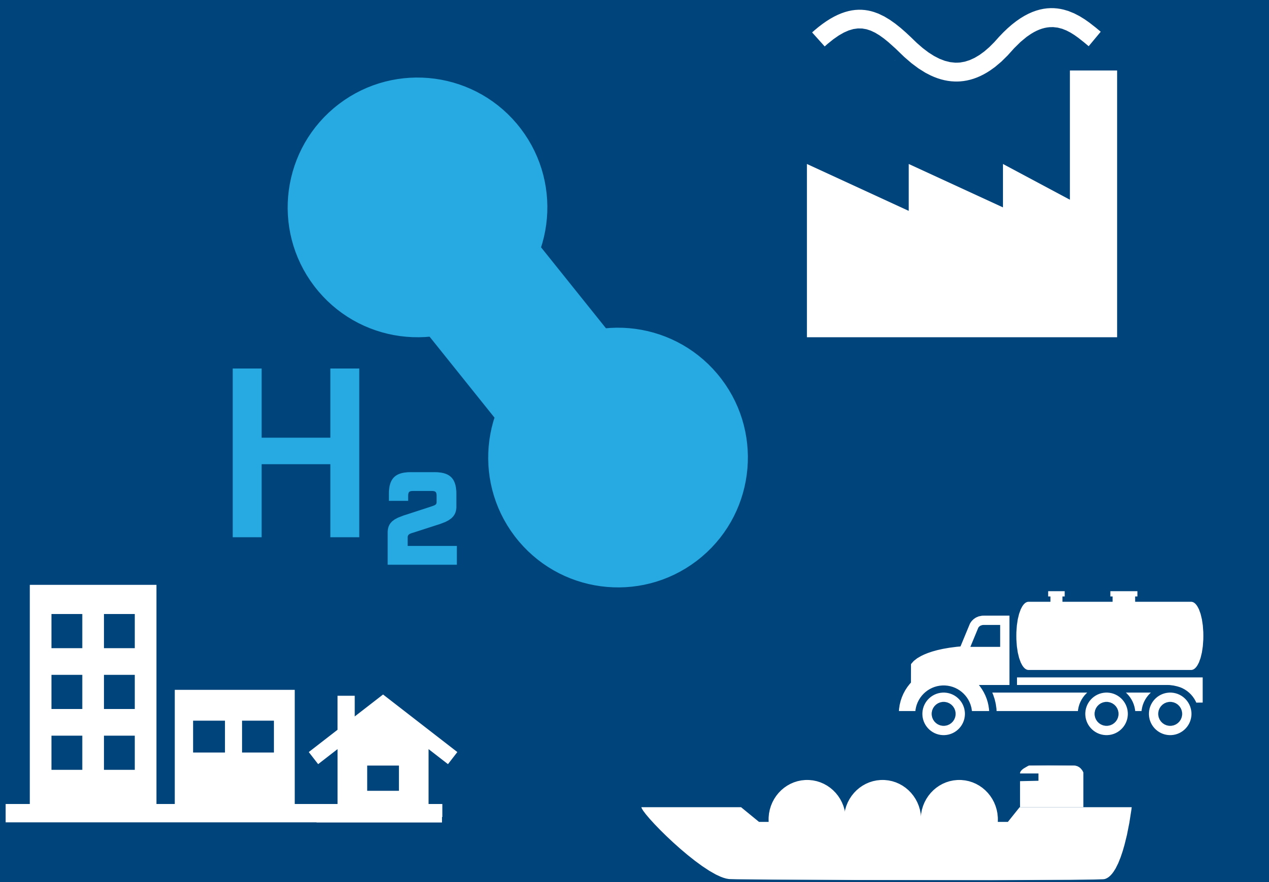
Hydrogen for Europe

Final report of the pre-study



This report is a cooperation between IFPEN and SINTEF

2019:00597- Unrestricted

Report

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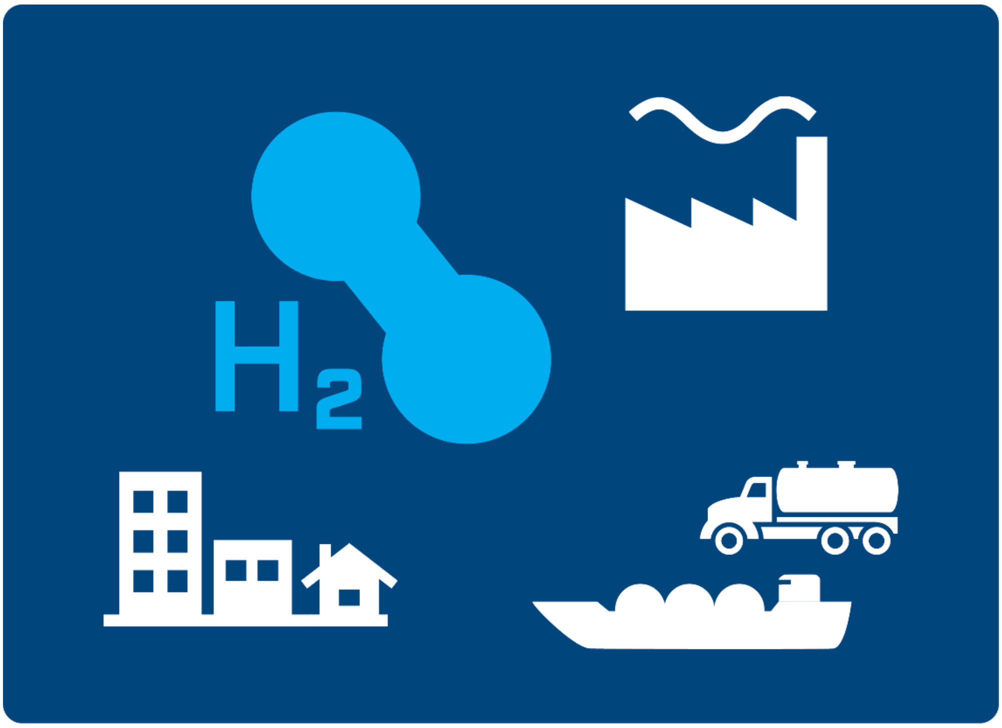

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KEYWORDS:
Hydrogen, CCS, energy system, decarbonization, Europe

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CLIENT(S)	CLIENT'S REF.
European Petroleum Refiners Association Concawe Division, International Association of Oil & Gas Producers, Norsk Olje og Gass, EQUINOR ENERGY BELGIUM NV, TOTAL SA, Polskie Górnictwo Naftowe i Gazownictwo SA, ExxonMobil International Ltd., Wintershall Holding GmbH, The UK Oil and Gas Industry Association Ltd.	Hydrogen for Europe

PROJECT NO.	NUMBER OF PAGES/APPENDICES:
502002187	120 + Appendices

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ABSTRACT

The potential for Hydrogen in Europe

At present there is an ongoing process within the EU on how to fulfil the commitment made to the Paris agreement. The role of hydrogen, and in particular hydrogen from natural gas combined with capture and storage of the produced CO_2 (CCS), is debated. The hydrogen for Europe pre-study has been undertaken with the purpose of assessing current knowledge about the potential hydrogen has to decarbonize the European economy.

The assessment has been set up to answer three main questions:

1. What is the potential for reducing greenhouse gas (GHG) emissions using hydrogen?
2. What is the relative cost of alternative transitioning pathways for the European energy system, from today to 2050 and beyond?
3. What is the viability, e.g. technology readiness, safety, policy and regulatory barriers, of the energy transition paths?

It is found that hydrogen from natural gas with CCS has the potential to reduce the current European GHG emissions by 19% by 2050, replacing fossil fuels in the power, residential, commercial, transport and industry sectors. This is regarded as an upper bounds value for the potential. Today and well beyond 2030, the emissions from production of hydrogen from natural gas with CCS is estimated to be significantly lower than emissions from production of hydrogen using electrolysers and average European grid electricity. Until the power sector is fully decarbonized, it is important to account for the impact on its decarbonization rate from the latter kind of hydrogen production. The average European grid electricity is used in the current study as a simplified approach.

With regards to cost of alternative transitioning pathways for the European energy system, and the viability e.g. in terms of technology readiness, there is limited knowledge at current. This is due to e.g. that hydrogen production from natural gas with CCS is not included, or that the results are derived for smaller geographic areas and thus not directly transferable to the EU as a whole.

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REPORT NO.	**ISBN**	**CLASSIFICATION**	**CLASSIFICATION THIS PAGE**
2019:00597	978-82-14-06329-5	Unrestricted	Unrestricted

MANAGEMENT SYSTEM CERTIFICATION
DNV·GL
ISO 9001 • ISO 14001
OHSAS 18001

Document history

VERSION	DATE	VERSION DESCRIPTION
1.0	2019-05-10	Version sent to the steering committee for comments
1.1	2019-06-03	Final version
1.2	2019-08-21	Final version with updated sections 1 and 2

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APPENDICES

[List appendices here]

1 The potential for hydrogen in Europe – executive summary of the Hydrogen for Europe pre-study

The Hydrogen for Europe pre-study has been carried out in the context of the ongoing process within the EU on how to fulfil the commitment made to the Paris agreement. Reaching climate neutrality, or near neutrality, by 2050 requires a significant increase in annual reductions of greenhouse gas (GHG) emissions compared to historic reductions from 1990 to 2016.

Hydrogen is an energy carrier which, as for electricity, has no greenhouse gas emissions related to it when being used. Further, hydrogen can be used in the industry, transport sector, power sector and to heat the building stock. Therefore, hydrogen could potentially be part of the solution to achieve the necessary decarbonization of Europe's energy system. The Hydrogen for Europe pre-study was launched to study current knowledge on the potential for hydrogen in Europe. Particularly, the study investigated available knowledge on the potential role of hydrogen produced from natural gas where the CO_2 produced is captured and stored and possible interplay with hydrogen produced from renewable sources. The study has assessed currently available knowledge with regards to what can be learned about the full potential of hydrogen in Europe and how future work could be carried out to gain more comprehensive knowledge about the potential.

In our work, three main sources have been used:

- "A Clean Planet for all" - In response to the Paris agreement and to confirm Europe's commitment for efforts and actions to limit climate change, the European Commission adopted a long-term strategic vision for a prosperous, modern competitive and climate neutral economy by 2050 - "A Clean Plant for all" . The consultation document assesses eight different pathways, two of which aim to achieve climate neutrality by 2050. The pathways explore the opportunities and efforts needed to reach EU's climate targets. They show the radical changes needed in the European energy system, which include the utilisation of hydrogen and synthetic methane as energy carriers.
- "Hydrogen Roadmap Europe" – A study on the potential of the European hydrogen market carried out by the Fuel Cells and Hydrogen Joint Undertaking and McKinsey. The study investigated two scenarios, Business as Usual and an ambitious scenario reaching the 2.0 °C scenario, and estimated the investment and technology needed to deploy hydrogen technologies.
- H21 North of England Report - The North of England project is a detailed analysis of hydrogen production and distribution in northern England for heating purposes. This study was conducted by Northern Gas Networks and Equinor to study the decarbonization of the heating sector. All fossil fuel-based production pathways include CCS. Hydrogen production technologies analysed include natural gas reforming in both a steam methane reformer (SMR) and an autothermal reformer (ATR), coal gasification, offshore wind-powered electrolysers, as well as storage of hydrogen in the form of ammonia. Furthermore, they investigated the required hydrogen transport network and the seasonal storage of hydrogen. The results of the different production routes can be compared due to similar assumptions in the report.

The assessment of the potential benefits of hydrogen in the energy transition should address three main questions:

1. What is the potential for reducing GHG emissions in Europe using hydrogen?
2. What is the cost of transitioning the European energy system, from today to 2050, and beyond? Of special interest is the relative cost of transition paths with different degree of hydrogen utilization and other paths with no use of hydrogen.
3. What is the viability of energy transition paths? Relevant parameters for assessing the viability are technology readiness and possible deployment rates, policy and regulatory risks and barriers, technology safety and social acceptance.

In the following, we will give a summary of the main assessment results of the Hydrogen for Europe pre-study, in accordance with the questions above.

1.1 The potential for reduced GHG emissions in Europe due to the application of hydrogen

Hydrogen can be produced from electricity, natural gas, and biomass where biomass includes biogas. Biomass gas is already present in the European gas network. Biomass can also be used to produce hydrogen, through gasification and reforming processes, as illustrated in Figure 1. Electrolysers are used to produce hydrogen from electricity and water. Natural gas can be used to produce hydrogen through reforming processes, either steam methane reforming (SMR) or autothermal reforming (ATR). The CO_2 produced can be captured and stored to significantly reduce the emissions from the production.

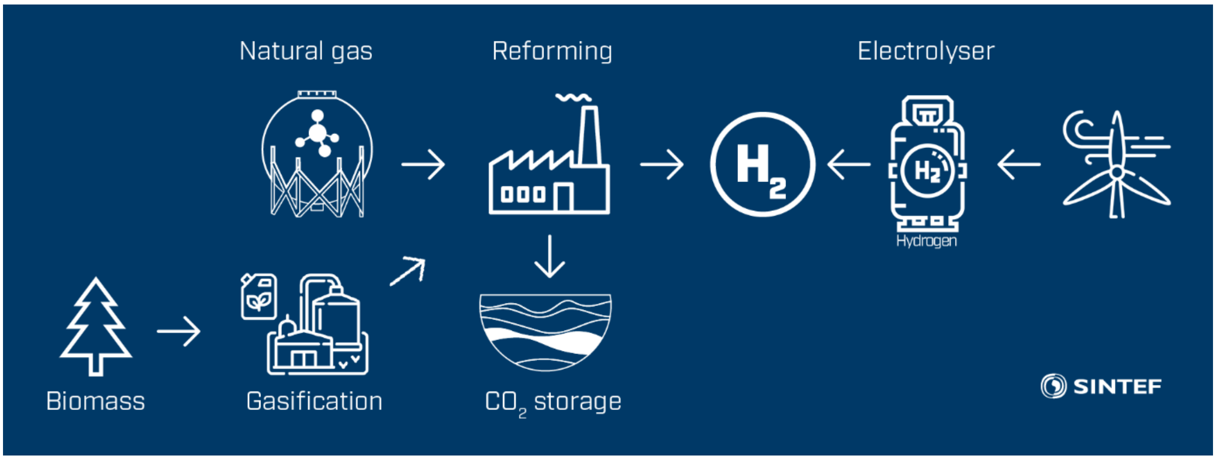

Figure 1: Hydrogen production pathways from renewable sources and natural gas.

Figure 2 compares emissions from hydrogen production from grid electricity and from natural gas with CCS. The average European grid electricity has been chosen as the source for hydrogen production through electrolysis as a simplified approach to include the emissions from the power generation. In 2016, 43 % of the energy used to produce electricity were fossil without CCS[1]. Production of renewable energy dedicated to hydrogen production could potentially affect the decarbonization rate of the European power sector until the fossil fuels used to produce electricity have been replaced by renewable sources or the CO_2 produced in the electricity generation is captured and stored. A future study should develop an increased knowledge about the effect of dedicating renewable energy to hydrogen production and how this affects the decarbonization of the power sector that differs across Europe and is predicted to have an increased demand.

As seen in Figure 2, emissions related to hydrogen production have been compared for three points in time. The result for 2016 is based upon an average European CO_2 emission intensity of 296 kg CO_2 per MWh[2] with a corresponding emissions rate of 393 g CO_2 per kWh (based on the higher heating value) of produced hydrogen[3]. This is 7.7 times higher than for hydrogen produced from natural gas with CCS, where up- and mid- stream CO_2 emissions have been included.

Outlooks from "A Clean Planet for all"[4] and IRENA's "Renewable Energy Prospects for the European Union"[5], give a corresponding ratio in the range of 5.3 to 5.6 for 2030, compared to 7.7 for 2016. Hence it is reasonable to assume that well beyond 2030 the hydrogen with the lowest carbon intensity would be produced from natural gas with CCS.

The estimate for 2050 is made from the most ambitious scenario presented in "A Clean Planet for all" which reaches climate neutrality in 2050. It shows that by this time, the carbon footprint of electricity pro-

[1] Source: Energy statistical datasheets for the EU countries from Eurostat
[2] EEA CO_2 emission intensity; accessed on 31.05.2019
[3] Assuming production of hydrogen with a final state of 20 bar.
[4] All scenarios have a similar grid intensity of approximately 168 kg CO_2/MWh grid intensity in 2030.
[5] REmap case, which assumes a grid intensity of 177 kg CO_2/MWh in 2030.

duction is small enough to produce hydrogen with least emissions. The precise timing for this transition is uncertain and will depend on the pace of deep decarbonization of the grid post 2030. This pace could be affected by the future deployment rate of hydrogen and the sources it is produced from as e.g. high shares of hydrogen from renewably produced electricity increases the total electricity demand. Further details about the estimates presented in Figure 2 is presented in Section 2.2.

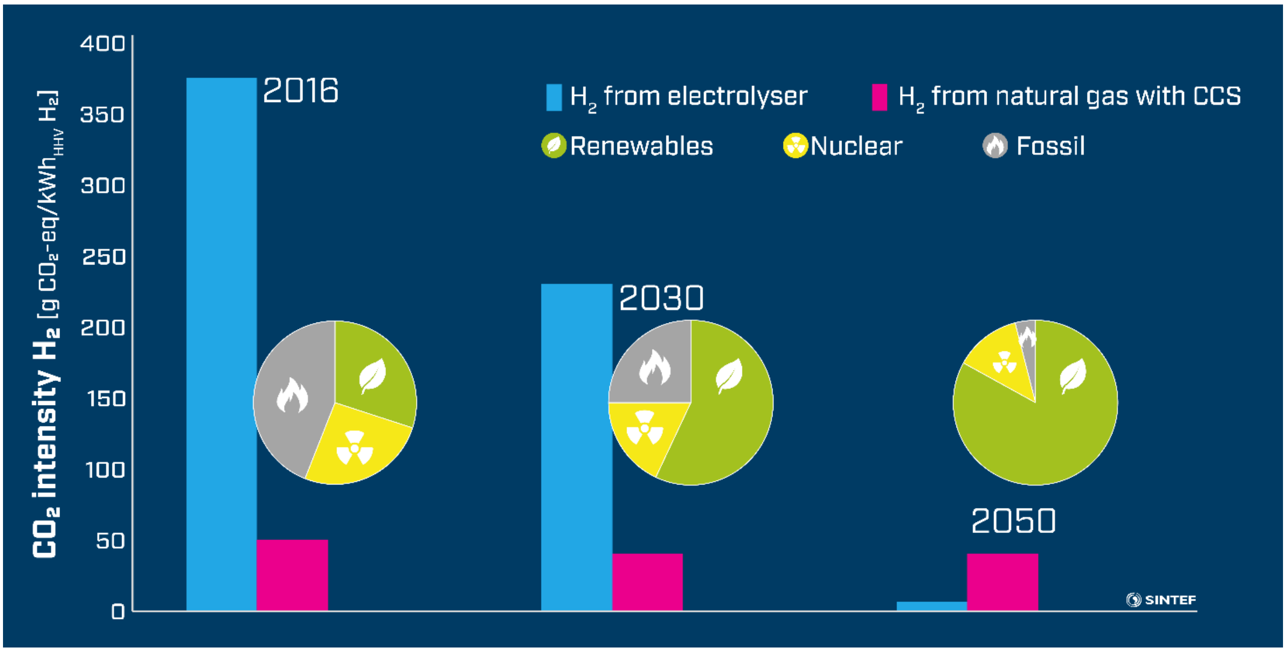

Figure 2: Comparison of the CO_2 intensities of hydrogen production using electrolysers and grid electricity (blue bars) and natural gas with carbon capture (pink bars). The pie charts illustrate the desired electricity mix according to the REmap case for 2030 and the decarbonised scenarios from "A Clean Planet for all" for 2050.

Figure 3 presents upper limits for reduction of European CO_2 emissions by replacement of fossil fuels with hydrogen from natural gas with CCS in the power, residential and commercial, transport and industry sectors by 2050. The estimates are based on IEA statistical energy information, the European Commission's Baseline forecast for 2050 of "A Clean Planet for all", and outlooks from Hydrogen Roadmap for Europe. For each sector, the potential for hydrogen to replace the use of fossil fuels has been evaluated. For example, in the transport sector, only heavy-duty road transport and rail has been considered, in heating of building stock it has been assumed that hydrogen can be used to replace all use of fossil fuels. A forecast of the degree of deployment within each sector has not been included in the estimate, with the exception of the power sector, where a modest deployment has been assumed due to the expected future increase of electricity produced from renewable energy sources. This has been done to allow readers to perform individual assessments of deployment rates for each of the sectors.

Further details about the development of the potential for emissions reductions per sector can be found in Section 2.3.

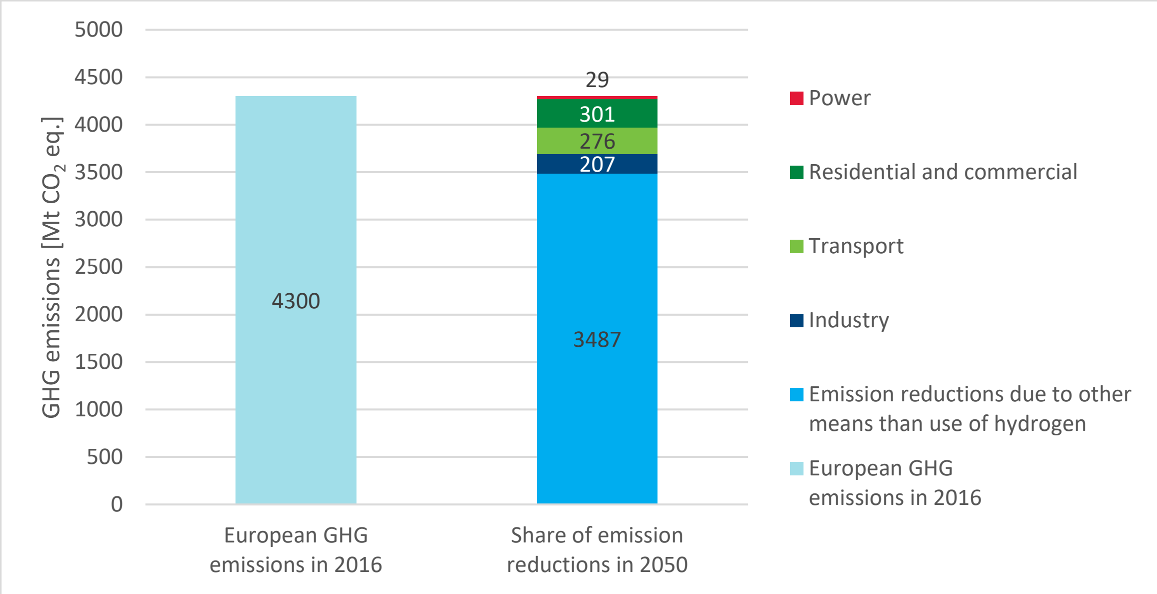

Figure 3: Estimated upper bounds for annual emission reductions in Europe due to the use of hydrogen from natural gas with CCS to replace fossil fuels. The estimated use of hydrogen is based upon predicted energy demand per sector in 2050 with a corresponding annual potential of 19% reduction of Europe's current GHG emissions.

The assessment showed that the hydrogen potential is within the limits of the volume of hydrogen that can be produced from the natural gas currently consumed in Europe. The corresponding total annual GHG removal by 2050 was estimated to 813 Mt CO_2 eq., or 19% of current GHG emissions in Europe.

A full overview of potential GHG emission reductions for different combinations of hydrogen sources should be derived in a future study.

1.2 The cost of the energy system transition, from today and until 2050 and beyond

Currently, "A Clean planet for all" is the most comprehensive study on the European energy system transformation. The study presents comparisons of overall costs of the selected scenarios. However, production of hydrogen from biomass and natural gas with CCS is not included. Hence, the relative costs of the transition paths that include hydrogen from natural gas with CCS have not been estimated.

The two scenarios of the Hydrogen Roadmap Europe include the use of hydrogen. However, the study does not contain any information on the relative cost compared to other viable pathways to decarbonization.

The H21 North of England project has focused on a specific geographical area and is therefore not readily applicable to the rest of Europe due to e.g. differences in sectorial energy demands, natural gas storage and distribution system and available storage sites for CO_2. The data available in the report largely covers the need for technical information on hydrogen production and transport, including transport and storage of CO_2, which is useful for a future European-wide study.

One observation made in the current pre-study is that hydrogen production from natural gas using CCS could be integrated into industrial clusters. This could

- Increase the volume of CO_2 transported from the cluster to the storage location. If the cluster contains industries that can only be decarbonized with CCS, the additional volumes of CO_2 could provide economies of scale benefits and reduce the CCS unit costs.
- Provide two ways to decarbonize the industrial cluster – hydrogen and direct implementation of CO_2 capture at the industrial plant.
- Decarbonization of building stock heating, transport sector, power sector and other industrial plants through distribution of hydrogen in the network infrastructure.

A future study should assess whether such an integration of hydrogen production into industrial clusters has the potential to reduce the cost of decarbonization. Such a study should also investigate possible technology lock-out effects for hydrogen and CCS caused by limited technology investments in an early phase and the possible impact on overall costs of decarbonization.

In conclusion, no current studies have examined the comparable costs of viable paths to decarbonization such that it is possible to assess the potential for hydrogen in Europe. However, our overview shows that most of the data needed to conduct such a study are available. Additional information is mainly needed on the cost and efficiency of hydrogen appliances. A future study should also investigate the sensitivity of the estimated costs to the expected consumption costs for natural gas, biomass and electricity.

1.3 The viability of the energy transition paths

A "Clean Planet for all" included substantial information on the necessary deployment of technologies for the selected scenarios. The results are however to a limited extent investigated in terms of feasibility of these technologies e.g. technology maturity and realistic deployment rates.

The "Hydrogen Roadmap Europe" included an estimate of the investment and the technology needed to reach the development assumed in the scenarios. In both scenarios, the projections are based on a given set of market developments for the transport, industry, building stock heating and industry sectors. However, an in-depth discussion on the realism of the scenarios is not presented.

H21 North of England study assessed the feasibility of providing the electricity capacity required for hydrogen production. Within the H21 North of England project, it was concluded that the necessary installation of 18.4 GW electrolysers would not be feasible in the desired timeframe, even if large companies like ThyssenKrupp deploy their concept to a full extent. On the contrary, natural gas-based hydrogen production could be installed at this level within a limited time frame, due to a mature industry and the large-scale production of natural-gas based hydrogen in the chemical industry. The conversion of the natural gas grid and the domestic and industrial heating sector is, according to the report, ambitious, but achievable.

Based upon the current findings, there is a need to better understand the feasibility of deployment rates of hydrogen appliances as well as technologies related to hydrogen production and energy storage concepts such as batteries and large-scale hydrogen storage.

In addition to the technical viability of hydrogen deployment cases, barriers to the use of hydrogen from natural gas has been investigated in the current pre-study. The results of the HyLaw project were the main source of the investigation. It was found that many of the barriers to hydrogen deployment result from regulatory gaps caused by a lack of harmonization of rules and approaches at European level. However, EU legislation increasingly refers directly to hydrogen and has a major impact on the deployment of hydrogen technology, especially on the use of hydrogen as a fuel.

In all EU countries barriers are present but their severity varies. In any case, actions are necessary to unlock the full potential of hydrogen technologies in all countries and at EU level. Relevant authorities should review technical and gas composition rules to establish legal pathways to support Power-to-Gas operations and increase hydrogen use in transmission and distribution gas networks.

It is essential to carry out a coordinated EU wide review of the safety and technical integrity limitations for the injection of hydrogen into the gas grid. A more comprehensive overview of barriers is presented in Section 2.6.

1.4 References

- **A Clean Planet for all** by the European Commission (2018).
  https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2050-long-term-strategy
- **Hydrogen Roadmap Europe** by FCH-JU (2019)
  https://fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
- **H21 North of England** (2018)
  https://www.northerngasnetworks.co.uk/event/h21-launches-national/
- **Energy statistical datasheets for the EU countries** from Eurostat (2018)
  https://data.europa.eu/euodp/data/dataset/information-on-energy-markets-in-eu-countries-with-national-energy-profiles
- **Renewable Energy Prospects for the European Union**, IRENA, 2018
  https://www.irena.org/publications/2018/Feb/Renewable-energy-prospects-for-the-EU
- **HyLAW project,** Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications. Grant agreement No 737977. End Dec. 2018
  www.hylaw.eu
- **Global headline energy data** from IEA (2016)
  https://www.iea.org/statistics

2 Details on the potential for hydrogen in Europe from the pre-study

2.1 The climate change challenge and European status

The average global surface temperature is used as a key indicator to measure the state of our climate. In 2018, the average temperature was 0.97 °C above the pre-industrial level[6]. From 2015 to 2017, the average temperature was more than 1.0 °C above normal.

The Paris agreement, reached in December 2015 and ratified in November 2016, constitutes a global effort to keep the global temperature increase in this century well below 2 °C above pre-industrial levels and to pursue efforts to limit this increase to 1.5 °C.

In 2018, IPCC launched its special report on the impacts of global warming of 1.5 °C above pre-industrial levels. The report presents scientifically based information on the global benefits of limiting the global average temperature to 1.5 °C, and states that "Global warming is likely to reach 1.5 °C between 2030 and 2052 if it continues to increase at the current rate." Further, the report shows that the impact on sustainable development, poverty eradication and inequalities reduction would be greater if global warming were limited to 1.5 °C rather than 2 °C, provided that certain measures were taken during the decarbonization phase.

For the EU, leading the world towards climate neutrality means achieving it by 2050[7]. In 2016, total greenhouse gas emissions in Europe amounted 4300 Mt CO_2 eq., a reduction of 24 % compared 1990 emissions. As illustrated in Figure 4, this corresponds to an average reduction of 50 Mt CO_2 eq. per year over the period. With a goal set for a climate neutral economy in 2050, an average reduction of 130 Mt CO_2 eq. per year from 2017 to 2050 is required.

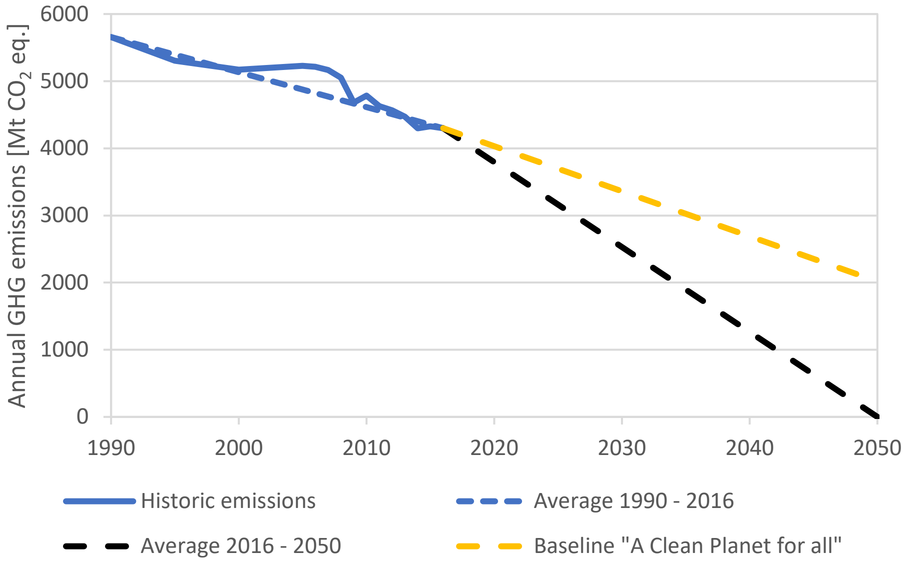

Figure 4: Total greenhouse gas emissions in EU-28 and Iceland, excl. land- use, land-use change and forestry (LULUCF) from 1990 to 2016 (source: EEA 2018) and needed reduction of emissions to reach climate neutrality in 2050.

The Baseline scenario of A Clean Planet for all, shown in Figure 4 by its emission prediction for 2050, represents the current decarbonization trajectory of EU. The scenario was included to model the GHG emission

[6] Global Climate Report - Annual 2018, https://www.ncdc.noaa.gov/sotc/global/201813. Pre-industrial level is the average global surface temperature of the years 1880 to 1900.

[7] Press release, "The Commission calls for a climate neutral Europe by 2050", November 2018. https://europa.eu/rapid/press-release_IP-18-6543_en.htm

reductions resulting from agreed EU policies and policies that had been proposed by the Commission and were under discussion in the European Parliament and Council at the time of the development of the document. The scenario results show that significant additional measures are needed to reach a goal of climate neutrality in 2050.

As presented in Figure 5, the EU GHG emissions are mainly found in the sectors of public electricity and heat generation (29 %), road transport (25 %), manufacturing industries and construction, petroleum refining, cement and steel production (20 %) and residential, commercial and institutional (15 %)[8].

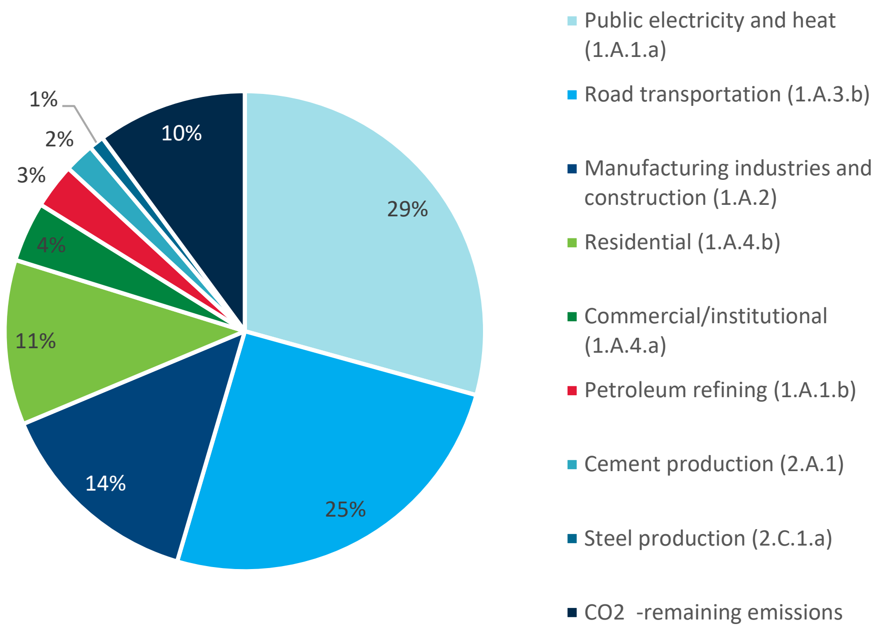

Figure 5: CO_2 emissions in EU-28 and Iceland in 2016 - share of key source categories and all remaining categories. Total CO_2 emissions amounted to 3496 Mt CO_2 in 2016. Source: EEA, 2018.

2.2 Emissions related to production of hydrogen from electricity and from natural gas with CCS

A comparison of the CO_2 intensity of hydrogen production from EU average grid electricity and from natural gas with CCS is presented in Figure 2. In 2016, the average emissions per MWh generated were 296 kg CO_2 in the EU countries[9]. Production of hydrogen from electricity with such a CO_2 intensity would result in an emission rate of 393 g CO_2 per kWh (based on the higher heating value) of produced hydrogen[10]. If the hydrogen was produced from natural gas with average European up- and mid- stream CO_2-emissions, combined with CCS, the emission rate would be 51 g CO_2 per kWh (based on the higher heating value) of produced hydrogen. This assumes 80 % conversion efficiency and a cost-effective capture rate of CO_2 at 94 %. Hence, the CO_2-emissions are 7.7 times lower for hydrogen produced from natural gas with CCS than for hydrogen produced from the grid electricity.

Outlooks from "A Clean Planet for all"[11] and IRENA's Renwable Energy Prospects for the European Union[12], give a corresponding ratio in the range of 5.3 to 5.6 for 2030, compared to 7.7 for 2016. Hence it is

[8] Data for 2016. Source: Annual European Union greenhouse gas inventory 1990–2016 and inventory report 2018 from EEA.
[9] CO_2 emission intensity, electricity generation, EEA; accessed on 31.05.2019
[10] Assuming production of hydrogen with a final state of 20 bar.
[11] All scenarios have a similar grid intensity of approximately 168 kg CO_2/MWh grid intensity in 2030.

reasonable to assume that well beyond 2030 the hydrogen with the lowest carbon intensity would be produced from natural gas with CCS.

The estimate for 2050 is made from the most ambitious scenario presented in "A Clean Planet for all" which reaches climate neutrality in 2050. It shows that by this time, the carbon footprint of electricity production is small enough to produce hydrogen with least emissions. The precise timing for this transition is uncertain and will depend on the pace of deep decarbonization of the grid post 2030. It is uncertain when hydrogen production from natural gas with CCS and electricity are equally clean. On-going efforts to reduce the CO_2 emissions up- and midstream for natural gas, as well as for the hydrogen production with integrated CCS, will prolong the period where natural gas-based hydrogen has the least emissions. These estimates are partly included, e.g improved carbon capture ratio of 96 % and a reduction in up-and midstream emissions of methane of 33 %[13] for the emissions in 2030 and 2050 in line with the first collective methane target for member companies of the Oil and Gas Climate Initiative. Furthermore, the presented emissions only include direct emissions of electricity generation. Indirect emissions in the electricity sector (e.g. construction) are not accounted for in this picture.

2.3 The potential for hydrogen in Europe – the pre-study estimate

The estimated potential for hydrogen in Europe, as presented in Section X have been made using statistical energy information from IEA, the baseline predictions for 2050 from "A Clean Planet for all" by the European Commission, and outlooks from Hydrogen Roadmap for Europe. The estimates have been made with as few assumptions as possible to allow for the readers to assess the values as transparently as possible since in practice, the degree of realization of the potential will most probably be somewhat lower and it will be different for each sector.

In brief, the following assumptions have been made for each of the sectors for 2050:

Industry[14]	Clean hydrogen from natural gas with CCS is assumed to be used: • As feedstock in chemical industry, replacing the use of hydrogen from natural gas without CCS in refineries, ammonia production and production of methanol. Assumes capture of CO_2 for current demand of hydrogen and that the total consumption of hydrogen as feedstock remains constant until 2050. 282 TWh hydrogen. Annual reduction of CO_2 emissions of 60 Mt CO_2. • To produce medium- and high-grade heat, replacing fossil fuels. Assumes that 40 % of the current natural gas consumption in the industry sector is related to medium- and high-grade heat production, and that this part is replaced by hydrogen. 470 TWh hydrogen and an annual CO_2 reduction potential of 85 Mt CO_2. • To replace coal currently used for heat production in the cement industry. This corresponds to an assumption of using hydrogen to cover 40 % of today's heat demand in the cement industry. 44.8 TWh hydrogen. Annual reduction of CO_2 emissions of 15 Mt CO_2. • As reduction agent in 20 % of the steel manufacturing industry. 140 TWh hydrogen. Annual CO_2 reduction potential of 46 Mt CO_2.

[12] REmap case, which assumes a grid intensity of 177 kg CO_2/MWh in 2030
[13] Oil and Gas Climate Initiative sets first collective methane target for member companies https://oilandgasclimateinitiative.com/oil-and-gas-climate-initiative-sets-first-collective-methane-target-for-member-companies/
[14] For assumptions, see Section 4.6.1

Transport[15]	Hydrogen is assumed to replace fossil fuels in the heavy-duty segment of road transport, currently emitting 27 % of the greenhouse gases of the transport sector. The energy need for heavy-duty transport is assumed constant. Potential: 409 TWh hydrogen, with corresponding reduction of CO_2 emissions of 271 Mt CO_2. Hydrogen is also assumed to replace fossil fuels currently used in the train sector. Potential: 23 TWh hydrogen, corresponding to annual reduction of 4.7 Mt CO_2. The potential of hydrogen as maritime fuel has not been developed in the current study but should be included in further work.
Residential and commercial[16]	Hydrogen is assumed to replace fossil fuels used for heating. Assumed a reduced energy consumption of the residential and commercial sectors of 38 % and 15 % respectively. This corresponds to a reduced need for fossil fuels of -47 % and 16 % for the two sectors. Potential: 1503 TWh hydrogen, 301 Mt CO_2 annual emissions reductions.
Power[17]	Hydrogen is assumed to replace natural gas in power production. The estimate is based upon the 1.5TECH scenario of "A Clean Planet for all" and assume that 50 % of its natural gas for power production is replaced by hydrogen. Potential: 180 TWh hydrogen. A CO_2 potential of 29 Mt CO_2.

2.4 Hydrogen production from biomass as a GHG removal technology

Production of hydrogen from biomass (including biogas) with CCS is a greenhouse gas (GHG) removal technology. Using a mixture of already available biogas and natural gas as feedstock gives climate neutral or even climate positive hydrogen within the next years. Biomass is however a limited resource due to area limitations and the need for food production. Knowledge on the exact potential for biomass available for hydrogen production is scarce due to competing application areas like biofuels, heating, and power generation.

To illustrate and provide an example of the scale of possible hydrogen production, it is assumed that 20 % of the total amount of biomass in the Baseline scenario of "A Clean Planet for all" can be used. All other scenarios in "A Clean Planet for all" (except for 1.5LIFE-LB) assume significantly higher energy available from biomass (12-49 % more than Baseline). This indicates, that the potential for hydrogen from biomass could be higher.

In order to estimate the scale of the captured CO_2 relative to the needed EU efforts to remove of CO_2 from the atmosphere, a rough assessment has been made. The estimated production of hydrogen from biomass with CCS results in removal of CO_2 from the atmosphere of 147 Mt CO_2 per year in 2050[18]. This would cover approximately 57 % of the demand for CO_2 removal in the 1.5 °C Technical scenario (1.5TECH) of "A Clean Planet for all". This is the 1.5 °C scenario with significant BECCS. Additional removal could potentially be obtained through e.g. CCS combined with biomass currently used for power generation or direct air capture with storage of CO_2. The estimate thus indicates that the volumes of CO_2 that must be removed from the atmosphere annually by 2050 to reach a climate neutral economy in EU are feasible and hydrogen produced from biomass with CCS could play a key role.

