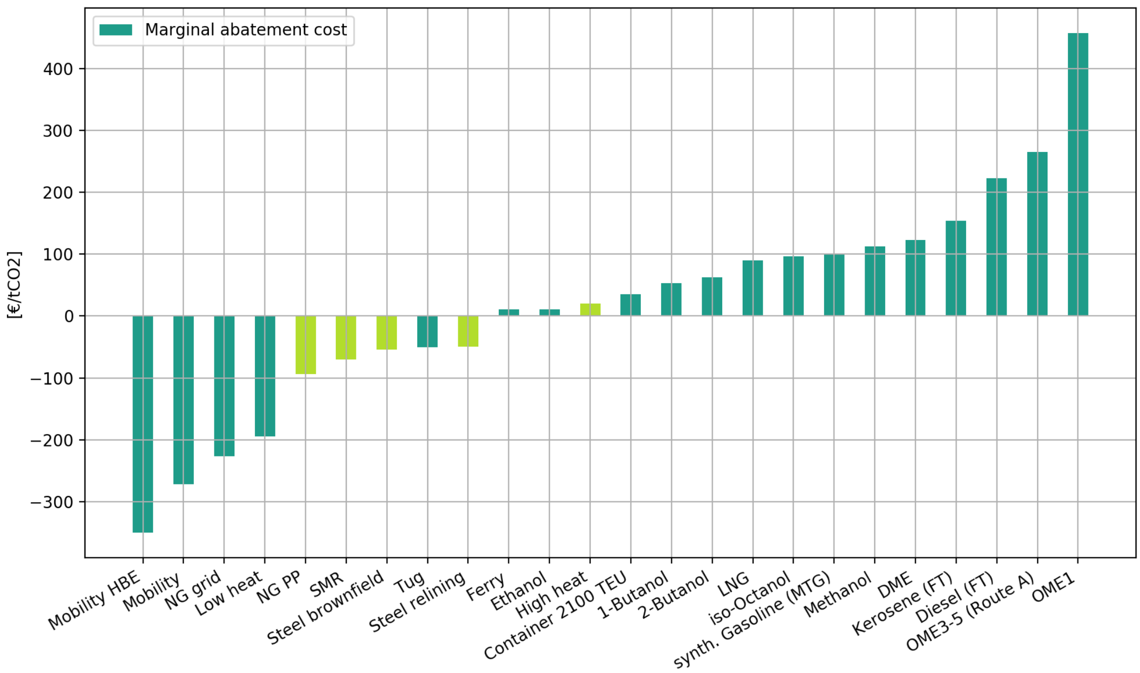

Figure 27: Marginal abatement cost curve for an import hydrogen price of 1.47 [€·kg^{-1}] and an ETS price of 80 [€·t^{-1}]. The light green hydrogen markets have an ETS price included.

5 Discussion

The aim of this second part of the two-part research has been to identify which hydrogen markets in the hinterland of the PoR are techno-economically feasible and what the associated carbon emission reductions would be. Even though this question might seem straightforward for the carbon emission reduction green hydrogen import from Oman could achieve in various hydrogen markets, there are various factors such as regimes, technological development and policies that affect whether hydrogen import from the Port of Sohar becomes economically feasible. In this Chapter these complexities, limitations and other considerations are evaluated.

First and foremost, it should be noted that this research has been an exploration of where the added value of imported green hydrogen is the highest. In order to do so, various assumptions have to be made. Perhaps most importantly the framework by Geels proposed various regimes to take into account that influence the success of a new technology to enter the existing socio-technical system. This study has taken a limited approach that only includes existing policy measures, the techno-economic costs as well as the margin that is left to be either covered by a further premium or a required subsidy. Furthermore, additional costs are incurred due to infrastructure required to receive, transport and distribute hydrogen towards each hydrogen market, which have been neglected.

From a methodological perspective, it should be noted that the underlying techno-economic studies are all grounded on different assumptions. For example, the $WACC$ rates vary in the following way. The interest considered in the study by Vogl et al. is 5%, whereas Weeda uses a 6% rate, Schemme employs an interest rate of 8%., Mulder of 5%, the Argonne National Laboratory 10% (Vogl et al., 2018; Weeda & Niessink, 2020; Mulder et al., 2019; Schemme et al., 2020; Papadias et al., 2019). It is illustrative of the variability in assumptions. However, in this research it was opted for to stick with the original WACC used in each study. Not to mention the fact that most research actually still uses the lower heating value of hydrogen. As a result, hydrogen is put at a disadvantage in some hydrogen markets. Even in fuel cell applications some studies still use this lower heating value, while it would chemically make sense to use the higher heating value (Papadias et al., 2019).

