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The Potential of Low-Carbon Hydrogen in Norway

A Linear Programming Analysis of Hydrogen Supply Chains in the Norwegian Energy System Towards 2050

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Abstract

In this thesis, we conducted a linear programming analysis to assess the future potential for domestic production and consumption of low-carbon hydrogen in Norway. Our analysis is based on the Institute for Energy Technology's long-term energy system model "IFE-TIMES-Norway" (ITN), which is intended to describe the Norwegian energy system in its entirety. Our analysis in ITN has been performed according to the current-best estimates for the techno-economic parameters of hydrogen technologies. The primary focus of our data work with the ITN model has been to expand its range of production technologies by adding steam methane reformation with carbon capture and storage, colloquially known as "blue hydrogen". This allowed us to explore the potential of hydrogen in increased detail compared to prior analyses with ITN. In our analysis, we have analyzed production and consumption of low-carbon hydrogen, and how it flows through the energy system from a supply chain perspective. This has been analyzed through a variety of model runs intended to capture contrasting energy futures. The primary years of our analysis cover the interval 2030 to 2050.

The main findings suggest that there is significant potential for low-carbon hydrogen in the Norwegian energy system towards 2050 in industry, road transport, and maritime transport. Our results indicate that the highest potential for hydrogen is as a feedstock in the metal- and chemical industry, for heavy-duty vehicles in road transport, and in the form of ammonia in maritime transport. The competitiveness of hydrogen is however highly dependent on carbon pricing as a higher CO_2 tax is connected to increased volumes of hydrogen production and consumption. In addition, the availability of competing zero-emission alternatives is a significant factor for the potential of hydrogen. For current carbon pricing and its expected future increases, hydrogen is the cost-effective option for many end-use processes based on large- and/or small-scale production. However, carbon prices in excess of current and expected future values are associated with higher volumes and adoption across additional end-use processes. At large scales, steam methane reformation with carbon capture and storage is the dominant hydrogen production technology, but its position is challenged by Alkaline electrolysis if power prices are particularly low. At small scales, a combination of PEM electrolysis and alkaline electrolysis is generally preferred, but PEM is increasingly competitive across the model horizon. In addition, our results suggest that hydrogen may be distributed with trucks, but only for shorter distances within spot price regions.

Abbreviations

AEL	Alkaline Water Electrolysis
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
EU ETS	European Union Emissions Trading System
FCEV	Fuel Cell Electric Vehicle
GAMS	General Algebraic Modeling System
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hours
H_2	Hydrogen
H_2-CENT	Low-pressure hydrogen
H_2-COMP	Compressed hydrogen
H_2-TRA	High-pressure hydrogen for road transport
HRS	Hydrogen Refueling Stations
HV	High-voltage
ICE	Internal Combustion Engine
IFE	Instituttet for Energiteknikk (Institute for Energy Technology)
ITN	IFE-TIMES-Norway
KW	Kilowatt
KWh	Kilowatt hour
LNG	Liquefied Natural Gas
LP	Linear Programming
LV	Low-voltage
MDO	Marine Diesel Oil
MGO	Marine Gas Oil
MW	Megawatt
MWh	Megawatt hour
NH_3	Ammonia

NVE	Norges Vassdrags- og Energidirektorat (The Norwegian Water Resources and Energy Directorate)
OPEX	Operational Expenditure
PEM	Polymer Electrolyte Membrane (electrolysis)
RES	Reference Energy System
SMR	Steam Methane Reformation
TIMES	The Integrated MARKAL-EFOM System
TWh	Terawatt hour
VEDA	VErsatile Data Analyst
ZEV	Zero Emission Vehicle

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1 Introduction

Hydrogen is commonly expected to be a central commodity in the world's future energy system, and is thus the subject of substantial interest, investments, and research (Hydrogen council, 2021). The degree of support for hydrogen has even led to arguments for a future "hydrogen economy", in which the world's energy carrier use largely revolves around hydrogen (Pandev et al, 2017). In later years, pilot projects, plans, and pledges are quickly transforming into concrete investments and full-scale projects that represents promising prospects for the future of hydrogen (DNV GL, 2021).

Hydrogen has a wide range of uses, including power generation, heating, fuels, and industrial feedstock, but regardless of specific applications, the core debate revolves around its potential to contribute to the decarbonization of the energy system (DNV GL, 2019). According to the International Energy Agency (IEA, 2019), achieving net-zero greenhouse gas (GHG) emissions is contingent on the deployment of clean energy, of which hydrogen may play a vital role as a clean, secure, and affordable energy carrier. For hydrogen to contribute to decarbonization however, low- or zero-carbon production technologies will be required, for instance, water electrolysis and steam methane reformation with carbon capture and storage. In addition, clean hydrogen will have to constitute a much larger share of the world's total energy consumption. Today however, 95% of hydrogen is produced from natural gas and coal in an unabated manner and requires only about 4% of global energy use (IRENA, 2019). Estimates of hydrogen's share of total future energy consumption vary, for instance between 6% according to IRENA (2019), and 18% according to The Hydrogen Council (2017) in 2050. The expectation is either way that hydrogen will constitute a significant share of total energy supply and demand.

In parallel with international discussions, the potential for hydrogen in the Norwegian energy system is debated in policy circles, by technical experts, and by energy companies attempting to identify decarbonization pathways or seeking to leverage the country's potential and competitive advantages in renewable energy and natural gas resources. Despite wide support of hydrogen as a path to decarbonization, skepticism remains. Dissenters cite for instance, inferiority to alternatives such as batteries in cars (Plötz, 2022), and unsuitability for energy storage and power generation due to low energy efficiency (Baxter, 2020). Questions also remain as to how exactly the supply chains will be configured. This includes the composition of production technologies, the scale at which production will occur, and how the commodity will be transported and distributed. This thesis seeks to contribute to answering such questions and provide insight into the potential of hydrogen in the Norwegian energy system. Our primary research question is thus:

- *What is the potential of low-carbon hydrogen in the Norwegian energy system?*

Given the complexity of the energy system and its many interacting parts, the overarching research question can be decomposed into the following sub-questions:

- *Which factors dictate the prevalence of hydrogen in the Norwegian energy system?*
- *Which end-use processes are hydrogen likely to be competitive in?*
- *To what degree will future hydrogen supply rely on production from large-scale vs. small-scale facilities?*
- *What is the likely composition of hydrogen production technologies?*
- *Will hydrogen distribution by trucks be economically feasible?*

Our approach to studying these questions is by using the long-term energy system model IFE-TIMES-Norway (ITN). Our model is derived from the base IFE-TIMES-Norway model which has been developed to be applied for hydrogen analysis previously. Our main contribution to this model is the inclusion of blue hydrogen production from steam methane reformation with carbon capture and storage. By applying the best-current estimates for the techno-economic parameters dictating the production and consumption of low-carbon hydrogen, we attempt to evaluate the relative competitiveness of production technologies, assess potential supply chains, and explore the factors that may dictate the prevalence of hydrogen in the Norwegian energy system towards 2050. We believe that current estimates of techno-economic parameters associated with hydrogen production and consumption will lead to significant investments and production volumes. However, our hypothesis is that the prevalence of hydrogen is sensitive to uncertainties in the cost parameters associated with production inputs, and particularly to the level of carbon pricing in the energy system. We will explore these underlying assumptions and hypotheses through contrasting scenarios, and sensitivity analysis.

1.1 Background and motivation

Given the high interest in hydrogen and its expected potential in the energy system, public entities in Norway are generating considerable literature on hydrogen in effort to inform stakeholders such as private companies, the public, and energy policy governance. The Norwegian Water Resources and Energy Directorate (NVE) is one such entity who took the initiative for this thesis and is a co-developer and user of the TIMES model framework in Norway. The Institute for Energy Technology (IFE), the other co-developer of TIMES in Norway, was later added as a collaborator due to their technical expertise on-, and prior experiences with hydrogen modeling in TIMES. This thesis project was thus incorporated in formal frameworks for cooperation between the two organizations and represented an opportunity to contribute to the literature and knowledge of both organizations. The particular focus of our research was a result of IFE's expressed need to expand the scope of their version of the model to include additional production technologies. Thus, we added steam methane reformation with carbon capture and storage ("blue hydrogen") and performed analysis to explore the potential of hydrogen for a wider range of technologies.

1.2 Literature review

There is substantial research on the global potential of low-carbon hydrogen and its possible supply chains in the future. However, most literature focus on hydrogen in an international context. From a Norwegian perspective, the DNV GL synthesis report from 2019 on "Production and consumption of hydrogen in Norway" is perhaps the most comprehensive study in recent years. In the DNV GL (2019) report, the role of hydrogen as a zero-emission energy carrier in the Norwegian energy system is evaluated from a value chain perspective towards 2030. The report concludes that the most feasible hydrogen production technologies in Norway are steam methane reformation and water electrolysis. In addition, it estimates that the bulk of hydrogen demand will come from the industry sector, and road- and maritime transport. In addition, it concludes that climate policy is an important driver of future hydrogen demand in Norway. In contrast to the DNV GL report, however, we analyze the potential of hydrogen in the Norwegian energy system for a longer time horizon, and with the methodological approach of linear programming in an energy system model.

When it comes to literature with a similar methodological approach for long-term analysis of hydrogen in Norway, there is only a handful of publications available. Although NVE and IFE both use the TIMES model, IFE has been the main contributor to Norwegian energy system analyses with hydrogen in terms of published works. In a SINTEF report by Dammen et. al (2020), and a related article by Espegren et al. (2021) in the International Journal of Hydrogen Energy, the IFE-TIMES-Norway model was used to analyze the role that hydrogen production may play in Norway's green energy transition towards 2050. The findings of both papers indicate that hydrogen will play a key role in Norway and may even be a pre-requisite for Norway to achieve its decarbonization goals. However, both these studies can be categorized as sustainable transition studies, as the modeling results are driven by scenarios for reaching climate goals and the phase-out of oil production. In contrast, we do not consider such decarbonization pathways explicitly in our thesis. Instead, we assess the potential of hydrogen based on expected developments in the Norwegian energy system, although with some climate policy variations in our scenarios.

Furthermore, the ITN model has also been used to study hydrogen in other publications from IFE, such as the report from Danebergs et al. (2022a) on the "Impact of zero emission heavy-duty transport on the energy system". In addition, version 2 of the IFE-TIMES-Norway documentation (Danebergs et al., 2022b) provide some example results of hydrogen modelling in ITN based on the ITEM project (Integrated Transport and Energy Models). Although these example results are not exhaustive or particularly detailed, they provide additional indications for the potential of hydrogen in the Norwegian energy system. In these results, road transport is a significant avenue for hydrogen consumption, depending on the specific scenario applied. The scenarios, defined by different trajectories of CO_2 tax, indicate that carbon pricing is a significant driver of the hydrogen production and consumption. The more detailed results from (Danebergs et al, 2022a) provide the same indications that higher carbon pricing is strongly correlated with a higher prevalence of hydrogen. While these results are focused on road transport and particularly trucks, Danebergs et al. (2022a) suggest that hydrogen in significant volumes is likely to occur faster in other end-use sectors as hydrogen is in significant competition with battery electric powertrains in road transport. Based on the results from these publications, we expect the patterns of hydrogen adoption and sensitivity to carbon pricing to be applicable for additional end-use sectors. This final point is also mentioned in Danebergs et al. (2022a) where analysis of how hydrogen technologies may be adopted in additional sectors is discussed for further work.

1.3 Scope of the thesis

This thesis applies data related to hydrogen supply chains to the IFE-TIMES-Norway model (ITN) in effort to assess the potential of low-carbon hydrogen in the future Norwegian energy system. As a linear programming model, ITN is well suited for optimization of investments in technologies by rational economic agents but does not for instance consider behavioral factors.

While there are many aspects of hydrogen supply chains that warrants further research, this thesis is limited by the mathematical nature of the model, meaning for instance that the non-linear nature of real-world economic activity is not considered. In addition, as ITN is a large model of the entire Norwegian energy system, our narrow research focus resulted in the omittance of several interesting aspects that would warrant a closer look in a different context, for instance how hydrogen production may affect the utilization of primary energy sources. This and similar results, are however available with the methodology and approach used in this thesis.

The priority of our work has been to increase the scope and level of detail for hydrogen production in the model. We have included blue hydrogen production and conducted a range of model runs to capture differing assumptions about the trajectory and future state of the energy system and explore their implications for the role of hydrogen. Our range of model runs were based on scenarios with differing future energy- and carbon prices. In addition, we performed sensitivity analysis for carbon prices as this is assumed to be a particularly important factor for hydrogen prevalence in the Norwegian energy system.

We consider three technologies for hydrogen production: SMR with CCS, Alkaline water electrolysis (AEL), and polymer electrolyte membrane (PEM) electrolysis. Three end-use sectors are considered with exogenously provided demand: industry, road transport and maritime transport. Our model covers complete supply chains from production to end-use consumption including conversion, storage, and distribution of compressed hydrogen, but does not consider a complete range of all available or promising technologies. The resolution and level of detail in our model is limited by the current content of the ITN model, by data availability, and by time. As a result, there are several simplifications and notably excluded technologies. For instance, while electrolysis technologies are expected to be connected directly to renewable energy in many instances, only grid-connected electrolysis is considered in this thesis. Only hydrogen gas is included, while liquefaction or other means of conversion are omitted. The only means of transporting the commodity is by tube-trailers, while pipelines and ships are not modeled. In addition, hydrogen is not considered for power sector applications. Only investments in new equipment are considered, and not lifetime extensions or retrofitting of existing equipment. For instance, CCS cannot be added to existing SMR plants. Several technical solutions that may potentially be a part of future low-carbon hydrogen supply chains in Norway are therefore not considered. While import- and export considerations may dictate the logic of hydrogen supply to a large degree in the future, only domestic production and consumption is considered in this thesis.

1.4 Thesis overview

In Chapter 2, we discuss hydrogen supply chains including different methods of production, and potential applications in end-use sectors. In Chapter 3, we describe the IFE-TIMES-Norway model and our approach to analysis. Chapter 4 provides a complete overview of hydrogen related data used for the analysis. In Chapter 5, our scenarios and sensitivity analysis are presented. In Chapter 6, the results are discussed in an assessment of investments in hydrogen production and consumption, and the potential supply chains it may partake in in the future. In Chapter 7, we discuss limitations and suggest future work, before we finally draw conclusions on our research in Chapter 8.

2 Hydrogen

In this chapter we provide an overview of the hydrogen supply chains we consider in this thesis along with their practical, operational, and economic considerations. First, we will discuss key characteristics of hydrogen in the energy system. Next, we discuss each component of the supply chains including production, compression, storage, distribution, and end-use consumption. Finally, we discuss all these components in the context of hydrogen supply chains applied to the Norwegian energy system.

2.1 Hydrogen in the energy system

While hydrogen is the most abundant element in the universe, it is a very reactive element which means it is very rarely found in pure form in nature. Any process to produce hydrogen must therefore be a way of separating it from its chemical bonds with other elements. Notable compounds with hydrogen bonds include water (H_2O) and methane (CH_4). When hydrogen is combusted, energy is released along with water as the only biproduct. Hydrogen therefore represents a promising emission-free alternative for a range of purposes, such as a fuel for transportation and a feedstock in industrial processes. Note that hydrogen is an energy carrier, not an energy source. This distinction is important. An energy carrier can take on various forms and be converted from one form to another. Energy source, however, refers to the original resource the production of an energy carrier is based on.

As with any other energy carrier, an important consideration for its applications is the question of how consumers will procure it. Central questions include the choice of production technology, where it will be consumed relative to where it is produced, and how it is transferred between these two endpoints. The logic of these considerations is captured through assessing supply chains. There are many available configurations for hydrogen supply chains, but overall, they consist of a certain range of processes, which can be summarized as (DNV GL, 2019):

Input → production → conversion → storage → transportation → storage → consumption

This generalized supply chain can be applied to a varying degree, for instance depending on whether storage is a necessary intermediate step, or if the hydrogen can be delivered directly to consumption processes. How the supply chain is configured is in principle an economical and practical problem of how to deliver hydrogen to consumers in an appropriate form at a lowest possible cost. The costs of the end-use hydrogen depend on the scale and technology of its production, production input prices, and any subsequent supply chain steps that are applied. Different configurations results in different efficiencies, energy requirements, and costs. According to findings from IEA (2015) and ICCT (2018), the most significant factors driving hydrogen cost is the supply chain elements of production input (e.g., electricity and natural gas), storage, and transportation.

Any additional processing step of hydrogen, such as conversion or storage, is associated with decreasing its energy efficiency, which means that more energy is required per unit of hydrogen consumption. In addition, each additional processing step is associated with added time, equipment costs, infrastructure, logistics, and loss of hydrogen. Regarding the latter point, hydrogen will leak from any container it is held in with rates of up to 0.5-1% loss per 24 hours (Valland, 2020). In many instances, deciding which supply chain steps to apply is a question of weighing the benefits of an additional process step against its added costs. For example, an end-use process that can rely on hydrogen at varying compression levels must weigh the benefits of higher compression against its added costs. In other instances, additional processing is a practical requirement that cannot be bypassed, for instance conversion processes for storage and distribution.

Each end-use process is also associated with its own set of equipment and practical requirements that dictate the feasibility of hydrogen. In addition, the characteristics of the commodities a process otherwise relies on is a significant factor. The importance of these characteristics varies for different end-use processes, but a common denominator is that energy density is a defining metric for the choice among alternate energy carriers.

Energy density refers to the amount of energy that can be stored in a given system, substance, or region of space. It can thus be decomposed to *volumetric* and *gravimetric* energy density. The volumetric energy density refers to the amount of energy the carrier provides relative to the space it requires, for instance in terms of megajoules per liter (MJ/L). Gravimetric density on the other hand refers to the amount of energy the carrier provides as according to its mass, for instance in terms of megajoules per kilogram (MJ/kg) (Adolf et al., 2017; DNV GL, 2019). See Figure 2.1 for the energy density of different energy carriers according to both measures. Higher energy density according to these two measures means higher efficiency for end-use processes as less of the relevant energy carrier is needed, and each unit of energy requires less volume and weight. The energy density of hydrogen is further discussed throughout this chapter. Section 2.3 discusses how volumetric energy density can be increased through compression, and the requirements for energy density in different end-use processes are discussed throughout the remainder of Chapter 2.

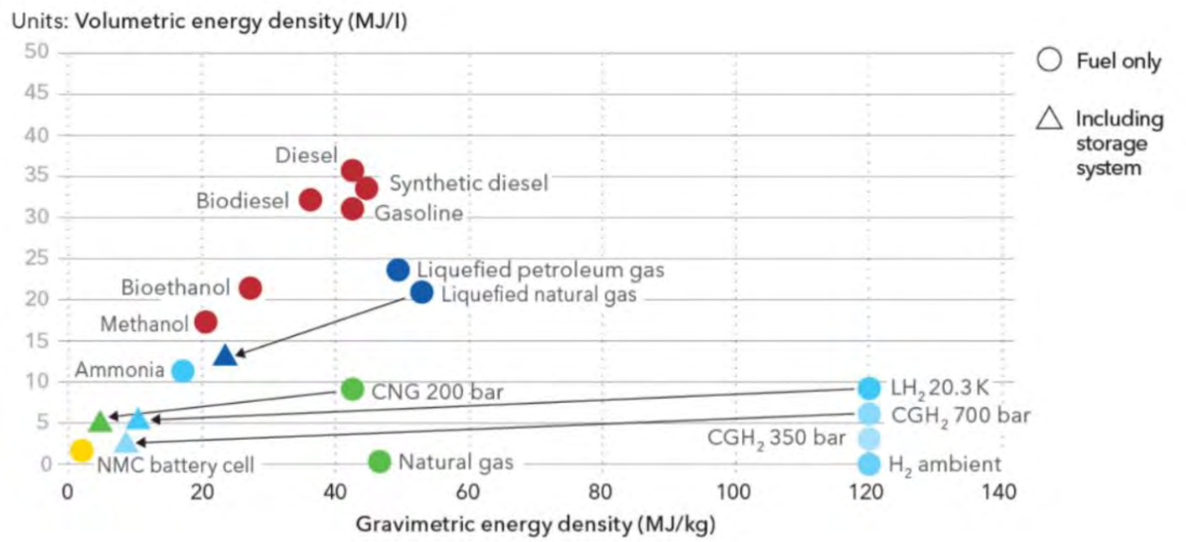

Figure 2.1: *Volumetric and gravimetric energy density for different energy carriers. From figure 4 in Valland (2020).*

Notice the energy density of hydrogen in light blue color in Figure 2.1. Compared to other energy carriers such as diesel, gasoline, and natural gas, hydrogen has high gravimetric- but low volumetric energy density. When considering the weight of the storage system, the gravimetric energy density decreases significantly. We will discuss gravimetric energy density in relation to system weight in Section 2.4.2.

2.2 Hydrogen production

Currently, 95% of global hydrogen is produced from coal and gas in an unabated manner (IRENA, 2019), but low- or zero carbon production technologies are required for hydrogen to contribute to decarbonization. The Norwegian government's hydrogen strategy points out that the production costs of these technologies must be reduced for low-carbon hydrogen to become a competitive energy carrier (OED & KLD, 2020). The most common and mature techniques for low-carbon production are alkaline water electrolysis (AEL) and polymer electrolyte membrane electrolysis (PEM). In addition, fossil fuel-based production with carbon capture and storage (CCS) is expected to contribute to low-carbon production in the future. Among the fossil-based production technologies, steam methane reformation of natural gas is the most mature technology today (IEA, 2019) and is expected to be an important avenue for application of CCS-technologies (IEA, 2021a). Colloquially, water electrolysis is generally referred to as “green hydrogen” if it is based on renewable energy, while SMR with CCS is referred to as “blue hydrogen”. The use of colors seeks to distinguish low-carbon production technologies from conventional production technologies. For instance, unabated production from natural gas is commonly referred to as “gray hydrogen”. An informal nomenclature with additional colors is applied for additional production technologies according to the specific technique and energy source required for its operation. For the purposes of this thesis however, only SMR with CCS, and AEL- and PEM electrolysis is considered.

2.2.1 Steam methane reformation with carbon capture and storage

Unabated reforming of natural gas is the most widespread method for producing hydrogen and constitutes approximately 68% of global hydrogen production today (DNV GL, 2019). Three reforming methods are in current use: steam reformation, partial oxidation, and autothermal reforming. Steam methane reformation (SMR) is however the most common method. SMR is also likely to remain the dominant technology for large-scale hydrogen production in the near future due to favorable economies of scale and the large number of existing SMR plants in operation currently (IEA, 2019). While the scale of SMR plants vary, it is most likely to be deployed in capacities over 100 MW H_2 and most cost estimates are based on plant sizes around 300 MW H_2 (BEIS, 2021). The large capacity requirements of SMR plants makes it particularly suitable for production in areas with large demand such as industrial clusters (DNV GL, 2019). SMR works by separating hydrogen (H_2) from its chemical bonds in methane (CH_4) that makes up a significant fraction of natural gas. The byproduct of the process is carbon dioxide which is emitted unless it is captured and utilized or stored.

Carbon capture and storage (CCS) refers to a range of different technologies that can be applied to capture CO_2 from various production processes, or even directly from the air, and subsequently transport it to and store it at relevant storage facilities. Storage is typically done by injecting the captured CO_2 into deep geological formations, for instance depleted oil and gas reservoirs (IEA, 2021a). There are various ways in which CO_2 can be captured from an SMR plant, and the capture rate will depend on system design and where in the process the CO_2 is captured. At maximum deployment, a modern carbon capture system can lead to an overall emission reduction of 90% or higher (IEA, 2021a). In general, higher CO_2 capture rates are associated with higher costs. The ultimate design of the capture system will depend on the production costs and specific end-use of the hydrogen.

SMR with CCS is of particular interest in the Norwegian energy system as using the country's significant natural gas reserves for hydrogen production can contribute to GHG-emission reductions domestic and abroad (DNV GL, 2019). In addition, the Norwegian continental shelf has significant capacity for CO_2 storage. In other discussions, the economic incentives associated with the continued use of natural gas is emphasized (Hovland, 2021). According to the energy company Equinor, SMR with CCS can be the key to retaining Norwegian natural gas as a valuable resource in a low-carbon future (Equinor, n.d.a). However, blue hydrogen also faces opposition from opponents who doubt its suitability to contribute to decarbonization. According to a recent study from Cornell and Stanford universities (Howarth & Jacobson, 2021), blue hydrogen causes more emissions than coal due to the vast quantities of natural gas required. Other opponents, including a former chair of the UK Hydrogen and Fuel Cell Association referred to blue hydrogen as an "expensive distraction" (Ambrose, 2021). Regardless of opinions on benefits and drawbacks associated with blue hydrogen, further research is necessary to identify its potential and limitations.

According to IEA (IEA, 2021c) which runs a database for global hydrogen projects, three SMR with CCS projects are currently in development in Norway. The feasibility studies "HyDEMO", "Barents blue ammonia", and the concept study, "Aukra CCS". The two feasibility studies are expected to have operational production plants in 2025. In addition, there are projects that develop supply chains for transportation and storage of CO_2 with no direct connection to SMR-based hydrogen production. The most notable of these is the "Longship" project which is expected to be the world's first full-scale supply chain for the transportation and storage of CO_2 (Northern Lights, n.d.). Northern Lights, an incorporated partnership between Equinor, Shell, and TotalEnergies, is responsible for developing and operating the CO_2 transport and storage infrastructure. They aim to offer their services to third parties such as blue hydrogen producers, both domestically and internationally. The feasibility of H_2 production from SMR with CCS in Norway will to a large degree depend upon the availability and such of such services. Currently, the infrastructure network of Northern Lights is expected to be operational and open to third parties from 2024 (Northern Lights, 2021; Equinor, n.d.b). In the longer term it is likely that additional domestic, and international supply chains are developed, which may establish a competitive market for the transportation and storage of CO_2.

In addition to serving as full-scale proof of concepts, these blue hydrogen and CCS projects contribute with additional information to improve estimates regarding the costs of such operations. The production cost of SMR with CCS depends on a range of technical and economic factors, but the two most significant are natural gas input prices, and capital expenditures (CAPEX) (IEA, 2019). Adding CCS to SMR production leads on average to cost increases of 50% for CAPEX, and a 100% increase for operational expenditures (OPEX) due to CO_2 transport and storage costs, according to IEA (2019). Depending on natural gas prices, the current production cost of hydrogen produced with SMR with CCS is in the range of 1-2 USD per kilogram globally (IEA, 2021a)

2.2.2 Water electrolysis

Electrolysis is a manufacturing technique where electricity is run between two electrodes to drive a chemical reaction that otherwise would not occur. Water electrolysis technologies operate according to different specific methods but have in common that they produce hydrogen (H_2) by separating it from its chemical bond to oxygen (O) in water (H_2O) using electricity as the only input. The only byproduct is oxygen, and the process is thus a means of producing emission-free hydrogen depending on the source of its electricity input. If the electricity is from renewable sources, it is referred to as “green hydrogen”. DNV GL (2019) assumes however that distributed production plants in Norway will primarily rely on electricity from the grid as opposed to renewable energy plants. According to IEA’s database of hydrogen projects, 27 electrolysis projects are currently in progress in Norway, covering the range from feasibility studies to full-scale operation (IEA, 2021c).

Two methods dominate within water electrolysis currently: alkaline water electrolysis (AEL) and polymer electrolyte membrane electrolysis (PEM) (DNV GL, 2019). Additional promising electrolysis techniques are in development including Solid Oxide Fuel Cell (SOFC), but this technology and other emerging alternatives are still at the experimental stage (DNV GL, 2019). Electrolysis systems are compact, modular, and can be used in capacities from a few kilowatts up to the megawatt range. They are therefore well suited for distributed production directly connected to hydrogen refueling stations (HRS) which avoids the need for transportation and large storage facilities (DNV GL, 2019). To date, electrolyzer capacities for hydrogen production have generally been deployed at capacities under 10 MW electricity (el), but several higher capacity projects are in development. The current largest electrolyzer plant in operation is a 25 MW el facility in Peru (IEA, 2021a). Electrolysis deployment have been limited thus far as the total worldwide capacity is only 290 MW el. Of this total capacity, 92% is AEL and PEM electrolysis with a 61% and 31% share respectively (IEA, 2021a).

The chemistry behind electrolysis is fundamentally the same regardless of the specific technique used. However, there are practical and operational considerations that distinguish the two technologies from each other. AEL is a well-established technology up to the megawatt range that has been used for more than 100 years (DNV GL, 2019). PEM however was developed in 1966, to overcome the disadvantages of AEL (Kumar & Himabindu, 2019). While PEM is also a mature technology, its cost reduction potential is assumed to be higher than that of AEL (DNV GL, 2019; IEA, 2019). The main advantage of AEL is that it is the simplest method and has significantly lower investments- and operating costs than PEM, and a slightly higher energy efficiency (DNV GL, 2019). PEM however has many advantages over AEL such as a more compact system design and a higher pressure for the hydrogen output (Kumar & Himabindu, 2019). A more compact system design makes PEM more feasible in dense urban areas and off-grid applications, and a higher output pressure means that less energy is required for the conversion processes following production (IEA, 2019). The most significant advantage of PEM, however, is its fast response time in adjusting load factor, and a wide operating range of 0-100% (Cockerill, n.d.). AEL on the other hand requires a minimum part load of 10-40% of max operation depending on the specific equipment (Brauns & Turek, 2022). In addition, the start-up time of AEL facilities can be up in in the range of hours, while PEM facilities have a response time down to five minutes (Ruth et al., 2019). The start-up and shut-down cycles of AEL facilities are also associated with a higher degree of equipment degradation than PEM. AEL facilities are therefore generally designed to operate at more constant loads. The higher flexibility of PEM electrolysis makes it more suitable to use with renewable energy and makes it easier to utilize electricity price fluctuations for lower production costs.

Regarding the costs of these technologies, electrolysis production is generally considered to be costly but can potentially benefit from increased mass manufacturing of equipment in the future (IEA, 2019). The production costs of hydrogen from water electrolysis depend on several technical and economic factors, but CAPEX, efficiency, annual operating time, and electricity costs are considered the most important (IEA, 2019). According to DNV GL (2019), electricity costs is the single most significant factor. With decreasing operating time however, the investment costs dominate as they are divided by a lower volume of hydrogen output (IRENA, 2020). CAPEX for PEM-based plants is higher, particularly due to a reliance on expensive materials including elements such as platinum and iridium (IEA, 2021a). On the other hand, OPEX is lower for PEM as its operation rely on fewer components and materials

(IRENA, 2020). Current estimates place the cost per kilogram of hydrogen produced with electrolysis based on renewable energy at 2-3 times the cost of SMR (IEA, 2021a).

2.3 Compression, storage, and distribution

The delivery of hydrogen from its point of production to its final end-use destination will require some sort of storage and/or transportation given that the hydrogen is not used instantly after its production. However, in comparison to other energy carriers, the low volumetric energy density of hydrogen makes it relatively difficult to store and transport. Thus, to enable effective storage and transportation, the produced hydrogen gas must first be converted into a state of higher volumetric energy density. This is most commonly achieved through compression or liquefaction. In addition, it is possible to convert hydrogen into a material-based state through chemical and physical sorption. The material-based conversion involves transforming the gas into a hydrogen-based energy carrier, of which ammonia is considered to be among the most viable options (IEA, 2019).

Today, compressed gaseous hydrogen is the most established and commercially viable method for storage and transportation of hydrogen (Adolf et al., 2017; Abe et al., 2019; IEA, 2019). Storage and transportation of liquid hydrogen and ammonia have limited end-use applications, and often require additional re-conversion processes that are both costly and energy consuming. However, they may have the potential to be cost-effective options for large-scale storage and long-distance distribution of hydrogen in the future (DNV GL, 2019; IEA, 2019). As the scope of our thesis is limited to compression, storage, and transportation of gaseous hydrogen, this will be discussed in further detail in Sections 2.3.1 through 2.3.3.

2.3.1 Compression

After hydrogen is produced, it is typically subject to low levels of pressure. For instance, hydrogen from AEL electrolyzers normally has a pressure under 30 bar, while PEM electrolyzers can achieve a pressure between 30 to 60 bar (IEA, 2019). Then, the gas needs to be compressed, which involves subjecting the hydrogen gas to higher levels of pressure, subsequently increasing its volumetric energy density. The level of pressure will vary depending on its final end-use application. For use in road transport, for example, the gas is typically compressed to 350 or 700 bar as this has become the current standard for hydrogen used in fuel cell electric vehicles. Despite significant compression, the hydrogen still has a low energy density, for instance compared to gasoline. The volumetric energy density of hydrogen at 700 bar compression is approximately 75% lower than for gasoline. In addition, the compression process entails higher production costs. For instance, compression to 700 bar requires additional energy usage equivalent to approximately 8% of its original energy content (DNV GL, 2019).

2.3.2 Storage

When storing hydrogen as a compressed gas, the most appropriate storage technology depends on several factors, such as costs, the volumes to be stored, required pressure levels, the duration of storage, and the geographic availability of different storage options (IEA, 2019). For intermediate storage, the most common storage option is to store the gas in metallic tanks or cylinders that can hold relatively high pressures, upwards of 1 000 bar. In a technical review of storage and delivery technologies, Moradi & Growth (2019) categorize four types of pressure vessels that can be used for storing hydrogen gas. Among these types, the most conventional and cheapest type is fully metallic pressure vessels. These are ordinarily made from aluminum or steel and can withstand pressures up to 500 bar. The price of pressure vessels is still relatively high and increases with higher pressure requirements (Moradi & Growth, 2019).

Another option is to store the compressed hydrogen gas in salt caverns, depleted natural gas and oil reservoirs, or aquifers. This is commonly referred to as underground or geological storage (IEA, 2019). This type of storage involves transporting the gas underground through pipes, where natural barriers can entrap large amounts of hydrogen over long time periods. Among the geological storage options, salt caverns are the most suitable for storing hydrogen. The feasibility and costs related to depleted gas/oil reservoirs and aquifers, however, are highly uncertain (Adolf et al, 2017; Moradi & Growth, 2019; IEA, 2019). Salt caverns have been used for many years to store natural gas, but there are only a handful of hydrogen storage caverns in operation today.

Underground storage has the advantage of significant economies of scale, along with low operational costs, improved safety, and high efficiencies. On the other hand, geographical availability is a natural limitation for the construction of geological storage sites. According to IEA (2019), underground storage is likely to be the best option for large-scale and long-term hydrogen storage, making the method especially attractive for power sector applications, such as system balancing. However, other end-use applications, such as storage at hydrogen refueling stations, will only require storage in the range of hours. For storage at smaller-scales and shorter time periods, pressure vessels are the most feasible and promising storage option (IEA, 2019).

2.3.3 Distribution

Transportation of compressed gaseous hydrogen is commonly done using trucks or pipelines (Adolf et al., 2017; Moradi & Growth, 2019; IEA, 2021a). Today, most hydrogen distribution is done by transportation of compressed gaseous hydrogen in trucks for quite low volumes at distances less than 300 km (IEA, 2019). However, distribution of hydrogen by trucks is a relatively high-cost option, which becomes increasingly expensive for longer distances. For larger volumes and longer distances (over 1000 km), pipelines become an increasingly competitive alternative to trucks (DNV GL, 2019; IEA, 2019).

The trailer trucks used to transport hydrogen are often referred to as tube trailers, as the hydrogen is distributed in several tubes (storage tanks/cylinders) that are bundled together and loaded onto the trailers. Theoretically, the largest tube trailers can hold a tank volume of up to 1 100 kg of compressed H_2 at a pressure level of 500 bar (Adolf et al., 2017; IEA, 2019). However, such tank volumes are rarely achieved in practice, as vehicle regulations typically limit the allowable height, width, pressure, and weight of the tubes that can be transported on trailers (IEA, 2019). Thus, it is more common to use tube trailers that hold pressure levels of approximately 250 bar. At 250 bar, a single tube trailer can transport roughly 500 kg of compressed gaseous hydrogen, according to Adolf et al. (2017). Although these volumes are relatively low, there are several advantages with tube trailer transportation, including low infrastructure requirements and flexibility in delivery location. In addition, transportation by tube trailers is associated with minimal hydrogen loss (Moradi & Growth, 2019).

An alternative to tube trailers is to transport the compressed hydrogen gas via pipelines. This can either be achieved by building a network of new pipelines that are dedicated to hydrogen transportation, or by repurposing existing natural gas pipeline systems. However, there are some significant challenges associated with the latter option, especially considering technical and regulatory barriers for blending hydrogen in gas networks (IEA, 2019; Norwegian petroleum, 2021). On the other hand, the DNV GL (2019) report points to the possibility of building dedicated hydrogen pipelines along the coastlineH_2 volumes. However, hydrogen pipelines are capital-intensive projects with high upfront investment costs and significant economic risks (IEA, 2021a). Thus, the mentioned pipeline project may not be feasible without economic support from the Norwegian Government, as argued by DNV GL (2019).

2.4 Hydrogen applications

In this section, we will discuss the potential hydrogen applications in industry, road transport, and maritime transport. In the Norwegian government's hydrogen strategy (OED & KLD, 2020; Regjeringen, 2020), these three sectors are highlighted as having the highest potential for low-carbon hydrogen applications in Norway. We will discuss the current state of hydrogen in each sector, its expected developments, and the different factors that dictate hydrogen competitiveness in the different end-use processes.

2.4.1 Industry

According to IEA (2019), current hydrogen consumption in industry occurs primarily in three sectors: oil refining, chemicals, and metal (iron and steel). In the oil refining sector, hydrogen is mostly used to remove impurities from crude oil and upgrade heavier crude oil. This sector accounts for about 33% of global hydrogen use today. Within the chemical industry, hydrogen is primarily used in production of ammonia (27%) and methanol (11%). In addition, there is an emerging potential for hydrogen to act as a reduction agent in iron and steel production processes, currently accounting for 3% of global hydrogen use (IEA, 2019).

The industrial sector is also the primary contributor to hydrogen production in Norway today. According to DNV GL (2019), Norway currently has an annual hydrogen production of about 225 000 ton from industrial process. About 75% of this volume is produced and consumed in Equinor's methanol production at Tjeldbergodden and Yara's ammonia production at Herøya. The remainder of production mainly comes from the two oil refineries at Mongstad and Slagentangen. In the Norwegian metal industry however, use of hydrogen is not common today (DNV GL, 2019).

