A systemic innovation approach towards a Danish hydrogen gas grid

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STUDENT REPORT

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Abstract:

The purpose of this study is to evaluate the economic and technical feasibility of a Danish hydrogen gas grid by 2050. With the use of EnergyPLAN was developed a Danish energy scenario containing a hydrogen gas grid. The simulated scenario was compared to the IDA 2050 scenario. From the comparative analysis was possible to assess the technical and economic impact of said infrastructure. Finally, it was mapped a matrix of driving innovation employing a systemic innovation approach. The economic impact of innovation and consequent electrolyser cost reduction was determined.

Preface

This report was written by Liliana Andreia Morais Gomes at the Department of Planning at Aalborg University, as a semester project with the subject: *Sustainable Energy Planning on Professional Development.*

The internship was effected in the International Renewable Energy Agency (IRENA), an intergovernmental organisation that actively supports more than 180 countries in their energy transition. IRENA only promotes renewable resources and technologies as the key solutions to a sustainable green future.

Acknowledgements

There are numerous individuals who had significantly contributed to the conclusion of this project. Firstly, I would like to take this opportunity to show my gratitude to my supervisor Dr. Steffen Nielsen, that had shared his expertise and support.

I would also like to extend my deep appreciation to all past and present Innovation team members, Alessandra Salgado, Arina Anisie, Francisco Boshell, Elena Ocenic, Stefan Gahrens, and Mustafa Abunofal. I am especially thankful to Elena Ocenic for her tireless dedication and guidance as a supervisor, it has been a tremendous growth experience to be allowed to work closely with such a professional.

The realization of the internship was done during the Covid-19 pandemic, such atypical times required additional adaptation efforts, both physically and mentally. In addition to quarantine due to the contraction of the virus.

Reflection on the internship

The internship in IRENA overcame any kind of expectations. As an intern, I was given the opportunity to do the most variety of roles and work closely as a team member. Some of this myriad of activities include the realization of the IRENA Virtual Innovation Week and publication of two reports, the *Innovation outlook: Thermal energy storage* and the *Quality infrastructure for smart mini-grids.* As part of the dissemination of one report, I was also trusted to present a webinar about *Thermal Energy Storage: A Key Enabler of Increased Renewables Penetration in Energy Systems.* Moreover, I also have compiled research about power to molecules, one of the three vectors of the forthcoming IRENA Innovation Landscape report.

This was a brief overview of the tangible accomplishments, however having the opportunity to work in an international environment, learning with the best experts is something astonishingly intangible. Furthermore, the performance of the internship can be said to be successful as the duration of the internship was extended to a maximum period of nine months. To conclude my reflection on the internship, I would like to summarize it using our team motto, *intense but under control.*

Readers guide

The bibliography from page 49 shows the literature used in the project. The references follow the APA citation format, as seen below.

[Author][Title](Institution)(ISBN)[Year](URL)(Date Accessed)

Where square brackets are mandatory and the parentheses are optional. The bibliography is listed, by author, in alphabetic order.

The following appendices are included in the report:

- Hydrogen state of the art
- Hydrogen in the EnergyPLAN
- EnergyPLAN output

Table of Contents

Problem analysis 1

1.1 International approach to climate change

The Paris agreement is an agreement on international climate. In this treaty 165 countries legally bound to limit the rise of global temperature to 1.5 Celsius degrees, in comparison to pre-industrialization. In order to successfully achieve this goal, it is necessary that all sectors reach zero carbon dioxide emissions. Figure 1.1 shows the carbon emissions that need to be reduced by each sector and possible action lines.

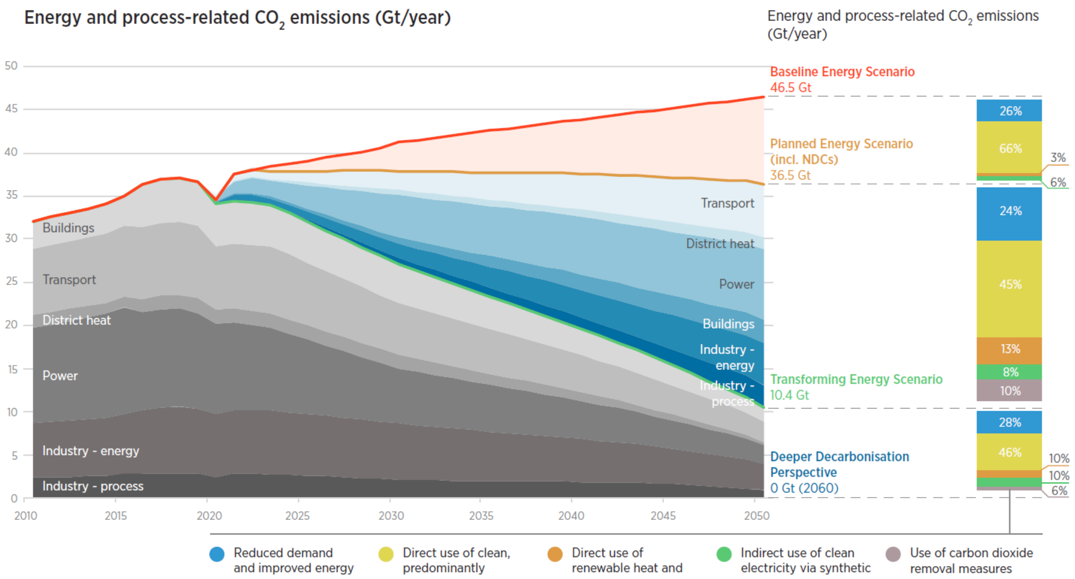

Figure 1.1. Energy use and emissions from 2010 to 2050. [IRENA, 2020e]

Some of the key aspects include demand reduction and improvement of energy efficiency, direct use of clean electricity, direct use of renewable heat and biomass, indirect use of clean electricity via synthetic fuels and feedstock, and finally the use of carbon dioxide removal measures such as carbon capture, utilisation and storage (CCUS). IRENA [2020e] mentioned that in hard to decarbonize sectors, like industry and long-haul transportation the indirect use of electricity could play a crucial role. Other studies state that by 2050 hydrogen could supply 24% of the world's energy needs [BloombergNEF, 2020b].

The interest in hydrogen has reached a global level. As visible in Figure 1.2, several countries have already defined concrete goals and policies to implement a national hydrogen strategy.

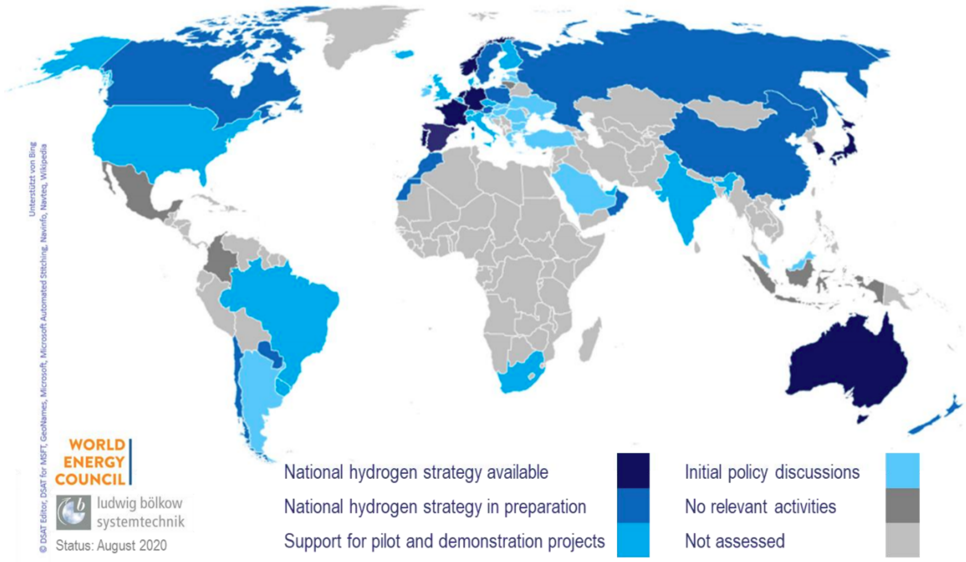

Figure 1.2. Hydrogen strategies around the world. [Albrecht et al., 2020]

This interest in hydrogen is particularly relevant in Europe, mainly colored as dark blue as a representation of available hydrogen strategies. However, most of the current use of hydrogen happens in refineries and in the production of chemical feedstocks. The European total use of hydrogen in 2019 accounted for 340 TWh, out of which 153 TWh were used in refining processes and 129 were utilized to produced ammonia for fertilizers. Nevertheless, according to FCH [2019], in 2050 hydrogen could supply 24% of the total European energy demand, which is equivalent to a 2,250 TWh consumption of hydrogen. It is a considerable rise of 1,910 TWh when compared to 2019 consumption.

The growing interest in hydrogen is related to the possible key role in the production of synthetic fuels and as an enhancer of the flexibility of power systems, and consequently higher integration of variable renewable energy (VRE) [SolarPower Europe and LUT University, 2020]. Figure 1.3 represents the expected electrolyser installed capacity by 2050 if the European Commission ambition of being carbon neutral by 2050 is achieved a decade earlier.

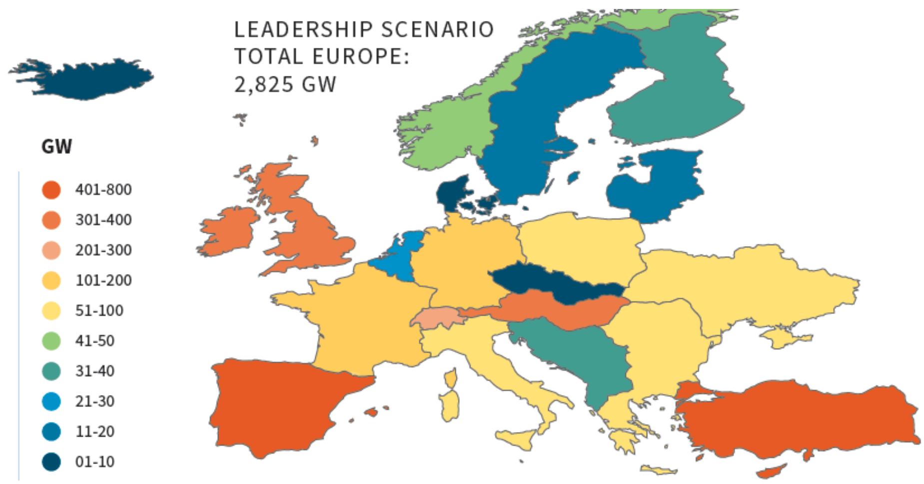

Figure 1.3. Electrolyser installed capacity in Europe by 2050. [SolarPower Europe and LUT University, 2020]

The total electrolyser installed capacity of 2,825 GW represents an enormous effort, especially in the south of Europe. The southern European countries are expected to have higher electrolysers capacity due to the possibility to generate lower levelised cost of electricity (LCOE). The reason behind the possible lower LCOE is related to the abundant renewable energy resources. An in-depth study has shown that in 2030 southern Europe will manage to have competing synthetic fuel prices, even with Northern Africa. This future lower cost of hydrogen production in Europe can ensure security of supply and create business opportunities in a global market [SolarPower Europe and LUT University, 2020].

In order to harness this potential, the European Union (EU) has formally stated its intention in the European Green Deal to be at the forefront of hydrogen production.

1.2 European Green Deal

The EU Green Deal targets by 2030 a 55% reduction in greenhouse gas emissions, relative to the 1990 baseline, and carbon neutrality by 2050. To achieve this goal, the EU aimed to increase the electrolyzer capacity from the current 60 MW to 500 GW in 2050. This growth is tremendous. To put this number in context, this would mean that new electrolyser installations would almost be equal to the biggest electrical peak load ever accounted in Europe of 545 GW [BloombergNEF, 2020a].

The European Commission (EC) has announced recently the goal of having at least 6 GW of electrolysers by 2024 and 40 GW by 2030, at a cost between 24 and 42 billion euros. Only the production of hydrogen from renewable energy sources is considered. In addition to the domestic production, the EC also aims to have a 40 GW capacity in neighboring countries that would export to Europe.

Additionally to the electrolysers cost mentioned, the spending of 220 to 340 billion euros will be required for the installation of 80 to 120 GW new solar and wind capacity. Extra costs would also include 11 billion euros to retrofit half of existing fossil-based hydrogen plants with carbon capture and storage (CCS) and 65 billion euros for hydrogen infrastructure in transport, distribution, storage, and refueling stations. In sum, the total investment cost would be 320 billion to 458 billion euros [European Comission, 2020].

Several countries have already translated this European goal into their national policies, as seen in Figure 1.4. This figure represents the commitments done regarding electrolyser installed capacity by 2030. As it can be seen, only four countries have translated the European ambition to their individual national goals.

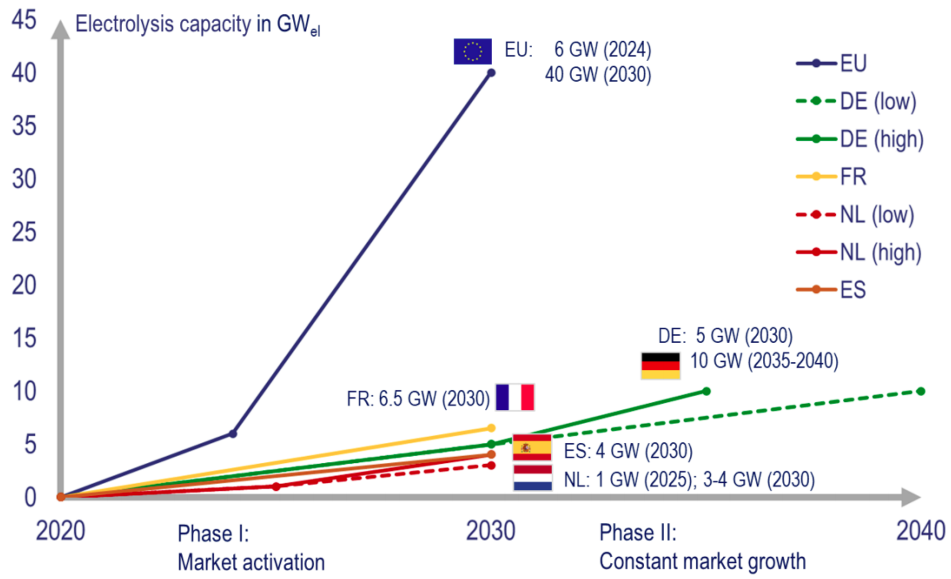

Figure 1.4. Target electrolysis capacity in Europe. [Albrecht et al., 2020]

However, Figure 1.4 does not take into account the newly commitment done by Portugal of 2.5 GW and Italy of 5 GW regarding the installation of electrolyser capacity by 2030 [Republica Portuguesa, 2020] [PV magazine International, 2020]. Taking into account these two new commitments plus the represented in the Figure, it is possible to conclude that 27 GW have been officially translated into national goals from the 40 GW at the European level. These commitments show that countries are interested and are responding fast since the European hydrogen strategy was published in July 2020.

Despite the fact that countries like Denmark have not yet published a hydrogen strategy, the governmental interest is visible as shown by the following quote done by the Danish Ministry of Climate [2020]:

> "In Denmark, we have a really good starting point for the development of Power-to-X. We have significant wind resources, a well-functioning energy system and strong business competencies" - Minister of Climate Dan Jørgensen.

The Power to X includes diverse products, as further scrutinized in the Appendix B. However, for a deeper understanding of this process, only Power to hydrogen will be considered as the production of hydrogen is the base for other synthetic and chemical products. In that sense, only the direct use of hydrogen will be analysed.

1.3 Direct use of hydrogen in Denmark

Denmark has a unique advantage in producing green hydrogen as it has high renewable energy generation potential, a modern district heating network, and gas infrastructure adaptable for hydrogen [Brintbranchen, 2020].

Gas infrastructure is especially crucial when one considers the transportation of hydrogen. As visible in Figure 1.5, the most affordable type of transportation for large volumes as one national hydrogen strategy would require is the transmission pipeline network.

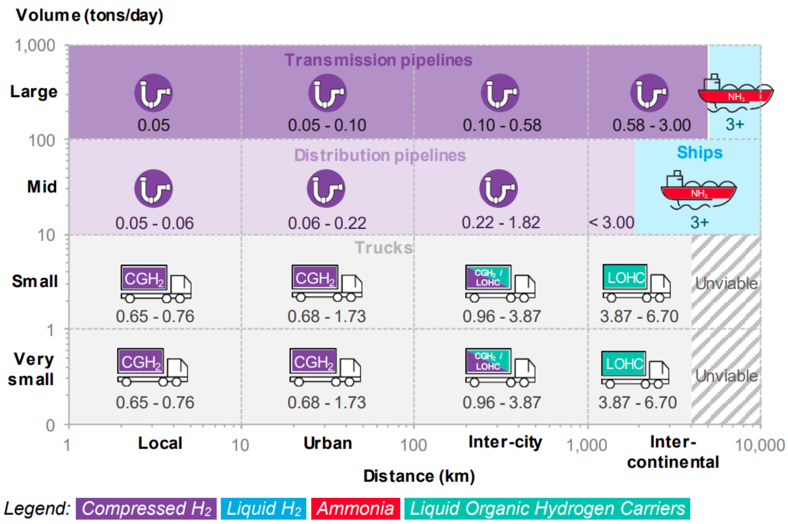

Figure 1.5. Transportation costs for hydrogen (USD/kg). [BloombergNEF, 2020b]

Moreover, McKinsey [2020] has also stated that countries with a gas network have the highest hydrogen market potential. Thus Denmark has a high potential to use its gas network in favor of a clean energy transition and achieve its goal to be carbon neutral by 2050. However, some questions arise when considering the transformation of the current gas network to a hydrogen gas infrastructure.

1.4 Problem formulation

How could Denmark implement a hydrogen gas grid in a technical and economically feasible way by 2050?

In order to properly answer this problem formulation, three underlining research questions have been formulated.

1. What is the current considered hydrogen role in the Danish energy system?
2. What would be the economical and technical implications of implementing a hydrogen gas grid?
3. Which innovations could facilitate a hydrogen gas grid?

Methodology 2

In this chapter, the research design and methods used in the project are presented, showing the structure and how the different sections contribute to answering the main research question.

2.1 Research design

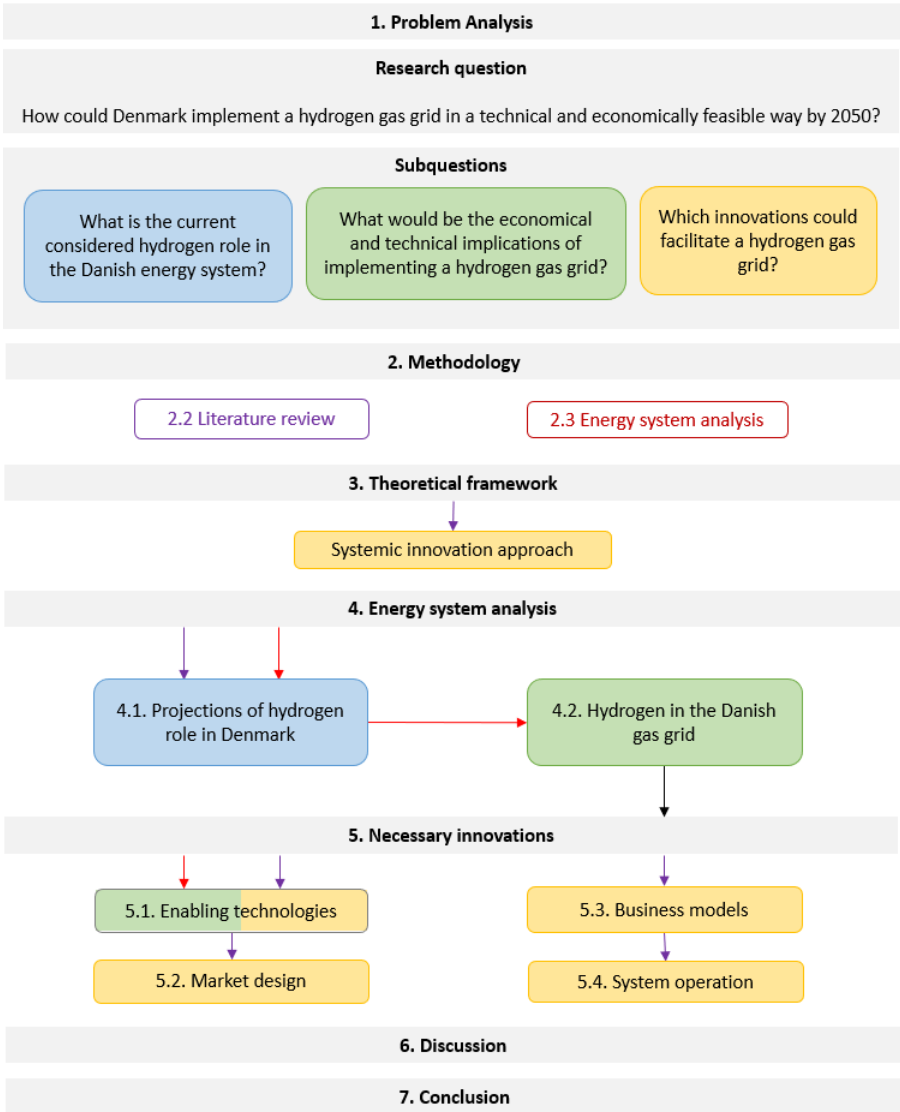

Figure 2.1. Research design of the project.

Figure 2.1 shows how the different chapters are connected with the research question and the respective methods and theories applied.

2.2 Literature review

In order to find relevant information on the research topic, several resources were used both characterized as primary and secondary search.