The reason is that it is methodologically impossible to redo all the specific research parts. Even though it is a disadvantage, it would have been too extensive to change these assumptions to improve consistency. On the other hand, this research contributes to literature by having overview of how these different hydrogen markets compare as well as highlighting that these fundamentally different assumptions have a pronounced effect on the outcome of the research.

Notwithstanding, it clearly is a drawback for the sake of comparability of hydrogen markets considered. Likewise, only five hydrogen markets considered in this study actually include an ETS price: brownfield steel, relining steel, SMR, NG PP and high heat. The other hydrogen markets are either not covered by ETS, or ETS is intrinsically part of the market price (e.g. synthetic fuels). In the latter case, a higher ETS price will also have an impact on the market prices of conventional fuels. Prices for conventional fuels would become higher, which increases the parity price and hence will benefit synthetic fuel production. It is however not included in this study.

Besides, the comparison of different hydrogen markets in Figures 24 and 25 is heterogeneous. Some hydrogen markets considered $OPEX$ only whereas other hydrogen markets also include $CAPEX$ costs. It does however give an idea about the relative attractiveness of these markets under current economic and policy conditions. The same Figures also show that the influence of the price difference (spread) between the green hydrogen alternative and the conventional market amplify the relative difference in price shown in these Figures.

It is important to point out that the economic feasibility of various hydrogen markets is relative. The imported green hydrogen has a certain price and is likely to be employed at the highest possible margin. Consequently, the hydrogen market with the highest parity price will be targeted. In this research mobility clearly is the most attractive from a margin perspective. Notwithstanding, the assumed hydrogen consumption was rather low (0.54 [$\mathrm{kg} \cdot 100\mathrm{km}^{-1}$] and further infrastructural costs might be incurred). It is probable that there exist even higher margin niches for which green hydrogen import could be employed. These are however almost per definition relatively small. Nevertheless, these niche markets could play an enabling role in entering and targeting higher volume markets.

Accordingly, in part one of this two-part study, the green hydrogen that would be received in the PoR would be in liquid state. Obviously, the theoretical value of liquid hydrogen is much higher than gaseous hydrogen. Nevertheless, this study only considered the plain price of hydrogen per unit mass leaving these potential benefits out. The reason is again to be as prudent as possible, since choosing an alternative mode of hydrogen transport (e.g. ammonia as a hydrogen carrier instead of liquid hydrogen shipping) would have the drawback of again adding heat to dehydrogenate the hydrogen carrier.

A comparison between the hydrogen parity prices of NG grid and NG PP in Figures 20 and 21 shows that the benefit of employing green hydrogen in power plants by not incurring ETS costs is diminished by a lower natural gas price for industry. This effect should be visible at low and high temperature heat as well. Furthermore, considering actual carbon emission reductions, the carbon emission reduction with for example a 5% volume blend in natural gas (assumed to be 100% methane), is particularly small. For a combined cycle gas power plant it would be about 4.9 [$\mathrm{g} \cdot \mathrm{kWh}^{-1}$] for point of use emissions.

In addition, for all the synthetic fuel routes considered in this study, only a change in the hydrogen price has been considered at the required amount of hydrogen per unit fuel (the two import prices from part one of this two-part research). At first a similar approach was chosen for these synthetic fuels as well that was applied to the other hydrogen markets (evaluating hydrogen parity prices). Keeping other assumptions the same would actually require a negative hydrogen price in some cases and was therefore not opted for.

The decision on where to put the point of comparison is a difficult decision. Two extremes are imaginable. The first extreme is comparing hydrogen import to hydrogen production in the Netherlands only by means of SMR or electrolyzers. The former approach would nullify the aim of this study, since in that particular case neither a carbon gain is achieved when SMR would be employed (most likely even an increase in carbon emissions). Neither does it allow for a better understanding of how hydrogen markets generally compare. The second extreme would be to compare the price of a final product (e.g. a car) of using green hydrogen as an energy carrier versus the conventional method in that particular industry.