[15] For assumptions, see Section 4.6.2
[16] For assumptions, see Section 4.6.3
[17] For assumptions, see Section 4.6.4
[18] Assuming 80 % energy efficiency from biomass to hydrogen, a CO_2 intensity of biomass of 0.4 kg CO_2/kWh, and a carbon capture ratio of 93 %.

2.5 A scenario for future production of hydrogen from natural gas, electricity from renewables and biomass

Figure 5 shows indicative hydrogen production from natural gas, natural gas with CCS, biomass and CCS, and electrolysis using renewable power – detailed pathways should be developed in a future, more comprehensive study. The scenario indicates how hydrogen from the different sources can support the development of a large-scale market for hydrogen, rather than being competitors.

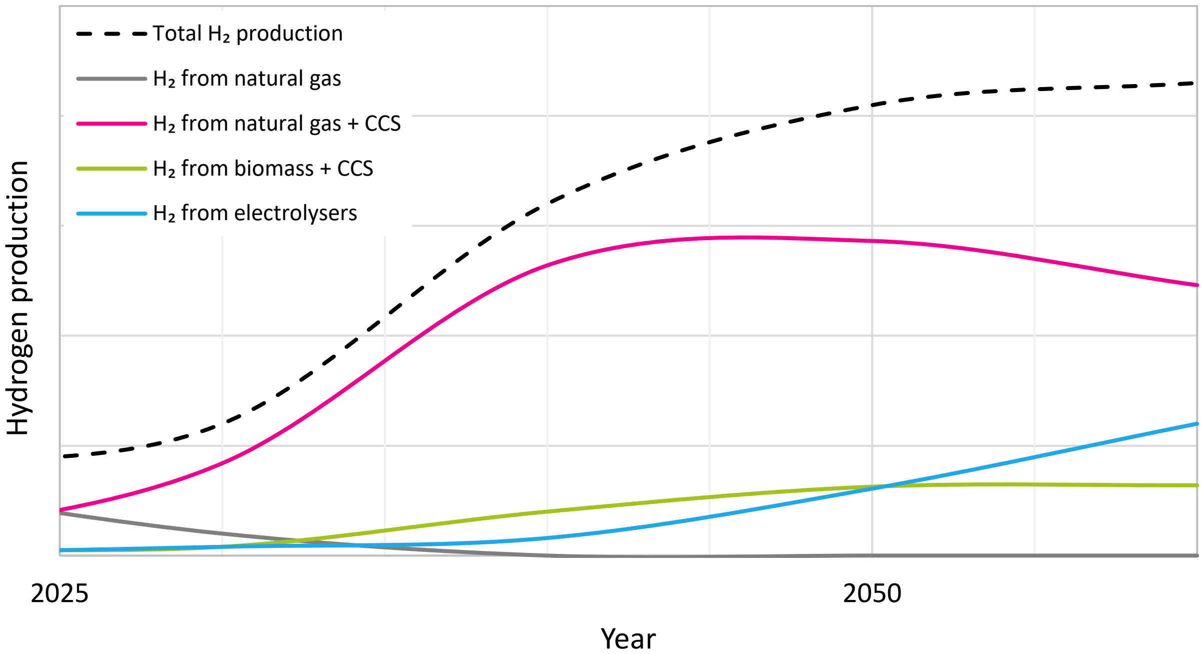

Figure 6: Scenario for future production of hydrogen from natural gas, electricity from renewables and biomass.

According to the Hydrogen Roadmap Europe, 325 TWh of hydrogen was produced in Europe in 2015. Fossil fuels as feedstock dominate the world market as 96 % of hydrogen is produced by fossil sources (IEA, 2015). Natural gas accounts for 48 % of the total production volume, electrolysis to 4 %. It is thus assumed that all hydrogen initially is produced from unabated natural gas (grey curve). The volumes of hydrogen produced from natural gas with CCS (pink curve) must be seen in relation to the current consumption of natural gas and the potential for hydrogen as outlined in Section 1.1 and section 2.3. In 2016, Europe consumed 4435 TWh natural gas. To give an indication of potential scale, if all this natural gas was replaced with hydrogen produced from the natural gas with CCS, a total amount of 3562 TWh of hydrogen could be produced and the European emissions could be reduced by 875 Mt CO2 per year. The potential for hydrogen presented in Section 1.1 implies an annual consumption of 3050 TWh of hydrogen. In Figure 6, it is assumed that hydrogen from natural gas with CCS covers approximately half of the potential for hydrogen in 2050.

The availability of the biomass, as presented in Figure 5, is based upon the Baseline scenario of "A Clean Planet for all". As described in Section 2.4, biomass is a limited resource and there is a scarce knowledge on the exact potential for biomass available for hydrogen production. The estimate presented in Figure 6 is made according to our best knowledge, and to illustrate and provide an example of the scale of production assuming that 20 % of the total amount of biomass in the Baseline scenario can be used for hydrogen production. All other scenarios in "A Clean Planet for all" (except for 1.5LIFE-LB) assume significantly higher energy available from biomass (12-49 % more than the baseline). This indicates, that the potential for hydrogen from biomass can be higher.

Production of hydrogen from renewably based electricity must be based upon the estimated future curtailment of renewable electricity, which will be a major driver for the business model. The exact amount of curtailment is depending on power grid investments, priority dispatch, and increase in renewable power generation. Currently, the knowledge on the future development of the curtailment is scarce. In its 2030 outlook for renewable energy, IRENA predicts a curtailment of electricity generation from renewable energy sources of 2 %. However, 2018 curtailment rates in Europe are as example 4.3 % in Germany (5.4 TWh) and 6 % in Ireland and Northern Ireland (707 GWh).

It is assumed that production of hydrogen will not be economically feasible for curtailment rates at these levels due to the low utilisation time of electrolysers. The estimate presented in Figure 6 is based upon the assumption that there is a business case for hydrogen from renewably based electricity from 2040 onwards, with only smaller volumes of hydrogen being produced before this. Further it is assumed that 10 % of the electricity consumption of the Baseline scenario of "A Clean Planet for all" is used for hydrogen production in 2050. Both these assumptions are made according to our best knowledge and should be assessed more in detail in further work.

The presented scenario for hydrogen production shows that there is a potential for production of large volumes of hydrogen based upon renewable sources in the long-term but that hydrogen from natural gas with CCS is dominant in the nearer term. Currently, gasification of unconventional biomass is still on pilot scale. Further, despite increasing renewable power generation, hydrogen production from renewable power sources through electrolysis is only commercially viable in niche applications and shows limited production capacity. Hence, until the cost of these technologies is reduced, clean hydrogen can be produced from natural gas with CCS in sufficient quantities to supply a European hydrogen market and gradually replace existing production of hydrogen from natural gas without CCS. This shows that the technologies for hydrogen production are complementary instead of competing.

2.6 Barriers to the use of hydrogen from natural gas

Numerous existing European legislative acts are relevant to the deployment of hydrogen as a product and in fuel cell technologies. Some legislative acts impact hydrogen technology deployment indirectly, such as health and safety, environmental, labour and transport laws. EU legislative acts are often a source of obligations for developers and manufacturers, and the extent to which they represent a barrier to hydrogen deployment depends mainly on national implementation which differs across countries and on involuntary mismatches between rules imposed at the national level (e.g. standards for fuel quality and measurement).

Hydrogen in the gas grid

Existing legal and administrative barriers to the injection of hydrogen into the gas grid are of high severity. These barriers are of a structural type, preventing the injection of hydrogen in the gas grid and Power-to-Gas facilities.

The regulatory framework has been drawn up around natural gas, and specifically, the quality standards are based on gas calorific value, or the Wobbe Index. Adding hydrogen to the gas stream impacts calorific value, flow properties, density and flame speed as well as pipeline materials and gas grid operations.

Widely varying national limits for hydrogen concentrations in the gas grid exist in Europe, and hydrogen injection permitting is considered on a case-by-case basis (Table 2).

Table 1: Legal framework for H_2 levels in the gas grid (HyLAW project).

Legal framework 'Acceptable' H_2 level (typically mandated by legislation	**Countries**
'Minimal' H_2 concentration at **0.1 to 0.5 vol%** (reflecting typical background concentrations in natural gas)	**IT, LV; SE, UK**
'Low' H_2 concentration at **1.0 to 4.0 vol%**	**FI, AT**
'Mid' H_2 concentration at **6.0 vol%**	**FR**
'High' H_2 concentration at **up to 10.0 vol%**. The applicable H_2 threshold may fall below this, depending on down-stream consumers H_2 tolerance and other factors (e.g. underground storages, large scale gas turbines, vehicle CNG cylinders type 1/CNG refueling stations	**DE**
No formal H_2 concentration rules but based on safety limits with reference to natural gas operations	**BE, BG, DK, ES**

European coordination appears necessary to validate gas grid operation where hydrogen thresholds are significantly higher (such as in DE, FR, NL & UK). Gas Appliance Directive and Gas Appliance Regulation revision will be necessary to allow higher hydrogen concentrations in the gas grids.

Barriers in residential and commercial buildings

An EU appliance assessment at the end-user level is essential to the large-scale deployment of hydrogen.. For example, there is an identified need to define the acceptable safety and operational threshold of end-user appliances at the domestic, commercial and industrial levels.

When new investments at the end-user side are needed to use hydrogen, e.g. in appliances able to use hydrogen, a supply chain assessment of global economic impact to identify additional costs at different actors' level and targeted incentives for the deployment of hydrogen will be necessary.

High economic barriers exist for stationary power in residential and commercial buildings (micro-Combined Heat and Power - CHP) due to a lack of financial incentives.

The legal framework for permitting Power-to-Gas plant and grid connection/injection requirements between the hydrogen supplier and the gas grid operators should be included within EU regulatory frameworks to ensure comparable treatment across the EU.

Gas Appliance Regulation revision will be necessary to hydrogen tolerant gas appliances.

Barriers in the transport sector

Road vehicles face barriers mainly associated with a lack of incentive policies and infrastructure investments.

The barriers in the production, stationary storage and use of hydrogen as a fuel in Hydro Refuelling Stations (HRSs) are not negligible, because the permitting process is long, costly and uncertain due to a lack of clear rules and procedures. Only Germany, Denmark, the UK and the Netherlands currently have rules to regulate the permitting of HRSs.

A potential conflict has been identified with the gas composition of the gas grid required for fuel supply to CNG vehicles. For CNG vehicles, the hydrogen limit is maximum 2% according to UNECE regulation R1106. This means that if a CNG fuelling station is connected to the gas grid, the admissible hydrogen concentration for that local grid must not exceed 2 vol%.

Other barriers in relation with HRSs are the overlap of various responsible authorities, a lack of administrative practice, and a lack of guidance provided to operators. The permitting requirements applicable to HRSs draw on obligations established at EU level, such as risk assessments (SEVESO Directive), health and safety requirements and conformity assessment procedures, (ATEX Directive), integrated environmental obligations (Industrial Emissions Directive - IED), and environmental impact assessment procedures (Strategic Environmental Assessment – SEA and Environmental Impact Assessment - EIA Directives).

Finally, hydrogen as a fuel for road vehicles lack consistent incentive policies, affecting its large-scale deployment.

In the case of hydrogen vessels (maritime and inland waterways), major regulatory barriers were identified. Maritime and inland-waterway transport face very high legal and administrative barriers to hydrogen, such as IMO regulation aiming to reduce CO_2 emissions by 50% by 2050 and imposing a 0.5% sulphur cap on marine fuel from 2020. This could represent an opportunity for new alternative fuels including hydrogen power vessels, however, “type approval” of hydrogen fuel cell vessels remains complicated due to the absence of rules.

Hydrogen specific requirements are not yet on the agenda in the International Maritime Organization/ Carriage of Cargoes and Container (IMO/CCC). For inland vessels, Directive 2016/1629/EU empowers CESNI (Comité Européen pour l’Élaboration de Standards dans le Domaine de Navigation Intérieure) to develop standards in the field of inland navigation. It is crucial for all actors to act in a coordinated manner at the IMO level to develop specific regulations for hydrogen.

In conclusion, many of the barriers to hydrogen deployment are a result of regulatory gaps caused by a lack of harmonization of rules and approaches at the European level. A growing body of EU law references hydrogen directly, and have a major impact on the deployment of hydrogen technology, especially on the use of hydrogen as a fuel.

Across the EU, barriers are present in all countries but they exhibit varying degrees of severity. In all cases, actions are necessary to unlock the full potential of hydrogen technologies in all countries and at the EU level. Relevant authorities should review technical and gas composition rules to establish legal pathways to support Power-to-Gas operations and increased hydrogen use in transmission and distribution gas networks.

A coordinated EU-wide review of safety and technical integrity limitations for hydrogen connection and injection into the gas grid is essential.

2.7 References

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- **Annual European Union greenhouse gas inventory 1990–2016 and inventory report 2018** from EEA (2018)
  https://www.eea.europa.eu/publications/european-union-greenhouse-gas-inventory-2018
- **Energy statistical datasheets for the EU countries** from Eurostat (2018)
- https://data.europa.eu/euodp/data/dataset/information-on-energy-markets-in-eu-countries-with-national-energy-profiles
- **Hydrogen Roadmap Europe** by FCH-JU (2019)
  https://fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf
- **HyLAW project,** Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications. Grant agreement No 737977. End Dec. 2018
  www.hylaw.eu
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- **Technology Roadmap: Hydrogen and Fuel Cells** by IEA(2015)
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- **Renewable Energy Prospects for the European Union**, IRENA, 2018
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3 The Hydrogen for Europe main study

The goal of the main Hydrogen for Europe study is to evaluate how Europe's energy system can be transformed to reach EU's climate targets for 2050, and what role hydrogen could have in the transition. The scope of the study will be further set after the pre-study is completed. Below is thus a short summary of the study as proposed in June 2019. For further information about the current status on the study we refer to François-Régis Mouton[19], IOGP.

A strong focus will be on possible development paths from today and to year 2100. The selected timespan is chosen to emphasise the possibility to have a longer transition period, which could reduce the costs of the transition. The study will thus focus both on the roll-out of technologies within the selected timeframe as well as on the state of the energy system in 2050 and 2100.

Our main hypothesis is that the use of hydrogen from natural gas will enable reduction of greenhouse gas emissions at a sufficient pace to reach the climate targets with reduced costs compared to decarbonization paths that exclude such hydrogen. We aim at setting up a transparent study which as objectively as possible assesses this hypothesis. The study should include the main relevant options for energy production, as well as for CCUS technologies to make sure that the study is not disregarded because it omits highly relevant options. The objectivity is an important part of the study. SINTEF and IFPEN thus proposes to publish study results in scientific papers. By doing so, peer-review quality control of the work is performed, and the approach and analysis methodology is made available for the wider scientific community.

A central activity of the study will be to use a selected energy system analysis tool to model the roll-out of technologies and transformation of the energy system. The development of simplified models describing infrastructure and production for hydrogen and electricity will be a key activity.

[19] E-mail: frm@iogp.org

4 Hydrogen cases

Europe's energy transition is on its way. The Member States have all signed and ratified the Paris Agreement during the COP 21, committing themselves to significantly reduce their carbon footprint to keep global warming “well below 2°C”. That’s why Europe must find cleaner sources of energy in order to regulate its CO_2 emissions. In this context, EU members have all interest in considering hydrogen as a possible future energy carrier. Whether produced by electrolytic conversion of renewable energies or methane reforming coupled with carbon capture and storage (CCS), hydrogen can play a major role in many sectors, such as industry, transport, heating, or power.

The aim of the current section is to derive three different cases for hydrogen in Europe based upon already published energy transition scenarios for hydrogen. The cases will provide a reference basis for low, medium and high deployment of hydrogen. These cases will further be compared to estimated potentials for hydrogen in the industry, transport, power, residential and commercial sectors. The cases can be used as a means of comparing development costs in a study on viable paths for reducing the emissions of the European energy system. It can also be used to show the relative potential for reduced CO_2 emissions, comparing the reduced CO_2 emissions for the low, medium and high cases to the 4300 Mt CO_2 eq. that must be cut to reach carbon-neutrality in Europe.

Public and private organizations are beginning to develop energy transition scenarios in which hydrogen has a prominent place. Two of the most relevant ones have been selected and detailed in this section. These two studies were written by authors with different objectives: one was written by an EU public private hydrogen partnership and presents it as “the best or only choice for at-scale decarbonization in selected sectors”; while the other was written by the European Commission who considers hydrogen only as one of several possible decarbonization ways. However, in optimistic cases, they foresee fairly the same amount of hydrogen in the final energy mix and took similar hypotheses for the deployment of hydrogen technologies.

This section will also focus on relevant studies on hydrogen that were not selected either because they were not detailed enough or because the geographical scope was not only Europe. Finally, this section presents a pathway that needs to be followed in order to achieve the objectives set by the different studies.

Hydrogen is a source of energy for the future that can be used in 4 different sectors:

- In **industry**, hydrogen can be used either to produce high grade heat or as feedstock in the production of chemicals (ammonia, methanol, etc.). In steelmaking, H_2 can also work as a reductant, substituting for coal-based blast furnaces.
- Hydrogen will be attractive for **transport** systems in which low energy density and high initial cost of batteries could be an obstacle (e.g. trucks, buses, ships, trains). In addition, hydrogen refueling stations are much smaller and easier to install than charging stations for battery electric vehicles.
- Since neither biogas nor electric pumps will be available at required scale for the whole residential sector, Hydrogen can be a major player in **heating** where it could be blend into the existing grid without major updates.
- H_2 can contribute to the integration of renewable **energy** (REn) by stocking the surplus produced when the demand is low and also by making REn easily movable from one place to another.

Some other applications can benefit from H_2 deployment, but their energy consumption is not significant enough to be mentioned here.

4.1 Selected Scenarios

More than ten studies have been found to produce this report. However, most of them had some major weaknesses: too small or too big geographical scope, focus only on the transportation sector, not enough quantified results and so forth. After excluding irrelevant studies two of them were remaining:

- **Hydrogen Roadmap Europe by** the FCH-JU
- **A Clean Planet for all** by the European Commission

4.1.1 Hydrogen Roadmap Europe

Study presentation

Author: Fuels Cells and Hydrogen – Joint Undertaking (FCH-JU)
The FCH-JU is a public private partnership supporting research, technological development and demonstration activities in fuel cell and hydrogen energy technologies in Europe. It is composed of three members: The European Commission, Hydrogen Europe Research and Hydrogen Europe (FCH-JU associations, composed of more than 100 industry companies, 68 research organizations as well as 13 national associations).

Publication date: January 2019

Methodology

- **Step 1:** Modeling the EU energy system.
  The power mix used in the study was based on Enerdata's «green scenario». Expert interviews and McKinsey Energy Insights on energy have been used to model granular development within sectors.
- **Step 2:** Estimation of the market potential of hydrogen in several sectors.
  The estimation is based on external studies (such as the Hydrogen Council report) and on insights of members of the FCH-JU. 2 Scenarios modeled: a Business As Usual (BAU) scenario and an ambitious scenario (2°C Scenario).
- **Step 3:** Estimation of the investment and the technology needed to reach the defined goals.

Spirit of the study: FCH-JU strongly believes in the potential of H_2: "Hydrogen is the best (or only) choice for at-scale decarbonization of selected segments in transport, industry, and buildings". It claims that technology is almost ready but significant investments are needed to develop it, hence we should start right now if we want to reach the decarbonization objectives set by the EU.

The Hydrogen Roadmap Europe study is very complete and detailed. However, it has been written by promoters of hydrogen as clean energy source. Hence, its results have to be interpreted cautiously. Moreover, some very important information concerning the technology costs is missing in the document.

Results

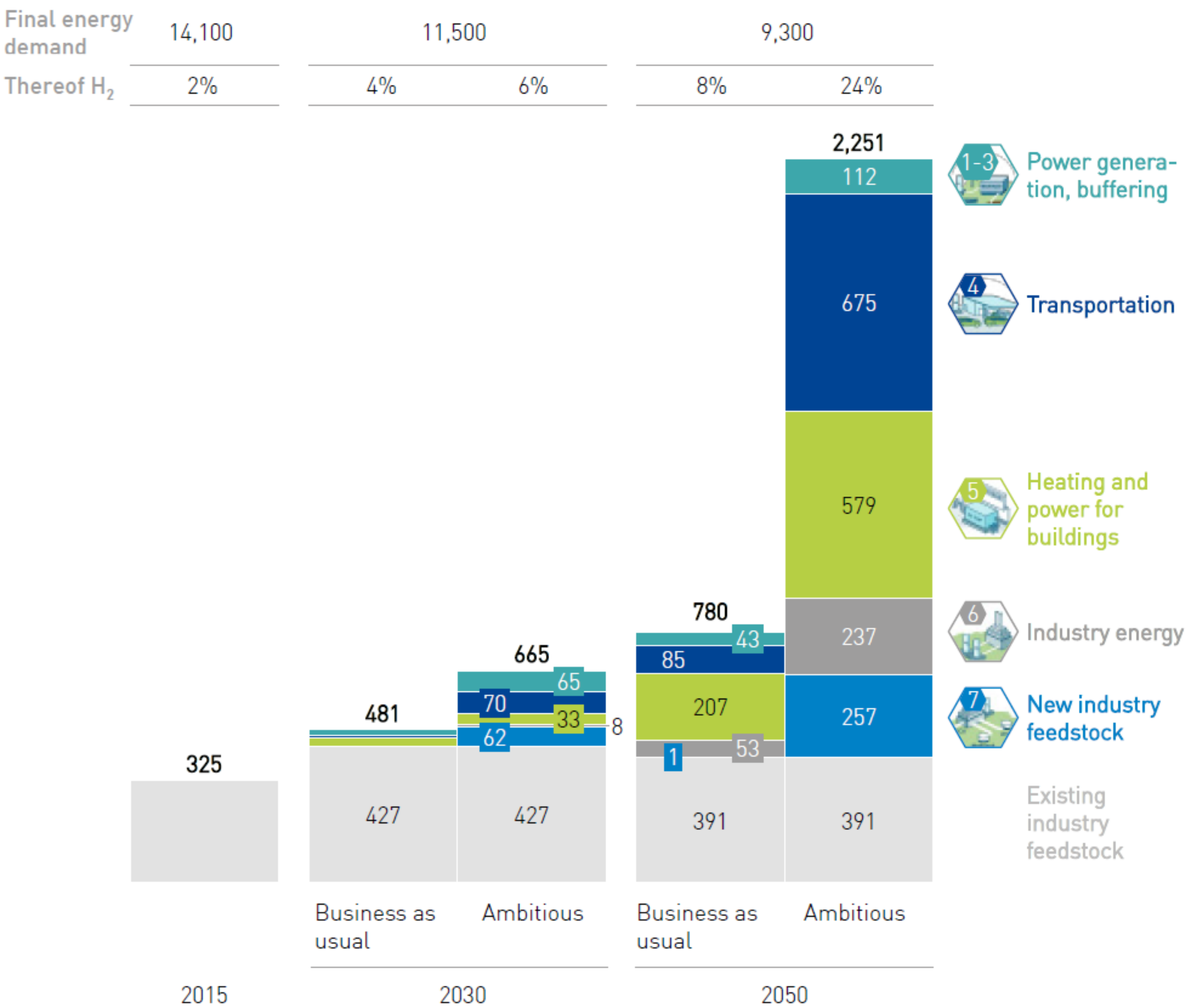


Figure 7: Hydrogen in final energy demand in TWh.

In its 2 °C Scenario (Ambitious), FCH forecasts that hydrogen will represent 24 % of the final energy demand in 2050 for a total consumption of 2,251 TWh. This increase in H_2 consumption is associated with a 33 % decrease in the final energy demand (from 14,100 TWh to 9,300 TWh).
The development of H_2 will occur in two phases:

- From 2015 to 2030: a slow start. R&D is not over yet and the technologies are not completely accepted by the mass market.
- From 2030 to 2050: massive adoption. Hydrogen technologies are completely integrated in the markets. Consumers and industry are ready to use them.

Transportation (30 % of the final energy demand in H_2), heating (25 %) and industry (40 %) will be the main beneficiaries of the hydrogen development. The evolution of these sectors will rely on a €70 billion investment by 2030 (no data for 2050) that will be divided in several segments:

- 40 % for infrastructures in production and distribution (electrolysers and SMR) (€ 28 billion)
- 25 % for distribution and retail in transportation, heating and industry (€ 17.5 billion)
- 15 % for the development of new FCEV (€ 10.5 billion)
- 20 % "others" (€ 14 billion).

The FCH doesn't give a clear statement about technologies for hydrogen production but thinks that policy makers should focus on both electrolysers (for renewable power integration) and SMR (a mature technology that will be needed in industry).
All these investments would engender a global value of €800 billion and create 5.4 million jobs.
Although the Business As Usual (BAU) scenario is less ambitious, it still forecasts a 8 % share of H_2 in final energy demand (780 TWh) in 2050.

The BAU Scenario foresees that CO_2 emissions will almost be divided by 2 between 2015 and 2050 (from 3356 Mt to 1841 Mt). An additional 562 Mt of CO_2 can be avoided by following the ambitious pathway. This would represent a 78 % reduction of GHG emissions compare to 1990 (the European reference for GHG emission level).

Hydrogen deployment

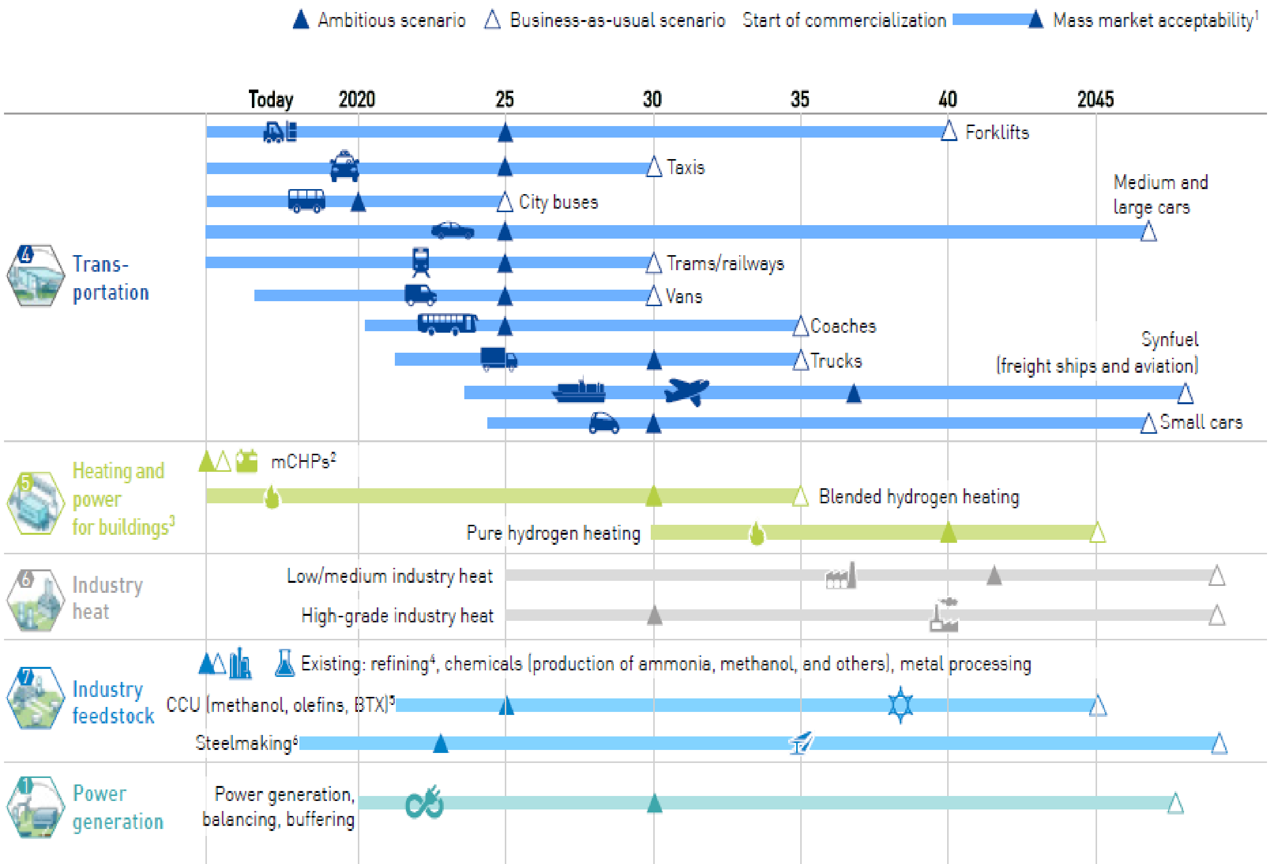


Figure 8: Hydrogen technology acceptability.

Figure 10 shows the pace of adoption of the hydrogen technologies for various sectors. It let us think that the ambitious scenario will require a very fast acceptability of H_2 services and huge investments in very short time. Some of the hypothesis that are made, look unreachable (mass market acceptability of large cars in 2025? of hydrogen heating in 2030?) which makes the ambitious scenario more or less undoable.
Table 2 shows some example of results FCH get for different sectors in the ambitious scenario.

With the current trends of the H_2 market, BAU scenario seems more realistic. However, some hypothesis also looks pretty ambitious. Globally, the feasibility of both scenarios will rely on political actions in favor of hydrogen.

It is interesting to note that there are very few economic hypotheses that are written down in the report. One can assume that they are “included” in the mass market acceptability

Table 2: Numeric results of the FCH study for several sectors.

	2030	**2050**
Transport	4.2 million FCEV 45,000 FC trucks 570 FC trains	42 million large FCEV 1.7 million FC trucks 5,500 FC trains
Heating	2.5 million households	52 million households 10 % of building power demand
Industry		20 % of high-grade heat process 8 % of medium 5 % of low 20 % of crude steel 30 % of methanol produced with H_2
Power	25 TWh of surplus renewable electricity stored in the form of hydrogen	58 TWh of surplus renewable electricity stored in the form of hydrogen

4.1.2 A Clean Planet for all

Study Presentation

Author: European Commission (EC)
The report presents the multiple pathways that the EC have created to respect the Paris Agreement.

Publication Date: November 2018

Methodology:

- The European Commission has used **the** model Primes that they developed to forecast the demand of energy in several sectors[20].
- The EC has developed 9 different scenarios. Each highlights a different energy carrier (Electrification, H_2, Power-to-X) or a different way of consuming (Energy Efficiency, Circular Economy) that could reduce drastically the CO_2 emissions. In our case, only the H_2 scenario and the baseline scenario will be studied.

Spirit of the H_2 scenario: The H_2 Scenario examines the impacts of switching from the direct use of fossil fuels to hydrogen. It assumes timely deployment of the necessary hydrogen infrastructure and distribution of hydrogen via the gas grid.

[20] https://ec.europa.eu/clima/sites/clima/files/strategies/analysis/models/docs/primes_model_2013-2014_en.pdf

Although it is less detailed than the FCH study, the European Commission proposes a fairly similar hydrogen vision. However, scenario H_2 is only one of the scenarios considered by the EC and the place of hydrogen in the other cases is very small.

Results

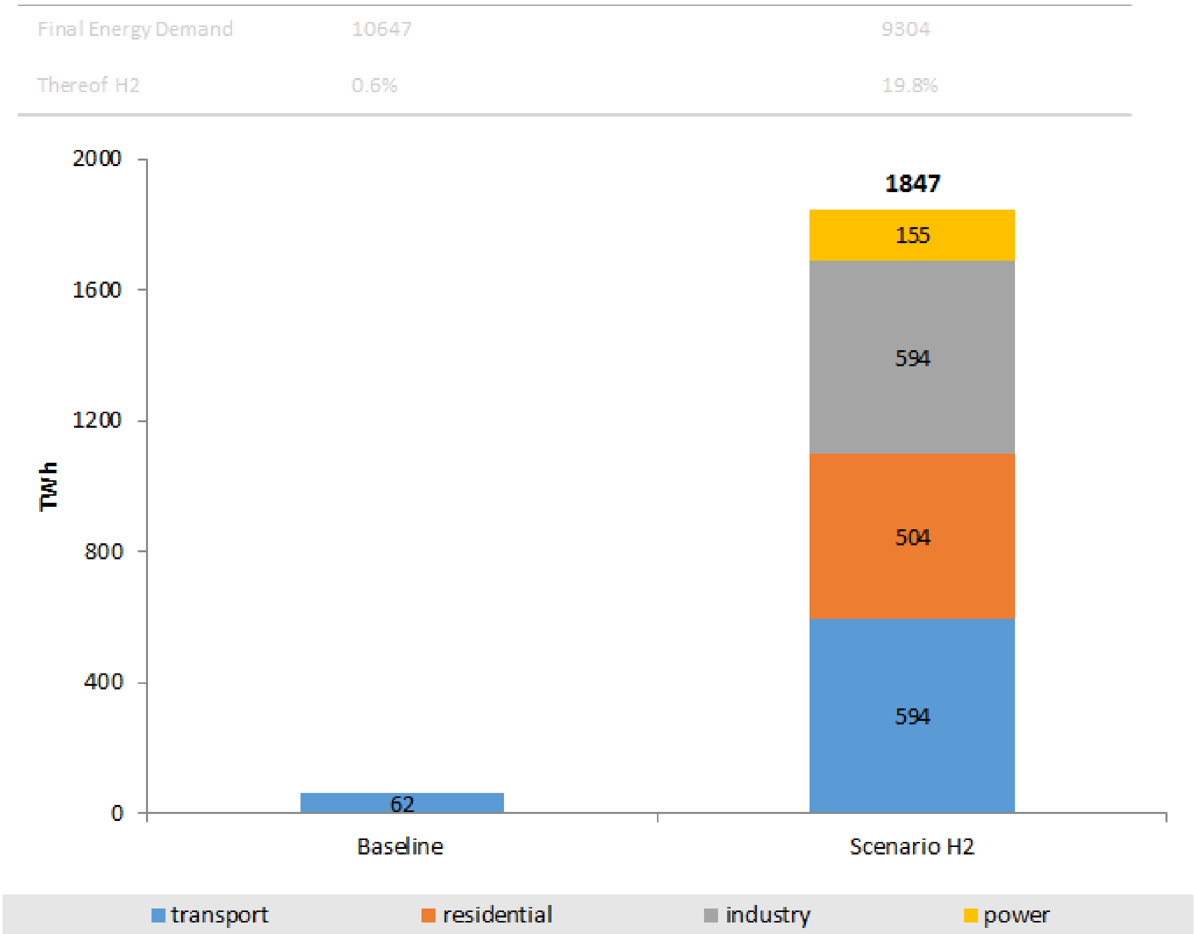


Figure 9: Hydrogen in final energy demand.

In its H_2 Scenario, The European Commission forecasts that hydrogen will represent 20 % of the final energy demand in 2050 for a total consumption of 1,847 TWh. As in the FCH study, this increase in H_2 consumption is associated with a 33 % decrease in the final energy demand.

Transportation (32 % of the final energy demand in H_2), heating (27 %) and industry (32 %) will be the main beneficiary of the hydrogen development. According to the EC, the development of this scenario will require an investment for all energy sectors of €1,361 billion. It is interesting to note that, due to the high expenditures required for fuel cell vehicles, H_2 is the scenario that needs the higher investments.

The H_2 scenario belongs to the “well below 2 °C” ambition which mean that it could reduce the GHG emissions of 80 % compared to 1990.

The H_2 scenario assumes a faster learning for fuel cells and the large-scale availability of hydrogen refueling stations that will lead to higher uptake of fuel cell drivetrains to the detriment of plug-in hybrids. This will result in hydrogen accounting for 21 % of the transport energy demand and fuel cell vehicles representing:

- 16 % of total car stock
- 42 % of the light vehicles
- 13 % of the heavy duty

The European Commission makes a few more assumption about H_2 deployment:

- The scenario assumes timely deployment of the necessary hydrogen infrastructure and distribution of hydrogen via the gas grid
- H_2 is assumed to be produced within EU
- The scenario assumes a high renovation rate of the buildings.

The Baseline scenario describes a very small development of hydrogen (62 TWh). Only the transportation sector through FCEV will consume some hydrogen in 2050. Although a little pessimistic, this perception of things could be the more accurate if no effective decisions in favor of hydrogen are taken.

4.1.3 Scenario comparison

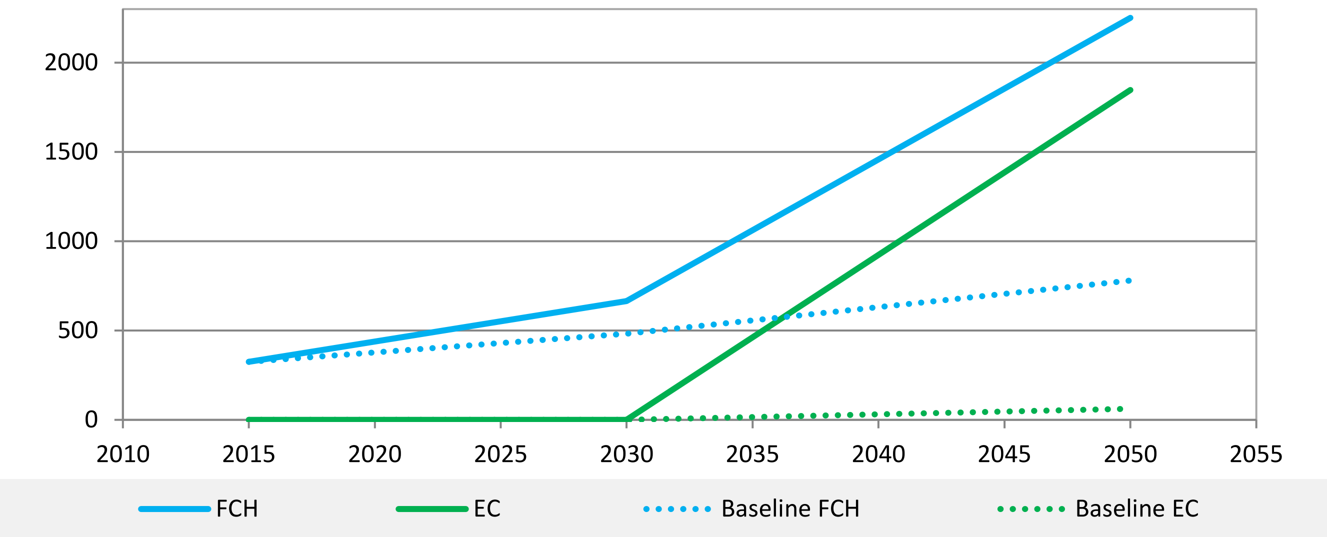


Figure 10: Final energy demand of hydrogen.

Even if the FCH study is more optimistic, both have fairly similar visions concerning the trajectory of evolution of H_2. H_2 will be a minor energy until 2030 but will boom to reach 24 % (FCH) or 20 % (EC) of the final energy demand in 2050.

Figure 12 confirms that the baseline scenario in the FCH study is very optimistic (H_2 represents 10 % of the final energy demand) and that the European Commission baseline scenario is more in line with a non-development of H_2 (0.6 % of the final energy demand)

The other numerical results are hard to compare because the way of presenting figures is different (for investment, GHG emissions…).

Concerning the sectorial repartition, Figure 13 shows that, even if the FCH favors a bit more industry, both scenarios have very close repartition of H_2 in the different segments.

The studies also agree that no production technology (SMR vs. electrolysers) will have a clear advantage over the other and their development will mainly depend on the sector H_2 is used in. However, they both claim that blue hydrogen will be cheaper than green hydrogen and might be a bit more used to produce H_2.

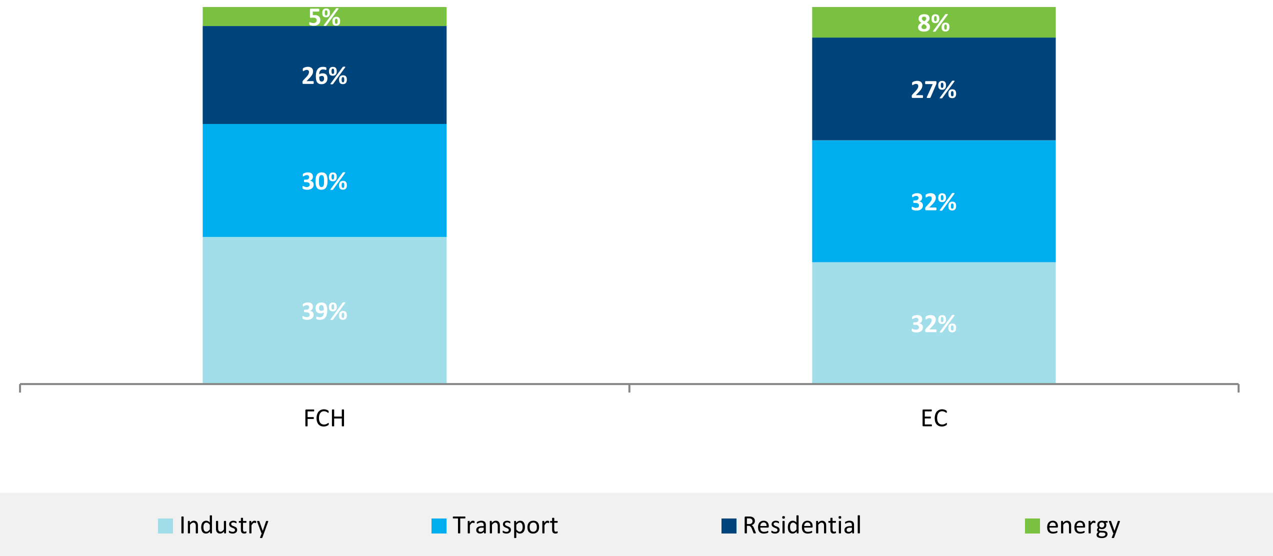


Figure 11: Sectorial repartition of hydrogen energy consumption in 2050.

To conclude, it seems important to recall that, although the studies have the same view on H_2, they are both very optimistic and rely on very ambitious hypothesis (a very fast readiness, deployment and acceptability of H_2).