Primary search is described as the information collected directly from the source. European Commission official documents such as the hydrogen strategy were the main primary information sources of this report.

Secondary sources include information gather trough second-hand sources such as websites, online libraries, databases, and online newspapers. In this report, the secondary literature used consisted of EU reports, scientific reports, expert reports, and official country statements. The reliability of each piece of information was assessed by comparing different sources.

2.3 Energy system analysis

To perform the wanted energy analysis the free software EnergyPLAN was used. The scope of the energy analysis is visible in Figure 2.3, this study encompasses only the direct use of hydrogen for heating and cooling in buildings, specifically via the gas grid.

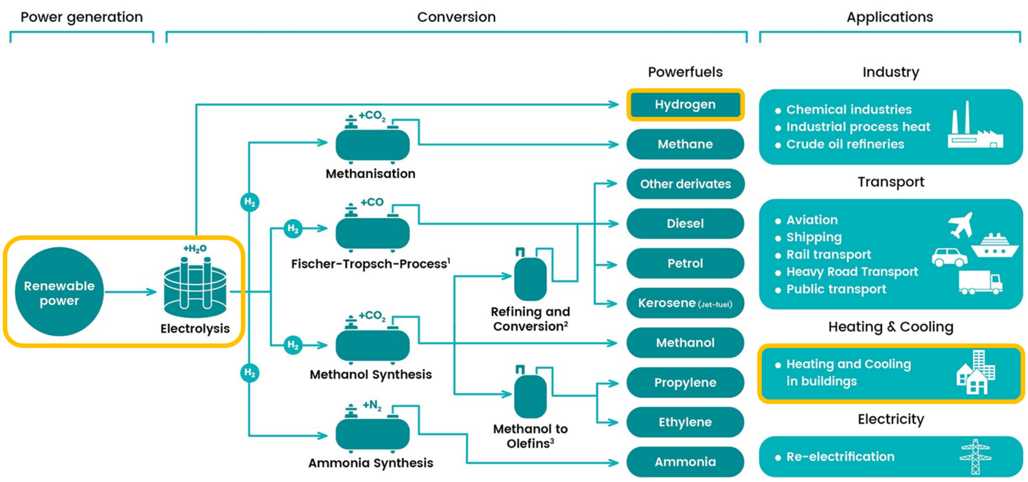

Figure 2.2. Scope of the hydrogen, from production to application.

In EnergyPLAN, none of the three option shown in the Appendix B allow the user to directly include hydrogen in the gas grid. In that sense, a methodology was developed to evaluate the impact of supplying the heat demand in the district heating at a national level in Denmark with hydrogen, produced from renewable power.

2.3.1 Methodology to include hydrogen in the gas grid

This section will explain the methods used to find the hydrogen demand, the demand profiles, and finally how to balance the incorporation of hydrogen with the energy system.

Hydrogen demand

The first step was to understand how much hydrogen would be necessary to be produced for the district heating. In order to know the amount of fuel used in the CHPs and boilers connected to the district heating, it was assumed that the coal category would be the only fuel used in the 'Fuel distribution' tab. This method allows the disguise of hydrogen in the coal category. The coal category was chosen because coal was not considered in the 2050 IDA scenario, meaning that all the consumption that would appear in the primary energy supply would be used in the district heating. Oil category could be also used, obtaining the same results. The value obtained corresponds to the amount of hydrogen that is used in boilers and CHP to produce the correct amount of heat for the district heating. However, this approach has its limitations as it is being assumed that hydrogen would have the same thermal behavior as other fuels, which is not entirely correct as the different conversion processes have correspondent efficiencies. Nevertheless, the EnergyPLAN does not take this factor into account since independently of the four options available on the fuel distribution being, coal, oil, natural gas, or biomass the primary energy supplied calculated is always the same.

The value of the hydrogen demand was included in the 'Industry and fuel' tab, meaning that in the output sheet the value of hydrogen produced for Industry is in reality the one used in the district heating. The hydrogen demand was included in the Industry as this option was not used in previous scenarios, meaning that the outcome would be entirely correspondent to the gas grid and it also allows the addition of one distribution profile correspondent to the hydrogen demand. In addition, the carbon emissions for coal were set to zero as the production of green hydrogen would not emit CO_2.

Profile of hydrogen demand

Not only it is necessary to calculate the hydrogen demand (TWh/year) but also define the hourly demand profile of hydrogen, hence three demand profiles were obtained to test three different operation modes of the electrolyser. The three hydrogen demand profiles that represent the operation of the electrolyser are the following:

1. Constant operation
2. Operation accordingly to the availability of renewable sources
3. Operation depended on the heat demand

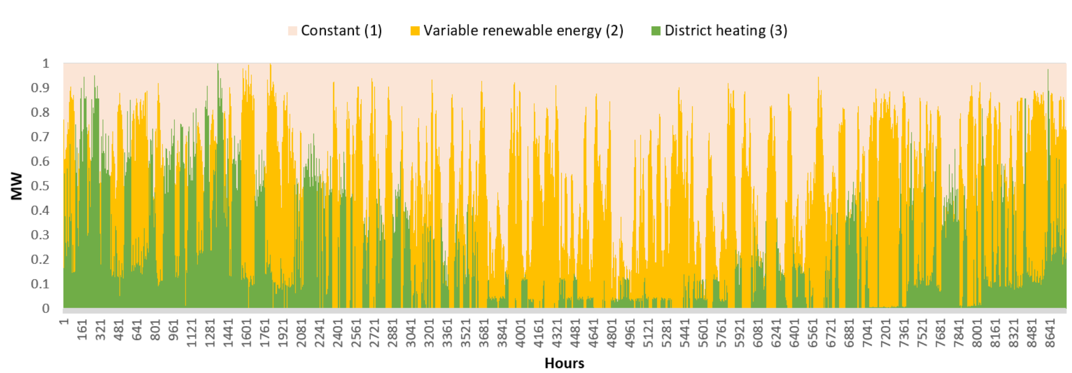

Figure 2.3. Three hourly hydrogen demand profiles.

The first demand profile is easy to obtain as the constant distribution file can be created by repeating the number 1 during the 8784 rows, hence obtaining a constant demand throughout all hours of the year. However, the remaining 2 demand profiles require further calculations.

For the second demand profile that assumes that hydrogen will only be produced accordingly to the renewable power generation, it was necessary to sum all hourly values of electricity generated, including wind, offshore wind, solar photovoltaic (PV), run-of-river-hydropower, tidal, and wave power. Afterwards, the values were divided by the maximum value so that one could obtain a relative distribution. Using a relative distribution instead of the overall renewable power distribution allows the user to include a profile regardless of the demand.

For the third option, the operation of electrolysers is done accordingly to the heat produced in the district heating (DH). The same process was done, now adding the heat production from the CHP operating as backpressure mode and boilers in the three district heating groups. In this sense, the profile would match the moment that these technologies need fuel to produce heat for the district heating.

All hourly values used to create the two distributions were obtained in the scenario where coal is the only fuel of the district heating, that way both the VRE and DH profile follow similar behavior as if the gas grid was entirely run by hydrogen.

2.3.2 Sensitivity analysis

To produce the additional green hydrogen demand it is necessary to supply the electrolysers with electricity. Therefore, the increase in electricity demand was followed by an increase in **renewable power generation** capacity. A sensitivity analysis was carried out to find the best fitting renewable source for the 2050 energy scenario. In this analysis, additional generation capacity, in an interval of 5 TWh/year, was added to the system. Parameters such as the critical excess electricity production (CEEP) and the total system cost were used to compare the generation of onshore wind, offshore wind, and PV.

Another aspect important to scrutinize is the electrolyser and hydrogen storage capacity accordingly to the three different demand profiles. First, it was assumed for the three demand profiles that there was no hydrogen storage to see the implications on the **electrolyser** installed capacity. It was initially assumed a maximum hydrogen storage and electrolyser capacity to understand in theoretical conditions what would be the maximum electrolyser capacity used in the entire year. Knowing the maximum electrolyser capacity used is crucial because if a higher electrolyser capacity is installed it will not be fully operated and the system will be considered oversized. Afterwards, to reduce the system cost the minimum electrolyser capacity was obtained. After some iterations, an ideal electrolyser installed capacity was obtained that ensures hydrogen production and avoids CEEP.

With the electrolyser capacity constant throughout the three different demand profiles tested, it was possible to calculate the minimum **hydrogen storage** necessary, having the same primary energy supply. In other words, the minimum hydrogen storage needed to fully supply the district heating demand was calculated.

Theoretical framework 3

In this chapter, the theoretical framework of the project is presented. The theoretical approach addresses the framework of the research and the main line of thinking.

As mentioned in Problem formulation, the inclusion of hydrogen in the energy system is an emerging possibility, that requires a new political framework. The systemic innovation approach was chosen as a theoretical framework for this report to assess the necessary adaptations to successfully include hydrogen on the Danish gas grid.

3.1 Systemic innovation approach

In a recent report, IRENA [2019a] has investigated the necessary landscape of innovations to foster the VRE integration. It is stated that to increase the share of VRE, synergies between different dimensions are necessary, such as innovations in enabling technologies, business models, market design, and system operation. This approach was named Systemic Innovation and the synergies across the different dimensions of innovation are represented in Figure 3.1.

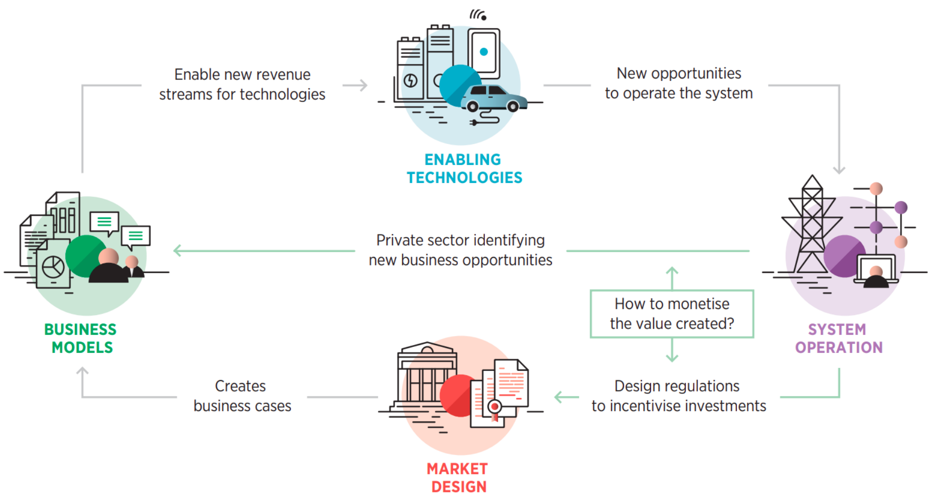

Figure 3.1. Systemic innovation synergies. [IRENA, 2019a]

Systemic innovation is vital for a future renewable energy system, as the integration of VRE involves new enabling technologies. These opportunities created by emerging technologies require that the way the energy system operates also adapts and includes innovative operation modes. Similarly, the market design should encompass the requirements and characteristics of the new operation so that profitable business models are created. That way, the cycle is completed with the new revenues being invested in new technologies.

In that sense, the systemic innovation approach can be said to exist when the political process takes into account the four dimensions in innovation. The importance of each dimension is further explained.

Enabling technologies and infrastructure ease the integration of renewable energy by including innovative elements such as electricity storage, electrification of end-use sectors, digital technologies, and new grids.

Business models are crucial to monetise the new value created by these technologies and foster their deployment. Innovative business models could empower the consumer (peer-to-peer trading) and enable ownership of the energy supply.

Market design and regulations impact the economical feasibility of innovative options, hence they should also adapt and innovate accordingly to the new ambitions. Only then new business cases can also emerge. These adaptations on the market designed might include options on the wholesale or retail market

The **system operation** has to change with the increasing share of distributed systems since the decentralization transforms the grid system into a bi-directional power flow. The innovations in operation might occur on the way the uncertainty of VRE is accommodated, with grid reinforcement, or even in the way the operators cooperate.

From the application of the systemic innovation approach to the power system, IRENA has published 30 innovation briefs that serve as practical guidelines for policymakers. These briefs include concrete examples and implementation requirements of the thirty mapped innovations across the four dimensions [IRENA, 2019a]. This systemic innovation approach was also used to create four solutions tailored to increase the VRE share on the Swedish power system [IRENA, 2020c].

3.2 Delimitations

The systemic innovation approach was initially developed to create a landscape of innovations that can incorporate higher shares of VRE in the entire energy system. However, this study has been delimited to the application of purely renewable power-to-hydrogen on the energy system.

Energy system analysis 4

This chapter analyses the role of hydrogen in a smart energy system and the current hydrogen projections. Moreover, is evaluated the technical and economic impact of a hydrogen gas grid with the construction of an energy scenario for 2050.

The transition from a fossil fuel-based energy system to a renewable energy-based system requires mammoth changes. The conventional system, represented in Figure 4.1, relies on hydrocarbon fuels to fulfill its demand. The use of oil, natural gas, and coal allows effective and affordable storage of energy, hence, the system flexibility is based on the storage of high energy density resources.

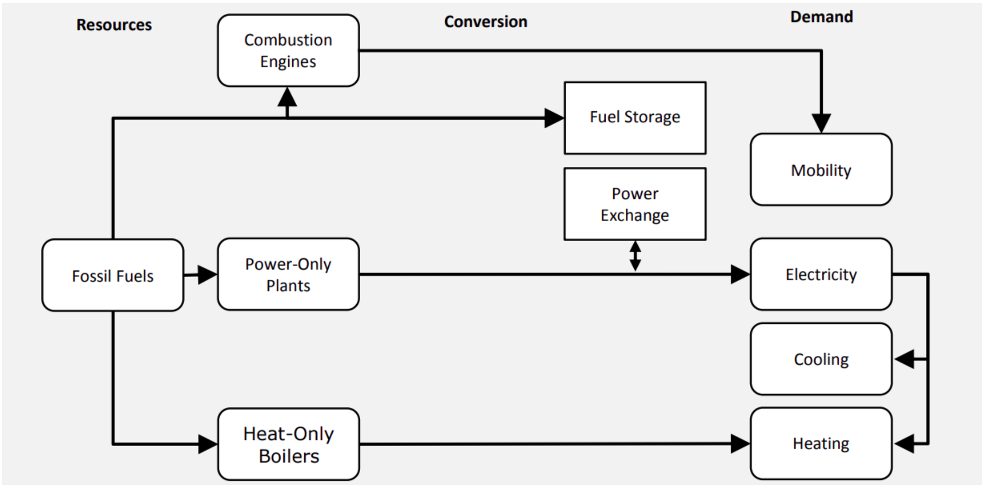

Figure 4.1. Fossil fueled based energy system. [Connolly et al., 2015]

Another key characteristic of a fossil fuels based system is that the different demands, mobility, electricity, cooling and heating are decoupled, in other words, the different energy sectors are treated independently. However, the replacement of fossil fuels by VRE requires the use of renewable electricity in the heat and transport sector. Hence, to successfully transition to a VRE system it is necessary to apply a holistic approach and consider the interactions between sectors.

Aalborg University has studied and classified the interactions between the sectors as a Smart Energy System. Represented in green on Figure 4.2 is shown how surplus electricity from VRE can be transformed into electrofuels and both help to meet the mobility demand, and be stored.

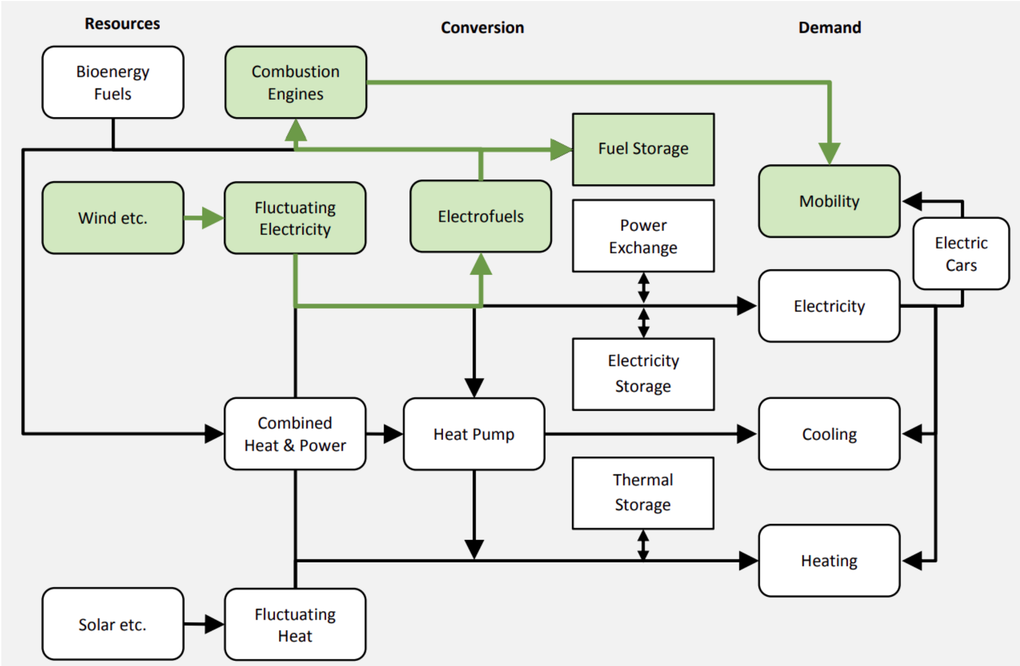

Figure 4.2. Hydrogen role in a Smart energy system. [Connolly et al., 2015]

Therefore, hydrogen produced from high intermittent sources can connect the power sector with fuel storage and mobility, offering more flexibility to the entire energy system.

There are many possible paths to produce hydrogen, as shown in Appendix A.1. However, only the production of hydrogen through electrolysis will be examined in this study as this is the only option that allows the direct use of renewable electricity.

4.1 Projections of the hydrogen role in Denmark

This section encompasses two different projections of the inclusion of hydrogen in the energy system. One made by Brintbranchen and the second by the danish society of engineers. The scrutiny of each prognostic will be followed by a comparative analysis.

4.1.1 Brintbranchen

Brintbranchen (Hydrogen Denmark) is an association that represents Danish stakeholders in the hydrogen field. The latest report Brintbranchen [2020] shows the prospects of green hydrogen in Denmark. The report portraits hydrogen as the key to a green transition and highlights the global market potential.

Key findings:

- Government should make an investment of at least DKK 5 billion for hydrogen and Power to X, between the next two years
- For future domestic consumption in 2030, a 2-3 GW installed electrolysis capacity would be necessary to supply 10-12 TWh for Power to X products
- By 2030, USD 40 billion of investment is expected, accounting for both private and public

- New 53,000 jobs could be created in 2030
- Revenues from exportation of green hydrogen could reach 50 to 84 billion DKK
- Danish manufactures represent one-fourth of the world's hydrogen filling stations

The study defines a national target for Denmark of 1 GW by 2025 and 6 GW by 2030. If 6 GW of electrolyser capacity is installed, 6 to 12 TWh (depending on the technology) of surplus heat produced during electrolysis could be used on the district heating. The report also identifies Germany as one of the potential importers of hydrogen produced in Denmark since Germany expects a demand of 110 TWh but only production of 14 TWh.

4.1.2 Danish Society of Engineers

The Danish Society of Engineers (IDA) created two energy scenarios for Denmark, one in 2050 that encompasses a 100% renewable energy system and another for 2035 as a transition for a carbon-neutral system [Ridjan et al., 2015].

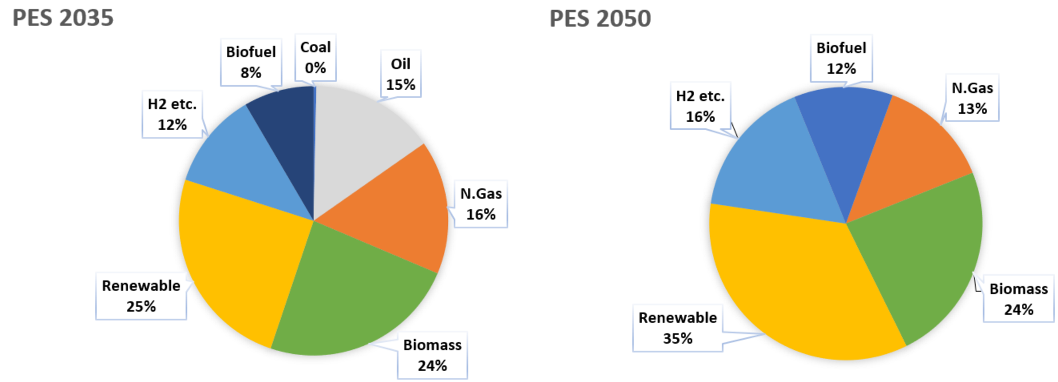

Figure 4.3. Primary energy supply (PES) in 2035 and 2050.

As seen in Figure 4.3, the hydrogen share as primary energy supply is increasing over the years, from 12% in 2035 to 16% in 2050. However, hydrogen's role in IDA scenarios is limited to the production of electrofuels, which are further used in the transportation sector. In addition, the district heating, both in 2035 and 2050, is supplied by syngas and biomass. Figure 4.4 represents the fuel distribution of the DH in 2050.