Currently, the hydrogen production and consumption within the Norwegian industry stems from the use of fossil fuels, leading to a large amount of CO_2 emissions (DNV GL, 2019). At both the methanol and ammonia facilities of Equinor and Yara, hydrogen is produced from unabated steam methane reforming of natural gas as an integrated part of the chemical production process. Thus, there is significant potential to decarbonize these processes with low-carbon hydrogen production methods. For this to be an economically viable option, central factors are the price of natural gas and CO_2-qoutas relative to the costs of low-carbon hydrogen (DNV GL, 2019; IEA, 2021a). In relation to the DNV GL report from 2019, Yara stated an interest in water electrolysis production, while Equinor expressed considerations for a feasibility study on blue hydrogen production. In 2021, Yara launched a project with governmental support to decarbonize its ammonia production by replacing its SMR-based hydrogen production with green hydrogen (Yara, 2021). Another such project is the Barents Blue project of Horisont Energi, which also received governmental funding to produce blue hydrogen for clean ammonia production in Finmark (Hovland et al., 2021; Horisont Energi, 2021).

For Norwegian oil refineries, the potential use of low-carbon hydrogen is limited. First of all, the demand for hydrogen in this sector is dependent on national oil production and global demand for fossil fuels such as gasoline and diesel. Although not an issue in the short-term, DNV GL (2019) points to the possibility of substantial reduction in oil production towards 2050. Secondly, neither of the two oil refineries in Norway use a hydrocracker to upgrade heavy oils, which is one of the main hydrogen-consuming processes in a refinery (DNV GL, 2019; IEA, 2019). Instead, both refineries are self-supplied on hydrogen, as this is a biproduct of their refining processes. Thus, they do not need dedicated hydrogen production facilities, nor do they need to purchase hydrogen. However, this could be a possibility in the future, given a well-functioning hydrogen market with secure supply. Nonetheless, this would require them to retrofit equipment and significantly change their production methods (DNV GL, 2019). As hydrogen production and consumption is so closely integrated with their operations, it is hard to make a strong business case for retrofitting.

Furthermore, there is potential for low-carbon hydrogen to decarbonize the Norwegian metal industry. The potential of using hydrogen as a reduction agent in Direct Reduced Iron (DRI) processes is becoming increasingly promising and widespread globally (IEA, 2021a). However, this is currently not an option for the Norwegian metal industry, as no steel is produced with iron ore in Norway today. On the other hand, it is possible for hydrogen to replace the use of coal in other pre-reduction processes (DNV GL, 2019). In particular, this relates to using hydrogen as a reduction agent in blast furnaces, which would require technological developments specific to individual production plants. According to IEA (2021a), such technologies are currently being trialed, and the most successful operations are still at demonstration scales (IEA, 2021a). So far, only one industrial facility in Norway, TiZir, has begun work to develop technology for using hydrogen as a reduction medium. In 2021, TiZir was granted funding to replace their current use of coal with hydrogen from water electrolysis in pre-reduction processes at their ilmenite upgrading facility in Tyssedal (Enova, 2021).

2.4.2 Road transport

In road transport, hydrogen is utilized for vehicles using fuel cell powertrains, referred to as fuel cell electric vehicles (FCEVs). The combination of zero-emission potential and high gravimetric energy density makes hydrogen an attractive fuel option for road transport purposes. However, of the entire current vehicle fleet in Norway, approximately 90% rely on various forms of fossil fuels as their main energy carrier (DNV GL, 2019). Only 145 fuel cell cars were registered in Norway as of 2020 (OFV, n.d.). The share of low- and zero emission vehicles is increasing, particularly in the cars segment where battery electric has seen significant growth in later years. Hydrogen adoption on the other hand, is currently very limited across all vehicle categories. In addition to battery electric- and hydrogen powertrains, plug-in-hybrids, and biofuels are considered as lower-emission alternatives to conventional internal combustion engines (ICE) relying on fossil fuels. (Danebergs et al, 2022a). For the time being, ICE powertrains have favorable energy density, economics, and reliability. In competition with ICE, fuel cell costs, hydrogen tank volumes, and hydrogen prices are limiting factors for FCEVs. The competitive landscape also depends on carbon taxes and vehicle fees among other policy factors (Danebergs et al., 2022a).

The competitiveness of hydrogen fuel cells is primarily evaluated in comparison to battery electric systems as these two powertrains are assumed to be the main competitors in low-carbon powertrains. Generally, most vehicle manufacturers assume that battery electric will be the competitive option for lighter vehicles with shorter driving distances, and that fuel cell electric will be competitive for heavier vehicles with longer daily distances or heavy cargo (Morrison et al., 2018). This assumption relies mainly on two factors: One, that larger batteries require longer charging times or very high power output, and two, that fuel cell systems are more feasible to scale up. Scaling up the powertrain is a necessity for heavier vehicles as more energy is required for their operation.

The difference in scalability warrants additional explanation, but in summary, scalability differences occur due to differences in the volumetric and gravimetric energy density of the total powertrain system. For road transport purposes, in which all equipment is designed to be in motion, the total weight of fuel, fuel tank, and powertrain is a significant factor that affects the feasibility of using different energy carriers. The implications of these factors are different according to which energy carrier is used, and generally, the total system weight has varying implications for different vehicle sizes. For battery electric systems, the weight of the battery scales approximately linearly with its capacity. This contrasts with hydrogen fuel cell systems where both cost and weight per unit of energy decreases with system size. Doubling the capacity of a battery doubles its weight, while doubling the capacity of a hydrogen fuel cell only increases the weight of the fuel tank and does so at a far lower rate than the weight of the additional fuel. Thus, the differences in gravimetric energy density of the entire system increasingly favors hydrogen compared to battery electric with increasing vehicle weight. In similarity with the considerations for system weight, increased battery capacity is closely correlated with increased volume of the entire system, while the increased volume for fuel cell systems is limited to the fuel tank only. While increased weight primarily affects the energy efficiency of the vehicle, increased powertrain volume is directly connected to less available space for cargo. Thus, volumetric energy densities also favor hydrogen for heavier vehicles. The considerations for energy density means that hydrogen fuel cells are more likely to be a cost-effective option for heavier vehicles such as buses and trucks. For smaller vehicles such as cars however, battery electric is currently preferred due to their high efficiency, acceptable range, and lower costs (DNV GL 2019).

In addition to energy density, the choice of low-emission technologies for vehicles relies on a range of other factors. DNV GL (2019) highlights the following: efficiency, emissions, costs, access to vehicles, infrastructure, logistics, refueling time, and temperature dependency. For FCEVs, access to vehicles, costs, and infrastructure have been particularly limiting factors (DNV GL, 2019). Currently, few FCEVs are commercially available across all vehicle types and their purchase costs are generally far higher than alternatives. Regarding infrastructure, FCEVs rely on hydrogen refueling stations. HRS may be deployed in a commercial capacity serving a single fleet of vehicles such as buses or trucks or can be accessible by the general public. At the time of writing, only three HRS are in operation in Norway, one in Trondheim and two outside of Oslo. The former serves four fuel cell trucks for the grocery wholesaler ASKO, while the latter two are available to the public. Several additional stations are however planned for both public availability and limited commercial use (H2 Stations, n.d.; NHF, n.d.). In addition, access to fuel vehicles is also improving. In later years, vehicle manufacturers are increasingly offering FCEV options, and several Norwegian companies have placed active orders (Danebergs et al, 2022a).

2.4.3 Maritime transport

Both internationally and domestically, there is increasing focus on measures that can contribute to reducing emissions from maritime transport. One of these measures is the introduction of alternate fuels such as hydrogen for maritime propulsion systems (DNV GL, 2019). The current stock of maritime vessels primarily consists of propulsion systems based on fossil fuels with marine gas oil (MGO) and marine diesel oil (MDO) as the primary contributors (Danebergs et al, 2022b). Electrification is however increasingly occurring, particularly for shorter distance vessels such as ferries (DNV GL, 2019). Hydrogen as a maritime fuel has been subject to many feasibility studies and pilot projects in later years. However, only one hydrogen powered vessel in Norway, a ferry, is close to full operation as it undergoes its final testing at Karmøy (Førde, 2021). This vessel is not only the first in Norway, but the first of its kind in the world. In addition to battery electric and hydrogen propulsion systems, other energy carriers are considered for decarbonization in maritime transport. Prior analysis by DNV has also considered biofuels and liquefied natural gas as lower emission alternatives to conventional fossil fuels (DNV GL, 2018).

The maritime sector is very heterogenous with a large variety in vessel types, sizes, and operational patterns. For instance, the distances of their routes, the time between bunkering, and their use of international infrastructure vary widely. The propulsion systems, and choice of energy carriers must therefore be adapted to the energy demands and operational patterns of individual ships (DNV GL, 2019). The potential for alternative fuels in maritime transport depends particularly on infrastructure on land, modifications of existing ships, accessibility, costs, and carbon footprint (DNV GL, 2019). Regarding infrastructure, hydrogen refueling stations is also a requirement for hydrogen deployment in this sector. Maritime HRS can be deployed at centralized locations with sufficient activity such as delivery terminal and ports. However, vessels in remote locations or with fixed routes such as ferries, are more likely to rely on proprietary refueling equipment connected to production plants with self-serving capacities. These vessels are particularly attractive candidates for hydrogen applications as they do not require extensive infrastructure investments (DNV GL, 2019).

The considerations for energy density in road transport are also applicable to maritime transport as the weight and volume of the propulsion system impacts the feasibility of different energy carriers. While electrification is increasingly occurring in this sector, battery electric solutions are currently insufficient to cover the requirements of the longer and more energy demanding distances (DNV GL, 2019). For such purposes, battery electric systems are considered too heavy and the charging times too long. Hydrogen is therefore an attractive alternative due to its fast refueling and lower system weight. The considerations for energy density dictate the general feasibility of hydrogen for maritime vessels, but also which variations of hydrogen they can rely on.

Compressed hydrogen is mostly relevant for vessels where energy storage requirements are relatively low. This is due to high- system weight and space requirements, and challenges with bunkering (Valland, 2020). Liquid hydrogen is more relevant for higher energy storage requirements, as discussed in Section 2.3, and may therefore be the preferred option for many vessels. For vessels with high energy requirement that typically sails for weeks without bunkering, ammonia (NH_3) is considered most relevant as it has the highest energy density of these fuels and lowest volume for storage systems (Valland, 2020). However, ammonia is toxic and has an unpleasant odor which limits its relevance for smaller passenger vessels such as domestic ferries. As ammonia is traded commercially and often transported by maritime vessels, there may be significant transfer of knowledge to its use as a fuel. For low-carbon fuel purposes, ammonia can partake in hydrogen supply chains as its production can be an extension of the hydrogen production process. Ammonia (NH_3) consists of hydrogen (H_2) and nitrogen (N), and one way of producing ammonia is by combining hydrogen produced from water electrolysis with nitrogen from the air (The Royal Society, 2020). When ammonia is used as a fuel, it is considered to be a hydrogen energy carrier (Valland, 2020).

2.5 Supply chains for the Norwegian energy system

In this thesis, we consider and distinguish between two generalized supply chains for hydrogen in the Norwegian energy system, namely the centralized and distributed supply chain. The two supply chains refer to differences in both production capacities and distributional considerations as according to the processes and technologies discussed in Section 2.1 through Section 2.4. This distinction between centralized and distributed supply chains are also discussed in DNV GL (2019). See Figures 2.2 and 2.3 for an overview of the centralized and distributed supply chains, respectively.

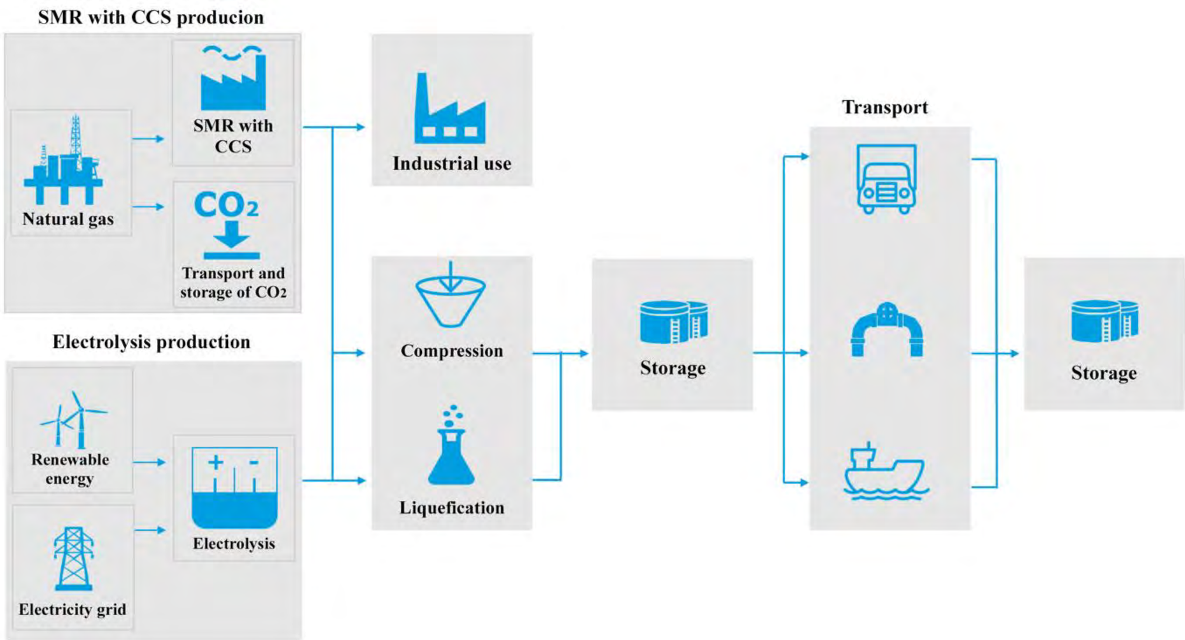

Figure 2.2: *Centralized supply chain for hydrogen. From figure 6-3 in DNV GL (2019), translated.*

The rationale behind a centralized supply chain considers the practical requirements of SMR with CCS production and the economies of scale associated with large-scale production of all three production technologies. The centralized production scale however limits the end-use potential of the produced hydrogen as additional processes are required to deliver hydrogen to consumers. In the centralized supply chain, hydrogen can be produced from SMR with CCS with natural gas input, or from electrolysis based on renewable energy or grid power. The resulting hydrogen can either be used directly in local industry or converted to compressed- or liquefied form for other uses. The hydrogen is subsequently stored and transported with tube-trailers, pipelines, or ships to its end destination where it is stored before consumption. At the centralized production scale, DNV GL (2019) assumes that SMR with CCS will be the cheaper option compared to electrolysis, at least for the next ten years.

The distributed production scale on the other hand is based on the logic of producing hydrogen closer to where it is consumed, for instance at refueling stations for road transport. This reduces storage requirements and eliminates the need for distribution. However, it also excludes the economies of scale associated with centralized production. In the distributed supply chain, only electrolysis production is available as SMR with CCS is considered unfeasible at this scale (DNV GL, 2019). After the hydrogen is produced, it is compressed and subsequently stored before consumption in road transport.

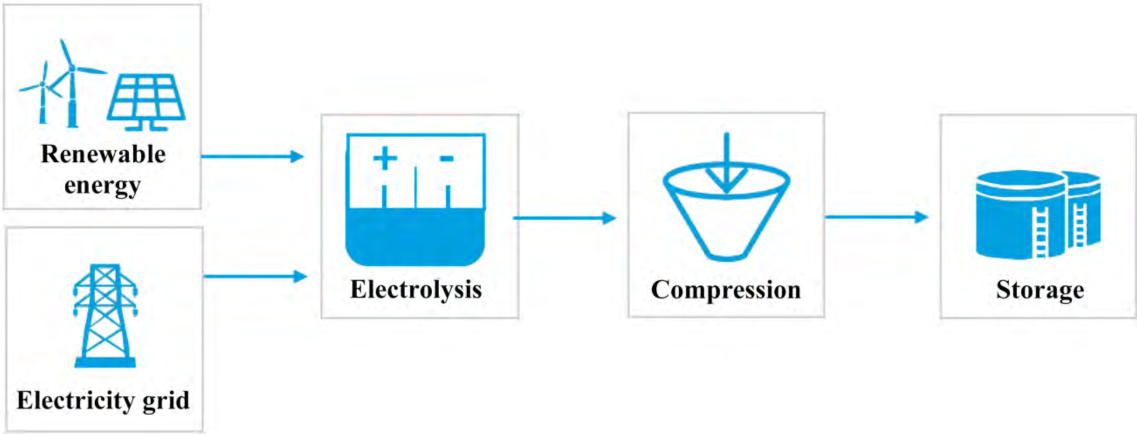

Figure 2.3: *Distributed supply chain for hydrogen. From figure 6-2 in DNV GL (2019), translated.*

For end-use processes, the centralized and distributed supply chains are effectively in competition, as equivalent hydrogen can be acquired from a differentiated set of processes. The centralized supply chain is likely to achieve lower production costs per kilogram of hydrogen, but this benefit is weighed against additional processes connected to compression and transportation (DNV GL 2019). As DNV GL (2019) also points out, there exists a theoretical equilibrium distance for end-use processes where the choice of procurement is indifferent to the two supply chains, I.e., that the hydrogen market price is equal for both production scales. This equilibrium distance depends on a range of factors including, distance to distribution- or consumption points, production volume, and regional power prices (DNV, 2019). Generally, the cost-effectiveness of the centralized supply chain decreases as the distance to the consumption point increases. In Section 4.1, we return to the discussion on supply chains in relation to how it is configured in our model.

3 Methodology

This chapter outlines the modelling framework and our approach to analyzing the potential role of hydrogen in the Norwegian energy system. First, the IFE-TIMES-Norway model (ITN) is presented with its functionality and properties. Then, we discuss our approach to hydrogen analysis in ITN including scenarios and sensitivity analysis.

3.1 The IFE-TIMES-Norway model

This master thesis uses the IFE-TIMES-Norway model to analyze the potential of hydrogen in the Norwegian energy system. TIMES (The Integrated MARKAL-EFOM System) is an economic model generator for energy systems with a technology-rich basis for energy dynamics over a long-term, multi-period time horizon (Loulou et al, 2016a). TIMES is developed and maintained by ETSAP (Energy Technology Systems Analysis Program) (IEA-ETSAP, n.d.) which is a collaboration program within IEA (International Energy Agency). TIMES-Norway is a model for the Norwegian energy system that was originally co-developed in 2017 by IFE and NVE. This development process was based on a prior version of TIMES-Norway from 2009, which can race its roots to the MARKAL-Norway model developed in 1992. Since 2017, IFE and NVE have developed and adapted the base model to their individual needs, resulting in a degree of divergence between the two organizations respective versions of the model. IFE-TIMES-Norway (ITN) is the IFE-specific version of the model which has been continuously developed to increase its scope, level of detail, and number of included technologies. As ITN is a long-term model, uncertainty about the future require continuous development and improvements of estimates considering the dynamic landscape of energy technologies and their associated supply and demand. While ITN can be characterized as IFE-specific, this refers to its specific contents and settings, while its properties and functionality are derived from the general TIMES framework.

The TIMES framework is used to build, run, and analyze linear programming models. Its operation relies on the modeling language GAMS (General Algebraic Modeling System). GAMS is a high-level language which was developed specifically to facilitate the construction and operation of large-scale mathematical optimization models. The process of constructing and solving a Linear Programming (LP) problem in TIMES consists of translating a TIMES database into an LP matrix and submitting it to an optimizer which generates a solution. All these processes are written in GAMS. A range of optimizers are available, but for the purposes of this thesis, the CPLEX solver has been used. A TIMES database consists of a set of Excel-files where all constraints are quantified and applied using TIMES-specific keywords, syntax, and formatting. Several software tools have been developed to adjust the settings, run the optimization, and analyze the result of TIMES models. For our work with this thesis, we have used the interface known as "VEDA" (VErsatile Data Analyst) (KanORS-EMR, n.d.). To avoid licensing costs for the desktop version of VEDA, we used the cloud-based version "VEDA Online" with the TIMES database hosted on GitHub. For more information about the TIMES framework, refer to its comprehensive documentation (Loulou et al, 2016a, 2016b; Goldstein et al, 2016, 2021).

TIMES, as an energy system analysis tool, is well suited to perform analysis on the interactions between energy supply and demand, the economy, and the environment. The model results, i.e., the best possible values for the decision variables, can provide valuable information for the investment decisions of private firms and can be an important tool to inform the process and decisions of public energy policy (Lind, 2018). This is evident by TIMES' widespread use in IFE and NVE in Norway as two major public entities informing energy policy. Decision variables can for instance relate to energy flows, activity levels, total capacities, new investments, and marginal costs for energy carriers. The decision variables play a different role according to the specific project and analysis conducted in TIMES. Examples of analyses includes determining the economic feasibility of different energy consumption scenarios, predicting the outcomes of energy policy, and finding the causes of, and solutions to failures in markets, policies, or technologies.

3.1.1 The economy and basic structure of TIMES

ITN is a linear programming model with the objective function of satisfying the aggregate energy service demand of the entire system at an optimal cost level. The model minimizes the net total cost, or equivalently, maximizes the total net surplus (i.e., the sum of producers' and consumers' surplus) over the entire time horizon by making simultaneous decisions on investments in equipment and its operation, primary energy supply, and energy trade for each region. It does so based on the characteristics of technologies, on the economics of energy supply, and on environmental criteria. It is thus a vertically integrated model of the extended energy system in its entirety. The model is said to have perfect foresight (or to be clairvoyant), meaning that all investment decisions are made with full knowledge of future events.

3.1.1.1 The TIMES energy economy and mathematical properties

The TIMES energy economy consists of producers and consumers of commodities, who each maximizes their own utility or profits. Commodities include for instance energy carriers, materials, and emissions. The model assumes a perfectly competitive market for all commodities, resulting in a supply-demand equilibrium. This means that in each period, the prices and quantities are at a level where supply is equal to the quantities demanded by the consumers. The market equilibrium has the property that it maximizes the total economic surplus, with the marginal prices of commodities equal to their marginal costs.

The ITN model strictly follows constant returns with linear relationships between input and output in any process, as with LP models in general. This linearity is what allows the optimization problem to be formulated and enables the equilibrium solution to be solvable with LP techniques. As linearity means that increased production of a commodity requires increasing inputs in a fixed proportion, no economies of scale are considered by the model and must therefore be expressed implicitly through the cost parameters associated with a specific technology. For instance, this can be done by basing costs for different production scales on representative capacities. In other instances, economies of scale are represented through decreasing costs over time following a logic of reduced equipment costs through higher overall production volumes of equipment, or prevalence of relevant infrastructure such as refueling stations. In addition, the linear relationship between input and output means that investment capacities are provided on a continuum rather than in the discrete sizes they are typically available for. As a result, instances can occur in which the invested capacities are smaller than realistic scales.

Following the properties we have discussed thus far, and the characteristics of duality in linear programming (Remme et al., 2009), the market price of a commodity in ITN is equal to is marginal price and marginal cost and can be assessed by the shadow price for the commodity provided by the dual solution of the LP problem. The shadow price is equal to the marginal change of the objective function per unit of increase of the relevant commodity (Loulou et al, 2016a). It can be interpreted as the maximum price one should be willing to pay to obtain an additional unit of the commodity, and therefore, its market price. Result interpretation in TIMES may contain a degree of assessing shadow prices as they can contribute to evaluating the competitiveness of competing energy carriers.

3.1.1.2 Demand for energy services

The model is demand-driven with externally sourced estimates of end-use demand (Loulou et al, 2016a). Note that demand is not provided for commodities but is expressed in terms of the service they may provide. For instance, there is demand for kilometers driven by trucks, or for GWh of reduction agents in chemical industry, but not specifically for diesel or coal. As demand is provided in terms of energy services, it will be up to the model to decide on the supply of alternative and competing commodities and technologies. The model decides the supply mix according to the cost-effectiveness and availability of competing alternatives. Each energy service demand category can be satisfied through existing and/or new technologies using one or multiple energy carriers, such as electricity, bio energy, fossil fuels, or hydrogen. For a given energy service demand, changes in the relative prices of associated energy carriers may result in substitution effects in the composition of the supplied energy. Total energy consumption however cannot increase more than proportionally to energy service demand but can be reduced through cost effective investments in energy efficiency improvements such as more efficient powertrains for vehicles. ITN does not model adaptions in human behavior such as rebound effects of increased energy use associated with improvements in energy efficiency.

3.1.1.3 "Bottom-up" model

ITN is a "bottom-up"-model specifying the individual components of the system to a high level of detail (Loulou et al, 2016a). The model does so with a wide range of attributes and parameters capturing the specific characteristics and operational patterns of a given technology and its associated commodities. The technologies (also called processes) are the components in the model that transform commodities into others. They are linked together by their inputs and outputs (commodities) and are logically arranged in sectors (e.g., industry, road transport, power). In this way, sectoral output (e.g., a million vehicle kilometers) is provided through combining the outputs of the technologies that can satisfy the demand for an energy service in this sector. Thus, the production function of a given sector is implicitly constructed, rather than explicitly specified as is the case of "top-down" models (Loulou et al, 2016a).

3.1.1.4 Techno-economic input values

The set of techno-economic parameters applied to the system represents the assumptions and logic for the pathways from the transformation of primary resources into energy services (Loulou et al, 2016a). This includes technology- and fuel prices, and technical characteristics such as efficiency, availability, lifetime, load factor, and annual milage. These values are defined according to how one commodity is transformed into another, for instance how fuels and processes combine to result in an energy carrier that can satisfy end-use demand, its associated emissions, and the power requirements for its production. The model user additionally provides estimates of existing stock of energy related equipment, and sources of primary energy supply and their potentials.

All the values for demand, prices, technical characteristics, existing stock of energy equipment and primary energy supply are applied to a set of equations designed to capture the mechanisms and codependences that governs the interactions between the systems' constituent parts. The final iteration of all these calculations is the objective function that derives the total system cost. Since TIMES will invariably shift the entirety of investments into the cheapest supply alternative for an energy service at any given point in time, additional user constraints can be specified to enforce more realistic modelling conditions. This can for instance be limitations on growth and market shares for various technologies. Figure 3.2 illustrates the general flow of how input variables are applied to the modeling equations and the objective function to provide results in terms of values for decision variables.

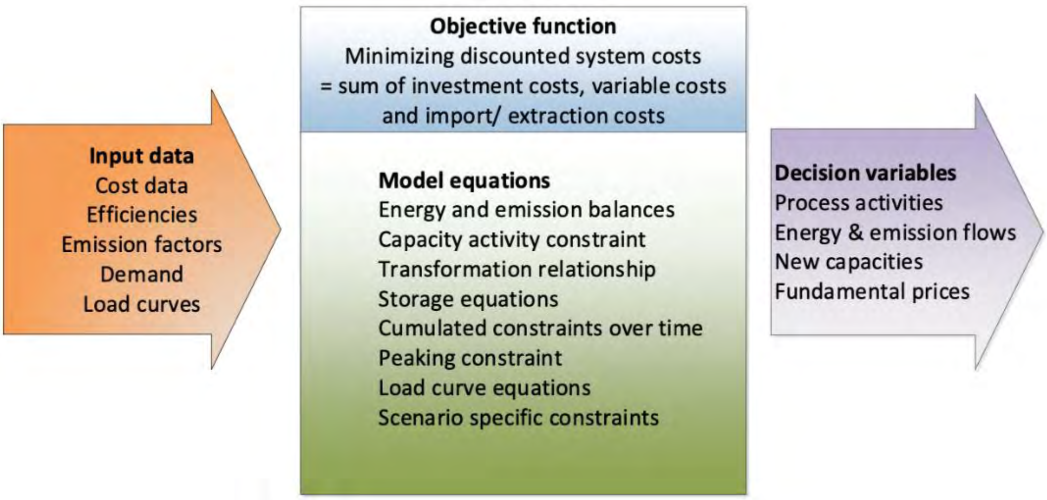

Figure 3.1: *Illustrative schematic of inputs, outputs, and main equations in TIMES (Lind, 2018).*

3.1.1.5 Regulated- and partial equilibriums

While perfectly competitive markets are the default in ITN, it departs from this assumption through the inclusion of various user constraints such as growth limits for technological adoption. Market imperfections also result from regulatory constraints for example in the form of emission constraints, taxes, or subsidies. With the inclusion of such user constraints, the equilibrium is regulated. When the model equilibrium is computed, the energy system of a set of regions is configured over the relevant time horizon in a way that minimizes the net total cost while satisfying such constraints. The entire system, but also individual energy service markets are computed according to supply and demand equilibriums. As noted by Loulou et al (2016a), the marginal production costs of supply in an energy service market can be represented by an inverse production function in which the costs are plotted as a function of the total quantity supplied. The partial equilibrium for an energy service is achieved at the point where the inverse supply function intersects with the demand function, as illustrated in Figure 3.1. It is a standard result in LP theory that this inverse supply function is stepwise and increasing with quantity (Loulou et al, 2016a). Note that the demand curve on the other hand is strictly vertical as the demand for an energy service is exogenously provided in ITN.

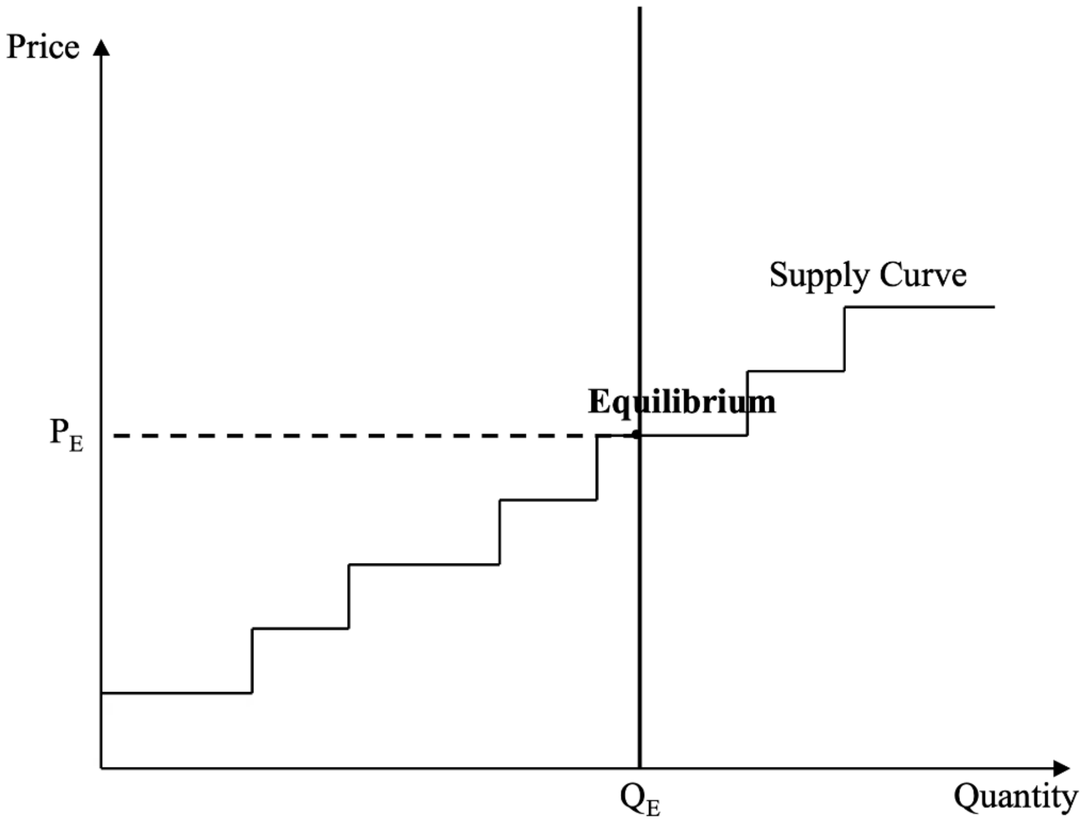

Figure 3.2: *Stepwise inverse supply function and the partial equilibrium for an energy service with exogenously provided demand. From figure 3.3 in Loulou et al (2016a).*

The inverse supply function for an energy service is stepwise since increasing quantity means that the availability of supply alternatives is exhausted. As the quantity increases, the supply mix must add additional and increasingly expensive alternatives as illustrated by the vertical increase of the inverse supply function. Supply alternatives are added until the energy service demand is satisfied. Within a step, the curve is strictly horizontal as this corresponds to the linear input-output relationship of a specific supply alternative. The horizontal width of a step represents the maximum availability of a technology, for instance limited by the potential of its underlying resource or by other user constraints specified in the model. As the equilibrium is achieved by the last added (and most expensive) supply alternative, the marginal system value of an additional unit for this energy service is the marginal value of this last added supply alternative. According to the logic of partial equilibriums and stepwise inverse supply, one can assess the choice of supply alternatives within an end-use sector. The composition of technologies within an end-use sector is driven by the cost-effectiveness and availability of competing technologies, represented by the stepwise inverse supply function.

3.1.2 IFE-TIMES-Norway structure and details

As IFE-TIMES-Norway is a vast model intended to incorporate all energy service demand and supply in Norway, our focus is to convey pathways and data that may have significant implications for hydrogen supply chains. Many model structures and data values in ITN are therefore not presented in this thesis but can be found in "Documentation of IFE-TIMES-Norway v2" (Danebergs et al., 2022b). This publication will be referred to as "the ITN documentation" throughout this thesis. In the rest of Section 3.1.2, we will provide information on central characteristics including model horizon, time slices, and geographical regions. More information on the model structures and data values specifically related to hydrogen are provided in Chapter 4 of this thesis.

The ITN model covers all land-based energy use in Norway. The end-use demand sectors are industry, buildings, and transport. The model includes the energy sectors, power and district heating, and a range of energy sources, energy carriers, and power production technologies. See Figure 3.3 for a general overview of the inputs and outputs related to the main sectors and process in the ITN model. Exogenous inputs in ITN are generally provided for resource availability, various fuel prices, and end-use demand. The range of techno-economic parameters applied for conversion-, transmission, and end-use processes generates values for decision parameters related to capacities and energy flows among others.

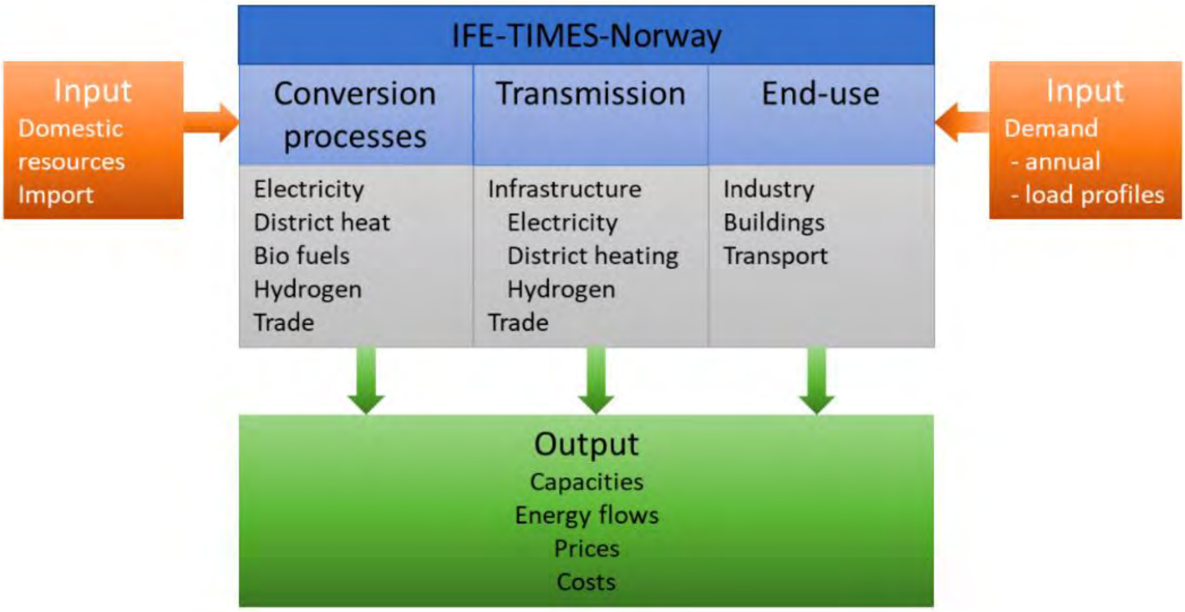

Figure 3.3: *General schematic of inputs and output in the IFE-TIMES-Norway model. From figure 2 in Danebergs et al. (2022b).*

The activity unit and commodity unit used in ITN is Gigawatt hours (GWh), while megawatt (MW) is used for capacity. For several transport categories, million vehicle-kilometers is used, which is derived from energy consumption values in GWh. As ITN is often used for energy policy analysis, many processes output GHG emissions in terms of CO_2-equivalents. The resulting CO_2-commodity is subject to a user-specified carbon price, thus incorporating decarbonization incentives in the optimization logic. Notably, the ITN model does not separate between emissions that are subject to the EU Emission Trading Scheme (EU ETS) and those that are not. Hence, all CO_2 emissions in the ITN model can be considered as non-quota emissions, which are subject to a national carbon tax (Danebergs et al., 2022b).

3.1.2.1 Time period and time slices

The time period considered in ITN is the years 2018 to 2050 with model periods of five years following 2020 within this interval. Model runs are typically conducted over a slightly extended period to include the lifetimes of investments made late in the time horizon. Each period consists of a set of representative years with a milestone year in the middle of the period. As input data values are generally only applied for milestone years, ITN must interpret the values and apply them across the years in the entire period. In ITN, this is done through linear interpolation, generally including forward extrapolation that applies the input value to subsequent milestone years. For instance, if an input value is provided up to the year 2040, the same value is applied to 2050. The interpolation typically applies to values that are subject to changes over time such as demand, costs, or efficiencies.

Each year is divided into four seasons of equal length and has a resolution down to 24 hours, which results in a total of 96 sub-annual time slices. Individual days are omitted due to the computational cost of running the model with a higher number of sub-annual time slices. Instead, each day within a season is considered identical. The resolution, i.e., the time slice level a process is defined for, dictates the flexibility of its operation. An illustration of the time horizon and time slice levels of the model is shown in Figure 3.4.