4.1.4 Synthesis

Author	FCH	EC
Publication date	January 2019	November 2018
Data source	Enerdata Hydrogen council McKinsey	Primes
Final H_2 Consumption	**2,251 TWh**	**1,840 TWh**
Hydrogen share in 2050	**24 %**	**20 %**
Main segment of development	• Industry, Transports, residential	•Industry, Transports, residential
Scenario Advantage	• Very detailed study • Written by H_2 experts • Clear roadmap to get to the fixed objectives • Quantified environmental and value objective • Respect the 2 °C of the EU	•Very Serious Study •Possibility to compare the scenario with other decarbonation path-ways •Clear methodology •«unbiased writer»
Scenario Disadvantage	• Written by a public private part-nership • Not enough data on the cost reduction considered • Too ambitious scenario and hy-potheses • Very optimistic	• Not enough data on the cost reduction considered • Less detailed • It would be interesting to have a special focus on hydrogen now
Final view	These scenarios have a similar mindset and although the FCH scenario is a bit more optimistic. The development of hydrogen follows the same path-way in both studies.	

SINTEF

4.2 Unselected Scenarios

In addition to the two pathways that have been detailed, more scenarios have been found. These scenarios were interesting but all of them had major weaknesses. Among them, the Hydrogen Council study was of major interest, but its geographical scope was not correct for us (world vs Europe).

All the unselected scenarios will be detailed in the following section.

4.2.1 Hydrogen Scaling-up

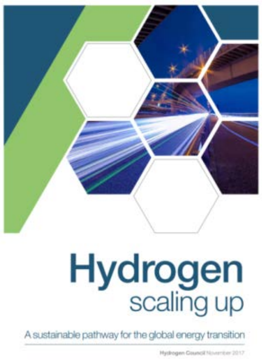
Presentation of the study

Author: Hydrogen Council
Group of 39 companies within energy, transport and industry who are working together to promote hydrogen as a key component of the energy transition.
Main members: Air Liquide, BMW, Royal Dutch Shell, Bosch…

Publication Date: November 2017

Methodology:

- Chapter 1: Presentation of the vision of the hydrogen council.
  Description of the potential of hydrogen technology, considering it as an enabler in the energy system as well as an energy vector for a wide range of applications in transport, buildings, and industry.
- Chapter 2: Describing the roadmap to achieve this vision in 2050.
  To quantify it, two main sources have been used: the IEA Energy Technology for the sectorial demand and hydrogen council members inputs for the potential of hydrogen.
- Chapter 3: Estimation of the investment and the technology needed to reach these goals.



Spirit of the study: The Hydrogen Council strongly believes in the potential of H_2: “We, the members of the Hydrogen Council, are convinced that hydrogen can offer economically viable, financially attractive, and socially beneficial answers to the challenges of transitioning to low-carbon energy and improving air quality in cities”
It also claims that the required technology is ready and that it’s time to deploy hydrogen.

Main limitation of the study: the scenario described in the study only examines hydrogen on a global level and do not regionalize its results. However, it is possible to see that this study has a very close mindset that the *Hydrogen Roadmap Europe* and presents similar results. It seems a little more ambitious on some aspects (the pace of hydrogen deployment and the revenues generated by the sector for instance). On the other hand, they suggest a lower share of hydrogen in the final energy mix.

Beyond the results, the two studies seem very connected. Approximately 30 % of the stakeholders belong to both Hydrogen Council and FCH-JU what let us think that the “insights for members” could be more linked than imagine. Moreover, the FC-JU directly quotes Hydrogen Council as source in its publication which suggests a wide interaction between the two groups.

Results

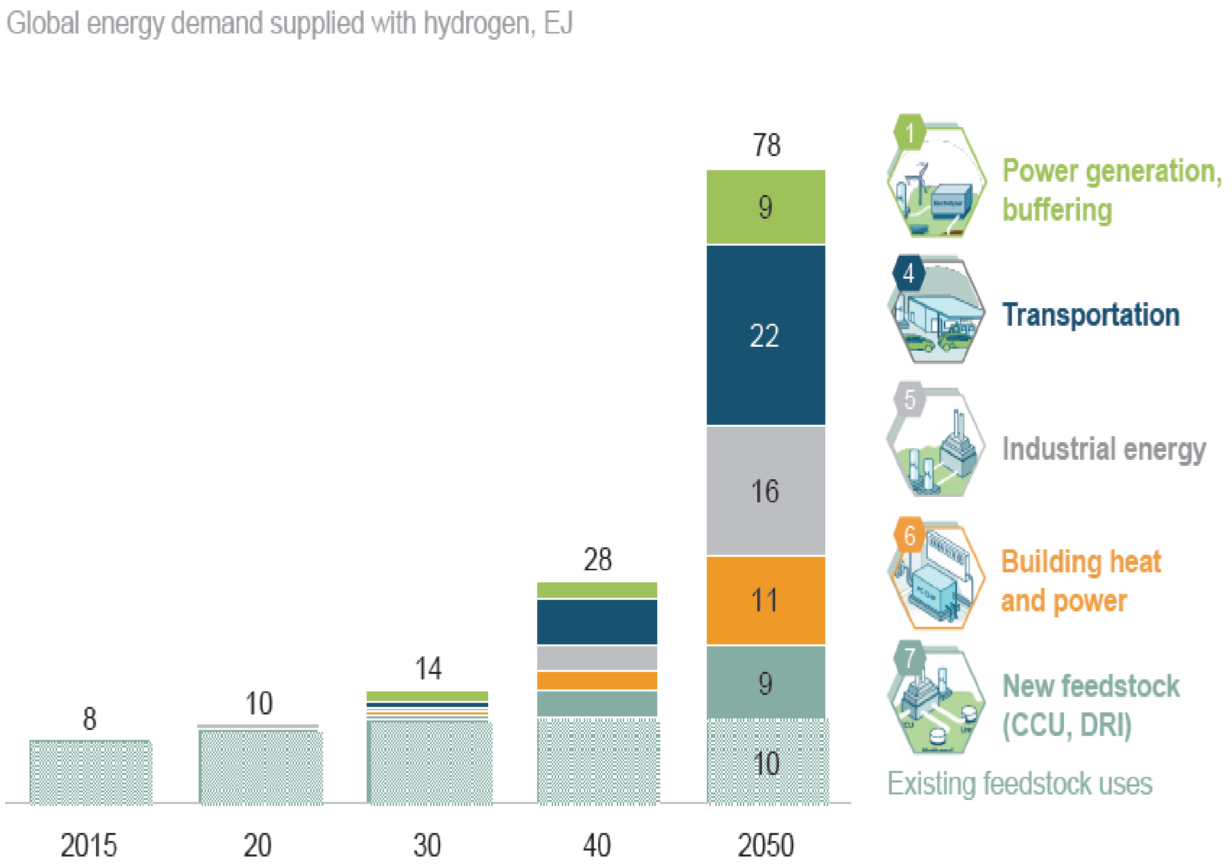


Figure 12: Hydrogen in final energy demand.

The Hydrogen Council forecasts that hydrogen will represent 18 % of the world final energy demand in 2050 for a total consumption of 78 EJ (21,684 TWh). Europe[21] would then represent approximately 10 % of the global demand in H_2.

The sectorial repartition of H_2 is a bit different in this case. Two sectors will benefit the most from the development of H_2: Industry (45 % of the final energy demand in H_2) and transportation (30 %). This could be explained in that case by the industrial production mainly located outside Europe.
The development of these segments will require a global investment of €280 billion and it would create a value of €2,500 billion and 30 million jobs.

The H_2 development is the same as for Europe: a slow start until 2030, followed by a massive adoption by 2050.
The Hydrogen Council foresee that H_2 would reduce annual CO_2 emissions by roughly 6 Gt compared to today and meet roughly 20 % of the abatement to reach the two-degree scenario.

[21] All the mentions of Europe in this section refers to the results of the FCH-JU study

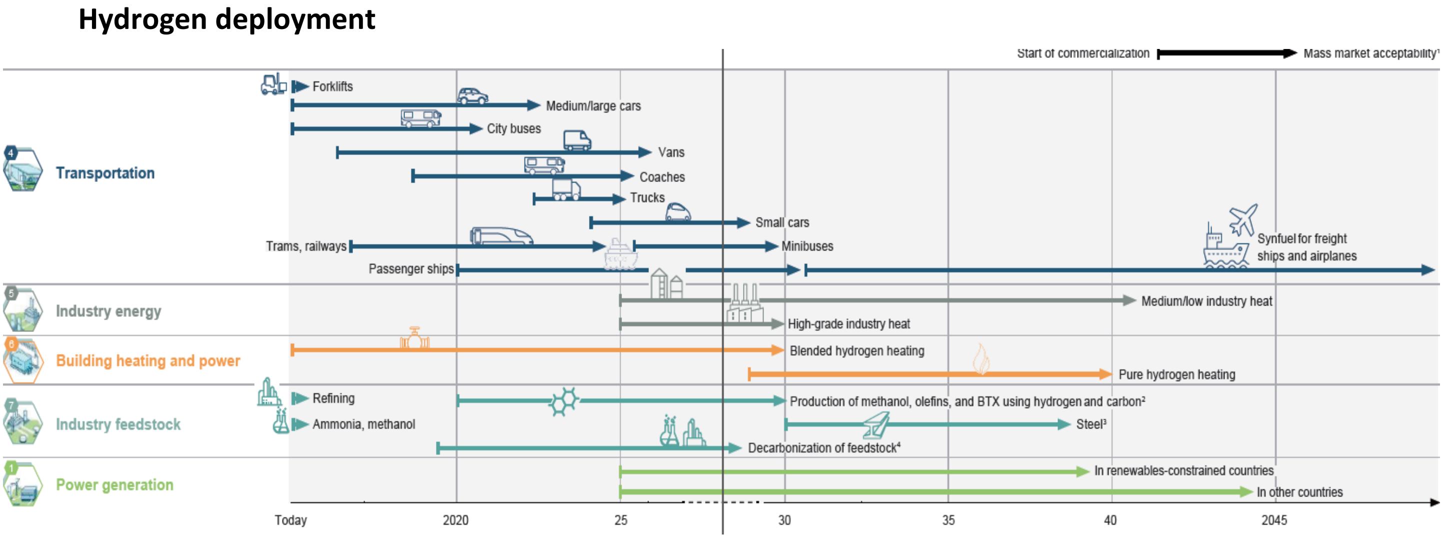


Figure 13: Hydrogen technology acceptability.

Figure 15 shows the pace of adoption of hydrogen technologies for various sectors. As for Europe, the scenario described will require a very fast acceptability of H_2 services and huge investments in very short time. Some of the hypotheses that are made seem even more optimistic (mass market acceptability of large cars in 2023 rather than 2025). This trend is probably due to the fact that the Hydrogen Council study have been published 18 months before FCHs.

Table 3 shows some example of results of the Hydrogen council for different sectors

Table 3: Numeric results of the hydrogen council study for several sectors.

	2030	2050
Transport	10-15 million FCEV 50 000 FC trucks	400 million large FCEV (25 % of total) 5 million FC trucks (30 %) 15 million bus (25 %) 20% of today's diesel trains
Heating	6.5 million households	50 million households 8% of building power demand
Industry		12% of global energy demand 10% of crude steel prod, 30% of methanol and ethanol derivatives production
Power	250 to 300 TWh of excess solar and wind	500 TWh of excess solar and wind converted to hydrogen

Two main things are of interest:

- The amount of FC vehicles and the excess renewable converted in hydrogen is ten times higher than for Europe. That could be in line with the fact than the final energy demand for the Hydrogen Council is ten times the final energy demand in the FCH study.
- For heating, the trend is different: both studies give the same number of households fueled by hydrogen.

4.2.2 Other studies

Author: IHS Markit

Publication date: 2019

Study description: This PowerPoint is the presentation of a forum organized by IHS concerning the future of hydrogen.

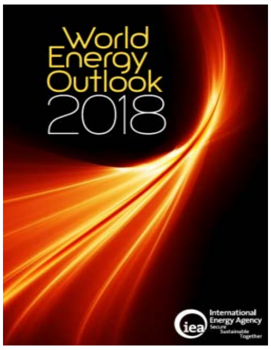
Limitation: A lot of information is missing and most of the slides have a pedagogical value to teach about opportunities of hydrogen.

Main results:

- Electrolysis hydrogen is three times more expansive than CCS + SMR
- CCS increases the cost of hydrogen produced from natural gas by 25 %

Author: IEA

Publication date: 2018



Study description: The WEO is the flagship publication, widely recognized as the most authoritative source for global energy projections and analysis. It represents the leading source for medium to long-term energy market projections, extensive statistics, analysis and advice for both governments and the energy business.

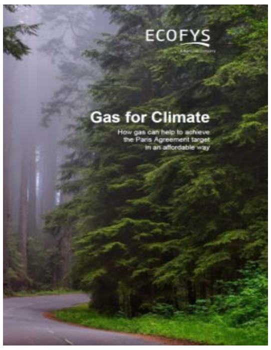
Limitation: The focus on hydrogen is very little and the IEA view on this energy will be published in September 2019 during the G20.

Main results:

- 60 Mt of hydrogen is produced today
- The use of low-emissions hydrogen is central to reducing emissions in the refining sector. Steam methane reforming with CCUS is likely to remain cheaper than using electricity to produce hydrogen.

Author: Ecofys

Publication date: 2018



Study description: Ecofys is the energy and sustainability branch of the American management consultancy firm Navigant Consulting. This study explores the role of gas (in all its form) in a fully decarbonised energy system by 2050.

Limitation: Ecofys focuses on all type of gas and the H_2 Scenario is not developed enough.

Main results:
- 24 Gm^3 of H_2 in 2050 (234 TWh)
- Production cost of Hydrogen by electrolysis: 23 €/MWh

Author: Shell

Publication date: 2017

Study description: The study looks at the current state of hydrogen supply pathways and hydrogen applications technologies. It gives Shell's vision of the potential and prospects for H_2 as an energy source in the energy system of tomorrow. Although a bit optimistic, this vision seems nevertheless achievable.

Limitation: Shell only focuses on the transportation sectors and gives few quantified results.

Main results:
- Fuel cell electric vehicles will be cheaper than internal combustion engines (in terms of total cost of ownership).
- FCEV will ham the same TCO than the battery electric vehicles.
- There will be approximately 2 Mt H_2 (65 TWh) and 3.5 million FCEV in 2050 in the top four H_2 European countries (Germany, UK, France, Italy). This represents 10 % of the final energy demand for the transportation sector described in the FCH-JU study.

Author: CertifHy

Publication date: 2015

Study description: The report assesses the current hydrogen market, its structure, the main players and how demand in going to between 2015 to 2030.

Limitation: In an area with large changes in very short time, a study published 5 years ago is not "up to date" anymore. Some of the definitions and results they got were used by the FCH-JU for its study.

4.3 Pathways to develop hydrogen

Most of the investigated studies propose pathways to realize the ambitious objectives they have set. These pathways could vary from one study to another but could be summarized in 8 major proposal:

1. Regulators and industry should jointly set out clear, long-term, realistic, and holistic decarbonization pathways.
2. The European industry should invest in hydrogen and fuel cell technology to remain competitive and positioned to capture emerging opportunities.
3. Regulators and gas companies should begin to decarbonize the gas grid. As forcing mechanisms, they could use binding targets for renewable content in the gas grid.
4. In the power system, regulators should encourage the use of electrolysers to balance the grid, e.g., by exempting them from grid fees and ensuring competitive access to renewable power on the market.
5. In transport, regulators should overcome the chicken-and-egg problem by setting out a clear and credible roadmap, developing policies for zero-emission mobility and in parallel, developing the refueling infrastructure.
6. In industry, stakeholders should kickstart the transition from grey to low-carbon hydrogen and further substitution of fossil fuels with new hydrogen usages.
7. To produce ultra-low-carbon hydrogen on a large scale, companies should enlarge their electrolysis operations to commercial levels and prove CCS can produce hydrogen of very low carbon intensity on a large scale within the next ten years.
8. Industry and regulatory stakeholders should continue to develop additional hydrogen and fuel cell applications and plans to scale up successfully proven ones.

4.4 Conclusion of existing studies

This section has shown and detailed multiple studies describing hydrogen scenarios for the future. They present a vision in which H_2 is one of the major sources of energy in Europe and represents a significant amount (20-25 %) of the final energy demand in industry, heating and the transportation sector. These scenarios require major investment for installing the new hydrogen production facilities and the refueling stations for the fuel cell electrical vehicles. Following these guidelines will enable Europe to respect their commitment took during the COP 21 and respect a "Well below 2 °C" ambition by reducing the GHG emissions by 80 % compare to 1990.

4.5 Chosen hydrogen scenarios

Based on the two scenarios shown in Section 4.1, three different cases were proposed for this study. The cases correspond to an energy consumption of 780 TWh, 1,415 TWh, and 2,049 TWh respectively. Figure 16 illustrates the magnitude of the cases in comparison to the two scenarios outlined in Section 4.1. The low H_2 case will hereby correspond to the H_2 usage in the Business As Usual scenario of the FCH JU, the high case the average of the FCH JU ambitious scenario and the EU Clean Plant for All H_2 scenario. The medium case is the average of the high and low case.

The selection of the hydrogen cases is based upon the two selected hydrogen scenarios described above. It is decided to select three different cases; low- mid and high-consumption cases. These cases can then be used to investigate the consequences of different hydrogen deployments in the European energy system. The high-consumption case of hydrogen is selected as the average of the Ambitious scenario in "Hydrogen Roadmap Europe" and the Hydrogen scenario of A Clean Planet for all. The business as usual scenario of "Hydrogen Roadmap Europe" is used as the low-consumption case. The mid-consumption case is set as the average between the low- and high- consumption cases. Figure 16 shows the three proposed cases and compares them with the scenarios that they are built upon.

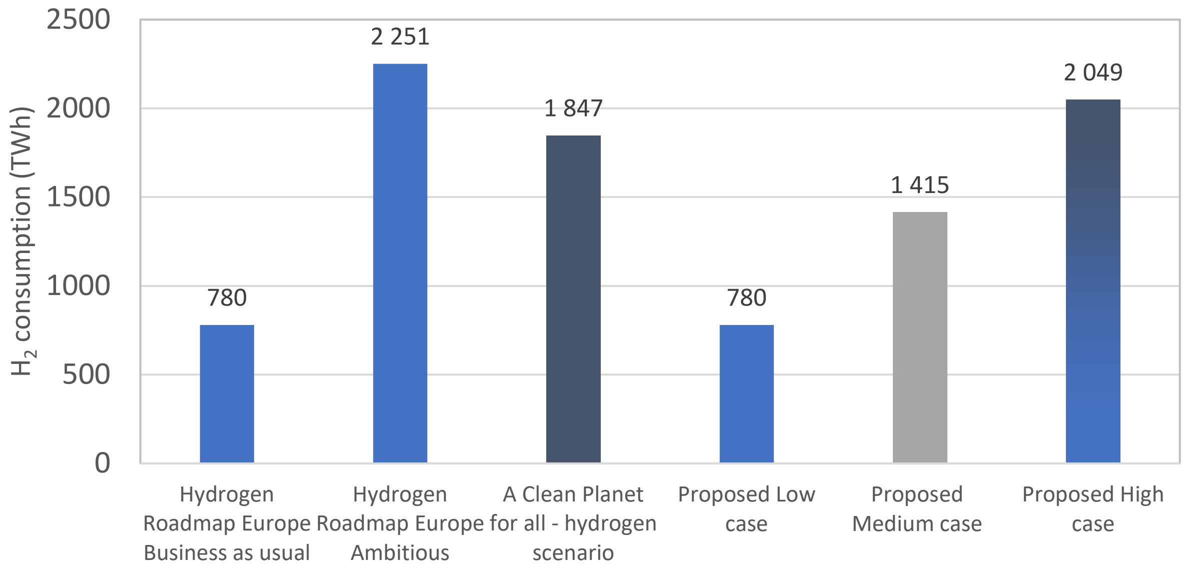


Figure 14 Selected hydrogen consumption cases (low, medium and high) and comparison to scenarios that they are built upon

4.6 The potential for hydrogen in Europe[22]

In the following paragraphs, the potential for hydrogen in Europe will be considered based upon the current energy demand per sector and prospects for each sector. The energy use in 2014, as reported by IEA is shown in Figure 17. The fuel consumption for electricity and heat are estimated based upon data from Euro-stat for 2014, as shown in Table 4. In the following it is assumed that hydrogen can replace all fossil fuels in production of heat. The same assumption may be made for electricity production. However, as renewable energy sources as sun and wind to a large degree is converted to electricity first, it is expected that renewably

[22] Some of figures presented in this section will be also presented in Chapter 5. They are included for improving the understand of the section.

based electricity production will replace large share of the fossil sources with natural gas serving as fast balancing energy source. Hydrogen can replace natural gas in the power section as clean energy source.

Table 4: Fuel consumption (in TWh) for electricity and heat in 2014 (Eurostat, 2018)

Fuel	Electricity	Heat
Solid fuels	808	174
Petroleum and products	58	30
Gases	491	250
Nuclear	876	1
Renewables	931	148
Other	27	51
Total	3191	654

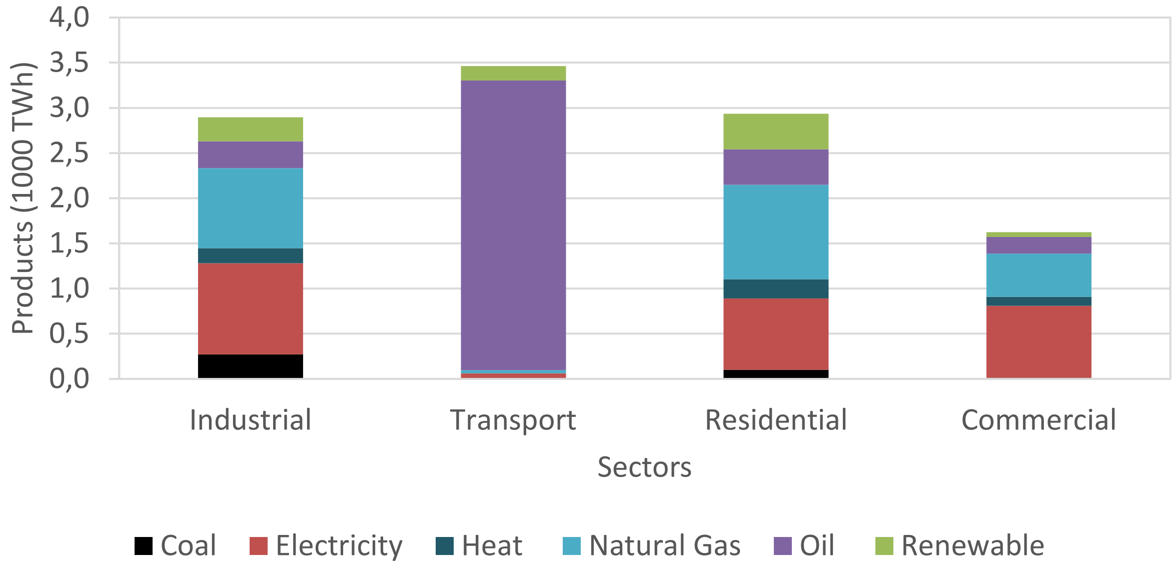


Figure 15 Products used for the industrial, transport, residential and commercial sectors in 2014 (IEA, 2016)

4.6.1 The potential for hydrogen in the industry sector

Figure 18 shows the historical development of energy consumption in industry. Although the energy consumption was reduced by 27 % from 1971 to 2014, this reduction is not equal for all energy carriers. Especially oil and coal usage were reduced by 82 % and 75 % respectively, whereas electric power consumption increased by 60 %, natural gas consumption by 105 %, and renewable energies by 422 %. Due to the variety of applications (heat, feedstock, reduction agent), it is not straight forward to predict the future development. In "A Clean Planet for all", industrial energy consumption is reduced by 23 % in the baseline scenario due to improved feedstock utilization and energy efficiency.

The potential for clean hydrogen in the industry sector can be separated into three different fields (see also FCH JU Hydrogen Roadmap Europe and the introduction):

1. Substitution of existing hydrogen applications with clean hydrogen;
2. Delivery of medium- and high-grade heat to industrial process;
3. As reduction agent in steel making.

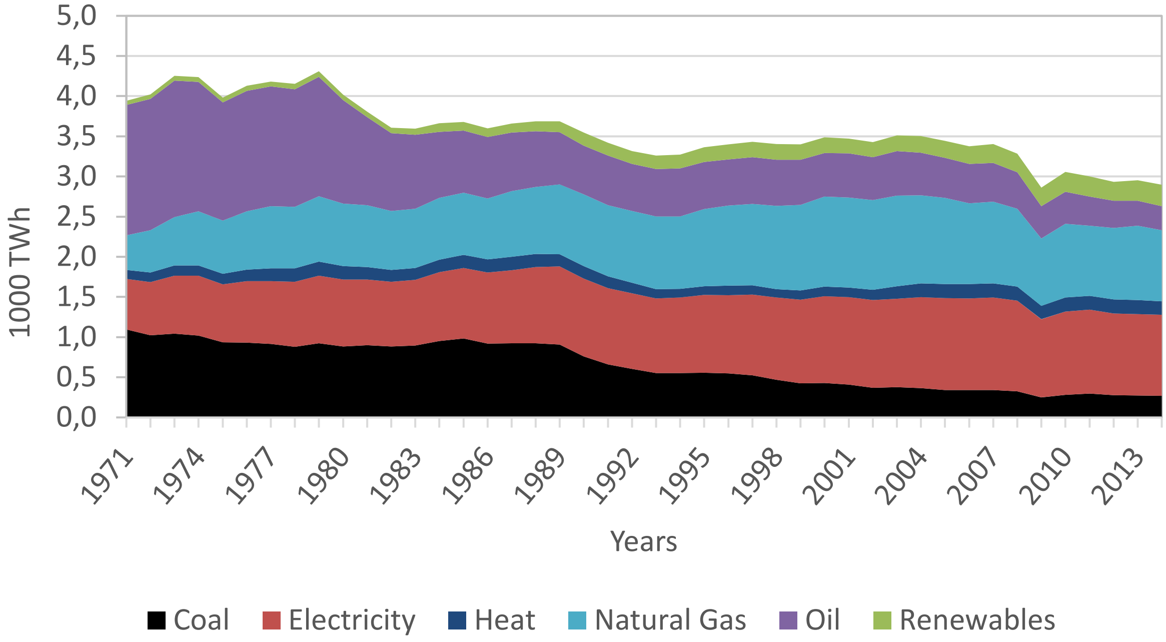


Figure 16: Historical development in the use of different products within the industrial sector (IEA, 2016)

Current application of hydrogen can be found mostly in the chemical industry. Here, hydrogen is used as feedstock for a large magnitude of reactions in refineries and in the ammonia production. Furthermore, the production of methanol is entirely based on natural gas-derived hydrogen. Currently, the majority of hydrogen is produced using natural gas reforming without CO_2 capture. A potential hydrogen infrastructure allows the application of clean hydrogen. According to the FCH JU report "Hydrogen Roadmap Europe", the current application of hydrogen in refineries and ammonia production in Europe corresponds to 282 TWh. Assuming an energy efficiency from methane to hydrogen of 80.0 % (due to the utilization of methane for providing heat to the endothermic reaction), this corresponds to 352.5 TWh of natural gas. Substituting this demand by clean hydrogen will correspond to annual CO_2 reductions of 60 Mt CO_2, a reduction of 80 %. We assume that the overall consumption of hydrogen will remain the same as today. This can be reasoned by increased ammonia production to feed the growing world population with reduced usage of hydrogen in refineries due to reduced need for fossil fuels.

Medium- and high-grade heat is currently mostly provided by burning oil, natural gas, or coal. Here, clean hydrogen can provide a route for the decarbonization. In a first step, addition of hydrogen to natural gas may result in a simple method for emissions reductions and development of hydrogen as heat source. In subsequent steps, hydrogen can be the only fuel source for providing medium- and high-grade heat. Estimates for heat usage are included in the defined cases. We assume that all provided heat (see Figure 17) now derived from fossil sources is substituted with hydrogen and that 40 % of current natural gas consumption is related to providing high- and medium-grade heat and will remain at this level in 2050. This corresponds to a hydrogen potential of 470 TWh and a CO_2 reduction potential of 85 Mt CO_2. Contrary to high- and medium-grade heat, low grade heat can be provided using heat pump. Applying hydrogen would result in a large exergy destruction.

In addition to the provided heat and heat from natural gas burning, heat is as well generated from both coal, oil, and waste. The cement industry is one example of an industry requiring large amount of high-grade heat, around 5-7 % of industrial energy demand. The heat demand of the cement industry is estimated at 117 TWh in 2012, of which 40 % is provided by alternative fuels, e.g. biomass and waste, whereas the rest is provided mostly by coal (Ecofys, 2017). The utilization of alternative fuels is expected to increase to 60 % on a medium-term outlook. Hence, we assume that 40 % of the energy demand of cement production can be provided by hydrogen, that is hydrogen substitutes coal in the heating. According to the "Technology Roadmap: Low-Carbon Transition in the Cement Industry" of the IEA, the energy demand will remain roughly the same in 2050 as today. This is reasoned by an increased production volume and improved energy efficiency. Combined with 40 % of the energy provided by hydrogen, this corresponds to 44.8 TWh hydrogen and a CO_2 reduction potential of 15 Mt CO_2. Note, that 2/3 of the emissions associated to cement production are process emission and changing the energy source for heating does not influence these emissions.

Currently, only 1 % of steel is produced using hydrogen as reduction agent in direct reduction furnaces. Here hydrogen has a large potential for reduction of carbon emissions. FCH JU Hydrogen Roadmap Europe report reported an emission reduction by 66 % and a potential of 20 % of the steel manufacturing in 2050. This corresponds to a hydrogen potential of 140 TWh of hydrogen and a CO_2 reduction potential 46 Mt CO_2 when the emissions for hydrogen production are included.

4.6.2 The potential for hydrogen in the transport sector

In the transport sector, hydrogen has the largest potential in replacing fossil fuels in the heavy-duty segment, for applications like heavy-duty vehicles and in the maritime sector. Currently, data for the maritime sector has not been collected, and we will therefore focus on road-based transport. The maritime sector should however be included in future work.

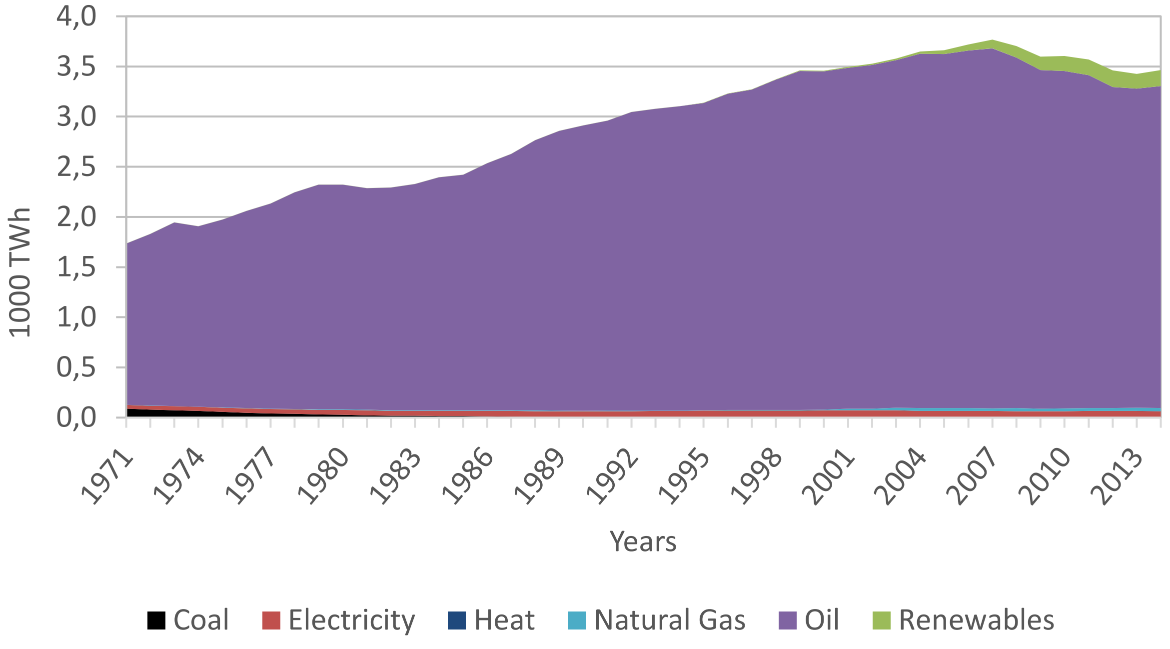


Figure 17: Historical development in the use of different products within the transport sector (IEA, 2016)

The road-based transport consumed 3,365 TWh in 2014 and based on the historical development shown in Figure 19 a complete utilization of oil is assumed. In "CO2 emission standards for heavy-duty vehicles", the European Commission states that the share of emissions from heavy-duty vehicles amounted to 27 % of the road transport emissions in 2016, and that the share will increase without new policies. It is thus assumed that the share of energy consumption by heavy-duty vehicles is approximately equal to 27 %, and zero-growth in energy demand is used as a conservative approach. This implies a potential for hydrogen in 2050 equal to 409 TWh, and a corresponding potential for reduced emissions of 271 Mt CO_2.

The rail sector corresponds in 2015 to 0.5 % of the emissions in the transport sector which is equivalent to 5.85 Mt CO_2. Assuming that trains use diesel for propulsion and a similar efficiency for diesel engines as for fuel cells, this would correspond to an energy demand of 23 TWh hydrogen and a CO_2 reduction potential of 4.69 Mt CO_2. With higher efficiencies of hydrogen trains, the emission reduction increases, and the demand of hydrogen decreases. Currently, hydrogen trains have an efficiency of around 50 % compared to diesel-electric trains of around 50 %. Substitution of electric trains with hydrogen trains is unlikely as the infrastructure for electric trains is existing and hydrogen trains are less efficient due to the production of hydrogen and the conversion to electricity in a fuel cell. Both processes are less efficient than using the electricity directly.

4.6.3 The potential for hydrogen in the residential and commercial sectors

The historic development of energy usage in the residential and commercial sectors are shown in Figure 20 and Figure 21. The Baseline scenario of "A Clean Planet for all" is used as a basis for predicting the energy consumption in 2050. The scenario represents the development of the energy system of EU given the implementation of "agreed EU policies, or policies that have been proposed by the Commission but are still under discussion in the European Parliament and Council". In this scenario, the residential and service sectors have a change in final energy consumption of -38 % and -15 %, respectively, from 2005 to 2050.

The use of fossil fuels in the two sectors is probably entirely for heating purposes. Hence, it is assumed that hydrogen can be used to replace the fossil fuels consumed, including the fossil fuels used to generate the heat consumed (see Figure 20 and Figure 21). For the residential sector it is assumed that the entire change in final energy consumption is due to reduced demand for fossil fuels for heating. For the commercial sector it is assumed that the need for electricity and heat (non-electricity in Figure 21) is reduced equally. The deviation in assumption for residential and commercial sectors is based upon the comparably larger share of electricity consumed in 2014 in the commercial sector. A reduced consumption of fossil fuels is thus estimated to -47 % and -16 % for the residential and commercial sectors, respectively. In total this amounts to a predicted potential for H_2 of 1,503 TWh in 2050. If the entire potential is implemented, this equals a total reduction in GHG emissions of 301 Mt CO_2.

Note, that the current application of coal and oil in the residential sector is in regions with limited access to a natural gas grid, and hence, a potential hydrogen grid in the future. However, based on the historic reduction in consumption of oil and coal in the residential sector, it can be expected that both energy sources will be substituted by either electricity or hydrogen in the future, both requiring investment into infrastructure.

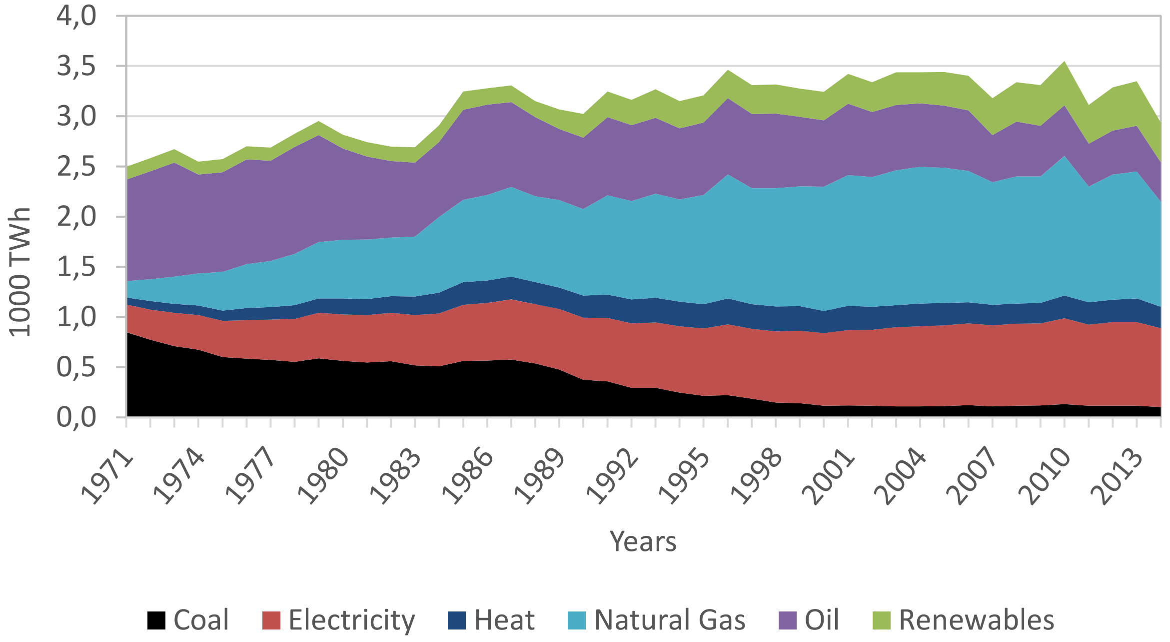


Figure 18: Historical development in the use of different products within the residential sector (IEA, 2016).

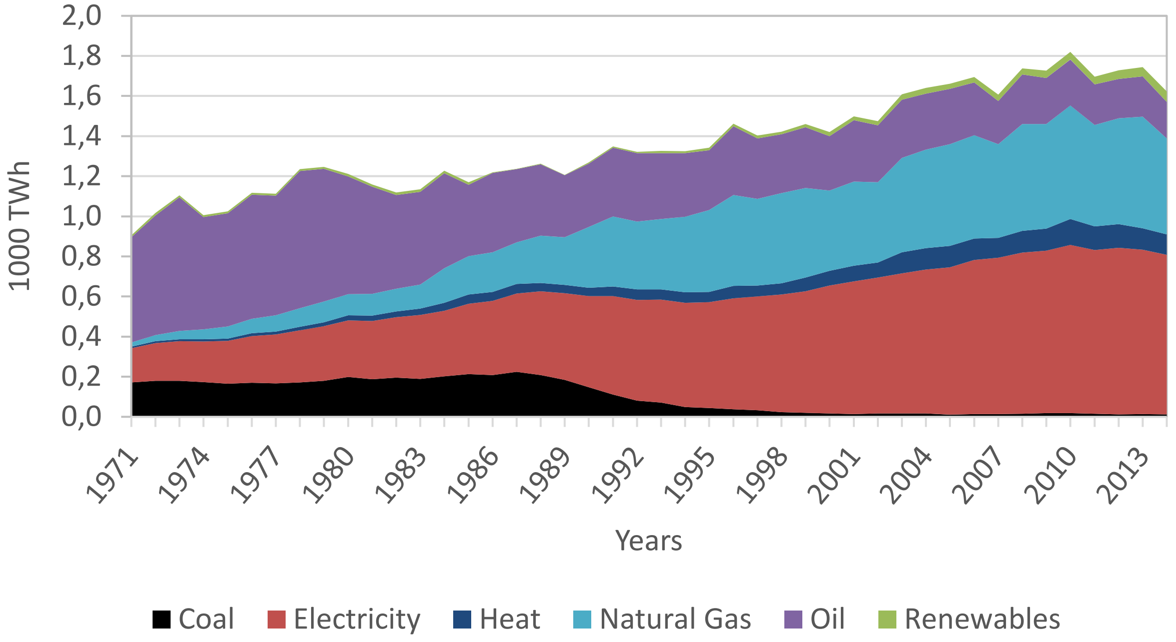


Figure 19: Historical development in the use of different products within the commercial sector (IEA, 2016).

4.6.4 The potential for hydrogen in the power sector

Hydrogen can be used as decarbonised energy source in the power sector. For example, Equinor and Vattenfall are investigating the utilization of hydrogen at the Magnum combined cycle gas power plant in the Netherlands[23]. The advantage of using hydrogen compared to natural gas with CCS is a faster response to the changes in the power demand as a gas turbine allows faster ramping of power output without a coupled carbon capture unit. The total annual natural gas demand in the power sector varies in "A Clean Planet for all" from 70 TWh in the energy efficiency scenario via 360 TWh in the 1.5C Tech scenario to 930 TWh in the baseline scenario.

We assume that 50 % of the natural gas for power generation in the 1.5C Tech scenario is substituted with hydrogen. This corresponds to an annual potential of 180 TWh and a CO_2 reduction potential of 29 Mt CO_2 if the power production with natural gas does not include CCS. This is 1.8 times higher than the assumption in the FCHJU report. However, it is still lower than today's consumption of natural gas for the power production as outlined in Table 4.

4.7 Selected hydrogen cases and the potential for hydrogen in Europe

Figure 22 compares the three chosen hydrogen cases to the potential for hydrogen estimated in the previous section. The chosen cases correspond to 25.6 %, 46.3 %, and 67.1 % of the overall energy consumption in these three areas. The remaining required energy will most likely be delivered using electricity, *e.g.* using heat pumps for heating in the residential commercial sector and battery electric vehicles as light duty vehicles.