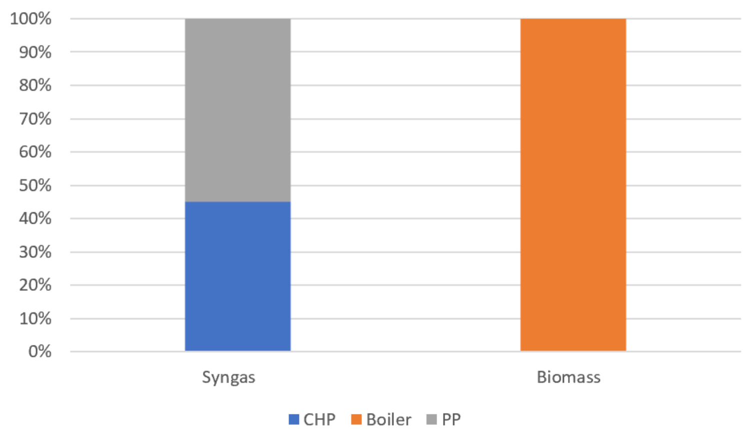

Figure 4.4. Fuel distribution in the district heating of the IDA scenario.

4.1.3 Comparison between both projections

Brintbranchen assumed a hydrogen consumption of 12 TWh by 2030, which coincides with the evolution seen in the IDA projected demand of 22.49 TWh in 2035.

To compare the projected capacity of the electrolysers, it has been assumed that Denmark would represent 15% of the European installed electrolyser capacity. This assumption follows Brintbranchen's logic, as the 6 GW predicted in Denmark would represent 15% of the total European electrolyser capacity by 2030 (40 GW). Figure 4.5 represents the capacity installed on the IDA scenarios for 2035 and 2040 and compares in light blue what would be the capacity for the same years, assuming the growth proposed by Brintbranchen.

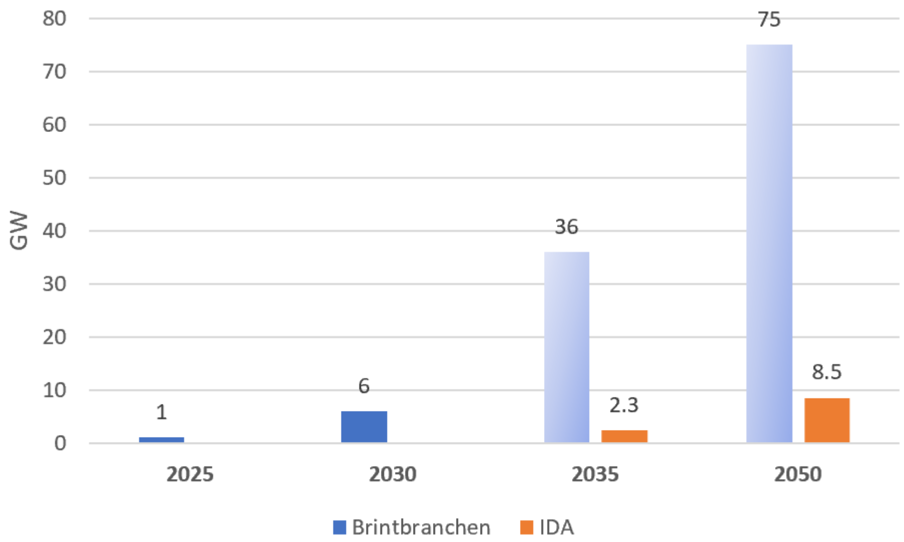

Figure 4.5. Electrolyser installed capacity on the IDA scenario (orange) versus the rate of growth proposed by Brintbranchen (light blue).

The 75 GW of installed capacity represent an enormous difference compared to the 8.5 GW on the IDA scenario, however, this value is just a 15% share of the European ambitious goal of 500 GW by 2050 [European Comission, 2020]. To put this 75 GW into perspective, the total VRE generation installed in 2050 is expected to be 24.3 GW, approximately three times smaller than the electrolyser capacity proposed.

Significant investment would have to be done if the growth of installed capacity follows the behavior shown in figure 4.5. If one considers an electrolyser cost of 0.4 euros per MW in the EnergyPLAN, the total investment of just the electrolyser technology would be 30 billion euros. The investment would be spread until 2050, yet 2 billion would have to be spent annually just for the electrolysers, in comparison with a total of 15 billion spent annually on the IDA scenario. In other words, the 30 billion euros necessary to install 75 GW of electrolysers are roughly the double amount that is spent in one year on the entire IDA 2050 scenario, meaning that the total cost of the electrolyser would be equivalent to two annual year expenses.

4.2 Hydrogen in the Danish gas grid

This section tests the possibility of a hydrogen gas grid in Denmark, both in a near future and in the long-term by 2050. To evaluate a hydrogen gas grid by 2050, it was done a sensitive analysis of the inclusion of hydrogen. Thereafter it was simulated a hydrogen gas grid scenario.

4.2.1 Present possibility of a hydrogen gas grid

The Danish gas network is operated by one distribution system operator (DSO), Evida, and Energinet as the only transmission system operator (TSO) [Energinet]. Currently, the total length of the distribution network is 17,000 km and the biggest international transit of gas happens between the North Sea and central Europe [Danish Energy Agency].

The recent EUDP [2020] report has shown that the Danish natural gas network could transport up to 15% of hydrogen without major alterations on the system, and up to 12% with no changes required. This assumption was obtained in a real test facility, as seen in Figure 4.6.

Figure 4.6. Hydrogen stand-alone system for tests. [EUDP, 2020]

The technical possibility to include up to 12% of hydrogen into the natural gas grid without any changes, allows Denmark to create a hydrogen demand, hence promoting the production of hydrogen. Several countries such as the Netherlands are already using the bleeding of hydrogen into the gas grid to incentive growth in the hydrogen market [Government of the Netherlands, 2019]. Establishing medium-term goals such as blending would ease the long term goal of a 100% renewable hydrogen gas grid.

4.2.2 Sensitivity analysis of hydrogen inclusion

The 2050 scenario will be used as a based scenario and for comparison, the output is in the Appendix C.2. Previously to the simulation of a hydrogen gas grid scenario is necessary to evaluate the impact of hydrogen production in the energy system. For that reason, with the use of EnergyPLAN, a methodology was created for the specific analysis of a hydrogen gas grid, as explained in detail in Section 2.3.1.

Moving all fuel supply in the DH to the coal category it was possible to identify the annual fuel demand for hydrogen. This means enough hydrogen would have to be produced to fulfill heat demand. Since the production of green hydrogen considered is done through electrolysis there was an increase in electricity consumption due to the additional hydrogen produced.

The additional electricity demand raised by the production of hydrogen requires extra renewable energy generation. Hence, an analysis of the current system was done to evaluate the most suitable renewable energy source, as shown in Figure 4.7.

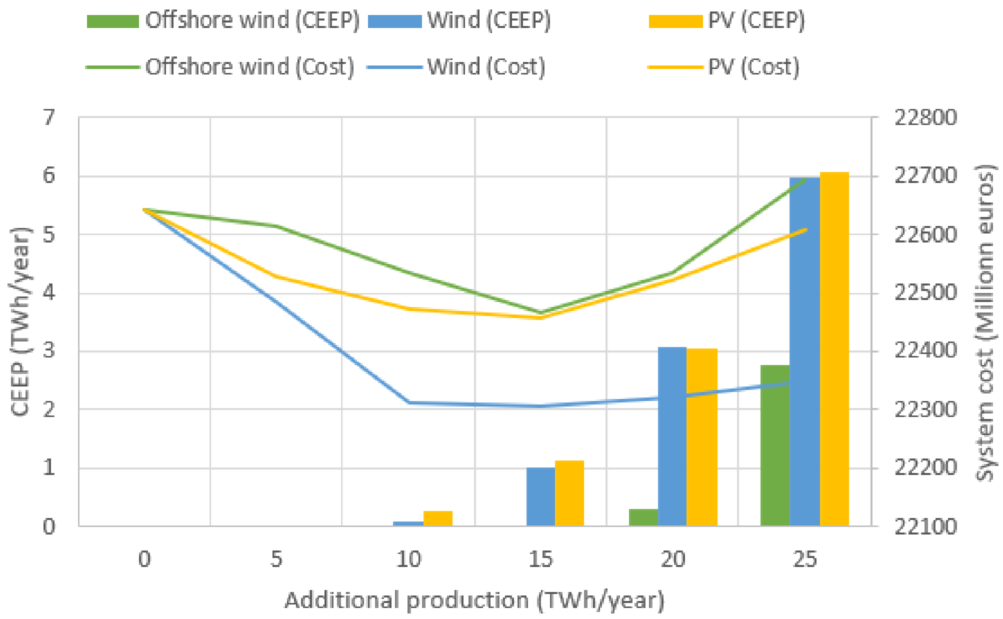

Figure 4.7. Cost and energy system impact of additional renewable power generation.

On the horizontal axis, the zero additional production represents the original scenario. The vertical axis represents the evolution of the system cost on the right side and on the left is represented the critical excess electricity production (CEEP). Up to the first 20 TWh generated from any renewable sources, the cost of the system is reduced as the electricity generated is no longer being used for domestic production but for export.

The offshore wind generation, colored as green, is the option that creates less critical excess electricity production, yet it is also the one that increases the total cost of the system the most. On the other hand, onshore wind production is the most affordable option but is not so compatible with the energy system as offshore wind. Solar PV addition will be disregarded as in the Danish case, has higher costs than onshore wind and similar CEEP.

Accordingly to the analysis done in Figure 4.7 it was added a 5 TWh/year of additional wind, as it is the most affordable option, and until that threshold is not created CEEP. Afterwards, the remaining electricity necessary to supply the electrolysers will come from offshore wind. The offshore wind ensures better coordination with the energy system and does not present land space restrictions. The total renewable power capacity installed and production for the sensitivity analysis is represented in Table 4.1.

	Wind		Offshore wind	
	Capacity (MW)	Production (TWh/year)	Capacity (MW)	Production (TWh/year)
Original	5000	10.9	14000	52.93
New	7300	15.9	19740	74.63

Table 4.1. Renewable power generation in the original 2050 scenario and in the new hydrogen scenario.

With new power generation able to supply the electrolysis process, three hourly hydrogen demand profiles were tested using the method described in Section 2.3.1. The three different hourly hydrogen demand profiles include a constant demand, a demand following the VRE generation (Figure 4.8), and a hydrogen demand that coincides with the heat consumption in the district heating (Figure 4.9).

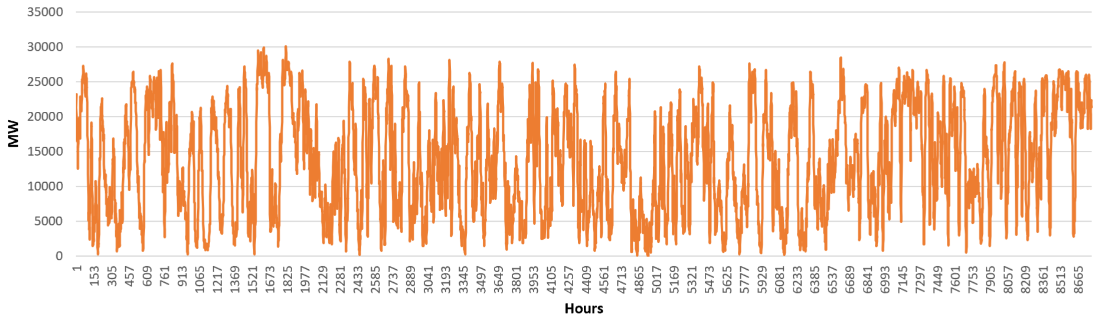

Figure 4.8. Hourly renewable power generation distribution.

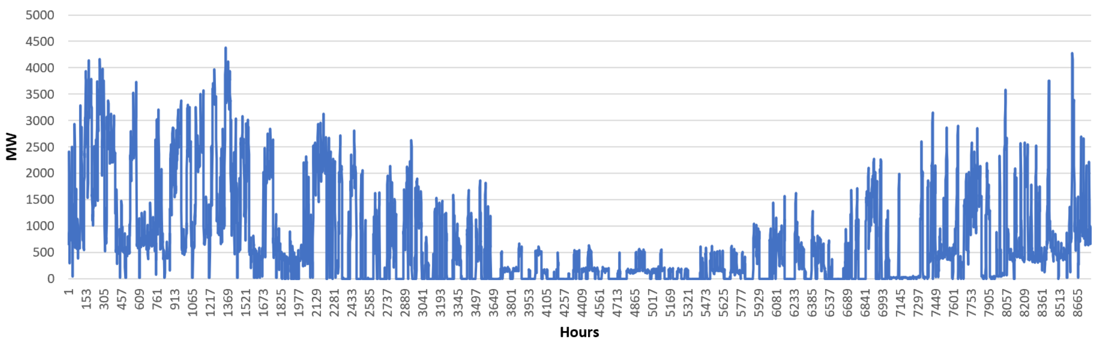

Figure 4.9. Hourly district heating distribution.

Theoretically, if extremely large hydrogen storage is considered, the hydrogen demand profiles according to VRE or district heating (DH) would be irrelevant, as it would be only required the minimum electrolyser capacity to fulfill the demand. In other words, if it was possible to have unlimited storage capacity then the production and consumption would always match and this is the case less electrolyser capacity would be necessary. In that sense, to analyse the impact of the three different hourly demand profiles, the minimum electrolyser capacity that would be able to produce hydrogen and avoid critical excess production was first found. The ideal electrolyser capacity for this energy analysis was found to be 14 GW, with the distribution visible in Figure 4.10.

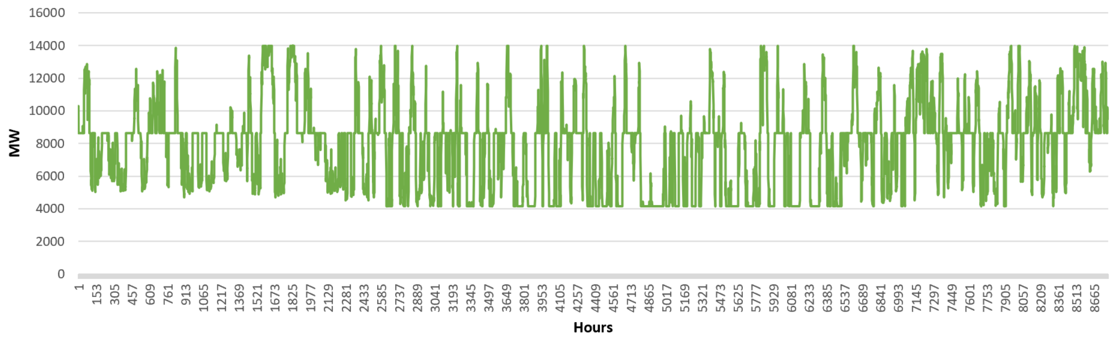

Figure 4.10. Hourly operation of the electrolyser.

The minimum of 4151 MW electrolyser capacity in operation, visible in Figure 4.10, is explained by the transportation demand already consider in the IDA 2050 scenario. As the hydrogenation for the production of electrofuels is consider constant a minimum operation of the electrolyser is necessary.

Assuming the same VRE generation and electrolyser capacity, it was possible to evaluate the impact of the three different hydrogen strategies. As it can be seen in Table 4.2, the hourly hydrogen demand profile that follows the VRE generation is the one that requires less hydrogen storage, as the hydrogen is being produced when renewable power generation occurs. On the other hand, if a constant hydrogen production is assumed, one would have to consider an additional 1.5 TWh of hydrogen storage. This considerable difference can be explained by the intermittency of renewable sources since green hydrogen production is based on the availability of VRE, bigger storage would be required to ensure a constant supply of hydrogen. Lastly, the third hourly hydrogen profile assumes that hydrogen production matches the district heating demand. This case would require even more storage compared to the VRE, an additional 10 TWh, since not only it would have to balance the intermittency of renewable sources but also the variable heat demand.

	Electrolyser capacity (MW)	**Hydrogen storage (GWh)**
Constant	14,000	20,500
VRE	14,000	19,000
DH	14,000	29,000

Table 4.2. Hydrogen system according to the three different demand profiles.

The hourly hydrogen storage accordingly to the three hydrogen demand profiles is visible in Figure 4.11. The lowest consumption of heat in the district heating occurs between May and August, shown in Figure 4.9, which coincides with the hydrogen storage behavior since it is around May (approximately 3600 hours) that the hydrogen storage starts to be filled.

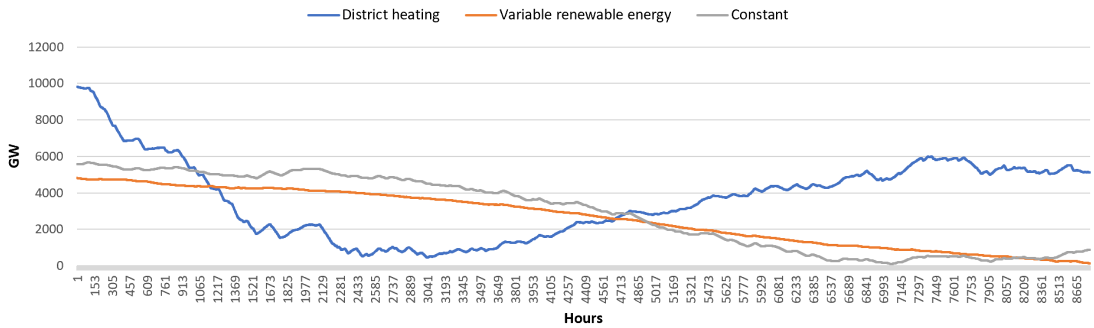

Figure 4.11. Hourly storage accordingly to each hydrogen demand profile.

Another aspect also analysed was how would the system react if no storage was considered, the results are visible in Table 4.3.

	Electrolyser capacity without storage (MW)
Constant	8,651
VRE	13,846
DH	31,915

Table 4.3. Impact of the 3 demand profiles in the electrolyser capacity, without hydrogen storage.

In this case, the energy system balance is not taken into account, meaning that it would not make sense at a national level. But for instance, if a private investor wanted to produce 28.57 TWh/year of hydrogen with no storage then a constant supply and production of hydrogen would be the most suitable option. The second-best option (13,856 MW) would be to produce hydrogen when renewable power is available and the worst of the three options would be to only operate the electrolyser when the heat is necessary.

The previous analysis has shown that the hourly hydrogen demand following the VRE profile is the one that has better integration with the energy system, for that reason, this approach will be used to develop a hydrogen grid and further compared it with the original IDA 2050 scenario.

4.2.3 Hydrogen gas grid scenario

The past energy analysis has shown that at a national level the best approach would be to operate the electrolysers according to the VRE generation, this option would require less hydrogen storage and consequently less investment. For that reason, this approach will be used to not only supply the district heating with hydrogen as previously shown but also to replace all the syngas used in the gas grid. This means replacing all the syngas and biomass used to supply the DH in the IDA scenario (Figure 4.4) and an additional 8.41 TWh/year of syngas that was used in the industry. This way is simulated a 100% hydrogen gas grid. Afterward, the obtained results will be compared with the original IDA scenario.

In summary, the simulated hydrogen gas grid scenario will replace all fuels used in the DH and the syngas used in the industry.

The total annual cost of the hydrogen gas grid scenario is 22754 million euros, 112 million euros more expensive than the original scenario (22642 million euros). The breakdown between the costs for both scenarios is represented in Figure 4.12.

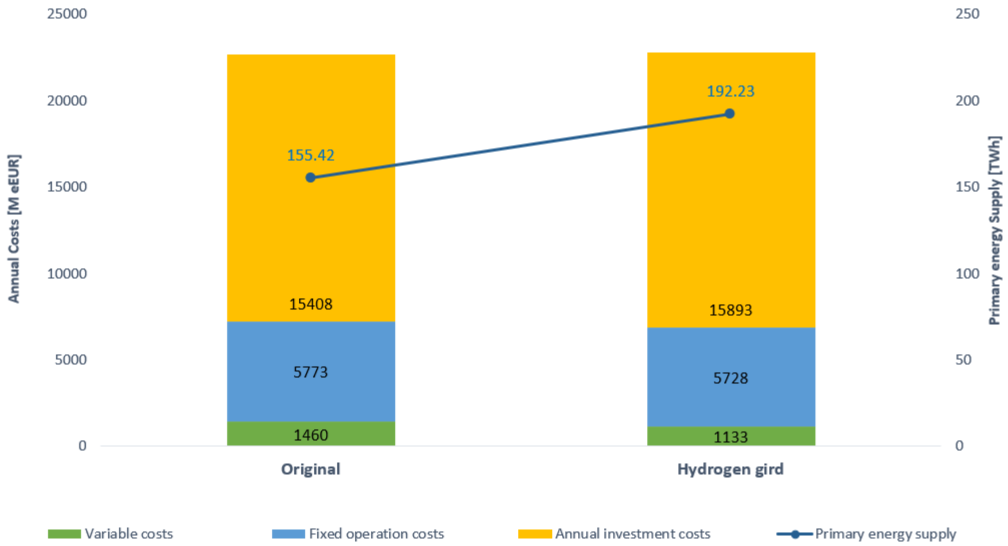

Figure 4.12. Comparison of annual costs (million euros) and primary energy supply (TWh/year) in both original and hydrogen grid scenarios.

Each of the costs, being variable, fixed operation and annual will further be explained in detail.

The **primary energy supply** in the hydrogen gas grid scenario is higher (192.23 TWh) than the original since to fulfill the added demand is necessary to generate renewable power. The role of each source of energy is represented in Figure 4.13.