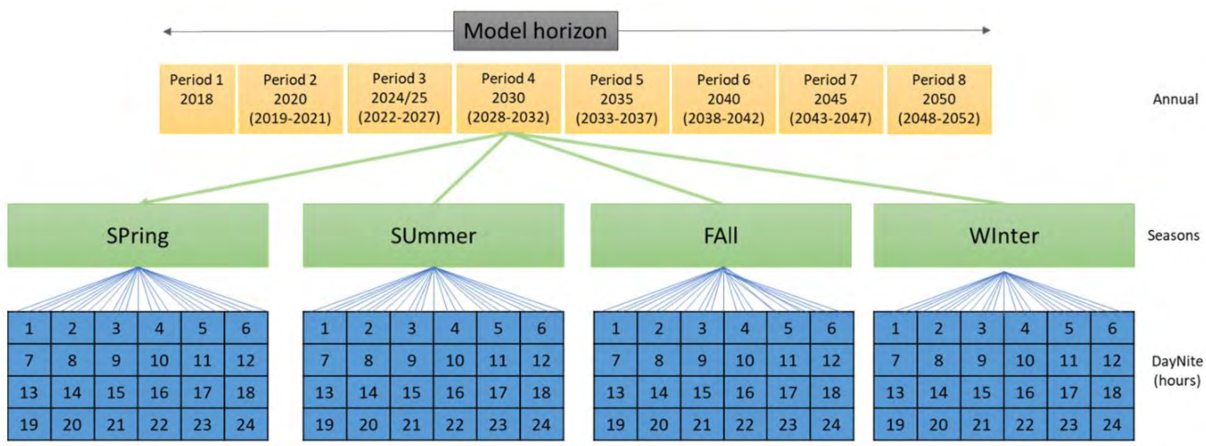

Figure 3.4: *Time slice tree of the IFE-TIMES-Norway model. From figure 4 in Danebergs et al. (2022b).*

The model horizon and time slices for our analysis reflects the time slice tree in Figure 3.4, with the exceptions of periods 5 and 7 which were combined with their preceding periods to make up two longer periods in the later years of the model period. The milestone years in our analysis were therefore 2018, 2020, 2024/25, 2030, 2040, and 2050. Note that while the milestone year is set to middle year in period 3 (-24/25), it is normally generalized to 2025 in analysis, and discussion. As ITN is long-term model, results are generally assessed over longer time periods and for our purposes 2030, 2040, and 2050 were chosen as the main years for analysis.

3.1.2.2 Additional details

The ITN energy system is also geographically divided into Nord Pool’s five different spot-price regions to capture a degree of geographical variations within the country. See Figure 3.5 for a map of the spot-price regions. Geographical differences are typically connected to demand levels, primary resource supply, and existing stock of energy equipment. In addition, for trade and distribution purposes, each region varies in terms of distances to other regions and power grid connections among other factors.

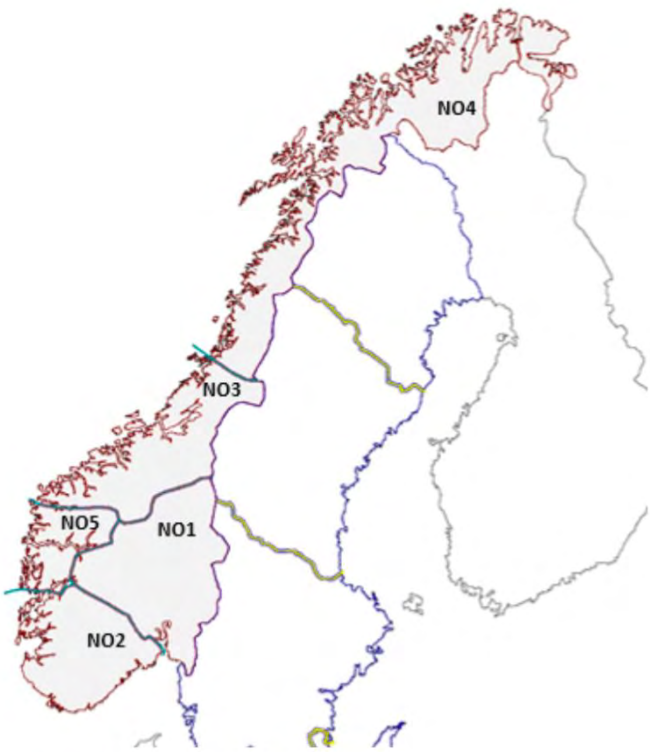

Figure 3.5: *Spot-price regions included in IFE-TIMES-Norway. From figure 3 in Danebergs et al. (2022b).*

ITN uses 2016 NOK as currency and an annual discount rate of 4%. Conversion to 2016 NOK has not been conducted for more recent cost values by IFE, based on the reasoning of minor changes in purchasing power in the subsequent years. Currency either way represents a minor source of error relative to high uncertainties and rough estimates in many other data values.

3.2 Hydrogen analysis in IFE-TIMES-Norway

A particular case ITN is well suited for is to model the investments in new and emerging technologies and their corresponding capacities. As ITN seeks to describe the entirety of the energy system, it provides a detailed context in which the role of hydrogen can be assessed as it competes for the same resources and end-use demand as alternative technologies and energy carriers. It can inform us on the overall- and relative competitiveness of differing hydrogen production technologies and the pathways they partake in to serve end-use demand. The decision variables of total capacities and new investments are therefore of particularly interest. As a production technology will not be invested in unless it contributes to satisfying energy-service demand at a lower cost than competing technologies, the investments on the demand side are also of interest. By analyzing the cost-effectiveness in end-use processes, including the prices of the resulting hydrogen, we can assess the economic rationale for hydrogen and its potential from a supply chain perspective. Our work with the model consisted of adding SMR with CCS as an additional technology and ensuring that the descriptions of existing technologies reflect their current state and future estimates. This enabled us to assess hydrogen supply chains in an expanded scope compared to prior hydrogen projects with ITN.

3.2.1 Data collection

Most of the data relied on in this thesis is sourced from the ITN base model. Our work with this data was primarily verification and revisions in collaboration with IFE personnel in effort to ensure accurate and up-to-date data. The major exception is data and assumptions connected to blue hydrogen, I.e., steam methane reformation (SMR) and carbon capture and storage (CCS). The inclusion of data and pathways for blue hydrogen supply chains is our main contribution to the continuous development of ITN. In addition, we have collected data related to the scenarios and sensitivity analysis, as outlined in Section 3.2.2, and described in detail in Chapter 5.

The IFE-TIMES-Norway documentation (Danerbergs et al., 2022b) has served as a guiding reference for the work in this thesis as it conveys the structure and contents of the base ITN model and its data. For the hydrogen production data presented in the ITN documentation, a common denominator is the reliance on synthesis reports summarizing the current state and expected developments of hydrogen production technologies. For data on SMR with CCS we have relied on IEA's "Global hydrogen review 2021", and particularly its assumption annex (IEA, 2021a; IEA, 2021b). This synthesis report is the de facto successor of "The future of Hydrogen" (IEA, 2019) which previously has been a major source for hydrogen data in ITN. While there are many alternate publications providing data on hydrogen production, our reliance on synthesis reports from the same organizational environment as existing model data contributes to continuity in modeling and coherency in included data.

3.2.2 Price scenarios and sensitivity analysis

As ITN identifies solutions in a deterministic manner where input data is handled as objective truth and future events are calculated exactly, the modeling results rely heavily on estimation and quantification of future conditions over a long period. All assumptions and input data should therefore be periodically revised to reflect the current state and expectations of the energy system. However, even in the case of exceedingly accurate knowledge of current and future events, a high degree of uncertainty will remain. In effort to address this uncertainty and evaluate its implications, we modeled different scenarios and sensitivity analysis for selected parameters that may significantly impact the potential of hydrogen in the Norwegian energy system.

TIMES is particularly well suited to the exploration of possible future energy situations through the application of contrasting scenarios. A given scenario in TIMES represents a set of assumptions about the trajectories of drivers in the energy system. Such drivers can for instance be linked to environmental policy, decarbonization, power scarcity, and limits to utilization of natural resources and primary energy. A scenario is typically designed to encompass a narrative of macroeconomic developments and trends that have implications for multiple parts of the energy system. In our thesis, we have modeled three different energy price scenarios with varying price levels for the national CO_2 tax, selected fossil fuels, and electricity import- and export prices. The input variations embedded in our scenarios may for instance affect decisions on investment and operation, power prices, hydrogen production capacities, and the relative competitiveness of competing hydrogen technologies. They represent ways of analyzing hydrogen supply chains according to differing underlying assumptions and provides additional information on drivers and barriers for hydrogen prevalence. They therefore provide a means of enhancing the external validity of modeling results.

In addition to our scenarios, we performed sensitivity analysis to address uncertainty in our modeling. Differing from scenarios, sensitivity analysis is performed for input variation in a single parameter that may have large implications for the model results. For our sensitivity analysis we focused on carbon pricing as this assumed to be a particularly uncertain, but also central parameter for hydrogen prevalence in the Norwegian energy system. A full description of our modeling runs can be found in Chapter 5.

4 Hydrogen modeling and data

In this chapter, we provide a detailed explanation of our modelling of hydrogen in the IFE-TIMES-NORWAY model. In Section 4.1, we provide an overview of the hydrogen modeling structure. In the subsequent sections, we present the data and assumptions used to model each component of the supply chains. The hydrogen production technologies are described in Section 4.2. In Section 4.3, we describe the necessary infrastructure that is modeled to deliver hydrogen from production to consumption. This includes compression, storage, distribution, and hydrogen refueling stations. Lastly, we describe how the three end-use sectors for hydrogen are modeled in Section 4.4.

This chapter can be read in its entirety for full comprehension or revisited for reference in context of analysis results. If you prefer the latter, we suggest you skip Sections 4.2 through 4.4. Note that the data presented in this chapter applies universally to the model, but that some parameters are subject to variation in scenarios and sensitivity analysis. The different scenario parameters will be presented in Chapter 5.

Furthermore, this chapter relies to a high degree on the most recent published version of the ITN documentation (Danebergs et al, 2022b). Note that while this is the latest version of the documentation, the model values are updated more frequently. This means that there are several deviations between values in the documentation and those we provide here. Such deviations might for instance have resulted from updated estimates or improved calculation methods. The documentation varies somewhat in its consistency in providing data sources, but they have been added in throughout the chapter in instances where they are available.

4.1 Hydrogen modeling structure

This section describes the modeling structures we have used for hydrogen in ITN. The relevant commodities, processes, and pathways are discussed in summary to provide a general overview. The details for each specific component of the modeling structure and its associated data are provided throughout the remaining sections of Chapter 4.

4.1.1 Overview

In the ITN model, hydrogen can be produced from three technologies, namely steam methane reformation with carbon capture and storage (SMR with CCS), alkaline water electrolysis (AEL), and polymer electrolyte membrane electrolysis (PEM). The two electrolysis technologies are available at both a centralized and distributed scale, while SMR with CCS is only available at a centralized scale. On the distributed scale, the two electrolysis technologies are modeled in direct connection to Hydrogen refueling stations for road transport. The two production scales are based on different capacities assumed to be representative of production at small and large scales with corresponding differences in costs and technical parameters. These differences are intended to incorporate a degree of economies of scale and operational differences such as reliance on the high- or low voltage grid for electrolysis at the centralized and distributed scale respectively. The produced hydrogen commodity is either used directly or compressed for storage and/or distribution. In addition, different end-use sectors have different practical requirements for compression. Hydrogen can be used to satisfy energy service demand in industry, road transport, and maritime transport. In industry, it can serve as an alternative feedstock input to coal and gas, while in the two transport sectors it is an alternative to other fuels.

In ITN, centralized production outputs hydrogen at low compression levels. This variation of the hydrogen commodity is referred to as "H_2-CENT" in our model. The low-pressure hydrogen can be used without further processing in industry or maritime transport. For storage and distribution, the hydrogen is assumed to be compressed at 250 bar (H_2-COMP). The compressed hydrogen can also be used in industry or maritime transport, but additional compression up to 700 bar is needed to satisfy energy density requirements in road transport (H_2-TRA). The distributed electrolyzers outputs this variation of hydrogen directly as the necessary compression equipment is integrated with hydrogen refueling stations (HRS) at this scale. The hydrogen structures of our model resemble the supply chains illustrated in DNV GL (2019) which were discussed in Section 2.5 (Figure 2.2 and 2.3). However, renewable energy for electrolysis and liquefaction is not included, and the only way of transporting hydrogen is with trucks.

4.1.2 Reference Energy System

The various components of hydrogen supply chains and the relationships between them can be visualized in a network diagram referred to as a "Reference Energy System" (RES). The RES illustrates the connection between commodities and technologies, as it shows how they interact to result in commodities and energy carriers that can satisfy energy service demand. A RES diagram of how we modeled hydrogen in the ITN model is presented in Figure 4.1.

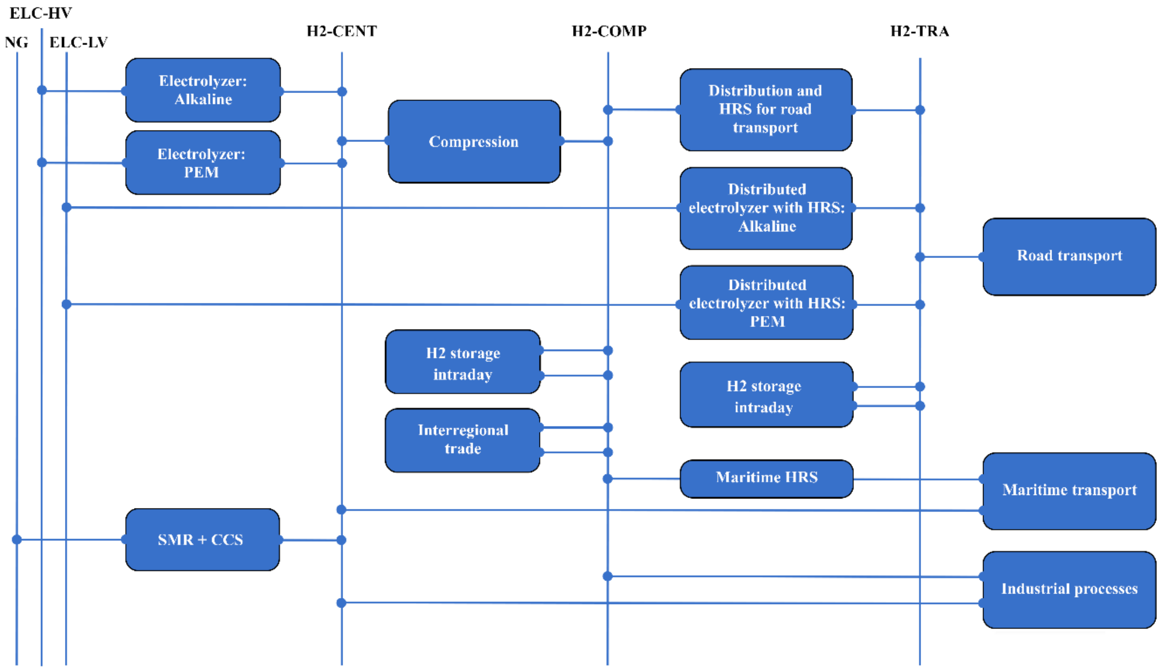

Figure 4.1: *RES diagram for hydrogen in ITN. Adapted from figure 21 in the ITN documentation (Danebergs et al., 2022b).*

In a TIMES RES, processes are presented as boxes and commodities are presented as vertical lines. The processes are related to production, compression, trade, storage, and end-use demand, while the commodities are inputs for production and variations of the hydrogen commodity. Horizontal connections between process boxes and commodity lines illustrate the various commodity flows, or technology chains, while vertically stacked boxes depict alternate or competing processes. The alternative flows connecting commodities to multiple processes thus demonstrate the potential supply chain variations, from input commodities on the left to end-use demand on the right. For instance, maritime transport can use hydrogen produced centrally with electrolyzers and/or SMR, and hydrogen for road transport may be sourced from distributed production or from centralized production with additional compression steps.

4.1.3 Energy carriers

A range of energy carriers have relevance for hydrogen modeling in ITN as they compete with it for end-use demand in transport and industry. In addition, natural gas is used as a production input in SMR with CCS. In Table 4.1, the energy carriers are listed with associated emission factors, exogenous prices, and special taxes in instances they occur. See section 3 of the ITN documentation for additional details (Danebergs et al, 2022b). Further details about how the energy carriers are used is described in Section 4.4 about the end-use demand sectors. Note that the prices for coal and gas will be presented in relation to the scenarios in Section 5.1.2. Hydrogen prices are modelled endogenously.

Table 4.1: *Prices, special taxes and emission factors used for energy carriers in the ITN model.*

Energy carrier	NOK/MWh	Special taxes (NOK/MWh)	Ton CO_2/MWh
Coal	(See Section 5.1.2)	-	0.239
Fossil fuels (Diesel)	675	356	0.266
H_2 (Electrolysis)	(Endogenous)	-	-
H_2 (SMR+CCS)	(Endogenous)	-	0.017
Liquefied natural gas (LNG)	590	-	0.20
Natural Gas	(See Section 5.1.2)	-	0.24
Marine gas oil (MGO)	440	173	0.27
Biofuel	1 234	407	-
Biogas (two cost classes)	1 000 / 2 000	-	-

The modeling of bio-based energy carriers differs from others as their availability is limited. For biofuels, availability is derived from imports with gradual reductions in availability and domestic production according to national biomass resources. The total biomass available for biofuel production is 15.7 TWh in 2020 and increases to 31 TWh in 2030 The import availability is 4.17 TWh in 2025 which is linearly reduced to zero in 2035. From this point on, all biofuel must be supplied by domestic production capacity. See section 4.3 of the ITN documentation for the techno-economic parameters associated with domestic biofuel production and the estimates of underlying biomass potential. Biogas on the other hand is only domestically available, but as of yet, no production pathway is modelled. Biogas is therefore exogenously priced, and the total resource potential is estimated to be 2.7 TWh. The availability of biogas is based on a study in which two cost classes of biogas are derived according to their resource potential (Carbon limits, 2019). The two cost classes are 1 000 NOK/MWh up to 1.2 TWH, and 2 000 NOK/MWh for the remaining 1.5 TWh. Both are available from 2030. Prior to 2030, only 0.4 TWh of the cheapest cost class is available.

4.1.4 Electricity

In addition to the energy carriers, electricity is an important commodity for hydrogen modeling in ITN as it is both used for hydrogen production input, and for battery-electric technologies that compete with hydrogen in end-use processes. In ITN, a wide range of electricity commodities are modeled based on a variety of energy sources and end-use sectors. See section 3 of the ITN documentation for a detailed explanation (Danebergs et al, 2022b). For our purposes, the most important characteristics of electricity in ITN is that its price is endogenously modeled, and that its availability is distinguished between the high- and low-voltage grids. The low-voltage (LV) grid is modelled with a grid fee of 0.456 NOK/KWh. In addition to the grid fee, the endogenous pricing of electricity is based on domestic supply and demand, and transmission flow through international grid connections.

4.2 Hydrogen production technologies

This section provides data and assumptions for the three hydrogen production technologies: SMR with CCS, AEL electrolysis, and PEM electrolysis.

4.2.1 SMR with CCS

The production of "blue" hydrogen from steam methane reformation of natural gas (SMR) with carbon capture and storage (CCS) is assumed to be centralized, large-scale production. In accordance with DNV GL (2019), we do not expect SMR with CCS to be a viable option for small-scale hydrogen production in Norway in the foreseeable future. Furthermore, we assume that access to existing gas infrastructure and a CCS supply chain is a prerequisite for blue hydrogen production in Norway, as expected by DNV GL (2019). Therefore, investments in SMR with CCS is included for all spot price regions except NO1, as there is no available infrastructure for natural gas in this region (Norwegian petroleum, 2021). Regarding access to a CCS infrastructure, a full-scale CCS supply chain is currently under development in Norway through the Longship project as discussed in section 2.2.1. As the project is expected to be fully operational with access to third parties from 2024, we have modeled SMR with CCS as available from the milestone year of 2025 in the model.

In the ITN model, SMR with CCS plants are assumed to be operating as merchant plants, meaning that they are standalone facilities that can supply hydrogen freely to various end-use processes. The costs and technical assumptions for SMR with CCS plants are based on values from the assumption annex of The International Energy Agency's (IEA's) Global Hydrogen Review from 2021 (IEA, 2021b). The Global Hydrogen Review 2021 is the first annual report by IEA to track the progress in hydrogen production and demand and is based on the latest available data from publications, industry agents, and governments. The technology costs presented in IEA (2021b) are based on global averages, with the exception of costs for CO_2 transport and storage which are provided at regional levels. All costs from IEA (2021b) have been converted from USD (2019) to NOK with an exchange rate of 1 USD = 8,8 NOK, which was the average exchange rate in 2019 according to Norges Bank (n.d.). All cost data and further assumptions for hydrogen production from SMR with CCS are presented in the sections 4.2.1.1 through 4.2.13.

4.2.1.1 CAPEX

In IEA (2021b), the capital expenditures (CAPEX) for an SMR-based hydrogen plant with CCS is assumed to be almost 13 million NOK/MW H_2. The CAPEX costs represent the total costs of installing the SMR based hydrogen plant and the CO_2 capture system. The capture system is assumed to have an overall CO_2 capture rate of 95% as according to IEA (2021b). In comparison to IEA's cost assumptions for a SMR based hydrogen plant without CCS, the inclusion of such a capture system increases CAPEX by approximately 88%. CAPEX is assumed by IEA (2021b) to be constant towards 2050 and is therefore kept identical across the entire model horizon in ITN. Furthermore, the SMR with CCS plants are assumed to have an economic lifetime of 25 years. SMR plants can typically not be readily turned off or on, as this may take several days. Thus, the plants are assumed to be operating as a baseload producer with a maximum average load factor of 95%, as done in IEA (2021b).

Notably, IEA (2021b) does not provide specific numbers for the capacity of the plant which they have based their costs on, as they are based on global averages. Although the scale of the production technology varies, it is most likely to be deployed in scales upwards of a 100 MW H_2, according to BEIS (2021). In BEIS (2021), a comparative literature review on CAPEX estimates for SMR with CCS plants was performed. They found that most CAPEX estimates were based on plant sizes of around 300 MW H_2. This is also in line with the assumption of the IEAGHG (2017) report, which is among the references in IEA (2021b). Thus, we assume that the cost estimates used for SMR with CCS are representative for large-scale production units with a capacity of about 300 MW H_2.

4.2.1.2 OPEX

The operational expenditures (OPEX) can be divided into fixed and variable costs. The variable OPEX will vary depending on the production volume of the plant, while the fixed OPEX is defined as an annual cost that accrue regardless of the operating load. Fixed OPEX costs typically include operating labor costs, administrative costs, annual operating and maintenance costs, insurance, local taxes, and fees. However, it is hard to derive precise estimates of the individual cost components, as they vary depending on the individual assumptions of different publications. Therefore, it is common to calculate the fixed OPEX as a share of the total CAPEX. Based on the cost assumptions from IEA (2021b), the annual operational expenditures are set to be 4% of the total CAPEX in all model years. This is equivalent to an annual OPEX cost of about 500 thousand NOK per MW H_2.

The variable OPEX is derived from the input and output streams of the production process. Input factors that may be considered relevant for an SMR based hydrogen plant includes natural gas, electricity, raw water, chemicals, and catalysts (IEAGHG, 2017). However, the costs associated with the usage of raw water, chemicals and catalysts are omitted from the model, as they are assumed to be insignificant based on values presented in BEIS (2021). In addition, the overall power demand of the plant is assumed to be completely self-satisfied by utilizing excess steam from the production process to generate electricity, as assumed in both IEAGHG (2017) and BEIS (2021). Thus, natural gas is the only input commodity in the production process of blue hydrogen in our model. In this process, natural gas is both used as a fuel and a feedstock, with an overall efficiency of 69% (IEA, 2021b). Consequently, it is assumed that 1.45 MWh of natural gas is required to produce 1 MWh of "blue" hydrogen. As SMR is a proven technology, efficiency improvements are assumed to be marginal and efficiency is therefore kept constant towards 2050, as done in IEA (2021b). The costs associated with the use of natural gas are varied between our scenarios and will be presented in Section 5.1.2.

The use of natural gas in unabated SMR emits CO_2 by a factor of 0.24 ton CO_2/MWh gas (Danebergs et al., 2022b). However, the addition of carbon capture is assumed to reduce the emission factor by 95% to 0.012 ton CO_2/MWh gas. In terms of hydrogen output, the emission factor is 0.017 ton CO_2/MWh H_2. These emissions are subject to the CO_2 taxes applied in the model, as will be presented in Section 5.1.1. However, the captured CO_2 must also be transported and stored according to a capture rate of 0.33 ton CO_2 per MWh of hydrogen output. In the ITN model, we have applied the CO_2-transport and storage costs presented in IEA (2021b), which are generalized costs for blue hydrogen facilities in Europe. The costs used are 439 NOK/ton CO_2 in 2021, and 291 NOK/ton CO_2 from 2030. See Table 4.2 for these costs in terms of hydrogen output.

4.2.1.3 SMR with CCS data summary

In Table 4.2, we provide a summary of costs and technical assumptions associated with blue hydrogen production from SMR with CCS. The variable costs associated with use of natural gas are not included, as these costs are varied between scenarios.

Table 4.2: *All costs and technical assumptions for SMR based hydrogen plants with CCS.*

Cost component	Units	2025	2030	2050
CAPEX	**NOK/MW H_2**	12 941 439	12 941 439	12 941 439
Annual OPEX	**% of CAPEX**	4	4	4
	NOK/MW H_2	517 658	517 658	517 658
CO_2 transport and storage	**NOK/MWh H_2**	141	96	96
CO_2 capture rate	**%**	95	95	95
Efficiency	**%**	76	76	76
Availability	**%**	95	95	95
Economic lifetime	**years**	25	25	25

4.2.2 Water electrolysis

The costs associated with water electrolysis in the ITN model are provided throughout this section. The values presented for electrolysis in this thesis correspond closely to the reported values found in the ITN documentation (Danebergs et al, 2022b), but there are minor changes as data has been updated in more recent model versions.

Hydrogen production with electrolysis is assumed to be produced in each spot-price region, in either a centralized (large-scale), or distributed (small-scale) manner. IFE has derived costs from distributed electrolyzers with a capacity of 3 MW electricity (el), and centralized large-scale electrolyzers with a capacity of 20 MW el. The corresponding cost values are representative of small- and large-scale production facilities for the two technologies and incorporates a degree of economies of scale. Note that while the costs in this section are based on electrolyzer capacity in terms of megawatts of input electricity (MW el), the costs themselves are provided relative to hydrogen output capacity (NOK/MWh H_2). Conversion between these two capacity units is calculated with the electrolyzers' efficiency as this value dictates the relationship between input and output quantities.

An important distinction between PEM- and AEL electrolysis is the time-slice resolution their operation is available for. PEM is modeled with a time-slice resolution of "daynite", while AEL uses "seasonal", as according to the available time slices in Figure 3.4 in Section 3.1.2.1. This means that the load factor of the facilities is adjustable hourly and seasonally for the two technologies respectively. This distinction is included to approximate the higher operational flexibility associated with PEM electrolyzers. The maximum average load factor is assumed to be 95% for both technologies.

The overall costs for electrolysis production depend on the values for electrolyzer efficiency and the lifetime of the facilities as discussed in Section 2.2.2. The efficiency rates and economic lifetimes of the electrolysis technologies are based on middle value estimates from IEA (2019) and are assumed by IFE to be equal for both the centralized and distributed production units. Table 4.3 shows the assumed efficiencies and lifetimes for AEL and PEM electrolyzers in representative milestone years.

Table 4.3: *Efficiency rates and economic lifetime for AEL and PEM electrolyzers.*

		AEL			**PEM**		
Parameters	**Units**	**2018**	**2030**	**2050**	**2018**	**2030**	**2050**
Efficiency	**%**	67	68	75	58	66	71
Lifetime	**Hours**	75 000	95 000	125 000	60 000	75 000	125 000
	Years	9	11	14	7	9	14

4.2.2.1 CAPEX

In the ITN model, the CAPEX for both centralized- and distributed electrolyzers is built up from two cost categories: electrolyzer and other costs. However, an important distinction between the centralized- and distributed production technologies is the inclusion of compression costs in the CAPEX. For the distributed electrolysis technologies, compressors are assumed to be an integrated part of the facility and is therefore included in the aggregated investment costs. On the other hand, compression is not always considered to be necessary in the centralized supply chain and is consequently omitted from the CAPEX of the centralized production units. Thus, compression costs are not included in the CAPEX values presented in this section but is rather described in Section 4.3.1. In Table 4.4, we provide a detailed overview of the cost categories that the CAPEX values are based on, and costs that have not been included by the IFE. Furthermore, we present the values and data sources used to estimate the CAPEX.

Table 4.4: *Electrolysis CAPEX categories and details.*

Cost category	Details
Electrolyzer	• Transformers, rectifiers, control panel with PLC • Water demineralizer/deionizer • Electrolyzer stack(s) • Gas analyzers, separators, and separating vessels • Scrubber or gas purifier system & recirculating pump
Other costs	• Engineering costs • Distributed control system (DCS), and energy management unit (EMU) • Interconnection, commissioning
Omitted costs	• Land costs • Civil works, defined as: construction of foundation, industrial buildings, lighting, water supply, fencing, and security • Electrolyzer lifetime extension

Investments costs for electrolyzers and auxiliaries in the ITN model are based on Proost (2019). These investment costs are applied to the base year of the model, while the cost developments towards 2050 are based on cost decrease estimates from IEA (2019). In table 3 of IEA (2019), CAPEX ranges are presented for the two electrolyzer technologies as a reflection of uncertainties in future estimates. The cost development assumed for the technologies are based on the middle values of these CAPEX ranges. Consequently, the electrolyzer investment costs for AEL are assumed to decrease by 34% by 2030 and 53% by 2050. On the other hand, the assumed cost development of PEM electrolyzers is lower towards

2030, with a 17% decrease, but higher towards 2050, with a 62% decrease. In Table 4.5, the investment costs for the two technologies at both large- and small-scale are presented in NOK/MW H_2.

Table 4.5: *Investment costs for electrolyzers in NOK/MW H_2.*

		2018	2030	2050
Centralized	**AEL**	8 571 926	5 515 026	3 600 209
	PEM	12 769 257	8 382 871	3 984 733
Distributed	**AEL**	10 157 680	6 535 272	4 266 226
	PEM	13 584 762	8 918 241	4 239 216

Furthermore, other costs are calculated as a share of the investment costs for electrolyzers and are based on values from Chardonnet et al. (2017). Other costs are expected to be subject to economies of scale and are therefore assumed to be 36% and 45% of the investment costs for the large- and small-scale electrolyzers, respectively. Other costs are presented in Table 4.6.

Table 4.6: *Other costs for electrolyzers in NOK/MW H_2.*

		2018	2030	2050
Centralized	**AEL**	3 085 893	1 985 409	1 296 075
	PEM	4 596 933	3 017 834	1 434 504
Distributed	**AEL**	4 570 956	2 940 873	1 919 802
	PEM	6 113 143	4 013 208	1 907 647

4.2.2.2 OPEX

The annual OPEX for the electrolysis technologies is calculated as a share of the electrolyzer CAPEX, as done in both IEA (2019) and BEIS (2021). In the ITN model, the fixed operational expenditures are assumed by IFE to be 3% of CAPEX. The annual OPEX for centralized and distributed electrolysis technologies are presented in Table 4.7.

Table 4.7: *Annual OPEX for electrolyzers in NOK/MW H_2.*

		2018	2030	2050
Centralized	**AEL**	257 158	165 451	108 006
	PEM	383 078	251 486	119 542
Distributed	**AEL**	304 730	196 058	127 987
	PEM	407 543	267 547	127 176

Furthermore, the electrolyzer facilities have variable costs from their electricity input. It is assumed that electrolyzer facilities do not have a power purchase agreement with a fixed electricity price, and the costs are rather subject to the variable market price for electricity in the ITN model. However, the large- and small-scale electrolyzer facilities are distinguished by electricity source. The centralized electrolyzers are assumed to use power from the high-voltage grid, while the distributed electrolyzers are connected to the low-voltage distribution grid. Distributed electrolyzers are therefore subject to a grid fee of 0.546 NOK/KWh in addition to power costs. Note that OPEX does not include electricity input as these are variable costs modeled endogenously by ITN.

4.2.2.3 Electrolysis data summary

In Table 4.8 and 4.9, we provide a summary of the costs and technical assumptions associated with the two electrolysis technologies. In Table 4.8, the costs for the centralized electrolysis facilities are summarized.

Table 4.8: *All costs and technical assumptions for centralized electrolysis facilities.*

		AEL			PEM		
Cost component	**Units**	**2018**	**2030**	**2050**	**2018**	**2030**	**2050**
CAPEX	**kNOK/MW H_2**	11 658	7 500	4 896	17 366	11 401	5 419
Annual OPEX	**% of CAPEX**	3	3	3	3	3	3
	kNOK/MW H_2	257	165	158	383	251	120
Efficiency	**%**	67	68	75	58	66	71
Availability	**%**	95	95	95	95	95	95
Economic lifetime	**years**	9	11	14	7	9	14

The costs for distributed electrolysis facilities are summarized in Table 4.9. The efficiency, availability, lifetime, and OPEX share is equal for centralized and distributed electrolysis production. Note that compression equipment costs are added for the distributed electrolyzers, as compression is assumed to be an integrated component of the distributed electrolysis facilities. The cost components and data for compression is discussed in detail in Section 4.3.1. The distributed production will also rely on hydrogen refueling stations to deliver hydrogen to end-use consumers. Hydrogen refueling stations are discussed in Section 4.3.4.

Table 4.9: *All costs and technical assumptions for distributed electrolysis facilities.*

		AEL			PEM		
Cost component	**Units**	**2018**	**2030**	**2050**	**2018**	**2030**	**2050**
CAPEX	**kNOK/MW H_2**	14 729	9 476	6 186	19 698	12 931	6 147
Annual OPEX	**% of CAPEX**	3	3	3	3	3	3
	kNOK/MW H_2	305	196	128	408	268	127
Compression equipment CAPEX	**kNOK/MW H_2**	5 037	2 367	2 015	3 524	1 656	1 410
Compression equipment OPEX	**% of CAPEX**	6	6	6	6	6	6
	kNOK/MW H_2	208	98	83	146	69	58
Efficiency	**%**	67	68	75	58	66	71
Availability	**%**	95	95	95	95	95	95
Economic lifetime	**years**	9	11	14	7	9	14

4.3 Hydrogen infrastructure

This section covers the necessary infrastructure that is modeled to get hydrogen from its source of production to its point of end-consumption. Before hydrogen can be stored, distributed, and used for transportation purposes, the hydrogen gas must first be compressed into a higher energy density. In the ITN model, hydrogen is assumed to be compressed at a level of 250 bar, given that it is not used directly in industrial processes or maritime transport. Correspondingly, storage and distribution of hydrogen is assumed to be at 250 bar. However, for final end-use in vehicles and certain maritime vessels, the hydrogen gas needs to be further compressed to higher pressures. This is assumed to be handled by the hydrogen refueling stations. In sections

4.3.1 through 4.3.4, the costs and assumptions for compression, storage, distribution and trade, and hydrogen refueling stations will be presented.

4.3.1 Compression

In the ITN model, the investment costs of compressors are based on data from Ulleberg (n.d.), which have been refined in Danebergs (2020). The investment costs are calculated based on costs per KW of installed electrolyzer capacity, as described in a detailed manner in Danebergs et al. (2022b). In addition to equipment costs, other costs are calculated as a share of the investment costs and included in the total CAPEX for compressors. The other cost shares are based on Chardonnet et al. (2017) and calculated identically to the other costs of electrolyzer investments, as described in Section 4.2.2.1. The annual OPEX for the compressors are assumed by IFE to represent 6% of the investment cost for compressor equipment. Furthermore, compressor costs are expected to decrease as the production volumes of hydrogen refueling stations (HRS) increase globally. Reddi et al. (2017) assumes that a production of 5 000 HRS could reduce compressor costs by 53%, and that 10 000 HRS will reduce the costs by 60%. IFE assumes that these production volumes will be achieved in 2030 and 2050, respectively (Danebergs et al. 2022b). The cost decrease factors from Reddi et al. (2017) are used for both small- and large-scale compressors.

Compression of hydrogen is modelled somewhat differently in the ITN model according to hydrogen production scale. In the case of small-scale hydrogen production, the compressor is considered as an integrated component of the electrolysis facilities. As such, the compressor costs are included in the total investment costs for the distributed electrolysis technologies. The CAPEX is based on required compressor capacities to pressurize hydrogen from an AEL and PEM electrolyzer with an installed capacity of 3 MW el. The output pressure from an AEL and PEM electrolyzer is assumed by IFE to be at 15 and 55 bar, respectively. As the output pressure from AEL production is lower, more energy is required for its compression to 250 bar. Thus, the compressor costs are higher for AEL electrolyzers. In addition, IFE assumes that a compressor for an AEL facility will have an energy usage equivalent to approximately 5% of the original energy content, while the corresponding energy demand for PEM compressors are assumed to be 3%. Since the compressor costs are included in the costs for small-scale electrolysis technologies, the compressors are assumed to have the same lifetimes as the electrolyzers. The costs for small-scale compressors are presented in Table 4.10.

Table 4.10: *The costs for distributed (small-scale) compressors in NOK/MW H_2.*

			2018	2030	2050
AEL	**CAPEX**	**Investment costs**	3 473 660	1 632 620	1 389 464
		Other costs	1 563 147	734 679	625 259
		Total cost	5 036 806	2 367 299	2 014 723
	OPEX		208 420	97 957	83 368
PEM	**CAPEX**	**Investment costs**	2 430 566	1 142 366	972 226
		Other costs	1 093 755	514 065	437 502
		Total cost	3 524 321	1 656 431	1 409 728
	OPEX		145 834	68 542	58 334

While compressors are modelled as an integrated part of the small-scale production units, compression of hydrogen from large-scale production facilities is modelled as a separate process. Although large-scale hydrogen production is based on different technologies with varying output pressures, the cost of large-scale compression is assumed to be identical for large-scale electrolyzers and SMR with CCS. As such, it is assumed that all large-scale production facilities have very low hydrogen output pressures, close to atmospheric levels. Therefore, the compressor costs are calculated based on required compressor capacity for an AEL electrolyzer with an installed capacity of 20 MW el. The compressor has an assumed lifetime of 10 years and an energy consumption equivalent to 6% of the original hydrogen content. The costs for large-scale compressors are presented in Table 4.11.

Table 4.11: *The costs for centralized (large-scale) compressors in NOK/MW H_2.*

		2018	2030	2050
CAPEX	**Investment costs**	2 701 735	1 269 816	1 080 694
	Other costs	972 625	457 134	389 050
	Total cost	3 674 360	1 726 949	1 469 744
OPEX		162 104	76 189	64 842

4.3.2 Storage

Today, the two main storage methods for compressed gaseous hydrogen involves storage in pressure vessels or in salt caverns underground, as discussed in Section 2.3.2. In general, pressure vessels are better suited for short-term or intermediate storage, while underground storage is the best option for long-term seasonal storage of very large quantities. In the ITN model, however, only the option of storing hydrogen within a 24-hour interval is included. As such, hydrogen storage is assumed to be done in pressure vessels that can hold a pressure of 250 bar. The pressure vessels have an assumed lifetime of 25 years, and there are no efficiency losses assumed in the storage process (Danebergs et al., 2022b).