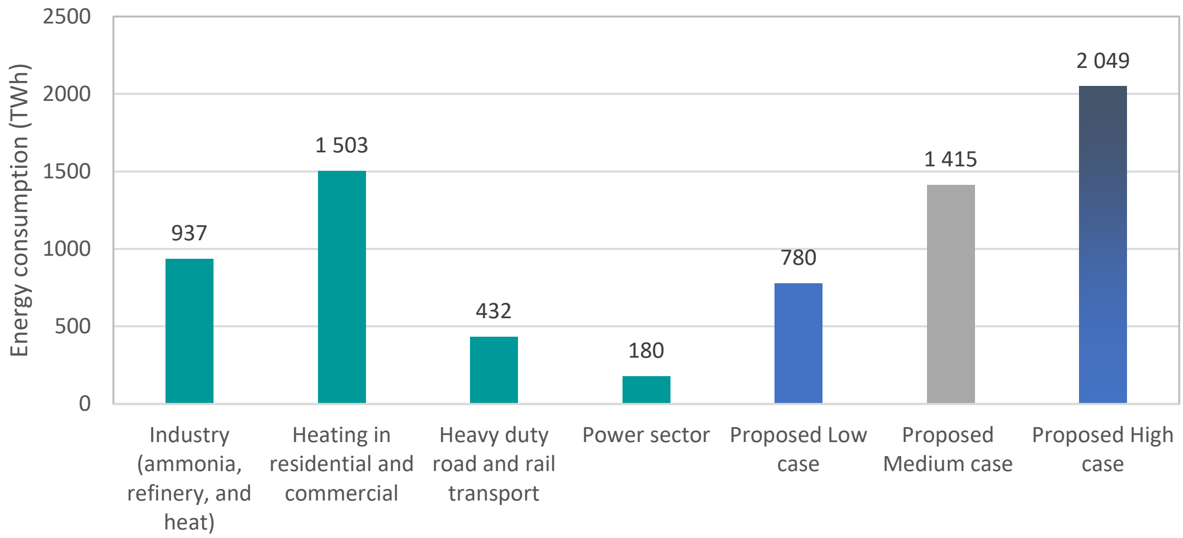


Figure 20: Energy consumption in four applications (2014) and proposed hydrogen cases for this study.

Table 5 provides an estimate of the potential for reduced CO_2 emissions for each of the sectors and proposed hydrogen cases. The estimate is given as the reduced emissions given that the sector's potential for hydrogen is covered as far as possible by the proposed case. The division of the case amounts of hydrogen between the different sectors will be scenario specific and must be derived in the main study.

[23] https://www.equinor.com/en/news/evaluating-conversion-natural-gas-hydrogen.html.html

Table 5: Reduced CO_2 emissions [Mt CO_2] per sector and hydrogen case, given maximum use of hydrogen in the given sector.

	Estimated total potential	Low case	Medium case	High case
Industry	207	172	207	207
Residential and commercial	301	156	283	301
Road and rail transport	276	276	276	276
Power Sector	29	29	29	29

The overall hydrogen potential is 3 052 TWh. This corresponds to 3 816 TWh of natural gas if all hydrogen should be produced from natural gas and an efficiency of 80 % based on the higher heating value. In 2016, the final energy consumption of gases was 2 852 TWh in the European Union and the gross inland consumption 4 453 TWh. Hence, the overall hydrogen potential corresponds to 134 % of the final energy demand and 86 % of the gross inland consumption. As a fraction of the hydrogen will be produced from biomass (around 300 TWh) and electrolyser (around 300 TWh), it can be assumed that current import infrastructure is sufficient for providing the required natural gas.

4.8

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4.9 References

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  https://www.iea.org/statistics

5 Overview of the European energy system

The purpose of this chapter is to provide an overview of the overall existing European energy system in terms of Energy consumption per sector, per product, and per different geographical regions. The objective of this review is to collect a solid dataset that describes the historical development of the European Energy system and that can be utilised as a basis for more comprehensive energy systems analyses within a future main study. In fact, an established knowledge and understanding of the historical trends and developments of the Energy system, is a key element to allow the development of future energy demand projections.

Background information like those presented in this chapter are key elements to build a solid starting point that allows for better understanding of the hydrogen potential. In particular, an overview of the historical energy consumption per sector is useful to look at the potential role of hydrogen on a sector basis (i.e. in residential, commercial, industry, transportation) as the potential pace and cost of any transition to hydrogen is likely to vary significantly between the sectors. It is also important to show the existing use of different fuel types by region as a baseline, because there will be regional differences in the potential role for hydrogen (for example, decarbonisation of residential heating in South Europe may be better met through electrification as compared to West Europe, where heating has a greater peak and is currently provided by natural gas). Moreover, details on renewable energy consumption are also needed, in order to establish a starting point to discuss how much renewable generation would be needed to supply hydrogen from renewable resources.

In order to collect data of the European energy system, two main data sources freely available on the web have been investigated: Eurostat dataset, and International Energy Agency (IEA) dataset. The reason behind the choice of showing the results available from two different resources, is linked to the possibility for validation. The possibility to look at data coming from two different resources is a way to check the validity and accuracy of the available information. Moreover, the two resources provided a dataset organised in different ways and with different details. Therefore, one dataset was more suitable to extract certain information than the other and vice versa. In particular, IEA dataset was including some additional information in terms of utilisation of products for each sector. Such kind of fine data were not available in the Eurostat source. Moreover, IEA was also allowing a smoother extraction of regional data compared to Eurostat.

Eurostat (European Statistical Office) is a Directorate-General of the European Commission located in Luxembourg. Its main responsibilities are to provide statistical information to the institutions of the European Union. The International Energy Agency is a Paris-based autonomous intergovernmental organization serving as an information source on statistics about the international oil market and other energy sectors. Both resources were providing dataset organised in excel sheets, useful to get an overview of the current and historic European energy system. In particular, the Eurostat dataset has been used to map the total EU28 energy consumption per different products (namely solid fuels, gas, electricity, petroleum, renewable and heat) and per different sectors (namely industry, transport, residential, services, agriculture and fishing). The IEA dataset has been used to map the energy consumption for different regions identified in Europe. For this purpose, the European area have been split into four regions (namely north, south, west and central east) and for each region the total energy consumption per product and per sector have been mapped. The following sections will present the most relevant findings from the two mentioned resources.

5.1 Final energy consumption and gross inland consumption in the EU28

The dataset provided by Eurostat turned out suitable to map the overall energy consumption in the EU28 per sector and product. The Eurostat reports highlight an important difference between the so called "gross inland energy consumption" and the so called "final energy consumption". According to the Eurostat website, the definitions follows.

Final energy consumption is the total energy consumed by end users, such as households, transportation, industry and agriculture. It is the energy which reaches the final consumer's door and excludes that which is used by the energy sector itself. Final energy consumption excludes energy used by the energy sector, including for deliveries, and transformation. It also excludes fuel transformed in the electrical power stations of industrial auto-producers and coke transformed into blast-furnace gas where this is not part of overall industrial consumption but of the transformation sector. Final energy consumption in "households, services, etc." covers quantities consumed by private households, commerce, public administration, services, agriculture and fisheries. The Energy end user categories include private households, agriculture, industry, road transport, air transport (aviation), other transport (rail, inland navigation), services, other.

Gross inland energy consumption is the total energy demand of a country or region. It represents the quantity of energy necessary to satisfy inland consumption of the geographical entity under consideration. Gross inland energy consumption covers:

- consumption by the energy sector itself;
- distribution and transformation losses;
- final energy consumption by end users;
- 'statistical differences' (not already captured in the figures on primary energy consumption and final energy consumption);
- but does not include energy (fuel oil) provided to international maritime bunkers.

Primary production of energy is any extraction of energy products in a useable form from natural sources. This occurs either when natural sources are exploited (for example, in coal mines, crude oil fields, hydro power plants) or in the fabrication of biofuels. **Recovered products** are by-products of other processes and may be re-used for other purposes. They include slurries, combustible waste-heap shale, recycled lubricants, and certain products recovered from industrial processes. **Bunkers** includes all dutiable petroleum products loaded aboard a vessel for consumption by that vessel. International maritime bunkers describe the quantities of fuel oil delivered to ships of all flags that are engaged in international navigation. It is the fuel used to power these ships. International navigation may take place at sea, on inland lakes and waterways, and in coastal waters.

Transforming energy from one form into another, such as electricity or heat generation in thermal power plants (where primary energy sources are burned), or coke production in coke ovens, is not primary production, but part of transformation losses.

As per Eurostat definition, the main difference between the gross inland energy consumption and the final energy consumption lies in the electricity production. The final energy consumption excludes the transformation into other energy carriers, such as in the electricity production. The concept of final energy consumption is better clarified in Figure 23.

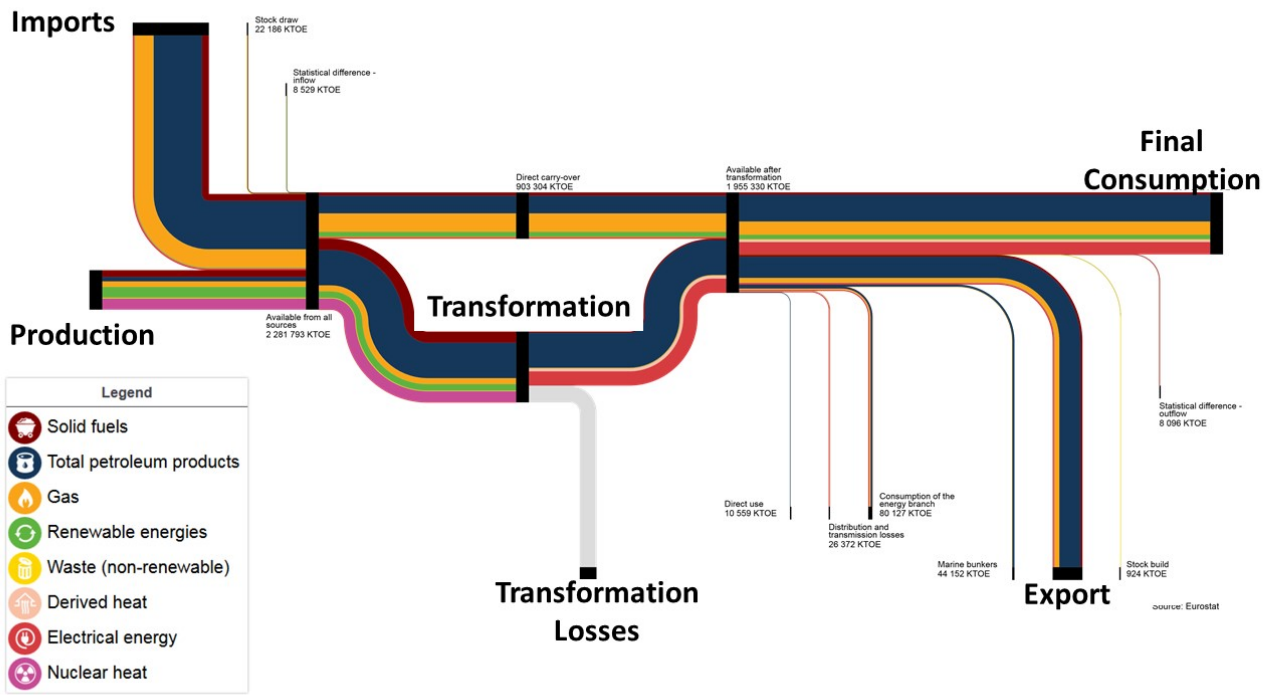


Figure 21: Energy flow diagram for EU28 in 2016 (Eurostat, 2018).

Figure 24 shows the comparison between final energy consumption and gross inland consumption for the EU28 since 1990. As per definition, the gross inland consumption includes the final energy consumption and therefore it always appears higher. Figure 25 shows the final energy consumption per sector for the EU28 since 1990. Given its definition, the gross inland energy consumption per sector is not available. In fact, as per Eurostat definition, when dealing with sectors, it is the final energy consumption that matters.

It can be observed, that the total value of both and their ratio is rather constant throughout this period. However, during the last decade a continuing slight decrease can be observed for the gross inland consumption, while the final energy consumption is rather constant, indicating reduced transformation and transport losses in the energy sector. In all the following figures a significant dip in consumption in 2009 can be observed, which occurred due to the economic crisis.

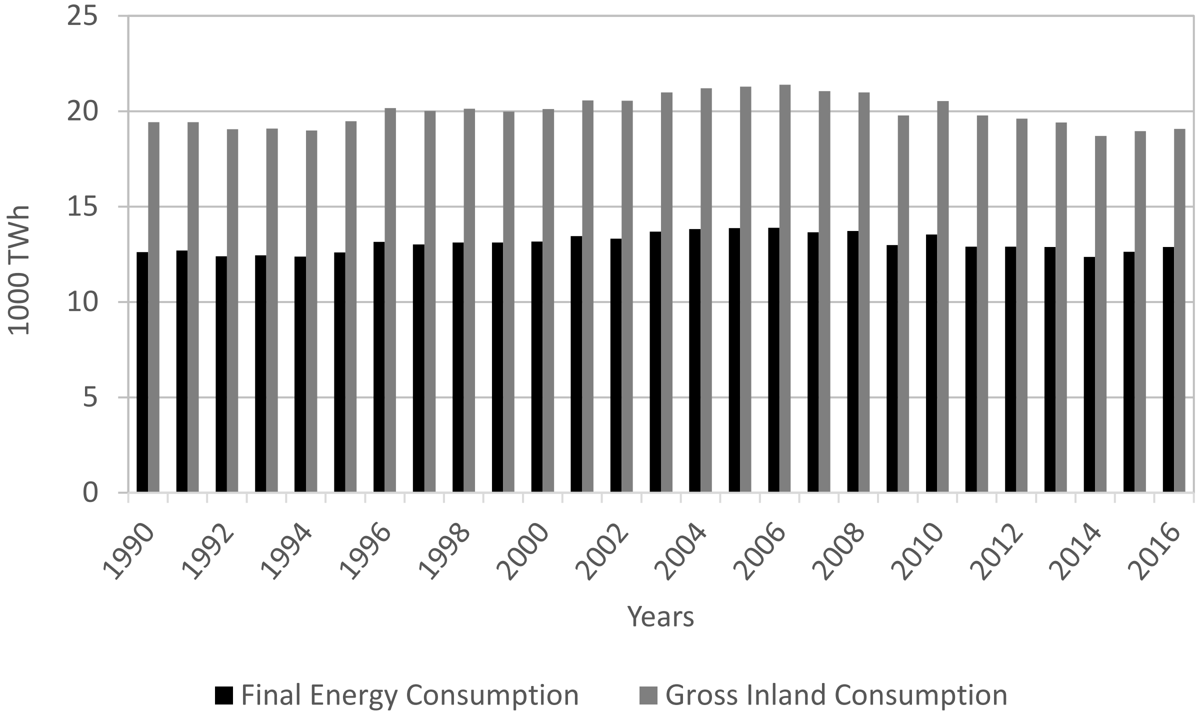


Figure 22: Final energy consumption and gross inland consumption in EU28 (Eurostat, 2018).

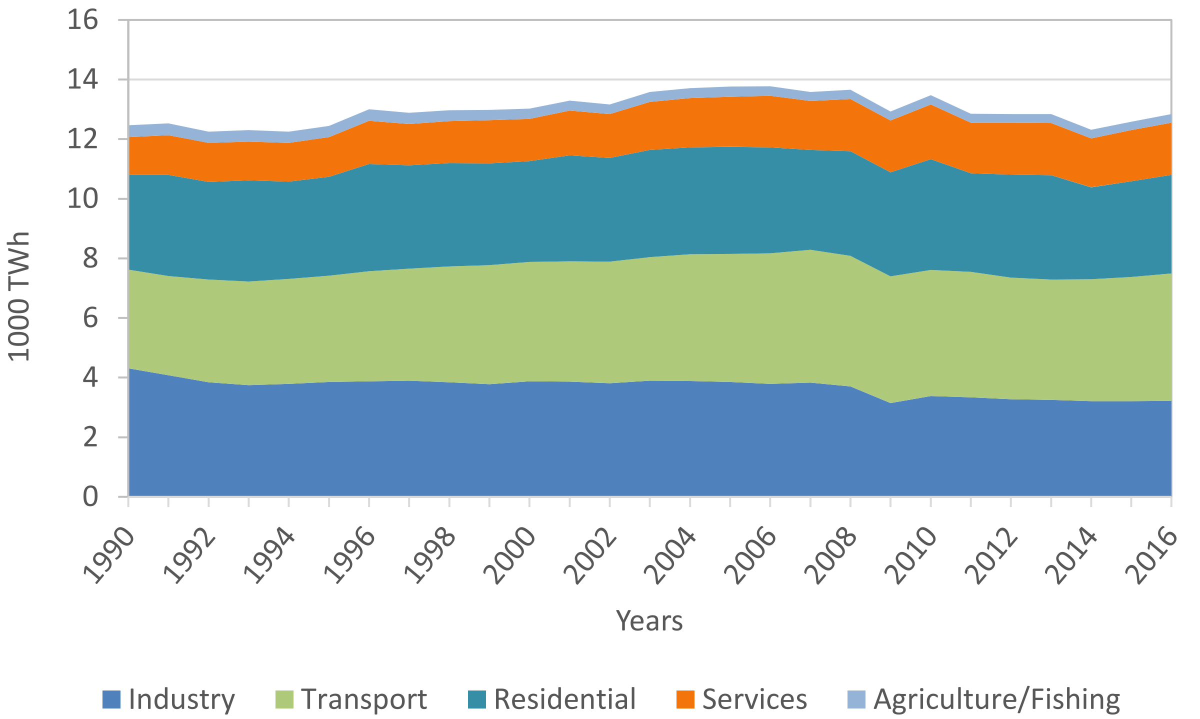


Figure 23: Final energy consumption by sector in EU28 (Eurostat, 2018).

Figure 26 and Figure 27 show the final energy consumption and the gross inland energy consumption per product respectively. According to the EU definitions, renewable energy sources shown in the figures include the following: biomass (solid biofuels) which may be used for heat production or electricity generation; biogases (landfill gas; sewage sludge gas; other biogases from anaerobic digestion; bio gases from thermal processes); liquid biofuels (bio gasoline, biodiesel, bio jet kerosene (aviation fuel) and other liquid biofuels); renewable waste; hydropower; geothermal energy; wind energy; solar energy; tide, wave ocean. According the EU definitions, derived heat shown in the figures refers to heat used for warming spaces and for industrial processes and is obtained by burning combustible fuels like coal, natural gas, oil, renewables (biofuels) and wastes, or also by transforming electricity to heat in electric boilers or heat pumps. One can observe that the transport sector has taken over the role as the largest consumer of energy from the industry sector, whereat the total value is rather constant as seen before. In addition, there is some growth in the services sector.

The consumption per energy carrier shows that there is a decline in the direct consumption of solid fuels, such as coal and an increase in electricity consumption and renewables. However, the largest energy carrier is petroleum throughout the whole period around one third of the primary energy consumption. It can be observed, that there is a slight decrease during the last decade. While in the beginning of the period (1990), solid fuels had a larger share than gasses, the latter ones have taken over as the second biggest energy resource. Thereby a reduction of solid fuels of nearly 50 % can be observed. At the same time there was a nearly doubling of renewables, which now reached the volume of nuclear or solid fuel energy resources. However, the largest energy resource is petroleum, which has a share of about 30 %. As for secondary energy consumption, it can be observed that electricity is strongly dominating compared to heat.

Through the Eurostat dataset, it is possible to further break down the analyses into different industrial sectors (namely iron and steel, chemical and petrochemical, non-ferrous metals, non-metallic minerals, mining and quarrying, food and tobacco, textile and leather, paper pulp and print, transport equipment, machinery, wood, construction) and different transport sectors (namely rail, road, domestic aviation, domestic navigation, consumption in pipeline transport). Such level of detail is not proposed in this report, but can be achieved if needed, by properly extracting data from the Eurostat available material.

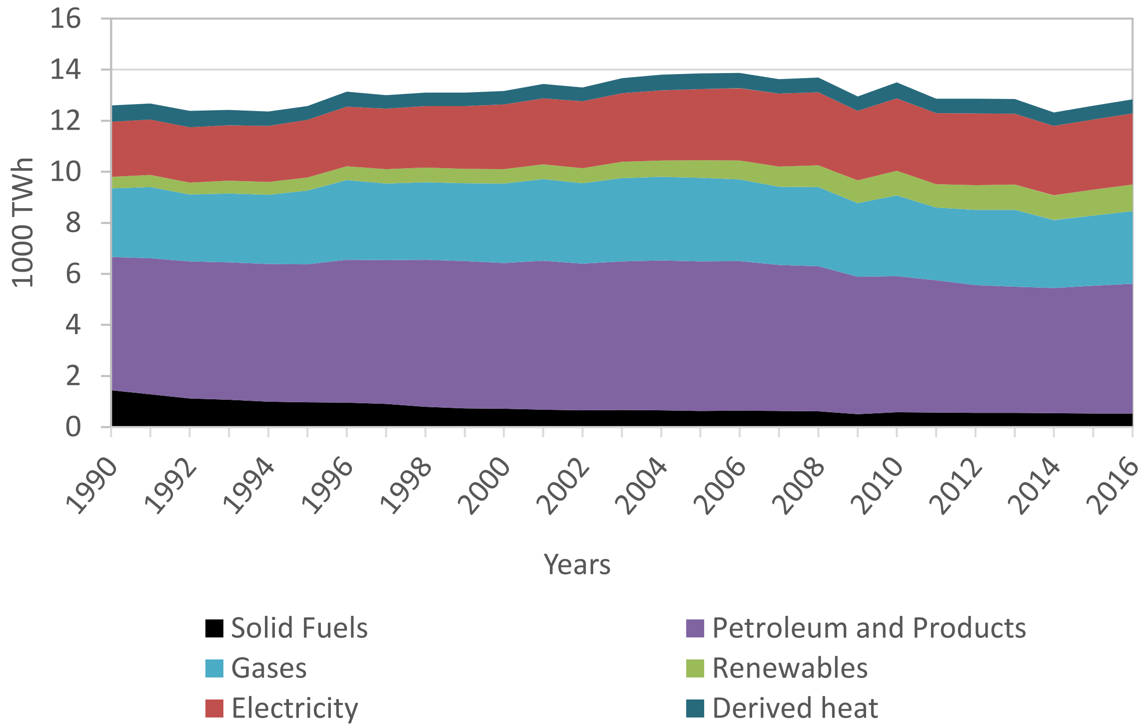


Figure 24: Final energy consumption by product in EU28 (Eurostat, 2018).

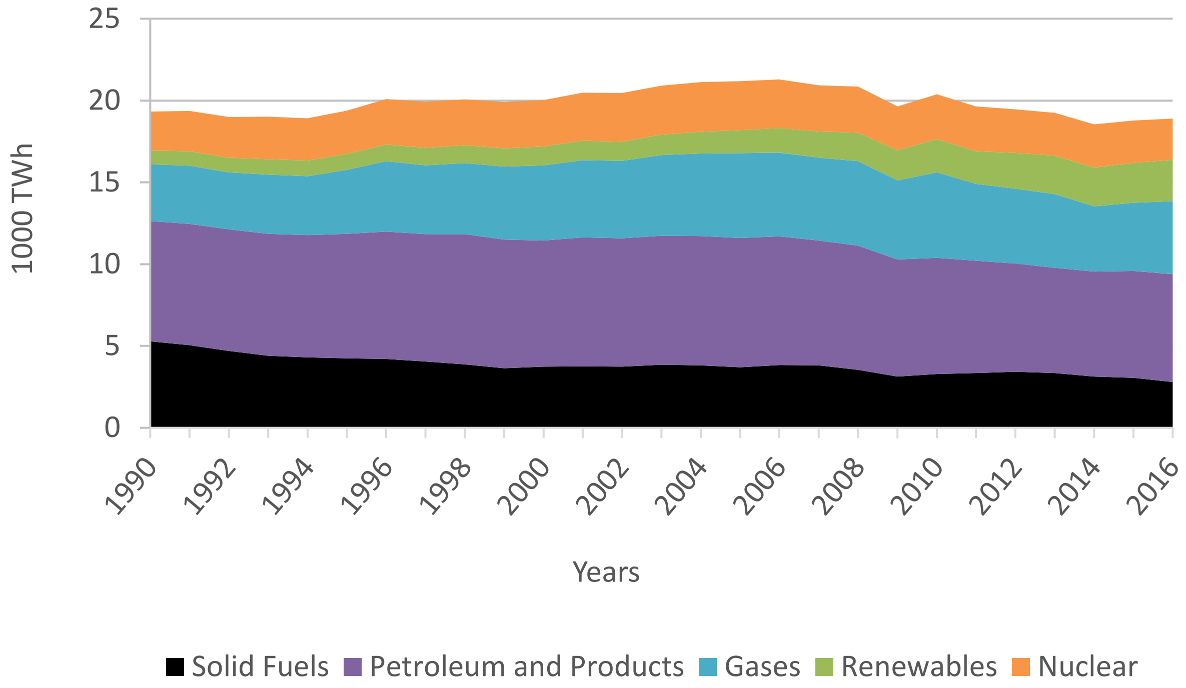


Figure 25: Gross inland energy consumption by product in EU28 (Eurostat, 2018).

The following Figure 28 and Figure 29 show the gross electricity generation and heat generation by fuel type respectively. In both cases there has been an increase in the use of renewables and a quite strong decrease in the use of petroleum and products. The use of solid fuels for electricity generation remained almost constant with a slight decrease in the last decades. While the use of solid fuels for heat generation show a much stronger decreasing trend. The use of gases is almost dominating for heat generation while it is limited for the electricity generation. In the latter case a slow increment can be observed until 2008, followed by a quite strong reduction in the last decades.

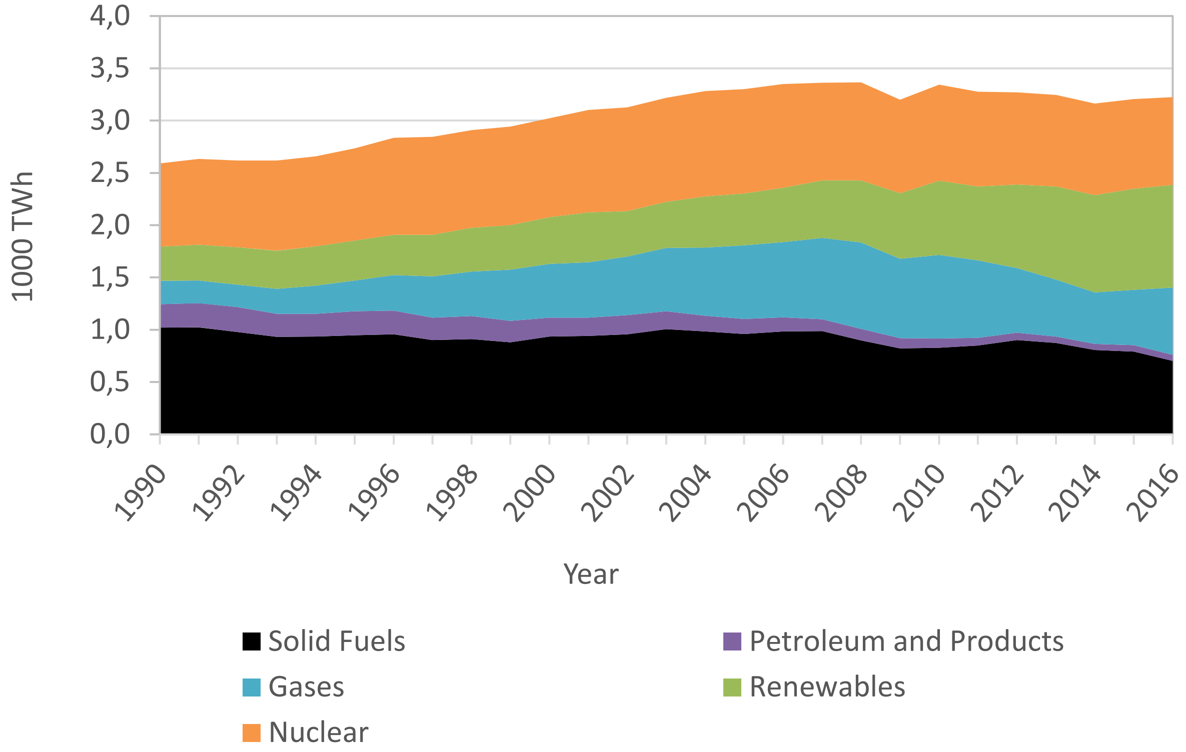


Figure 26: Gross electricity generation by fuel type in EU28 (Eurostat, 2018).

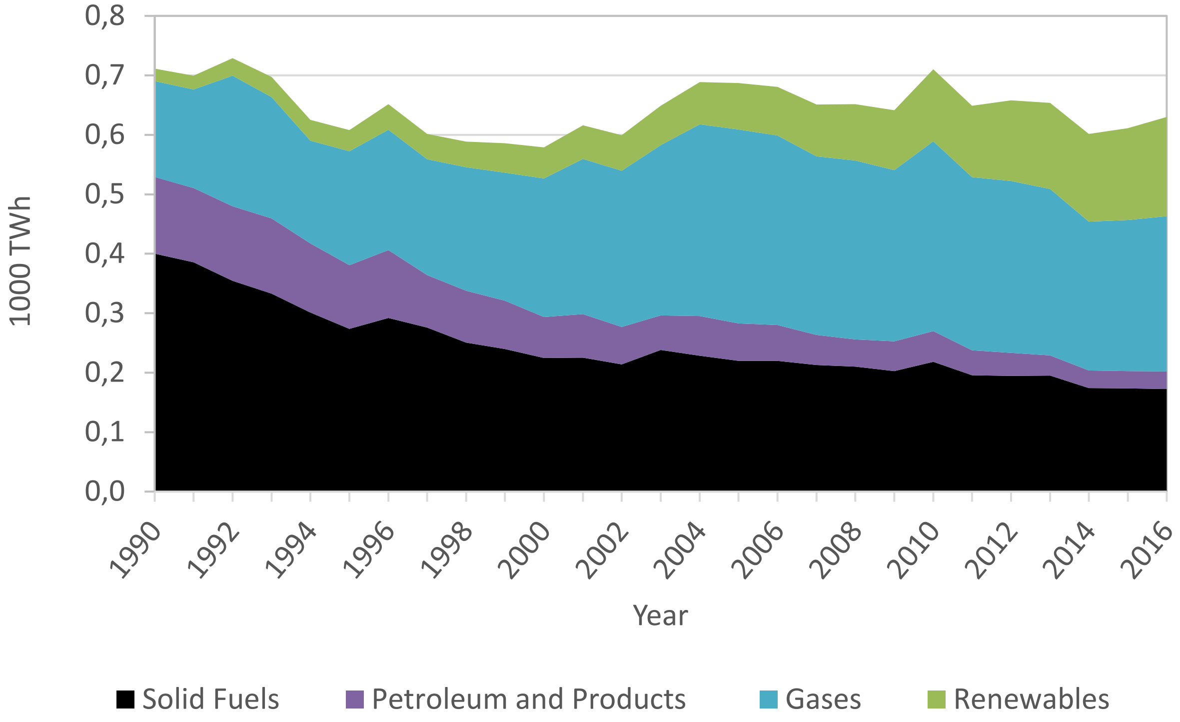


Figure 27: Gross heat generation by fuel type in EU28 (Eurostat, 2018).

5.2 Renewable energy consumption

This section aims at showing details of the contribution of renewable energy in the final and gross inland energy consumption. In particular, Figure 30 shows a comparison between the final and gross inland energy consumption for the whole renewable energy sector. While following Figure 31 and Figure 32 show which is the contribution of renewable energy resources in the gross inland and final energy consumption.

The share of renewable energy sources in gross inland energy consumption increased in the EU28 since 1990. In 2012, the main contributors to the gross inland consumption of renewable energy were biomass and renewable waste, followed by hydro and wind. The share of renewable energy in final energy use in the EU28 has almost doubled since 2005, but has slowed down in recent years.

Given that the biomass consumption is considerably higher than the other renewable sources, it has been decided to show the related trend in a secondary axis. This way the trends of the other resources can be clearly represented in the diagram. According to the Eurostat definitions, biomass is organic, non-fossil material of biological origin (plants and animals) used as a raw material for production of biofuels. It includes wide range of materials harvested from nature or biological portion of waste. The most typical example is wood (firewood, wood residues, wood waste, tree branches, stump, wood pellets, ...), which is the largest biomass energy source. Other examples of biomass are grass, bamboo, corn, sugarcane, animal waste, sewage sludge and algae.

The comparison shows that there is a much larger increase in utilisation of renewable energy sources, than for the final energy consumption. That indicates that a larger share of renewables is used to generate other energy carriers (see also Figure 23). In addition, it can be observed, that the ramp of renewables has increased from about 2000.

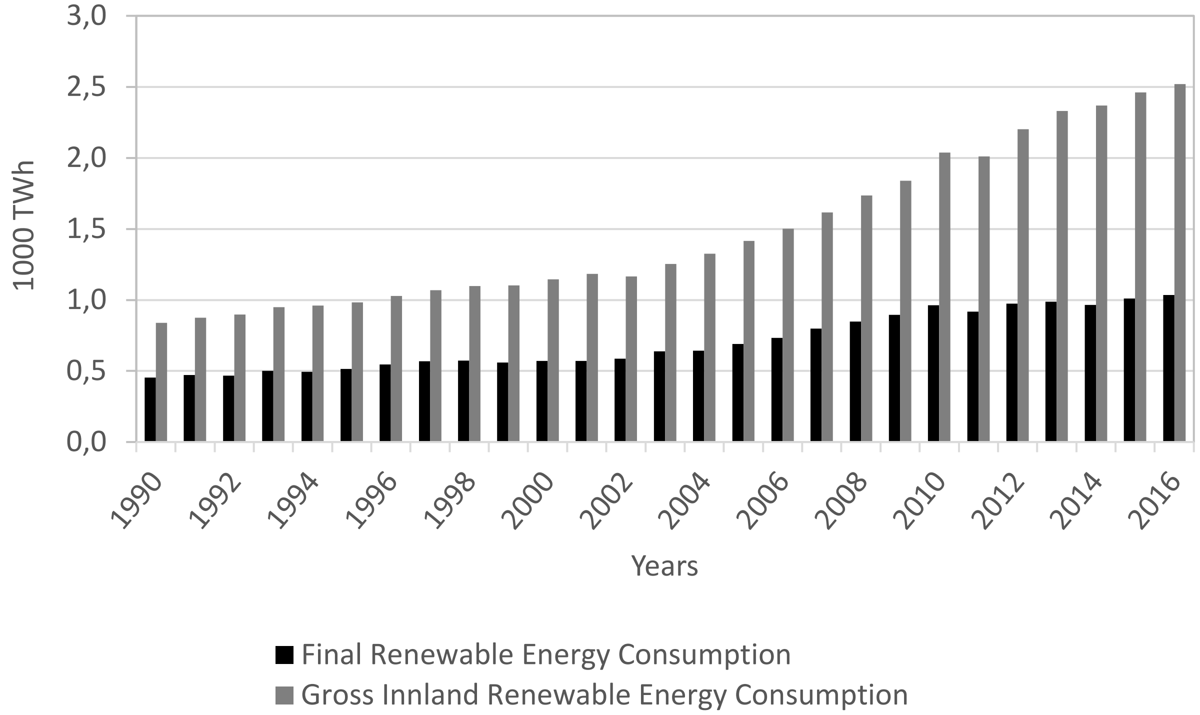


Figure 28: Final and gross inland renewable energy consumption in EU28 (Eurostat, 2018).

The final renewable energy consumption shows a large share of biomass, which is used for heating and industrial processes. Furthermore, there is a significant increase of solar, which is also used for heating, while consumption of geothermal energy is nearly constant.

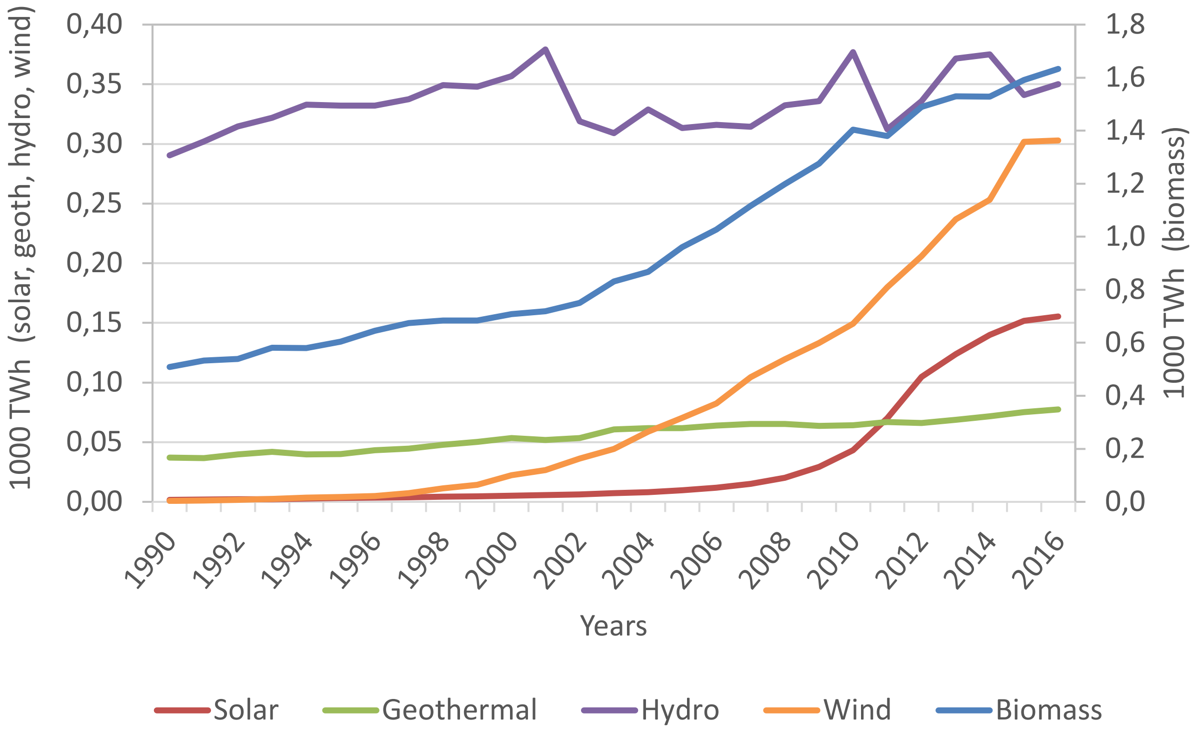


Figure 29: Contribution of renewable sources to gross inland renewable energy consumption in EU28 (Eurostat, 2018).

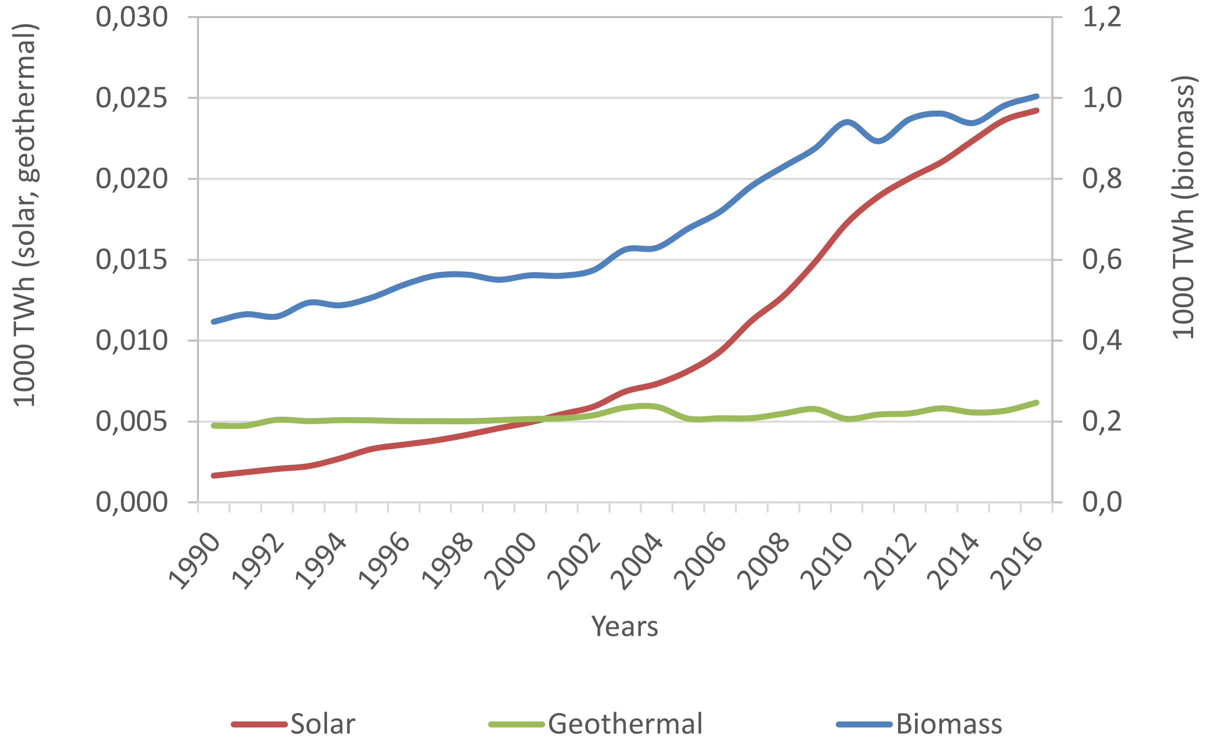


Figure 30: Contribution of renewable resources to final renewable energy consumption in EU28 (Eurostat, 2018).

One can observe a somewhat increasing trend for hydropower and geothermal, however the biggest increases are for solar, wind and biomass. Thereby wind and solar started at a level near zero in 1990. Furthermore, one can see that the speed of solar expansions is reduced in the latest years. But it has to be taken into account that the figure depicts the produced energy and not the installed generation capacity.