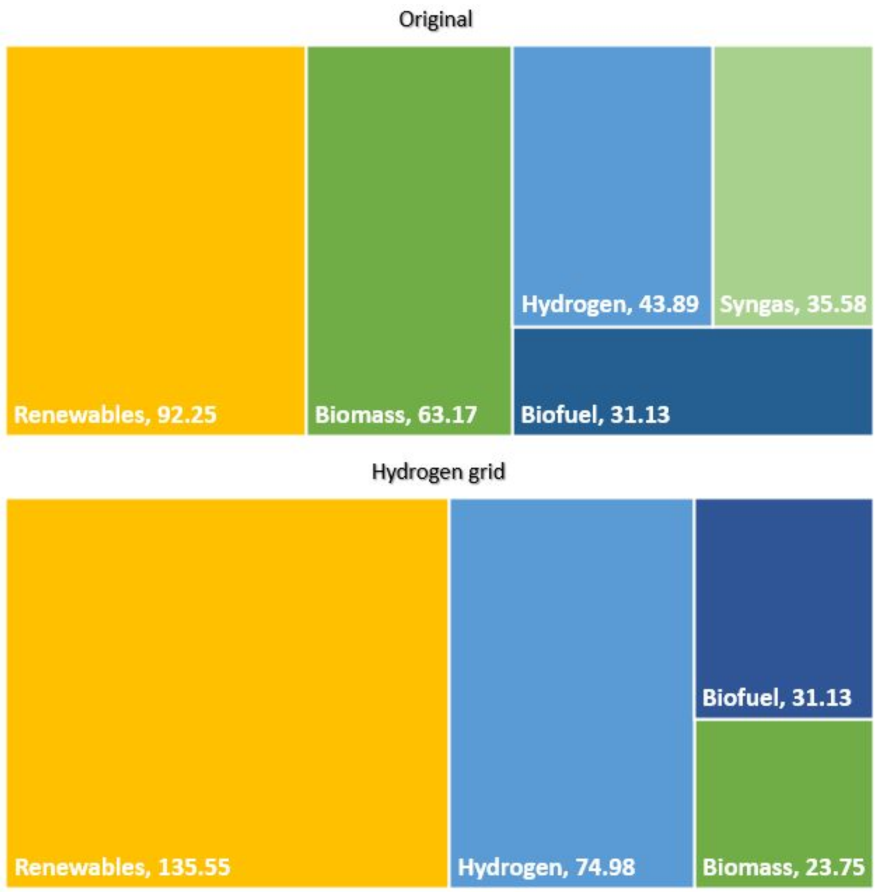

Figure 4.13. Primary energy supply (TWh) of the original and hydrogen scenario.

The biomass usage was reduced since its no longer use to supply the DH and syngas was fully replaced. The biofuels supply is maintained as its utilization is restricted to the transportation sector, a sector that is outside the scope of this study. The growth in hydrogen demand and electricity supply for electrolyser has to be followed by an increase in installed capacity, this evolution is shown in more detail in Table 4.4.

	Original	Hydrogen grid
Demands		
Hydrogen (TWh/year)	43.89	74.98
Electricity (TWh/year)	38.51	89.26
Installed capacities		
Hydrogen storage (GWh)	532	135
Wind (MW)	5000	7300
Transmission lines (MW)	7100	9100
Electrolyser (MW)	8510	18000
Offshore Wind (MW)	14000	21870

Table 4.4. Output comparison between the original and the hydrogen grid scenario.

Despite the fact that the hydrogen demand has increased in the hydrogen grid scenario, the hydrogen storage considerably is less (135 GWh). Yet in the hydrogen grid scenario, the hydrogen hourly demand profile follows the VRE generation, hence both the production and consumption of electricity in the electrolyser match. For that reason, it requires less hydrogen storage as hydrogen is being produced when renewable power is being generated.

The **variable costs** represented as green in Figure 4.12, include the marginal operation costs, the costs with electricity exchange, carbon emission costs and lastly with the costs with fuels, as seen in Table 4.5.

	Original (Million EUR)	Hydrogen grid (Million EUR)
Marginal operation	64	74
Electricity exchange	-90	-12
Carbon emissions	0	0
Fuels	1487	1071
Total	**1461**	**1133**

Table 4.5. Variable costs (million euros) in both scenarios.

Both scenarios have zero costs related to carbon emissions since both are 100% based on renewable energy. The major contributor to the variable costs are the fuel costs, the evaluation of each fuel cost is visible in Table 4.6.

	Original (M EUR)	Hydrogen grid (M EUR)
Coal	0	336
Oil	0	0
Gasoil/Diesel	291	291
Petrol/JP	11	11
Gas handling	38	0
Biomass	1147	433
Waste	0	0
Total	**1487**	**1071**

Table 4.6. Fuel costs (million euros) in both scenarios.

In Table 4.7 is shown the costs related to electricity exchange. In the hydrogen grid scenario, the imports of electricity are higher, this might be explained by the approximation of the hourly demand for hydrogen following VRE. Meaning that this VRE is not exactly the same as the one happening, however, in theory, it should decrease the imports. Nevertheless, a national grid should not be build to profit from exports but to find a balance between imports and exports, and in that sense, the hydrogen grid scenario is closer to the optimal balance.

	Original	Hydrogen grid
Electricity exchange	-90	-12
Import	142	219
Export	-232	-231

Table 4.7. Electricity exchange costs (million euros).

As seen in Table 4.8, the hydrogen gas grid scenario has lower **fixed operation costs**, also mentioned as operation and maintenance (O&M) costs. The biggest reduction of O&M costs in the hydrogen gas grid scenario is with the biogas plant. Since hydrogen has replaced the syngas, the gasification, methanation, and biogas systems are no longer needed. The total reduction of the system operation costs is 45 million euros.

	Total investment (M EUR)	Annual investment (M EUR)	O&M (M EUR)
Wind offshore	14009	715	255
Electrolyser	3796	255	114
Transmission lines	2400	103	24
Wind	1610	82	26
Biogas upgrade	-149	-12	-4
Methanation	-191	-11	-8
Gas Storage	-300	-12	-8
Gasification upgrade	-1698	-114	-29
Biogas plant	-1861	-125	-260
Hydrogen storage	-3017	-173	-75
Gasification plant	-3320	-224	-80
Total difference	**112**	**485**	**-45**

Table 4.8. Difference of hydrogen gas grid costs with the IDA original scenario (million euros).

The **annual investment cost** difference between the two scenarios (485 million euros) is explained by the necessity to install electrolysers, hydrogen storage, and increase the renewable energy power generation and transmission line capacities.

Driving innovations 5

This chapter presents the innovations for green hydrogen inclusion to the natural gas grid, using IRENA's systemic innovation approach.

5.1 Enabling technologies

5.1.1 Electrolysers cost reduction

The European hydrogen strategy aims to decrease the current levelised costs of hydrogen (LCOH) that is around 2.5 to 5.5 EUR/kg, to between 1.1 and 2.4 EUR/kg by 2030 [European Comission, 2020]. The pathway to affordable green hydrogen is shown in Figure 5.1.

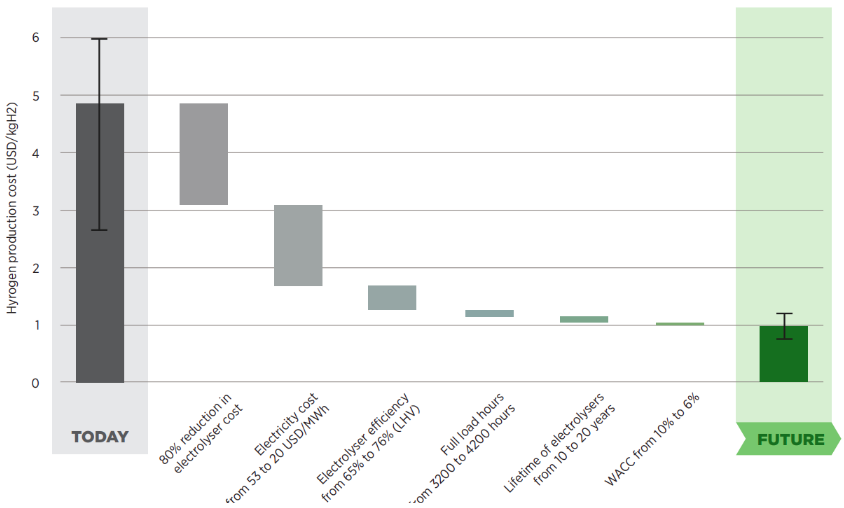

Figure 5.1. Cost reduction of green hydrogen production (USD/kg). [IRENA, 2020a]

The first step identified by IRENA [2020a] towards a green hydrogen cost reduction was a the 80% reduction in the electrolyser cost. The importance of electrolyser cost reduction was also shared in the European Strategy, which aims to drive electrolyzers costs from 900 EUR/kW to 450 EUR/kW by 2030, and continue decreasing in the following years [European Comission, 2020]. In that sense, the EU is doing an effort to develop and catch up with the biggest competitors in the market, focusing on SOEC and PEM electrolysers [BloombergNEF, 2020a]. The Chinese market and its companies have vast expertise in the production of electrolyser and are already supplying equipment at 200 USD/kW. However, the mature electrolysers manufactures have their expertise in alkaline electrolysers, that are not suitable for variable supply such as VRE.

If Europe does not succeed to produce cost-competitive electrolysers in a global market, the technology cost reduction could have similar behavior to what happened with the cost reduction seen in solar PV. In the PV case, the main manufacturing achievement and related profits are located in Asia. However, this does not seems to be the European goal as it is stated in the hydrogen strategy concrete goals for the production of hydrogen and electrolyser.

The European Comission [2020] published the Hydrogen strategy identifies PEM and SOEC as prominent technologies, for that reason only these two electrolysers will be further scrutinized. In both 2035 and 2050 IDA scenarios mentioned in Section 2.3, the electrolysers considered were the SOECs, with the characteristics shown in Table 5.1.

	2035	2050
Efficiency (%)	74	74
Cost system (Euro/MW)	0.6	0.4
O&M (% of total investment)	3	3
Lifetime (years)	15	20

Table 5.1. SOEC characteristics used on IDA scenarios [Ridjan et al., 2015]
Note: O&M = Operation and maintenance.

Usually, IDA scenarios use the Danish Energy Agency (DAE) technology catalogs to collect technical data. These technology catalogs encompass a myriad of technologies, including electrolysers. Data from the DEA [2017] technology catalog and Table A.2 (IRENA [2020a] report) were treated so they could be compared.

First, it was considered a hydrogen heating value between 120 and 143 MJ/kg [World Nuclear Association]. It has been assumed an average heating value, which is equivalent to 36.39 kWh/kg. This value has been divided by IRENA [2020a] assumption of 40 kWh/kg, obtaining an efficiency of 0.9. Moreover, it has been assumed a conversion rate of 1 dollar to 0.82 euros.

The results for the both SOEC and PEM technologies are visible in Table 5.2 and Table 5.3, correspondingly.

	IRENA 2020	DEA 2020	IRENA 2050	DEA 2050
Operating temperature (°C)	700-850	750	<600	650
Lifetime (years)	2.3	20	9.1	30
Efficiency (%)	<90	76	>90	79
Cost system (EUR/MW)	2.4	2.2	0.4	0.4

Table 5.2. Comparison between SOEC parameters.

As seen in Table 5.2, the predicted costs of the SOEC system in 2050 have the same value of 0.4 EUR/MW in both projections. However, there is a significant difference in the efficiency and lifetime foreseen, as IRENA assumes an efficiency bigger than 90%, yet with only 9 years of lifetime.

	IRENA 2020	DEA 2020	IRENA 2050	DEA 2050
Operating temperature (°C)	50-80	80	80	90
Lifetime (years)	5.7	15	11.4	15
Efficiency (%)	44 - 73	58	81	67
Cost system (EUR/MW)	1.2	1.1	0.2	0.4

Table 5.3. Comparision betewen PEM parameters.

Regarding the PEM, the differences are more visible, as represented in Table 5.3. IRENA anticipates half of the system cost compared with DEA, with a value equal to 0.2 EUR/MW. The disparity is also present in the efficiency, as IRENA has more optimistic projections. In relation to the lifetime, DEA continues to assume the system will operate for more years, however, the difference of years is smaller than in comparison with the SOEC.

The values for 2050 mentioned in Tables 5.2 and 5.3 were used to update the IDA scenario. As represented in Figure 5.2, two scenarios have been simulated, one scenario that only considers SOEC electrolysers (represented in blue) and a second where only PEM electolysers were contemplated (orange).

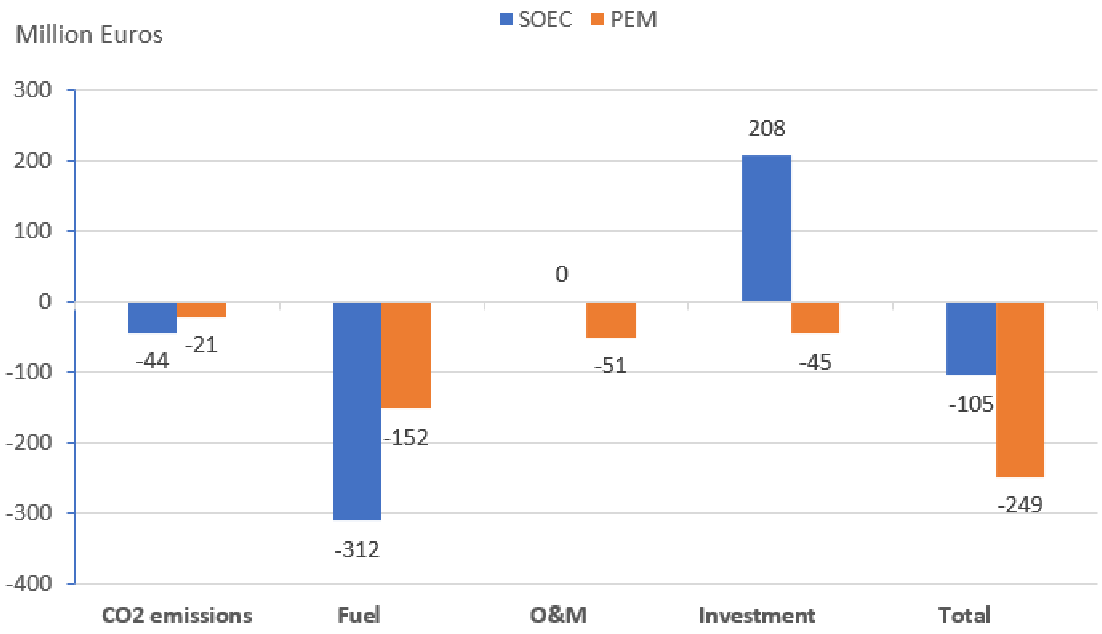

Figure 5.2. Socio-economic impact of IRENA cost projection for PEM and SOEC technologies in the IDA 2050 scenario.

The cost reduction of the electrolyser has a significant impact on the total cost of the system. If the IRENA electrolyser projections are considered, in the case of the SOEC the system cost can be reduced by 105 million. In the PEM case, the impact is even higher, with a cost reduction of 249 million euros. Operation and maintenance of the SOEC have no difference compared to the original scenario because on the EnergyPLAN the O&M is given by a percentage of the cost of investment, in this case, this percentage is 3% and the cost of investment predicted by IRENA coincides with the original, a cost of 0.4 euros per kW as seen in Table 5.2.

For the hydrogen gas grid scenario the only electrolyser consider was the PEM since the hourly hydrogen demand follows VRE is necessary an electrolyser that could be coupled with variable supply. Moreover, only the cost reduction of the electrolyser to 0.2 EUR/MW and a lower lifetime of 11.2 years were considered. The increase in the efficiency from 0.74 to 0.81 was disregarded as this would require a new energy system configuration.

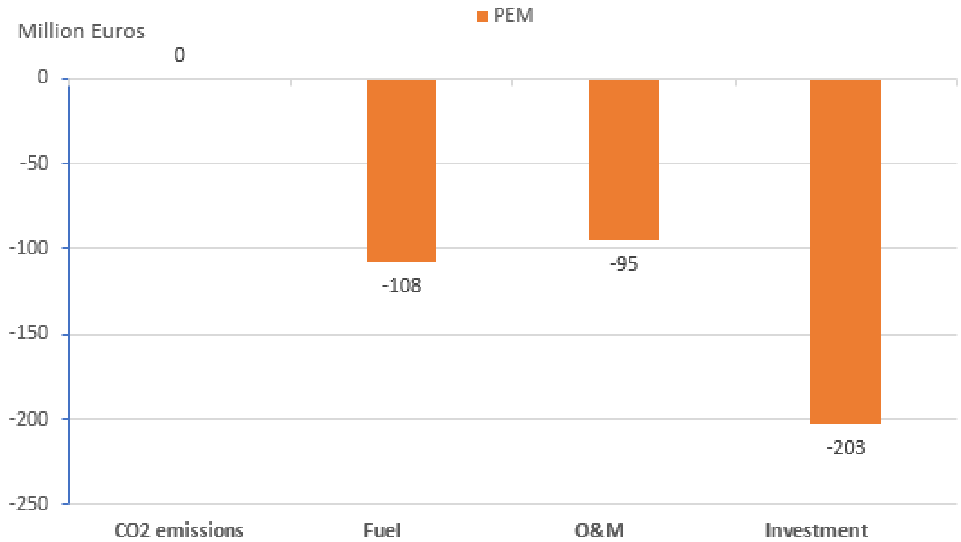

Figure 5.3. Socio-economic impact of IRENA cost projection for PEM technologies in hydrogen gas grid scenario.

Nevertheless, just considering economical improvements in the electrolyser price and lifetime, the cost of the hydrogen gas grid scenario is reduced by 203 million euros. Meaning that the new total annual cost would be 22551 million euros, the output of the scenario is in the Appendix C.1.

Operation hours

The ideal operation of an electrolyser would occur with low electricity prices, low investment cost and long operating hours, these conditions would obtain the most affordable green hydrogen. Figure 5.4 illustrates the influence of the investment cost and electricity price on the production cost of green hydrogen.

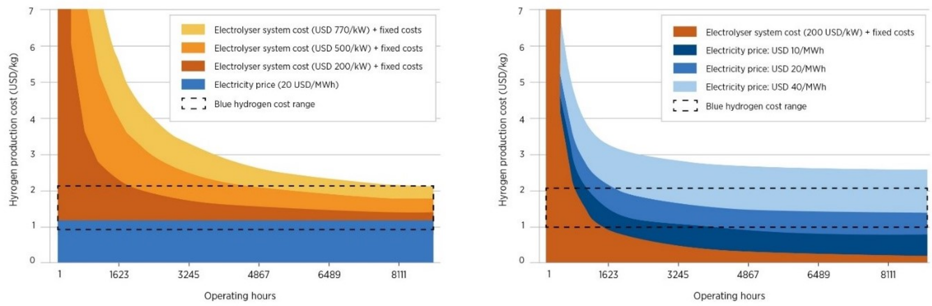

Figure 5.4. Hydrogen production cost (USD/kg) varying the investment, electricity price and operating hours. [IRENA, 2020a]

The longer the operation hours, the minor is the impact of the CAPEX, as the investment cost is spread across the time. For example, if the system operates less than 2000 hours, the electrolyser system cost would have to be lower than 200 USD/kW so that the green hydrogen produced is competitive with blue hydrogen. That is a significant decrease considering that today's electrolyser cost that are around 600 to 1000 USD/kW (see Table A.1).

In the on-site production of hydrogen coupled merely with VRE, the electrolyser operates in limited hours, as the intermittence of VRE excludes the possibility of constant electricity supply. For instance, an electrolyser coupled with only a photovoltaic (PV) power plant would operate less than 2000 hours per year, hence increasing the significance of the capital cost.

As a deduction, if a fixed electricity supply is desired in order to increase the electrolyser capacity factor then, the system should be connected to the grid or to an autonomous renewable energy system. A profitable partnership could occur between SOECs electrylsers and Concentrated solar power (CSP) plants since the electrolysis is an endothermic process and could benefit both the electricity and the heat produced to improve the process efficiency.

Electricity cost

The cost of electricity has a significant impact on the final hydrogen production cost. As seen in Figure 5.1, the electricity reduction cost from 53 to 20 USD/MWh would reduce the hydrogen production cost from 3 USD/kg of hydrogen to less than 2 USD/kg. Hence, the different forms of electricity supply have a great influence on the hydrogen production cost.

The electrolyser could be coupled with off-grid VRE generation, thus the electricity cost would be equal to the LCOE of the renewable generation system. Moreover, it can be also understood that if the VRE system did not have any type of storage, the capacity factor of the electrolyser would be the same as the VRE technology coupled. In other words, the hydrogen would only be produced when renewable resources are available. This off-grid configuration without storage would limit significantly the operation time of the electrolyser and consequently its capacity factor.

Another possible configuration is to couple the electroyser to the power grid, thereupon the electricity price would be the wholesale price. However, the wholesale electricity price varies during the day, meaning that the time of consumption is crucial to the reduction of hydrogen production cost. If only surplus electricity is used, to avoid curtailment, then the electricity cost could be assumed as zero but that would limit the operation hours of the electrolyser. On the other hand, if the operation hours of the electrolyser is extended beyond surplus electricity, the total cost of electricity increases and the electrolyser start to consume electricity in more costly hours. This means that when taking the wholesale electricity price into account, one must find a compromise between the optimal operation hours and the impact of the capital expenditures (CAPEX). Figure 5.5 represents the different levelised cost of hydrogen (LCOH) in Germany, depending on different operating hours.