The costs for hydrogen storage are based on values from Ulleberg and Hancke (2020) and are assumed to be 6 300 NOK per kg H_2 in the starting year (Danebergs et al., 2020b). In similarity to the cost development of compressors, IFE expects that storage costs will decrease as the deployment of HRS expands globally. Based on cost decrease factors from Reddi et al. (2017), IFE assumes that storage costs will decrease by 21% by 2030 and 25% by 2050. Furthermore, there are no OPEX costs included for hydrogen storage in the model, as operational cost data for storage facilities is limited and assumed to be very low. The storage costs are shown in NOK/kg H_2 and NOK/MWh H_2 in Table 4.12. The calculations from kg to MWh is based on the lower heating value of the gravimetric energy density of H_2, which is 33.33 kWh/kg (Horne & Holde, 2019; Danebergs, 2020).

Table 4.12: *Costs for hydrogen storage.*

	2018	**2030**	**2050**
NOK/kg H_2	6 300	4 977	4 725
NOK/MWh H_2	189 019	149 325	141 764
Cost decrease	-	21%	25%

In the ITN model, storage within a day is modelled as an available option for the centrally produced (H_2-CENT) and compressed hydrogen (H_2-COMP), as well as the hydrogen that have been locally produced or centrally distributed for road transport purposes (H_2-TRA). The alternative option of seasonal storage in underground salt caverns have been evaluated for centralized production facilities but is not included due to uncertainties connected to the geographical availability of salt caverns.

4.3.3 Distribution and trade

In the ITN model, hydrogen can only be traded between adjacent geographical areas within Norway. As such, international trade of hydrogen is not included as an option in the model. The only hydrogen commodity that can be traded and distributed within the model is the centrally produced hydrogen (H_2-COMP). The costs for hydrogen trade are based on the distances between the main cities in each price region. Furthermore, the costs calculations are based on a total daily delivery of 2 000 kg of compressed hydrogen transported in several 40-foot tube trailers (Danebergs et al., 2022b). The distances between regions and transportation costs are shown in Table 4.13.

Table 4.13: *Distance between regions and transport costs for hydrogen trading.*

From		To	Distance (km)	Transport costs (NOK/kg H_2)	Transport costs (NOK/MWh H_2)
Region	**City**				
NO1	**Oslo**	NO2	320	15	450
		NO3	490	23	690
		NO5	460	22	660
NO2	**Kristiansand**	NO1	320	15	450
		NO5	470	22	660
NO3	**Trondheim**	NO1	490	23	690
		NO4	1 100	49	1 470
		NO5	700	32	960
NO4	**Tromsø**	NO3	1 100	49	1 470
NO5	**Bergen**	NO1	320	15	450
		NO2	470	22	660
		NO3	700	32	960

Furthermore, the cost of hydrogen distribution within a region will be affected by the size of the region. Based on the distances between regions, provided in Table 4.13, IFE has developed a simple method for calculating the distances and associated costs of distribution within a region. This methodology is illustrated in Figure 4.2. First, a distance (*D*) is calculated as the average distance between the main city of a region and the main cities of all its adjacent regions. Secondly, it is assumed that large-scale hydrogen production facilities will be close to the main cities of each region. Lastly, distribution within a region is divided into categories of "short" and "long" distances. An average distance of *D*/6 is assumed for distribution to hydrogen refueling stations that are in relative proximity of the production sites (short-distance distribution), while an average distance of *D*/3 is assumed for long-distance distribution (Danebergs et al., 2022b).

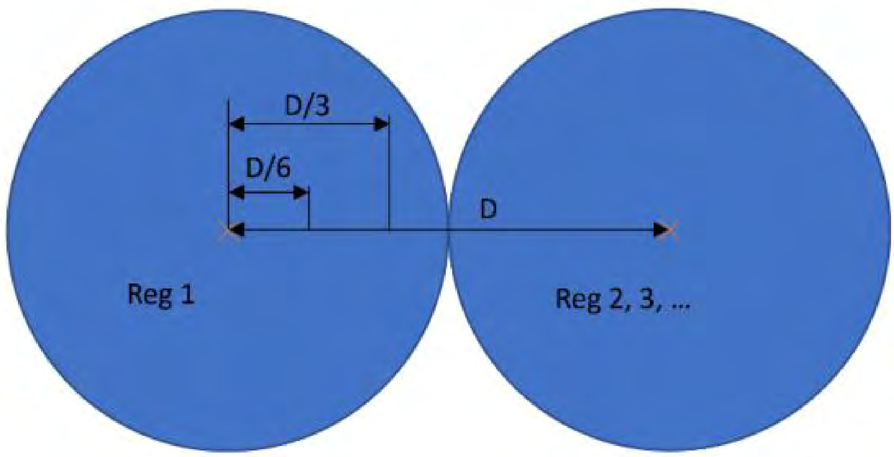

Figure 4.2: *Illustration of how distribution distances within regions are calculated. From figure 22 in Danebergs et al. (2022b).*

In the ITN model, it is assumed that hydrogen demand in road transport cannot be satisfied entirely by short-distance distribution from centralized hydrogen production. As such, an exogenous variable dictate that a minimum of 20% of the demand must be covered by long-distance distribution or small-scale hydrogen production. Furthermore, the costs for hydrogen distribution within regions are based on transportation in 40-foot tube trailers that can deliver 500 kg H_2 per day. The average distances and associated costs of distribution within each region is presented in Table 4.14.

Table 4.14: *Distances and costs of distribution within regions.*

Region	Average distance to other regions, D (km)	Long distribution within region			Short distribution within region		
		D/3	NOK/ kg	NOK/ MWh	D/6	NOK/ kg	NOK/ MWh
NO1 (Oslo)	423	141	9	270	71	6	180
NO2 (Kristiansand)	395	132	9	270	66	6	180
NO3 (Trondheim)	763	254	14	420	127	9	270
NO4 (Tromsø)	1 100	367	19	570	183	11	330
NO5 (Bergen)	497	166	10	300	83	7	210

4.3.4 Hydrogen refueling stations

Hydrogen refueling stations (HRS) are a necessary part of the infrastructure to enable hydrogen use in the road transport segment. The costs of HRS can vary greatly depending on the design of the HRS-system with regards to size, pressure, compression system and degree of utilization (Danebergs et al, 2022b). In Elgowainy et al. (2017), the most expensive 350 bar configuration costs slightly over 35 NOK/kg H_2. Furthermore, the levelized costs of the cheapest 700 bar solution in Reddi et al. (2017) was nearly 40 NOK per kg H_2. The costs from Reddi et al. (2017) were based on a refueling station with a "low production volume" of 200 kg H_2 per day. At the same time, Danebergs (2020) showed that a 700 bar HRS with a "high production volume" of 1 000 kg H_2 per day could cost as little as 32 NOK/kg H_2.

Based on available literature, IFE assumes an average cost of 40 NOK per kg H_2 for hydrogen refueling stations in the road transport segment in the start year (Danebergs et al., 2022b). In addition, the costs are expected to decrease as the number of hydrogen refueling stations increase globally. Reddi et al. (2017) assumes that a global increase to 5 000 HRS will decrease the costs by 40%, and that 10 000 HRS will lead to a 45% cost reduction. As mentioned in Section 4.3.1, IFE assumes that these production volumes will be achieved in 2030 and 2050 respectively. The costs for hydrogen refueling stations are presented in Table 4.15.

In the ITN model, the costs of hydrogen refueling stations are added as a variable cost for distributed electrolysis production and distribution of centrally produced hydrogen to the road transport sector. Furthermore, it is not distinguished between 350 bar and 700 bar HRS-systems in the model. In other words, it is assumed that the hydrogen refueling stations can compress and dispense hydrogen at both 350 and 700 bar. Consequently, the compression level of the output commodity H_2-TRA is unspecified in the model.

Table 4.15: *Variable costs for HRS in the road transport segment.*

	2018	2030	2050
NOK/kg H_2	40	24	22
NOK/MWh H_2	1 200	720	660
Cost decrease	-	40%	45%

Furthermore, HRS stations are also required for utilizing hydrogen in ships that run on fuel cells in the maritime sector. The cost data related to HRS for maritime transport is highly uncertain, as no such HRS-systems are currently available as discussed in Section 2.4.3. Nonetheless, HRS will represent an additional cost in the hydrogen supply chain for ships with fuel cell propulsion systems. Based on the expectation that HRS will handle large quantities of hydrogen, and subsequently benefit from economies of scale, the costs of using HRS for maritime transport is simply assumed to be half of the cost for using them in road transport. The costs assumed for HRS in maritime transport are presented in Table 4.16. These costs are added as a variable cost for ships with fuel cell propulsion systems.

Table 4.16: *Variable costs for HRS in the maritime transport segment.*

	2018	2030	2050
NOK/kg H_2	20	12	11
NOK/MWh H_2	600	360	330
Cost decrease	-	40%	45%

4.4 End-use demand for hydrogen

This section covers the potential avenues for consuming hydrogen in industry, road transport, and maritime transport. We provide demand projections for the associated energy services, and an overview of energy-using technologies including existing stock, costs, and fuel efficiencies. In addition, important model constrains are presented.

4.4.1 Industry

In the ITN model, the industry sector is divided into nine different sub-sectors, which all have a demand for heat, electricity and/or feedstocks. Among these sub-sectors, hydrogen is modelled as a feedstock option for the metal industry and chemical industry. In both industries, hydrogen has the potential to replace the use of coal in some selected reduction processes. In addition, hydrogen is modelled as an alternative input option to natural gas for use in production of chemical products. In the ITN model, energy demands projections for the industry sector are based on the national energy balance of 2018 (Statistics Norway, n.d.a) and planned developments in the coming years. For the reduction- and chemical production processes, the demand is constant across the model horizon. The load profiles of the industrial processes are assumed to be flat, meaning constant operation all year with no seasonal variation (Danebergs et al., 2022b). The total energy demands of the industrial processes are presented in Table 4.17.

Table 4.17: *Total energy demand in metal and chemical industry processes..*

Industry	Processes	Region	GWh/year
Metal	**Reduction processes**	**NO1**	202
		NO2	1 717
		NO4	2 056
		NO5	1 636
Chemical	**Reduction processes**	**NO3**	1 704
		NO4	934
	Production of chemical products	**NO2**	10 997
		NO3	5 878

IFE assumes that it is unrealistic that hydrogen can replace all use of coal and natural gas in these industrial processes. Hence, they have defined some upper bounds on the industrial usage of hydrogen, which are based on available literature and information about individual development projects. The upper bounds of hydrogen usage associated with the energy demands of the metal- and chemical industry are presented in Table 4.18.

Table 4.18: *The upper bound of hydrogen to satisfy energy demands in industrial processes, in GWh and percent of the total energy demand.*

			2025		2030		2035	
Industry	**Process**	**Region**	**GWh**	**%**	**GWh**	**%**	**GWh**	**%**
Metal	**Reduction process**	**NO2**	400	23%	1 118	65%	1 717	100%
		NO4	0	0%	120	6%	220	11%
		NO5	0	0%	38	2%	70	4%
Chemical	**Reduction process**	**NO3**	0	0%	927	54%	1 700	100%
	Production of chemical products	**NO2**	1 447	13%	1 447	13%	1 447	13%

It should be noted that these upper bounds are based on uncertain data and that there are great uncertainties linked to the future demand for hydrogen in the Norwegian industry. According to IFE, the potential demand for hydrogen in industrial processes should be reviewed and updated in the future. Nonetheless, we have used the data and assumptions made by IFE in our model, as demand projections for hydrogen are beyond the scope of our thesis. In the chemical industry, IFE has restricted the possibility of using hydrogen instead of natural gas in production processes to Yara's ammonia production facility in NO2. Furthermore, it is assumed that hydrogen cannot be used in most reduction processes before 2030, as the technological feasibility of such process still are in relatively early stages. On the other hand, IFE assumes that hydrogen can be utilized from 2025 in Yara's ammonia production facility at Herøya (NO2) and TiZir's ilmenite upgrading facility in Tyssedal (NO2).

Another important factor that will affect the demand for hydrogen is the technical efficiencies associated with the use of hydrogen in reduction- and chemical production processes. In both processes, it is assumed that coal and natural gas have an efficiency of 100%. In contrast, hydrogen is assumed to have an efficiency of 77% in the process of producing ammonia at Herøya. As such, it would require about 30% more energy from hydrogen than natural gas to produce the same quantity. On the other hand, hydrogen is assumed to be four times more efficient than coal in reduction processes. Thus, only 1/4th of the energy content of coal is required by hydrogen to satisfy an identical energy demand. By applying the efficiency factors, the maximum possible demand for hydrogen in GWh H_2 can be calculated, as presented in Table 4.19.

Table 4.19: *Maximum hydrogen demand (GWh H_2) in the metal- and chemical industry.*

Industry	Process	Region	2025	2030	2035
Metal	**Reduction process**	**NO2**	100	280	429
		NO4	0	30	55
		NO5	0	10	18
Chemical	**Reduction process**	**NO3**	0	232	425
	Production of chemical products	**NO2**	1 879	1 879	1 879

Furthermore, the hydrogen commodities that can be used in these industrial processes are either the centralized, low-pressure hydrogen (H_2-CENT) or the centralized and compressed hydrogen (H_2-COMP). It is assumed that the centrally produced hydrogen can be delivered directly to the industries without any additional distribution costs, as the large-scale production plants are assumed to be located very close to industrial facilities.

4.4.2 Road transport

This section provides a description of the road transport sector in the ITN model. We provide an overview of all data points, while further explanation of methods to derive the data, assumptions, and sources can be find in section 5.3 of the ITN documentation (Danebergs et al, 2022b). The road transport sector exclusively uses the variation of the hydrogen commodity with the highest compression level (H_2-TRA). The road transport sector is divided into four main categories: cars, vans, trucks, and buses. Trucks are divided further into three segments according to size and transport distance, where the size is provided in total gross weight including trailers. See details and descriptions of vehicle types in Table 4.20.

Table 4.20: *Road transport demand segments.*

Vehicle type		Description
Cars		Vehicles transporting up to 9 persons including driver. Taxis and ambulances are also included in this group.
Vans		Vehicles designed for carriage of goods with gross vehicle weight under 3.5 tons. Also includes motorhomes and other specialized vehicles in the same size.
Trucks	**Small (S)**	Weight between 3.5 and 50 tons, all distances.
	Large and short (LS)	Weight over 50 tons, short haulage (less than 300 km).
	Large and long (LL)	Weight over 50 tons, long haulage (more than 300 km).
Buses		Vehicles transporting 10 persons or more.

The truck category is subdivided into the three segments as trucks constitute a wide range of sizes and daily milage. These values are central parameters for energy requirements and suitability for different types of powertrains as discussed in Section 2.4.2. Further details about truck fleet composition can be found in tables 30 and 31 in the ITN documentation (Danebergs et al, 2022b).

4.4.2.1 Demand projections

IFE has based demand projections in road transport according to the National Transport Plan (NTP) 2022-2033 (Meld. St. 20 (2020–2021)) with increasing demand based on relative changes in million vehicle kilometers per year. Table 4.21 provides the total demand in different transport segments according to NTPs default scenario in 2018, 2030, and 2050. The demand values in this table are aggregated from NTPs regional data from to the five spot-price regions in Norway. See Figure 4.3 for an illustration of relative growth in demand compared to the base year, and Appendix A for regional breakdown of demand projections.

Table 4.21: *Aggregated demand in million vehicle km per year for different road transport segments and percentage change from base year.*

Vehicle type	2018	2030	Δ%	2050	Δ%
Car	35 149	40 062	14%	45 097	28%
Van	7 307	9 358	28%	12 720	74%
Truck (S)	510	405	-20%	365	-28%
Truck (LS)	773	1 024	32%	1 438	86%
Truck (LL)	773	1 024	32%	1 438	86%
Bus	574	601	5%	622	8%

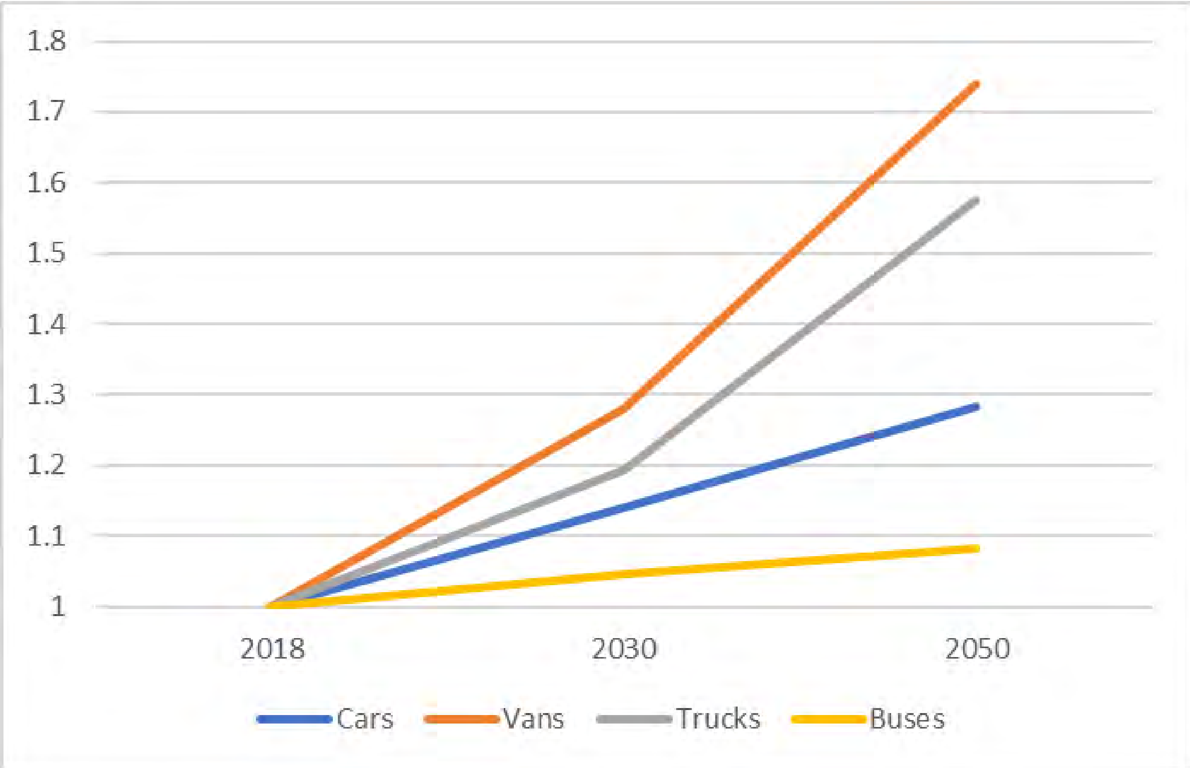

Figure 4.3: *Relative growth in road transport demand compared to the base year. The tree truck types are aggregated.*

4.4.2.2 Powertrains

A range of technologies with corresponding commodities are available to satisfy the demands of each segment. In IFE-TIMES, powertrains include internal combustion engines (ICE), plug-in hybrids with ICE, battery electric, gas-powered ICE, and fuel cell electric which runs on hydrogen. The powertrains and their available input commodities are summarized in Table

4.22. An important modelling consideration for powertrains are whether attribute values for commodities are set exogenously or modelled endogenously. Several fuels have set constant exogenous prices and no limitations on capacity and can therefore be considered as imports. This distinction is not universally applicable, however. Exogenous prices, for instance for fossil fuels (which are based on diesel prices), could also constitute a simplification where its production simply is not modelled. For commodities with both exogenous and endogenous prices such as biofuels however, the exogenous prices correspond directly to import prices of this commodity. See Table 4.1 in Section 4.1.3 for exogenous prices of associated energy carriers.

Table 4.22: *Powertrains and commodities for road transport.*

Powertrains	Description	Commodities	Commodity prices
Internal combustion engine (ICE)	ICE constitutes both petrol and diesel, as well as hybrids that are not plug-in and can run on fossil fuels, biofuels, or a mix	Fossil fuels	Exogenous
		Biofuels	Imports and domestic production
Plug-in hybrid	Petrol and Diesel cars where a share of the energy can be supplied by electricity	Fossil fuels	Exogenous
		Biofuels	Imports and domestic production
		Low-voltage electricity	Endogenous
Battery electric vehicles (BEV)	BEVs are modelled to be charged by electricity provided from charging infrastructure	Low-voltage electricity	Endogenous
Fuel cell electric (FCEV)	Fuel cell electric system entirely powered by hydrogen.	High-compression H_2 (H_2-TRA)	Domestic production
Gas-powered ICE	Based on liquefied or compressed biogas used in ICE for urban buses	Biogas	Exogenous

Several powertrains can be fueled by alternative commodities, and some fuels have limitations for how small or large share they can be of the total energy consumption for a powertrain. For instance, it is assumed that electricity can only provide up to 30% of total energy supplied to plug-in hybrids. See table 33 in the ITN documentation (Danebergs et al, 2022b) for further details. Theoretically, any powertrain is available to all vehicle types, but not all are considered relevant because of economical or technical feasibility. Feasibility, however, is subject to uncertainty related to forecasts of future technological and political developments. For flexibility in the model, powertrains are available for a wider range of road transport segments than current conditions or projections suggest is likely to be feasible. For instance, battery powertrains are available for large trucks with long haulage but is usually not included in reference scenarios in ITN as it is not considered to be a practically viable solution. Table 4.23 summarizes powertrain availability for the different vehicle types.

Table 4.23: *Powertrains and vehicle applications for road transport segments.*

	ICE	**Plug-in-hybrid**	**Battery**	**Fuel Cell**	**Gas-powered ICE**
Cars					
Vans					
Trucks (S)					
Trucks (LS)					
Trucks (LL)					
Buses					

Note: As battery electric is assumed to be an infeasible powertrain for Trucks (LL), this combination has been omitted from the ITN model.

Note that while a particular combination of vehicle and powertrain is both available and practically feasible, this does not suggest that this combination will serve to satisfy transport demand. While fuel cells are available for regular cars, current cost levels, vehicle availability, and infrastructure suggest that battery powertrains will dominate this segment for the foreseeable future. Any such considerations are however heavily dependent on the choice of input parameters and scenarios.

4.4.2.3 Lifetime and annual average mileage

Lifetime and annual mileages are two necessary, and correlated inputs in ITN. In reality, a vehicles' average annual mileage is higher in the first years and drop considerably with age. IFE has simplified this data to an average annual mileage and assumes that lifetimes are equal within each type of vehicles. See section 5.3.5.4 in the ITN documentation (Danebergs et al, 2022b) for how this data has been derived and additional details. The lifetime and annual mileage for all the vehicle types are presented in Table 4.24.

Table 4.24: *Lifetime and average annual mileage for vehicle types.*

	Lifetime (years)	Average annual mileage (km)
Cars	17	13 200
Vans	15	15 300
Trucks (S)	15	30 000
Trucks (LS)	13	35 000
Trucks (LL)	6	90 000
Buses	10	41 800

4.4.2.4 Existing stock

The model also requires data on current vehicles as existing stock also has implications for future investments. Any existing vehicle will fulfill its lifetime according to Table 4.24 before it eventually is replaced with new investments. In ITN, the existing fleet of vehicles at the start year is primarily modelled as a stock of ICE powertrains which linearly decreases to zero during a time span equivalent to the vehicle's lifetime. The exceptions are battery and hybrid powertrains for cars as they have emerged and experienced rapid growth during the last few years. Battery and hybrid stocks are defined according to past investments and are based on road traffic volumes provided by Statistics Norway (n.d.b). Road traffic volumes for battery vehicles are based on data from 2012 to 2019, while data from 2016 to 2019 has been used for plug-in hybrid vehicles. The existing stock of cars with ICE powertrains is the difference between total demand in 2018, and the stock of battery electric and plug-in-hybrid cars. The existing stock of cars is subject to regional differences, but the aggregated values for Norway are presented in Table 4.25.

Table 4.25: Existing stock of cars by different powertrains in million vehicle-kilometers.

	ICE	Battery	Plug-in hybrid	Sum
Existing stock	31 329	2 405	1 415	35 149
Share of total stock	89%	7%	4%	100%

For the other vehicle types, existing stock is modelled as ICE powertrains equal to demand in 2018, summarized in Table 4.26. Additional details about the existing stock of vehicles can be found in section 5.3.4 of the ITN documentation (Danebergs et al, 2022b).

Table 4.26: Existing stock of vehicle types in million vehicle-kilometers.

Vehicle type	Powertrain	Stock in 2018
Cars	**Multiple**	35 149
Vans	**ICE**	7 307
Trucks (S)	**ICE**	510
Trucks (LS)	**ICE**	773
Trucks (LL)	**ICE**	773
Buses	**ICE**	541
	Gas powered ICE	33

4.4.2.5 Growth and market share limitations

As TIMES always chooses to invest in the option with the lowest lifetime cost available, growth limitations are provided for different vehicle types and powertrains to limit the model from transferring all investments into the cheapest option over the course of a single year. This is intended to reflect the fact that technology replacement is a gradual process. See Table 4.27 for growth limitations for different vehicle types. The growth limitations are provided based on percentage growth from current capacity in each year inspired by a 2021 report from the Institute of Transport Economics (Fridstrøm & Østli, 2021). The resulting growth potential over time is therefore exponential which makes it more limiting in terms of total volume for technologies with low existing stock, compared to matured widespread technologies. See section 5.3.6 of ITN documentation for additional details (Danebergs et al, 2022b).

Table 4.27: *Growth limitations for vehicle types.*

Vehicle type	Growth limitation
Cars	32%
Cars (ZEVs)	16%
Vans	42%
Vans (ZEVs)	21%
Trucks	34%
Trucks (ZEVs)	17%
Buses	34%

Note: For all vehicle types, growth limitations refer to the vehicle type as a whole, except for "ZEVs" (Zero emission Vehicles) which are combined growth constraints for battery electric and hydrogen powertrains

To model a more realistic development of vehicle investments, some technologies are also limited in terms of market shares. A maximum fuel share constraint limits a specific technology, and simultaneously ensures that alternate powertrains must satisfy the remainder of demand within a vehicle type. Whether such limitations have effects on modelling results depend on the specification of model scenarios as market shares do not necessarily reach their upper bounds. The combinations of vehicle types and powertrains that are subject to upper market share limitations are provided in the Table 4.28.

Table 4.28: *Upper market share limitations for selected vehicle types and powertrains.*

<table>
<tr><th>Vehicle type</th><th>Powertrain</th><th>2018</th><th>2020</th><th>2030</th><th>2040</th></tr>
<tr><td rowspan="3">Vans</td><td>Battery</td><td>0%</td><td>15%</td><td>100%</td><td>-</td></tr>
<tr><td>Plug-in hybrid</td><td>0%</td><td>1%</td><td>100%</td><td>-</td></tr>
<tr><td>Hydrogen</td><td>-</td><td>0%</td><td>100%</td><td>-</td></tr>
<tr><td>Trucks (S)</td><td>Battery</td><td>0%</td><td>-</td><td>100%</td><td>-</td></tr>
<tr><td>Trucks (LS)</td><td>Hydrogen</td><td>0%</td><td>-</td><td>100%</td><td>-</td></tr>
<tr><td rowspan="3">Buses</td><td>Battery</td><td>0.1%</td><td>5%</td><td>65%</td><td>92%</td></tr>
<tr><td>Biogas</td><td>-</td><td>5%</td><td>50%</td><td>100%</td></tr>
<tr><td>Hydrogen</td><td>-</td><td>0%</td><td>-</td><td>100%</td></tr>
</table>

Select vehicle investments are also modelled with lower bounds as there is significant political will to drive investments in ZEVs. IFE has therefore applied minimum shares of ZEVs for new investments, as provided in Table 4.29.

Table 4.29: *Minimum ZEV investment share for vans and trucks.*

Vehicle type	2025	2030
Vans (ZEVs)	45%	-
Trucks (ZEVs)	15%	30%

For vans, new investments in BEVs and FCEVs must constitute a combined 45% of new vehicle investments from 2025. For trucks, this applies to the same powertrains, but with 15% from 2025 and 30% from 2030.

4.4.2.6 Cost values and efficiency

In order to model which commodities and powertrains that will satisfy demand in the different road transport segments, costs associated with the various vehicle types and powertrain technologies are required. A complete overview of these costs is found in Appendix A, including investment costs, and operating and maintenance costs across the model horizon. In addition, data on fuel efficiencies for different vehicle types and powertrains are provided as they are a significant driver of energy costs for vehicles.

4.4.3 Maritime transport

The other transport sector modeled for hydrogen use is maritime transport. The data and modelling logic in this sector is comparable to road transport but relies more on assumptions and simplifications given the complex international nature of maritime transport and lower availability of data in this sector. Dividing maritime transport into distinct segments is a significant challenge. Consequently, there are significant limitations in maritime transport modeling in ITN, including lack of fixed operating and maintenance costs and constant fuel efficiency. As ships have a large variety in size, design, and operational patterns, IFE has used simplified disaggregates to identify segments where hydrogen, or hydrogen derivatives are available for bunkering. The demand for sea transport is thus divided only between fishing vessels and vessels operating in coastal areas. See section 5.4.3 of the ITN documentation (Danebergs et al, 2022b) for additional details including how maritime transport segments and demand have been identified. The maritime transport sector is divided into three vessel types: passenger vessels, fishing vessels, and other vessels. Lifetime is assumed to be 25 years for all vessel types.

4.4.3.1 Propulsion systems and commodities

The fossil fuels used for maritime transport include marine gas oil (MGO) and marine diesel oil (MDO) used in ICE propulsion systems which are simplified in ITN to be represented by the commodity “MGO”. In addition, there is liquefied natural gas (LNG) used in LNG propulsion systems. Both ICE and LNG propulsion systems can alternatively use bio-based fuels. Biofuel is available for ICE propulsion systems while biogas is available for LNG propulsion systems. The alternative propulsion systems are battery electric, compressed hydrogen and ammonia.

Battery- and hydrogen-based propulsion systems are available for short-distance trips while ammonia is available for deep-sea trips. This differences in propulsion system availability are modeled through fuel share limitations. As short and long trips each constitute a share of total transport demand within a vessel type, so does the maximum fuel share for this vessel type. As discussed in Section 2.4.3, ammonia is a hydrogen derivative, but no separate pathway for its production is modeled, so it is represented by low-pressure hydrogen (H_2-CENT). Vessels using hydrogen are modeled using compressed hydrogen (H_2-COMP) and relies on the HRS infrastructure discussed in Section 4.3.4. The fuel alternatives for maritime transport vary in the model according to exogenous or endogenous pricing. See Table 4.30 for propulsion systems, the commodities they rely on and how they are priced in the model.

Table 4.30: *Propulsion systems and commodities.*

Propulsion system	Commodities	Commodity prices
ICE	Marine gas oil (MGO)	Exogenous
	Biofuel	Import and domestic
LNG	Liquefied natural gas	Exogenous
	Biogas	Exogenous
Battery	Low-voltage electricity	Endogenous
Hydrogen	Compressed hydrogen (H_2-COMP)	Endogenous
Ammonia	Hydrogen from centralized production (H_2-CENT)	Endogenous

4.4.3.2 Demand and existing stock

The demand for and existing stock of sea-transport is divided between fishing and coastal transport. The aggregated sea-transport demand is summarized in Table 4.31. The demand values are provided in terms of GWh per year for ICE propulsion systems. Maritime transport demand is subject to regional variations but is presented here in aggregated values for the country. See also Figure 4.4 for a visualization of the relative growth in demand compared to the base year.

Table 4.31: *Aggregated sea-transport demand in GWh/year and percentage change from base year.*

Type of vessel	**2018**	**2030**	**Δ%**	**2050**	**Δ%**
Passenger vessels	3 488	3 562	2.1%	3 512	0.7%
Fishing vessels	2 725	2 978	9.3%	3 151	15.6%
Other vessels	4 687	5 122	9.3%	5 419	15.6%

Note: Passenger vessels include for instance high speed ferries and cruise ships, while other vessels include offshore vessels, freight ships, and bulk ships among others.

Figure 4.4: *Relative growth in maritime transport demand compared to the base year.*

Existing stock of maritime vessels is modelled with ICE and LNG propulsion in GWh per year and is presented in Table 4.32.

Table 4.32: *Existing stock of maritime vessels in GWh/year.*

Type of vessel	Propulsion system	Stock in 2018
Passenger vessels	**ICE**	3 031
	LNG	457
Fishing vessels	**ICE**	2 725
Other vessels	**ICE**	4 230
	LNG	457

4.4.3.3 Fuel efficiency

IFE has assumed a fuel efficiency for ICE in maritime transport at 45%. Battery electric systems are assumed to have an efficiency of 80% while hydrogen, ammonia, and LNG are assumed to be equal to conventional ICE. Efficiency is equal across all three vessel types. As the demand for maritime transport is provided in GWh/year for ICE propulsion systems, fuel efficiency for ICE is set to 1, and other efficiencies are modeled as relative to this value. The modeled efficiency values are thus a ratio expressing how much more or less demand a fuel can satisfy in comparison to an ICE propulsion system. For instance, as battery electric systems have an efficiency of 80%, it is 1.78 times more efficient than ICE meaning that the energy service demand can be satisfied with a lower amount of energy input with this propulsion system. See Table 4.33 for relative fuel efficiencies for maritime propulsion systems. Ammonia is derivative of hydrogen, but no process for its production has been modeled in ITN. Therefore, IFE has approximated the additional energy required for its production with a relative fuel efficiency reduction of 17% compared to hydrogen. Its efficiency value in the model data is therefore 0.83 rather than 1.

Table 4.33: *Relative fuel efficiency for maritime propulsion systems in demand / input*

Propulsion system	Relative efficiency
ICE	1
LNG	1
Battery	1.78
Hydrogen	1
Ammonia	0.83

4.4.3.4 Market share limitations

Table 4.34 shows the maximum market share a propulsion system can constitute for different vessel types, derived from work by Ocean Hyway Cluster (Valland, 2020). The years with 0% correspond year in which availability starts to emerge. Hydrogen and ammonia are immature technologies in maritime propulsion and are therefore available from after 2025. There are no limitations set for ICE propulsion systems.

Table 4.34: *Maximum share of each fuel and/or propulsion system in maritime transport.*

Type of vessel	Propulsion system	2018	2025	2030	2040
Passenger vessels	**LNG**	0%	-	86%	-
	Battery	0%	-	49%	-
	Hydrogen	-	0%	13%	-
	Ammonia	-	0%	38%	-
Fishing vessels	**LNG**	0%	-	-	50%
	Battery	0%	-	5%	25%
	Hydrogen	-	0%	5%	25%
	Ammonia	-	0%	5%	50%
Other vessels	**LNG**	0%	-	-	90%
	Battery	0%	-	5%	10%
	Hydrogen	-	0%	5%	10%
	Ammonia	-	0%	5%	90%

4.4.3.5 Investment costs

In effort to provide values for investment costs in the maritime sector, representative examples of vessels were identified to derive costs per MWh of demand. See section 5.4.3 of the ITN documentation (Danebergs et al, 2022b) for explanation of the method and sources used. This generalization was necessary to simplify the complex and diverse nature of maritime vessels which constitutes a wide distribution of sizes and operational patterns. Regarding investment costs for other propulsion systems than ICE, relative price differences are assumed. Investment costs in LNG vessels are assumed to be 20% higher than for ICE vessels in the start year, while other propulsion systems are assumed to be 50% higher. Investment costs are assumed to be constant for ICE and LNG vessels, but a 20% cost reduction towards 2030 is assumed for vessels with battery, hydrogen, and ammonia propulsion systems. Thus, in 2030, their investments costs are on parity with LNG ships, and only 20% higher than ICE vessels. Table 4.35 provides investment costs for different vessel types and propulsion systems in NOK per MWh of energy consumption.

Table 4.35: *Investment costs for maritime vessels and propulsion technologies in NOK/MWh.*

Vessel type	Propulsion technology	2018	2030
Passenger and fishing vessels	**ICE**	949.12	-
	LNG	1 138.94	-
	Battery, hydrogen, and ammonia	1 423.67	1 138.94
Other vessels	**ICE**	890.39	-
	LNG	1 068.46	-
	Battery, hydrogen, and ammonia	1 335.58	1 068.46

5 Price scenarios and sensitivity analysis

In this chapter, we present the data and assumptions related to our various model runs with different price scenarios and sensitivity analysis.

5.1 Price scenarios

In this thesis, we have defined three scenarios with different price levels for parameters that may have significant implications for the development of the Norwegian energy system. These parameters include the national CO_2 tax, the price of natural gas and coal, and power prices in countries that Norway can trade electricity with. Our scenarios are specified to convey differing competitive conditions for hydrogen by varying the price levels of its production inputs, and by varying the CO_2 prices that emitting production technologies are subject to. The scenarios include one Baseline scenario, and two scenarios where the price levels of the parameters are relatively higher and lower compared to Baseline. The latter two scenarios are referred to as the High price- and Low price scenario, respectively. In Section 5.1.1 and 5.1.2, the sources and data for the different scenario parameters are presented.

5.1.1 CO_2 tax

The CO_2 tax levels used for the different scenarios are based on CO_2 price trajectories from the Norwegian Ministry of Finance, recommended for use in socio-economic analysis. In the ITN model, we have applied the carbon prices presented for non-quota emissions in table 2 of (Ministry of Finance, 2021a) to the national CO_2 taxes in the Baseline scenario. This carbon price trajectory is based on a gradual increase of the CO_2 tax to 2 000 NOK/ton CO_2 in 2030, which is in line with the climate policies that the Norwegian Government announced in “Klimaplan for 2021-2030” (Ministry of Finance, 2021b; Meld. St. 13 (2020–2021)). The Baseline scenario thus reflects the announced and expected climate policy of the Norwegian government. The CO_2 tax levels used in the High- and Low price scenarios, however, are based on the high and low carbon price trajectories presented in table 3 of (Ministry of Finance, 2021a). The CO_2 taxes applied in the three scenarios are presented in Figure 5.1.