5.3 Regional energy consumption in Europe per sector and product

The dataset provided by IEA is suitable to map the regional energy consumption in Europe per sector and product. A division in different regions is done to assess potential differences due to the geographic location and the availability of energy resources. For this purpose, the whole Europe has been divided into four main regions (namely north, south, west and central east) and relevant countries has been selected as part of each region. Figure 33 shows the chosen regional classification according to the IEA data availability.
The following diagrams will map the regional energy consumption per sector and product, by using the same colours of Figure 33 to facilitate the reading. Data from IEA is available from 1971 in contrast to Eurostat, where it is available from 1990.

According to the IEA definitions, the final energy consumption covers the energy supplied to the final consumer for all energy uses. It is calculated as the sum of the final energy consumption of all sectors. These sectors are disaggregated to cover industry, transport, households, services and agriculture. The relative contribution of a specific sector is measured as the ratio of the final energy consumption of that sector to the total final energy consumption, calculated for each calendar year. It is a useful indicator that highlights a country's sectoral needs in terms of final energy demand.

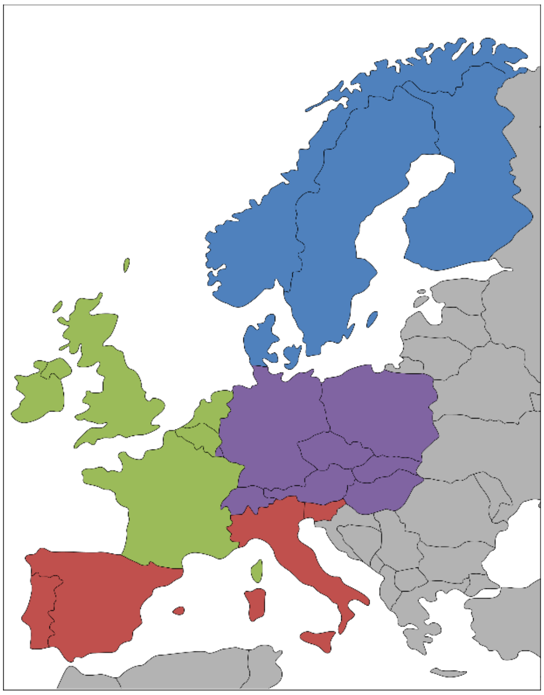


Figure 31: The different countries available for each region (from IEA).

Area	Countries
North Europe	Norway, Denmark, Finland, Sweden
South Europe	Italy, Spain, Portugal, Slovenia
West Europe	France, UK, Belgium, Netherlands, Ireland
Central/East Europe	Germany, Luxembourg, Austria, Switzerland, Czech Republic, Poland, Slovak Republic, Hungary

Within the final energy consumption, it can be observed that there is a steady increase of consumption in Europe, where the largest relative increase can be seen for southern Europe. The consumption in Northern Europe is nearly constant throughout the period.

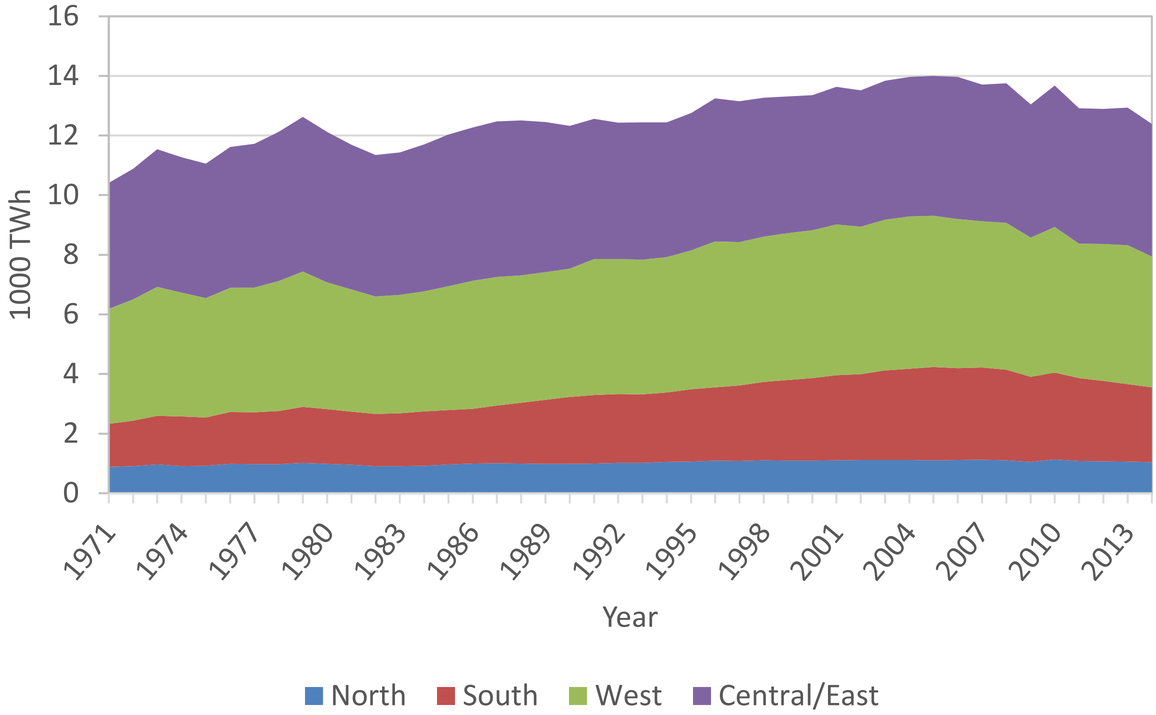


Figure 32: Total final energy consumption per region in Europe (IEA, 2016).

The following sections will show the final energy consumption details for different products and different sectors, in each of the four regions that have been identified, using the IEA dataset.

5.3.1 Final energy consumption per region by product

This section aims at showing the details of the final energy consumption per region for different products. The main products identified are heat (i.e. district heating and heat delivery to industrial processes), coal/peat/oil shale, crude/NGL/feedstocks, oil, natural gas, renewables/waste, electricity,

There is a significant increase in the demand for heat (as a product), which means district heating or back pressure deliveries to process industry. While there already has been a significant amount in heating in central Europe, there has been implementation of heat deliveries in the other regions during the last decades.

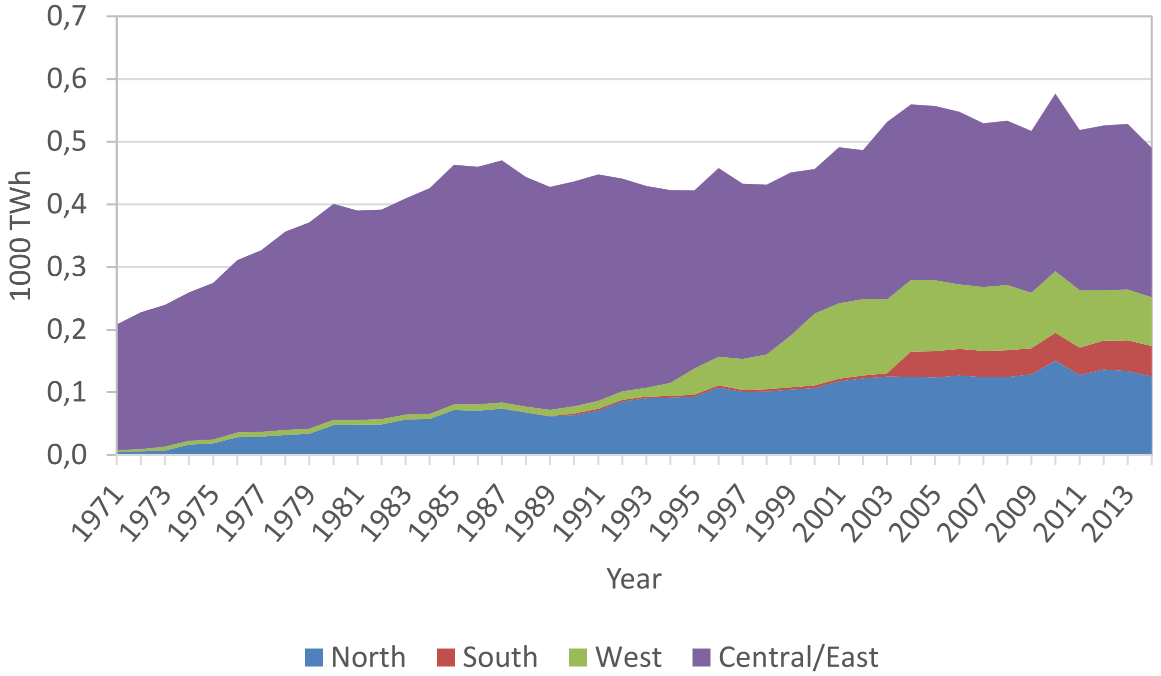


Figure 33: Heat consumption per region in Europe (IEA, 2016).

Looking on the demand for coal consumption one can observe a decrease over time for all of Europe, where there is a tremendous fall in consumption during the early 90s in Central and East Europe, certainly due to the end of the cold war and the resulting decline of the heavy industry.

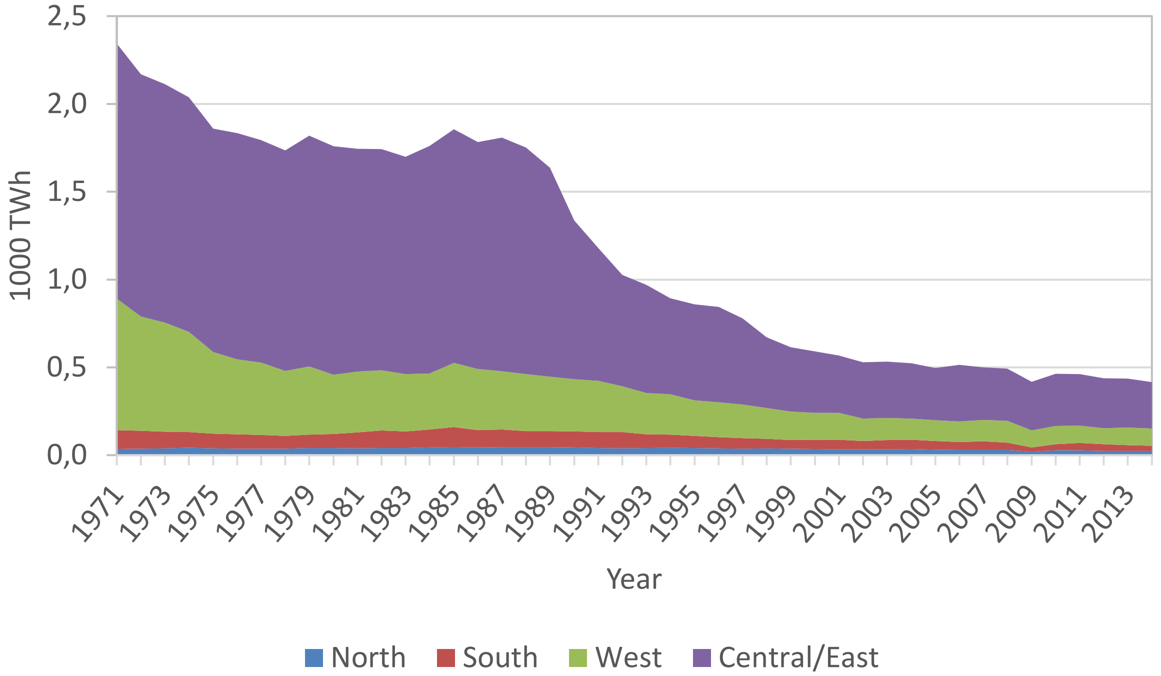


Figure 34: Coal, peat, oil shale consumption per region in Europe (IEA, 2016).

The oil consumption shows a decrease during the last decade in all of the regions, where the peak was reached in early 2000.

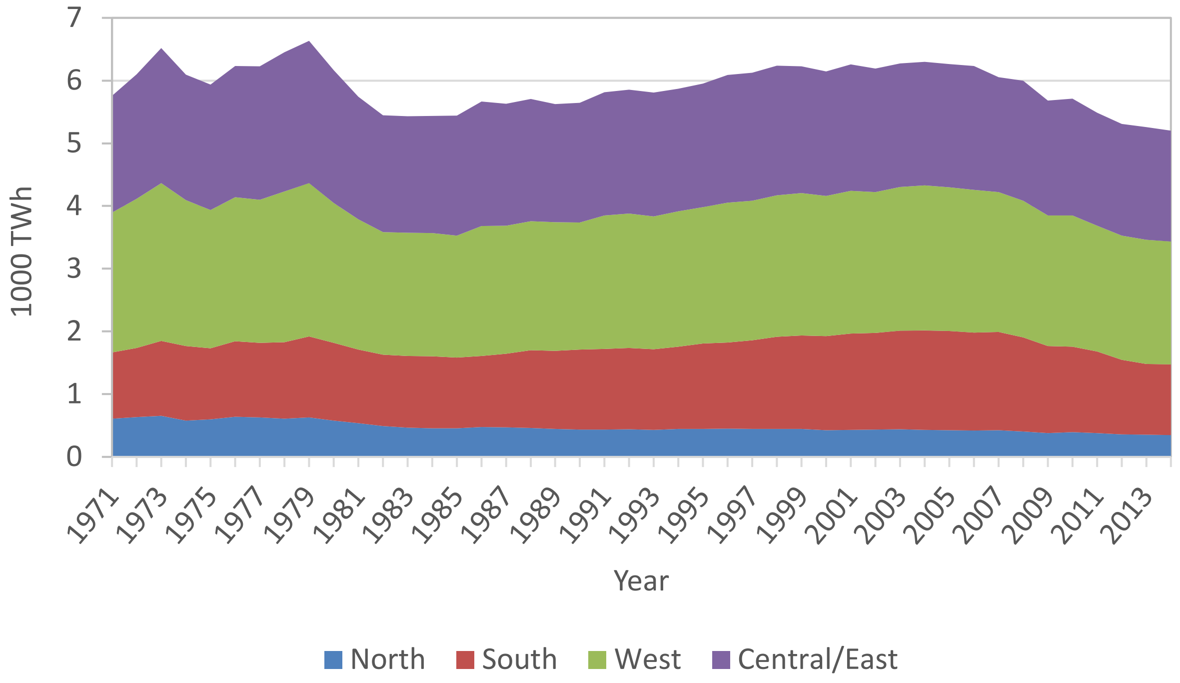


Figure 35: Oil products consumption per region in Europe (IEA, 2016).

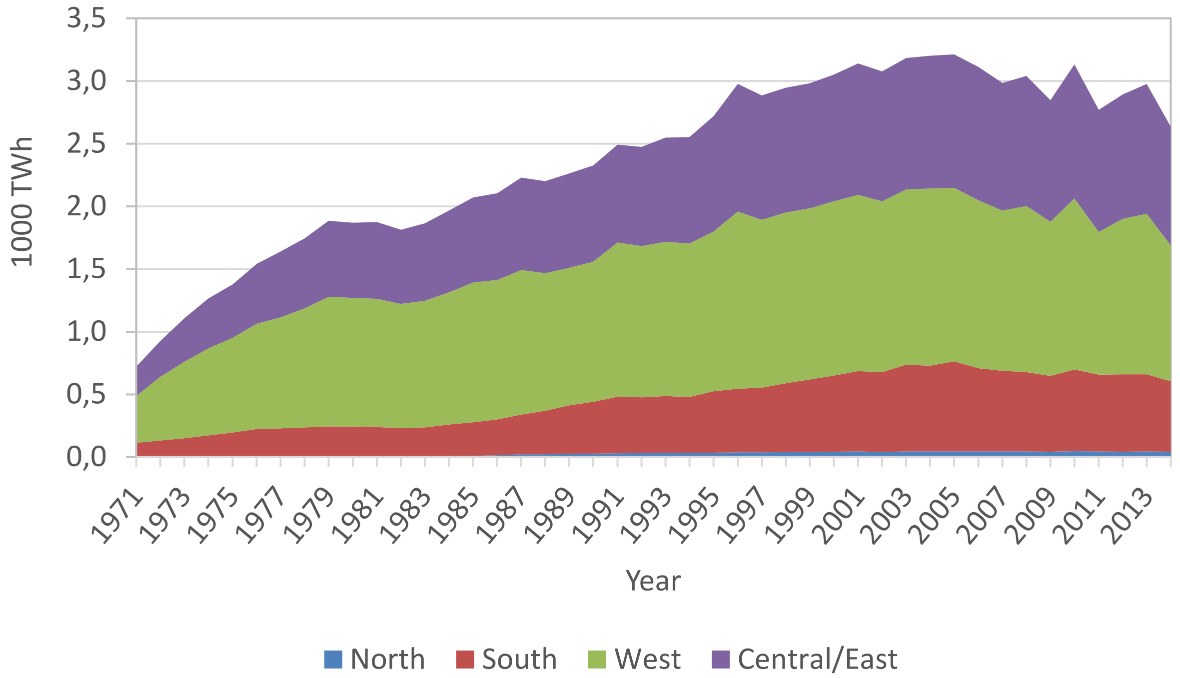


Figure 36: Natural gas consumption per region in Europe (IEA, 2016).

In contrast to the oil consumption, there is a significant increase in gas consumption, which however also declined somewhat during the last decade. The highest share of gas consumption can be seen in West Europe, while there is nearly no demand in North Europe.

Regarding renewables, a significant increase can be observed in the 90s and even more so from 2000 onwards. It can be observed, that the consumption in North Europe is rather constant, certainly due to the hydropower resources, which are already significantly utilised before 1970.

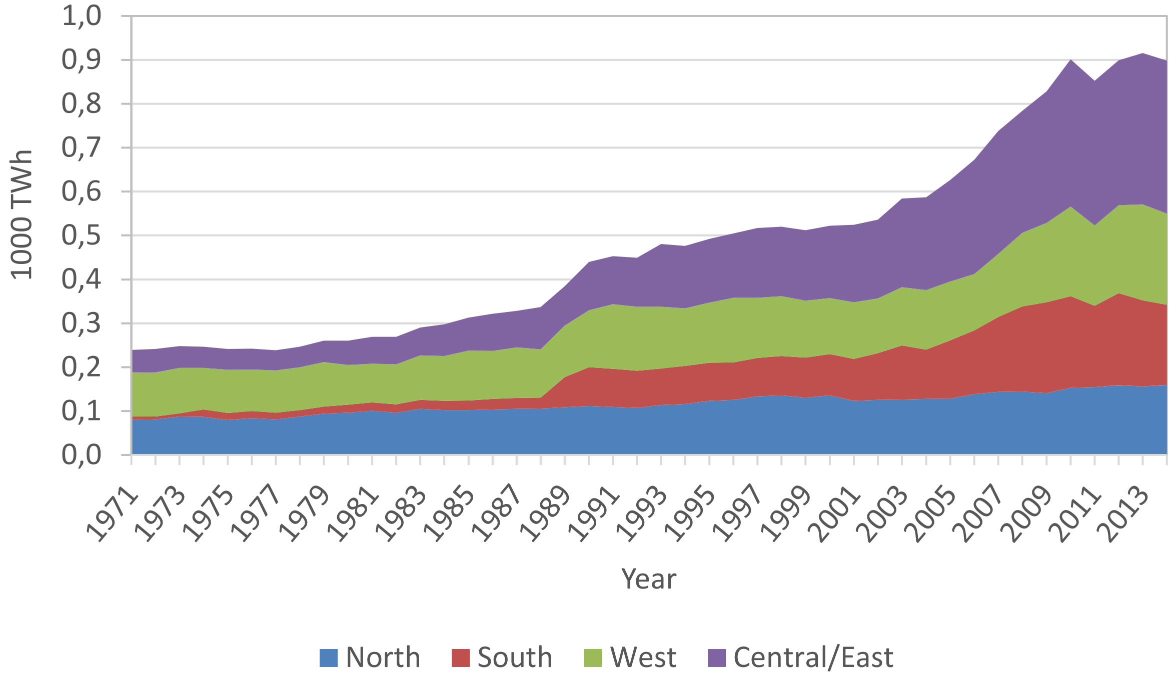


Figure 37: Renewables and waste consumption per region in Europe (IEA, 2016).

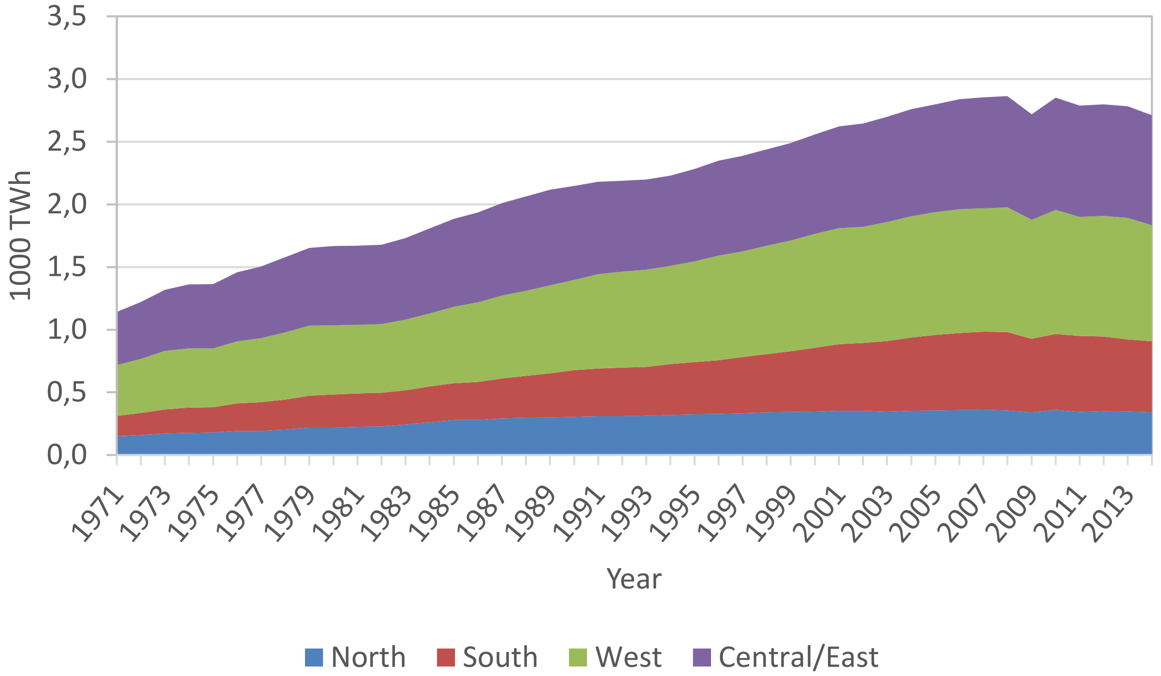


Figure 38: Electricity consumption per region in Europe (IEA, 2016).

There is an increasing trend of using electricity during the period, where the annual consumption in Europe more than double. Again, one can see that the consumption in North Europe is rather stable, due to the early utilisation of the hydropower resources, which generate electricity.

5.3.2 Final energy consumption per region by sector

This section aims at showing the details of the final energy consumption per region for different sectors. The main sectors identified are industry, transport, residential and commercial. The following figures summarise the trends.

There is a decrease of the energy consumption in the energy sector, which specifically happened during the early 80, due to the decline of the heavy industry in western Europe and in the early 90s due to the decline of the heavy industry in eastern Europe.

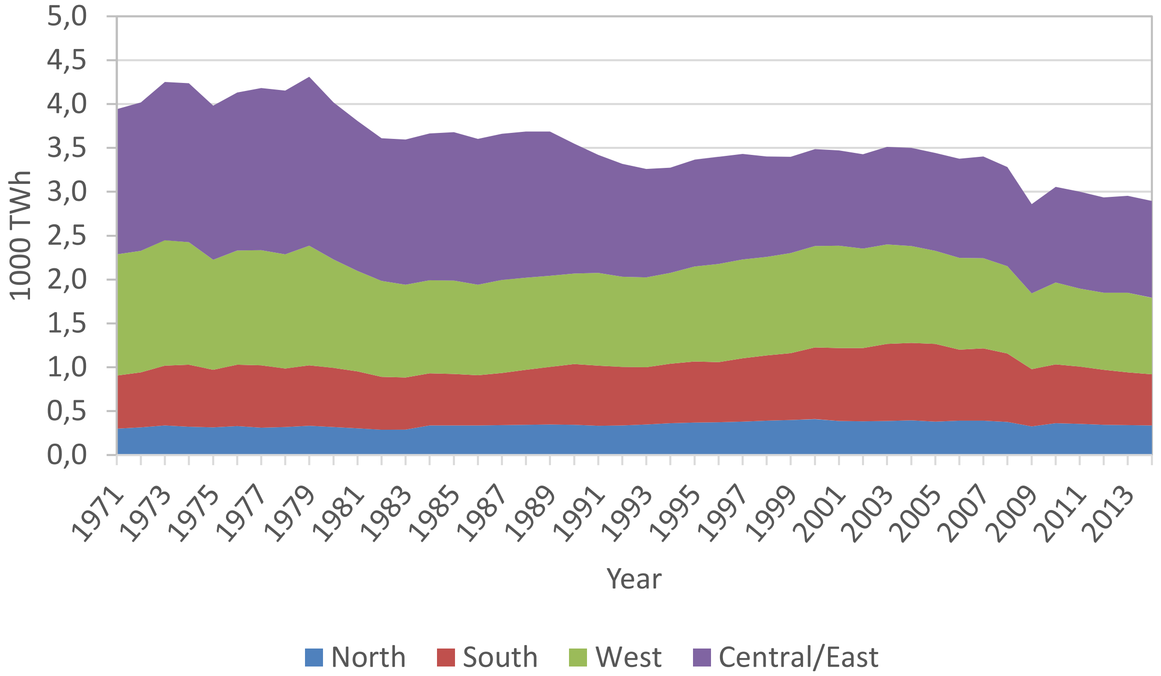


Figure 39: Energy consumption in the industry sector per region in Europe (IEA, 2016).

On the other side there is a large increase in energy consumption in the transport sector, which peaked around 2005. This increase can be observed in all regions.

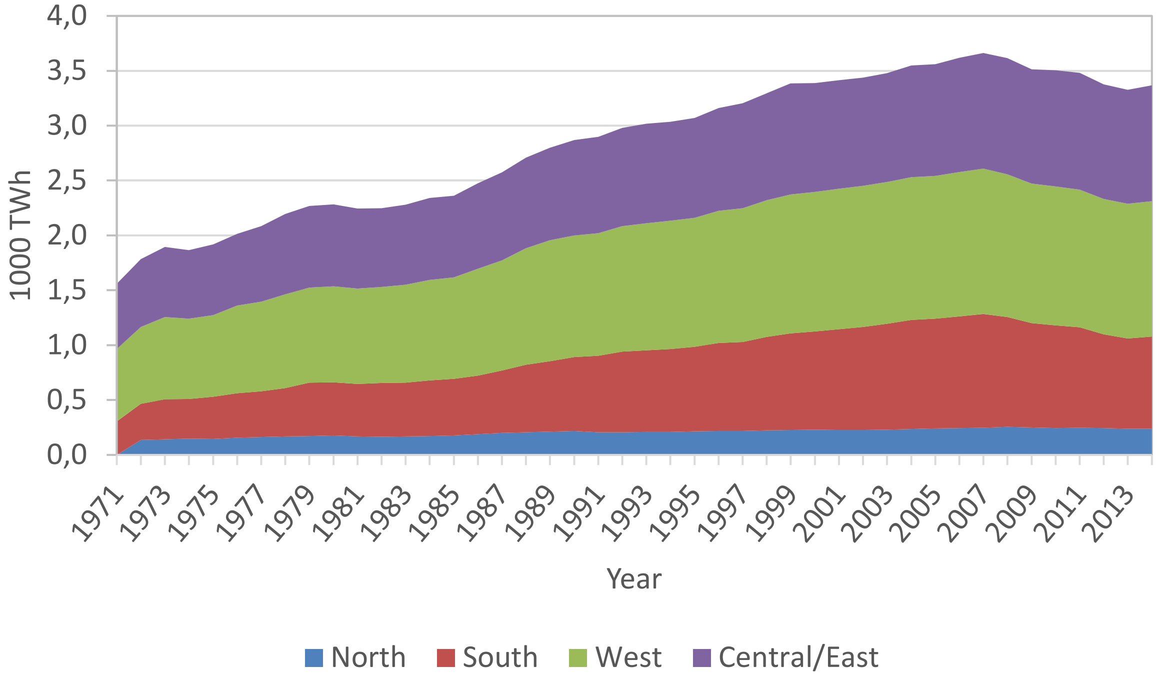


Figure 40: Energy consumption in the transport sector per region in Europe (IEA, 2016).

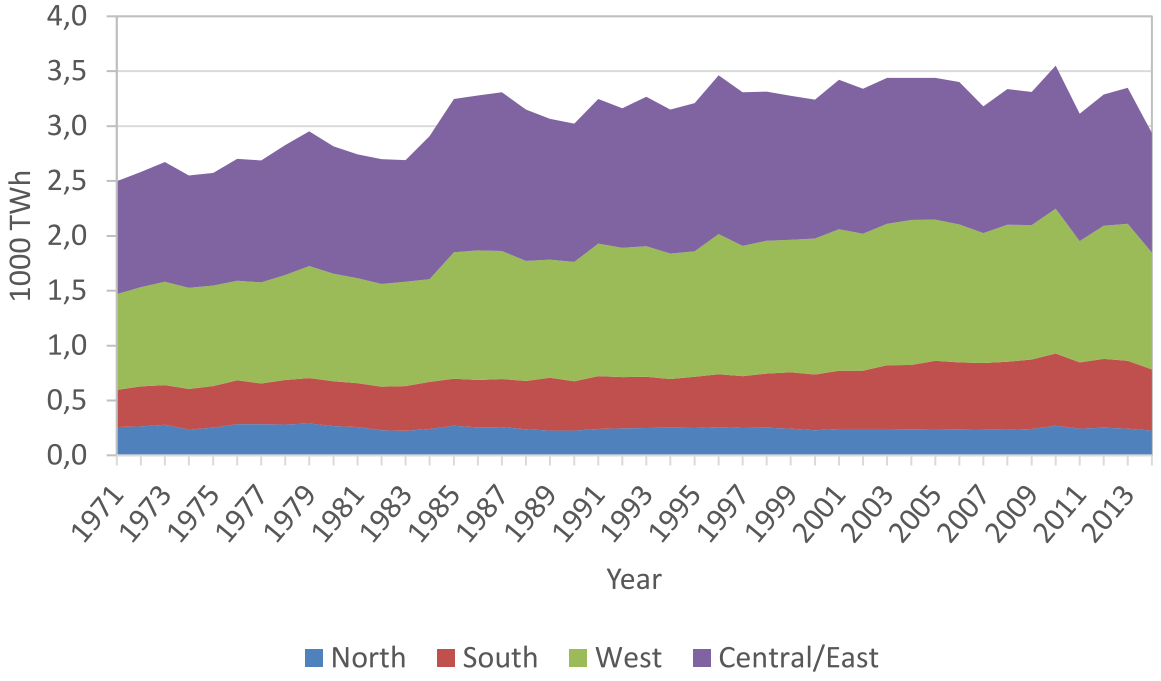


Figure 41: Energy consumption in the residential sector per region in Europe (IEA, 2016).

The energy consumption in the residential sector is rather constant, but varies significantly from year to year, potentially due to temperature variation and hence a variation in the heating demand.

Finally, there is a significant increase in the consumption of the commercial sector, especially in North and South Europe.

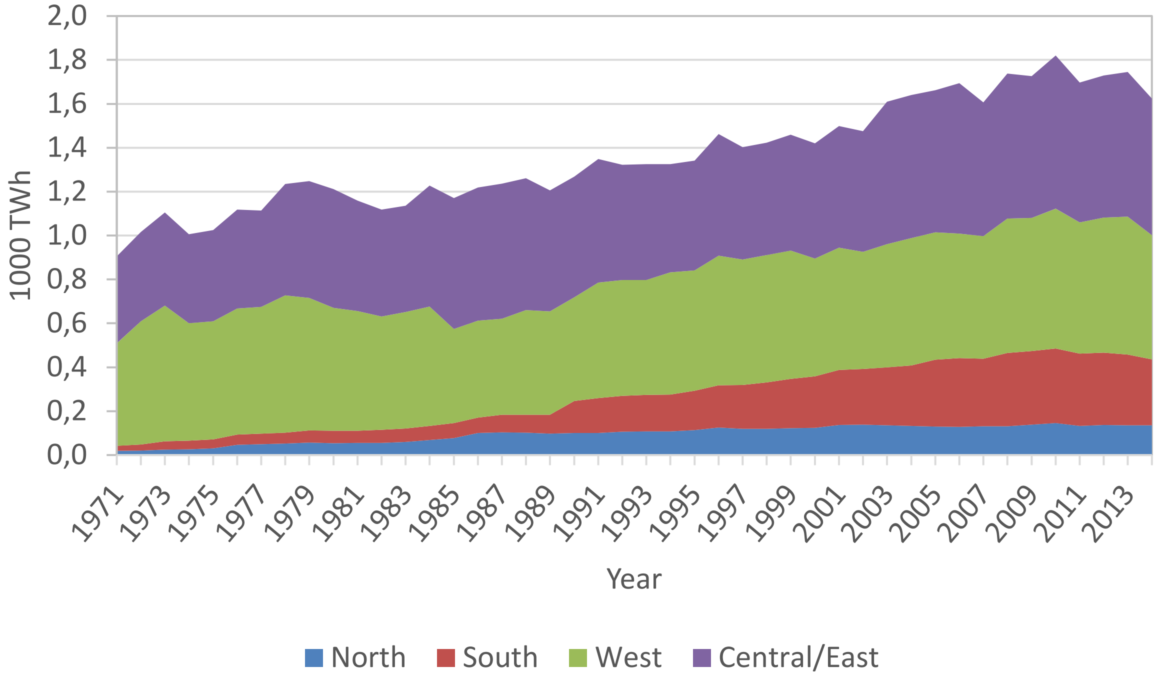


Figure 42: Energy consumption in the commercial sector per region in Europe (IEA, 2016).

5.4 Energy consumption trends summary

A summary of the energy consumption trends in terms of percentage increment and decrement for products and sectors is shown in Table 6. Figure 45 shows a summary of the total amount of each product that is used in each sector, for 2014. Both values in TWh and percentage are shown for convenience. Table 6 shows that there is a decline in the energy consumption in nearly all sectors during the last decade, despite the service sector.

Table 6: Energy consumption trends between 2005 and 2016 per product and sector in the EU.

	Change (%)
Energy Consumption	-7.1
• Industry	-16.4
• Households	-8
• Fishery/Agriculture/Forestry/Others	-24.7
• Transport	-0.5
• Service	3.8
Oil Consumption	-13.2
• Industry	-41.8
• Transport	-4
Electricity	0
• Industry	-10.4
• Households	0.8
• Service	14.5
Natural Gas	-12.6
• Industry	-22
• Households	-11
• Service	5
Solid Fuels	-16.2
• Industry	-16.2
• Households	0

Figure 45 depicts the utilisation of energy resources in the various sectors. It can be observed that the distribution is somewhat equally distributed, despite from the transport sector, which consumes nearly all oil products, while being the largest energy consumer at the same time.

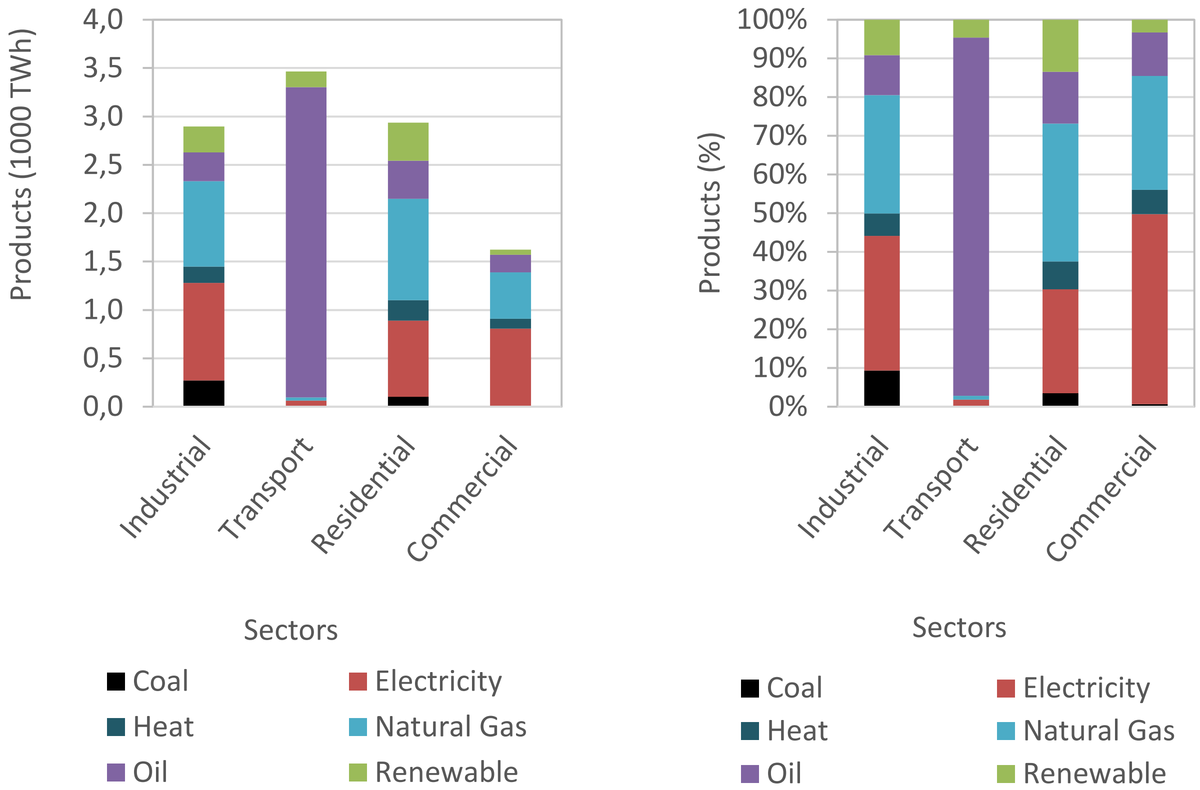


Figure 43: Products used in each sector in absolute values and percentages in 2014 (IEA, 2016).

The following figures will show the details of the historical development in the use of different products for the industrial, transportation, residential and commercial sectors.

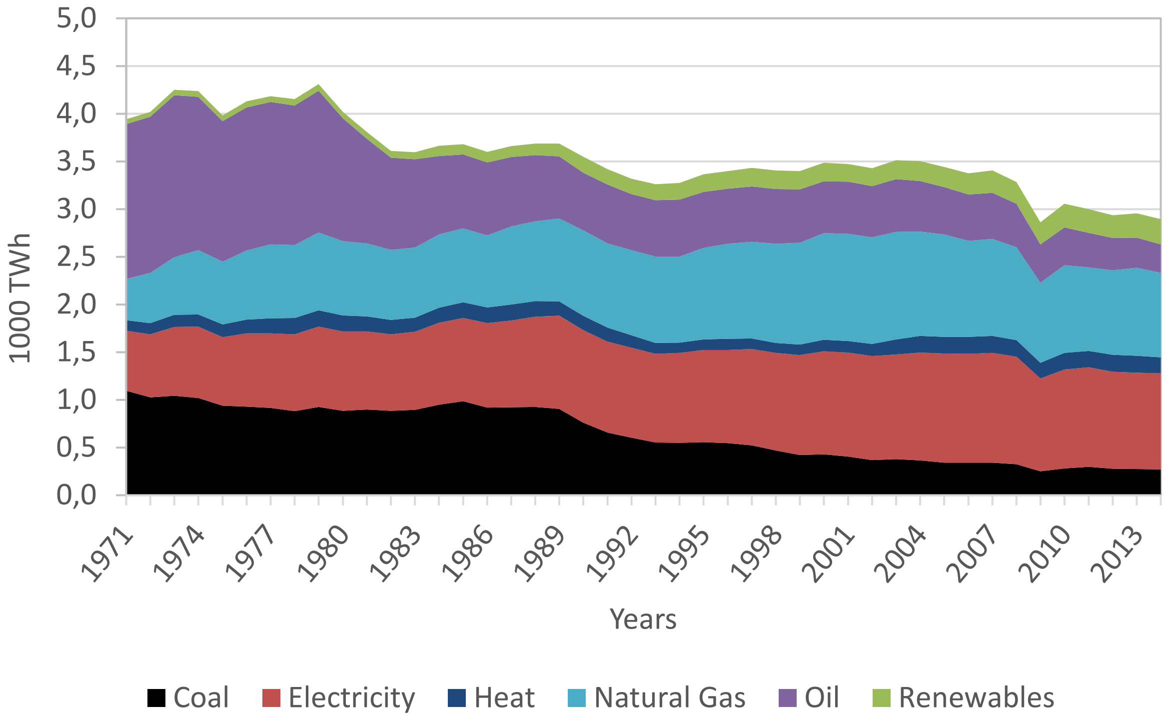


Figure 44: Historical development in the use of different products within the industrial sector (IEA, 2016).