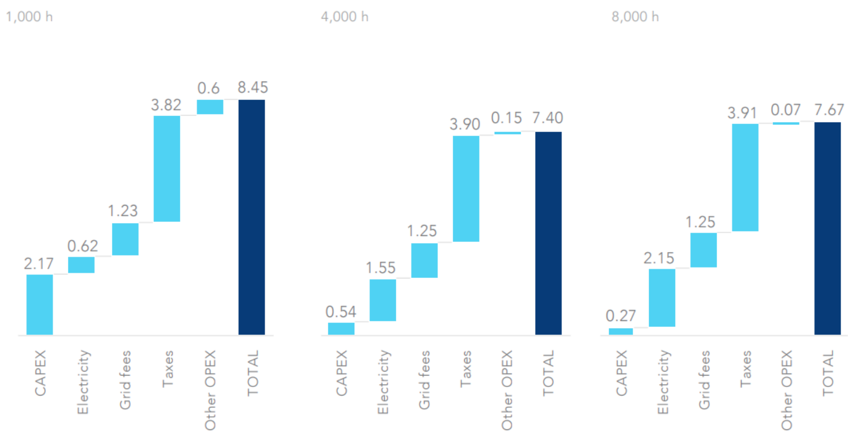

Figure 5.5. Comparison of the hydrogen production cost (euros per kg) considering different operating hours. [Hydrogen Europe, 2020a]

As it can be seen in Figure 5.5, with 1000 hours of operation the LCOH is higher as the CAPEX significantly impacts the cost of each kg of hydrogen produced. Inversely, if the operation hours are extended until 8000 hours the impact of the CAPEX and OPEX is reduced but the electricity purchased is done in peak hours, hence increasing the LCOH compared to the 4000 hours cost. Consequently, it can be concluded that the optimal amount of operating hours is around 4000.

IIn summary, it was mentioned the importance and key aspects of reducing the electrolyser price and the economic impact of future PEM and SOECs developments on the entire energy system. Investment in research and development could propel new and current Danish electrolysers manufacturers. Currently, there are two Danish companies, Green hydrogen system that produces alkaline electrolysers, and Haldor Topsoe that sells SOEC technology [Green Hydrogen Systems] [Haldor Topsoe].

5.1.2 Super gas grid

A group of eleven European natural gas companies has presented the Backbone plan, a plan for the hydrogen transport infrastructure. They foresee a network of 6,800 km of pipeline by 2030, mainly to connect hydrogen valleys. As represented in Figure 5.6, in 2040 hydrogen pipelines would have a length of 23,000 km, however is assumed that only 25% of this value would be new pipeline connections, the reaming would be converted natural gas pipelines. This network would be able to supply 1130 TWh of hydrogen demand and has an estimated cost ranging between 27 and 64 billion euros [Gas for Climate, 2020b].

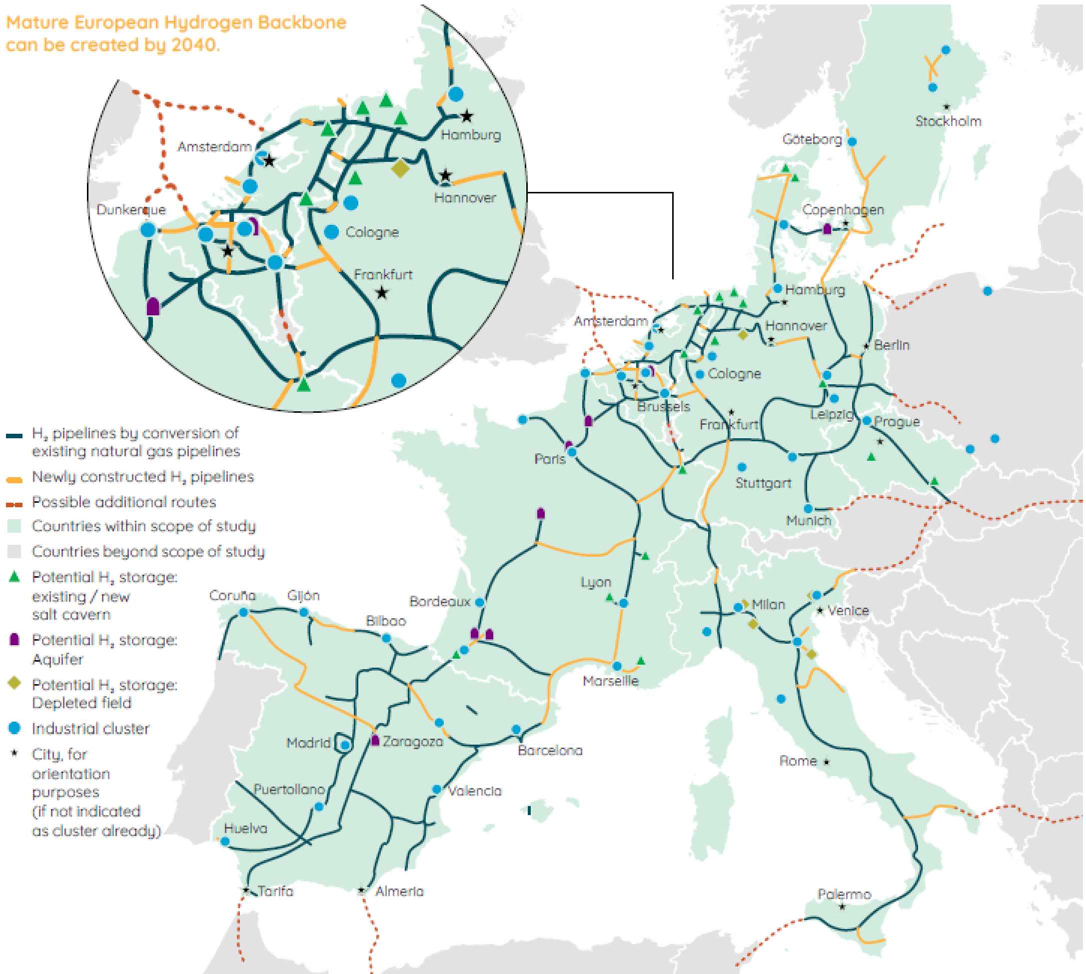

Figure 5.6. European hydrogen grid by 2040. [Gas for Climate, 2020b]

The expansion of the network would include the retrofitting of the eastern route until Copenhagen and new connections to Sweden and in Jutland.

There is a possibility to use the exiting double-lined system that connects Germany with Denmark to transport hydrogen since one of the pipes could be retrofitted. However, most of the current Danish pipeline network consists of single pipelines that do not offer this possibility.

The current Baltic contract of 15-years ensures the transportation of natural gas from Norway to Denmark and Poland will only expire in 2038. Excluding the possibility of short-term investments in an integrated national hydrogen network.

The levelised cost of the network is estimated to be between 0.09 and 0.17 euros per kilogram of hydrogen, per 1000 km. This estimation encompasses a wide range since this cost is highly dependent on the location chosen. In that sense, the planning of a hydrogen pipeline infrastructure should be done on cooperation, in a transnational environment, and with long-term well-defined goals so that the cost is reduced. Furthermore, a gas grid based on hydrogen instead of natural gas would require more entry points as the hydrogen production would be distributed.

Additionally to the transmission pipelines, key grid infrastructure components also include compression stations that control pressure, valves that allow safe O&M and metering stations, that are installed in strategic places, such as exits, entry and cross-border points, to allow the TSO to control, manage and measure (CMM) the gas grid [Gas for Climate, 2020b].

5.1.3 Storage

Hydrogen storage can provide deep resilience to a highly electrified future and net-zero economy. The prospects for the levelised cost of storage (LCOS) for hydrogen and options are shown in Table 5.7.

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited

Figure 5.7. Cost of hydrogen storage (USD/kg). [BloombergNEF, 2020b]
Note: LOHC = liquid organic hydrogen carrier.

The most affordable way of storing hydrogen is in salt caverns, however, this option is limited to geographical conditions. The second cheapest option is to store hydrogen in pressurized containers, similar to the way natural gas is currently stored, in this way unlimited quantities can be stored.

As seen in Figure 5.8, Denmark could store around 9,000 TWh of hydrogen in salt caverns. However, due to its geographical limitations, further investments would have to be done since the majority of capacity storage is located offshore, at a higher distance than 50 km from the coast. To a lesser extend, Denmark also has the possibility to store onshore in salt caverns within 50 km from the coast.

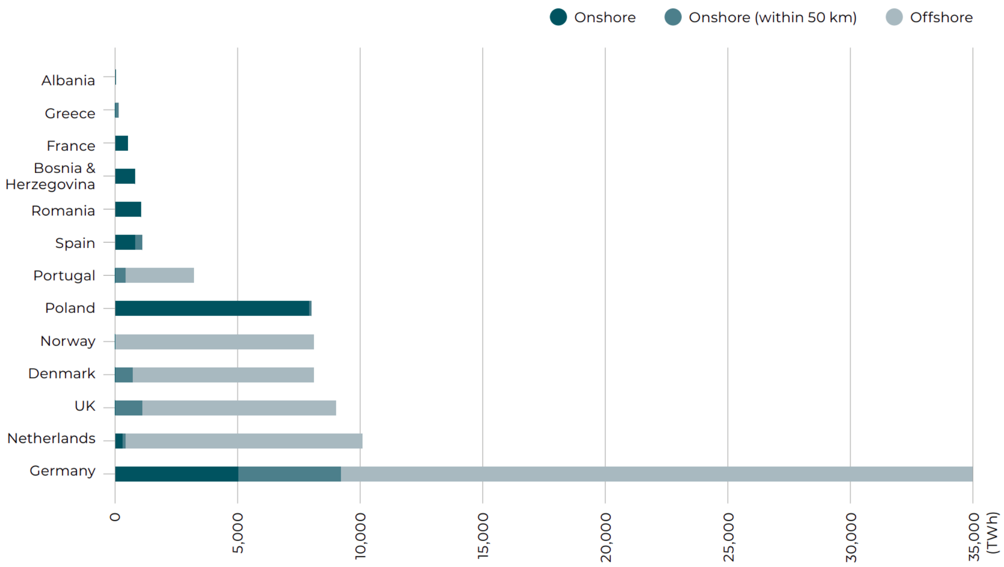

Figure 5.8. Salt cavern capacity storage of hydrogen (TWh). [Gas for Climate, 2020a]

Green Hydrogen Hub Denmark is an example of good practices on hydrogen storage as intends to be the first fully large-scale green hydrogen production, with a compressed-air energy storage (CAES) solution as storage. In 2030 is aimed to have an installed electrolyser capacity of 1 GW, 400 GWh hydrogen storage, and a 320 MW CAES plant. Moreover, this project will use the Northern Jutland's large salt caverns as suitable storage of hydrogen [Green Hydrogen Hub Denmark, 2020].

5.1.4 Renewable power generation

To supply the considerable electricity demand necessary to produce green hydrogen it would be necessary to install new renewable energy generation technologies. Another characteristic important to note is that if the electrolysers are connected directly to the grid, then the carbon intensity of the national grid should be lower than the amount of carbon dioxide acceptable to classify the hydrogen as green. Analysing the carbon intensity of the Norwegian and European grids, represented in Figure 5.9, it is possible to see that only seven countries would fulfil the different requirements so that the hydrogen produced is green. The average pollution of the 27-EU countries, using electricity from the grid to produce hydrogen would result in an emission of 14.8 kg CO_2/kg H_2 [Hydrogen Europe, 2020a], meaning that European grids still have a challenging road to produce low carbon electricity and achieve a 100% renewable energy electricity grid.

Take Denmark as an example and only the EU emissions trading system (ETS) Benchmark of 8.85 kg CO_2/kg H_2 would be accomplished. In other other words, if an established common definition of green hydrogen is more ambitious and requires less CO_2 emitted than the EU ETS, then the electrolysers could not be continuously supplied by the Danish grid. However, if the consumption from the grid occurs solely when there is CEEP one could assume that the hydrogen produced would be green.

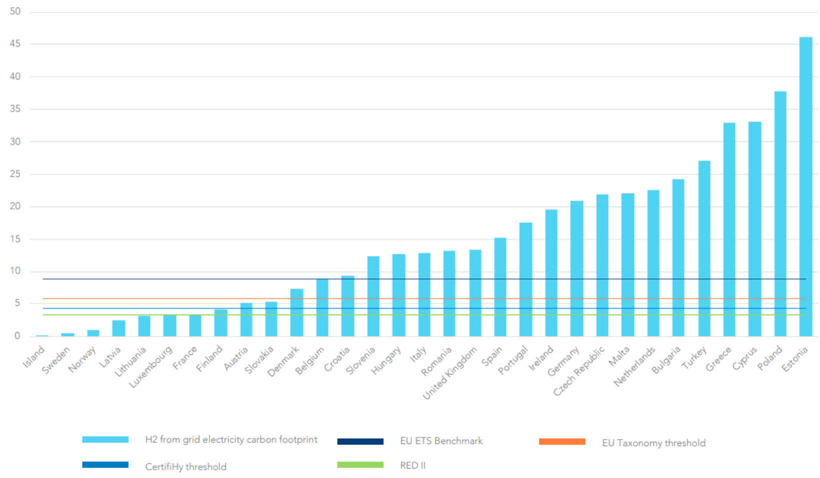

Figure 5.9. Carbon intensity of hydrogen produced from grid electricity (kg CO_2/kg H_2). [Hydrogen Europe, 2020a]

In order to reduce the content of carbon dioxide on the grid, Denmark could take advantage of its vast endogenous renewable energy resources and increase VRE penetration. Denmark has a high potential for offshore wind production and recently strengthened its position by joining forces with Germany, to build offshore hubs for VRE integration and for future Power to X products. Future plans include two offshore hubs, each with a capacity of 5 GW [Recharge, 2020].

The theoretical offshore wind potential in Denmark is estimated to be more than 100 GW of installed capacity, however, more realistic predictions assume values between 40 and 60 GW [Brintbranchen, 2020]. Innovative concepts such as the offshore platform visible in Figure 5.10 open potentially new incomes for Denmark.

Figure 5.10. Tracatebel platform and offshore wind. [Tracatebel, 2020]

As an example of innovative systems, the offshore platform shown in Figure 5.10 plans to use the electricity produced from offshore wind to supply electrolysers and desalination plans, producing both green hydrogen and potable water [Tracatebel, 2020].

5.1.5 Digital innovation technologies

Power systems are becoming more complex and decentralized, for instance, in a future smart home we could have solar panels, boiler, smart charging point for the electric vehicle (EV), smart meter, smart plugs, thermostats, and other electronic devices. Internet of Things (IoT) can collect a large amount of data of the devices connected and streamline all the information so that the big data collected can be used for energy system optimisation [IRENA, 2019b].

Artificial intelligence (AI) supports the decision-making process by building knowledge without the need for additional programming. The use of AI is being spread by the collection of big data and it can help faster and intelligent decisions regarding the energy system, increasing grid flexibility and VRE integration.

AI can help with the integration of higher shares of renewable energy as it can assist in the generation forecast, demand forecast and therefore, perform a more efficient demand-side management. It can also be used to improve the energy storage operation and market design [IRENA, 2019a].

The Danish company Tomorrow [2020] is a concrete example of how AI could have a meaningful impact. The algorithm developed by Tomorrow analyses the CO_2 emissions from different sources and displays in real-time the emissions related to electricity consumption, imports, and exports worldwide. This tool could be used to make sure that electrolysers would only use electricity when the content of CO_2 related to generation is low or null, and therefore, ensure the hydrogen is green.

5.2 Market design

5.2.1 Universal hydrogen classification

Classifying hydrogen purely based on a color code, as shown in Appendix A.3, already shows signs of immaturity, as this simple subjective classification cannot establish the necessary clear boundaries.

One concrete example is the production of hydrogen from electrolysers that are connected to the grid, as most of the electrical systems are not supplied only by VRE, the hydrogen produced could not be considered green. In other words, only an off-grid renewable energy system could guarantee that the hydrogen produced is green or 100% renewable power grid. In that sense, policymakers should develop an objective method to evaluate the life-cycle emissions from production to consumption. Ideally, this method would be universally accepted so that the global market for hydrogen is based on the same frameworks [IRENA, 2020b].

As an example, Table 5.4 shows how divergent are the possible European classifications of green hydrogen according to the carbon emitted. The varied definitions include the EU emissions trading system (EU ETS) Benchmark, the CertifHy threshold for low carbon hydrogen, the EU Taxonomy threshold for sustainable hydrogen, and the RED II threshold for Renewable Fuels of Non-Biological Origin (RFNBO).

Classification	**Carbon content per hydrogen ($kg\ CO_2$ / $kg\ H_2$)**
RED II	3.38
CertifHy	4.40
EU Taxonomy	5.80
EU ETS Benchmark	8.85

Table 5.4. Green products classifications.

Thus, an achievable first step towards a universal hydrogen classification would be to unify a European classification. Thereafter a universal definition could be agreed upon, hence creating an even global playing field in an international hydrogen market.

5.2.2 Regional hydrogen market

Regarding electricity, Denmark is part of the pan-European electricity market, operated by NordPool, and participates both in the day-ahead and intraday market. IRENA [2019c] considers that there is a deep market integration, as there are several interconnections (to Germany, Norway, and Sweden), trading arrangements, and harmonized rules.

Similarly to the regional electricity market, to successfully implement a European hydrogen market, it would be necessary to have cross-border coordination between TSOs, regulators, and market operators so that there is a harmonized market design. To achieve harmonization, the first crucial step would be to have a clear pricing methodology.

5.2.3 Taxation

In a European market, Denmark has the highest hydrogen production cost as shown in Figure 5.11. It is assumed that the electricity used is from the grid, in that sense, countries with a high wholesale electricity price such as Cyprus would have a high hydrogen production cost. However, that is not the reason why Denmark presents a higher hydrogen production cost, as it has one of the lowest wholesale prices, represented in dark blue. The reason why the total cost of production is so high is the additional tax added to the wholesale electricity price colored in light blue.

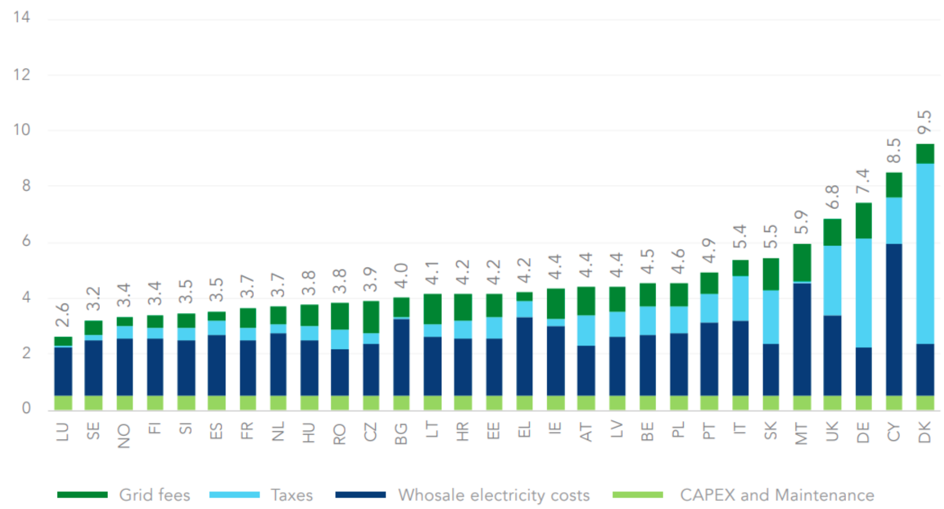

Figure 5.11. Hydrogen production costs (EUR/kg) in 2019. [Hydrogen Europe, 2020a]

For the 9.5 EUR/kg of hydrogen produced, the taxation added is calculated to be 6.43 euros. Yet, if Denmark decides to only charge grid fees costs to hydrogen producers, then the price of hydrogen production could drop to 3.11 EUR/kg, making Denmark the second most competitive country in Europe [Hydrogen Europe, 2020a]. However, the Danish social welfare system is supported by the taxes paid, on a bigger scale, paying fewer taxes would mean having less access to public services.

If we consider the previously assumed hydrogen energy density of 36.39 kWh/kg, then even without any taxation the 3.11 EUR/kg of hydrogen produced would translate into 0.085 EUR/kWh. This hydrogen price is still higher than the 2020 Danish natural gas price for household consumers of 0.075 EUR/kWh [Eurostat, 2020]. Meaning that at the present moment hydrogen is not a cost-efficient option when compared to natural gas. For hydrogen to be competitive and to consider as the only supply to the gas grid, further taxation and incentives would have to be implemented to ensure competitiveness. Further incentives could include an increase in carbon pricing so that the price of natural gas would reflect a bigger environmental impact.

As mentioned in Section **??**, further developments expected by the European Commission predict a green hydrogen price between 1.1 and 2.4 EUR/kg, by 2030. These values would translate to a range of 0.030 to 0.066 EUR/kWh of green hydrogen, making in 2030 hydrogen directly competitive with natural gas (0.075 EUR/kWh). Considering that the production price of natural gas would have a stable behavior from 2020 to 2030, the market price could only increase since carbon prices are expected to also increase during the energy transition towards renewables.

5.2.4 Innovative ancillary services

One of the advantages that electrolysers could bring to the energy system balance is their ability to provide power ancillary services. As shown in Table A.1, the PEM technology is the most promising in this regard, and studies have proved that PEM can be used to provide ancillary service such as fast frequency response [Alshehri et al., 2019].

In Denmark, the power generated from wind is allowed to participate in the existing ancillary service market, providing balancing services [IRENA, 2019d]. Similarly, the same could be done so the flexibility that electrolysers can provide is utilized to integrate higher shares of VRE.

5.3 Business models

Green hydrogen hubs

Hydrogen Hubs join industry, businesses, stakeholders, and authorities at a local level to deploy hydrogen as a means to supply the local community energy demand. In this way, the transmission and distribution costs are reduced since the production is located near the demand [HydrogenHub, 2020].

At Green lab, one of the first largest Power to X facilities, local Danish power from wind and solar PV is converted into electrofuels, heat, and green products. The excess heat produced from the 12 MW electrolysis plant is shared on the local grid where all the industries are connected. This sharing process was named SymbiosisNet and at a bigger scale allows on-site industries to exchange excess heat, biomass, and electrofuels [GreenLab, 2020].