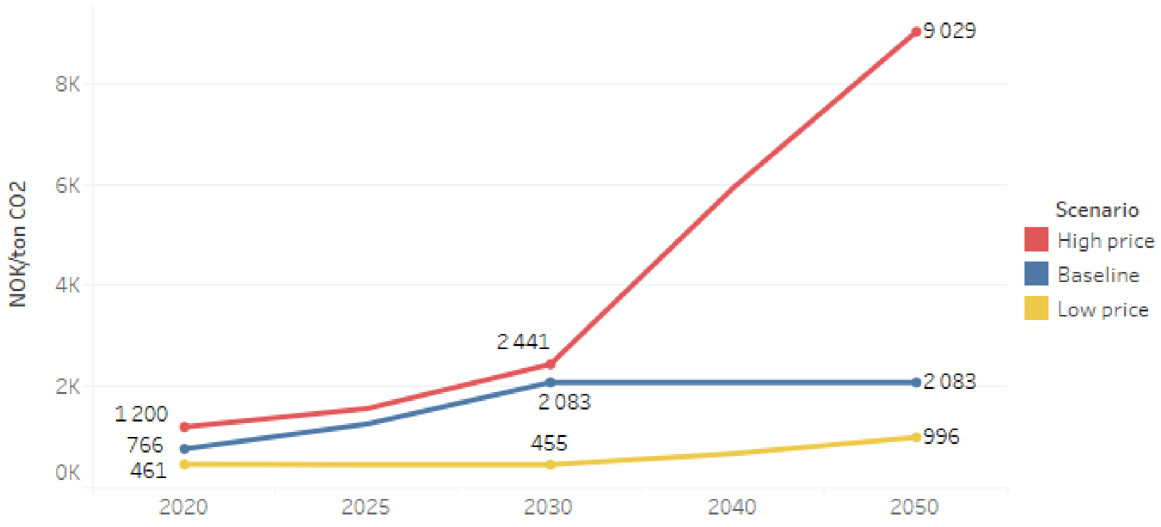

Figure 5.1: *CO_2 tax by scenario and year. A table of the CO_2 taxes can be found in Appendix B.*

In the carbon price trajectories presented by the Ministry of Finance, the CO_2 prices vary from year to year in the period between 2021 and 2050. In the ITN model, however, we have applied the CO_2 prices to the representative milestone years of the model horizon. Then, the annual CO_2 tax within a model period is calculated based on linear interpolation between milestone years. The CO_2 prices presented for 2021 are used for 2020 within the model, as this is the closest milestone year.

5.1.2 Fossil fuels- and power prices

In the ITN model, the hourly electricity prices of each spot-price region are modeled endogenously based on all the various factors that impact electricity prices. A significant factor in this calculation is the hourly electricity prices for countries with transmission lines to Norway, which are provided exogenously. For the purposes of our thesis, we have used electricity price projections from NVE's long-term power market analysis from 2021 (Birkelund et. al, 2021) to model the import and export prices for electricity. In their analysis, NVE presents three different projections for electricity prices in countries that have transmission capacity to Norway. The projections from NVE includes one reference (baseline) scenario and two projections with relatively higher and lower electricity prices which we have applied to our own scenarios.

Notably, the projections from NVE only include hourly power price data for the model years of 2021, 2025, 2030 and 2040. We therefore applied the prices from 2021 for the base year of our model and constant prices from 2040 and onwards. For the period within 2021 and 2040, linear interpolation was used to apply the electricity prices to years between successive milestone years. In Table 5.1, the average power prices in countries that Norway can trade electricity with is presented for the three scenarios.

Table 5.1: *Average trade price for electricity in countries that Norway can import electricity from, by scenario and year in NOK/MWh.*

	Baseline			High price			Low price		
Country	**2025**	**2030**	**2040**	**2025**	**2030**	**2040**	**2025**	**2030**	**2040**
Sweden	502	512	469	608	655	579	416	398	352
Denmark	552	551	526	668	706	669	457	430	393
Finland	478	467	471	576	593	576	399	366	356
Germany	573	564	542	697	726	697	474	440	403
Netherlands	546	532	551	664	684	713	449	414	408
UK	599	560	621	713	718	816	501	437	454
Russia	237	264	334	284	336	434	189	202	234

The electricity price projections from NVE were modeled to capture the uncertainty of future electricity prices, and the estimates were based on variations in central parameters that impact the electricity price. In particular, the projections were based on different price trajectories for coal, natural gas, and CO_2 prices within the EU ETS and Great Britain (Birkelund et al, 2021). To design a consistent set of scenarios, we applied the different price levels for natural gas and coal assumed by NVE in our three scenarios. On the other hand, the assumed CO_2-quota prices are not included, as a representation of the EU ETS is not included in the ITN model. Instead, the national carbon tax levels presented in the Figure 5.1 are used to capture the direct effects of CO_2-pricing. The prices for natural gas in the different scenarios are presented in Figure 5.2, while the prices for coal are presented in Figure 5.3.

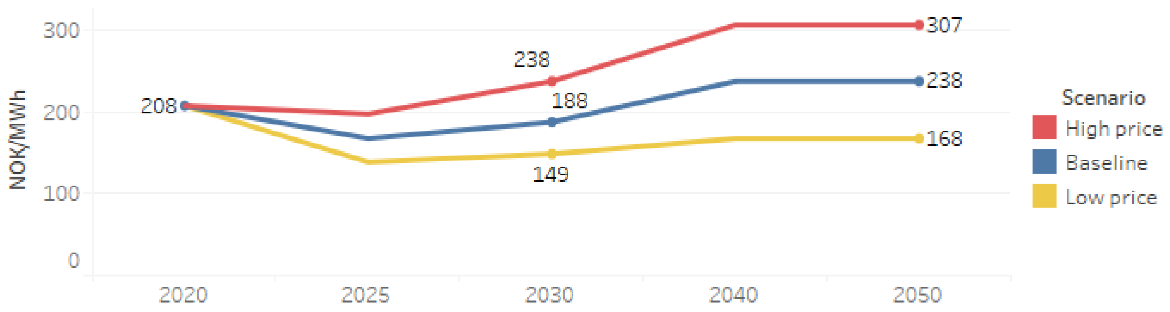

Figure 5.2: *Natural gas (NG) prices by scenario. See Appendix B for a table of the NG prices.*

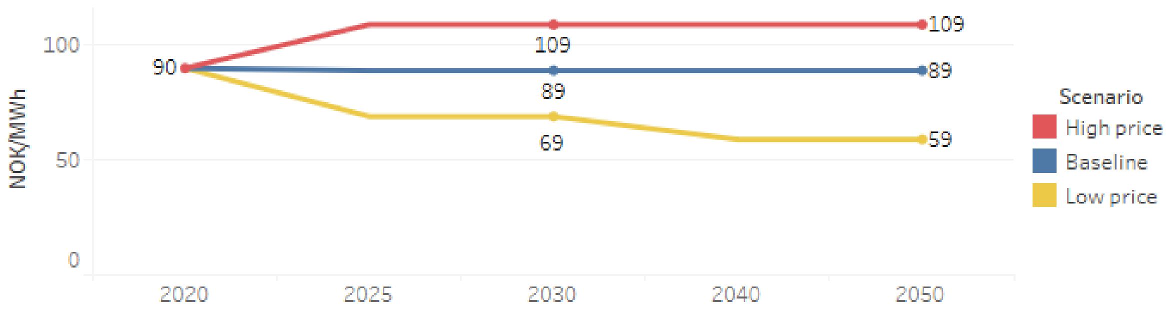

Figure 5.3: *Coal prices by scenario. See Appendix B for a table of the coal prices.*

The inclusion of coal and gas price projections in our scenarios contribute to their coherency and comprehensiveness as they cover additional implications and assumptions associated with higher power prices. Higher CO_2 prices drive the prices of the emission-heavy primary energy sources gas and coal, which again impacts the costs of electricity production. As of 2021, fossil fuels accounted for 37% of electricity generation in the EU (Moore, 2022). While the share of fossil fuels for electricity generation is lower in the countries that Norway trade electricity with compared to the EU average, fossil fuel generation also impact the prices of these countries through their own set of transmission connections with other countries. The correlation between the included prices, and between grid-connected countries forms the justification of parameter selection for scenarios in our modeling work.

5.2 CO_2 tax sensitivity

As a hypothesis was that hydrogen prevalence is particularly sensitive to carbon pricing, our analysis included model runs to specifically assess how sensitive hydrogen prevalence may be to variations in CO_2tax. For this purpose, we included two model runs where the High- and Low price scenarios were run with the Baseline values for the CO_2 tax. This enabled us to isolate the effects of the CO_2 tax from the variations in the other scenario parameters.

6 Results

In this chapter, we discuss our results from the various modeling runs presented in Chapter 5. In Section 6.1, we explain the analytical approach used to evaluate and compare the model results. In Section 6.2, we present an overview of the main results from the three scenarios and the CO_2 tax sensitivities. Section 6.2 is used to illustrate the overall effects of the various parameters that drive the variations between scenarios. In the subsequent sections, the main results from the scenarios will be analyzed in higher detail, with a special focus on the Baseline and High price scenario. In Section 6.3, we focus on how hydrogen is produced in the model and compare the competitiveness of the different production technologies. In Section 6.4, we assess how the hydrogen supply chains are utilized to deliver hydrogen from its point of production to end-consumption. In Section 6.5, we present the consumption of hydrogen in the three end-use sectors and discuss the competitiveness of hydrogen relative to competing energy carriers and technologies. Finally in Section 6.6, we summarize our results and discuss them in relation to our research questions.

6.1 Analytical approach

Before we proceed to our results, we will revisit the optimization logic and model behavior of ITN as discussed in Chapter 3, and explain the decision variables, result parameters, and metrics we rely on throughout our analysis.

6.1.1 Decision variables and metrics

On the supply side, the most significant decision variables of our analysis are the total capacities and new investments in different production technologies and their corresponding activity (production output). In addition, we inform our assessment of hydrogen supply by analyzing the long run marginal costs for hydrogen. Recall from Section 3.1.1.2 that the results for supply are driven by demand for energy services. As TIMES calculates a partial equilibrium for energy markets, the endogenous supply of energy carriers is optimized such that its production is exactly equal to the quantities that end-use consumers are willing to buy. The supply of hydrogen and competing energy carriers are dictated by their cost effectiveness and availability in various end-use processes as according to the stepwise inverse supply function. We assess the cost-effectiveness on the demand side by calculating lifetime costs for each end-use technology. This approach will be explained in higher detail in Section 6.5. The lifetime costs of end-use processes are calculated according to a combination of input data for their techno-economic parameters, and result values for operational costs. The most significant results for these calculations are the values for CO_2 costs and fuel costs for hydrogen and its competing alternatives. The calculation of lifetime CO_2 costs enable us to assess its impact on cost-effectiveness for end-use alternatives, and assess how, and to what degree, it shifts the ranking of competing technologies.

The mutual dependency between the endpoints of the supply chain calls for a holistic approach to analysis of the markets for hydrogen, including how hydrogen flows in the energy system. We therefore also assess how the centralized and distributed supply chains interact, and how the supply of hydrogen to end-use processes may rely on storage and distribution.

6.1.2 Scope of analysis

The cost-effectiveness of hydrogen can be assessed down to a level of detail which generally includes scenario, spot-price region, and year. Throughout this chapter, individual specifications of this detail level are referred to as "instances". A specific instance is for example, "High price scenario, NO2, 2040". The level of detail provides context for analysis as regional and temporal variations explain the model behavior to a significant degree. Variations across regions or years such as energy service demand and commodity prices, can be determining factors for the model output on decision variables. Consequently, the total volumes of hydrogen in our results reflect the sum of instances where hydrogen is the cost-effective option for an end-use process, and therefore investments in production and consumption technologies occur. The production and consumption results for a single instance should be understood as: Investments in hydrogen technologies occur because hydrogen can be produced at a market price that makes it the cost-effective option for an end-use process, in a particular region at a given point in time. As the model optimizes according to perfect foresight, hydrogen must be the cost-effective option not only at the time of investment, but also across the entire lifetime of the relevant equipment. Besides cost-effectiveness, the optimization logic is also subject to additional user constraints as discussed in Section 3.1.1.4. These user constraints, as provided throughout Chapter 4, include limitations on regional availability of production technologies, growth limitations for end-use equipment, and maximum fuel shares for hydrogen or its alternatives in end-use sectors. The user constraints will be discussed throughout this chapter in instances where they are binding.

6.2 Results overview

In this section, we provide an overview of the main results from the three scenarios and the CO_2 tax sensitivities and discuss the overall effects of their parameter variations. The total annual production and consumption of hydrogen in 2030, 2040, and 2050 are represented for the three scenarios and CO_2 tax sensitivities in Figure 6.1. The results show that production and consumption of hydrogen emerges from 2030 with increasing volumes towards 2050 across all model runs. However, there are significant variations in the total hydrogen volumes between the different model runs. In the Baseline scenario, an annual volume of about 9.5 TWh hydrogen is produced and consumed by 2050, equivalent to about 3 thousand tons of hydrogen. In comparison, the total volume is approximately 75% higher in the High price scenario, and 90% lower in the Low price scenario.

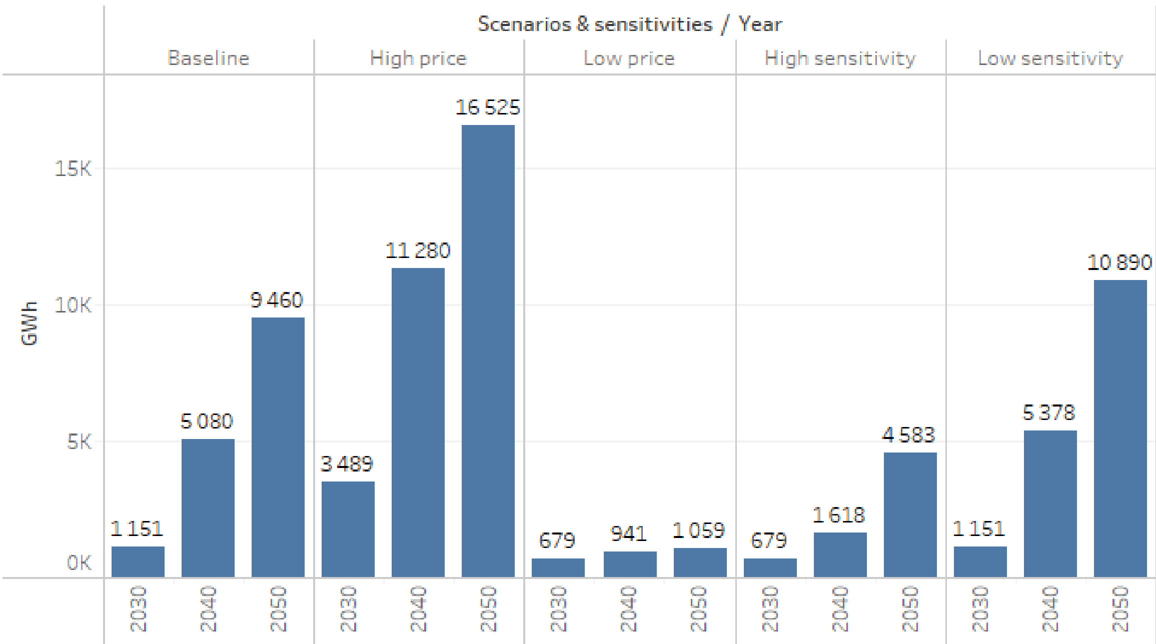

Figure 6.1: *Annual hydrogen production and consumption in the three scenarios (Baseline, High price and Low price) and the two CO_2 tax sensitivities (High- and Low sensitivity).*

The differences in the overall hydrogen volumes presented in Figure 6.1 is an indication of the overall competitiveness of hydrogen in the different model runs. The effects of the input price parameters in the scenarios (power and fossil fuel prices) can be isolated from the effects of the CO_2 tax by assessing the results from the CO_2 tax sensitivities in relation to the scenarios. In particular, the results from the High price scenario must be evaluated in relation to the High sensitivity, while the Low price scenario must be seen in relation to the Low sensitivity. The only parameter variation between the mentioned scenarios and sensitivities is the CO_2 tax, as this is unchanged from the Baseline scenario in the CO_2 tax sensitivities. Thus, the differences between the respective scenarios and sensitivities can be attributed entirely to the CO_2 tax. When compared only to each other, the sensitivities show the isolated effects of variations in fossil fuels- and power prices. A summary of how the scenario parameters are varied between our modeling runs is presented in Table 6.1.

Table 6.1: *Summary of scenario parameter variations for the different model runs.*

	Baseline	**High price**	**Low price**	**High sensitivity**	**Low sensitivity**
CO2 tax	Middle	High	Low	Middle	Middle
NG & coal prices	Middle	High	Low	High	Low
Import & export electricity prices	Middle	High	Low	High	Low

From the High sensitivity in Figure 6.1, we can see that higher fossil fuel- and power prices lead to less production and consumption of hydrogen, and vice versa for the Low sensitivity. Higher prices for natural gas and electricity results in higher production costs for SMR based hydrogen plants and water electrolysis technologies, respectively. On the other hand, the High price scenario shows that higher CO_2 tax levels counteract the effects of increased input prices for hydrogen production technologies, and vice versa for the Low price scenario. An increase in the CO_2 tax results in higher costs for emission-intensive energy carriers, and effectively renders low- and zero-emission alternatives such as hydrogen more competitive. Interestingly, the effects of the input price variations on the overall hydrogen volumes are significantly outweighed by the effects of the CO_2 tax variations. Thus, the CO_2 tax is the single most important driver for the overall competitiveness of hydrogen in our model results. The effects of the CO_2 tax will be discussed in further detail throughout Section 6.5, where the relative competitiveness of hydrogen in the end-use sectors is assessed.

In the remainder of this chapter, the results from the Baseline and High price scenario will be the main focus of our analysis. These are the scenarios with the most significant volumes of hydrogen production and consumption, which enables a more detailed analysis of supply chain patterns. On the other hand, the hydrogen production capacities seen in the Low price scenario are minimal. In most instances, the investments in the Low price scenario corresponds to capacities that are substantially lower than the scales for which the techno-economic parameters of the production technologies are based on. Thus, the results of the Low price scenario may be considered to be unrealistic, and the analysis of this scenario will therefore be quite limited. In addition, the results from the CO_2 tax sensitivities will not be explicitly analyzed in the remainder of this chapter, as they were only included to highlight the isolated effects of the scenario parameters.

6.3 Hydrogen production

In this section, we analyze the investments in the hydrogen production technologies. We will first provide an overview of the total production volumes before we discuss the composition of production technologies at the centralized and the distributed scale in a higher detail in Section 6.3.1 and 6.3.2. In Figure 6.2, the total annual hydrogen production volumes from all production technologies are presented for the three scenarios. The production results show that hydrogen production and consumption emerge from 2030 with increasing production volumes over time.

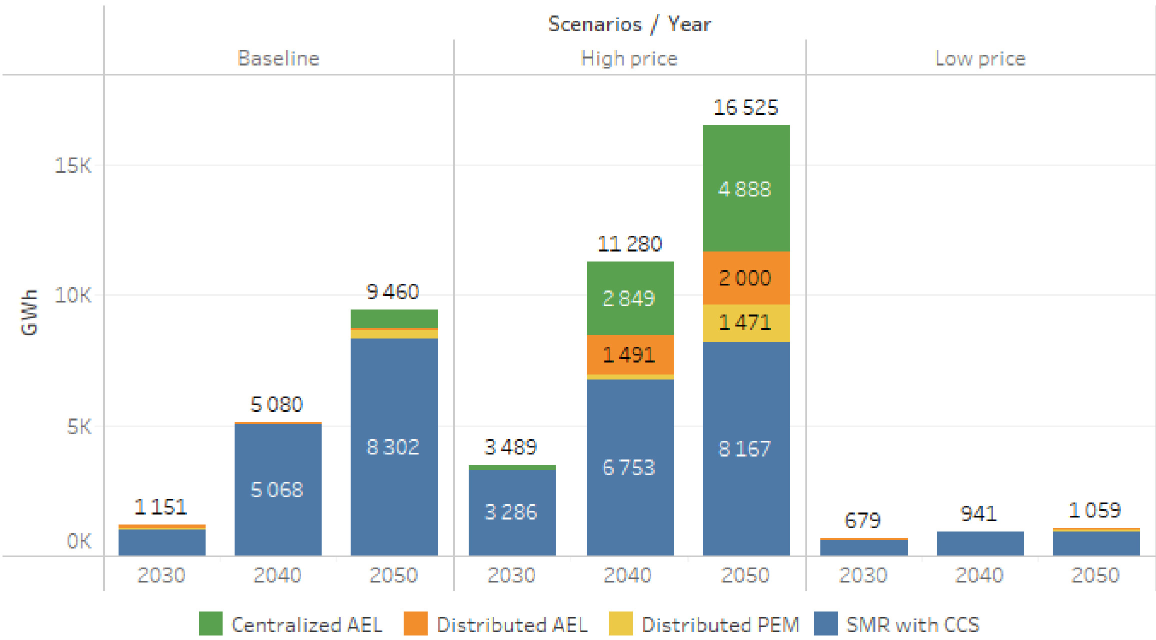

Figure 6.2: *Total annual hydrogen production by technology in the three scenarios.*

Furthermore, the results show that the bulk of hydrogen production comes from centralized, large-scale production plants, and particularly from SMR with CCS. SMR with CCS is the dominant production technology across all years and scenarios, as it accounts for the greatest share of the production volume. However, its overall share of production decreases towards 2050 as water electrolysis technologies become more competitive. At the centralized scale, AEL is the universally preferred electrolysis option as PEM is never cost-effective and is not invested in. At this scale, the investments- and operation costs are too high compared to AEL. At the distributed scale, both AEL and PEM electrolysis is invested in, as the cost-effective supply solution is generally a combination of the two technologies.

6.3.1 Centralized production

In this section, we provide an analysis of the investments in the centralized hydrogen production technologies. First, we discuss the invested capacities in the production technologies across the model horizon. Then, we present the hydrogen market prices for the production technologies and analyze how the scenario parameters affect the variable costs of their production activity.

6.3.1.1 Centralized production investments

To assess the capacity investments in the centralized technologies, a regional breakdown is in order. This is presented for the Baseline and High price scenario in Figure 6.3. As can be seen in the figure, SMR with CCS is generally the chosen production technology in the regions where it is available (NO2-NO5). In all regions apart from NO4 in 2050, SMR with CCS is the preferred investment option in the Baseline scenario. In the High price scenario, AEL is invested in earlier and in more regions, with investments from 2030 in NO4 and additional investments in both NO1 and NO3.

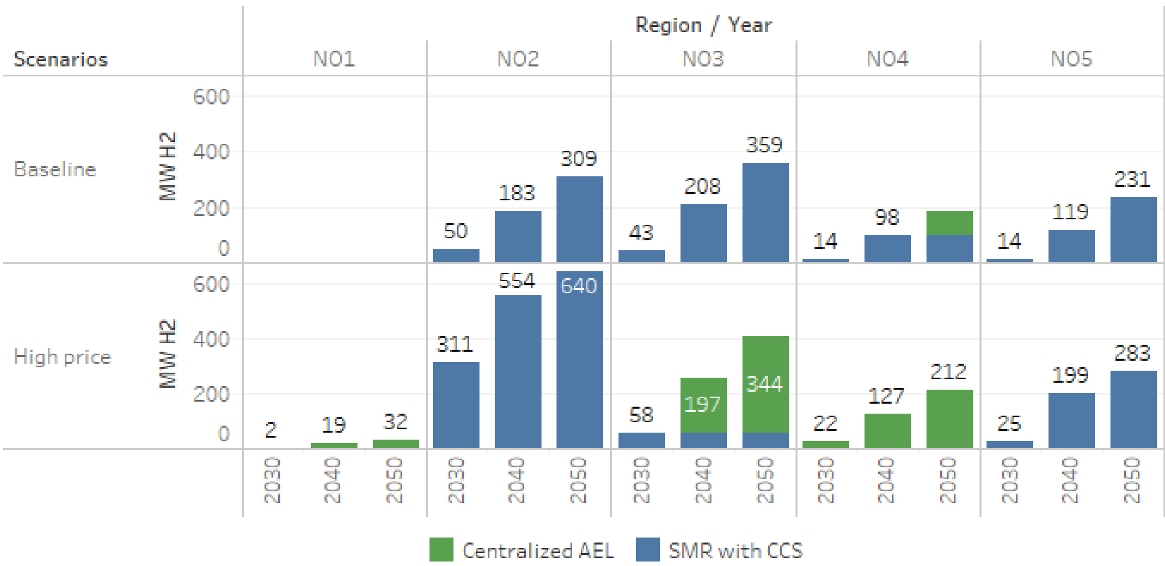

Figure 6.3: *Cumulative capacity investments in centralized hydrogen production per region in the Baseline and High price scenario.*

The distribution of investments in the centralized production technologies can be explained by the scenario variations that impact their production costs and corresponding market prices for hydrogen. In particular, the variable unit cost of production is a significant factor for the cost-effectiveness of a technology, and therefore the invested capacity. We will discuss prices, costs, and cost-effectiveness to a higher degree in Section 6.3.1.2, but the general explanation is: SMR with CCS is the cost-effective investment option, except for instances where the high-voltage power prices are particularly low. In these instances, investments are exclusively in AEL.

6.3.1.2 Centralized hydrogen market prices

A more detailed assessment of the investments in the centralized production technologies warrants a look at the capacities' corresponding market prices. In Table 6.2, the marginal system value, i.e., the market prices, for a kilogram of hydrogen are provided for centralized AEL electrolysis and SMR with CCS. The price of low-pressure hydrogen (H_2-CENT) at the centralized scale exhibit low variation within single milestone years, meaning that the prices are similar across regions. The SMR prices remain relatively stable across the Baseline scenario but increases across the model horizon in the High price scenario. According to IEA's Global Hydrogen Review 2021 (IEA, 2021a), the global production costs of hydrogen from natural gas with CCS were in the range of approximately 10-20 NOK in 2020 and is expected to increase slightly over time because of future increases in CO_2 prices. The SMR prices from our Baseline scenario are close to the upper value of this range, while the prices in the High price scenario are significantly higher. At most, the SMR prices in the High price scenario are 31% higher than IEA's estimates.

On the other hand, the AEL prices exhibit higher variations within years, and decreases over time. According to IEA (2021a), the current costs of electrolysis production based on grid electricity is in the range of approximately 30 to 50 NOK/kg H_2 based on a power price range of 500 to 1000 NOK/MWh. IEA also estimates that the prices could fall to approximately 20 NOK/kg H_2 by 2030 and 15 NOK/kg H_2 by 2050. Future AEL price estimates are however highly dependent on assumptions about technological developments for electrolyzer equipment costs and operation. IEA's estimates rely on assumptions that future production will be based on renewable energy, which is unavailable in our model. Our prices are thus not entirely comparable with IEA's estimates as renewable energy could contribute to lower power costs for electrolysis production. Our average price in the High price scenario of 31.44

NOK in 2030 and 25.19 NOK in 2050 are quite higher than IEA's estimates. However, the average 2050 price from the Baseline scenario of 17.98 NOK is reasonably close.

Table 6.2: *National weighted averages (Avg.) and regional minimum (Min.) and maximum (Max.) prices for hydrogen in NOK/kg H_2 from centralized production units in the Baseline and High price scenario.*

		2030			2040			2050		
Scenario	**Technology**	**Min.**	**Avg.**	**Max.**	**Min.**	**Avg.**	**Max.**	**Min.**	**Avg.**	**Max.**
Baseline	**Centralized AEL**	-	-	-	-	-	-	17.98	17.98	17.98
	SMR with CCS	18.59	18.90	18.94	19.79	20.52	21.56	17.98	20.89	21.21
High	**Centralized AEL**	30.98	31.44	37.08	21.71	24.59	35.23	21.80	25.19	33.38
	SMR with CCS	21.58	21.85	23.02	25.58	25.84	25.86	26.68	28.36	28.47

Note: All hydrogen prices are weighted averages for a single milestone year. The minimum and maximum values are weighted averages for a single region, while the national average is a weighted average of all the regional prices. The national average prices have been weighted by the regional productional volumes. The regional production volumes and prices can be found in Appendix C. Note that prices are not available for AEL in the baseline scenario in 2030 and 2040 as there are no capacity investments in the technology in these instances.

6.3.1.3 Variable production costs and cost-effectiveness

The price of hydrogen from centralized production is a product of the technologies' variable cost in addition to their techno-economic parameters. For SMR with CCS, all techno-economic parameters remain constant from 2030 onwards, meaning that variations in the market price and cost-effectiveness of the technology can be explained entirely by changes in variable costs. For SMR with CCS, the variable costs are made up by the price of natural gas input and CO_2 tax costs. For AEL on the other hand, power price is the only variable costs, but technological improvements have been modeled for the AEL technology which affects the market prices of its production and its cost-effectiveness across the model horizon. However, as we will explain throughout this section, the variations in market prices for AEL can also be mostly attributed to the variable costs of production.

The costs of SMR with CCS that are subject to variations across the years 2030 to 2050 is natural gas costs and the CO_2 tax costs. The CO_2 tax costs are however only varying for the High price scenario in this model period. Our natural gas costs ranges between an average of 44% of the total production costs for SMR in the Baseline scenario in 2030, to an average of

47% in the High price scenario in 2050. IEA (2019) estimates the cost of natural gas to account for 45% to 75% of production costs globally, which places our results on the lower end of this spectrum. The estimates from IEA (2019) however does not take CO_2 costs into account as a variable cost which would drive their natural gas share of production costs down. The CO_2 tax component constitutes a range from 6.3% of total unit cost in the Baseline scenario in 2030, to 18% in the High price scenario in 2050. In monetary terms, the range of natural gas costs correspond to a maximum difference to unit costs of 5.22 NOK, while the CO_2 cost range corresponds to a difference of 3.94 NOK. The most significant driver of increasing market prices for hydrogen produced from SMR with CCS is thus the price of its natural gas input. In the absence of natural gas price increases, the market price increase would correspond more closely to IEA's expectations of a slight cost increase driven by CO_2 prices.

For the centralized AEL plants however, the only variable cost is the prices of its power input from the high-voltage grid. In contrast to the natural gas input cost for SMR with CCS, the levels and trajectories of these prices are subject to regional differences. See Figure 6.4 for the regional high-voltage power prices in the High price scenario across 2030 to 2050. In comparison to SMR with CCS, the production inputs for AEL constitutes a much larger share of the total unit cost. From its minimum value (NO4, 2030) to its maximum value (NO1, 2050), the power input cost varies between 85% to 92% of total unit cost for AEL. In monetary terms, the range is 19.4 to 32.53 NOK/kg H_2. The power costs share of hydrogen production in our model is thus in the upper end of the range from IEA (2021a) which estimates a share of 50 to 90% of the overall production cost. As AEL relies on a single variable cost with larger variations than SMR with CCS, it is far more sensitive to input price variations than SMR with CCS. The power input prices for AEL must however be assessed relative to its technological improvements across the model horizon. In regions where the power prices are high and increases across the model horizon, they counteract the efficiency improvements and equipment cost reductions of AEL. As a result, AEL is not cost-effective and investments do not occur unless it is the only available centralized technology in the region, as is the case in NO1. The maximum market price for AEL in the High price scenario seen in Table 6.2 is from NO1, as this is the region with both the highest power prices and the largest power price increase across the model horizon.

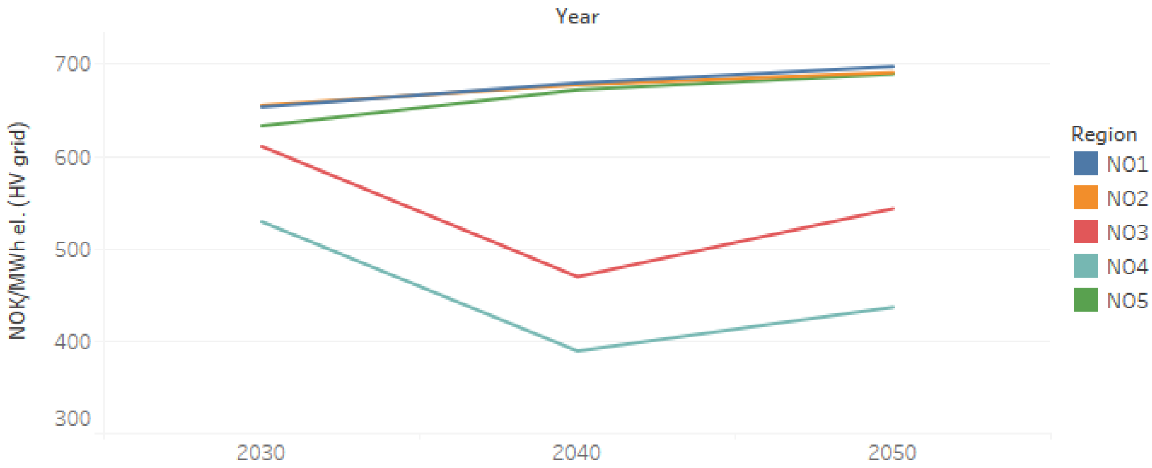

Figure 6.4: *Yearly average power prices for electricity in the HV-grid in all spot-price regions for the High price scenario.*

In regions where the power prices are lower and decreasing over time however, the power prices compound the effects of technical improvements on AEL cost-effectiveness. In these instances, the production costs in 2050 are significantly lower than in 2030, driving the cost-effectiveness and investments in AEL across the model horizon. As seen in Figure 6.4, the spot price regions with a net decrease in power prices is NO3 and NO4. The minimum market price for hydrogen from AEL in the High price scenario is in NO4 in both 2030 and 2050. This is the region with the lowest power prices, and the largest power price decrease across the model horizon. Besides NO1, where SMR with CCS is unavailable, the instances in which AEL is invested in corresponds to regions in which the power prices are initially the lowest, and where they decrease across the model horizon, as is the case in NO3 and NO4. This also holds true for the single instance of AEL investments in the Baseline scenario. The power price level and trajectory in NO4 are sufficient to make AEL cross the threshold of cost-effectiveness in 2050 also in this scenario. While the price trajectories for high-voltage power are different across the regions where AEL is invested in, the net effect of the price effects and the technological improvements is a decreased national average market price of centrally produced from AEL, as seen in Table 6.2.

6.3.2 Distributed production

In this section we discuss the results regarding capacity investments in the two electrolysis technologies at the distributed scale. First, we explain the invested capacities before we discuss the resulting hydrogen prices at HRS for road transport consumption.

6.3.2.1 Distributed production investments

In contrast to centralized production, the capacity investments on the distributed scale generally does not choose a single cost-effective technology, but rather relies on a combination of investments in PEM and AEL. See Figure 6.5 for cumulative capacity investments in the distributed technologies by year, scenario, and region. The results show that in most of the instances where investments occur, they are in both technologies. The regional differences are driven by the demand volumes and cost-effectiveness of hydrogen in road transport in each individual region. We will return the discussion of cost-effectiveness for road transport in Section 6.5.2, but for now we will discuss the supply mix in distributed production and explain why both technologies are relied on across instances.

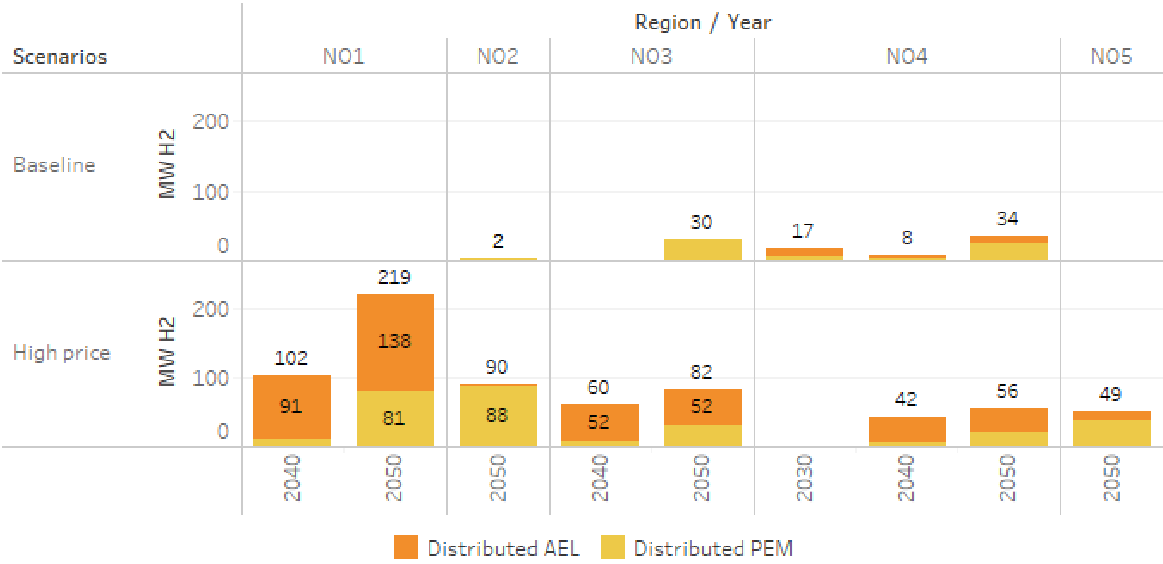

Figure 6.5: *Cumulative capacity investments in distributed water electrolysis technologies per region in the Baseline and High price scenario.*

While the optimization of ITN generally dictates that a sole cost-effective available technology will be preferred for investments, this only holds true when the alternatives are operationally and functionally equivalent. While PEM and AEL electrolysis produce the same commodity based on the same inputs, they are not fully equivalent technologies since their operational flexibility differs. As discussed in Section 2.2.2, the fast response time of PEM plants means that it can adapt its production activity to fluctuations in power prices to a higher degree than AEL, which may result in lower production costs. On the other hand, AEL is the cheaper technology on average across time slices but does not have the same operational flexibility to adjust its output according to high or low power price fluctuations. A more accurate description of this optimization is thus: A supply alternative is not invested in unless it can *contribute* to satisfying energy service demand at a lower cost, and on the distributed scale, both PEM and AEL does so in many instances, but with temporal variations within the time slices of the year. We can assess and explain this in further detail by analyzing the technologies' behavior in different instances. Particularly, we can look at power price fluctuations and production activity for PEM across the time slices of a year, and its relationship with hydrogen storage. This is shown in Figure 6.6, which illustrates the hourly correlation between electricity prices, PEM production activity, and hydrogen storage. The example is from the NO3 region in 2050, in the Baseline scenario, but is representative for its behavior across instances.