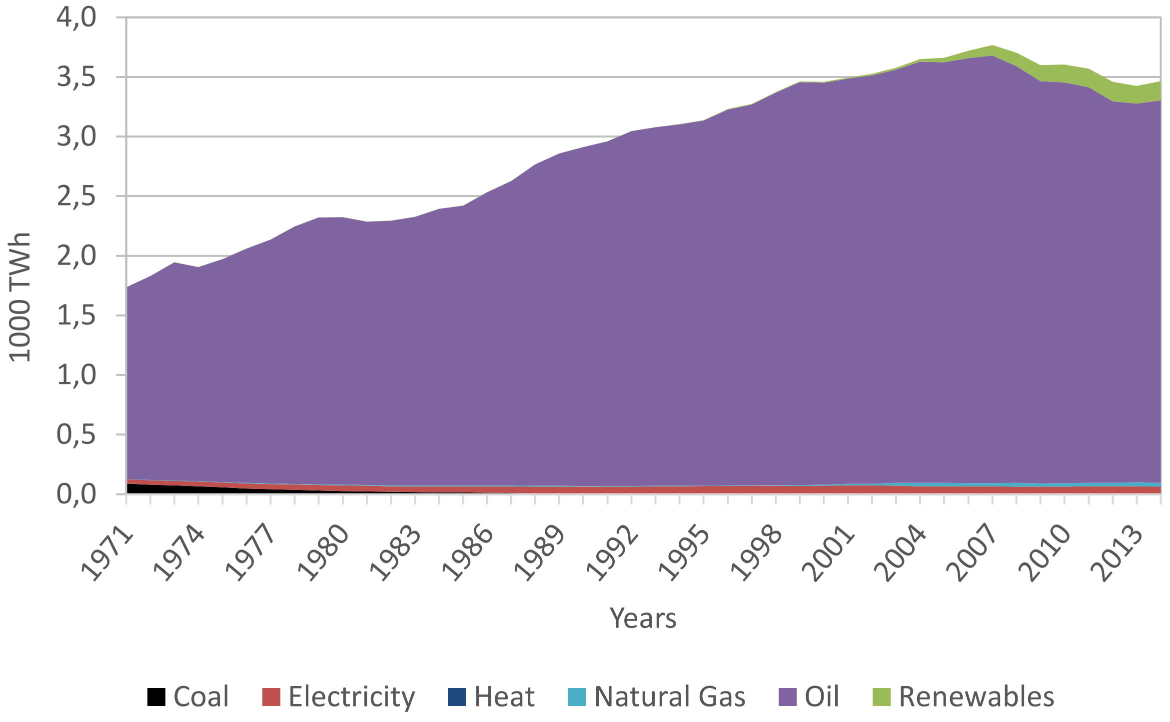


Figure 45: Historical development in the use of different products within the transport sector (IEA, 2016).

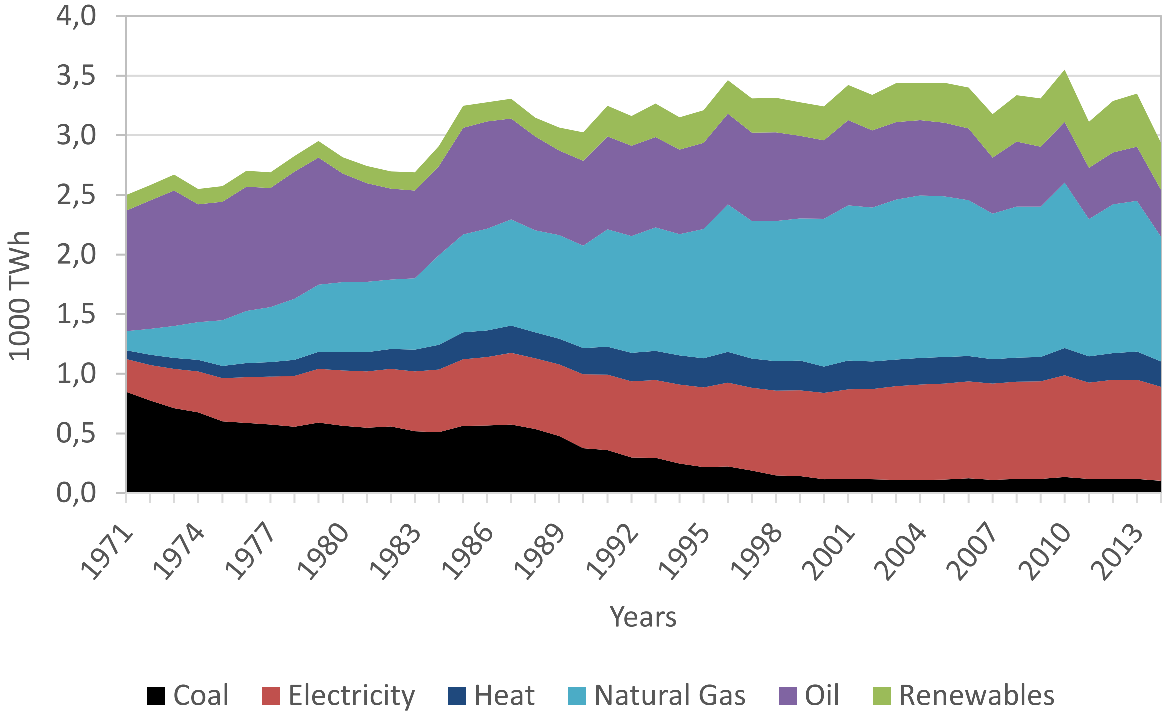


Figure 46: Historical development in the use of different products within the residential sector (IEA, 2016).

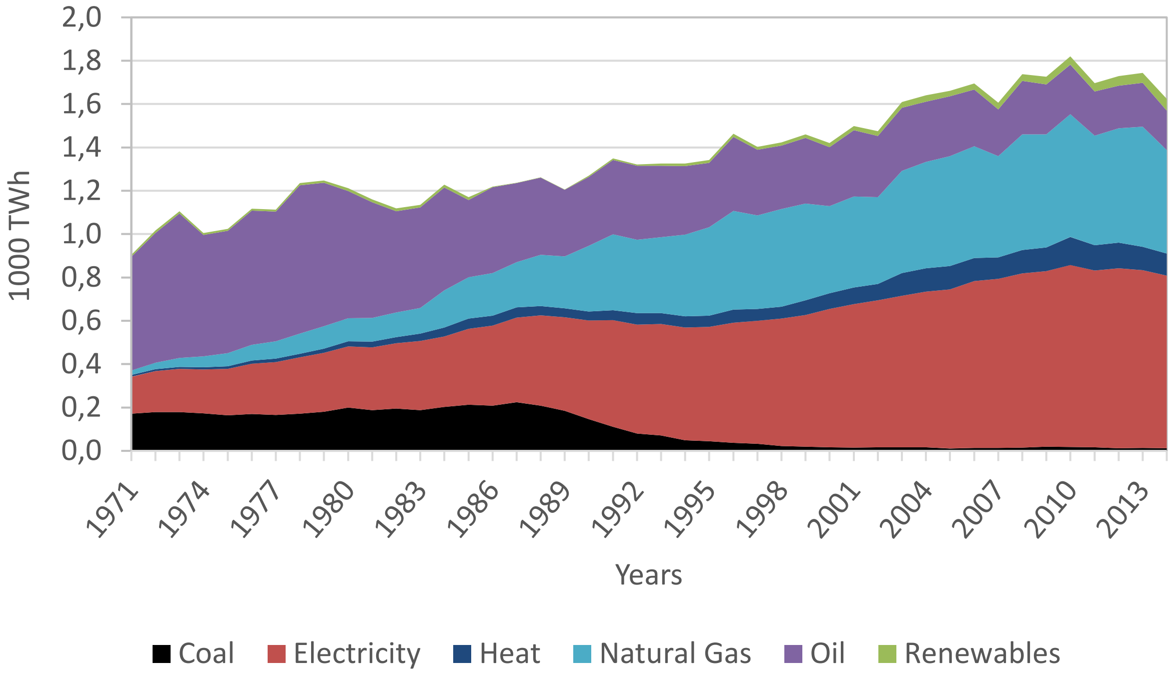


Figure 47: Historical development in the use of different products within the commercial sector (IEA, 2016).

5.5 Discussion of the European energy system

This section aims at commenting the previous diagrams in order to provide inputs to better understand where the hydrogen potential is lying, where is the renewable potential (and consequently the potential for hydrogen from renewable resources) lying, which countries represent potential markets, and how big is the challenge to decarbonise the energy sector. Of course, the authors recognise that it is not possible to properly and fully discuss the role of hydrogen by only focusing on historical energy consumption developments. In fact, more in-depth future demand projections as well as future scenarios definitions should be addressed before facing such complex and multi-faced topic. This goes beyond the scope of the present report that rather aims at collecting and presenting data resources to build the foundations for future more in-depth hydrogen scenario analyses. However, still the historical trend and the current energy system situation is giving some initial hints, so that preliminary broad thoughts can already be drawn as a preparatory introduction to more precise analyses that will be performed within future studies.

The diagrams developed in the previous sections, show that the transport sector is the one with the highest energy consumption (see Figure 25) followed by the industrial and residential sectors. The last two show more or less the same level of energy consumption. The transport sector is highly energy demanding; however, it is mainly dominated by oil as shown in Figure 44. Therefore, the petroleum and related products cover the highest share of final energy consumption (see Figure 27), followed by electricity and gases which cover more or less half share each. This gives an initial indication that the transport sector is the one where the biggest challenges of decarbonisation are lying given that it is currently dominated by oil. Therefore, there is a potential for hydrogen within the heavy-duty segment of the transport sector.

The industrial, residential and commercial sectors are dominated by electricity and natural gas (see Figure 44). The highest share of electricity consumption lies in the commercial sector while the highest share of natural gas consumption lies in the industrial sector. According to the diagrams discussed in previous sections, there is a potential for replacing natural gas with hydrogen as well as a potential for replacing the fossil fuel part of electricity generation with hydrogen. According to diagrams showed in Section 5.3.2 since the 90ties the energy consumption increased quite deeply within the transportation sector and the commercial sector, while it decreased in the industrial sector and slightly increased in the residential sector. However, since 2005 the energy consumption in the transportation sector experienced a slight decrement. Hence, even though the current situation is giving hints that transportation and industrial sectors are promising in terms of hydrogen potential penetration, the decreasing consumption trends registered in the last years put uncertainty in the way such sectors will actually develop in the forthcoming future. More in depth future energy demand projections should therefore be analysed to better discuss the actual future hydrogen potential in such sectors.

According to Figure 44 renewable sources are still covering a very small share of energy consumption, with a slightly higher exploitation in the residential sector. However, as shown in Figure 30, the gross inland renewable energy consumption has increased rapidly since 2004 and such trend is likely to carry on. Among renewable resources, biomass is dominating with 1,628 TWh in 2016 (see Figure 31) however, solar and wind have been increasing rapidly since 2008 and 2002 respectively. In 2016 the amount of energy covered by wind sources was much higher (above 290 TWh) than the one covered by solar sources (lower than 175 TWh). There is therefore a potential for hydrogen generation from renewable resources, even though still the renewable production is very low to fully sustain this. However, given the rapid increase in renewable generation that is registered in the last years, there may be an increasing potential for renewable hydrogen in the future. Given that solar production somewhat settled, while the wind production showed a stronger and higher increasing trend, it is possible to claim that there is more potential for hydrogen from wind (through electrolysis units) rather than solar. Moreover, given that biomass is strongly dominating, potential for hydrogen generation through biomass gasification should be investigated with priority. Growing biomass removes carbon dioxide from the atmosphere, hence the net carbon emissions of this method can be low, especially if coupled with carbon capture, utilization, and storage in the long term.

The figures in Section 5.3.1 show that in North Europe, the energy consumption has been stable and very low, with an exception for heat, that is the only type of consumption for which a constant increment is visible since the 90ties for the Nordic countries. Moreover, the consumption from natural gas, renewable and electricity increased rapidly, as opposed to coal and oil which show a decrement trend.

Finally, the diagrams developed in Section 5.3 clearly show that the higher energy consumption lies in central East and West Europe, which therefore represent a good potential for a future decarbonisation through hydrogen.

5.6 References

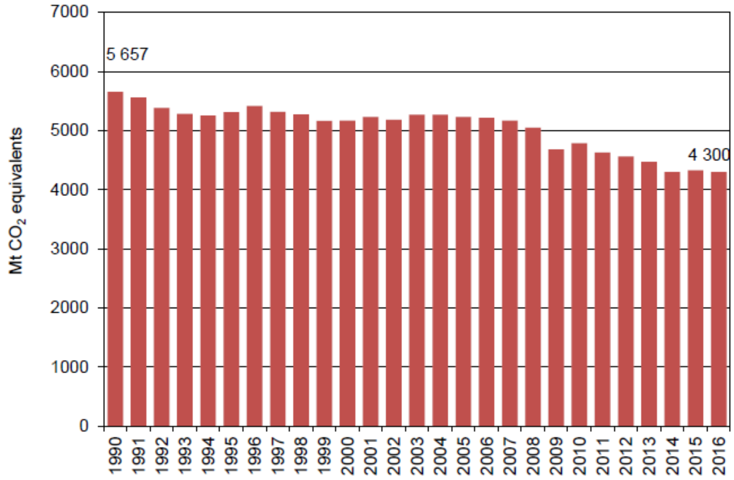
- **Energy statistical datasheets for the EU countries** from Eurostat (2018)
  https://data.europa.eu/euodp/data/dataset/information-on-energy-markets-in-eu-countries-with-national-energy-profiles
- **Global headline energy data** from IEA (2016)
  https://www.iea.org/statistics

6 The greenhouse gas emissions related to the European energy system

The following chapter provides an overview of the greenhouse gas (GHG) emissions of the European energy system based on the EEA report "Annual European Union greenhouse gas inventory 1990–2016 and inventory report 2018". Note, that there is inconsistency in the provided data, especially regarding the methane emissions. Section 6.1 will first introduce the historical development of greenhouse gas emissions in EU28 with the emissions of each country. Section 6.2 show the contribution of the different greenhouse gases and their main sources. Section 6.3 identifies the major contributors to the emissions in the Energy Sector with a detailed analysis of the sectors Energy Industries, Manufacturing Industries and Construction, and Transport. Section 6.4 provides estimates for the emissions in hydrogen production, whereas Section 6.5 summarize the findings of this report. Section 6.6 provides an overview of the different sectors.

6.1 Development of greenhouse gas (GHG) emissions in the EU28 in 1990-2016:

The total GHG emissions, excluding (LULUCF), in the EU28[24] amounted **to 4,300 Mt CO_2 eq. in 2016** (including indirect CO2 emissions[25]). In 2016, total GHG emissions were **24.0 %** (1,356 Mt CO_2 eq.) below 1990 levels (Figure 50).



Notes: GHG emission data for the EU-28 and Iceland as a whole refer to domestic emissions (i.e. within its territory), include indirect CO_2 and do not include emissions and removals from LULUCF; nor do they include emissions from international aviation and international maritime transport. CO_2 emissions from biomass with energy recovery are reported as a Memorandum item according to UNFCCC guidelines and are not included in national totals. In addition, no adjustments for temperature variations or electricity trade are considered. The global warming potentials are those from the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC).

Figure 48: EU28 plus Iceland GHG emissions (excl. LULUCF) (EEA, 2018).

There has been a progressive decoupling of gross domestic product (GDP) and GHG emission compared to 1990, with an increase in GDP of about 53 % over the period.

The overall EU GHG emission trend is dominated by **Germany and the United Kingdom,** both accounting for 32 % of total EU GHG emissions in 2016. These two member states have also achieved total GHG emission reductions of 656 Mt CO2-eq. compared to 1990, accounting for 48 % of the total net reduction in the EU of the past 26 years (Table 7).

The main reasons for the favorable trend in Germany were increasing efficiency in power and heating plants and the economic restructuring of the new Länder after German reunification. The reduction of GHG emis-

[24] All the data of EU28 include Iceland
[25] Direct CO_2 from the atmospheric oxidation of CH_4, CO and NMVOCs

sions in the United Kingdom was primarily the result of liberalizing energy markets and the subsequent fuel switches from oil and coal to gas in electricity production and N_2O emission reduction measures in the production of adipic acid.

Four countries (France, Italy, Poland and Spain) account for other more 37 % of the total EU GHG emissions in 2016.

France and Italy were the third and fourth largest emitters with a share of 11 % and 10 %, respectively. **Italy's** GHG emissions were 18 % below 1990 levels in 2016. Italian emissions decreased significantly since 2006 with a significant drop in 2009, which was mainly due to the economic crisis and reductions in industrial output. **France's** emissions were 16 % below 1990 levels in 2016. In France, large reductions were achieved in N_2O emissions from the chemical industry, but CO_2 emissions from road transport and HFC emissions from electronics industry and product uses increased considerably between 1990 and 2016.

Poland is the fifth largest emitter in the EU28, accounting for 9 % of total EU GHG emissions (396 Mt CO_2 eq.). Poland's GHG emissions were 15 % below 1990 levels in 2016. The main factors for decreasing emissions in Poland were the decline of energy-inefficient heavy industry and the overall restructuring of the economy in the late 1980s and early 1990s. The notable exception was transport (especially road transport), where emissions increased.

Spain, the sixth largest emitter in the EU28, **increased** its emissions by 13 % between 1990 and 2016. This was largely due to emission increases from road transport, electricity and heat production, and households and services.

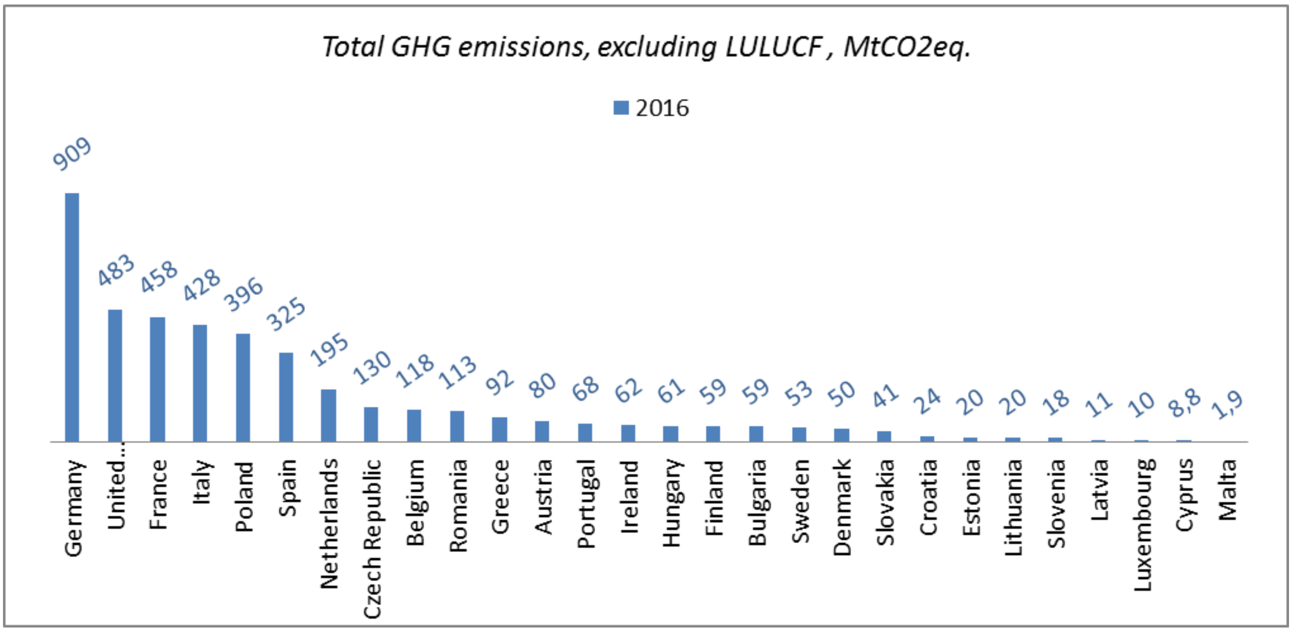


Figure 49: Total GHG emissions per countries 2016 (Mt CO_2 eq.).
Adopted by IPFen from EEA (2018).

Countries with more than 40 % of reductions between 1990 and 2016 are: Bulgaria, Estonia, Latvia, Lithuania, Romania, Slovakia, see Table 7.

Table 7: GHG emissions per country in Europe (Mt CO_2 eq.).

Member state	1990	2016	2016-1990 (Mt CO_2 eq.)	2016-1991 (%)
Germany	1252	909	-343	**-27,4 %**
United Kingdom	797	483	-314	**-39,4 %**
France	546	458	-88	**-16,1 %**
Italy	518	428	-90	**-17,4 %**
Poland	467	396	-71	**-15,2 %**
Spain	288	325	37	**12,8 %**
Netherlands	221	195	-26	**-11,8 %**
Czech Republic	200	130	-70	**-35,0 %**
Belgium	147	118	-29	**-19,7 %**
Romania	247	113	-134	**-54,3 %**
Greece	103	92	-11	**-10,7 %**
Austria	79	80	1	**1,3 %**
Portugal	60	68	8	**13,3 %**
Ireland	55	62	7	**12,7 %**
Hungary	94	61	-33	**-35,1 %**
Finland	71	59	-12	**-16,9 %**
Bulgaria	104	59	-45	**-43,3 %**
Sweden	72	53	-19	**-26,4 %**
Denmark	70	50	-20	**-28,6 %**
Slovakia	74	41	-33	**-44,6 %**
Croatia	32	24	-8	**-25,0 %**
Estonia	40	20	-20	**-50,0 %**
Lithuania	48	20	-28	**-58,3 %**
Slovenia	19	18	-1	**-5,3 %**
Latvia	26	11	-15	**-57,7 %**
Luxembourg	13	10	-3	**-23,1 %**
Cyprus	5,6	8,8	3,2	**57,1 %**
Malta	2,1	1,9	-0,2	**-9,5 %**

Almost all EU member states reduced their emissions compared to 1990. Only five countries (Austria, Cyprus, Ireland, Portugal and Spain) have increased their GHG emissions between 1990 and 2016 by a small total of 56 Mt CO_2 eq. as can be seen Figure 52.

The countries with the biggest changes in volumes (+/-) between 2016 and 1990 are:
Germany (-343 Mt CO_2 eq.), United Kingdom (-314 Mt CO_2 eq.), Romania (-134 Mt CO_2 eq.), Italy (90 Mt CO_2 eq.), France (-88 Mt CO_2 eq.).

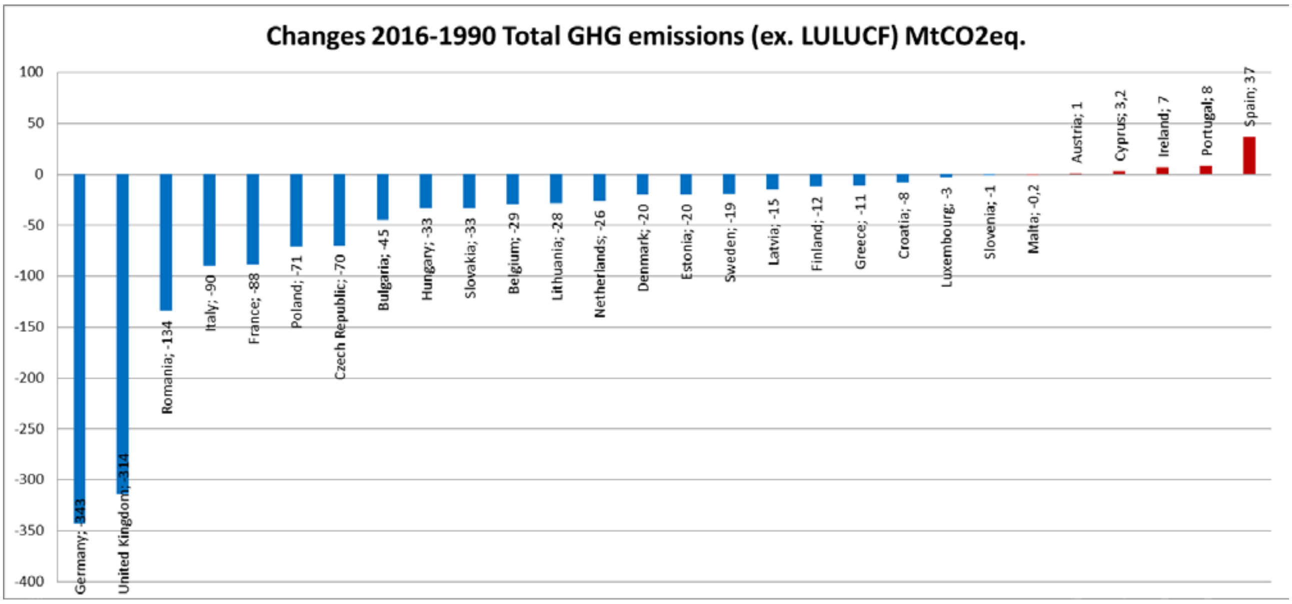


Figure 50: Changes 2016-1990 Total GHG emissions. Adopted by IPFen from EEA (2018).

The GHG emissions decreased in the majority of sectors between 1990 and 2016, with the notable **exception of Road Transport and Refrigeration and Air conditioning** as shown in Figure 53. The emission reductions were largest for manufacturing industries and construction, electricity and heat production, and residential combustion

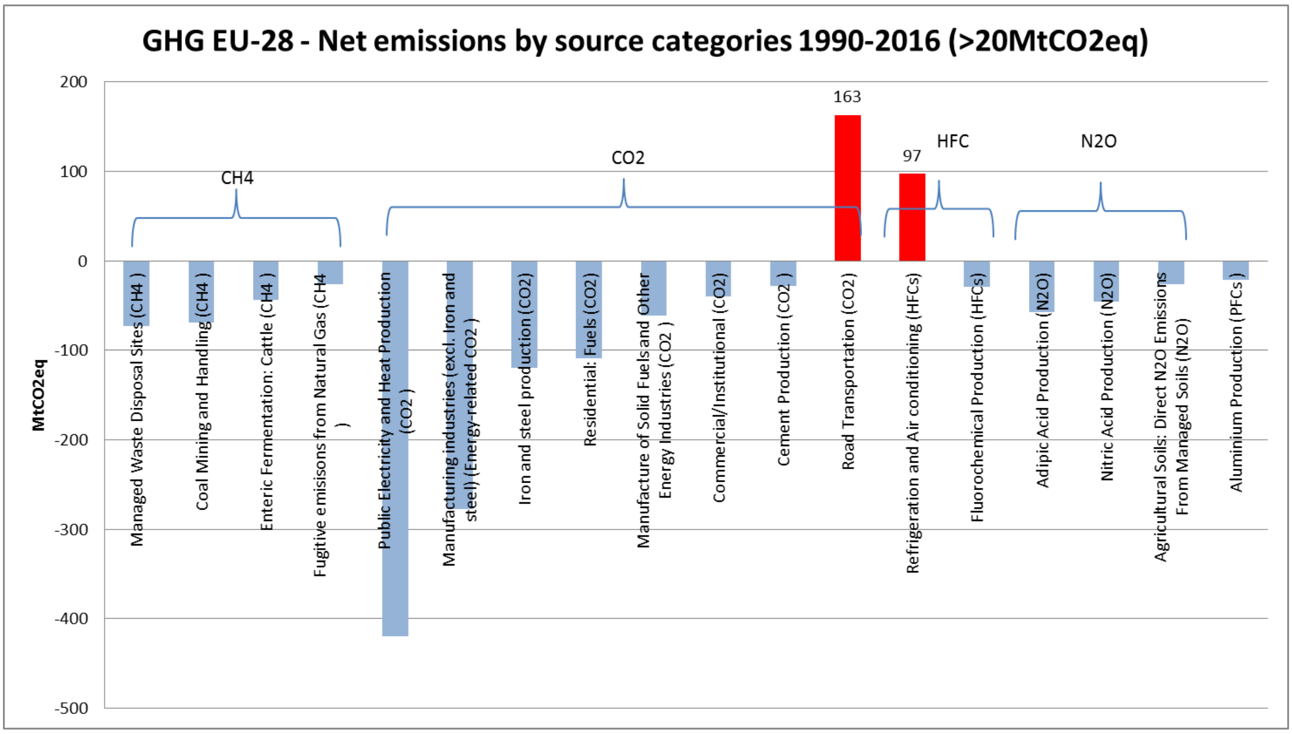


Figure 51: Overview of EU28 plus Iceland source categories whose emissions increased or decreased by more than 20 Mt CO_2 eq, in the period 1990–2016. Adopted by IPFen from EEA (2018).

- ✓ A combination of factors explains **lower emissions in industrial sectors**, such as improved efficiency and carbon intensity as well as structural changes in the economy, with a higher share of services and a lower share of more-energy-intensive industry in total GDP.
- ✓ **Emissions in the residential sector** also represented one of the largest reductions. Energy efficiency improvements from better insulation standards in buildings and a less carbon-intensive fuel mix can partly explain lower demand for space heating in the EU as a whole over the past 26 years.
- ✓ The very strong increase in the use of **biomass** for energy purposes has also contributed to lower GHG emissions in the EU.
- ✓ A number of **policies** (both EU and country-specific) have also contributed to the overall GHG emission reduction, including key agricultural and environmental policies in the 1990s and climate and energy policies in the 2000s.

6.2 Contribution of the different greenhouse gases and their sources

In 2016 in the EU28, 79 % of the emitted greenhouse gas is CO_2, 11 % is CH_4 and 6.2 % is N_2O (Figure 54).

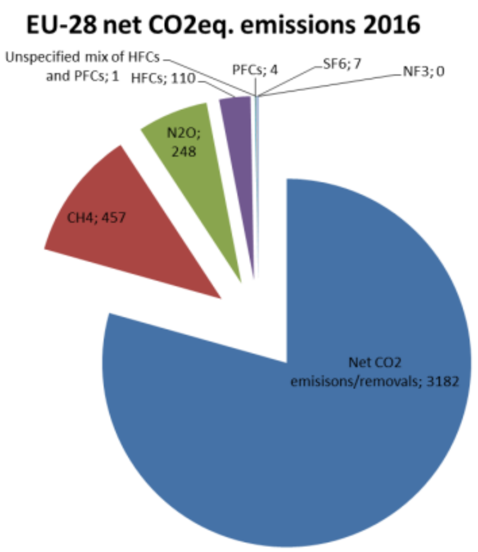


Figure 52: GHG share of EU28 and Iceland GHG emissions and removals in 2016 in CO_2 equivalent. Adopted by IPFen from EEA (2018).

CO_2 was also responsible for the largest reduction in emissions since 1990. Reductions in emissions from N_2O and CH_4 have been substantial, reflecting lower levels of mining activities, lower agricultural livestock, as well as lower emissions from managed waste disposal on land and from agricultural soils.

6.2.1 Main sources of CO_2 in EU28

The three largest key source categories for CO_2 emissions are **Public Electricity and Heat production (29 %), Road transport (25 %), Manufacturing Industries and construction (14 %)** as shown in Figure 55.

All source categories have been reduced between 1990 and 2016 their **CO_2 emissions with the exception of Road transportation** which increased by around 200 Mt CO_2 during the period.

CO_2 emissions from electricity and heat production decreased strongly since 1990 in EU 28:

- In addition to improved energy efficiency there has been a move towards **less carbon intense fuels**.
- Between 1990 and 2016, the use of solid and liquid fuels in thermal stations decreased strongly whereas **natural gas consumption doubled**, resulting in reduced CO2 emissions per unit of fossil energy generated.

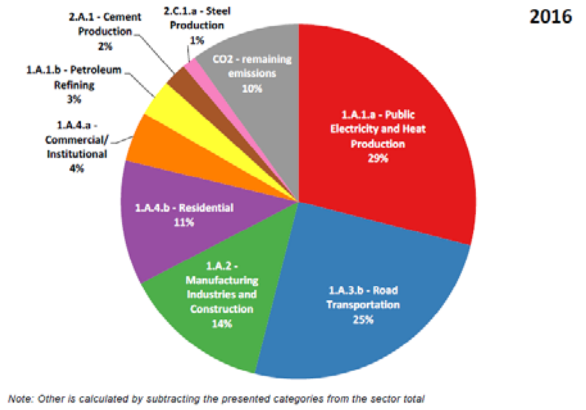


Figure 53: $\underline{CO_2}$ emissions share of key source categories in 2016 for EU28 and Iceland (EEA, 2018).

6.2.2 Main sources of CH_4, N_2O and fluorinated gas in EU28

CH_4 emissions account for 11 % of total EU GHG emissions in 2016 and decreased by 37 % since 1990 to 457 Mt CO_2 eq. in 2016. The two largest key sources are enteric fermentation (35 %) and anaerobic waste (19 %) (Figure 56, left).

N_2O emissions are responsible for 6 % of total EU GHG emissions and decreased by 37 % to 248 Mt CO_2 eq. in 2016. N_2O emissions derive mainly from the agriculture soils which accounts for about 64 % of N_2O emissions in 2016 (Figure 56, right). The main reason for large N_2O emission cuts were reduction in fugitive emissions from the chemical industry and agricultural soils.

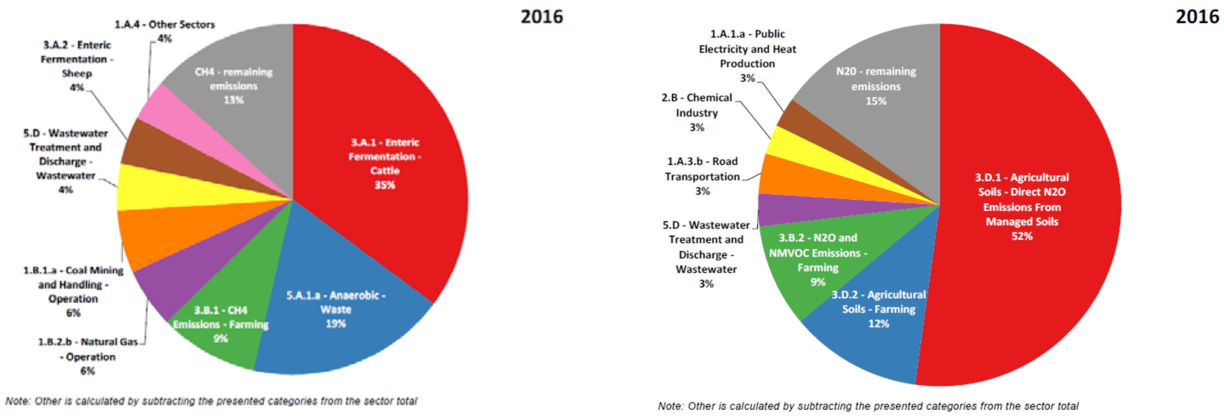


Figure 54: $\underline{CH_4}$ (left) and $\underline{N_2O}$ (right) share emissions of key source categories in 2016 for EU28 (EEA, 2018).

Fluorinated gas emissions account for only 2.8 % of total EU GHG emissions. **In 2016, emissions were 122 Mt CO_2 eq., which was 68 % above 1990 levels.** Refrigeration and air conditioning accounts for 80 % of fluorinated gas emissions in 2016 (Figure 57). HFCs from refrigeration and air conditioning showed large increases between 1990 and 2016. The main reason for this is the phase-out of ozone-depleting substances and the replacement of these substances with HFCs (mainly in refrigeration, air conditioning, foam production and as aerosol propellants).

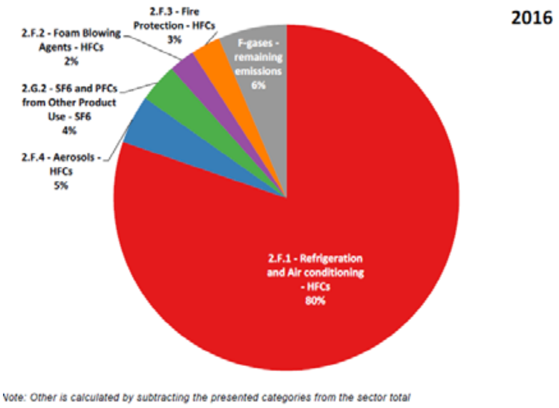


Figure 55: HFCs share emissions of key source categories in 2016 for EU28 and Iceland (EEA, 2018).

6.3 Emissions of the Energy Sector in 1990-2016

The most important emitting sector by far is the Energy Sector which accounted for **78 % of total EU GHG emissions** in 2016. The second largest sector is agriculture (10 %), followed by industrial processes (9 %) (Figure 58).

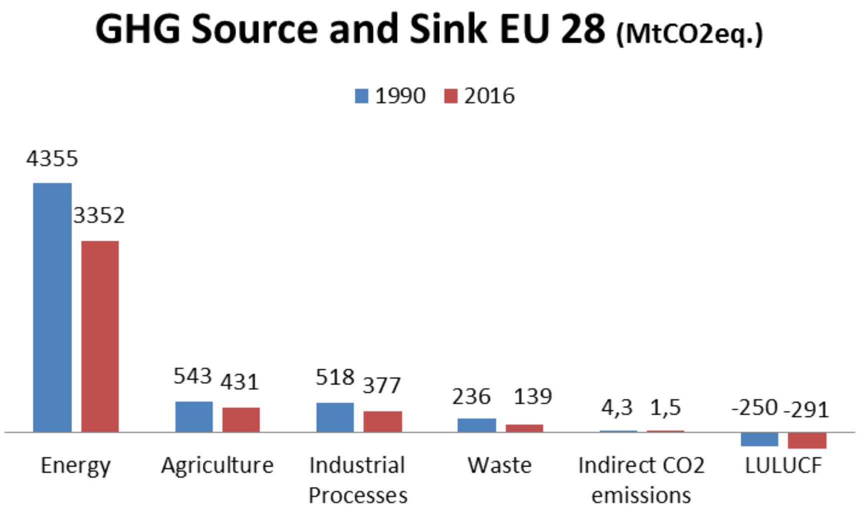


Figure 56: GHG Source and sink categories in EU 28. 1990 and 2016. Adopted by IPFen from EEA (2018).

<u>In the Energy Sector,</u> the main source categories of GHG are from *Energy industries, Manufacturing industries and construction, Transport, others…*

Total GHG emissions from the energy sector decreased regularly by 23 % from 4,355 Mt in 1990 to 3,352 Mt in 2016 (Figure 59). The most important energy-related gas is CO_2 that makes up 75 % of the total EU28 GHG emissions in 2016.

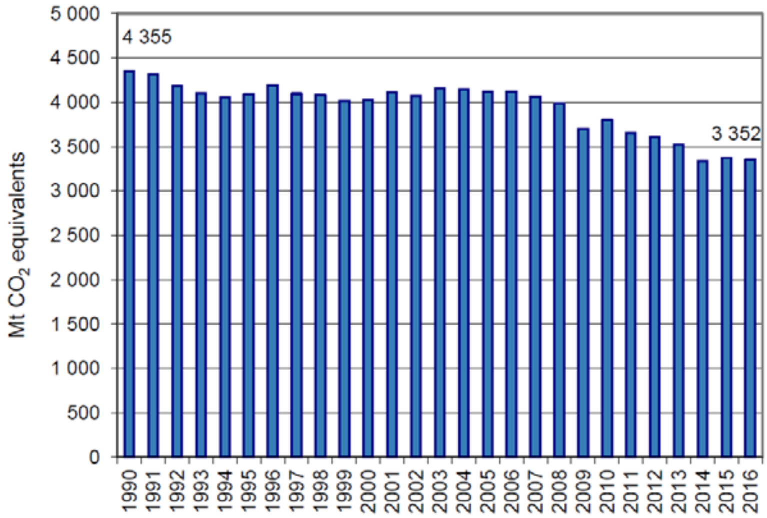


Figure 57: Energy sector: EU28 GHG emissions in CO_2 equivalents (Mt) for 1990–2016 (EEA, 2018).

In the Energy Sector 1, the 3 largest categories, **Public electricity and heat production(1A1a), Road transport(1A3b), manufacturing industries, and construction (1A2),** account for 70.3 % of GHG emissions (Figure 60). (See Annex: 6.6 for key categories in the energy sector)

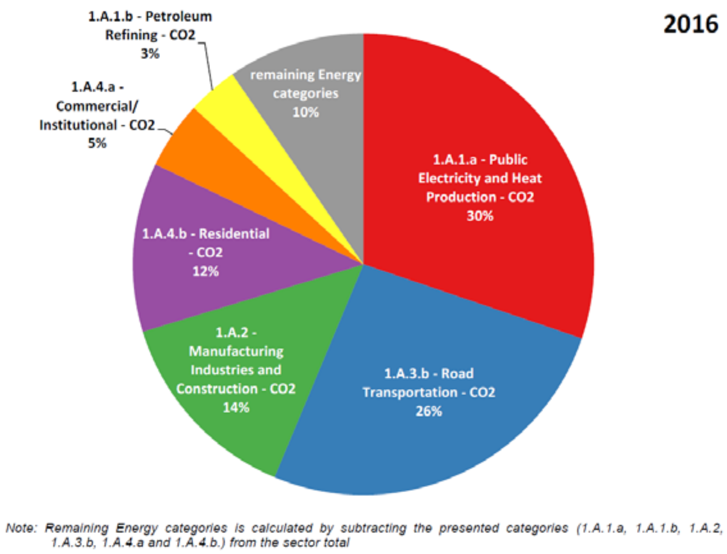


Figure 58: Energy sector 1, share of largest key source categories in 2016 (EEA, 2018).

- CO_2 emissions from Road Transportation had the highest increase in absolute terms of all energy-related emissions,
- while CO_2 emissions from Public Electricity and Heat Production as well as Manufacturing Industries decreased substantially between 1990 and 2016.
- The decreases in Public Electricity and Heat Production and Manufacturing Industries as well as the increases in Road Transportation occurred in almost all member states.

6.3.1 Energy Industries (Sector 1A1)

Energy Industries comprises emissions from **fuels combusted** by the fuel extraction or energy-producing industries. The energy industries is again subdivided in 3 categories: **Public Electricity and Heat Production, Petroleum Refining and Manufacture of Solid Fuels** (Figure 61).