HyBalance is a project that aims to test the use of hydrogen in the Danish energy system. The consortium accounts for the participation of several Danish companies and the Energinet partnership. The excess wind power is used to produce hydrogen, providing grid balance services. Afterward, the hydrogen is used by the industry and transportation sector in Hobro. Potential uses already mentioned are hydrogen refueling stations for fuel cell cars and buses in Hobro and the local industry. Hydrogen could be also stored in salt caverns in Hvornum and Lille Torup [CORDIS, 2014]

5.4 System operation

5.4.1 Specialized transmission system operation

If hydrogen is injected into the national gas grid it will be required to have a new set of technical knowledge from all the national gas grid operators, both the TSO (Energinet) and DSO. The transmission of hydrogen demands higher pressures, hence adds additional risks.

5.4.2 City gates stations

City gate stations are linked to the distribution system, where the gas pressure is reduced from the transmission lines to the end-use system, hence the coordination between DSO and TSO becomes crucial to reduce the costs of infrastructure.

City gate stations are an important concept, as they allow the distribution at lower pressure, and consequently lower cost of the system, the pipelines can have a smaller diameter and are required fewer compression stations [Gas for Climate, 2020b].

5.4.3 Virtual power lines

Virtual power lines consist of utility-scale storage systems connected both on the supply and demand side. This innovation offers an economically and technically viable alternative to a reinforcement of the grid, as it provides additional capacity where it is necessary.

Denmark does not have any example of a virtual power-lines system [IRENA, 2020d]. However, hydrogen storage could play a crucial role as a flexibility provider, hence reducing the need for extra grid reinforcements in specific locations of the grid.

Discussion 6

In this chapter, firstly a review of the issues identified is carried out, connecting problems identified from both energy sectors. Afterwards, the impact of the methodology and theoretical framework limitations is assessed, followed by an evaluation of the relevance of the delimitations imposed.

6.1 Discussion of identified issues

6.1.1 Impact of electricity supply configurations

The best electrolyser operation mode highly depends on the user and intention. As shown in Table 4.2, the most suitable configuration at a national level, aiming to balance the energy system and reduce the CEEP, is the operation of the electrolyser accordingly to renewable power availability. This operation mode would ensure that the hydrogen production is green and it could make sense from a TSO perspective. In this perspective, it would be also beneficial to consider innovations in the system operation such as virtual power lines and allow innovative ancillary services to participate in the market. Furthermore, as seen in Table 6.1 if one uses only surplus electricity the costs with the electricity supply could be considered null, yet the operating hours would be limit and the capacity factor reduce.

On the other hand, if a private investor considers the production of hydrogen then a constant operation would ensure higher capacity factors and less necessary electrolyser installed capacity for the same demand, as shown in Table 4.3. In this case, the electrolyser would be connected to a grid or an autonomous renewable energy system to ensure a constant electricity supply. The connection to the grid would require the payment of taxes and the cost of hydrogen produced would be depended on the wholesale price. As shown in the innovation analysis of taxation, if Denmark decides to reduce taxes it can become one of the European most competitive in hydrogen production. Furthermore, the classification of the hydrogen would be dependent on the RE penetration in the power grid. As a deduction, currently is not economical viable the private production of green hydrogen solely connected to the grid, as the wholesale prices are still considerable and the cases of a 100% power grid are rare. In the future, green hydrogen hubs and innovative ancillary services could open new business opportunities.

	Grid connection (constant supply)	Grid connection (surplus electricity)	Off-grid
Electricity cost	Wholesale price	Null	LCOE
Extra costs	Taxes and connection fees	Connection fees	RE generation system
Operation hours	Optimal value around 4000	Low and limited	Equal to the capacity factor of the RE
Green hydrogen	Dependent on the RE penetration	Yes	Yes

Table 6.1. Impact of different supply configurations.

The third case of off-grid systems would be suitable in locations with abundant VRE resources, where the LCOE of the generation system would be cheaper than the grid electricity cost. Enormous projects are being developed in places like Morocco, Chile, and Australia.

6.1.2 Different parameters for electrolysers

As seen in Tables 5.2 and 5.3, one of the biggest discrepancies between IDA and IRENA projections is the lifetime of the electrolyser. Take the SOEC as an example and DEA assumes a three times higher life expectancy. The reason behind this might be related to the operation of the electrolyser, as IRENA portraits electrolysers as a key part of the energy system and with a variable electricity supply. However, as mentioned in Section A.2 the optimal operation mode for electrolysers is with a constant electricity supply. If the future role of electrolysers becomes so predominant as IRENA predicts then is also expected that the deterioration of the components increases and its lifetime is reduced.

6.2 Hydrogen gas grid scenario

Regarding the hydrogen demand, Brintbranchen predicted a 12 TWh hydrogen demand by 2030, and the IDA scenario estimated a hydrogen demand of 22.49 TWh in 2035, this growth is equivalent to almost the doubling of the demand in just 5 years. If one considers such a speedy growth rate, then a hydrogen demand of 89.26 TWh/year by 2050 would be in accordance. Furthermore, the 18 GW of electrolyser installed capacity are higher than the IDA scenario (8.5 GW) since the use of hydrogen is higher. Nevertheless, if one considers a growth similar to what Brintbranchen suggested (Figure 4.5) then in 2050 the electrolyser installed capacity would be equal to 75 GW, considerably higher than the 18 GW obtained.

It was shown the enormous economic impact of innovations in the electrolyser and consequent cost reduction. Accordingly to IRENA electrolyser cost projections, the total cost of the IDA 2050 system could be reduced from 105 million euros considering SOEC electrolyser, to 249 million euros with PEM electrolysers. Since the hydrogen gas grid scenario has a higher electrolyser install capacity the difference in the total annual costs is even higher. If the electrolyser cost is updated from DEA to IRENA projections costs, the total saving is 5715 million euros. Thus, if one assumes that this electrolyser cost reduction would only happen in an energy scenario with high interest in hydrogen such as the Hydrogen gas grid scenario, then the hydrogen gas grid scenario could become not only technically but also economically feasible compared to the IDA scenario. As the new cost with IRENA projections would be 22551 million euros compared to the 22642 million euros of the original IDA scenario. However, since the interest in green hydrogen has grown globally it is likely that even if Denmark would not consider including more hydrogen than the IDA scenario, it could still benefit from the cost reduction of the technology seen in the international market.

The hydrogen storage considered was lower than the IDA scenario as the hydrogen demand profile following the renewable power generation allows better integration with the system. In addition, the analysis of driving innovation has shown that the potential for hydrogen storage in salt cavern is enormous, around 9,000 TWh. Yet, is important to note that this value only evaluates the geographical resources. Further studies regarding the economical feasibility would have to be carried out.

The offshore wind generation was the most significant economical addition when comparing the hydrogen gas grid scenario to the original. The offshore wind technology was chosen as it has shown to be the most suitable for the current system, creating less CEEP. Moreover, further innovations in offshore technologies and their integration with other systems, as shown in the Tracatebel platform (Figure 5.10), could reduce the investment cost.

The increase in the transmission line capacity in the hydrogen gas grid scenario is due to the extra pressure that electrolysers brings to the grid. Nonetheless, innovations such as a super European gas grid could alleviate the power system and bring even more flexibility to the overall energy system. This super gas grid proposes a growth from the current 17,000 km of the Danish distribution network to a European hydrogen gas grid of 23,000 km. Yet, Denmark could only invest in such innovation after 2038, as until there is bounded to the Baltic contract for natural gas transportation. This super gas grid would have to be followed by other innovations like a unified hydrogen classification, regional hydrogen market, city gates stations, and a specialized transmission system operator in hydrogen. Additionally, it could also benefit from digital innovation technologies.

6.3 Impact of the limitations in methodology

The two methodologies used during the report were literature review and the software EnergyPLAN. Regarding the literature review, it was found some limitations respecting the hydrogen literature available, concretely about hydrogen gas grid as is not so common. The lack of vast bibliography could be related to the innovative characteristic of hydrogen. Nevertheless, it was possible to use EnergyPLAN to simulate a Danish hydrogen green and evaluate the implication of such infrastructure in the energy system.

In the EnergyPLAN none of the three configurations mentioned in Appendix B allows the replacement of natural gas and biomass for the direct use of hydrogen on the district heating. For future scenarios created in EnergyPlLAN considering the inclusion of hydrogen, it would be useful to add one extra tab on the 'Fuel distribution' with a syngas/hydrogen option. This way the hydrogen could be a replacement for natural gas in the same way electrofuels (only liquid) are presented as a substitute for oil.

Furthermore, on the tab 'Biogases' it is possible to use biogas production as a primary energy supply that substitutes the use of natural gas, however, the same possibility is not available for syngas. Another possible improvement would be to add the option of supplying syngas as a primary energy supply on the 'Electrofuels' tab. Additionally, the methanol storage should also be connected to the gas grid, so it could provide balancing services. Currently, only the cost of the storage is taken into account.

Despite the fact that EnergyPLAN would not encompass the possibility to simulate a pure hydrogen gas grid, it was created a methodology to do so. One of the limitations of the methodology created is that hydrogen is included in the coal category, hence the thermal conversion efficiency does not correspond to the reality. However, all fuel categories (coal, oil, gas, and biomass) were tested and the required primary energy supply obtained was the same, thus the software does not take into account the thermal properties of the fuel categories. Alternatively, one could define the thermal efficiency of the boilers and CHPs accordingly to hydrogen use. A possible incoherence is that hydrogen is being used in the CHP, hence hydrogen can be used to create electricity for the production of hydrogen. This loop technically does not make sense and the primary energy supply was carefully check to try to avoid it. In the case that the electricity demand is supplied by VRE and is only necessary to produce heat, it would make sense to use hydrogen.

Another constrain is that two hourly hydrogen demand profiles were created based on renewable power and heat generation of previous scenarios. The hourly profiles are relative values and therefore do not depend on the hydrogen demand consider, however, the hourly values change accordingly to different energy system configurations. In order words, the VRE hourly demand profile does not match entirely to the VRE generation in the hydrogen gas grid scenario as the addition of renewable power generation will also impact the generation profile.

Even though EnergyPLAN does not consider the possibility of a hydrogen gas grid is still seen as the most suitable option, as it allows an hourly analysis. In 100% renewable energy systems as the one simulated, is crucial to do an hourly evaluation due to variability of renewable energy sources. In addition, an energy system analysis should encompass all sectors, this way a smart energy system can be obtained. Although only the heating and cooling sector was considered, the demand of the other sectors and the balance obtain in the overall energy system were taken into account. Moreover, the software permits the addition of hourly profiles, hence different strategies can be tested.

6.4 Significance of the theoretical framework

Basing the theoretical framework on an approach developed in a non-academic context might contain some inconsistencies. However, the practical application of the systemic innovation approach on the concrete Swedish case has proved its efficiency and practicality. Another aspect that one might raise is that establishing a framework solely on the thirty innovation briefs published could limit the identified driving innovations. As a result, the research was extended beyond the thirty innovations proposed, including extended analysis of the hydrogen implications.

The fact that only Power to hydrogen technologies was considered reduces the scope of the study. However, due to the delimitation, it was possible to perform a more in-depth analysis and tailor the proposed solution. Taking into account the mentioned limitations, the systemic approach is still seen as a suitable option to assess the necessary policy framework to include such an innovative option as hydrogen.

Conclusion 7

7.1 Recommendations

This has study has proven the technical feasibility of a hydrogen gas grid in Denmark. At the present moment, Denmark could establish a blending share of 12% without any modifications to the natural gas grid. The establishment of medium-term goals such as blending would introduce a hydrogen demand that consequently would incentivize growth in the hydrogen market. Assuming that Denmark would consider a hydrogen gas grid by 2050, the total energy system cost would be 22754 million euros, 112 more expensive than the original 2050 energy scenario developed by IDA thus proving not to be economically feasible.

Due to the innovative aspect of hydrogen inclusion in the energy system, one should consider a systemic innovation approach when creating a political framework. The group of recommended innovations that would improve the economical and technical feasibility is represented in Table 7.1.

Enabling technologies	Electrolyser cost reduction
	Super gas grid
	Storage
	Renewable power genaration
	Digital innovation
Market design	Universal hydrogen classification
	Regional hydrogen market
	Taxation
	Innovative ancialry services
Business models	Hydrogen hubs
System operation	Specialised TSO
	City gate stations
	Virtual power lines

Table 7.1. Innovation matrix.

The economic impact of investing in the research and development of the electrolyser technology was assessed. Assuming IRENA's latest projection of electrolyser cost reduction, the total cost of the Hydrogen gas grid scenario is lowered to 22551 million. A significant economic impact that would ensure that the Hydrogen gas grid scenario would be 91 million less costly than the original IDA scenario, hence verifying the economical feasibility of a hydrogen gas grid.

7.2 Further research

Future relevant research could also include a stakeholder analysis of key individuals involved in the transformation of a natural gas grid to a hydrogen gas grid. Moreover, the evaluation of hydrogen inclusion could be extended to the reaming sectors, like transportation, industry, and power sector. The analysis realized in EnergyPLAN could also encompass the different regulation strategies. Forthcoming research could also be done to assess the economic impact of the remaining innovations identified.

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Hydrogen state of the art A

A.1 Power to X

As shown in Figure A.1 the concept of Power to X encompass a wide range of products including hydrogen, synthetic gas (*e.g.* methane) as well as synthetic liquid fuels and chemicals such as methanol, ammonia and other Fischer-Tropsch products.

Hydrogen by itself can be a key enabler of system flexibly across the different energy sectors, however, hydrogen can also be used to create synthetic fuels and chemicals.

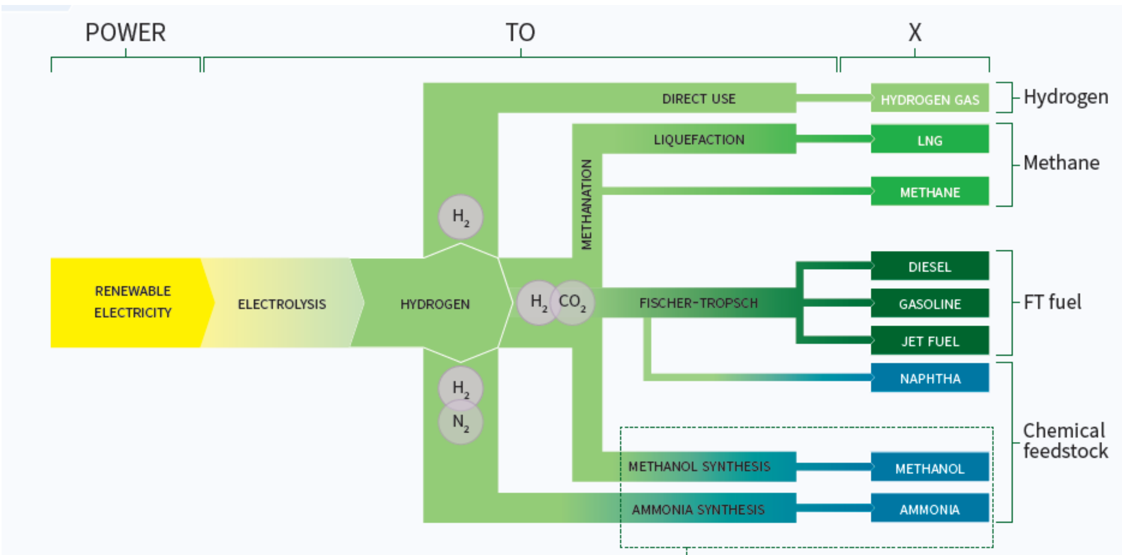


Figure A.1. Synthetic fuels and chemicals produced from hydrogen. [SolarPower Europe and LUT University, 2020]

For other application than direct use of hydrogen, carbon dioxide is necessary to produce hydrocarbon compounds. The carbon dioxide can be obtained trough direct air capture (DAC) or coupled with polluting industries such as cement plants.

Methanation transforms carbon dioxide and hydrogen into synthetic methane and with additional liquefaction, liquid natural gas (LNG) is created.

The Fisher-Tropsch also transforms carbon dioxide and hydrogen into synthetic crude. This product is then refined into the different liquid hydrocarbons fuels such as diesel, gasoline and jet fuel. Naphtha can be also created in this process and used as feedstock for chemical industry.

The methanol synthesis produces methanol that is one of the major chemical feedstocks.

Another available option is the production of ammonia with hydrogen and nitrogen. This product is mainly used in agriculture as a fertilizer [SolarPower Europe and LUT University, 2020].

The Power to X includes diverse products yet, for a deeper understanding of this process, only Power to hydrogen will be considered, as the production of hydrogen is the base for other synthetic and chemical products. In that sense, only the direct use of hydrogen will be analysed.

There are many possible paths to produce hydrogen, as shown in Figure A.2. The myriad of conversion technologies includes electrolysis, biochemical conversion, and thermochemical conversion processes such as steam methane reforming (SMR), partial oxidation, and autothermal reforming (ATR). The primary energy supply can be also both from renewable energy and fossil sources [Hydrogen Europe, 2020b].

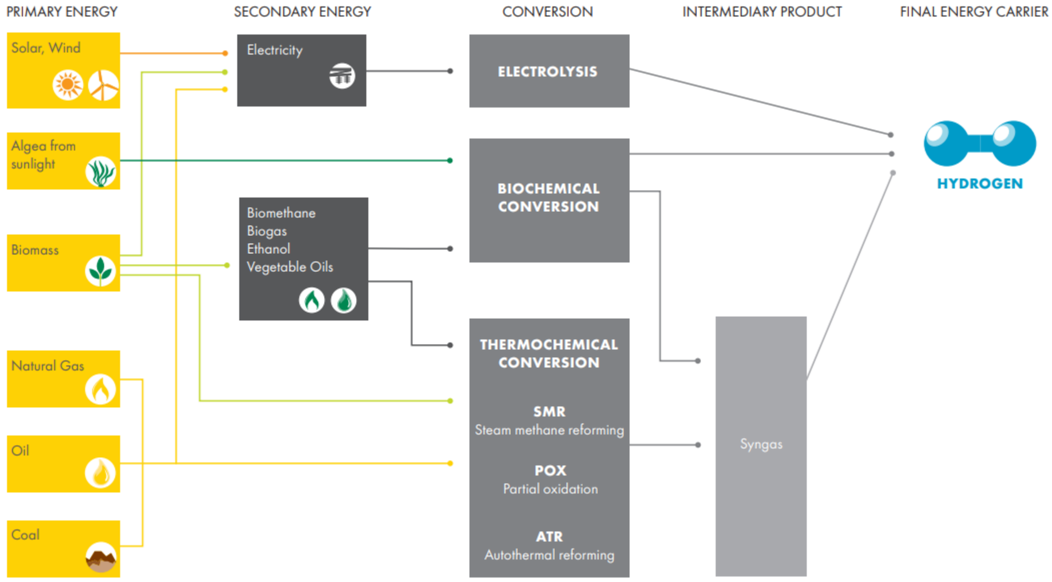


Figure A.2. Possibilities of hydrogen production. [Shell, 2017]

A.2 Electrolysers

This section contains the analysis of four different types of electrolysers, alkaline, polymer electrolyte membrane (PEM), solid oxide electrolysers (SOEC), and anion exchange membrane (AEM). The present operational parameters, costs, and possible services are visible in Table A.1.

	Alkaline	PEM	AEM	SOEC
		Operation		
Operating temperature (°C)	70-90	50-80	40-60	700-850
Operating pressure (bar)	1-30	<30	<35	<10
Cold start (nom. To load) (min)	<50	<20	<20	>600
Lifetime (hours)	60 000	50 000	>5000	<20 000
Electrical efficiency system (kWh/KgH2)	50 -78	50 – 83	N/A	>40
		Costs		
Cost stack (USD/kW)	270	450	N/A	>2000
Cost system (USD/kW)	600	1000	N/A	N/A
		Services		
Flexibility	Primary reserve services	Fast frequency response (FFR)	Fast frequency response (FFR)	No
Production coupled with VRE	No	Yes	N/A	No

Table A.1. Electrolysers parameters in 2020. [IRENA, 2020a]

Alkaline electrolysers are the most developed of the four, hence are more robust and have higher lifetimes of over 30 years. However, alkaline electrolyser has some limitations since when the gas permeation is compromised it is not possible to repair and the stack needs to be replaced. Additionally, the need for a constant supply of electricity makes it difficult to couple with VRE without considering any kind of storage or connection to the grid.

The **polymer electrolyte membrane (PEM)** electrolyser has the huge advantage of being able to be supplied by intermittent sources such as VRE. The variable supply of electricity will decrease the capacity factor of the electrolyser but is possible to operate a PEM in an off-grid system coupled with renewable power generation. PEM also generates pure hydrogen and further research in anion exchange membrane can reduce the technology cost. Nevertheless, nowadays the cost is still high due to the use of gold, iridium, and platinum and low scale.

Solid oxide electrolysis cells (SOEC) operate at high temperatures needed in industry and offer the possibility to operate both as fuel cell and electrolyser (reversibility). There is also the possibility to use waste heat produced to increase the efficiency of the electrolysis since the electrolyser operates between 700 to 850 Celsius degrees an shown in Table A.1. However this electrolyser is at lab-scale today, meaning that larger cells required for big scale are not yet proven and also has shorter lifetimes. Moreover, it requires storage to be coupled with VRE since it only works at constant electricity supply.

The **anion exchange membrane (AEM)** is less developed of the four electrolysers, hence it has unpredictable lifetimes and stability problems. Despite the low technology readiness level, it has potential as it operates in a less harsh environment than alkaline electrolysers, with the simplicity and efficiency of a PEM electrolyser [IRENA, 2020a].

With the increasing interest in the production of hydrogen, the electrolyser cost is expected to significantly decrease, as shown in Table A.2. The operation pressure is anticipated to increase, same can be also said for the electrical efficiency of the system.