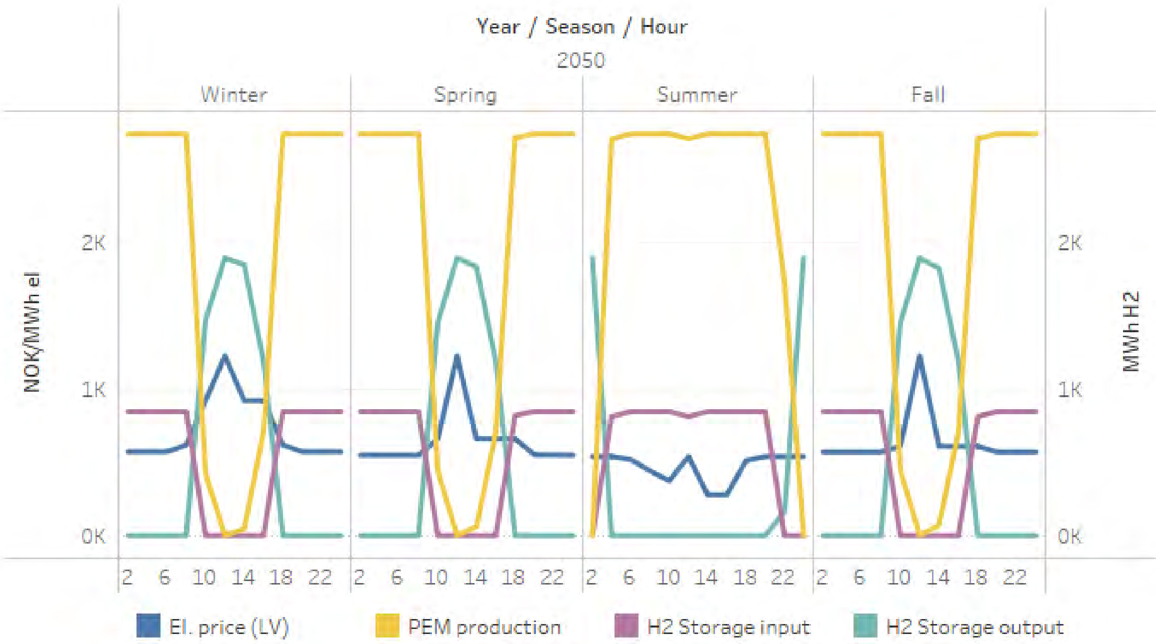

Figure 6.6: *Relationship between hourly electricity prices (in the low-voltage grid), distributed PEM production, and hydrogen storage. The prices and production volumes are from the NO3 region in 2050 in the Baseline scenario.*

In this instance, PEM is the sole supplier of hydrogen to road transport. It is therefore responsible for satisfying the entirety of demand. As the demand profile is flat, the supplied volumes are constant across all hours. Throughout a 24-hour day, the supply comes either directly from PEM production, from intermediate storage of hydrogen, or from a combination of the two. As seen in Figure 6.6, PEM electrolysis produce with a high load factor in the hours in which the power prices are relatively low. For all time slices with peak production in the figure, the load factor is 100%. As the demand is flat and constant across all time slices, any excess production must be stored temporarily. A stable share of production flows to storage throughout all peak production hours. In the mid-day hours when the power prices are the highest, PEM reduces its load factor to 0%, and the consumption shifts to rely entirely on stored volumes of hydrogen. As the storage is only available for the "daynite" time slice level, the net flow in and out of storage is zero within 24 hours. This pattern holds true for the winter, spring and fall seasons. In the summer, the load factor remains high throughout the day as there is no power price peak, and the storage output shifts to nighttime. As PEM is the sole supplier in this instance, its average load factors, production outputs, and storage volumes are the same across seasons and days. On a seasonal basis, the load factor is approximately 69%, 46 MWh is produced, and 13 MWh flows in and out of storage.

In instances with production capacity in both PEM and AEL, the behavior of PEM is somewhat different. However, the patterns of load factor and storage in relation to power prices from Figure 6.6 is still applicable. As the load factor is a very significant driver of the unit costs of production, PEM is still reliant on a high average load factor in order to be a cost-effective option despite not being solely responsible for satisfying demand. Rather than producing strictly according to leveraging fluctuating power prices, the PEM production must also contribute to satisfying the continuous demand of hydrogen for road transport. The differences in these instances lie in the fact that PEM is not the sole supplier and therefore have higher production flexibility across seasons.

While PEM may utilize power price fluctuations to a higher degree than AEL, the latter also benefits from lower power prices. For any hourly time slice in which the power prices are particularly low, AEL also nets a benefit to its variable production costs. The actual power costs that PEM and AEL are subject to in this instance is visualized in Figure 6.7.

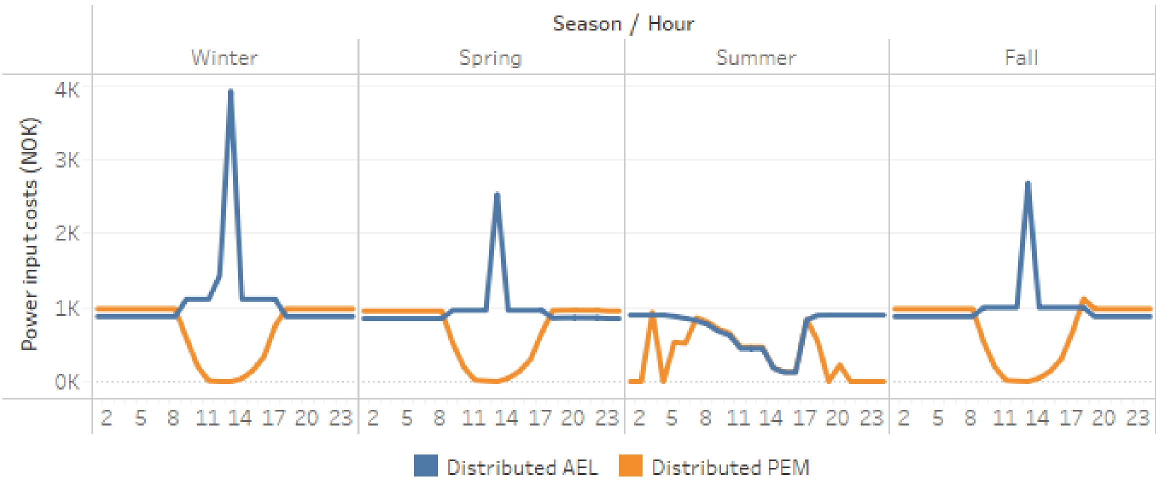

Figure 6.7: *Power input costs (NOK) per hour for PEM and AEL in NO3, 2050, High price scenario. The power input costs are the product of the technologies' efficiency, and the electricity price and load factor in a given time slice.*

As seen in Figure 6.7, the power costs of production correspond closely between the two technologies in many hours across a day. This occurs when the power prices are low and thus, the load factor of both technologies is at maximum. The minor variations occur due to a slight difference in the two technologies' efficiency (72% for AEL and 69% for PEM). The primary benefit of PEM is thus not that it increases production in hours of lower prices, but that it can *avoid* production at peak power price hours. The result is production at lower unit costs for a limited number of time slices. PEM is also subject to lower power costs than AEL on average across time slices, but this is counteracted by the lower load factors of its production. A lower load factor increases the unit costs as there is a lower volume of hydrogen that the equipment costs can be divided by. A summary of production metrics from the High price scenario (NO3, 2050) is provided in Table 6.3.

Table 6.3: *Production activity for PEM and AEL across seasons in NO3, 2050, High price scenario.*

Season	Technology	Production (MWh)	Load factor	Share of production
Winter	**AEL**	107	93.4%	69.8%
	PEM	46	69.5%	30.2%
Spring	**AEL**	106	93.3%	69.7%
	PEM	46	69.7%	30.3%
Summer	**AEL**	114	100%	74.8%
	PEM	39	58.1%	25.2%
Fall	**AEL**	107	93.3%	69.8%
	PEM	46	69.6%	30.2%

AEL has an annual availability of 95%, meaning that its average load factor across the year can be maximum 95%. It can however operate with a 100% load factor in limited time slices. AEL optimizes according to this constraint by maximizing its load factor in seasons when it is most beneficial compared to PEM. In our example instance, AEL increases its load factor to 100% in the summer, while PEM reduces its output slightly to compensate. As seen in Figure 6.7, there is no power price peak in the summer that PEM can leverage. AEL is therefore the prime benefactor of the power price fluctuations in the summer in this instance. In other instances, production shares and load factors are distributed differently according to the power prices and production capacities of specific regions and years. The net result of hourly optimization by PEM and the seasonal optimization by AEL is always that the unit costs are exactly equal in instances where there is capacity in both technologies. This is mathematically dictated by the model as any difference would favor one technology over the other.

6.3.2.2 Distributed hydrogen prices

The corresponding prices of the H_2-TRA commodity is, in addition to the techno-economic parameters for the technologies, a product of the composition of the production technologies and the input price variations. In addition, the prices are affected by storage utilization, and by the prices associated with the hydrogen that is distributed from centralized production. The hydrogen prices for road transport at hydrogen refueling stations are summarized in Table 6.4.

Table 6.4: *National weighted averages (Avg.) and regional minimum (Min.) and maximum (Max.) prices for hydrogen in NOK/kg H_2 at hydrogen refueling stations in the Baseline and High price scenario.*

	2030			2040			2050		
Scenario	**Min.**	**Avg.**	**Max.**	**Min.**	**Avg.**	**Max.**	**Min.**	**Avg.**	**Max.**
Baseline	72.08	72.10	72.22	51.04	51.11	51.51	50.87	52.62	56.21
High	67.06	67.06	67.06	57.01	66.41	71.89	54.49	64.16	67.99

Note: All hydrogen prices are weighted averages for a single milestone year. The minimum and maximums are weighted averages for a single region, while the national average is a weighted average of all the regional prices. The national average prices have been weighted by the regional productional volumes. The regional production volumes and prices can be found in Appendix C.

The hydrogen price at HRS exhibit some variation according to scenario but is mostly differing according to a trend of reduced costs over time. The current price of hydrogen at HRS has typically been at 90 NOK/kg according to Statistics Norway (Bøeng, 2021). Our price results thus constitute reductions of up to 43% in 2050 compared to current prices. In a 2022 white paper, the ICCT predict the average EU cost for hydrogen produced onsite at hydrogen refueling stations based on renewable energy (Zhou & Searle, 2022). The prices in their "mid-level" and "optimistic" scenarios suggests a price of approximately 62 to 73 NOK in 2030 and 47 to 52 NOK in 2050. In comparison, the prices from our model results range between 51 to 71 NOK in 2030 and 52 to 67 NOK in 2050 across the Baseline and High price scenarios. Our range is thus somewhat lower than their estimates in 2030, but higher in 2050. The ICCT's estimated prices relies rely on production from renewable energy while our model only considers grid connection. As cost estimates vary widely subject to each estimates' particular set of assumptions, a general comparison with other studies is challenging. The ICCT paper represents a fairly comparable study and suggests that our future hydrogen prices at HRS is a range within realistic expectations.

6.4 Hydrogen supply chain flow

In this section, we provide an overview of how hydrogen flows from its source of production to its final point of end-use in the model. This allows us to assess how the centralized- and distributed supply chains interact to deliver hydrogen in a cost-effective manner. As an illustration of the general flow of hydrogen in the model results, a Sankey diagram of the hydrogen flow in 2050 from the High price scenario is presented in Figure 6.8. In general, the way in which the supply chains are utilized to deliver hydrogen is similar across all three scenarios. However, a significant difference between the scenarios are the volumes of hydrogen that flow through each process of the supply chain, and the timing for when they are utilized.

As can be seen from Figure 6.8, most of the of hydrogen is consumed instantly after its production. Only a relatively small amount of hydrogen is stored before it is consumed in a final end-use process. Across all the scenarios, hydrogen storage only occurs at the hydrogen refueling stations in the distributed supply chain. In the centralized supply chain however, the produced hydrogen is either used momentarily in industrial processes and maritime transport, or directly transported to hydrogen refueling stations.

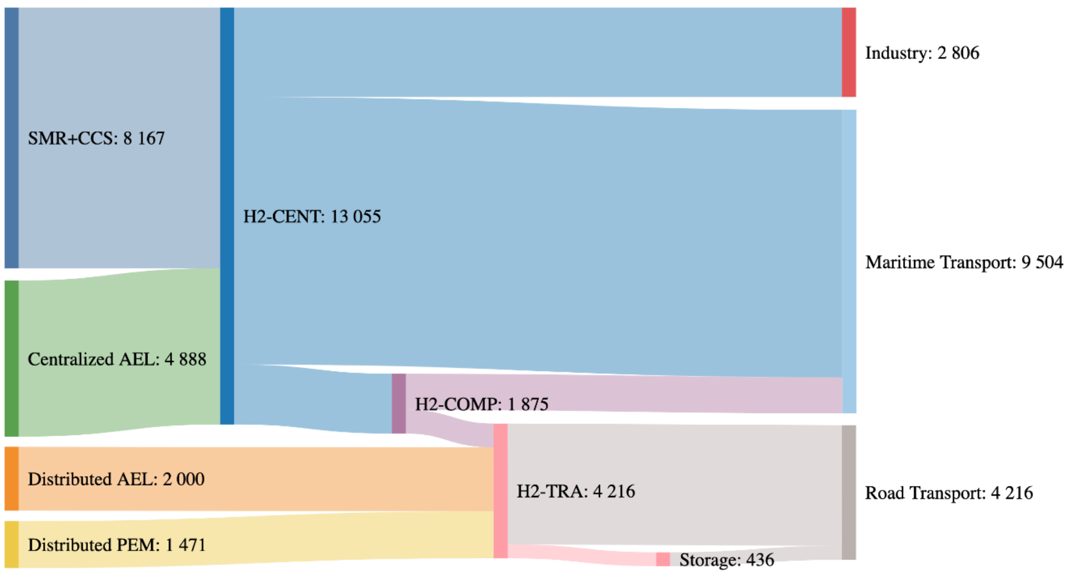

Figure 6.8: *The flow of hydrogen (GWh) from its production to end-use sector in 2050 for the High price scenario. The flow from H_2-COMP to H_2-TRA shows the amount of hydrogen that is distributed by trucks to hydrogen refueling stations within the same region.*

Furthermore, hydrogen is for the most part consumed close to its source of production. All hydrogen is consumed within the same region as where it is produced, as no inter-regional trade occurs in any of the scenarios. Thus, distribution of hydrogen by tube trailers for distances over 320 km, which is the shortest inter-regional distribution distance, is not a cost-effective supply option in any instance. This finding is also supported by various literature on the matter, such as DNV GL (2019) and IEA (2019; 2021a). On the other hand, distribution of hydrogen within regions occurs in several instances across our scenarios. The variations in hydrogen distribution can be seen in Figure 6.9, which shows the total annual supply of hydrogen for road transport in the Baseline and High price scenario.

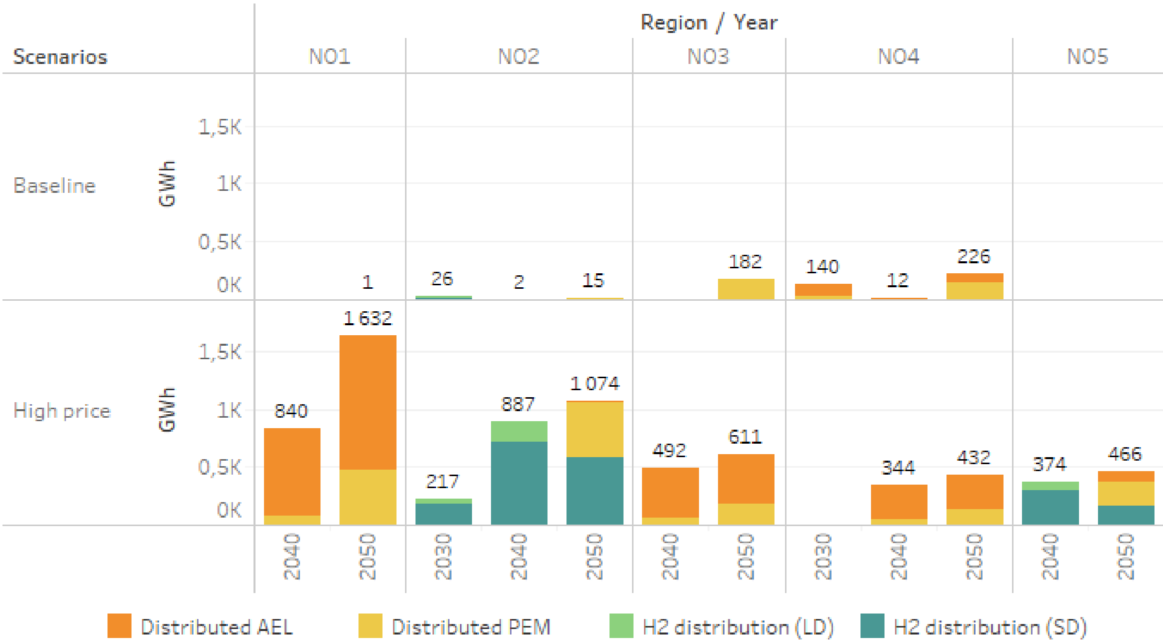

Figure 6.9: *Hydrogen distribution (long- and short distance) and distributed electrolysis production for use in road transport.*

Figure 6.9 shows that distribution of centrally produced hydrogen to HRS stations only occurs within the NO2 and NO5 region. The distribution results can be explained in relation to the regional power prices, the centralized production technologies, and the distribution distances associated with each region. In general, hydrogen distribution only occurs within regions where there are relatively high power prices, large-scale hydrogen production is from SMR with CCS, and the distribution distances are relatively short. This is the case for both the NO2 and NO5 region. In these regions, the high power prices and low distribution costs makes it cost-effective to transport hydrogen from SMR with CCS plants to hydrogen refueling stations, rather than to invest in distributed water electrolysis plants.

Furthermore, the distribution results show that the greater part of hydrogen distribution is carried out for shorter distances, as this is the only cost-effective distribution option. Long-distance distribution of hydrogen within regions only occurs due to a model constraint on hydrogen distribution. As described in Section 4.3.3, a minimum of 20% of the hydrogen for road transport must either be supplied by long-distance distribution or distributed hydrogen production. Thus, long-distance distribution only occurs in instances where this supply option is cost-effective compared to investments in distributed electrolysis production. This remains the case for the NO2 and NO5 region until 2050, when distributed electrolysis becomes the cost-effective supply option.

6.5 Hydrogen consumption

In this section, we will discuss the patterns of hydrogen applications in the three end-use sectors, industry, road transport, and maritime transport. The hydrogen applications in end-use sectors and its volumes will be discussed according to cost-effectiveness, and how it compares with competing energy carriers. We will discuss how and why hydrogen is invested in, and provide illustrative examples of its applications within scenarios, years and regions.

The annual hydrogen consumption in the three end-use sectors is presented for the three scenarios in Figure 6.10. The results show that hydrogen is competitive within the industry sector in all scenarios, with significant hydrogen consumption volumes from 2030. On the other hand, the use of hydrogen in road transport is minimal in the Baseline and Low price scenario. In the High price scenario however, it constitutes approximately 26% of the total consumption by 2050. The largest hydrogen consumption volumes are in maritime transport, which is the dominant end-use sector for hydrogen in both the Baseline and High price scenario. In the Baseline scenario, maritime transport represents as much as 84% of the total hydrogen consumption by 2050. In contrast, hydrogen consumption in maritime transport is minimal in the Low price scenario where no consumption occurs before 2050, and only accounts for 1% of the total hydrogen consumption.

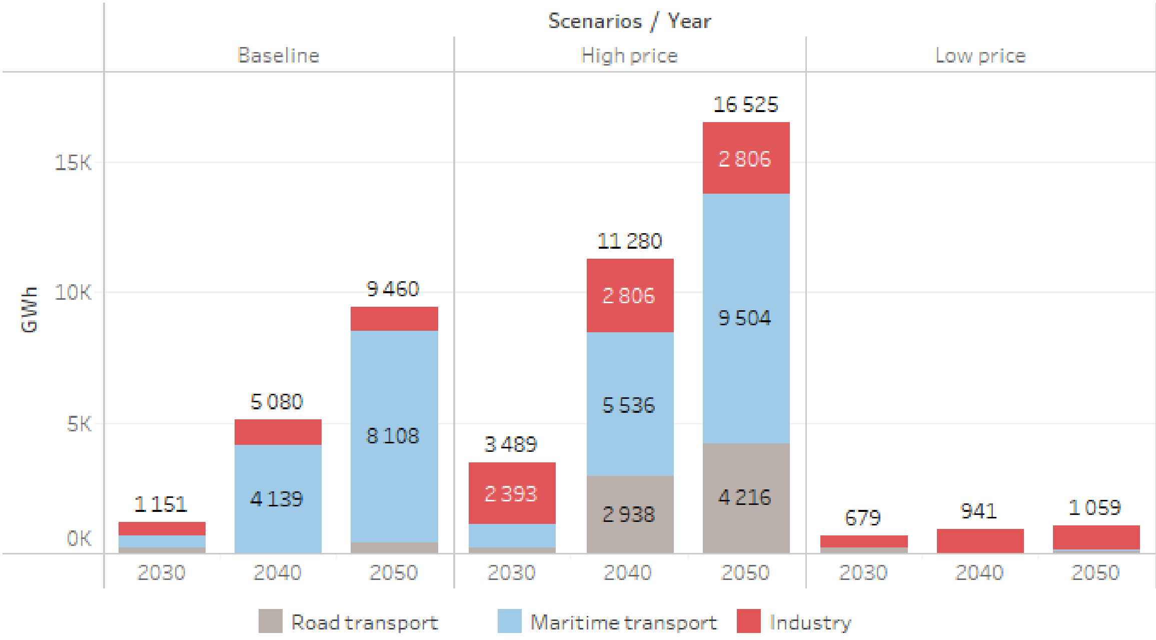

Figure 6.10: *Total annual hydrogen consumption by end-use sector in the three scenarios.*

The consumption volumes for the three sectors provide indications of the potential of hydrogen in each end-use sector. They are in part driven by the cost-effectiveness of hydrogen, but also the underlying demand levels of individual sectors. A clearer picture of hydrogen competitiveness will be provided in Sections 6.5.1 through 6.5.3 where we discuss the market shares and cost-effectiveness of hydrogen relative to competing alternatives in each end-use sector.

6.5.1 Industry

In the industry sector, hydrogen can be used as a low-emission feedstock alternative in both the chemical and metal industry. In these industries, hydrogen can replace the use of coal in reduction processes and natural gas in chemical production processes, as described in Section 4.4.1. In Figure 6.11, the use of feedstocks is presented as percentage shares of the annual energy demand of each industrial process. As can be seen from Figure 6.11, hydrogen is used to replace coal in reduction processes in all three scenarios, with identical consumption levels across all three scenarios. On the other hand, hydrogen only becomes an economically viable alternative to natural gas in chemical production processes in the High price scenario. In this scenario, a total of about 2.8 TWh hydrogen is consumed annually in industrial processes by 2050, of which 0.9 TWh is consumed in reduction processes. This is equivalent to the model's maximum demand for hydrogen in the industrial sector, as according to the upper bounds presented in Table 4.18. In all the processes where hydrogen becomes a cost-effective feedstock alternative, the upper bounds for hydrogen consumption are reached by 2040 at the latest.

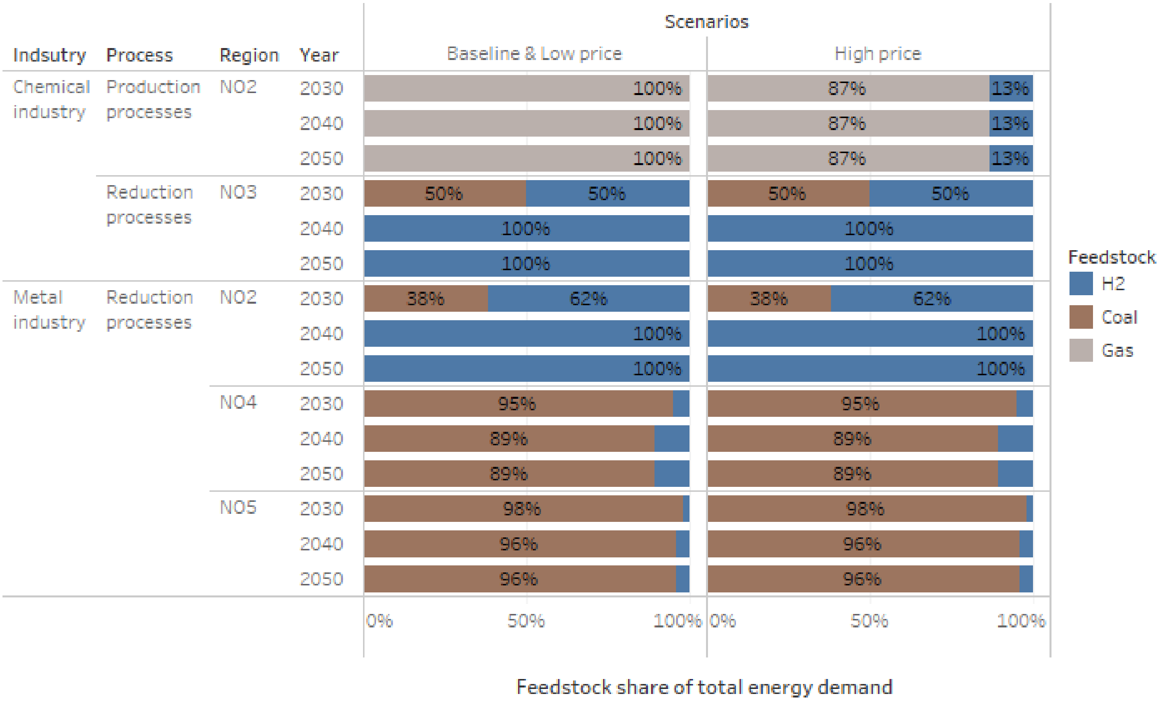

Figure 6.11: *Feedstock shares of total energy demand in the chemical and metal industry in the three scenarios. The Baseline and Low price scenarios are shown together, as they have identical feedstock shares.*

The competitiveness of hydrogen in the industrial processes is determined by the relative cost of using hydrogen to satisfy one unit of the process' demand. For instance, in production of chemical products, this translates to the costs incurred by using hydrogen instead of natural gas to produce one unit (e.g., MWh) of ammonia. Therefore, the cost of hydrogen as a feedstock is not only a product of its market price, but also its efficiency in each specific industrial process. In Figure 6.12, the cost of hydrogen and coal are shown in terms of NOK/MWh output from reduction processes in the NO2 region for both the Baseline and High price scenario. Although applications of hydrogen in reduction processes occur in more regions than NO2, the findings are representative for the competitiveness of H_2 in the other regions. As seen from Figure 6.12, the CO_2 tax is a decisive factor for whether hydrogen becomes a cost-effective alternative to coal in reduction processes. In these processes, the cost of hydrogen is slightly higher than the price of coal, even though hydrogen is assumed to be four times as efficient as coal. However, when the CO_2 tax is taken into account, hydrogen is the cost-effective option in all the scenarios.

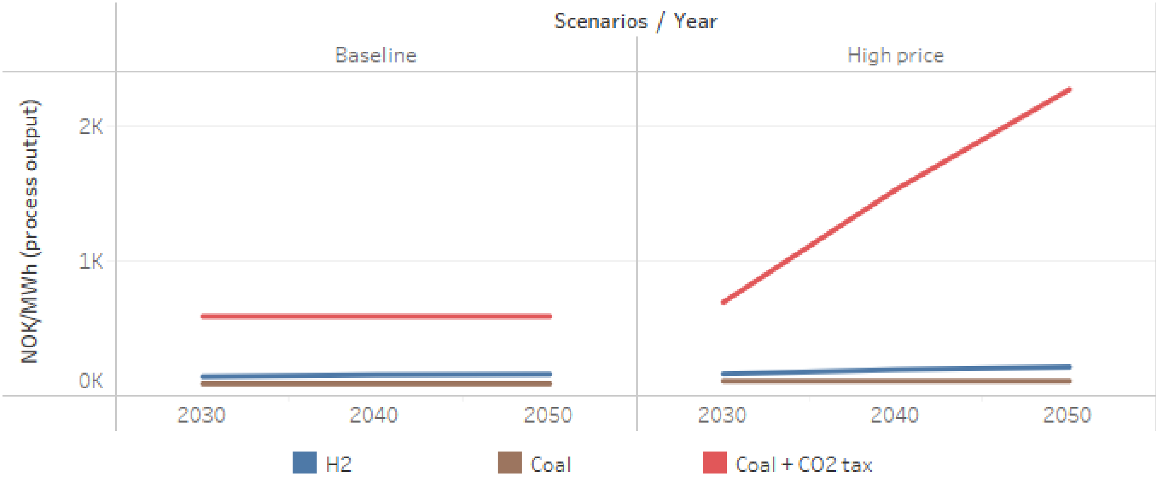

Figure 6.12: *The price of coal with and without CO_2 tax costs, and the average price of hydrogen in the NO2 region, given in terms of NOK/MWh output from reduction processes.*

Furthermore, the relative competitiveness of hydrogen in chemical production processes are illustrated in Figure 6.13. Figure 6.13 shows the cost of using hydrogen and natural gas in chemical production processes in terms of NOK/MWh output for both the Baseline and High price scenario. In similarity to reduction processes, the CO_2 tax is crucial for the relative competitiveness of hydrogen in chemical production processes. In these processes, where hydrogen has an assumed efficiency of 77%, the cost of hydrogen is significantly higher than the price of natural gas. The results show that a CO_2 tax of 2 000 NOK, as applied in the Baseline scenario, is not sufficient to make hydrogen competitive with natural gas in chemical production processes. Hydrogen only becomes cost-effective in the High price scenario, where the CO_2 tax increase from 2 441 NOK in 2030.

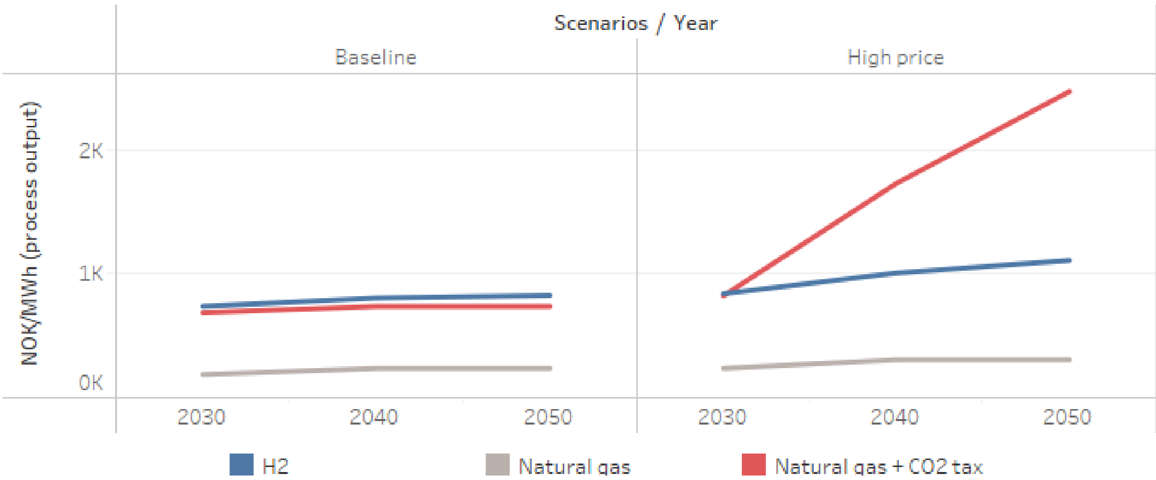

Figure 6.13: *The cost of hydrogen and natural gas, with and without* CO_2 *tax costs, in terms of NOK/MWh output from the chemical production process in NO2 for the Baseline and High price scenario.*

6.5.2 Road transport

In this section, we first provide an overview of hydrogen consumption in road transport and describe the general patterns of fuel usage in the different vehicle segments. Then, we discuss the relative competitiveness of hydrogen in the vehicle segments where hydrogen adaption is strongest.

In road transport, hydrogen can be used as a fuel in all the modeled vehicle segments, which are cars, vans, buses and trucks. Figure 6.14 shows the annual hydrogen consumption in road transport by vehicle types in the Baseline and High price scenario. As seen from Figure 6.14, hydrogen is for the most part used as a fuel in the heavier vehicle segment, namely trucks and buses. This finding is in line with most research on the matter, which suggests that fuel cell electric vehicles (FCEVs) can be a competitive option for heavy-duty vehicles with long daily distances and/or heavy cargo, as discussed in Section 2.4.2.

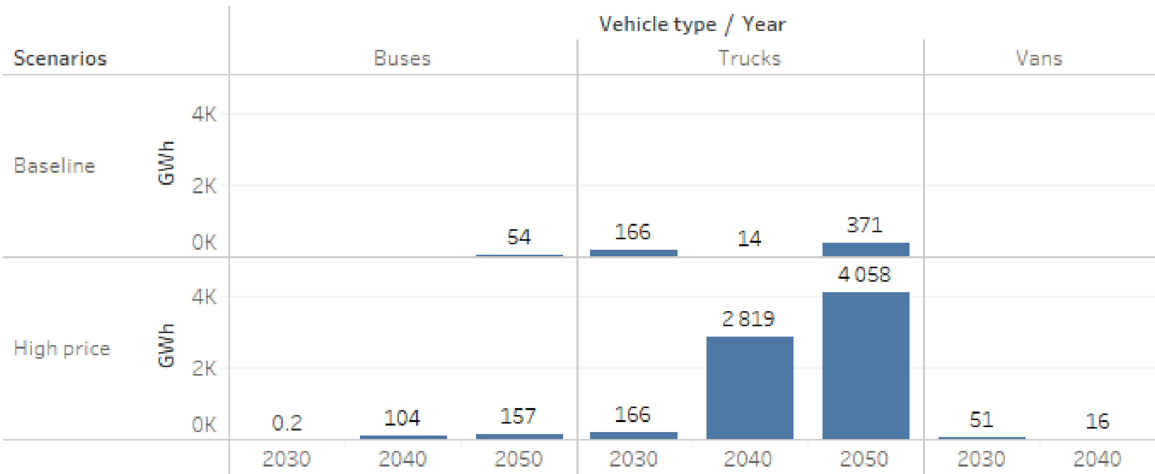

Figure 6.14: *Annual hydrogen consumption in road transport by vehicle types in the Baseline and High price scenarios.*

In the light-duty vehicle segment, i.e., cars and vans, hydrogen fuel cell-based vehicles are not a cost-effective investment option. Light-duty vehicles are dominated by battery electric vehicles (BEVs), which constitutes 100% of the powertrain share for cars and vans by 2050 in both the Baseline and High price scenario. In the cars segment, hydrogen is not competitive at all, as no investments are made in FCEVs over the entire model horizon. For vans, a minimal amount of hydrogen is consumed in the High price scenario due to a single instance of investments in 2025. However, this investment is driven by model constrains rather than the cost-effectiveness of FCEVs. The relevant constraints dictate a minimum of 40% zero-emission vehicles and a maximum market share of 15% BEVs for vans by 2025, as described in Section 4.4.2. In addition, the use of other low-emission fuel options, such as biofuel and biogas, are heavily limited this early in the model horizon. The combination of these limitations forces the model to investment in FCEVs in this particular instance. However, we do not consider this result to be a representative finding for the long-term potential of hydrogen in vans, as this analysis focus on investments from 2030 onwards. On the other hand, significant investments are made across a wide range of instances for buses and trucks. Thus, the market shares and cost-effectiveness of hydrogen in trucks and buses will be discussed in Section 6.5.2.1 and 6.5.2.2 respectively.

6.5.2.1 Trucks

The truck segment is responsible for the largest quantities of hydrogen consumption in road transport. As described in Section 4.4.2, the truck segment is divided into three vehicle types: small (S) trucks, large trucks with short daily distances (LS), and large trucks with long daily distances (LL). The powertrain's share of the demand for each of the truck types are shown for the Baseline and High price scenario in Figure 6.15.

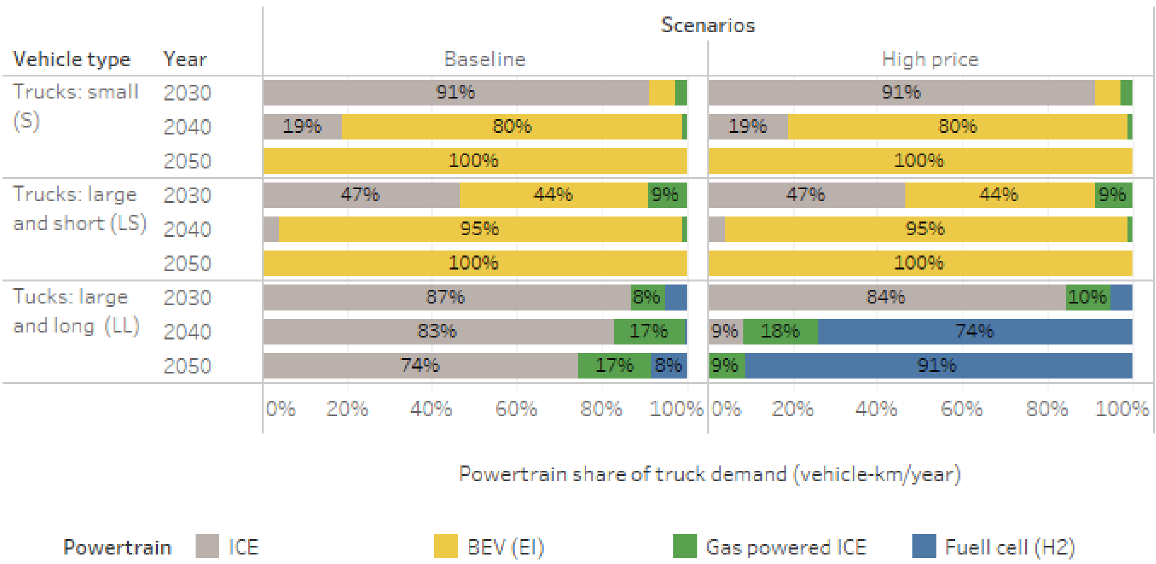

Figure 6.15: *Powertrain shares of vehicle-km/year for the different truck types in the Baseline and High price scenario.*

As seen from Figure 6.15, hydrogen consumption within the truck segment only occurs for trucks (LL). In the other trucks segments (S and LS), BEVs constitute 100% of the demand by 2050 in both the Baseline and High price scenario. However, a major difference between the truck types is the availability of BEVs, as battery electric powertrains are assumed to be technically infeasible for trucks (LL) in the model. As the techno-economic parameters for the three truck types are quite similar, the FCEV investments in trucks (LL) are highly dependent on the assumed infeasibility of BEVs.