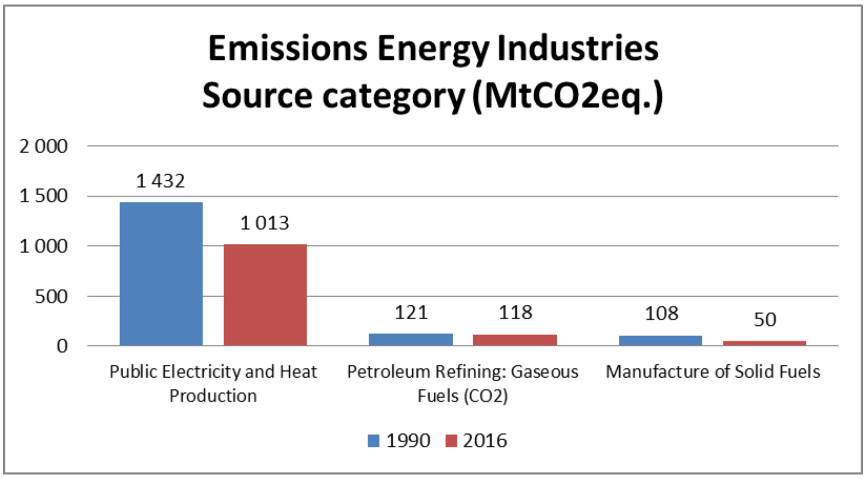


Figure 59: Emissions Energy Industries – Source category (Mt CO_2 eq.). Adopted by IPFen from EEA (2018).

- **Public electricity and heat production**: 1,013 Mt CO_2 eq. in 2016, in decline by -29 % compared to 1990. Represents about **85 % of GHG emissions in Energy sector** (1A1).
- **Petroleum-refining**: 118 Mt CO_2 eq., in decline by -2 % compared to 1990.
- **Manufacture of solid fuels** and other energy industries: 50 Mt CO_2 eq. in 2016, in decline by -54 % compared to 1990.

In 2016, energy Industries CO_2 emissions represent 1,181 Mt CO_2 eq, in decline by -29 % compared to 1990. The decrease in fuel consumption since 2006 can be explained by the effects of the economic downturn, the increased use of renewables, but also by enhanced energy efficiency in the newer EU member states as well as mild winters.

GHG emissions in the Energy Sector by member states

In terms of absolute contributions to EU28 GHG emissions from Energy Industries (**1,195 Mt CO_2 eq.**), the sector is dominated by **Germany, Poland, the United Kingdom and Italy** (Figure 62):

- The first two combined are responsible for 41 % of the EU's GHG emissions from energy industries, and
- all four countries represent 59 %.

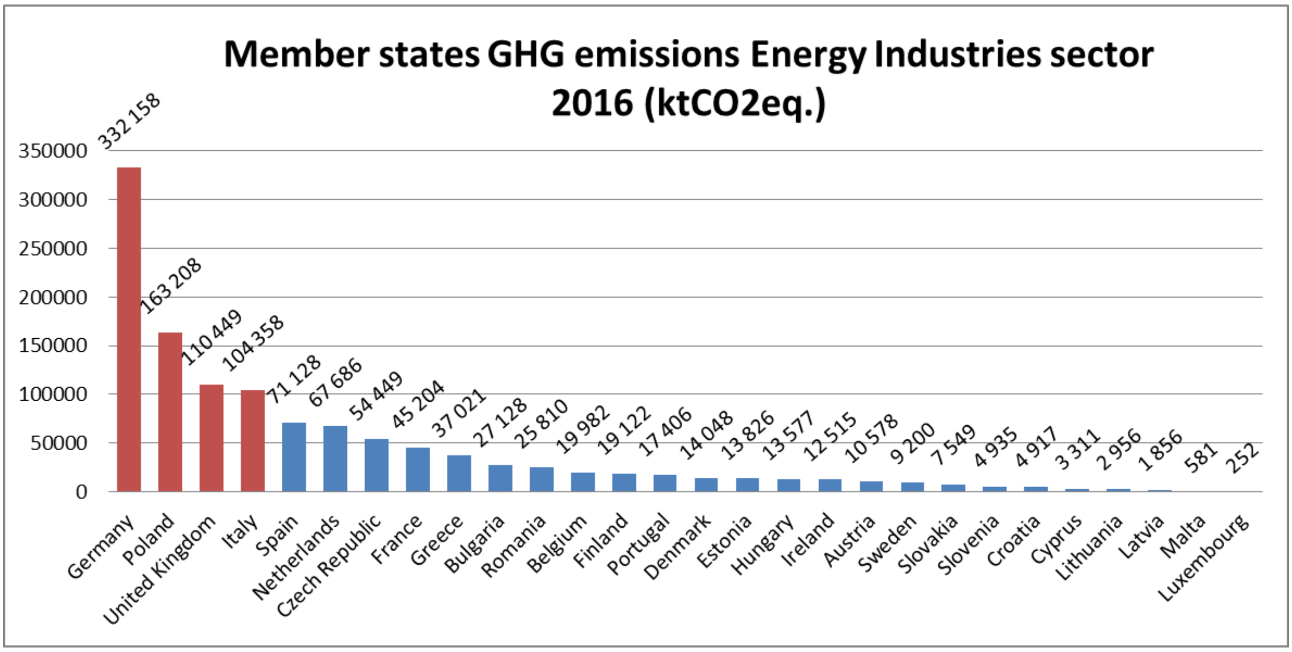


Figure 60: GHG emissions by member states in Energy Industries sector 2016 (ktCO_2eq.) Adopted by IPFen from EEA (2018).

Between 1990 and 2016, GHG emissions from Energy Industries increased in 6 Member State (Netherlands, Cyprus, Ireland, Portugal and Finland) and fell in the other 22 (Figure 63). The highest increase was accounted for by the Netherlands with 14 Mt CO_2 eq. On the other hand, United Kingdom, Germany and Poland, account for the largest part of reductions (-294 Mt CO_2 eq.). The change in the EU28 was a net decrease in the energy industries of about 483 Mt CO_2 eq. between 1990 and 2016.

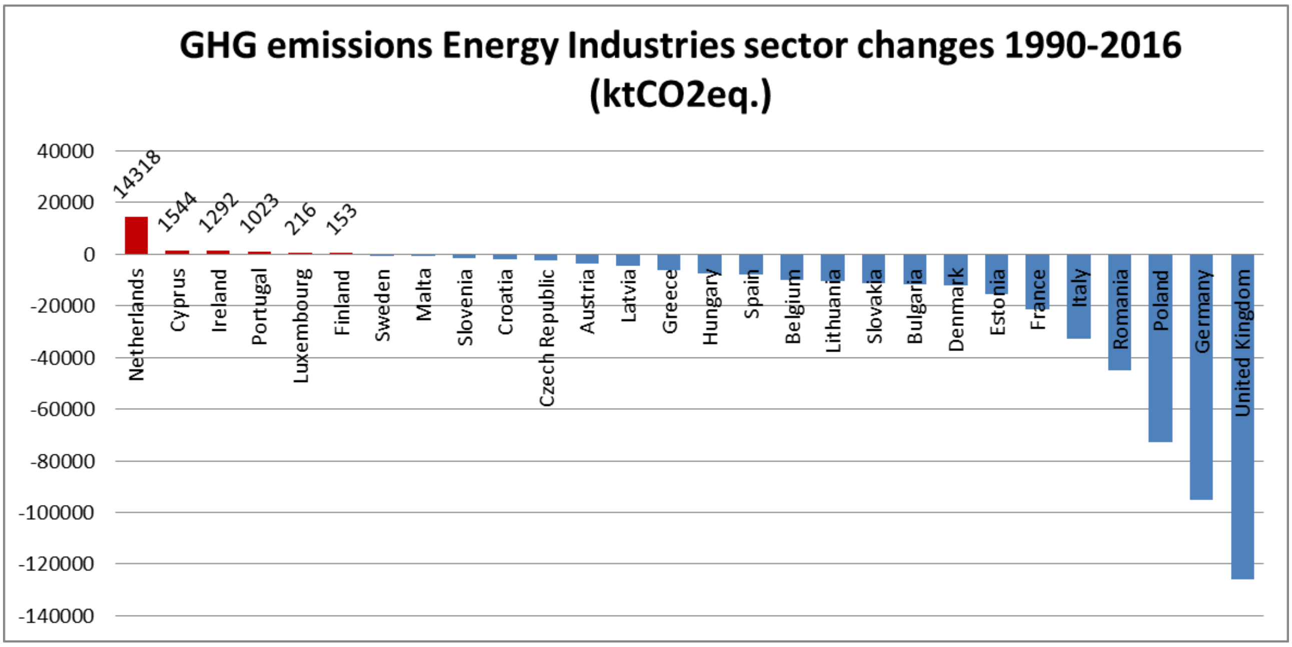


Figure 61: GHG emissions changes by member states in Energy Industries sector 1990-2016 (ktCO_2eq.). Adopted by IPFen from EEA (2018).

Electricity and Heat Production

CO2 emissions from electricity and heat production is the largest category in the EU28 accounting for 24 % of total GHG emissions in 2016 and **for 86 % of GHG emissions of the Energy Industries** sources.

Between 1990 and 2016, **CO_2 emissions from Electricity and Heat Production decreased by 29 %** in the EU28 despite the increase of the consumption/production (+20 %). Differences in the intensity of GHG emissions of heat and electricity production between the member states are explained by the **mix of fuels used** and specifically the **increased share of renewable energy, improvements in energy efficiency and (fossil) fuel switching from coal to gas**. Fuel used for public electricity and heat production decreased by 14 % in the EU28 between 1990 and 2016

- **Solid fuels still represent 51 %** of the fuel used in public conventional thermal power plants, although its combustion has been declining by 37 % between 1990 and 2016.
- **Gaseous fuels have increased very rapidly**. In 2016 its share amounts to 28 % of all the fuel used for the production of heat and electricity in the EU28.
- **Liquid fuels** still account for some 3 %.
- **The use of biomass has increased even more rapidly than the use of gas**, but its share in the fuel mix is relatively small, at around 13 % in 2016 (Figure 64).

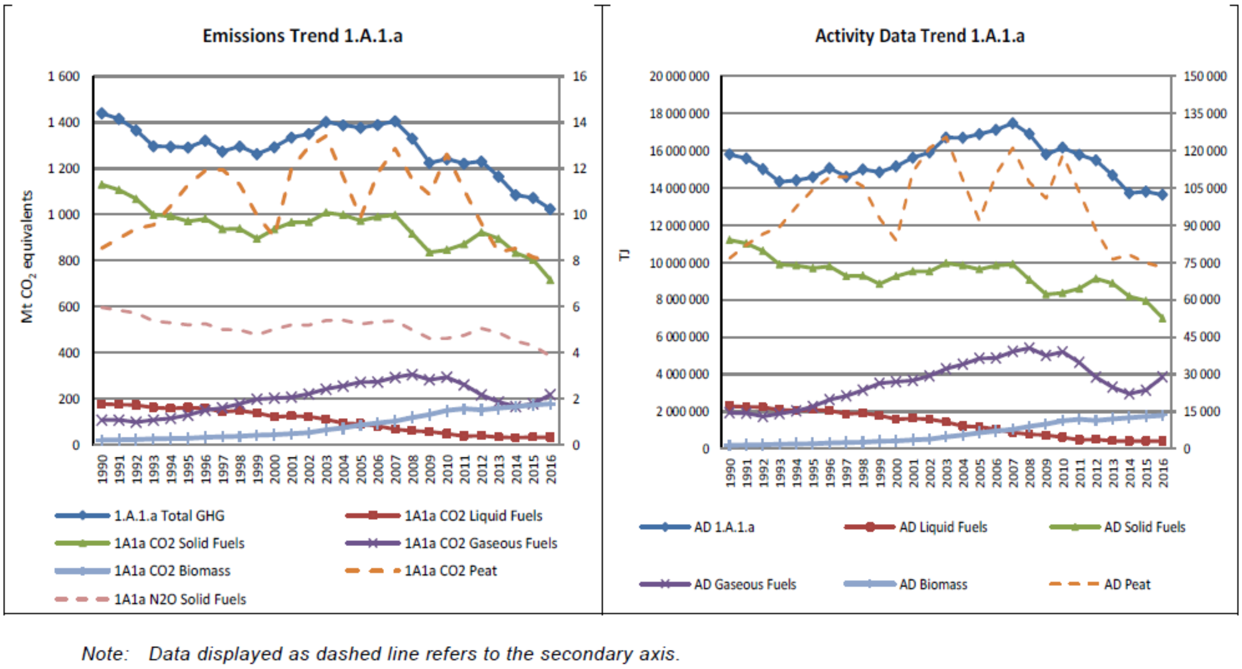


Figure 62: 1.A.1.a Public Electricity and Heat Production: Total, CO_2 and N_2O emission and activity data trends (EEA, 2018).

Electricity and heat production emissions by member states

Five countries (Germany, Poland, United Kingdom, Italy and Spain) are the main CO_2 emitters (65 %) of Public Electricity and Heat production (Figure 65).

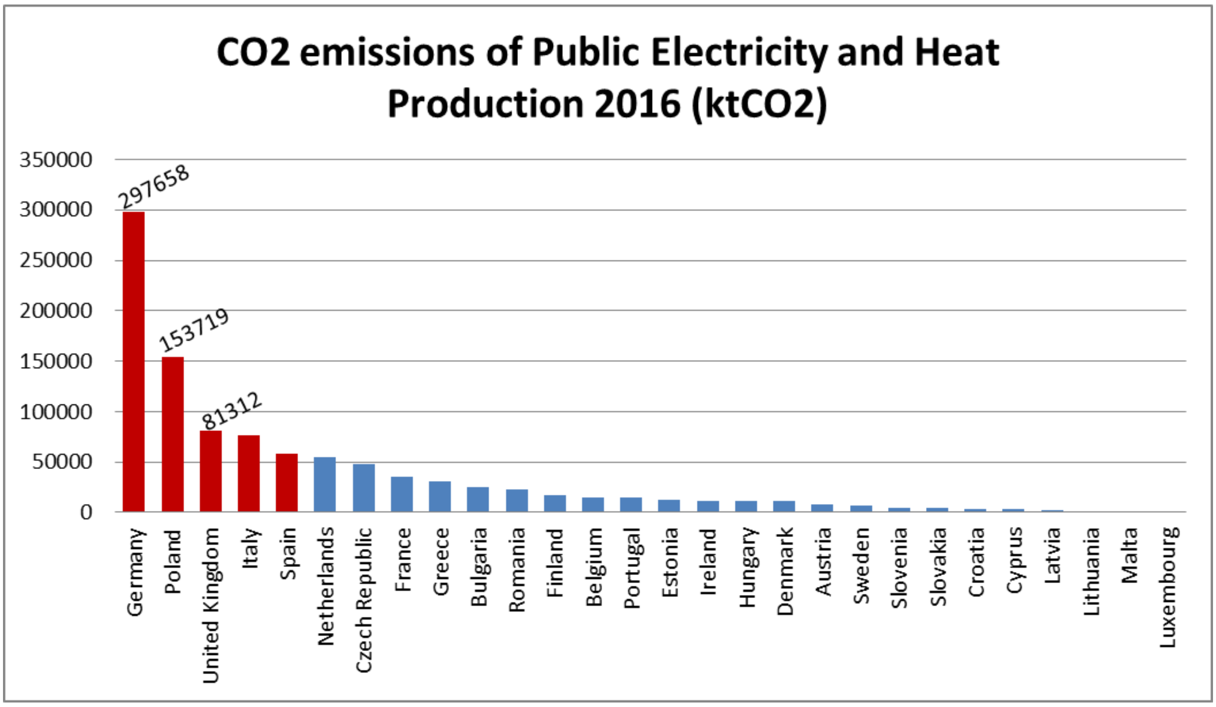


Figure 63: CO2 emissions of Public Electricity and Heat Production in 2016 (ktCO2). Adopted by IPFen from EEA (2018).

During 1990-2016 almost all countries have reduced their CO_2 emissions from Public Electricity and Heat production excepted the Netherlands (+14 854 ktCO2), Cyprus, Ireland, Portugal and Finland for lower quantities (Figure 66).

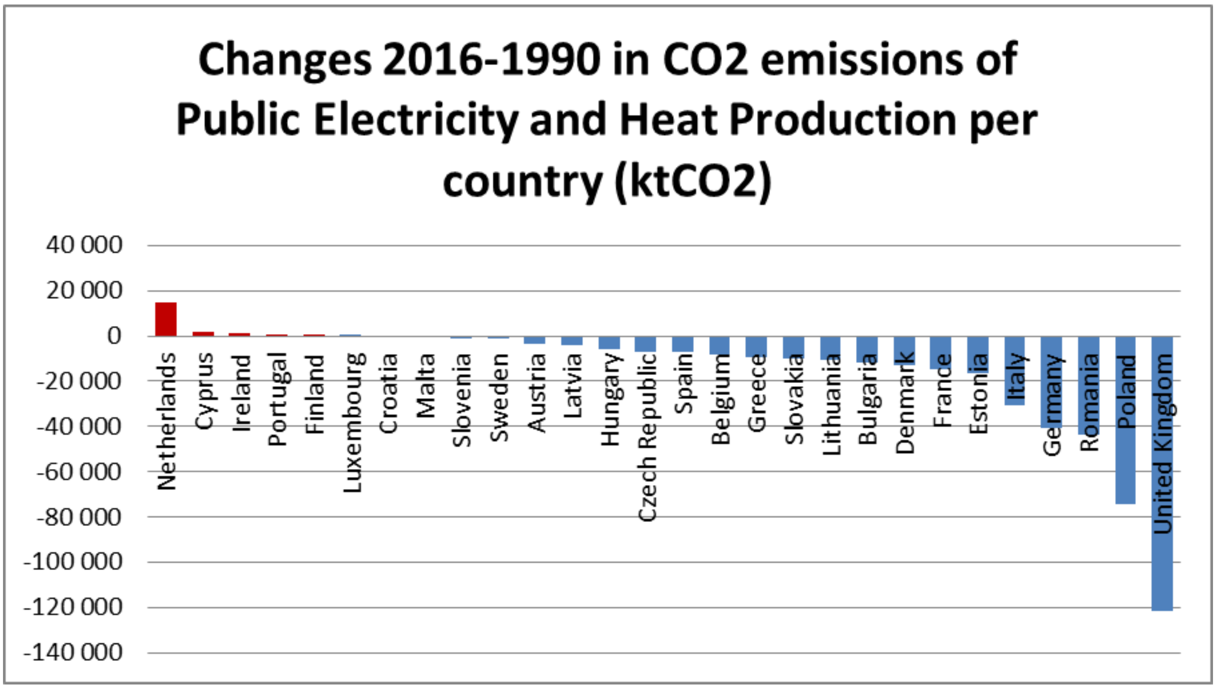


Figure 64: Changes 2016-1990 in CO_2 emissions of Public Electricity and Heat Production per country. Adopted by IPFen from EEA (2018).

Electricity and heat production emissions by fuel type

CO_2 Emission from liquid fuels in the Electricity and Heat Production by member states

In 2016 Spain (30 %), France (12.8 %), Greece (11.5 %) and Cyprus (10.4 %) are responsible for about 66 % of CO_2 emissions in electricity and heat production by liquid fuels. The strongest decrease in emissions took place in Italy because less oil is used as a fuel in the power sector. In 1990 Italy was responsible for 36.1 % of the emissions in this category and in 2016 only for 4.4 %.

CO_2 emissions from solid fuels in the Electricity and Heat Production by member states

CO_2 emissions from the combustion of solid fuels represented about 70 % of all greenhouse gas emissions from public electricity and heat production. Within the EU28 emissions fell by 37 % between 1990 and 2016 (-411.78 Mt CO_2 eq.) mainly because coal is being phased out of the fuel mix especially in the United Kingdom as well as in Germany. In 2016 Germany (34.9 %), Poland (20.8 %) are responsible for 55.7 % CO_2 emissions from solid fuels.

CO_2 emissions from gaseous fuels in the Electricity and Heat Production

CO_2 emissions from the combustion of gaseous fuels accounted for 21 % of all greenhouse gas emissions from public electricity and heat generation in 2016. Emissions increased by 103 % in the EU28 between 1990 and 2016. The United Kingdom and Italy together were responsible for 55.7 % of the increase in the last 26 years. Main contributing member states for emissions from gaseous fuels in the electricity and heat production are the United Kingdom (22.9 %), Italy (19.8 %) and Germany (14.4 %).

6.3.2 Manufacturing Industries and Construction (1A2)

The category 1A2 Manufacturing Industries and Construction includes emissions from combustion of fuels in manufacturing industries and construction[26].

In 2016, the category 1A2 contributed to **474.67 Mt CO_2 eq.** of which 98.7 % was CO_2, 0.9 % N_2O and 0.4 % CH_4. CO_2 emissions from Manufacturing Industries and Construction is the fourth largest sector in the EU28 accounting for 10.9 % of total GHG emissions in 2016. Between 1990 and 2016, CO2 emissions from manufacturing industries declined by 44 %, which was 35 % below 1990 levels in 2016. A shift from solid and liquid fuels to mainly natural gas took place and an increase of biomass by 145 % and an increase of other fossil fuels by 62 % has been recorded.

Between 1990 and 2016, **Germany, the Czech Republic, France, Italy, Romania and the United Kingdom** show by far the largest emission reductions in absolute terms. Only Austria, Cyprus and Ireland report emission increases.

[26] including fuel use of non-public electricity and heat generation (auto producers)

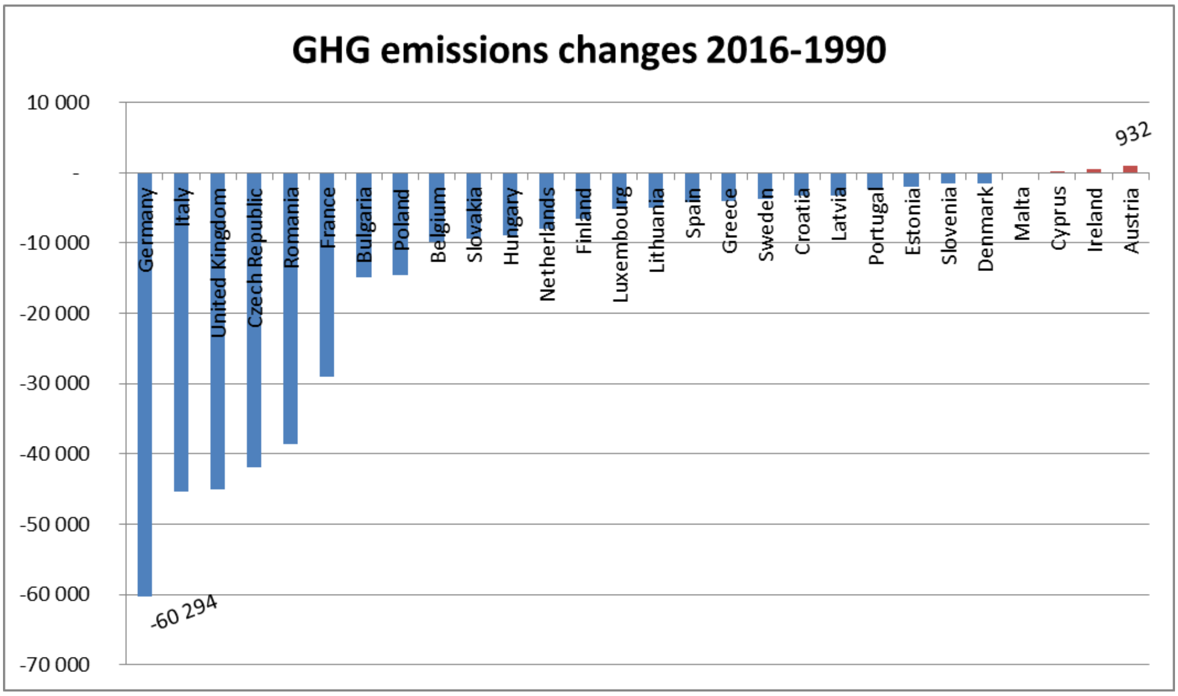


Figure 65: GHG emission changes 2016 per member state. Adopted by IPFen from EEA (2018).

The main reason for the large decline in Germany was the restructuring of the industry and efficiency improvements after German reunification as inefficient and CO_2 intensive industry in the former GDR was shut down. The main reasons for the large decline in the Czech Republic were the loss of markets and the energy saving behavior of newly privatized enterprises, following the political changes in the country in the early 1990s. Main reasons of the decline in Romania were the transition to a market economy and the reduction of energy intensive activities. The decrease of United Kingdom was mainly due to a strong reduction of liquid and solid fuel consumption among all sectors. The decline of emissions in Italy started in 2009 due to the effects of the economic recession. In 2010 and 2011 production levels have been restored for the iron and steel and pulp and paper sectors while the other sectors still continue to suffer from the economic crisis.

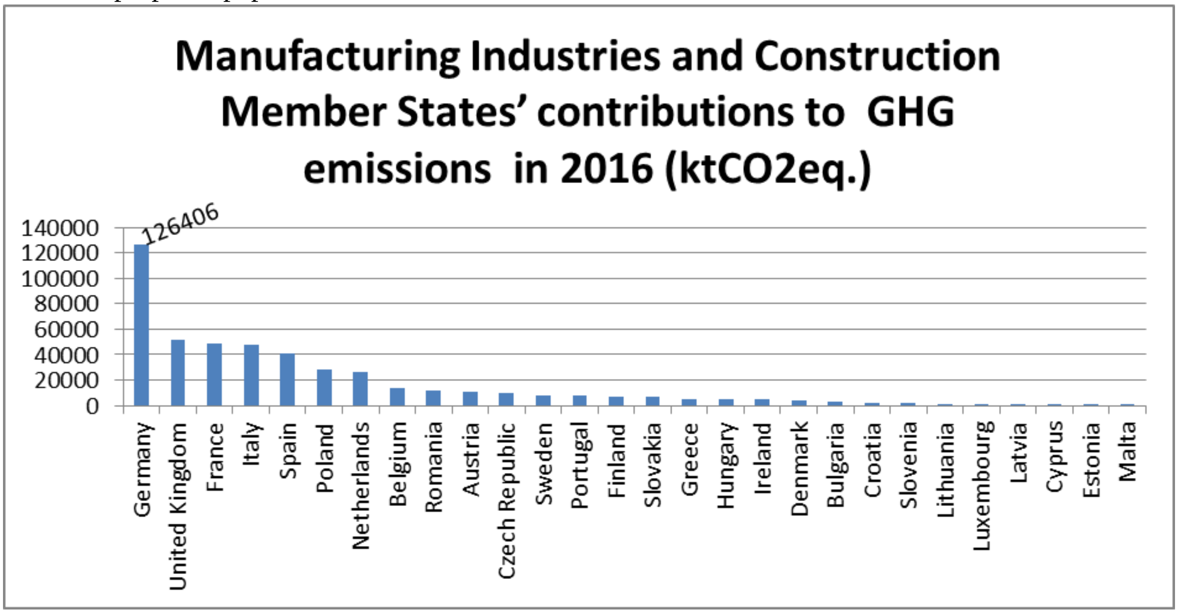


Figure 66: Manufacturing Industries and Construction member states' GHG emission in 2016. Adopted by IPFen from EEA (2018).

6.3.3 Transport (1A3)

GHG emissions from Transport (aviation + road + railways) account for 21 % of total GHG emissions in the EU28 (without LULUCF). Between 1990 and 2016, GHG from Transport increased by 18 % in the EU28 (Figure 69).

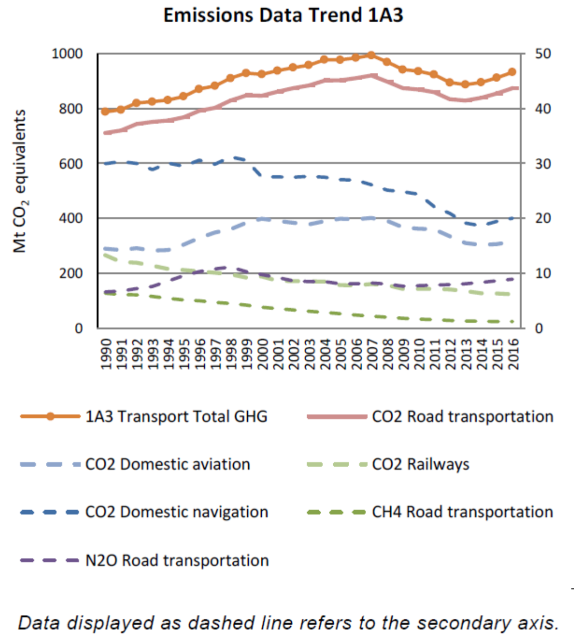


Figure 67: EU28 GHG emissions in the Transport (1A3) (EEA, 2018).

Germany, France, Italy, Spain and the United Kingdom account for most of the GHG and CO_2 emissions from Transport (66 %).

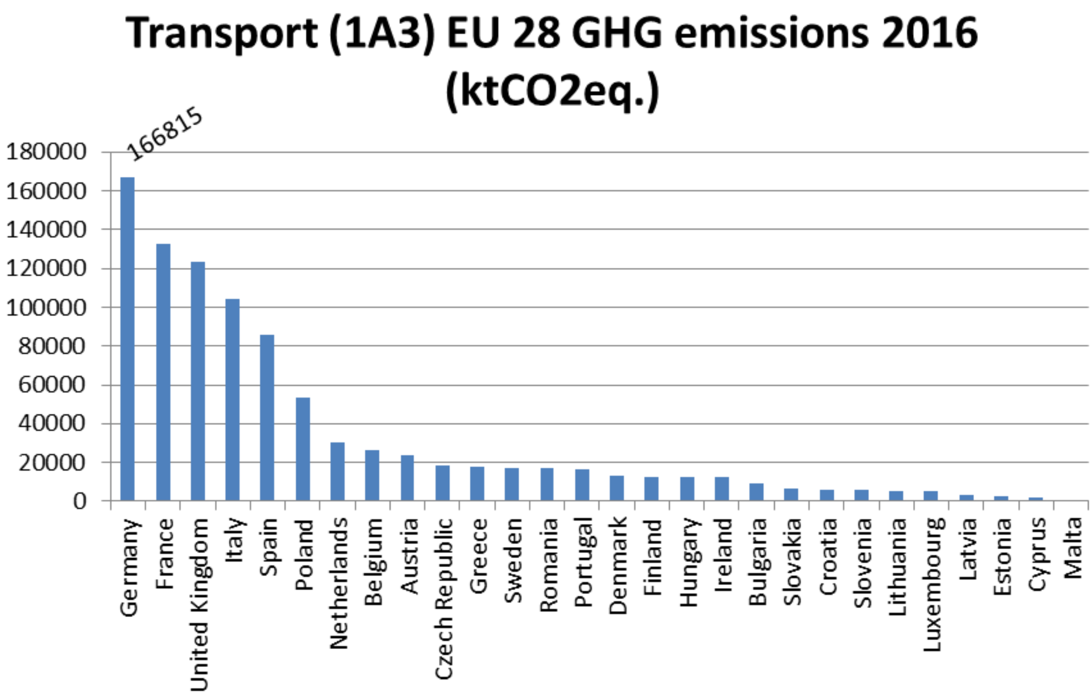
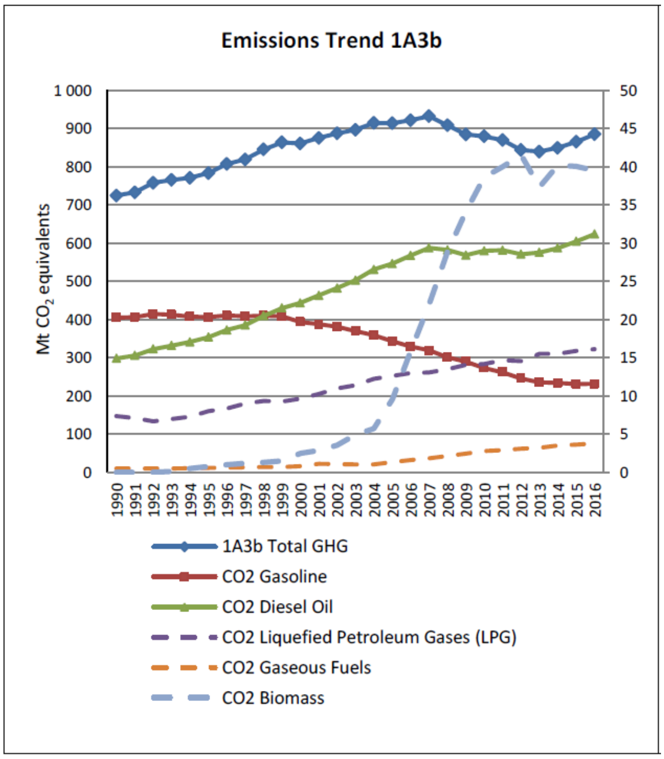


Figure 68: GHG emissions in the transports (1A3) per member states. Adopted by IPFen from EEA (2018).

The mobile source category Road Transportation **includes all types** of **light-duty vehicles** such as passenger cars and **light commercial trucks**, and **heavy-duty vehicles** such as tractors, trailers and buses, and two and three-wheelers (including mopeds, scooters, and motorcycles). These vehicles operate on many types of gaseous and liquid fuels.

CO_2 emissions **from Road Transportation** is the second largest key source of all categories in the EU28 accounting for **20 % of total GHG emissions in 2016**. Between 1990 and 2016, CO_2 emissions from road transportation increased by 23 % in the EU28. The emissions are due to **fossil fuel consumption, which increased by an equivalent 23 % between 1990 and 2016.**



Data displayed as dashed line refers to the secondary axis.

Figure 69: Transport EU28 GHG emissions trends (EEA, 2018).

Emissions from Road Transport by member states

All member states, except Lithuania (-1 %) and Sweden (-9 %), show increased emissions from road transportation between 1990 and 2016 (Figure 72). **In the case of Sweden**, the decreased emissions are explained by the total use of liquid biofuels (ethanol and FAME), which has increased by more than 850 % since 2003. Ethanol is used by passenger cars, by ethanol buses and E85 vehicles. The total use of FAME has increased by 33-49 % each year starting 2011.

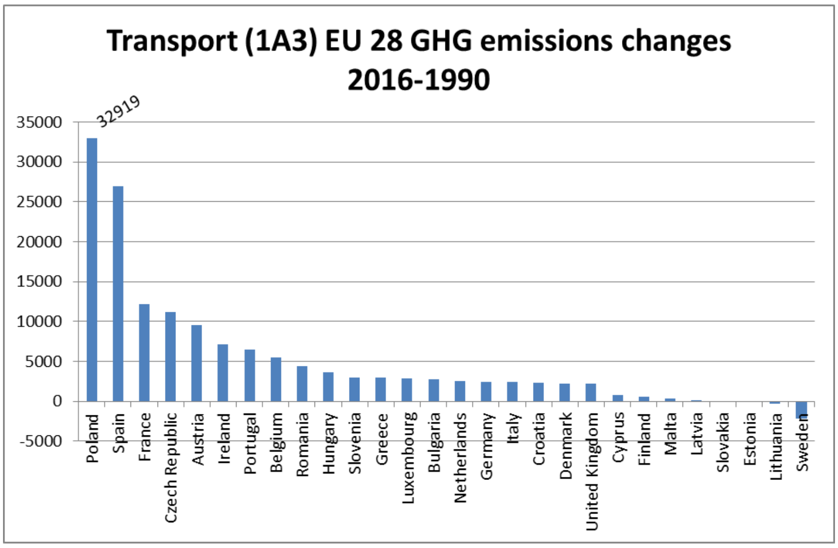


Figure 70: Transport EU28 GHG emissions changes 2016-1990. Adopted by IPFen from EEA (2018).

Emissions from Road Transport by fuels

CO_2 trend are caused by different fuels (liquid or gaseous fuels). The trend is mainly dominated by emissions resulting from the combustion of **gasoline and diesel oil**. The decline of gasoline and the strong increase of diesel show the gradual switch from gasoline to diesel passenger cars in several EU28 member states (Figure 71).

Diesel oil accounts for 68 % and gasoline for 26 % of different fuel in the total consumption in EU28. The highest LPG consumption is observed in Bulgaria (16 %) and Poland (10 %). The share of biomass is around 4 % for EU28 with Sweden having the highest percentage (18 %).

Road Transportation – gaseous fuels (CO_2)

CO_2 emissions from Gaseous fuels account for 0.4 % of CO_2 emissions from 1A3b Road Transport in 2016 (Figure 73). Between 2015 and 2016, CO_2 emissions from Gaseous fuels have increased by 4 %. Most member states showed increased emissions and particularly Italy. Germany, France, Italy and Spain contributed most to the CO_2 emissions from this source (80 %). In 2016 the Implied Emissions Factor (IEF) for the gaseous fuel was of 57 tCO2/TJ.

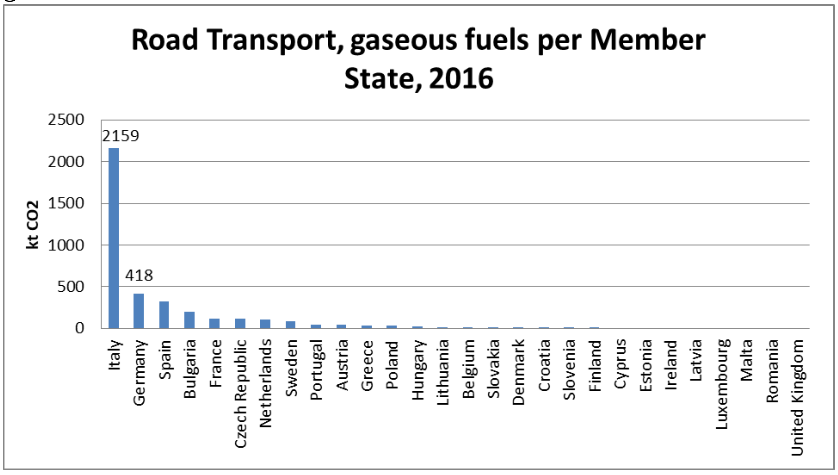


Figure 71: Road Transport gaseous fuels per Member State, 2016. Adopted by IPFen from EEA (2018).

Road Transportation – diesel oil (CO_2)

CO_2 emissions from Diesel oil account for 71 % of CO_2 emissions from 1A3b Road Transport in 2016. All member states show increased emissions from diesel oil between 1990 and 2016. France, Germany, Italy, Spain and the UK account for 67 % of CO_2 emissions from diesel oil in 2016 (Figure 74). The mean IEF is of 74 t/TJ in 2016.

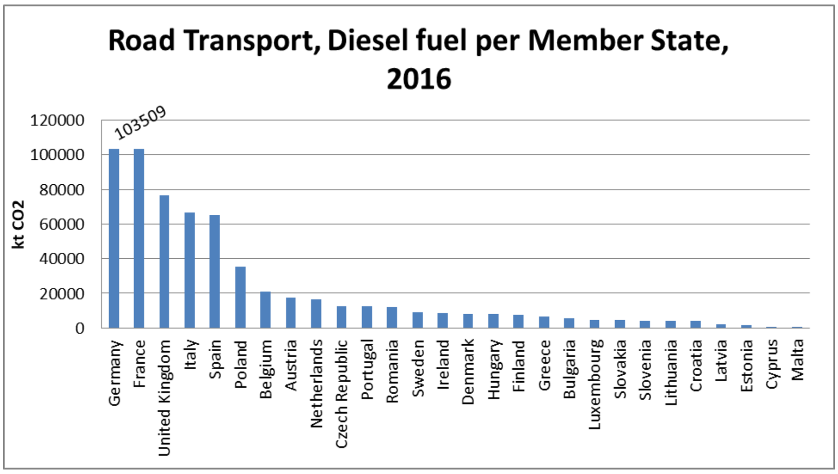


Figure 72: Road Transport Diesel fuels per Member State, 2016. Adopted by IPFen from EEA (2018).

Road Transportation – gasoline (CO2)

Between 1990 and 2016, CO_2 emissions from gasoline **decreased** by 43 % in the EU28. CO_2 emissions from gasoline account for **25 % of CO_2 emissions** from 1A3b Road Transport in 2016. France, Germany, Italy, Spain and the United Kingdom account for 64 % for CO_2 emissions from gasoline in 2016 (Figure 75). In 2016 the IEF mean value is around 72 tCO_2/TJ.

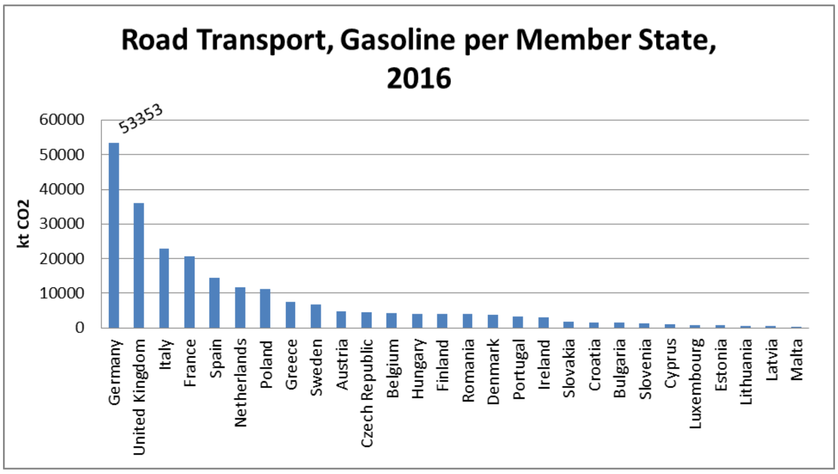


Figure 73: Road transport gasoline per member state, 2016. Adopted by IPFen from EEA (2018).

6.4 CO_2 emission of hydrogen production in EU28 - 2016

The EU ETS Directive was amended in 2009 to improve and extend the EU ETS. Since the third trading period (2013-2020) CO2 emissions from hydrogen plants are declared in the EU ETS under the code 43.

Emissions are included in EU ETS only for installations with a production capacity exceeding 25 t per day. EU ETS activity includes combustion and process emissions. In the CRF, there is no separate reporting category for emissions from hydrogen production. Hydrogen and synthesis gas production are recognised as part of integrated chemical production. Therefore, member states have chosen different approaches for the inclusion of emissions from hydrogen production (e.g. 2.B.8 or 2.B.10) Some emissions may also be reported under CRF category 1.B.2.a.iv Fugitive emissions from oil subcategory refining/ storage.
In 2016, 44 units of hydrogen production have been declared in the EU ETS for a total amount of **9 Mt CO_2 eq**.

6.5 Conclusions of the European emissions

In 2016, total GHG emissions in the EU28 amounted to **4.3 Gt CO_2 eq**. and reduced by 24 % compared to 1990 levels. **79 %** of GHG emitted in EU28 in 2016 is **CO_2** (11 % is CH_4 and 6.2 % is N_2O).