The latter case is neither desirable, as it would require a gigantic amount of data to identify the markup (alternatively an additional margin) on the final product. As an example for the steel industry, it would require data on each and every product that is supplied with steel production in the hinterland of the PoR and evaluating what the difference would be with the conventional alternative. Arguably, that would be desirable neither. It also raises the question of whether it is a reasonable comparison after all, to compare with a carbon intensive alternative. Instead, another carbon extensive alternative could be a better counterpart.

To illustrate how the price of hydrogen would affect the price of a final product, the following example is provided. Given the fact that on average 900 [kg] of steel is needed per vehicle, the premium could be calculated when the price difference is known between H-DR steel and conventional BOF steel (Worldsteel, 2018). When the imported green hydrogen price would be 1.47 [$€\cdot kg^{-1}$] and all other assumptions by Vogl. et al are constant, the price of H-DR liquid steel would be about 401 [$€\cdot tLs^{-1}$] using Equations 29 and 30. The base price of BOF steel is 318 [$€\cdot tLs^{-1}$] (Vogl et al., 2018). Subsequently, the premium could be calculated by multiplying the price difference between BOF and H-DR steel by the 0.9 [t] used in an average vehicle. This is found to be 75 Euro per average vehicle. It is illustrative since the price relative price difference for the steel producer is bigger than the price difference for the consumer. As a consequence, the higher willingness to pay for a more sustainable product is likely to be at the final consumer side.

The marginal abatement cost curves (Figures 26 and 27) show very similar relative attractiveness of hydrogen markets as the relative price curves (Figures 24 and 25). This result could be expected, since the numerator is the difference between a green hydrogen based product and the conventional product in either case. The denominator on the other hand is different. For the marginal abatement curves the denominator is the conventional carbon emission. On the other hand, the denominator for the relative curves is the very conventional product price itself. As a result, the deviation is profound for the marginal abatement cost curve. Moreover, in either case the influence of the ETS price is pronounced: an increased ETS price from 25 to 80 Euro makes four markets tip towards becoming economically attractive (while abating emissions). However, in the latter case also the hydrogen import price drops thereby amplifying this effect. It also raises the interest in a profound required increase in the ETS price if some hydrogen markets that are not covered by ETS would be covered by ETS to reach parity in some markets, even at a low green hydrogen import price.

In this study the point of use carbon emissions were considered (except for SMR). It is argumentative, since the specific carbon emissions of the trade link between Sohar and Rotterdam are not yet researched. Besides, under the CertifHy system these $CAPEX$ emissions are proposed not to be included nor the emissions due to shipping (Abad & Dodds, 2020). Therefore, also the TTW emission factors are used for conventional fuels in the comparison. Nevertheless, a more comprehensive comparison would be to actually consider the life-cycle emissions of each hydrogen market. At the same time, it raises the question of whether comparing with fossil alternatives should be done in the first place, given the ambitions for carbon emission reduction laid out in the Klimaatakkoord (Rijksoverheid, 2019).

Arguably, considering the effect of the ETS price on the relative techno-economic attractiveness of hydrogen markets, the societal need for a carbon border tax becomes clear. Hydrogen markets that do not require to comply with schemes such as the scheme by CertifHy, but are only covered by the ETS system, do not benefit from imported hydrogen being green. It could equally be grey hydrogen for these markets. The same applies to fossil fuel products.

For all synthetic fuels, it is probable that producing these fuels locally (in Oman in this case) is favourable. Not only from an economic perspective but also from a carbon emission reduction perspective, since hydrogen would not need to be liquefied saving substantial amounts of energy. Nevertheless, it will be a balance between synergies with existing refinery and chemical industry capacity and the advantage of having the opportunity of relocating due to the greenfield nature of these synthetic fuel production facilities.

Finally, several managerial considerations and implications could be identified. Even though it might be clear that importing vast quantities of green hydrogen is attractive from an carbon emission abatement perspective in all cases, and from an economic perspective in some cases, the key question is how these volumes develop. The latter question is especially important for the PoR, since there are substantial economies of scale within reach if a bigger system would be deployed in Sohar. Setting up such a hydrogen trade link therefore has a certain threshold to become attractive. At the demand side of the PoR, there should therefore be enough green hydrogen demand at once. Given the relatively high natural gas price for households, this volume might very well exist for NG grid, a hydrogen market that already is economically attractive at an import price of 1.97 [$€\cdot kg^{-1}$] (assuming hydrogen distribution cost to not differ significantly from natural gas distribution costs).