Furthermore, there are significant variations in the consumption of hydrogen between the scenarios. In the High price scenario, hydrogen is the universally preferred option for trucks (LL) across all regions in 2040 and constitutes 91% of the energy demand for this vehicle type by 2050. Trucks (LL) is thus entirely decarbonized by 2050 in the High price scenario, as the remainder of energy consumption relies on biogas (9%). In contrast, Trucks (LL) relies on ICE to a high degree across all years in the Baseline scenario, with only minimal hydrogen consumption. The differences between the scenarios can be attributed to the CO_2 tax, which will be discussed further as we compare the cost-effectiveness of powertrains for trucks (LL).

The reliance on the various powertrains for trucks (LL) can be assessed by ranking their cost-effectiveness and assessing the constraints that limit the availability of each technology, as according to the stepwise inverse supply function discussed in the beginning of Section 6.1.1. For the purpose of analyzing cost-effectiveness, we have selected NO4 in the Baseline scenario to illustrate how the investment decisions for powertrains occur. Figure 6.16 provides the total ownership costs of a large and long-distance truck for different powertrains and investment years in terms of NOK/km.

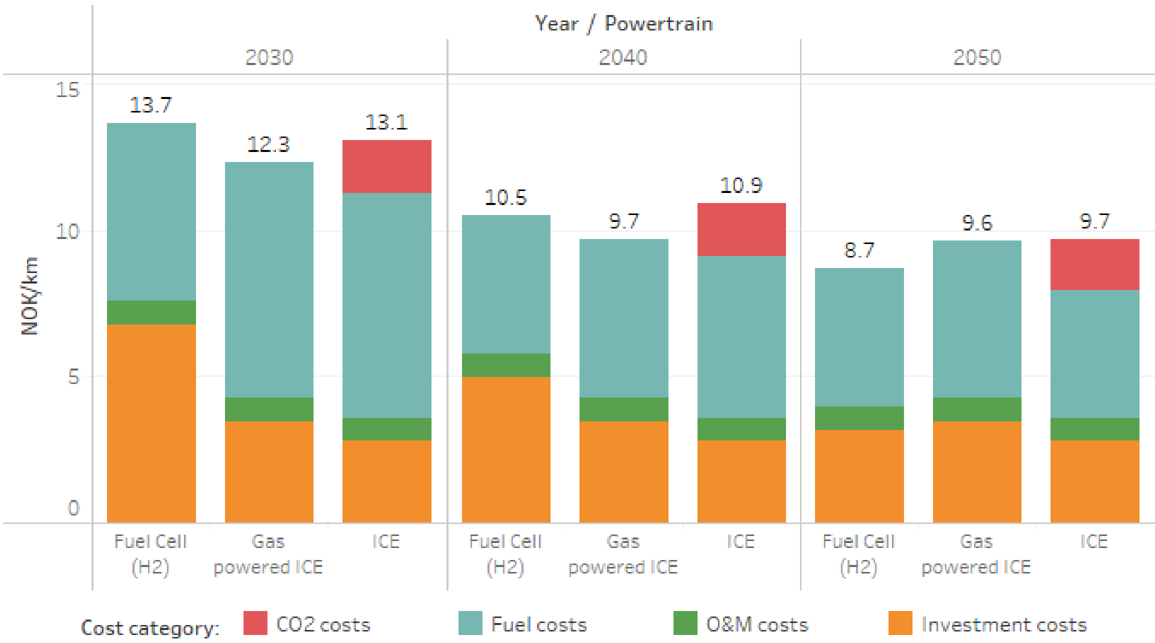

Figure 6.16: *Total ownership costs (NOK/km) for long- and large trucks by powertrain and cost category in the NO4 region for the Baseline scenario.*

In Figure 6.16, the variable costs for fuel and CO_2 are calculated across the lifetime of the vehicle. All fuel prices are based on the average price between the first and last years of the trucks' lifetime (6 years). For investments in 2050, only the 2050 price is used. As the ICE powertrain can rely on fossil fuels, biofuels, or both, its fuel costs are calculated according to a minimum biofuel share of 19%. For our example instance, the biofuel share does not leave this lower bound as it is not a cost-effective fuel option. CO_2 costs are calculated according to the same method as for fuel costs but will vary with both CO_2 price and the actual share of fossil fuels in ICE powertrains.

As can be seen from Figure 6.16, gas-powered ICE (biogas) is the cheapest option for Trucks (LL) in 2030, followed by ICE (fossil fuel) powertrains and finally fuel cells (hydrogen) as the most expensive option. However, there are no investments in gas-powered ICE in 2030, as available supply of biogas is provided to other segments and sectors. The availability of biogas must be viewed from a wider perspective than that of a single end-use process, as it's a constraint across all end-use processes that may rely on this energy carrier. The limited volume of biogas is supplied according to economic rationale and any individual supplier of biogas will supply to the sectors and processes in which the willingness to pay for it is higher. While biogas is a preferred supply option for Trucks (LL) in several instances, other sectors and segments may seize the available supply. As of 2030, the entire biogas supply of 1 200 GWh is divided between 82% in trucks (S) and (LS), and 18% in buses. The 2030 investments in our example are therefore distributed between ICE and fuel cell vehicles. Hydrogen is included in the supply mix as dictated by the constraint that 30% of truck investments in 2030 shall be zero-emission vehicles. In 2040 however, gas-powered ICE remains the cheapest option and is available for Trucks (LL) as it is no longer the cost-effective option in other segments. Consequently, the entirety of investments in 2040 is in gas-powered ICE vehicles. At this point, Trucks (LL) seize 86% of the entire supply of biogas. In 2050, fuel cell vehicles are the cost-effective option and constitute 100% of new capacity investments.

Noticeably, the relative competitiveness of hydrogen fuel cell vehicles is determined by the additional CO_2 costs for ICE powertrains. In the Baseline scenario in NO4, the CO_2 cost is sufficient to shift ICE powertrains from the first to the second ranked option in 2030, and from first to last ranked option in 2040 and 2050. In the absence of a sufficient CO_2 price and constraints on minimum investments in zero emission vehicles (ZEVs), ICE relying on fossil fuel would be the preferred option across all scenarios and years. In other regions, and particularly in the high price scenario, variations in CO_2 costs and fuel prices shift the cost-effectiveness ranking of supply alternatives making fuel cell vehicles more, or less competitive. The primary difference between vehicle investments in the Baseline and High price scenarios is that the higher CO_2 costs render ICE uncompetitive in many additional instances in High, thus driving the overall hydrogen consumption in this sector. Note that in some instances, the fuel consumption in ICE shifts entirely to biofuels as this becomes the cost-effective option and has sufficient availability. A shift to rely on 100% biofuel renders these powertrains emission-free and thus avoids the cost costs associated with fossil fuels. In these limited instances (NO1-NO3 in the High price scenario in 2040), ICE powertrains based on biofuels is the cost-effective option.

6.5.2.2 Buses

In the bus segment, Fuel cell powertrains reaches a maximum share of 8% of demand. See Figure 6.17 for each powertrain's share of demand for buses in the Baseline and High price scenario. The segment is almost entirely electrified as BEVs reaches their maximum market share of 65% in 2030, and 92% in 2040 and 2050.

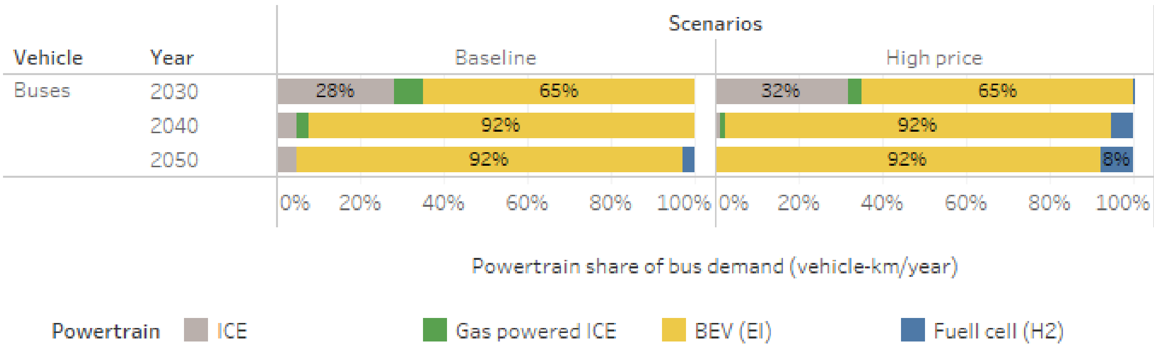

Figure 6.17: *Powertrain shares of vehicle-km/year for buses in the Baseline and High price scenario.*

The relative competitiveness of hydrogen fuel cell electric vehicles in the bus segment can be assessed by ranking the total ownership costs of the different powertrains. In Figure 6.18, we provide the total ownership costs for a bus in NOK/km in the Baseline scenario in the NO2 region. The costs are provided according to the same calculations as with total ownership costs for trucks (LL). As in Trucks (LL), biofuels generally do not leave its lower bound of 19% as it is not a cost-effective option. The CO_2 costs have therefore been calculated according to a 19% share for our chosen example. The only instance where biofuels is cost-effective is in NO5 in 2040 in the Baseline scenario where the biofuel share is 100%.

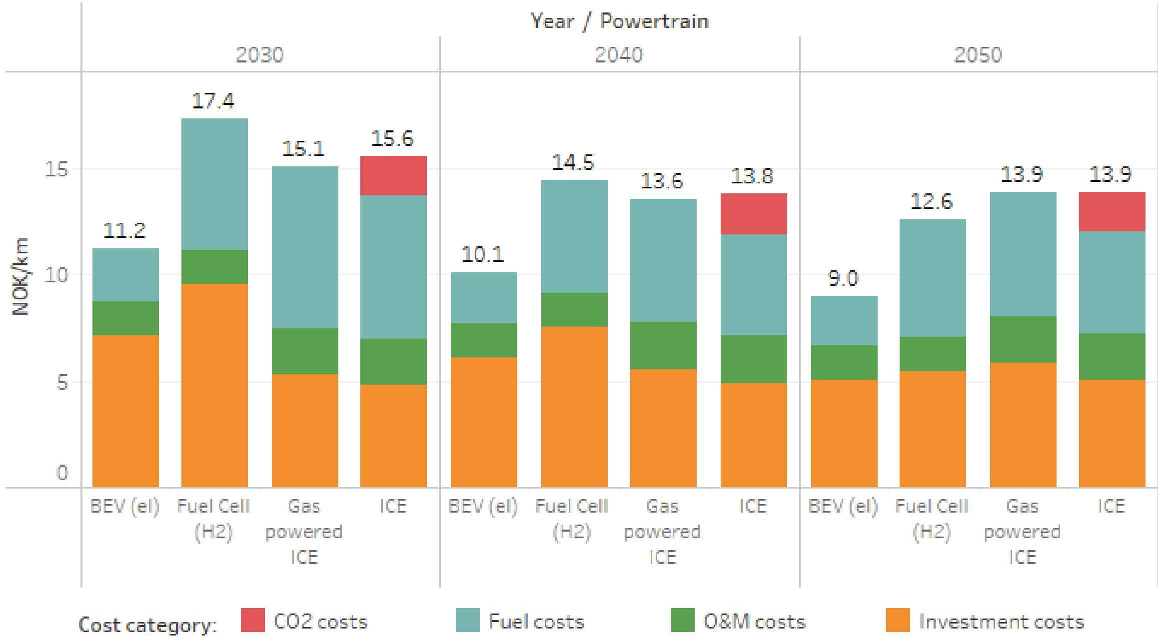

Figure 6.18: *Total ownership costs (NOK/km) for buses by powertrain and cost category in the NO2 region for the Baseline scenario.*

BEVs are the cost-effective option across all instances for buses. However, as its market share is limited, additional alternatives are invested across all years. In 2030, the remainder of new investments is covered by gas-powered ICE. By 2040 however, these investments are replaced by ICE as the available biogas is largely supplied to Trucks (LL) as discussed in Section 6.5.2.1. By 2050, investments in addition to BEVs are entirely in FCEVs as it has overtaken biogas as the second preferred investment option. Note that, as seen in Figure 6.18, the CO_2 costs for buses can be sufficient to render ICE uncompetitive even in the Baseline scenario. The most significant difference between the Baseline and High price scenario for the NO2 region, is that the investments in ICE and gas-powered ICE are entirely shifted to FCEVs across all years in the 2030 to 2050 period.

The cost-effectiveness ranking and availability of biogas differs somewhat in other regions compared to NO2 resulting in slightly different investment patterns. The aggregate result, however, is the distribution of powertrains seen in Figure 6.17. For other regions, a particularly notable result is the investments made in the NO1 region in the High price scenario in 2030. In this instance, the investments in ICE powertrains increase rather than decrease compared to Baseline despite the higher CO_2 costs. This counterintuitive result can be explained by how the BEV market share constraints apply to the model. The market share constraint is binding on average across regions, meaning that the investments in BEVs are optimized according to cost-effectiveness across regions. Electrification occurs to a larger extent in regions with lower power prices and vice versa. In the High price scenario in 2030, investments are 100% BEVs in NO2 to NO5 and only 51% in NO1. The aggregate result however is the maximum BEV market share of 65%. Rather than investing according to market share constraints on a regional level, a larger share of ICE investments is shifted to NO1 where the power prices are the highest and the operation of BEVs is the most expensive. As the market share constraints are not binding on the level of detail that investments are made according to, unintended consequences for investment patterns occur.

6.5.3 Maritime transport

In maritime transport, hydrogen consumption occurs across all vessel types in both the Baseline and High price scenario. This can be seen in Figure 6.19, which shows the annual hydrogen consumption in maritime transport according to vessel type and hydrogen propulsion systems. Vessels with ammonia propulsion systems are responsible for the bulk of hydrogen consumption in all scenarios, while consumption of compressed hydrogen only occurs in the High price scenario.

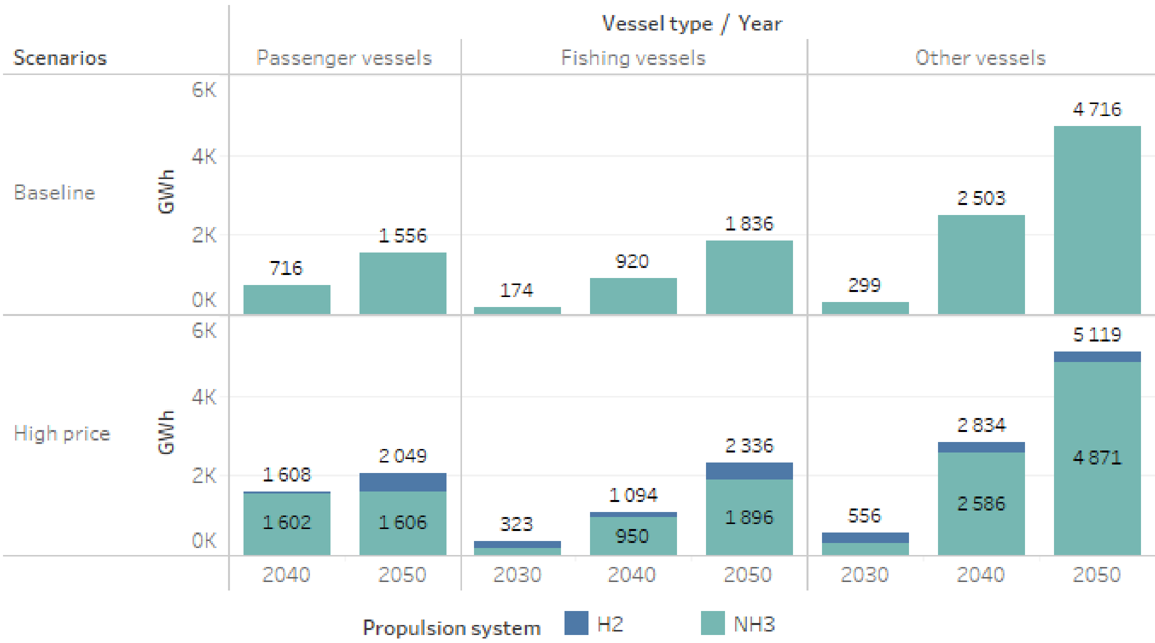

Figure 6.19: Annual hydrogen consumption in maritime transport by propulsion system for the different vessel types in the Baseline and High price scenario.

6.5.3.1 Propulsion system investments and market shares

The various propulsion systems' share of demand shows the overall extent of hydrogen reliance in maritime transport. This can be seen from Figure 6.20, which shows the propulsion system shares for each vessel type in the Baseline and High price scenario. The share of ammonia in maritime transport increases to significant shares of overall demand, particularly for other vessels. In this vessel segment, ammonia propulsion systems satisfy as much as 75% of demand by 2050 in the High price scenario.

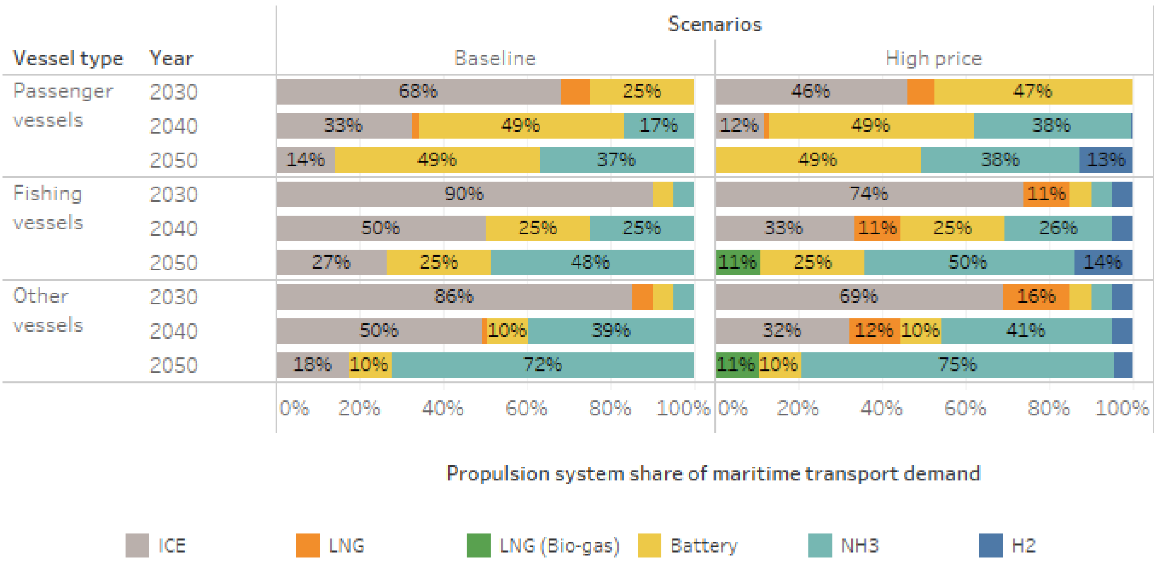

Figure 6.20: *Propulsion system shares of the total maritime transport demand for the different vessel types in the Baseline and High price scenario.*

ICE propulsion systems constitute significant shares of demand across the model horizon. This is primarily driven by the 25-year lifetimes of maritime vessels as existing stock and shorter-term investments retain shares of demand over a large part of the model horizon. No ICE investments occur after 2025 in the High price scenario and the maritime sector is thus entirely decarbonized by 2050. The aggregate vessel investments are presented for all propulsion systems and vessel types in the High price scenario in Figure 6.21.

The capacity investments are quite similar for fishing vessels and other vessels, but slight differences occur due to minor differences in investment costs, efficiency, and developments in demand. For passenger vessels on the other hand, the investments rely on battery electric propulsion systems to a much higher degree. As the techno-economic parameters are identical for passenger vessels and fishing vessels, the difference in investments can be entirely attributed to differences in market share constraints for these two vessel types. The relevant difference here is the far less strict market share constraint for battery electric in passenger vessels which is 49% by 2030 compared to 5% for fishing vessels. For passenger vessels, the market share of battery electric is maximized across all years with exception of 2030 in the Baseline scenario.

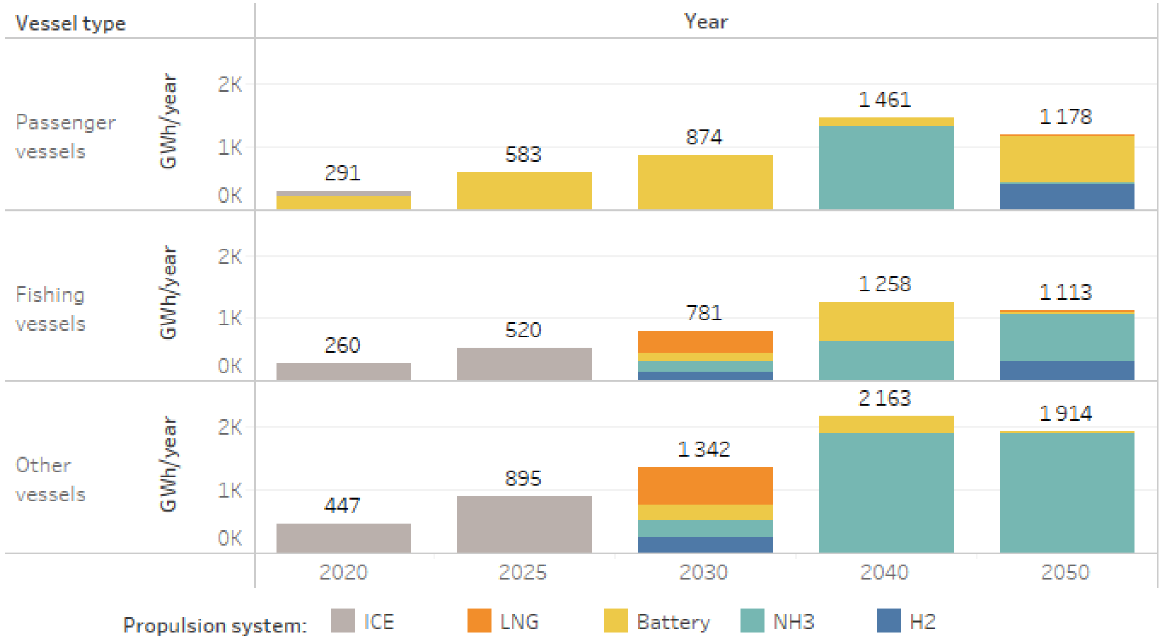

Figure 6.21: *Aggregate national investments in vessel types by propulsion system in the High price scenario.*

In the Baseline scenario, the vessel investments are quite similar to the High price scenario illustrated in Figure 6.21. The main difference is that investments in ICE propulsion systems also occur in 2030 in the Baseline scenario. In addition, LNG investments are far lower, and compressed hydrogen investments does not occur in any instance. While ICE propulsion systems may rely on both marine gas oil (MGO) and biofuel, they rely solely on MGO across all years and both scenarios as biofuel is not the cost-effective option in any instance. For LNG propulsion systems, biogas becomes cost-effective over time and all LNG vessels shift from liquefied natural gas to biogas by 2050. As discussed in Section 4.1, the availability and price of biogas is composed of two different cost classes. 2050 in the High price scenario is the only instance where the second cost-class of biogas (2 000 NOK/MWH) is included in the supply mix. At this point, biogas remains cost-effective in maritime transport despite the cost increase associated with the second cost-class. Consequently, the total biogas supply increases by 1.5 TWh to a total of 2.7 GWh of which 60% is supplied to maritime transport.

6.5.3.2 Cost-effectiveness in maritime transport

To explain how the propulsion system decisions occur in higher detail, investments in fishing vessels in the NO3 region from the High price scenario has been selected as an illustrative example. This instance was chosen due to its wide range of investments across the model horizon. See Figure 6.22 for new capacity investment in fishing vessels by propulsion system and year in the NO3 region in the High price scenario. Note that the investment patterns for fishing vessels in NO3 are almost identical to the aggregate investments provided in Figure 6.21. The only difference is a larger share of battery electric investments in 2040. In fact, the overall investments in propulsion systems are almost identical across regions for all vessel types.

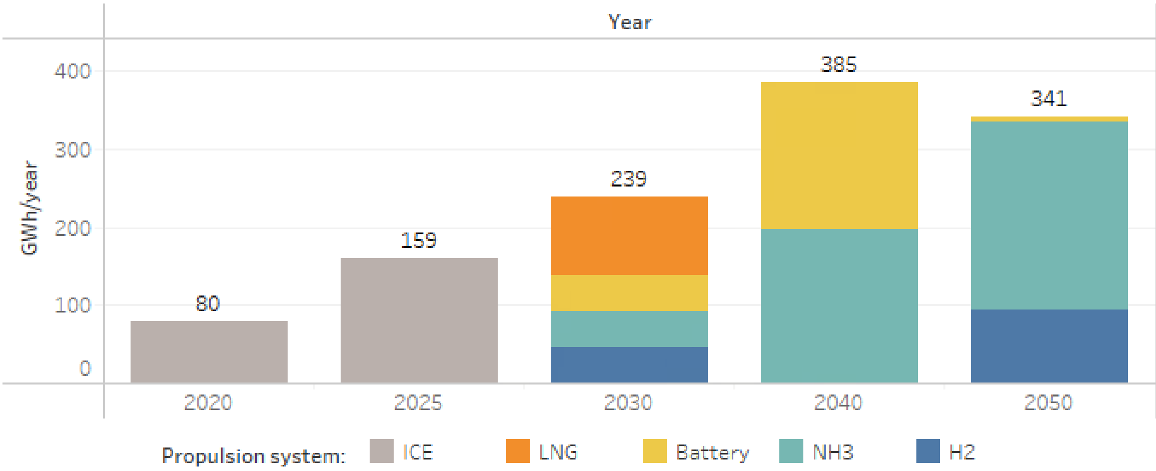

Figure 6.22: *New capacity investments in fishing vessels by propulsion systems in the NO3 region for the High price scenario.*

Up to 2030, the investments in fishing vessels in this instance is entirely in ICE propulsion systems. By 2030 however, investments occur across all available alternatives. By 2040 the investments are divided in battery electric and ammonia, and by 2050 hydrogen has emerged and the investments in battery electric are minimal.

The investments in new capacity are reflected in the cost-effectiveness ranking for maritime propulsion systems and the availability of fuel alternatives. Based on values from the NO3 region in the High price scenario, the total ownership costs for a fishing vessel are provided in Figure 6.23 in terms of NOK/MWh of demand for the different propulsion systems. The calculations for Figure 6.23 are performed similarly to the ownership calculations for buses and trucks, as presented in Section 6.5.2.1 and 6.5.2.2. The LNG propulsion system has been divided into its two fuel options to illustrate that their consumption shifts across the model horizon.

By assessing the cost-effectiveness ranking in Figure 6.23 in relation to the new capacity investments in Figure 6.22, one can see that the 2030 investments in our chosen example correspond to the four cheapest investment options. However, the investments in battery electric, hydrogen, and ammonia are limited by market share constraints, as discussed in

Section 4.4.3.4. The constraints dictate that each of the mentioned propulsion systems only can constitute a maximum fuel share of 5% by 2030. The remainder of new investment is therefore covered by LNG propulsion systems relying on liquefied natural gas. By 2040, the maximum fuel share constraints of the cheaper options have increased to a significant enough level such that the entirety of new investments is covered by battery electric and ammonia. Note that the vertical differences in fuel cost between LNG and LNG (Biogas) should indicate that LNG vessels switch to biogas by 2040. However, as discussed in Section 6.5.3.1, the available supply in 2040 is limited to the first cost-class of biogas which is entirely provided to road transport. By 2050, the maritime vessels can rely on the supply that is no longer seized by road transport, and the demand is sufficient to warrant the inclusion of the second cost-class. By 2040, battery electric has reached its maximum fuel potential of 25% and the minimal 2050 investments occur due to an increase in the overall demand. The other investments in 2050 are in ammonia and compressed hydrogen. Ammonia reaches its maximum fuel share of 50%, and the remainder of investments are therefore in compressed hydrogen.

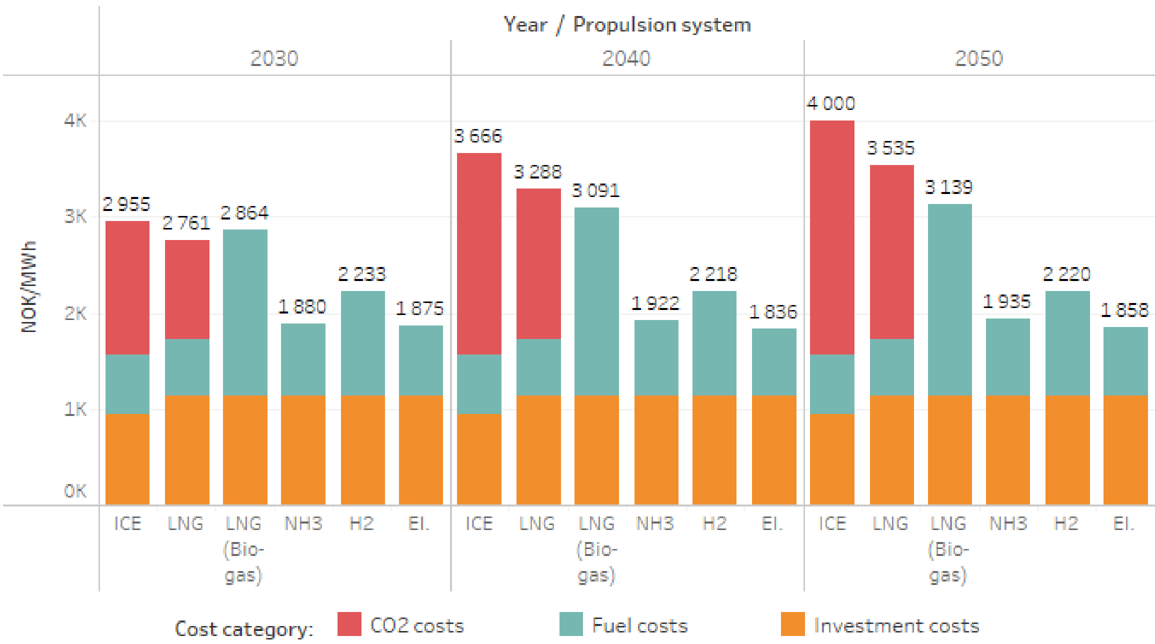

Figure 6.23: *Total ownership costs (NOK/MWh) for fishing vessels by propulsion system and cost category in NO3 region for the High price scenario.*

For the cost-effectiveness ranking of our example, note that substantial reductions in CO_2 costs are required to make fossil-based propulsion systems the cost-effective options. Equivalently, from 2040, further increases in the CO_2 tax would have no impact on investment patterns as fossil-based propulsion systems are already the most expensive alternatives. As the operation of vessels relying on MGO and liquefied natural gas is associated with significant emissions, the CO_2 costs are substantial. The CO_2 costs reduce the competitiveness of fossil-based systems to such a degree that the cost-effectiveness ranking, and thus the total hydrogen volume in maritime transport is quite similar in the Baseline and the High price scenarios. The cost-effectiveness ranking differs slightly across instances, but the aggregate results of these variations are expressed through the propulsion system shares provided in Figure 6.20, and the capacity investments provided in Figure 6.21. Note that, as with the market share constraints discussed for buses in Section 6.5.2.2, some unintended regional investment patterns also occur for maritime transport. As the market share constraints apply nationally, regional differences in technology costs drive the model to optimize market shares according to the region in which its cheapest to do so. The regional differences that apply to the optimization for maritime transport is demand levels and power prices. The latter affect the fuel costs for battery electric- and hydrogen-based propulsion systems.

As seen by our assessment of maritime transport results, the model results for maritime transport are dictated to a large degree by market share constraints in addition to the cost-effectiveness ranking. Recall that investments occur stepwise for technology alternatives until their availability is exhausted by market share constraints. However, the final option included in the supply mix is not constrained by market share and is rather limited by the remaining demand levels to satisfy. As compressed hydrogen is never the cost-effective alternative and is generally the final option to be included in the solution in the High price scenario, investments occur, but its market share remains lower than its maximum bound. In the Baseline scenario however, 2030 investments also occur for ICE investments which retains a share of demand across the model horizon. Investments in the preferred alternatives therefore occur within their market share constraints to larger degree, with the result that compressed hydrogen is not included in the solution. Ammonia on the other hand is generally included in the solution across most instances and has a significant maximum market share to the extent that it constitutes the greater part of demand by 2050.

While the market share constraints dictate the maritime transport results to a large degree, it should be kept in mind that they are intended to reflect operational differences between and within vessel types. As battery and-hydrogen propulsion systems are modeled to reflect an availability in short-distance trips, our results indicate that battery electric may be the dominant option for this purpose. This is in line with current and expected investment patterns in maritime transport as discussed in Section 2.4.3. As battery electric is more suitable for vessels with shorter routes and higher refueling frequency, its extensive investments in passenger vessels therefore seems reasonable. Similarly, as ammonia's maximum market share intends to reflect that it is primarily considered for deep-sea and longer-distance trips, our results indicate that it may be the preferred fuel option for this purpose.

6.6 Result summary

In this section, we provide a summary of our results by linking the main findings of our analysis to the specific research questions of this thesis.

Which factors dictate the prevalence of hydrogen in the Norwegian energy system?

As discussed throughout our thesis, several factors impact the cost-effectiveness of hydrogen production technologies and the subsequent competitiveness of hydrogen in end-use sectors. In our analysis, we have primarily focused on how future carbon prices and energy market factors, such as fossil fuel- and electricity prices, may affect the potential of hydrogen in Norway. The results from our analysis support our hypothesis that carbon pricing is the main factor dictating the prevalence of hydrogen in the Norwegian energy system. From the high-level result comparison provided in Section 6.2, it is evident that the CO_2 tax is the main driver for the overall competitiveness of hydrogen. The absence of a sufficient CO_2 tax renders hydrogen uncompetitive in almost every instance, as illustrated by the results from the Low price scenario. The natural gas- and power costs on the other hand, are significant for the relative competitiveness of hydrogen production technologies as they constitute significant shares of unit costs.

Which end-use processes are hydrogen likely to be competitive in?

The results show that hydrogen can be a cost-effective alternative in all three end-use sectors, although to varying degrees. Overall, the results show that the industry sector and maritime transport is responsible for most of the consumption of hydrogen across our scenarios while the consumption in road transport is more limited. On the hand, road transport constitutes a significant share of consumption in the High price scenario, indicating that the effect of a higher CO_2 tax is particularly strong in this sector.

In the industry sector, our results indicate that hydrogen can be a cost-effective alternative to coal in reduction processes. Notably, hydrogen remains cost-effective in the reduction processes regardless of variations in the modeled CO_2 prices. This is evident by its identical consumption levels across all three scenarios. In chemical production processes however, hydrogen only becomes a cost-effective alternative to natural gas in the High price scenario. As seen from the cost-comparison illustrations in Section 6.5.1, the differences in industry consumption are entirely a result of variations in CO_2 taxes that drive the cost-effectiveness of hydrogen in chemical production processes. In addition to the CO_2 tax, the potential for hydrogen in this sector depends upon the maximum consumption limits assumed for each industrial processes.

In road transport, hydrogen is the cost-effective option by 2050 in the High price scenario for the heaviest trucks with longest driving distances. However, the hydrogen investment in trucks rests on the assumption that battery electric is an infeasible option for this powertrain. Some consumption also occurs for buses but is also dependent on BEV assumptions in terms of its maximum market share. In many instances, bio-based alternatives are also the cost-effective alternative for heavy trucks and buses but is limited by resource availability. For light-duty vehicles, no hydrogen investments occur within the studied time horizon, as this segment is entirely dominated by battery electric. Overall, our results suggest that hydrogen can be the cost-effective alternative for certain heavy-duty vehicles. This finding is also in line with previous research on the matter, such as Danebergs et al. (2022a). However, the hydrogen investments in road transport depends on the feasibility and availability of alternate zero-emission powertrains, in addition to high carbon pricing.

In maritime transport, our results suggest that ammonia is a particularly attractive fuel that can constitute the greater part of demand in this sector by 2050. Compressed hydrogen on the other hand is only cost-effective in instances where the availability of preferred alternatives has been exhausted. The hydrogen consumption levels in maritime transport are highly dependent on assumed market share constraints, and the resource availability of biogas. In similarity to the other end-use sectors, the CO_2 tax is a crucial factor for the competitiveness of hydrogen in maritime transport. In contrast to road transport however, there is also significant maritime consumption in the Baseline scenario. This suggests that hydrogen is competitive at a lower level of carbon pricing in this sector.

To what degree will future hydrogen supply rely on production from large-scale vs. small-scale facilities?

The model results showed that the bulk of hydrogen production in Norway will come from large-scale production plants in the centralized supply chain. On the other hand, small-scale hydrogen production only accounted for a maximum of 21% of the national production volume across our various model runs. This finding reflects the relative competitiveness of hydrogen in the three end-use sectors and must be understood in the context of the modeled supply chains. In the centralized supply chain, hydrogen can be delivered for direct use in industrial processes and maritime transport. These two sectors represented the highest demand for hydrogen, as centrally produced hydrogen became a cost-effective alternative in several end-use processes within these sectors. Thus, centralized production became responsible for the greatest share of the overall hydrogen production in our model. In contrast, hydrogen was only a cost-effective alternative for heavy-duty vehicles in road transport. As the overall demand in road transport was relatively low, so was the production of hydrogen from distributed electrolysis facilities at hydrogen refueling stations. However, the greatest part of the hydrogen supply for road transport was provided by the small-scale electrolysis facilities, rather than being distributed from the centralized production facilities. Despite the comparably limited volumes in distributed production, small-scale electrolysis can be a cost-effective means of production.

What is the likely distribution of hydrogen production technologies?

Based on the techno-economic estimates applied in this thesis, our results show that SMR with CCS will be the dominant hydrogen production technology towards 2050. Across our various model runs, SMR with CCS is responsible for as much as 50 to 90% of the overall hydrogen production share by 2050. On the other hand, alkaline electrolysis becomes a cost-effective investment option at the centralized level in regions where the power prices are particularly low. According to our Baseline scenario, large-scale alkaline electrolysis does not become competitive with SMR with CSS before 2050. In contrast, the High price scenario suggests that alkaline electrolysis can become a cost-effective alternative in the centralized supply chain by 2030. The relative competitiveness of alkaline electrolysis is particularly sensitive to future power prices, as the power costs can constitute as much as 90% of the total unit costs for alkaline.

Furthermore, PEM electrolysis is not a cost-effective investment option at large scales, as the investment- and operational costs are too high compared to large-scale alkaline electrolysis. In contrast, the results show that there is potential for both alkaline and PEM electrolysis in the distributed supply chain. At the distributed level, the optimal supply solution is often a combination of the two electrolysis technologies, which can be attributed to the operational differences between the technologies. The superior flexibility of PEM electrolysis allows it to utilize power price fluctuations in combination with intraday hydrogen storage to effectively avoid peak power prices. Altogether, the load factor of PEM is optimized in accordance with AEL to supply hydrogen at the lowest possible cost for end-users. While the investment results generally provide a combination of the two technologies, PEM is increasingly favored across the model horizon as its costs are reduced compared to AEL.