	Alkaline	PEM	AEM	SOEC
Operation				
Operating temperature (°C)	>90	80	80	<600
Operating pressure (bar)	>70	>70	>70	>20
Cold start (nom. To load) (min)	<30	<5	<5	<30
Lifetime (hours)	100 000	100 000	100 000	80 000
Electrical efficiency system (kWh/KgH2)	<45	45	<45	<40
Costs				
Cost stack (USD/kW)	<100	<100	<100	<200
Cost system (USD/kW)	<200	<200	<200	<300
Services				
Flexibility	Primary reserve services	Fast frequency response (FFR)	Fast frequency response (FFR)	Primary reserve services
Production coupled with VRE	No	Yes	N/A	No

Table A.2. Electrolysers parameters in 2050. [IRENA, 2020a]

A.3 Hydrogen classification

Hydrogen can be produced using different processes, as previously shown, but also considering different sources. A color code visible on Figure A.3 was developed to classify hydrogen depending on both the source and process used.

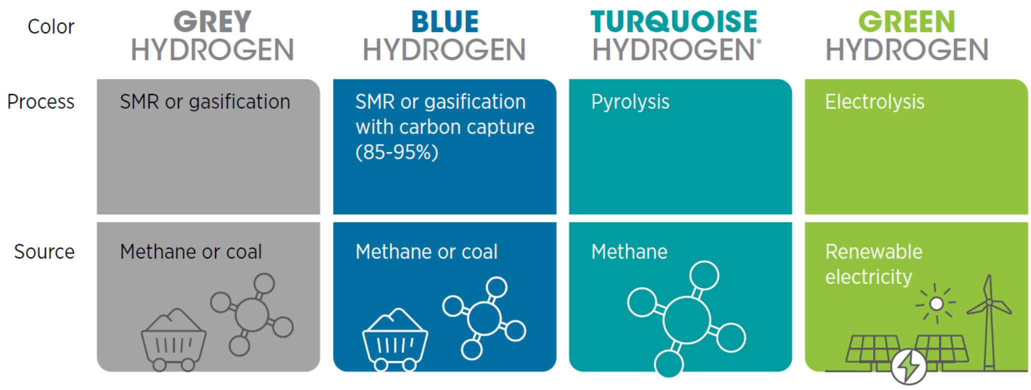


Figure A.3. Hydrogen color code. [IRENA, 2020b]

Grey hydrogen, sometimes also referred as black or brown, is produced with steam methane reforming (SMR) and coal gasification. The reliance on fossil fuels and consequent carbon emissions is inconsistent with the current carbon neutrality goals.

Blue hydrogen, is similar to grey hydrogen but includes CCS. Blue hydrogen could be a suitable short-term option as it allows the retrofitting of conventional by reducing harmful carbon emissions. However, the efficiency of CCS technologies is around 90%, which means that in long-term blue hydrogen is also not compatible with net-zero emissions ambition.

A new emerging type of hydrogen production is turquoise hydrogen trough pyrolsis. This process would allow carbon and hydrogen to be produced from methane without carbon emissions. The carbon produced is solid carbon black, that has already an established market, hence, providing extra revenues in addition to the hydrogen [IRENA, 2020b].

Currently the production of green hydrogen is negligible, with only 4% of the European production based on renewable electricity, the remaining are still based on fossil fuels [IRENA, 2019b]. Nonetheless, the decreasing prices of renewable electricity, technology advances, and compliance with carbon-free aspirations have increased substantially the interest in green hydrogen. As shown in Figure A.4, several countries had already committed to producing green hydrogen. An aspect interesting to note is that some countries consider blue and grey hydrogen but only as a step to achieve green hydrogen in a longer perspective.

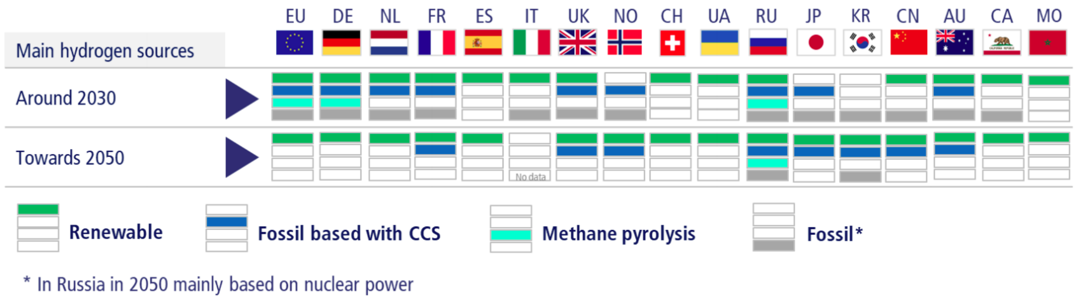


Figure A.4. Planning of hydrogen production on medium and long-term strategies. [Albrecht et al., 2020]

Hydrogen in the EnergyPLAN B

In EnergyPLAN, hydrogen can be incorporated in several ways to the energy system. It can be included in the transportation sector directly with the use of fuel cells and indirectly with electrofuels. In the industry sector its also possible to add a hydrogen demand.

Regarding the heating sector, there is the option to connect electrolysers so that the excess heat produced could be used in both the district heating group 2 and 3, and to add hydrogen as a fuel to a micro combined heat and power (CHP) plant. Additionally, electrofuels can also be used as a replacement of oil in district heating supply.

In summary, there are three electrolysers options covered by the EnergyPLAN:

1. Production of hydrogen for electrofuels, utilized in the transport and as a fuel for the district heating
2. Production of hydrogen for micro CHP
3. Connection to the district heating group 2 and 3, supplying excess heat and fuel production

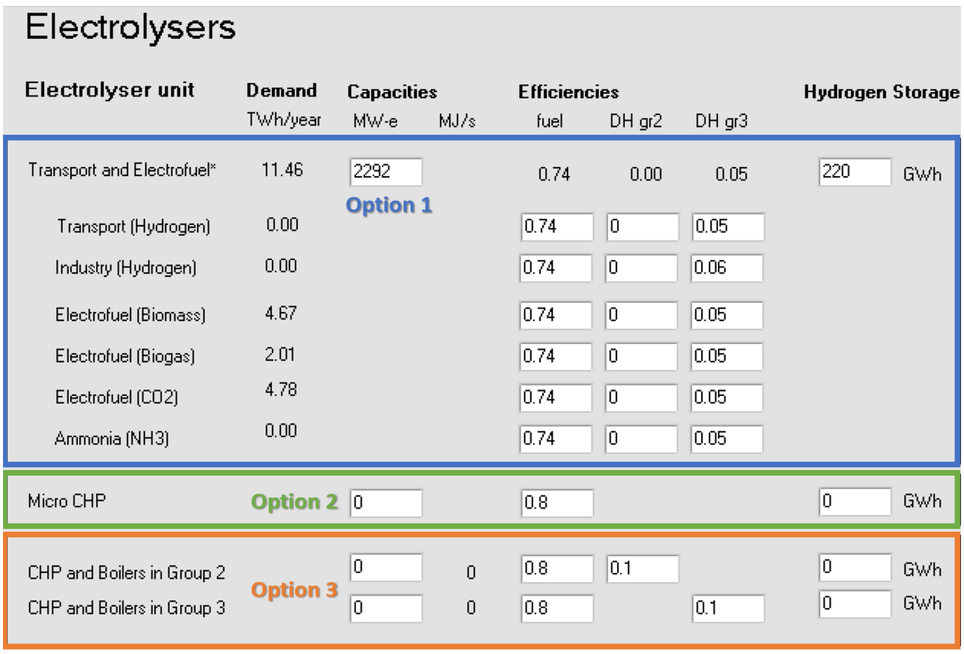


Figure B.1. Electrolysers options in EnergyPLAN.

The three option shown in Figure B.1 will be further scrutinized to understand how

EnergyPLAN prioritizes each demand and to analysis its limitations.

Option 1

After simulating the electrolysers for micro CHP (Option 2), the software will evaluate the necessary electrolyser capacity to supply the transportation and hydrogenation demand. On the **transportation**, the hourly demand of hydrogen is given by the distribution uploaded on the transportation tab.

In the case of hydrogen production for **industry** there is a possibility to add a distribution file so that the demand is variable, however, if just the demand is added the program will assume an constant demand.

On the other hand, the biogas and biomass hydrogenation demand is assumed constant. The hydrogen produced is combined with gasified biomass or biogas and is used to produce **electrofuels**, both liquid and gas form. The minimum capacity of the CO_2 hydrogenation plant is calculated similarly to the previous capacities. If the electrolyser capacity installed in option 1 is higher then the necessary minimum for both, transportation, industry and hydrogenation the available electrolyser capacity will be use to minimize excess electricity. Additional to this extra flexibility that electrolysers in option 1 and 2 can add to the system, the CO_2 hydrogenation plant has a unique characteristic as it can be use as a regulation strategy to balance the system. By choosing regulation strategy number 8 on the 'Balancing and Storage', one that increase the CO_2 hydrogenation to avoid CEEP. However, its important to note that this regulation strategy number 8 is only effective when the CO_2 hydrogenation plant capacity is higher than the minimum required, so that the extra flexibility is used to balance the energy system.

In the **ammonia** production there is no possibility to increase the capacity of the ammonia plant, meaning that all flexibility is located on the electrolysers.

Option 2

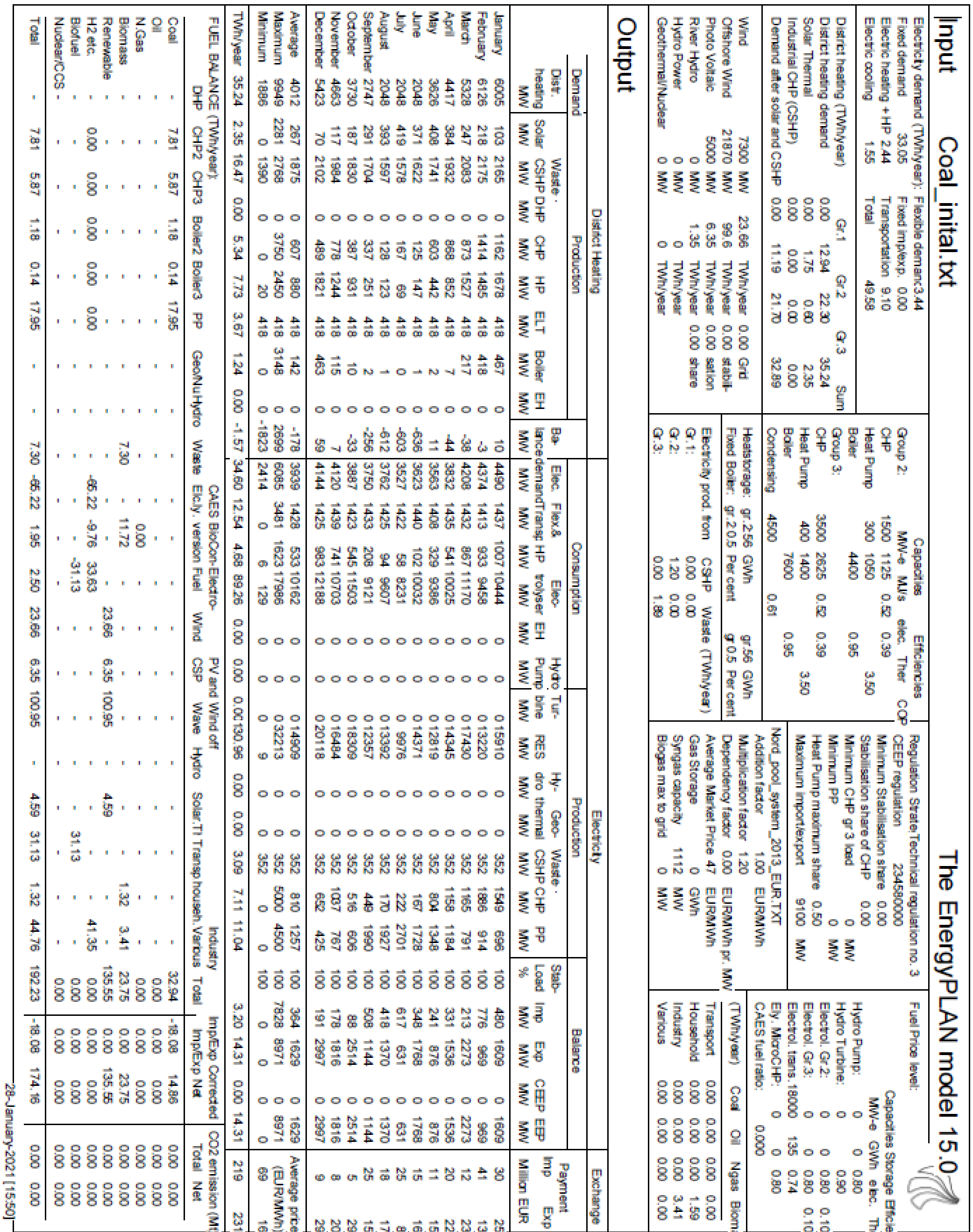
According to the heat demand inserted for individual micro CHP, the minimum electrolysers capacity necessary (input on the Hydrogen tab) is calculated. The required electrolyser capacity is also dependent of the hydrogen storage available. More hydrogen storage could reduce the necessary electrolyser capacity, as the storage would add flexibility to the variable heat demand.

Option 3

The problem with option number three is that it is not possible to define a demand as options 1 and 2 already fulfill the hydrogen demand for micro CHP, transportation and industry. Option 3 is only used later on in the calculation to avoid critical excess electricity production (CEEP). If there is CEEP, then the hydrogen produced is used to reduced the fuel consumption of the CHP and boiler located on the DH group and the excess heat produced will decrease the heat production of first the boiler, then CHP and heat pump.

C EnergyPLAN output

C.1 Hydrogen gas grid scenario



Input Coal_inital.txt — The EnergyPLAN model 15.0

Electricity demand (TWh/year):		Flexible demand	3.44
Fixed demand	33.05	Fixed imp/exp.	0.00
Electric heating + HP	2.44	Transportation	9.10
Electric cooling	1.55	Total	49.58

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0.00	12.94	22.30	35.24
Solar Thermal	0.00	1.75	0.60	2.35
Industrial CHP (CSHP)	0.00	0.00	0.00	0.00
Demand after solar and CSHP	0.00	11.19	21.70	32.89

Wind	7300	MW	23.66	TWh/year	0.00	Grid
Offshore Wind	21870	MW	99.6	TWh/year	0.00	stabil-
Photo Voltaic	5000	MW	6.35	TWh/year	0.00	sation
River Hydro	0	MW	1.35	TWh/year	0.00	share
Hydro Power	0	MW	0	TWh/year		
Geothermal/Nuclear	0	MW	0	TWh/year		

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1500	1125	0.52	0.39	
Heat Pump	300	1050			3.50
Boiler		4400		0.95	
Group 3:					
CHP	3500	2625	0.52	0.39	
Heat Pump	400	1400			3.50
Boiler		7600		0.95	
Condensing	4500		0.61		

Heatstorage: gr.2:56 GWh gr.56 GWh
Fixed Boiler: gr.2 0.5 Per cent gr 0.5 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.00	0.00
Gr.2:	1.20	0.00
Gr.3:	0.00	1.89

Regulation Strategy:	Technical regulation no. 3	
CEEP regulation	234580000	
Minimum Stabilisation share	0.00	
Stabilisation share of CHP	0.00	
Minimum CHP gr 3 load	0	MW
Minimum PP	0	MW
Heat Pump maximum share	0.50	
Maximum import/export	9100	MW
Nord_pool_system_2013_EUR.TXT		
Addition factor	1.00	EUR/MWh
Multiplication factor	1.20	
Dependency factor	0.00	EUR/MWh pr. MW
Average Market Price	47	EUR/MWh
Gas Storage	0	GWh
Syngas capacity	1112	MW
Biogas max to grid	0	MW

Fuel Price level:

	Capacities MW-e	Storage GWh	Efficiencies elec.	Ther.
Hydro Pump:	0	0	0.80	
Hydro Turbine:	0		0.90	
Electrol. Gr.2:	0	0	0.80	0.10
Electrol. Gr.3:	0	0	0.80	0.10
Electrol. trans.:	18000	135	0.74	
Ely. MicroCHP:	0	0	0.80	
CAES fuel ratio:	0.000			

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	0.00	0.00	0.00
Household	0.00	0.00	0.00	1.59
Industry	0.00	0.00	0.00	3.41
Various	0.00	0.00	0.00	0.00

Output

	District Heating Demand	District Heating Production									Electricity Consumption						Electricity Production							Electricity Balance					Exchange Payment	
	Distr. heating MW	Solar MW	Waste+CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW	Elec. demand MW	Flex.& Transp. MW	HP MW	Electrolyser MW	EH MW	Hydro Pump MW	Turbine MW	RES MW	Hydro MW	Geothermal MW	Waste+CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million EUR	Exp Million EUR
January	6005	103	2165	0	1162	1678	418	467	0	10	4490	1437	1007	10444	0	0	0	15910	0	0	352	1549	696	100	480	1609	0	1609	30	25
February	6126	218	2175	0	1414	1485	418	418	0	-3	4374	1413	933	9458	0	0	0	13220	0	0	352	1886	914	100	776	969	0	969	41	13
March	5328	247	2083	0	873	1527	418	217	0	-38	4208	1432	867	11170	0	0	0	17430	0	0	352	1165	791	100	213	2273	0	2273	12	23
April	4417	384	1932	0	868	852	418	7	0	-44	3832	1435	541	10025	0	0	0	14345	0	0	352	1158	1184	100	331	1536	0	1536	20	22
May	3626	408	1741	0	603	442	418	2	0	11	3563	1408	329	9386	0	0	0	12819	0	0	352	804	1348	100	241	876	0	876	11	15
June	2048	371	1622	0	125	147	418	1	0	-636	3623	1440	102	10032	0	0	0	14371	0	0	352	167	1728	100	348	1768	0	1768	15	16
July	2048	419	1578	0	167	69	418	0	0	-603	3527	1422	58	8231	0	0	0	9976	0	0	352	222	2701	100	617	631	0	631	25	8
August	2048	393	1597	0	128	123	418	1	0	-612	3762	1425	94	9607	0	0	0	13392	0	0	352	170	1927	100	418	1370	0	1370	18	17
September	2747	291	1704	0	337	251	418	2	0	-256	3750	1433	208	9121	0	0	0	12357	0	0	352	449	1990	100	508	1144	0	1144	25	15
October	3730	187	1830	0	387	931	418	10	0	-33	3887	1423	545	11503	0	0	0	18309	0	0	352	516	606	100	88	2514	0	2514	5	29
November	4663	117	1984	0	778	1244	418	115	0	7	4120	1439	741	10703	0	0	0	16484	0	0	352	1037	767	100	178	1816	0	1816	8	20
December	5423	70	2102	0	489	1821	418	463	0	59	4144	1425	983	12188	0	0	0	20118	0	0	352	652	425	100	191	2997	0	2997	9	29
Average	4012	267	1875	0	607	880	418	142	0	-178	3939	1428	533	10162	0	0	0	14909	0	0	352	810	1257	100	364	1629	0	1629	Average price	
Maximum	9949	2281	2768	0	3750	2450	418	3148	0	2699	6085	3481	1623	17986	0	0	0	32213	0	0	352	5000	4500	100	7828	8971	0	8971	(EUR/MWh)	
Minimum	1886	0	1390	0	0	20	418	0	0	-1823	2414	0	6	129	0	0	0	9	0	0	352	0	0	100	0	0	0	0	69	16
TWh/year	35.24	2.35	16.47	0.00	5.34	7.73	3.67	1.24	0.00	-1.57	34.60	12.54	4.68	89.26	0.00	0.00	0.00	130.96	0.00	0.00	3.09	7.11	11.04		3.20	14.31	0.00	14.31	219	231

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV and CSP	Wind off Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Net	CO2 emission (Mt): Total	Net
Coal	-	7.81	5.87	1.18	0.14	17.95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32.94	-18.08	14.86	0.00	0.00
Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
N.Gas	-	-	-	-	-	-	-	-	-	-	0.00	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biomass	-	-	-	-	-	-	-	-	7.30	-	11.72	-	-	-	-	-	-	-	1.32	3.41	23.75	0.00	23.75	0.00	0.00
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	23.66	6.35	100.95	-	4.59	-	-	-	135.55	0.00	135.55	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-65.22	-9.76	33.63	-	-	-	-	-	-	-	41.35	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	-	-	-	-	-	-	-	-	-	-31.13	-	-	-	-	-	31.13	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	-	7.81	5.87	1.18	0.14	17.95	-	-	7.30	-65.22	1.95	2.50	23.66	6.35	100.95	-	4.59	31.13	1.32	44.76	192.23	-18.08	174.16	0.00	0.00

28-January-2021 [15:50]

Output specifications Coal_inital.txt The EnergyPLAN model 15.0

District Heating Production

Gr.1

	District heating MW	Solar MW	CSHP MW	DHP MW
January	0	0	0	0
February	0	0	0	0
March	0	0	0	0
April	0	0	0	0
May	0	0	0	0
June	0	0	0	0
July	0	0	0	0
August	0	0	0	0
September	0	0	0	0
October	0	0	0	0
November	0	0	0	0
December	0	0	0	0
Average	0	0	0	0
Maximum	0	0	0	0
Minimum	0	0	0	0
Total for the whole year TWh/year	0.00	0.00	0.00	0.00