6 Conclusion and recommendations

In this research various hydrogen markets were studied ranging from direct application of hydrogen to substitute natural gas, to whole industries that would diverge to hydrogen as an energy carrier to make their processes less CO_2 intensive. A methodology was proposed to identify how these hydrogen markets compare. This evaluation is based on: regulatory pressure, techno-economic potential, willingness-to-pay of final consumers (margin) and marginal carbon abatement costs. Each hydrogen market has been introduced to two different hydrogen prices that were the result of part one of this two-part analysis. The first price scenario is a hydrogen price of 1.97 [$€\cdot kg^{-1}$] under current techno-economic conditions and an ETS price of 25 [$€\cdot t^{-1}$]. The second price scenario is a hydrogen price of 1.47 [$€\cdot kg^{-1}$] based on a 50% $CAPEX$ decline from current price levels in both solar pv module costs as well as electrolyzer costs, and an ETS price of 80 [$€\cdot t^{-1}$].

First, various current and future hydrogen markets were identified. These markets ranged from substituting SMR hydrogen production to very specific synthetic fuel routes. From a regulatory perspective, these markets markets face very different supportive policies that affect where green hydrogen markets will open first. ETS is the most clear policy and directly influences the parity prices. How other policies would help green hydrogen import is yet unclear (e.g. HBE or mandatory hydrogen blending).

Second, from an economic perspective and for a green hydrogen import price of 1.97 [$€\cdot kg^{-1}$] and an ETS price of 25 [$€\cdot t^{-1}$], the following hydrogen markets seem economically feasible: mobility HBE, mobility, NG grid, low heat and harbor tug. With a green hydrogen import price of 1.47 [$€\cdot kg^{-1}$] and an ETS price of 80 [$€\cdot t^{-1}$], the following hydrogen markets seem economically feasible: mobility HBE, mobility, NG grid, steel brownfield, low heat, steel relining, NG PP, SMR hydrogen and harbor tug.

Third, the point of use carbon emission reduction in all the different current and future hydrogen markets is substantial. At the same time, there are large differences in the carbon emission reduction for the different markets. The marginal abatement cost curve is similar to the relative price curves. The marginal carbon abatement cost ranges from minus 320 [$€\cdot t^{-1}$] to 510 [$€\cdot t^{-1}$] at a hydrogen import price of 1.97 [$€\cdot kg^{-1}$] and an ETS price of 25 [$€\cdot t^{-1}$]. On the other hand, the marginal abatement cost ranges from minus 350 [$€\cdot t^{-1}$] to 460 [$€\cdot t^{-1}$] at a hydrogen import price of 1.47 [$€\cdot kg^{-1}$] and an ETS price of 80 [$€\cdot t^{-1}$]. Yet, these differences in marginal emission abatement costs should be put in their techno-economic context.

Although the prices and carbon emission reductions calculated in this research are very specific, simplifications were indispensable to achieve this overview. It is very specific to each hydrogen market to what extent the relative price difference influences the difference in consumer prices. However, it does provide for an indication of what premium would be needed to reach parity in various hydrogen markets. Moreover, the techno-economic details of these markets are valuable context. The PoR should realize that setting up a green hydrogen import trade link with Sohar requires a long term dedication for two reasons. First, there is no global trade in hydrogen yet, therefore commitment is needed. Second, because a dedicated solar based green hydrogen production chain has a long lifetime. The PoR is recommended to first identify whether there is enough interest in the market to reach a certain minimum import volume that is needed to make green hydrogen import feasible and reach substantial economies of scale. Future research could focus on how other techno-economic parameters would develop and thereby influence the probability of hydrogen markets opening up. Besides, future research could evaluate the hydrogen volume that could develop at the given hydrogen import prices.

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Appendices

A Overview assumptions synthetic fuels

Table 7: Assumptions for synthetic fuel hydrogen markets.

	CAPEX [€/kW]	Hydrogen consumption [kgH2/kgProduct]	Market price [€/t]
Methanol	235	0.189	240
Ethanol	558	0.283	700
1-Butanol	673	0.384	900
2-Butanol	729	0.391	900
iso-Octanol	1137	0.446	1155
DME	298	0.263	334
OME1	578	0.15	339
OME3-5 (Route A)	794	0.268	339
synth. Gasoline (MTG)	312	0.403	600
Diesel (FT)	667	0.478	300
Kerosene (FT)	667	0.481	600