Will hydrogen distribution by trucks be economically feasible?

The results show that distribution of hydrogen by tube trailers between regions is not a cost-effective supply option, as no inter-regional trade of hydrogen occurs in any of the scenarios. In particular, this relates to transportation of hydrogen for distances longer than 320 km, as this is the shortest inter-regional distance modeled in ITN. On the other hand, distribution of hydrogen within regions occurs in several instances across all the scenarios. In such instances, it is cost-effective to distribute hydrogen from SMR with CCS plants to HRS, compared to investing in distributed electrolysis production. However, the results indicate that this type of local distribution only will occur when the distances to the refueling stations are relatively short, and the regional electricity prices are particularly high. Overall, these findings are supported by previous research on the matter, such as DNV GL (2019) and IEA (2019; 2021a), which conclude that it is not cost-effective to transport hydrogen by tube trailers over long distances.

7 Discussion

In this chapter, we will discuss the limitations of our model and data, and how it affects the external validity of our research. Furthermore, we propose and discuss avenues for further work related to the research of this thesis, and the development of the ITN model.

7.1 Limitations and external validity

The work conducted in this thesis represents a large set of assumptions and simplifications that impacts and limits our results to a varying degree. In Section 7.1.1 we will first discuss the limitations of the ITN model, and then the data we have relied on in our research in Section 7.1.2.

7.1.1 Limitations of the ITN model

While there is a multitude of limitations with the ITN model, and linear programming techniques in general, some characteristics have particularly notable implications for the research context of this thesis. Many such characteristics are a result of the fundamental properties and behavior of the ITN model. However, there are also several that relate to the specific way the ITN model is specified and applied. In our discussion, we are primarily concerned with the latter category. We will highlight and discuss the characteristics that we consider to be the most significant for our analysis. In addition, we will discuss how alternative modeling approaches and options may impact the results. The alternative model approaches may vary in their practicality and feasibility, but the discussion brings attention to the fact that the model results are significantly impacted by the way the model is specified.

7.1.1.1 Linear input-output relationships

The linear relationship between input and output in model processes only enables implicit expressions of economies of scale. However, real-world decisions on technology adoption are commonly concerned with utilizing economies of scale as it is may be a determining factor for cost-effectiveness. In this thesis, economies of scale are differentiated to a “centralized” and a “distributed” scale. While the two production scales incorporate a degree of economies of scale, they do not capture a representative range of available capacities. The modeling of additional production capacities could represent economies of scale to a larger degree. Theoretically, a sufficient number of differentiated linear production processes can approximate a nonlinear inverse supply function with increasing economies of scale. However, this is practically infeasible as it would require substantial amounts of work and data availability for a much larger range of production capacities than existing literature tend to provide. The dynamics of increasing or diminishing returns of production that individual plants may experience would however still be unavailable. It should be kept in mind that our methodology and results do not capture the fact that most input-output relations are non-linear in the real world.

A second point regarding linearity is that the ITN model provides capacity investments on a continuum, rather than the discrete capacities technologies are invested in in the real world. As discussed in Section 3.1.1.1, the model results can provide invested capacities that are lower than the scales that the technologies' techno-economic parameters are based on. These investments, that can reasonably be considered to be unrealistically low, occurred in several instances across our model runs. This was particularly the case for the Low price scenario, but such instances also occurred in the Baseline and the High price scenarios. However, as it occurred more rarely in the two latter scenarios, it had less significant effects on the overall results compared to the Low price scenario.

There are ways to mitigate unrealistically low investments in TIMES, particularly through a model option referred to as "lumpy investments" in which process capacities are only available at multiples of a given size. This would however transform the problem into a Mixed integer Program (MIP), which have implications for the interpretation of results. According to the TIMES documentation (Loulu et al, 2016a), this option also comes at the cost of significant increases in solution time. At the same time, if economies of scale and non-convex relationship were of primary importance to the study at hand, linear programming would not be the most appropriate method.

In our model results, investments in unrealistically small capacities typically occurred for initial investments when the cost-effectiveness of hydrogen is just emerging. Capacity investments in production technologies must start at some point in the model horizon according to the levels of demand for that given point in time. As the first instances of hydrogen investments typically reflect marginal cost-effectiveness for lower demand levels in limited end-use processes, preliminary investments are skewed towards unrealistically small scales. The likely impact of running the model according to lumpy investments is therefore limited to delaying preliminary investments to later in the model horizon where initial capacities can be higher. However, this suggests that the timing of our initial hydrogen investments may err on the side of optimistically early.

7.1.1.2 Perfect foresight

The perfect foresight of the ITN model means that uncertainties are not a factor in investment decisions. For emerging technologies such as hydrogen, uncertainty connected to future production costs and demand are particularly high and can have significant impacts on investment decisions. When there is perfect foresight however, there are no risks or benefits associated with being an early adopter. While all technologies have the same level of foresight and the model results thus dictate a cost-effective composition of investments, real-world uncertainty would impact different technologies in a varying manner. For instance, centralized large-scale investments may have lower uncertainty for production costs and demand levels compared to a distributed plant. An SMR with CCS facility for instance, is in part based on more mature technology and can rely on demand from a more diversified range of end-use processes compared to a distributed electrolysis plant. As we have seen in our discussion on the distributed production investments, PEM plants relies on not only the price level of its input electricity, but also its fluctuations in order to be cost-effective. In the absence of perfect foresight, it is therefore subject to an additional dimension of uncertainty compared to AEL. The impacts of uncertainty on production technologies differ both according to scale and technology. In real-world applications, decisions makers may prefer investments that are associated with a lower amount of uncertainty.

Options in TIMES to address this limitation include running the model with an option for "myopic investments" and running it in a stochastic manner (Loulou et al, 2016a). These two approaches have in common that they attempt to simulate the conditions of real-world decision making by ensuring that they are conducted according to risk and uncertainty. This departs from the perfect foresight approach with its socio-economically optimal decisions. Myopic investments refer to a model variant with limited foresight in which investments are not optimized according to knowledge of the entire lifetime, but according to a partial look-ahead. Stochastic runs on the other hand incorporates imperfect foresight in which future events are only known in a probabilistic sense. The stochastic modeling option however is founded on a different modeling paradigm than ITN is based on and is associated with drastic increases in computational complexity. The myopic investments option with limited foresight is thus the most practical option.

Limited or imperfect foresight could provide clearer indications for likely hydrogen investments as they can discern perceived- from actual cost-effectiveness. The most significant impact of running the model according to a different level of foresight is that investments may occur in instances where it is not cost-effective, and vice versa. Our model however only outputs capacity results where hydrogen is known certainly to be the cost-effective option. In this sense, our model's perfect foresight results are more a reflection of a theoretical maximum of hydrogen prevalence rather than its most likely or realistic potential in the energy system.

7.1.2 Modeling and data limitations

Regarding the contents of the model, there are many rough and inaccurate estimates that should be improved and simplifications that should be mitigated in order to improve the accuracy in applicability of the ITN model. Factors that are unaccounted for and additional technologies should be included to describe the current state and expected developments of the energy system more accurately and in a higher level of detail. As the ITN model is developed over time with varying focus on development areas, model structures and embedded data become outdated. For instance, many existing stocks of energy equipment and demand estimates are partially obsolete at the time of writing. Mitigating the former is a question of acquiring accurate data, while the latter concerns updating estimates that are associated with inherent uncertainty and developments over time. Many of these limitations are thus the subject of the regular and continuous development of ITN but must be prioritized according to importance, available capacity, and the balance between detail level and computational tractability. In this discussion, we are therefore concerned with the factors we consider to be most relevant for the scope of our research and for the analysis of hydrogen more generally. We will discuss the approach to- and effects of mitigating the most relevant limitations of our model- data and structures, and the implications it may have on results.

7.1.2.1 Fuel- and electricity price projections

Fossil fuel- and electricity prices are parameter values of significant importance for the overall competitiveness of hydrogen production technologies, as previously discussed throughout this thesis. Thus, it is important to be aware of the uncertainties associated with the price projections applied in the ITN model. Even though the projections are from a reliable energy agency (NVE), the projections are subject to several assumptions and simplifications that impact future price levels and fluctuations. For instance, the price projections for natural gas and coal do not account for seasonal and hourly variations as the prices are fixed within each milestone year in the model. Additionally, the time horizon of the fossil fuel- and electricity price projections from NVE are limited to 2040, requiring us to hold these scenario parameters constant towards 2050. Aside from such simplifications, alternate assumptions about the long-term development of the global energy market would naturally result in different price projections. While our scenario variations were intended to account for such uncertainties, they do not cover the entire range of possible future prices.

Furthermore, there are uncertainties connected to the future price developments of other energy carriers and fuels that are important when modeling hydrogen. For instance, the price of fossil fuels in road- and maritime transport, such as diesel and MGO, are of particular importance for the competitiveness of hydrogen in these sectors. However, we did not include varying price projections for such fossil fuels in our scenarios. The inclusion of different price projections for more fossil fuels, for example in the form of sensitivity analyses, would improve our representation of different energy futures and strengthen the external validity of our results.

7.1.2.2 The CO_2 tax

As seen throughout our model results, the national CO_2 tax is a parameter value of significant importance for the overall competitiveness of low-carbon hydrogen. Thus, it is important to be aware of the limitations of how the CO_2 pricing mechanism is configured in the ITN model. As described in Section 3.1.2, the national CO_2 tax is universally applied to all energy carriers, technologies and processes that emits GHG emissions in the model. The CO_2 tax is applied according to the emission coefficient of each process, which is calculated in terms of CO_2-equivalents. In reality however, certain greenhouse gases are exempt from taxes and fees in Norway, which is not considered in our model work. Furthermore, several sectors and industries in Norway are not subject to the national CO_2 tax but are rather part of the EU Emission Trading Scheme (ETS). This includes the Norwegian chemical- and metal industry, which are of particular relevance to our study due to their potential for hydrogen applications. Thus, we do not consider that these industries are subject to other CO_2 prices, which may differ significantly from the Norwegian CO_2 tax. A modeling approach that considers the pricing mechanism of an emission trading scheme or defines separate CO_2 price projections for EU ETS sectors, could yield different results than our analysis for the application of hydrogen in industry.

7.1.2.3 Uncertain demand estimates

As the ITN model is a demand-driven model, uncertainties related to future demand estimates have significant implications for our model results. In particular, there are great uncertainties related to the demand projections and assumptions for the industry sector and maritime transport sector in the ITN model. These are also the end-use sectors with the largest hydrogen consumption shares across our model runs. Hence, alternate demand projections for these two particular sectors could have significant impacts for the overall hydrogen prevalence seen in our analysis.

As described in Section 4.4.1, the demand projections for industrial processes in the ITN model are based on the national energy balance of 2018 and planned developments for the coming years. This data is therefore based on potentially obsolete estimates, and further research on the demand and planned developments is necessary. Not only are there uncertainties related to the aggregate levels of demand in this sector, but also individual processes and their upper bounds for hydrogen consumption. For instance, the demand for hydrogen in chemical production processes in the ITN model is assumed to be entirely limited to Yara's ammonia production facility at Herøya. This process is assumed to have a maximum annual demand of about 56 000 tons of hydrogen across the model horizon. According to DNV GL (2019) however, the annual hydrogen demand at Yara's ammonia facility is approximately 70 000 tons. In addition, hydrogen is not assumed to be an alternative option for Equinor's methanol production facility at Tjeldbergodden in the ITN model. Hence, the overall demand potential for hydrogen in chemical production processes could arguably be higher in the ITN model. On the other hand, there are significant uncertainties related to the future demand for hydrogen in reduction processes as no such consumption occurs today. Hydrogen applications in reduction processes are contingent on technological development and may therefore be overestimated in the model.

Furthermore, the modeling of demand for maritime transport in the ITN model particularly suffers from a lack of detail level as the operational patterns of different vessels are hard to quantify. An accurate quantification of demand and how it distributes among vessels and operational patterns is a very large and challenging undertaking that concerns a wide range of disciplines and stakeholders, including the Norwegian government. In ITN, at least for the time being, consumption results in maritime transport must be viewed with acknowledgement of this sector's significant modeling limitations.

7.1.2.4 Flat and exogenous demand

Another notable limitation on the demand side of the model is the way in which demand is specified and applied. As the demand for energy services is fixed, the model only minimizes the cost of satisfying this demand rather than adapting energy consumption according to the price levels it is subject to. This is illustrated in Figure 3.1 related to the discussion on the partial equilibrium of ITN, where the demand curve is a strict vertical line. Regardless of how the equilibrium is achieved, it always corresponds to the same fixed level of demand. In reality, demand levels are also variable with supply as higher and lower prices leads to higher or lower demand. For instance, if the prices of fuels are high, less kilometers are driven.

In a more accurate and realistic representation of how energy service markets work, demand is a quantity that varies with price, expressed by an "inverse demand function" as a counterpart to the inverse supply function. In TIMES, inverse demand functions are constructed by explicitly defining the price elasticity of the demand curve. The price elasticity is generally obtained by solving the model for a reference scenario in which demand projections are driven by defining explicit relationships between demand and economic and demographic drivers (Loulou et al, 2016a). Deriving demand elasticities is however associated with a significant amount of work. In addition, it would mean that the exogenously provided demand estimates that ITN rely on would no longer apply unless they can be formulated in terms of economic and demographic growth. With ITN's current approach to demand estimates, it is important to keep in mind that adaptations in overall energy consumption are not available in the model. If this was included, it is likely that the volume differences between the scenarios would be reduced. In the high price scenario, hydrogen demand and consumption might have been lower as a result of road transport demand adapting to particularly high energy prices, and vice versa for the Low price scenario

Another aspect of the way demand is specified also concerns variation, but within time slices. The demand values in ITN have so-called flat profiles, meaning that demand is constant and fixed within the time slices of a year. In reality, transport demand is of course variable within seasons and days, for instance related to mass transportation for holidays, or rush-hours in the morning and afternoons. Such variations in demand have consequences for the supply of energy carriers as they may affect patterns of storage, refueling, and production behavior. The practical approach to variations in demand is storage which in part is necessary specifically because of differences in timing between demand and consumption. For a PEM plant in isolation, variable demand within the hours of a day may simply result in changes in the distribution of flow- in and out of demand according to time slices with lower and higher demand. From a wider perspective however, when AEL and centralized production is considered, the result of variable demand profiles is likely increased utilization of storage across the model in its entirety. This would however entail higher hydrogen costs for end-users, as storage is associated with additional equipment and costs.

7.1.2.5 Neglected costs for industrial processes

The techno-economic detail level applied to the modeling of hydrogen applications in industrial processes are quite limited in the ITN model. In particular, this relates to a lack of investment and operation costs for utilizing hydrogen in the industrial processes. For instance, using hydrogen as a reduction agent in the metal industry may require substantial technological development, equipment investments, and operational adjustments. In most cases, the costs and technological solutions will be highly specific to each industrial processes and plant. In the ITN model however, there are no additional costs modeled for the uptake of hydrogen in any of the industrial processes. The inclusion of such costs would reduce the cost-effectiveness of hydrogen and might have rendered it uncompetitive in certain instances.

7.1.2.6 No ammonia production

As mentioned in Section 4.4.3.3, the process of producing ammonia from hydrogen is not modeled in the ITN model. Instead, the fuel efficiency of ammonia is reduced as a proxy for the additional energy required by the conversion process. The modeling of a complete production pathway would provide a more accurate picture of the cost-effectiveness of ammonia. A fully modeled production process would account for all the capital and operational expenditures associated with its production, which are significant according to IEA (2019). As ammonia then is explicitly associated with investments and operation costs, this could potentially make ammonia propulsion systems uncompetitive across several instances.

7.1.2.7 Modeling of CO_2 transportation and storage

Access to CCS infrastructure is a prerequisite for blue hydrogen production in Norway, as discussed in Section 2.2.1 and 4.2.1. While a full-scale supply chain for transportation and storage of CO_2 is expected to be operational from 2024, several factors may limit the potential to utilize such services in the future. For the purposes of this thesis, we have assumed that SMR with CCS plants have unrestricted access to CO_2 transport and storage at given prices. In reality however, the potential depends on storage capacities, access for third parties, and whether a competitive market is likely to develop. If one simply assumes favorable developments in these conditions, the operational logic of our SMR with CCS plants are unaffected. In contrast, if this market is subject to high levels of demand, availability may be subject to willingness to pay, which increases the costs for SMR with CCS production. Note from the discussion in Section 6.3.1.3 that our modeled costs for CO_2 transportation and storage constitute relatively small shares of the total unit costs. If these costs are significantly higher however, they may have significant implications for the cost-effectiveness of SMR with CCS.

In addition to the uncertainties associated with the general costs of CO_2 transportation and storage, there are also limitations for how it applies to different regions. These costs are likely to be variable with distance, but our model does not distinguish between distances from different production locations to storage sites. It is for instance likely that the costs for transportation and storage will be lower in the NO5 region where the distance to the storage location is the shortest.

7.1.2.8 Hydrogen loss

As noted in Section 2.1, hydrogen will leak from any container ensuring that hydrogen loss is an unavoidable consequence of additional time and processing. In our model however no loss occurs as the consumed volume of hydrogen are exactly equal to the volumes produced. The loss of hydrogen makes it less cost-effective, as more hydrogen must be produced per unit of consumption. The added costs of hydrogen loss are higher with additional processing and increased differences in timing between production and consumption. In our model however, all hydrogen is either consumed instantly or stored for a maximum of 24 hours. No single process is associated with the passing time. Even hydrogen storage is limited to be concerned with the flow in and out of storage and makes no considerations for how long a unit of hydrogen is stored. In theory however, a loss rate could be specified per hour and each process could be associated with a certain amount of time to complete. Either way, it should be noted that hydrogen loss is not included in the model, which might have had implications for the cost-effectiveness of hydrogen.

7.1.2.9 Domestic production and consumption of hydrogen

The Norwegian energy system is the focus of our model and hydrogen is limited to domestic the production and consumption. However, it is highly likely that hydrogen will partake in international markets. This would incur a logic of imports and exports that may have large implications for domestic production capacity. For instance, as discussed in Section 2.2.1, Norway has both significant natural gas reserves and capacity for CO_2 storage. This could constitute a competitive advantage for SMR with CCS production relative to other countries. The production of hydrogen from SMR with CCS may then far exceed the domestic levels of demand and consumption. International production costs and demand is difficult to quantify but would add an additional dimension to the efforts of researching the potential for hydrogen production in Norway.

7.2 Further work

In this section we provide suggestions for further work that can improve the detail level and increase the scope of hydrogen analysis in ITN, thereby providing more robust conclusions for the potential of hydrogen in the Norwegian energy system. Our suggestions are particularly concerned with efforts to increase the number of technologies and processes that can partake in hydrogen supply chains, and that can add additional perspective to analysis.

7.2.1 Additional technologies

A notable omission in our modeling of hydrogen is the inclusion of “green hydrogen”, i.e., electrolysis production based on renewable electricity. Connecting electrolysis facilities to renewable energy generation such as photovoltaics or hydro power could have large implications for the costs of hydrogen production, and therefore the cost-effectiveness and economic feasibility of electrolysis plants. It would be particularly interesting to see how the prices of green hydrogen production would be compared to grid-based electrolysis, and how the operation of electrolysis facilities is affected by the intermittency of renewable energy such as solar power.

In ITN and for the purposes of this thesis, several relevant and promising hydrogen technologies are not included. In addition, the level of detail varies as discussed in Section 7.1.2.6. The approach to analyzing hydrogen in ITN could be improved by adding additional technologies that are approaching maturity or are expected to partake in hydrogen supply chains in the future. These technologies include additional compression levels, conversion forms, infrastructure, and emerging production technologies such as solid oxide electrolyzer cells (SOEC electrolysis). In addition, it would be interesting to model longer-term storage such as seasonal. Such additions may provide a clearer picture of hydrogen potential by improving its cost-effectiveness in end-use processes or analyze its potential in additional sectors. Inclusions that may have particularly impactful implications for hydrogen prevalence is the addition of infrastructure such as pipelines or maritime vessels for transportation of hydrogen. An analysis of these two transportation methods may for instance contribute to literature by determining whether they are cost-effective, and if so, which implications they have for the production and consumption of hydrogen.

7.2.2 The subsidy perspective

Our analysis of cost-effectiveness in end-use processes was primarily concerned with how CO_2 costs render fossil fuel alternatives uncompetitive. However, an approach with an opposing perspective is available equally valid and informative. This opposing perspective is concerned with how to improve the cost-effectiveness of desired alternatives rather than decrease the cost-effectiveness of undesirable alternatives. This approach could constitute a reduced cost perspective where one attempts to quantify the necessary reduced costs, or subsidies that should be applied to hydrogen investments in order to render them cost-effective. A subsidy approach can be applied in place of carbon pricing, or in combination. A more elaborate approach is also available in which the proceeds of emission taxes are directly channeled towards subsidizing low- or zero-emission technologies. As TIMES is well-suited to quantifying and predicting the outcomes of energy policy, potential hydrogen subsidies can be evaluated effectively using ITN.

7.2.3 Alternative scenarios and sensitivity analysis

Our scenarios were specified in attempt to convey differing energy futures based on varying price levels. They are however not exhaustive in the sense they only cover a very limited set of possibilities, but particularly because the price projections do not cover all relevant energy carriers. If one attempts to convey an energy future where the prices of carbon, power, natural gas, and coal varies, it is reasonable to also include additional and related energy carriers, particularly those that compete for the same end-use processes. Energy carriers such as fossil fuels for transport are priced according to a flat rate that is invariable with the scenarios we are attempting to convey. In our model, the impacts on cost-effectiveness for these energy carriers are limited to the effects of the CO_2 tax. We therefore suggest an expanded scope of scenario specification that includes projections for additional energy carriers that compete directly with hydrogen in industry, road transport and maritime transport. Projections of future prices for fossil fuels, for instance based on resource availability, could have large implications for hydrogen prevalence by increasing or reducing the cost-effectiveness of conventional fossil fuels.

In addition to the expanding the scope of scenarios, we suggest additional sensitivity analysis for selected model parameters. Our sensitivity analysis concerned the CO_2 tax is it was assumed to be the single most dominant factor for hydrogen prevalence. However, there are many additional parameters which could have large implications for hydrogen analysis results. Many of these parameters are also highly uncertain and could warrant sensitivity analysis for a wide range of values. Specifically, we suggest conducting sensitivity analysis for the equipment costs of electrolyzers, and for the costs of CO_2 transportation and storage in relation to SMR with CCS facilities. These parameters are significant factors for the production costs of hydrogen but tends to rely on estimates with a wide range of assumptions, and in some literature even educated guesswork. By running sensitivity analyses on these parameters, one can provide additional information on how the cost-effectiveness of hydrogen is sensitive to highly uncertain and potentially critical techno-economic parameters of hydrogen production.

8 Conclusion

In this thesis, we have conducted a linear programming analysis with the IFE-TIMES-Norway model to study the future potential of low-carbon hydrogen in the Norwegian energy system. The purpose was to analyze how production and consumption may occur, and how hydrogen is likely to flow through national supply chains. We assessed a variety of production methods according to technology and production scale, and how they may supply hydrogen to three end-use sectors: industry, road transport and maritime transport. In addition to production and consumption, we have analyzed hydrogen storage, refueling stations, and distribution by means of trucks in order to enable a holistic supply chain perspective. We have verified pre-existing model data on hydrogen technologies, particularly the production technologies alkaline- and PEM electrolysis. In addition, we have developed the model with the inclusion of “blue hydrogen”, i.e., the production of hydrogen by Steam methane reformation (SMR) with carbon capture and storage (CCS). We conducted scenario- and sensitivity analysis to explore hydrogen prevalence according to differing energy price futures and to valuate which energy system factors that may have the largest implications for hydrogen prevalence.

The results suggests that hydrogen can be a cost-effective zero-emission alternative across several end-use processes in industry, road- and maritime transport in the Norwegian energy system towards 2050. The greatest potential for hydrogen is seen in industry and maritime transport, while applications in road transport is limited to the heaviest vehicle segments. Our analysis show that carbon pricing is the main factor impacting the competitiveness of hydrogen in these sectors, and subsequently the overall potential of hydrogen. In addition to carbon pricing, the potential of hydrogen is largely dictated by the modeled feasibility, availability, and maximum market shares of competing zero-emission alternatives such as battery electric vehicles and biogas.

According to our Baseline scenario, approximately 9.5 TWh of hydrogen can potentially be produced and consumed in Norway by 2050. This scenario is intended to reflect the expected energy policies of the Norwegian government, with an assumed CO_2 tax of 2 083 NOK/ton from 2030. However, carbon prices in excess of the expected levels make hydrogen cost-effective in additional end-use processes and instances. In our High price scenario, where the CO_2 tax increases to 9 029 NOK/ton in 2050, the national hydrogen volume increases to 16.5 TWh. The volume differences between the Baseline and High price scenario are primarily driven by increased hydrogen adoption in road transport, indicating that this sector is particularly dependent on higher carbon pricing. On this basis, we conclude that the national CO_2 tax must far exceed the currently expected levels of 2000 NOK/ton from 2030 to enable significant market shares for hydrogen in all three consumption sectors.

Regarding production, the results indicate that the greater part of hydrogen production will come from SMR with CCS. For large-scale production, alkaline electrolysis can become the cost-effective option in instances where the power prices are particularly low. On the other hand, PEM electrolysis is not a cost-effective option for large scale production at any point in the model horizon. On the distributed scale, the results show that there is potential for both alkaline and PEM electrolysis, most often in combination as PEM leverages its flexibility to produce hydrogen when power prices are low. For most of the model horizon, the investments occur in both PEM and AEL, but PEM is increasingly preferred over time as its costs are reduced compared to Alkaline electrolysis. Furthermore, our results suggest that hydrogen will be consumed within the same regions as where it is produced, as inter-regional distribution by trucks proved to be economically infeasible. In some instances, it could be cost-effective to transport hydrogen from SMR with CSS plants to refueling stations, rather than to invest in distributed electrolysis production. However, most of the hydrogen for road transport is expected to be supplied by small-scale electrolysis facilities, as local distribution only proved cost-effective in instances with particularly short driving distances and high regional power prices.

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Appendix

A: Road transport details

Regional demand

See Table A.1 to A.3 for regional breakdown of transport demand for different vehicle types. See Table A.1 for cars and vans, Table A.2 for buses, and Table A.3 for trucks. As existing stock of vehicles is modelled as equal to 2018 demand, the table also serves as a regional breakdown of existing stock.

Table A.1: *Regional breakdown of transport demand projections for cars and vans, in million vehicle kilometers per year.*

Vehicle type	Spot-price region	2018	2030	2050
Cars	**NO1**	16 195	18 621	20 949
	NO2	8 646	10 167	11 589
	NO3	4 146	4 648	5 306
	NO4	2 583	2 708	2 847
	NO5	3 579	3 918	4 406
	Sum	**35 149**	**40 062**	**45 097**
Vans	**NO1**	3 041	3 894	5 293
	NO2	1 773	2 270	3 086
	NO3	1 130	1 447	1 966
	NO4	678	868	1 180
	NO5	686	878	1 194
	Sum	**7 307**	**9 358**	**12 720**

Table A.2: *Regional breakdown of transport demand projections for buses, in million vehicle kilometers per year.*

Spot-price region	2018	2030	2050
NO1	239	250	259
NO2	139	146	151
NO3	89	93	96
NO4	53	56	58
NO5	54	56	58
Sum	**574**	**601**	**622**

Table A.3: *Regional breakdown of transport demand projections for trucks, in million vehicle kilometers per year.*

Vehicle type	Spot-price region	2018	2030	2050
Trucks (S)	**NO1**	221	179	161
	NO2	114	93	85
	NO3	70	54	48
	NO4	51	37	34
	NO5	55	41	37
	Sum	**510**	**405**	**365**
Trucks (LS)	**NO1**	334	453	635
	NO2	173	235	334
	NO3	106	137	189
	NO4	77	94	135
	NO5	83	104	146
	Sum	**773**	**1 024**	**1 438**
Trucks (LL)	**NO1**	334	453	635
	NO2	173	235	334
	NO3	106	137	189
	NO4	77	94	135
	NO5	83	104	146
	Sum	**773**	**1 024**	**1 438**

Investments costs

In Table A.4 to A.6, the investment costs for vehicle types and powertrains are presented. Investment costs for cars and vans are assumed until 2030, while other vehicles have values until 2050. See Table A.4 for investment costs for cars and vans, Table A.5 for trucks, and Table A.6 for buses. See Section 5.3.5.3 of the ITN documentation for sources and explanations on how investment costs have been derived.

Table A.4: *Investment costs for cars and vans with different powertrains.*

			Start year		2030	
Vehicle type	**Powertrain**	**Start year**	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**
Cars	**ICE**	2019	1.80	397	1.87	413
	Battery	2022	2.18	481	1.12	248
	Hybrid	2022	1.86	411	1.75	386
	Hydrogen	2020	3.46	765	1.68	371
Vans	**ICE**	2019	1.01	231	1.03	236
	Battery	2019	2.21	506	1.17	269
	Hybrid	2020	1.34	308	1.23	281
	Hydrogen	2020	3.36	770	1.58	362

Table A.5: *Investment costs for trucks with different powertrains.*

			Start year		2030		2050	
Vehicle type	**Powertrain**	**Start year**	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**
Trucks (S)	**ICE**	2019	3.33	1 500	3.33	1 500	3.33	1 500
	Gas	2019	3.78	1 700	3.78	1 700	3.78	1 700
	Battery	2022	9.44	4 250	6.47	2 910	3.37	1 515
	Hydrogen	2025	12.89	5 800	7.63	3 434	3.8	1 710
Trucks (LS)	**ICE**	2019	3.30	1 500	3.3	1 500	3.3	1 500
	Gas	2019	3.74	1 700	3.74	1 700	3.74	1 700
	Battery	2022	9.67	4 400	6.82	3 104	3.33	1 515
	Hydrogen	2025	12.75	5 800	8.04	3 658	3.76	1 710
Trucks (LL)	**ICE**	2019	2.78	1 500	2.78	1 500	2.78	1 500
	Gas	2019	3.44	1 860	3.44	1 860	3.44	1 860
	battery	2100	8.15	4 400	5.75	3 104	2.81	1 515
	Hydrogen	2025	10.74	5 800	6.77	3 658	3.17	1 710

Table A.6: Investment costs for buses with different powertrains

		Start year		2025		2050	
Powertrain	**Start year**	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**
ICE	2019	4.78	2 000	4.78	2 000	5.06	2 116
Gas	2019	5.26	2 200	5.26	2 200	5.83	2 435
Battery	2020	10.77	4 500	7.18	3 000	5.06	2 116
Hydrogen	2020	19.14	8 000	9.57	4 000	5.48	2 290

Operating and maintenance costs

Operating and maintenance costs are assumed to be constant in IFE-TIMES-NORWAY. The exception is fuel cell powertrains for cars, vans, and buses. For these vehicles, reductions are assumed until 2030. See Table A.7 for the operating and maintenance costs for these vehicles, and Table A.8 and A.9 for all other powertrains and vehicle types. See also section 5.3.5.2 of the ITN documentation for details on how these costs have been derived.

Table A.7: Operating and maintenance cost reductions for hydrogen fuel cell vehicles.

	Start year		2030		
Vehicle type	**NOK/km**	**Total cost (kNOK)**	**NOK/km**	**Total cost (kNOK)**	**Δ%**
Cars	0.45	101	0.28	63	-38
Vans	0.46	106	0.28	64	-39
Buses	1.9	794	1.6	669	-16

Table A.8: Operating and maintenance costs for cars and vans by powertrain.

		Start year	
Vehicle type	**Powertrain**	**NOK/km**	**Total cost (kNOK)**
Cars	**ICE**	0.62	139
	Battery	0.28	63
	Hybrid	0.45	101
Vans	**ICE**	0.65	149
	Battery	0.28	64
	Hybrid	0.46	106

Table A.9: *Operating and maintenance costs for trucks and buses by powertrain.*

		Start year	
Vehicle type	**Powertrain**	**NOK/km**	**Total cost (kNOK)**
Trucks (S)	**ICE**	0.98	441
	Gas	0.98	441
	Battery	0.98	441
	Hydrogen	0.98	441
Trucks (LS)	**ICE**	0.98	446
	Gas	0.98	446
	Battery	0.98	446
	Hydrogen	0.98	446
Trucks (LL)	**ICE**	0.79	427
	Gas	0.79	427
	Battery	0.79	427
	Hydrogen	0.79	427
Buses	**ICE**	2.2	920
	Gas	2.2	920
	Battery	1.6	669

Fuel efficiency

See section 5.3.5.1 of the ITN documentation for sources and explanation of fuel efficiency for road transport vehicles. Fuel efficiency developments are provided until 2025 for buses, until 2050 for other vehicles. See Table A.10 for fuel efficiency for buses, Table A.11 for cars and vans, and Table A.12 for trucks. Fuel efficiency values are distinguished between existing stock and new investments.

Table A.10: *Fuel efficiency for buses by powertrain and year, in KWh/km.*

Powertrain	**New/stock**	**2018**	**2025**
ICE	New	4.2	4.1
	Stock	4.83	-
Gas	New	5.38	5.25
	Stock	6.18	-
Battery	New	2.3	2.1
Hydrogen	New	3.33	3.33

Table A.11: *Fuel efficiency for cars and vans by powertrain and year, in KWh/km.*

Vehicle type	Powertrain	New/stock	2018	2050
Cars	**ICE**	New	0.57	0.39
		Stock	0.65	-
	Battery	New	0.19	0.17
		Stock	0.19	-
	Hybrid	New	0.42	0.32
		Stock	0.49	-
	Hydrogen	New	0.33	0.28
Vans	**ICE**	New	0.59	0.4
		Stock	0.73	-
	Battery	New	0.23	0.11
	Hybrid	New	0.44	0.33
	Hydrogen	New	0.34	0.29

Table A.12: *Fuel efficiency for trucks by powertrain and year, in KWh/km.*

Vehicle type	Powertrain	New/stock	2018	2050
Trucks (S)	**ICE**	New	3.37	3.1
		Stock	3.94	-
	Gas	New	4.15	3.82
	Battery	New	1.48	1.36
	Hydrogen	New	2.49	2.29
Trucks (LS)	**ICE**	New	4.83	4.44
		Stock	5.31	-
	Gas	New	5.95	5.47
	Battery	New	2.13	1.96
	Hydrogen	New	3.57	3.29
Trucks (LL)	**ICE**	New	4.19	3.86
		Stock	4.61	-
	Gas	New	5.27	4.85
	battery	New	1.84	1.7
	Hydrogen	New	3.1	2.85

B: Scenario details

In Table B.1 to B.3, price levels for the scenario parameters included in our modeling runs are presented. Table B.1 shows the national CO2 tax per milestone year and scenario, while Table B.2 and B.3 shows the natural gas- and coal prices, respectively.

Table B.1: *National CO2 tax by scenario and milestone year, in NOK/ton CO2.*

	2020	2025	2030	2040	2050
High price	1 200	1 566	2 441	5 940	9 029
Baseline	766	1 260	2 083	2 083	2 083
Low price	461	454	455	673	996

Table B.2: *Natural gas prices by scenario and milestone year, in NOK/MWh.*

	2020	2025	2030	2040	2050
High price	208	198	238	307	307
Baseline	208	168	188	238	228
Low price	208	139	149	168	168

Table B.3: *Coal prices by scenario and milestone year, in NOK/MWh.*

	2020	2025	2030	2040	2050
High price	90	109	109	109	109
Baseline	90	89	89	89	89
Low price	90	69	69	59	59

C: Result details

The regional hydrogen prices in Table C.1 and the production volumes in Table C.2 have been used for the calculation of the weighted average national prices of centralized production, as presented in Section 6.3.1.2. Table C.3 and C.4 have been used for the distributed prices presented in section 6.3.2.2. The national averages have been calculated by the average of regional prices, weighted by their corresponding production volumes within the region.

Table C.1: *Average regional hydrogen prices from centralized production technologies, in NOK/kg H_2.*

Scenario	Technology	Region	2030	2040	2050
Baseline	**Centralized AEL**	**NO4**	-	-	17.98
	SMR with CCS	**NO2**	18.94	20.67	21.21
		NO3	18.94	19.79	21.21
		NO4	18.59	21.56	17.98
		NO5	18.94	20.67	21.21
High	**Centralized AEL**	**NO1**	37.08	35.23	33.38
		NO3	-	25.43	26.52
		NO4	30.98	21.71	21.80
	SMR with CCS	**NO2**	21.58	25.86	28.47
		NO3	23.02	25.58	26.68
		NO5	21.58	25.86	28.47

Table C.2: *Regional hydrogen production from centralized production technologies, in GWh.*

Scenario	Technology	Region	2030	2040	2050
Baseline	**Centralized AEL**	**NO4**	-	-	733.26
	SMR with CCS	**NO2**	414.84	1 523.32	2 568.21
		NO3	361.82	1 734.36	2 989.95
		NO4	114.71	818.81	818.81
		NO5	119.79	991.50	1 924.74
High	**Centralized AEL**	**NO1**	15.41	156.66	265.92
		NO3	-	1 638.26	2 861.56
		NO4	187.16	1 054.24	1 760.33
	SMR with CCS	**NO2**	2 588.49	4 612.40	5 327.02
		NO3	485.87	485.87	485.87
		NO5	212.04	1 655.12	2 353.85

Table C.3: *Average regional hydrogen prices at hydrogen refueling stations, in NOK/kg H_2.*

Scenario	Region	2030	2040	2050
Baseline	**NO1**	-	-	56.21
	NO2	72.22	51.51	55.61
	NO3	-	-	54.53
	NO4	72.08	51.04	50.87
	NO5	-	-	55.60
High	**NO1**	-	71.89	67.99
	NO2	67.06	67.25	64.74
	NO3	-	61.29	58.08
	NO4	-	57.01	54.49
	NO5	-	67.51	66.40

Table C.4: *Distributed hydrogen supply for road transport, in GWh.*

Scenario	Region	2030	2040	2050
Baseline	**NO1**	-	-	1.14
	NO2	25.69	2.22	14.87
	NO3	-	-	182.29
	NO4	140.19	12.12	226.29
	NO5	-	-	0.25
High	**NO1**	-	840.46	1 632.08
	NO2	216.67	887.24	1 074.01
	NO3	-	492.49	610.73
	NO4	-	344.27	432.48
	NO5	-	373.80	466.33