Gr.2

	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Stor-age MW	Ba-lance MW
January	2205	77	354	478	876	0	409	0	23094	10
February	2249	163	357	581	810	0	342	0	21398	-3
March	1957	184	335	442	780	0	206	0	16385	10
April	1622	285	300	515	546	0	6	0	14595	-30
May	1332	304	256	428	315	0	2	0	23815	26
June	752	277	228	125	135	0	1	0	21188	-13
July	752	310	218	167	56	0	0	0	20893	1
August	752	296	222	128	111	0	1	0	22013	-5
September	1009	216	247	329	220	0	2	0	21898	-5
October	1370	140	276	270	672	0	10	0	26091	0
November	1712	87	312	471	721	0	114	0	24223	6
December	1991	52	340	246	920	0	433	0	23124	1
Average	1473	199	287	347	513	0	127	0	21572	0
Maximum	3653	1624	495	1125	1050	0	2165	0	41513	1204
Minimum	692	0	174	0	7	0	0	0	0	-836
Total for the whole year TWh/year	12.94	1.75	2.52	3.05	4.51	0.00	1.12	0.00		0.00

Gr.3

	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Stor-age MW	Ba-lance MW
January	3800	26	1811	684	802	418	58	0	18693	0
February	3876	56	1818	833	675	418	77	0	28343	0
March	3372	63	1748	432	747	418	11	0	24348	-47
April	2795	99	1631	353	307	418	0	0	40661	-14
May	2295	104	1486	175	127	418	0	0	43499	-14
June	1296	94	1394	0	13	418	0	0	43333	-623
July	1296	109	1360	0	13	418	0	0	43522	-605
August	1296	97	1375	0	13	418	0	0	43522	-607
September	1739	75	1457	8	31	418	0	0	43524	-251
October	2360	47	1553	117	258	418	0	0	42858	-34
November	2951	30	1671	307	523	418	1	0	40685	1
December	3432	18	1762	243	902	418	30	0	36168	58
Average	2539	68	1588	261	367	418	15	0	37429	-178
Maximum	6296	841	2273	2625	1400	418	1777	0	56000	2624
Minimum	1193	0	1216	0	13	418	0	0	0	-1823
Total for the whole year TWh/year	22.30	0.60	13.95	2.29	3.23	3.67	0.13	0.00		-1.57

RES specification

	RES1 Wind MW	RES2 Offshc MW	RES3 Photo MW	RES 4-7 MW	Total MW
January	2859	12746	149	156	15910
February	2096	10577	318	229	13220
March	3363	13041	844	181	17430
April	2897	10215	1112	121	14345
May	2230	9290	1183	116	12819
June	2562	10524	1177	108	14371
July	1694	6922	1267	93	9976
August	2317	9868	1081	125	13392
September	2007	9383	810	156	12357
October	3203	14501	407	197	18309
November	2856	13213	214	201	16484
December	4180	15673	100	166	20118
Average	2693	11339	723	154	14909
Maximum	7233	21620	4388	300	32213
Minimum	0	0	0	5	9
Total for the whole year TWh/year	23.66	99.60	6.35	1.35	130.96

Own use of heat from industrial CH0.00 TWh/year

ANNUAL COSTS (Million EUR)

Total Fuel ex Ngas exchange =		1071
Uranium =	0	
Coal =	336	
FuelOil =	0	
Gasoil/Diesel=	291	
Petrol/JP =	11	
Gas handling =	0	
Biomass =	433	
Food income =	0	
Waste =	0	
Total Ngas Exchange costs =		0
Marginal operation costs =		74
Total Electricity exchange =		-12
Import =	219	
Export =	-231	
Bottleneck =	0	
Fixed imp/ex=	0	
Total CO2 emission costs =		0
Total variable costs =		1133
Fixed operation costs =		5620
Annual Investment costs =		15798
TOTAL ANNUAL COSTS =		22551

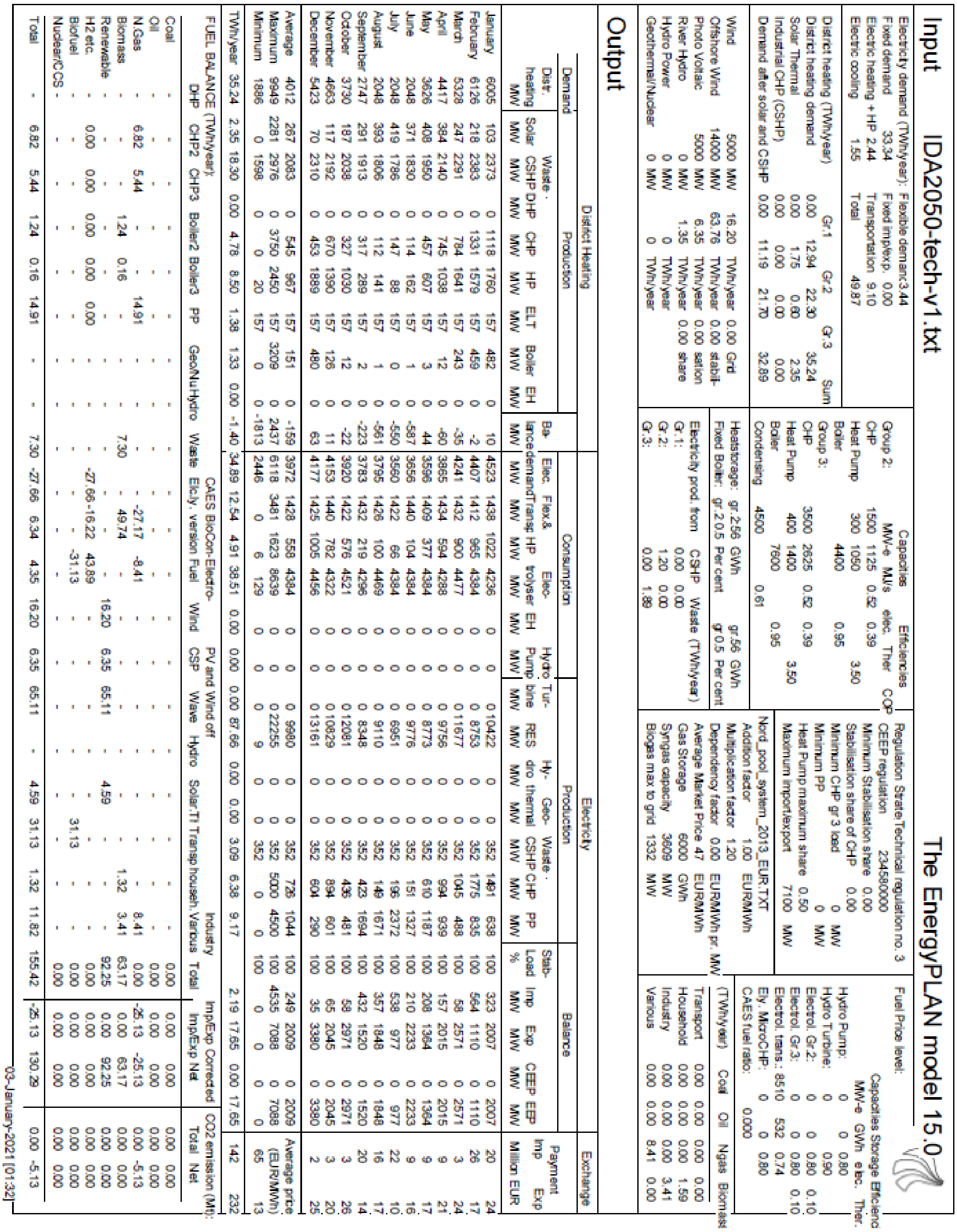
NATURAL GAS EXCHANGE

	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Indi-vidual MW	Trans port MW	Indu. Var. MW	Demand Sum MW	Bio-gas MW	Syn-gas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Stor-age MW	Sum MW	Im-port MW	Ex-port MW
January	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
August	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
December	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Average	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maximum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Minimum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total for the whole year TWh/year	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

RES Share: 82.9 Percent of Primary Energy 96.9 Percent of Electricity 132.8 TWh electricity from RES

28-January-2021 [15:50]

C.2 Original IDA scenario



Input IDA2050-tech-v1.txt — The EnergyPLAN model 15.0

Electricity demand (TWh/year):		Flexible demand	3.44
Fixed demand	33.34	Fixed imp/exp.	0.00
Electric heating + HP	2.44	Transportation	9.10
Electric cooling	1.55	Total	49.87

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	0.00	12.94	22.30	35.24
Solar Thermal	0.00	1.75	0.60	2.35
Industrial CHP (CSHP)	0.00	0.00	0.00	0.00
Demand after solar and CSHP	0.00	11.19	21.70	32.89

Wind	5000 MW	16.20	TWh/year	0.00	Grid
Offshore Wind	14000 MW	63.76	TWh/year	0.00	stabili-
Photo Voltaic	5000 MW	6.35	TWh/year	0.00	sation
River Hydro	0 MW	1.35	TWh/year	0.00	share
Hydro Power	0 MW	0	TWh/year		
Geothermal/Nuclear	0 MW	0	TWh/year		

	Capacities MW-e	Capacities MJ/s	Efficiencies elec.	Efficiencies Ther	COP
Group 2:					
CHP	1500	1125	0.52	0.39	
Heat Pump	300	1050			3.50
Boiler		4400		0.95	
Group 3:					
CHP	3500	2625	0.52	0.39	
Heat Pump	400	1400			3.50
Boiler		7600		0.95	
Condensing	4500		0.61		

Heatstorage: gr.2: 56 GWh gr.3: 56 GWh
Fixed Boiler: gr.2: 0.5 Per cent gr.3: 0.5 Per cent

Electricity prod. from	CSHP	Waste (TWh/year)
Gr.1:	0.00	0.00
Gr.2:	1.20	0.00
Gr.3:	0.00	1.89

Regulation Strategy: Technical regulation no. 3
CEEP regulation 234580000
Minimum Stabilisation share 0.00
Stabilisation share of CHP 0.00
Minimum CHP gr 3 load 0 MW
Minimum PP 0 MW
Heat Pump maximum share 0.50
Maximum import/export 7100 MW

Nord_pool_system_2013_EUR.TXT
Addition factor 1.00 EUR/MWh
Multiplication factor 1.20
Dependency factor 0.00 EUR/MWh pr. MW
Average Market Price 47 EUR/MWh
Gas Storage 6000 GWh
Syngas capacity 3609 MW
Biogas max to grid 1332 MW

Fuel Price level:

	Capacities MW-e	Storage GWh	Efficiencies elec.	Efficiencies Ther.
Hydro Pump:	0	0	0.80	
Hydro Turbine:	0		0.90	
Electrol. Gr.2:	0	0	0.80	0.10
Electrol. Gr.3:	0	0	0.80	0.10
Electrol. trans.:	8510	532	0.74	
Ely. MicroCHP:	0	0	0.80	

CAES fuel ratio: 0.000

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0.00	0.00	0.00	0.00
Household	0.00	0.00	0.00	1.59
Industry	0.00	0.00	0.00	3.41
Various	0.00	0.00	8.41	0.00

Output

	District Heating										Electricity																		Exchange	
	Demand	Production									Consumption						Production							Balance					Payment	
	Distr. heating MW	Solar MW	Waste-CSHP MW	DHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Balance MW	Elec. demand MW	Flex.& Transp MW	HP MW	Electrolyser MW	EH MW	Hydro Pump MW	Turbine MW	RES MW	Hydro MW	Geothermal MW	Waste-CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	CEEP MW	EEP MW	Imp Million EUR	Exp Million EUR
January	6005	103	2373	0	1118	1760	157	482	0	10	4523	1438	1022	4236	0	0	0	10422	0	0	352	1491	638	100	323	2007	0	2007	20	24
February	6126	218	2383	0	1331	1579	157	459	0	-2	4407	1412	965	4384	0	0	0	8753	0	0	352	1775	835	100	564	1110	0	1110	26	17
March	5328	247	2291	0	784	1641	157	243	0	-35	4241	1432	900	4477	0	0	0	11677	0	0	352	1045	488	100	58	2571	0	2571	3	24
April	4417	384	2140	0	745	1038	157	12	0	-60	3865	1434	594	4288	0	0	0	9756	0	0	352	994	939	100	157	2015	0	2015	9	21
May	3626	408	1950	0	457	607	157	3	0	44	3596	1409	377	4384	0	0	0	8773	0	0	352	610	1187	100	208	1364	0	1364	9	17
June	2048	371	1830	0	114	162	157	1	0	-587	3656	1440	104	4384	0	0	0	9776	0	0	352	151	1327	100	210	2233	0	2233	9	16
July	2048	419	1786	0	147	88	157	0	0	-550	3560	1422	66	4384	0	0	0	6951	0	0	352	196	2372	100	538	977	0	977	22	10
August	2048	393	1806	0	112	141	157	1	0	-561	3795	1426	100	4469	0	0	0	9110	0	0	352	149	1671	100	357	1848	0	1848	16	17
September	2747	291	1913	0	317	289	157	2	0	-223	3783	1432	219	4296	0	0	0	8348	0	0	352	423	1694	100	432	1520	0	1520	20	14
October	3730	187	2038	0	327	1030	157	12	0	-22	3920	1422	576	4521	0	0	0	12081	0	0	352	436	481	100	58	2971	0	2971	3	26
November	4663	117	2192	0	670	1390	157	126	0	11	4153	1440	782	4322	0	0	0	10829	0	0	352	894	601	100	65	2045	0	2045	3	20
December	5423	70	2310	0	453	1889	157	480	0	63	4177	1425	1005	4456	0	0	0	13161	0	0	352	604	290	100	35	3380	0	3380	2	25
Average	4012	267	2083	0	545	967	157	151	0	-159	3972	1428	558	4384	0	0	0	9980	0	0	352	726	1044	100	249	2009	0	2009	Average price	
Maximum	9949	2281	2976	0	3750	2450	157	3209	0	2437	6118	3481	1623	8639	0	0	0	22255	0	0	352	5000	4500	100	4535	7088	0	7088	(EUR/MWh)	
Minimum	1886	0	1598	0	0	20	157	0	0	-1813	2446	0	6	129	0	0	0	9	0	0	352	0	0	100	0	0	0	0	65	13
TWh/year	35.24	2.35	18.30	0.00	4.78	8.50	1.38	1.33	0.00	-1.40	34.89	12.54	4.91	38.51	0.00	0.00	0.00	87.66	0.00	0.00	3.09	6.38	9.17		2.19	17.65	0.00	17.65	142	232

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Geo/Nu.	Hydro	Waste	CAES Elc.ly.	BioCon-version	Electro-Fuel	Wind	PV and Wind off CSP	Wave	Hydro	Solar.Th.	Transp.	househ.	Industry Various	Total	Imp/Exp Corrected Imp/Exp	Imp/Exp Corrected Net	CO2 emission (Mt): Total	CO2 emission (Mt): Net
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
N.Gas	-	6.82	5.44	-	-	14.91	-	-	-	-	-27.17	-8.41	-	-	-	-	-	-	-	8.41	0.00	-25.13	-25.13	0.00	-5.13
Biomass	-	-	-	1.24	0.16	-	-	-	7.30	-	49.74	-	-	-	-	-	-	-	1.32	3.41	63.17	0.00	63.17	0.00	0.00
Renewable	-	-	-	-	-	-	-	-	-	-	-	-	16.20	6.35	65.11	-	4.59	-	-	-	92.25	0.00	92.25	0.00	0.00
H2 etc.	-	0.00	0.00	0.00	0.00	0.00	-	-	-	-27.66	-16.22	43.89	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Biofuel	-	-	-	-	-	-	-	-	-	-	-	-31.13	-	-	-	-	-	31.13	-	-	0.00	0.00	0.00	0.00	0.00
Nuclear/CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00
Total	-	6.82	5.44	1.24	0.16	14.91	-	-	7.30	-27.66	6.34	4.35	16.20	6.35	65.11	-	4.59	31.13	1.32	11.82	155.42	-25.13	130.29	0.00	-5.13

03-January-2021 [01:32]

Output specifications IDA2050-tech-v1.txt **The EnergyPLAN model 15.0**

District Heating Production

	Gr.1				Gr.2										Gr.3										RES specification				
	District heating MW	Solar MW	CSHP MW	DHP MW	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW	District heating MW	Solar MW	CSHP MW	CHP MW	HP MW	ELT MW	Boiler MW	EH MW	Storage MW	Balance MW	RES1 Wind MW	RES2 Offshore MW	RES3 Photo MW	RES 4-7 MW	Total MW
January	0	0	0	0	2205	77	354	455	888	0	421	0	23844	10	3800	26	2019	664	873	157	61	0	24963	0	1958	8159	149	156	10422
February	0	0	0	0	2249	163	357	532	838	0	362	0	21992	-2	3876	56	2026	799	742	157	96	0	27440	0	1435	6771	318	229	8753
March	0	0	0	0	1957	184	335	384	818	0	228	0	16795	7	3372	63	1956	400	823	157	15	0	29600	-42	2304	8348	844	181	11677
April	0	0	0	0	1622	285	300	436	616	0	11	0	14340	-26	2795	99	1840	310	423	157	1	0	45812	-34	1984	6539	1112	121	9756
May	0	0	0	0	1332	304	256	320	422	0	3	0	24667	27	2295	104	1694	137	185	157	0	0	45364	18	1527	5947	1183	116	8773
June	0	0	0	0	752	277	228	114	149	0	1	0	22017	-17	1296	94	1602	0	13	157	0	0	45143	-571	1755	6737	1177	108	9776
July	0	0	0	0	752	310	218	147	75	0	0	0	22084	2	1296	109	1569	0	13	157	0	0	45492	-552	1160	4431	1267	93	6951
August	0	0	0	0	752	296	222	112	128	0	1	0	22419	-7	1296	97	1583	0	13	157	0	0	45499	-555	1587	6317	1081	125	9110
September	0	0	0	0	1009	216	247	304	250	0	2	0	22682	-11	1739	75	1666	13	39	157	0	0	45705	-212	1375	6007	810	156	8348
October	0	0	0	0	1370	140	276	221	714	0	11	0	26808	7	2360	47	1762	106	316	157	0	0	45627	-28	2194	9283	407	197	12081
November	0	0	0	0	1712	87	312	411	769	0	125	0	25100	7	2951	30	1880	259	621	157	1	0	40172	4	1956	8458	214	201	10829
December	0	0	0	0	1991	52	340	216	943	0	440	0	23658	0	3432	18	1971	236	946	157	41	0	38149	63	2863	10033	100	166	13161
Average	0	0	0	0	1473	199	287	303	550	0	134	0	22214	0	2539	68	1796	242	417	157	18	0	39935	-159	1845	7259	723	154	9980
Maximum	0	0	0	0	3653	1624	495	1125	1050	0	2179	0	43077	920	6296	841	2481	2625	1400	157	1829	0	56000	2354	4954	13840	4388	300	22255
Minimum	0	0	0	0	692	0	174	0	7	0	0	0	0	-866	1193	0	1424	0	13	157	0	0	0	-1813	0	0	0	5	9
Total for the whole year TWh/year	0.00	0.00	0.00	0.00	12.94	1.75	2.52	2.66	4.83	0.00	1.17	0.00		0.00	22.30	0.60	15.78	2.12	3.66	1.38	0.15	0.00		-1.40	16.20	63.76	6.35	1.35	87.66

Own use of heat from industrial CHP 0.00 TWh/year

ANNUAL COSTS (Million EUR)

Total Fuel ex Ngas exchange = 1487

Uranium = 0

Coal = 0

FuelOil = 0

Gasoil/Diesel= 291

Petrol/JP = 11

Gas handling = 38

Biomass = 1147

Food income = 0

Waste = 0

Total Ngas Exchange costs = 0

Marginal operation costs = 64

Total Electricity exchange = -90

Import = 142

Export = -232

Bottleneck = 0

Fixed imp/ex= 0

Total CO2 emission costs = 0

Total variable costs = 1460

Fixed operation costs = 5773

Annual Investment costs = 15408

TOTAL ANNUAL COSTS = 22642

							NATURAL GAS EXCHANGE									
	DHP & Boilers MW	CHP2 CHP3 MW	PP CAES MW	Individual MW	Transport MW	Indu. Var. MW	Demand Sum MW	Biogas MW	Syngas MW	CO2Hy gas MW	SynHy gas MW	SynHy gas MW	Storage MW	Sum MW	Import MW	Export MW
January	0	2868	1037	0	0	957	4862	596	2497	0	957	0	0	811	1487	676
February	0	3413	1357	0	0	957	5728	596	2497	0	957	0	423	1254	1630	376
March	0	2010	793	0	0	957	3761	596	2497	0	957	0	-176	-114	1091	1205
April	0	1911	1526	0	0	957	4394	596	2497	0	957	0	-176	519	1332	813
May	0	1172	1930	0	0	957	4059	596	2497	0	957	0	-49	57	1118	1061
June	0	291	2158	0	0	957	3407	596	2497	0	957	0	11	-655	832	1488
July	0	376	3856	0	0	957	5190	596	2497	0	957	0	381	758	1421	663
August	0	287	2717	0	0	957	3962	596	2497	0	957	0	-392	302	1225	923
September	0	814	2755	0	0	957	4526	596	2497	0	957	0	0	475	1273	797
October	0	839	782	0	0	957	2579	596	2497	0	957	0	0	-1472	542	2014
November	0	1719	978	0	0	957	3654	596	2497	0	957	0	0	-397	978	1375
December	0	1161	472	0	0	957	2590	596	2497	0	957	0	0	-1461	571	2032
Average	0	1396	1697	0	0	957	4051	596	2497	0	957	0	0	0	1122	1123
Maximum	0	9615	7317	0	0	957	12199	596	2497	0	957	0	6233	1915	1915	3094
Minimum	0	0	0	0	0	957	957	596	2497	0	957	0	-5008	-3094	0	0
Total for the whole year TWh/year	0.00	12.27	14.91	0.00	0.00	8.41	35.58	5.24	21.94	0.00	8.41	0.00	0.00	0.00	9.86	9.86

RES Share: 100.0 Percent of Primary Energ 103.2 Percent of Electricity 89.6 TWh electricity from RES 03-January-2021 [01:32]