Germany, United Kingdom, France, Italy, Poland and Spain account for 70 % of the **total EU greenhouse gas** emissions in 2016. Only five countries (Austria, Cyprus, Ireland, Portugal and Spain) have increased their GHG emissions between 1990 and 2016 of a small total of 56 Mt CO_2 eq.

In EU28-2016, main sources of **CO_2** are from the "**Energy Sector I**":
- "**Public Electricity and Heat production"** (29 %),
- **"Road Transport"** (25 %) and
- **"Manufacturing Industries and construction"** (14 %)

GHG emissions decreased in the majority of sectors between 1990 and 2016, with the **notable exception** of
- CO_2 emissions from **Road Transport**[27] **(+163 Mt CO_2 eq.) and**
- **HFC emissions** from **Refrigeration and Air conditioning**[28] **(+97 Mt CO_2 eq.).**

The **Energy Sector** (Energy Industries, Manufacturing Industries, Transport, …) accounts for 3.3 Gt CO_2 eq., **78 % of total EU GHG** in 2016. In 2016, mainly due to emission reductions in Public Electricity and Heat Production as well as Manufacturing Industries, emissions of the **Energy Sector are 23 % below 1990 level**.

Energy Industries: 1,181 Mt CO_2 eq. (equivalent to 28 % of EU28-2016 total GHG emissions).
- **Public Electricity and Heat Production are the main emitters**: 1,013 Mt CO_2 eq. (equivalent to 86 % of Energy Industries emissions).
- 2016 emissions are 29.2 % below 1990 level despite the increase (+20 %) of consumption.
- **4 Member states (Germany, Poland, United Kingdom and Italy)** are responsible for 65 % of emissions in the Energy Industries sector. They are also the member states with the highest GHG emission reductions in 1990-2016.

[27] In Energy sector
[28] In Industrial Processes and product use sector

Manufactured Industries and Construction: the fourth largest sector in the EU28-2016 GHG emissions 474 ktCO_2eq. (10.9 %).

- GHG emissions in 2016 are 35 % below 1990 level.
- High shifts from solid and liquid fuels to natural gas and biomass.
- Germany is the highest emitter of the Manufactured industries and construction in the EU28-2016 and is also the Member State with the highest GHG emission reductions since 1990.

Transport: CO_2 emissions from Transport account for 21 % of total GHGH emissions in EU28-2016, 18 % above 1990 level.

- Germany, France, Italy, Spain and the United Kingdom contributed to 66 % to the GHG emissions from Transport.
- Between 1990 and 2016, CO_2 emissions from road transportation increased by 23 % in the EU28. Mainly due to fossil fuel consumption in Road Transport, which increased by 23 % between 1990 and 2016.
- All member states except Sweden show increased emissions from Road Transport since 1990.
- CO_2 emissions from gaseous fuels account for 0.4 % of CO_2 emissions from Road Transport in 2016
- CO_2 emissions from diesel oil account for 71 % of CO_2 emissions from Road Transport in 2016.
- CO_2 emissions from gasoline account for 25 % of CO_2 emissions from 1A3b Road Transport in 2016.
- All member states show increased emissions from diesel oil between 1990 and 2016.
- France, Germany, Italy, Spain and the UK account for 67 % of CO_2 emissions from diesel oil in 2016

The report highlights the main GHG sources by sector and by member states. The complexity of GHG emissions is related to the economy of the member states and to their own energy sources. Politics and regulations may in the future incentivize some energy carriers in order to achieve the European Climate goals in 2050.

The report highlights the key GHG emitter sectors where the deployment of hydrogen usages should be explored. What could be the technical feasibility of such deployment and the economic and environmental impact both for EU28 and for the main member states who have to reduce the most their GHG emissions to be in line with the COP21 European objective.

6.6 Key categories in the Energy Sector

- 1.A.1.a Public Electricity and Heat Production: Gaseous Fuels (CO2)
- 1.A.1.a Public Electricity and Heat Production: Liquid Fuels (CO2)
- 1.A.1.a Public Electricity and Heat Production: Other Fuels (CO2)
- 1.A.1.a Public Electricity and Heat Production: Peat (CO2)
- 1.A.1.a Public Electricity and Heat Production: Solid Fuels (CO2)
- 1.A.1.b Petroleum Refining: Gaseous Fuels (CO2)
- 1.A.1.b Petroleum Refining: Liquid Fuels (CO2)
- 1.A.1.b Petroleum Refining: Solid Fuels (CO2)
- 1.A.1.c Manufacture of Solid Fuels and Other Energy Industries: Gaseous Fuels (CO2)
- 1.A.1.c Manufacture of Solid Fuels and Other Energy Industries: Solid Fuels (CO2)
- 1.A.2.a Iron and Steel: Gaseous Fuels (CO2)
- 1.A.2.a Iron and Steel: Liquid Fuels (CO2)
- 1.A.2.a Iron and Steel: Solid Fuels (CO2)
- 1.A.2.b Non-Ferrous Metals: Gaseous Fuels (CO2)
- 1.A.2.b Non-Ferrous Metals: Liquid Fuels (CO2)
- 1.A.2.b Non-Ferrous Metals: Solid Fuels (CO2)
- 1.A.2.c Chemicals: Gaseous Fuels (CO2)
- 1.A.2.c Chemicals: Liquid Fuels (CO2)
- 1.A.2.c Chemicals: Solid Fuels (CO2)
- 1.A.2.d Pulp, Paper and Print: Gaseous Fuels (CO2)
- 1.A.2.d Pulp, Paper and Print: Liquid Fuels (CO2)
- 1.A.2.d Pulp, Paper and Print: Solid Fuels (CO2)
- 1.A.2.e Food Processing, Beverages and Tobacco: Gaseous Fuels (CO2)
- 1.A.2.e Food Processing, Beverages and Tobacco: Liquid Fuels (CO2)
- 1.A.2.e Food Processing, Beverages and Tobacco: Solid Fuels (CO2)
- 1.A.2.f Non-metallic minerals: Gaseous Fuels (CO2)
- 1.A.2.f Non-metallic minerals: Liquid Fuels (CO2)
- 1.A.2.f Non-metallic minerals: Other Fuels (CO2)
- 1.A.2.f Non-metallic minerals: Solid Fuels (CO2)
- 1.A.2.g Other Manufacturing Industries and Constructions: Gaseous Fuels (CO2)
- 1.A.2.g Other Manufacturing Industries and Constructions: Liquid Fuels (CO2)
- 1.A.2.g Other Manufacturing Industries and Constructions: Solid Fuels (CO2)
- 1.A.3.a Domestic Aviation: Jet Kerosene (CO2)
- 1.A.3.b Road Transportation: Diesel Oil (CO2)
- 1.A.3.b Road Transportation: Diesel Oil (N2O)
- 1.A.3.b Road Transportation: Gaseous Fuels (CO2)
- 1.A.3.b Road Transportation: Gasoline (CH4)
- 1.A.3.b Road Transportation: Gasoline (CO2)
- 1.A.3.b Road Transportation: Liquefied Petroleum Gases (LPG) (CO2)
- 1.A.3.c Railways: Liquid Fuels (CO2)

 1.A.3.d Domestic Navigation: Gas/Diesel Oil (CO_2)
 1.A.3.d Domestic Navigation: Residual Fuel Oil (CO_2)
 1.A.4.a Commercial/Institutional: Gaseous Fuels (CO_2)
 1.A.4.a Commercial/Institutional: Liquid Fuels (CO_2)
 1.A.4.a Commercial/Institutional: Other Fuels (CO_2)
 1.A.4.a Commercial/Institutional: Solid Fuels (CO_2)
 1.A.4.b Residential: Biomass (CH_4)
 1.A.4.b Residential: Gaseous Fuels (CO_2)
 1.A.4.b Residential: Liquid Fuels (CO_2)
 1.A.4.b Residential: Solid Fuels (CH_4)
 1.A.4.b Residential: Solid Fuels (CO_2)
 1.A.4.c Agriculture/Forestry/Fishing: Gaseous Fuels (CO_2)
 1.A.4.c Agriculture/Forestry/Fishing: Liquid Fuels (CO_2)
 1.A.4.c Agriculture/Forestry/Fishing: Solid Fuels (CO_2)
 1.A.5.a Other Other Sectors: Solid Fuels (CO_2)
 1.A.5.b Other Other Sectors: Liquid Fuels (CO_2)
 1.B.1.a Coal Mining and Handling: Operation (CH_4)
 1.B.2.a Oil: Operation (CO_2)
 1.B.2.b Natural Gas: Operation (CH_4)
 1.B.2.c Venting and Flaring: Operation (CO_2)

6.7 References

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7 Existing legal barriers and policy needs in Europe

7.1 Existing legal and administrative barriers

A long list of legislative acts is relevant to the deployment of hydrogen technologies. Some legislative acts impact indirectly hydrogen technology deployment like health and safety law, environmental law, labour law or transport law. European legislative acts are often source of obligations for developers and manufacturers and the extent to which these European legislative acts represent a barrier to hydrogen deployment depends mainly on their national implementation and this differs across the European countries.

A growing framework of European law references hydrogen directly and they have a major impact on the deployment of hydrogen technology, especially on the use of hydrogen as a fuel. On the other hand, these laws are rarely the source of an unreasonable barrier for the hydrogen deployment. In general, many of the barriers to hydrogen deployment are a result of regulatory gaps caused by a lack of harmonization of rules and approaches between European countries. (e.g. green hydrogen, certificates of origin, etc.) or by involuntary mismatches between rules imposed at national level (e.g. standards for fuel quality and measurement).

Nonetheless, the legal and administrative barriers to the injection of hydrogen into the gas grid are of high severity. These barriers are of structural type preventing injection of hydrogen into the gas grid and power to gas facilities. These barriers could also be associated with the recognition of power to gas as grid balancing service.

High economic barriers exist for stationary power in residential and commercial buildings (micro-CHP's) due to a lack of financial incentives.

The barriers in the production, stationary storage and use of hydrogen as a fuel in Hydro Refuelling Station (HRS) are not negligible because the permitting process is long and costly. In the case of hydrogen for road vehicles, no major regulatory barriers exist but a lack of consistent incentive policies affects large-scale deployment.

In the case of hydrogen vessels (maritime and inland waterways), major regulatory barriers are identified.

Regulatory framework of the gas grid and electricity grid issues has been drawn up around natural gas, and specifically the quality standards are based on gas calorific value or the Wobbe Index. When adding hydrogen to the gas stream, it impacts different important parameters like the calorific value, the flow properties, the density, the flame speed, pipeline materials, and gas grid operations.

The national limits for hydrogen concentrations in the gas grid exist in Europe vary widely (Table 8). Hence, the hydrogen injection permitting is considered on a case by case basis

Table 8: Legal framework for H_2 levels in the gas grid (HyLAW project).

Legal framework 'Acceptable' H_2 level (typically mandated by legislation	**Countries**
'Minimal' H_2 concentration at **0.1 to 0.5 vol%** (reflecting typical background concentrations in natural gas)	**IT, LV; SE, UK**
'Low' H_2 concentration at **1.0 to 4.0 vol%**	**FI, AT**
'Mid' H_2 concentration at **6.0 vol%**	**FR**
'High' H_2 concentration at **up to 10.0 vol%**. The applicable H_2 threshold may fall below this, depending on down-stream consumers H_2 tolerance and other factors (e.g. underground storages, large scale gas turbines, vehicle CNG cylinders type 1/CNG refueling stations	**DE**
No formal H_2 concentration rules but based on safety limits with reference to natural gas operations	**BE, BG, DK, ES**

7.2 End user's hydrogen appliance

For a large deployment of hydrogen, a European appliance assessment at the end user level is essential. For example, there is an identified need to define the acceptable safety and operational threshold of end-user appliances at domestic but also at commercial and industrial level.
At the same level, when modifications at the end user to use hydrogen are identified it will be highly necessary to make a supply chain assessment of global economic impact for the actors.

At that stage, a need of European coordination appears to validate gas grid operation with significantly higher hydrogen thresholds, like in Germany, France, The Netherlands and United Kingdom.
Gas Appliance Directive and Gas Appliance Regulation revision will be necessary to allow higher hydrogen concentrations in the gas grids and hydrogen tolerant gas appliances.

A potential conflict has been identified with the gas composition required for fuel supply to CNG vehicles. Indeed, as for Compressed Natural Gas (CNG) vehicles, the hydrogen limit is max 2% (according to UNECE regulation R1106). It means that if a Compressed Natural Gas fueling station is connected to the gas grid, the admissible hydrogen concentration for that local grid must not exceed 2 vol%.

The framework for permitting power to gas plant and grid connection / injection requirements, between the hydrogen supplier and the gas grid operators, should be included within European regulatory frameworks to ensure comparable treatment across European countries. For that, relevant authorities should review technical and gas composition rules to establish legal pathways to support Power-to-Gas operations and increased hydrogen use in transmission and distribution gas networks.

Then a coordinated European wide review of the safety and technical integrity limitations for hydrogen connection and injection into the gas grid is essential.

7.3 Transport sector and hydrogen barriers

Related to the production, storage and distribution of hydrogen at Hydrogen Refuelling Station (HRS) moderate legal and administrative barriers are identified.
However, the permitting process for HRSs generally is long, costly, and uncertain due to lack of clear rules and procedures. Indeed nowadays, only four countries Germany, Denmark, United Kingdom and The Netherlands have rules to regulate permitting HRSs.

Another barrier in relation with HRSs is the existence of different authorities responsible of them, the lack of administrative practice and the lack of clear guidance provided to operators.
The permitting requirements applicable to Hydrogen Refuelling Stations draw on obligations established at European level like risk assessments (SEVESO Directive), health and safety requirements and conformity assessment procedures, (ATEX Directive), Integrated Environmental obligations (IED), Environmental Impact Assessment procedures, (SEA and EIA Directives).

Road vehicles face barriers mainly associated to the lack of incentive policies and infrastructure investments instead hydrogen vehicles for **maritime and inland-waterway** transport face very high legal and administrative barriers like IMO regulation which reduces CO_2 emissions by 50 % by 2050 and imposes a 0.5 % sulphur cap on marine fuel from 2020.
This could be also viewed as an opportunity for new alternatives, including hydrogen power vessels but "Type approval" of hydrogen fuel cell vessels is complicated due to the absence of rules. However, hydrogen specific requirements are not yet on the agenda in IMO/CCC.

For Inland Vessels, Directive 2016/1629/EU empowers CESNI (Comité Européen pour l'Élaboration de Standards dans le Domaine de Navigation Intérieure) to develop standards in the field of inland navigation. It is crucial for all actors to act in a coordinated manner at IMO level to develop specific regulations for hydrogen.

Barriers are present in all European countries, but they exhibit varying degrees of severity. In all cases actions are necessary to unlock the full potential of hydrogen technologies in all countries and at EU level.

7.4 Policy needs

In short term, governments can take strategic decisions about the future uses of their natural gas infrastructure. These decisions are essential for investments decision of either high blend shares of hydrogen or full conversion to hydrogen grid. There is an opportunity for policy to support hydrogen blending in order to scale up hydrogen supply and reduce costs for all future uses of hydrogen.

Published clear roadmaps will reduce obstacles to grid conversions and help potential hydrogen suppliers to estimate market size. Grid upgrade, conversion programmes and turnover of consumer appliances for gas use take long time. Strategic decisions about future gas infrastructure and heating sources are important specially for cold countries.

At current cost levels, hydrogen blending requires policy support to stimulate end-user demand. This could be done by setting quotas, emission targets or blend levels, like to mechanisms for renewable electricity, for example, via the EU Renewable Energy Directive. Premium prices could be encouraged for gas containing hydrogen to meet obligations.

To reduce investment risks associated in new hydrogen supplies governments can clarify market and technical conditions including third party access, regulated returns for system operators and consumer protection.

Public sector can help in technologies associated with hydrogen production – electrolysers and CCUS –and providing safety case for hydrogen blending and conversion on the supply chain. Development of devices to separate hydrogen from gas blends at the end-user, and appliances that use pure hydrogen, may be accelerated with some public co-funding. R&D for underground storage of hydrogen in depleted oil and gas fields and aquifers is required to prove their suitability for use with hydrogen.

Ensuring safety of hydrogen in the gas grid, whether blended or pure, and when used in people's homes is of great importance. Public safety concerns or adverse events could seriously impair the speed of deployment. A key barrier to be addressed is the current low levels of blending permitted in many jurisdictions, including where cross-border pipelines exist.

Long term policy and international cooperation will be instrumental in ensuring public and private investment towards the development of hydrogen in Europe. Alignment of countries' national hydrogen strategies and roadmaps via bilateral and multilateral partnerships will be important to manage risks at both ends of the value chain.
In long term, hydrogen can be used in multiple sectors, but end-users will only switch to hydrogen, or hydrogen carriers, if it is cost-effective to do so. Governments can help make hydrogen cost effective in target sectors using portfolio standards, mandates, performance standards, tax exemptions, and CO_2 pricing.

In long term to manage risks and foster hydrogen trade, governments can clarify upfront the treatment of tariffs for hydrogen imports. The first commercial-scale hydrogen export and import infrastructure projects may benefit from being structured as public-private partnerships.

International standardisation will be crucial in this value chain, including for hydrogen composition, facilities' design and equipment specifications. Some of the International Maritime Organization (IMO) regulations may need to be revised or established for hydrogen.

7.5 Conclusion

This chapter has identified multiple barriers against hydrogen deployment in Europe. It also presents policy needs to upscale hydrogen production and usages.
The main conclusion is major involvements of the policy makers are essential to give incentives to companies and consumers to develop the hydrogen from natural gas market in Europe.

7.6 References

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- **Hydrogen scaling up** by the Hydrogen Council (2017) http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf
- **HyLAW project -** www.hylaw.eu , Hydrogen Law and removal of legal barriers to the deployment of fuel cells and hydrogen applications. Grant agreement No 737977. End Dec. 2018
- **Hydrogen** from IEA (2019)
- http://www.iea.org/hydrogen

8 Overview of technical data, analysis methodologies and tools

This chapter will focus on the available techno-economic information related to the production of hydrogen from several sources. The main technologies which will be focused on are:

1. H_2 from natural gas with CCS
2. H_2 from biomass with CCS
3. H_2 from renewable electricity sources (*e.g.* solar and wind) and electrolysis
4. H_2 distribution and CO_2 transport and storage
5. Electricity production and distribution

These five main technologies will be compared based on the energy efficiency, direct CO_2eq. emissions, total capital costs, operating costs, and projected hydrogen production costs. Note, that the costs of constructing renewable energy sources and estimates for the emissions of the renewable energy sources will be included in the calculations with additional values for only the electricity production.

Section 8.1 will focus on the technologies and costs for hydrogen production and transport. Two previous meta studies are analysed based on the levelized cost of hydrogen production. The main section is analysing the H21 North of England study conducted by Equinor and Northern Gas Networks. Based on the findings, it can be concluded that electrolyser-based production of hydrogen is at the moment neither economical, nor environmental viable option if compared to natural gas-based hydrogen with CCS. Furthermore, electrolyser-based production of hydrogen is currently not achievable at large scale due to limited production capacities of electrolyser manufacturers. Data related to CO_2 transport and storage as well as hydrogen transport is limited and depending heavily on the geography and geological conditions. Hydrogen from solid biomass with CCS is a future technology which can be used to achieve net negative emissions. Biogas is however produced with a volume of 187 TWh annually in the European Union in 2016 and could be used as feedstock for reforming processes.

The power sector is addressed in Section 8.2. The starting point are the special characteristics and complexity of the power system, requiring a continuous balance of the supply and the demand for the stable operation of the system. When supplying electricity, there are costs for generation, transmission and distribution as well as the system operation. In addition to that, a significant share of the end-user price for electricity comprises taxes, levies and subsidies. Hence, the end-user electricity price can be divided into:

- Electricity purchase prices (Electricity procurement)
- Network charges (Transmission and distribution)
- State-regulated components (Taxes, levies, RES support)

It can be observed, that the last components of regulated components increased during the last years in the EU, due to RES support. Furthermore, Power generation technologies based on RES are more capital intensive than fossil-fuelled power production, leading to higher upfront costs, which needs to be financed. However, the levelized cost of energy from RES came down to the level of fossil-fuelled power production during the last years, cf. (IEA, 2015). Finally, beside the power generation, transmission is a substantial cost component, which can have a significant impact for the investment in remote RES power production, depending on the localisation of the grid connection point. When the responsibility for connection to the transmission system lies with the system operator, it is the case that these investment costs are socialised through transmission tariffs instead of being directly targeted to the investments triggering these costs.

Section 8.3 discusses the societal impact of infrastructure projects. Section 8.4 provides a comprehensive summary of energy system modelling tools which can be used in the investigation of operational behaviour as well as expansion of the existing energy system.

8.1 Hydrogen production technologies and costs

8.1.1 Previous analysis of hydrogen production technologies

The costs of hydrogen production from various sources attracted significant attention in the last decades. Bartels et al. (2010) performed an economic survey based on several studies on the capital cost and hydrogen retail selling price for the production of hydrogen from natural gas and coal with and without CO_2 capture and storage, nuclear power, solar, wind, and biomass. Furthermore, different processes were investigated, *e.g.* pyrolysis, reforming, and gasification for fossil sources and biomass as well as electrolysis and thermo-chemical cycles for renewable and nuclear energy sources. Their findings highlight that at the technical stage of 2010, hydrogen from natural gas and coal is most economical with 2.48-3.17 $ (2007)/kg H_2 and 0.36-1.83 $(2007)/kg H_2 respectively. Renewable sources for hydrogen have costs exceeding 4 $ (2007)/kg H_2 being less competitive. Due to the age of this study and the recent decline in costs for renewable energies, we can assume that the prices for hydrogen from renewable sources is reduced.

In a more recent study, Parkinson et al. (2019) conducted an analysis related to the levelized cost of CO_2 mitigation for the production of hydrogen from 12 different technologies. These technologies include all of the above's technologies with the addition of coal gasification and thermochemical cycles. Similar to Bartels et al., they found that clean hydrogen production from natural gas with CCS results in a low levelized cost of hydrogen (LCOH) of 1.93-2.26 $ (2018)/kg H_2 closely followed by coal gasification with CCS. There esti-mates for H_2 are however significantly higher than the ones found in Bartels et al. (2010) due to different selected studies and cases. The low LCOH is reflected as well in the levelized cost of carbon mitigation. Nuclear energy powered thermochemical cycles have a slightly lower LCOH. However, large uncertainty is given by the investment costs of the nuclear power plant and regulations within different countries. In gen-eral, there exist large uncertainty, especially related to the electrolyser capital costs and the capacity factors of the power production. Hence, care has to be taken when comparing the different numbers.

8.1.2 Summary – North of England project

The North of England project is a detailed analysis for the production and distribution of hydrogen in the north of England for heating purposes (H21 North of England, 2018). This study was conducted by Northern Gas Networks and Equinor to investigate a decarbonization of the heating sector. All fossil-based production routes include CCS. The analysed hydrogen production technologies include natural gas reforming in both a steam methane reformer (SMR) and an autothermal reformer (ATR), coal gasification, offshore wind-powered electrolysers, as well as storage of hydrogen as ammonia. Furthermore, they investigated the re-quired hydrogen transport network and seasonal storage of hydrogen. The results of the different production routes can be compared due to similar assumptions in the report.

The main results for a 1.5 GW hydrogen production facility are presented in Table 9 and Table 10. Note, that none of the production routes include the generation of electricity required in the process. For other capaci-ties, economy of scale can be observed on the one hand for the ATR-based production route due to improved air separation units.

Table 9: Main results of the North of England project – Costs and size

	CCR	CO_2 footprint	Efficiency	CAPEX	CAPEX/kW	Area	Purity
	[%]	[g/kWh]	[% HHV]	[M£]		[ha]	[%]
Electrolyser	-	0.0	70.9	1740	1160	45-60	99.9
ATR	94.1	13.1	79.9	947	631	15-23	98.4
SMR	91.2	20.5	79.5	1082	721	38-45	97.5

Table 10: Main results of the North of England project – Import and export

	Water import	Electricity import	NG import	CO_2 captured	Steam production
	[m3/h]	[MW]	[MW]	[t/h]	[t/h]
Electrolyser	380.30	2116.0	0	0	0
ATR	80.00	72.6	1805	315	527
SMR	160.00	35.6	1850	312	496

On the other hand, SMR have an upper capacity and larger production units are in general uncommon. Electrolysers do only observe a limited economy of scale beyond a capacity of 1 MW. The production costs between the two natural gas routes are quite similar. ATRs are however slightly cheaper in manufacturing resulting in 10 % lower construction costs. Electrolyser units are 60-80 % more expensive than natural gas reformers capacity-wise. It has to be noted, that the capital costs for the electrolysers are at the lower end of reported values. Operation and maintenance costs are assumed to be 3 % of the capital cost for all production routes.

The CO_2 footprint of the different unit operations are in general quite small. ATR-based reforming has a very high carbon capture ratio (CCR) of 94.1 % whereas SMR-based reforming has a CCR of 91.2 %. The corresponding CO_2 footprint of 13.1 and 20.5 g CO_2/kWh respectively is the footprint of the hydrogen production. If we include the upstream footprint of the natural gas, we receive a CO_2 footprint of 49.7 g CO_2/kWh with the current English natural gas mix, and 16.87 g CO_2/kWh with natural gas from the Norwegian continental shelf. In comparison, the CO_2 footprint of power generation in the European Union was 295.8 g CO_2/kWh electricity excluding use in the power plant as well as transport and transformation losses. These values cannot be compared directly as one is heat and the other is electricity, it may however give an understanding of the difference in magnitude between these two values. The electrolyser route emissions are depending on the emissions of the power generation.

Note, that all power generation has associated CO_2 emissions, even if they utilize renewable sources primary energy sources. These CO_2 emissions are associated to the construction, infrastructure, and the supply chain emissions and are in the range of 15 (wind turbines) and 50 (photovoltaic) g CO_2/kWh (see Figure 86 in Section 8.2). With an efficiency of 70.9 % of electrolysers (HHV basis), this corresponds to a higher CO_2 footprint than hydrogen from Norwegian natural gas. Figure 76 illustrates the CO_2 intensity of hydrogen produced using an ATR at 93.4 % CO_2 capture ratio and using EU average natural gas up- and midstream emissions and electrolyser-based hydrogen production as a function of the CO_2 intensity of the electricity grid.

Furthermore, potential liquefaction is included for both production routes in the case of liquid-phase bulk transport. As we can see, electrolyser-based hydrogen results in lower CO_2 emission up to a CO_2 grid intensity of around 38 kg CO_2/MWh. It is also important to note that the Up-and midstream emissions of natural gas have the highest impact on the CO_2 emission of natural-gas based clean hydrogen. Using Norwegian continental shelf natural gas production, the intersection is reduced to 20 kg CO_2/MWh.

The study includes expenses as well based on satisfying the annual heating needs in the North of England in addition to the comparison on a 1.5 GW production level. Here, the electricity required in the electrolysers is provided by a dedicated offshore windfarm with high voltage direct current connection to the production facility. Hydrogen storage for inter-seasonal storage is included as well to account for the different production patterns. In this study, a project lifetime of 25 years with 8500 operation hours each year, a discount rate of 8 %, CO_2 transport and storage costs of 10 £/t CO_2, CO_2 emissions costs of 80 £/t CO_2, natural gas costs of 23 £/MWh and electricity costs of 60 £/MWh.

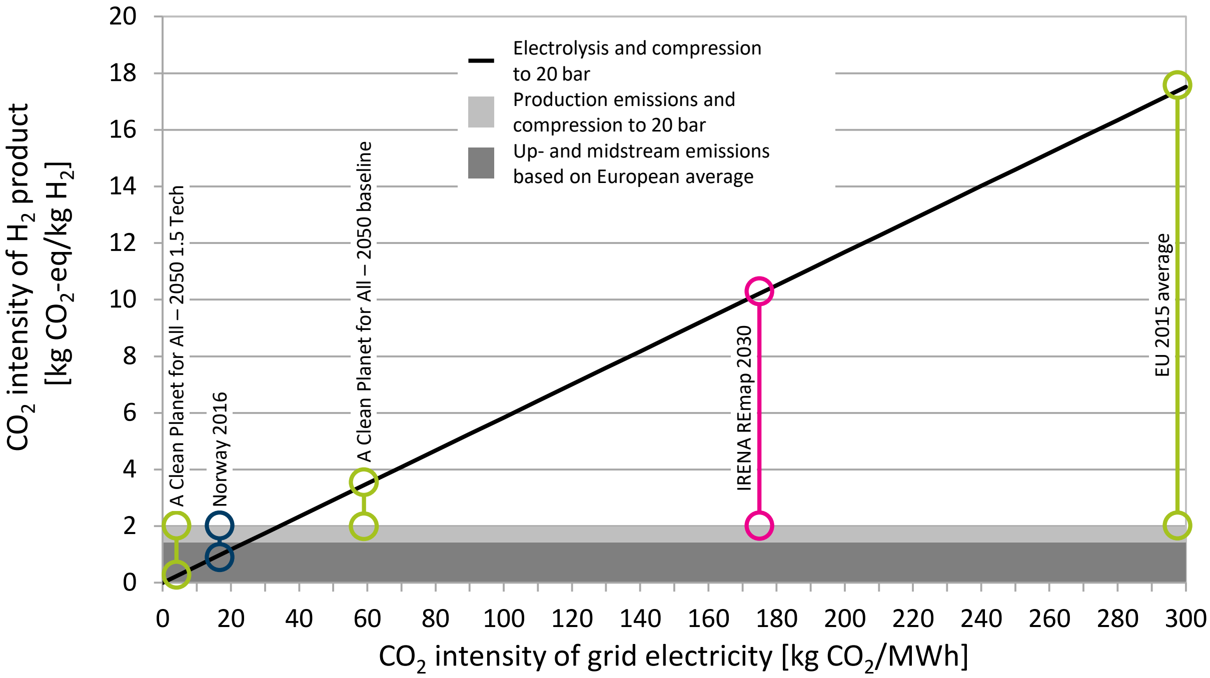


Figure 74: CO_2 intensity of hydrogen production from electrolysis and natural gas for varying CO_2 intensity of the electric grid, adopted from Berstad (2018).

Table 11 provides an overview of the main costs associated to the operating costs for ATR- and electrolyser-based hydrogen production. The main costs associated to electrolyser-based hydrogen production is given by the development of an offshore windfarm in combination with its connection to the land grid. This results in high capital expenditures, and hence, in high hydrogen production costs.

Table 11: Main results of the North of England project – Operating Expenses per year

	NG import	CO_2 emissions	Electricity import	Operation and Maintenance	CAPEX	OPEX and Energy	H_2 costs
	[M£]	[M£]	[M£]	[M£]	[M£]	[M£]	[£/MWh]
Electrolyser	0	0	0	2,778	92,595	2,778	155
ATR	2,061	92	234	320	10,678	2,708	50

Comparing the hydrogen costs of natural-gas based hydrogen in Table 11 to the hydrogen costs reported in previous studies, it is possible to conclude that they are at a similar range. Note, that the numbers in Table 11 are for the overall system, including the offshore wind park in the electrolyser route and the carbon capture and storage in the ATR route as well as intra- and inter-seasonal storage. Hence, they represent the overall costs for hydrogen production and storage for an annual hydrogen demand of 74.5 TWh (6.4 Mtoe).

Biogas-based production of hydrogen is in general similar to natural gas-based production. The main difference is the composition of the feedstock to the reforming section. The composition of biogas is heavily depending on the used resource. However, when introduced into the natural gas infrastructure, it has to be upgraded to reduce the composition of the main side product, CO_2. Hence, biogas can be seen as similar to natural gas-based production of hydrogen. However, the production of biogas results in higher costs than natural gas, although it may result in carbon negative emissions, when combined with hydrogen production and CO_2 capture. Cost data for the production of biogas is depending on the used biomass, which also influences the required operations. Investment costs including upgrading of biogas are in the range of 576 €/kW (IRENA, 2013) with overall operating costs of 15-40 USD/MWh which is in the range of the natural gas prices used in the North of England project excluding capital costs. An alternative is the direct utilization of biogas which would require modifications in the process due to different feed compositions and different reactions in the reformer.

A second option for biomass to hydrogen is the utilization of a biomass gasifier. Here, the composition of the outlet of the gasifier is a mixture of hydrogen, CO, CO_2, methane, higher hydrocarbons, and water. A 20 MW biomethane plant is existing in Sweden (Thunman et al., 2018). Here, either the biomethane or the synthesis gas post gasifier could be integrated into existing infrastructure for hydrogen production. The former is economically not viable as it would first produce synthesis gas (a mixture of CO and hydrogen) and methane, while latter reversing these two steps in the hydrogen synthesis. As biomass gasifiers are still on pilot scale, it is currently not possible to provide detailed cost analysis.

8.1.3 Hydrogen transport costs

To date, there are not a lot of studies related to the costs of hydrogen transmission. Yang and Ogden (2007) compared different transport modes for hydrogen. They concluded that for short transport distance and low hydrogen demand, compressed gas transport using trucks is the cheapest options whereas for large capacities, pipeline transport is the cheapest. Figure 77 summarizes the transport costs of hydrogen. Note, that the values are on a levelized cost of hydrogen basis, and not on investment costs. However, the range of transport volumes in the study was limited to a 100 MW-scale context. Furthermore, the study included only land transport and not potential future "LNG-scale" ship transport, which can have a major influence on costs

Capital and operating costs for a hydrogen transmission network were as well developed within the H21 North of England study. Here, the hydrogen transmission system is 520.5 km consisting of pipelines with 600, 900, and 1200 mm diameter at 40-80 bar pressure. Its total capacity is 125 GW. In addition, there is a local hydrogen transport system with 334 km pipeline length and diameters of 100-600 mm at 7-40 bar pressure. The combined capital costs are given at 2,400 M£. Furthermore, a hydrogen intermediate pressure system at 2-7 bar is included at costs of 0.5 M£/km. The operating costs for the system include maintenance and control of the hydrogen transmission network. As no booster stations are included, no other operating costs are necessary.

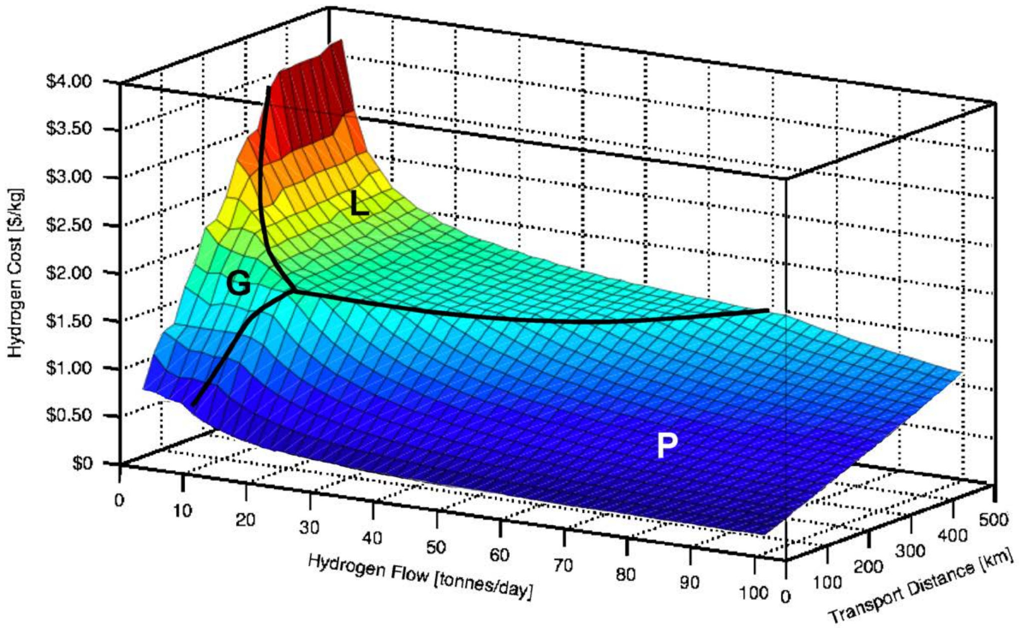


Figure 75: Hydrogen transmissions costs as a function of distance and hydrogen flow from Yang and Ogden (2007).

8.1.4 CO_2 transport and storage costs

Transport and storage of CO_2 is mostly applied for enhanced oil recovery. However, there are several projects where CO_2 is stored permanently in the seabed. Among these projects, the CO_2 capture process at the Sleipner field and at the Snøhvit field on the Norwegian continental shelf are in operation for several years. Within the H21 North of England project, two different storage solutions are investigated, one on the Norwegian continental shelf, and one at the British continental shelf. The British design includes 215 km of CO_2 pipeline whereas storage on the Norwegian continental shelf requires 845 km of pipeline. The overall capital costs are depending on the exact geographic formation in which CO_2 is planned to be stored. Capital costs are 1,300 M£ and 1,600 M£ respectively, with high shares for the pipeline and the wells and drilling. Both costs are heavily depending on the geological formation of the storage sites. The operating expenses are however comparatively low at 24 M£ and 21 M£ respectively.

Data from the North of England project can be used as estimates for subsequent analysis. No accuracy is provided for the data. This can be explained by the dependency of the costs on the geological formation for both pipeline and well development. Furthermore, carbon storage is only applied in a limited scale, resulting in less experience in cost estimation.

8.1.5 Transformation of the energy system to a hydrogen economy

An important point in the application of hydrogen as a clean fuel is the conversion costs from natural gas, oil-, or coal-based appliances to hydrogen-based. Due to the large variety of potential applications and initial energy source, it is not directly possible to provide costs associated to said conversion. Within the transport sector, first estimates related to the transformation costs are provided in the report *Hydrogen Roadmap Europe* developed for the Fuel Cells and Hydrogen 2 Joint Undertaking. However, no details related to the calculations are provided limiting the application of the provided numbers.

Conversion of heating systems were analysed in the H21 North of England project. This includes both domestic and industrial heating aas well as the conversion of the local gas grid to hydrogen. In total, 3.74 million meter points and boilers have to be converted for domestic heating resulting in a conversion cost of4,616 M£, 40 % of which are labour costs. Industrial meter points are divided in-between below and above 200 kW demand with costs associated at £ 30,000 and £ 1,250,000 respectively.

Another important point is the possibility to deliver the required size of hydrogen production. Within the H21 North of England project, it was concluded that the required 18.4 GW electrolyser facility would not be feasible in the desired timeframe, even if large companies like ThyssenKrupp deploy their concept to a full extent. Contrary, natural gas-based hydrogen production can be installed at this level in a limited time frame, due to a mature industry and the large-scale production of natural-gas based hydrogen in in the chemical industry. The conversion of the natural gas grid and the domestic and industrial heating sector is according to the report ambitious, but achievable.

8.2 Electricity generation and transmission costs

Electricity as an energy carrier and commodity is rather special in that it requires a continuous balance of the supply and the demand. The generation, transmission and distribution of electricity requires a complex system, that needs an active control to achieve a stable operation and to avoid partly or complete black-outs of the system.

Due to this complexity, there are costs for supplying electricity, consisting of generation, transmission and distribution, but in addition there are also substantial costs for operating the system in a stable mode. Beside the actual underlying costs, a significant share of the end-user price for electricity comprises taxes, levies and subsidies. Among others, an assessment of the different parts of the electricity end-consumer prices is done by Grave et al. (2015). Figure 78 provides a general overview of this shares for selected countries for small commercial consumers. Thereby the electricity price is divided into the three parts:

- Electricity purchase prices (Electricity procurement)
- Network charges (Transmission and distribution)
- State-regulated components (Taxes, levies, RES support)

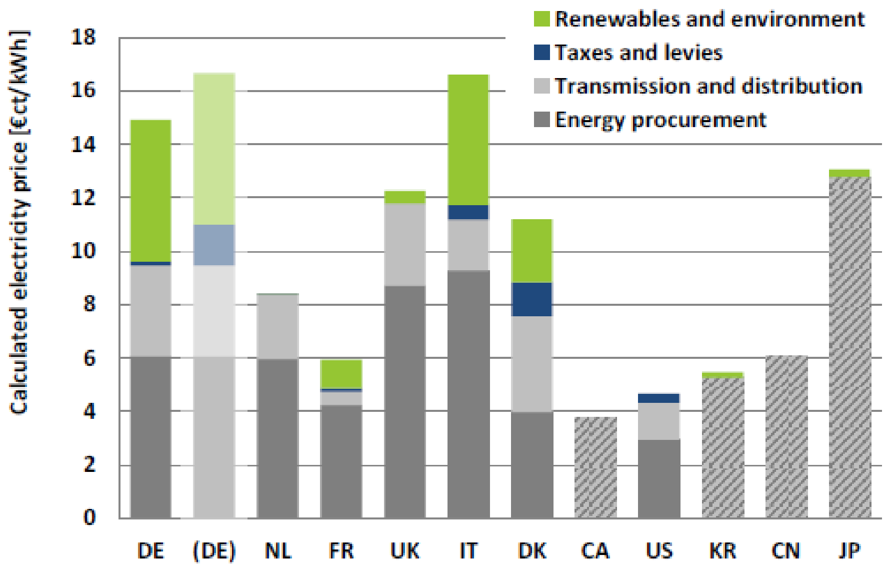


Figure 76: Cost components of the electricity end-user price for small consumer (Grave et al., (2015)).

The final electricity price describes the costs, which will occur when using electricity. This will also describe the alternative cost for electricity as the energy source for applications, which can choose between different energy sources. However, when taking the socio-economic perspective in order to optimise a whole energy system, components, such as taxes and RES support should not be included in the assessment, as this are not an actual cost component, but have the ability to change the utilisation of electricity.

Figure 79 and Figure 80 show the shares of the three components for the European countries for household and industrial end-users. The figures illustrate, that the price for households is somewhat double the price for the industry. Furthermore, there is a large variation in the shares throughout the different countries, due to different policies, network size and the power generation fleet.

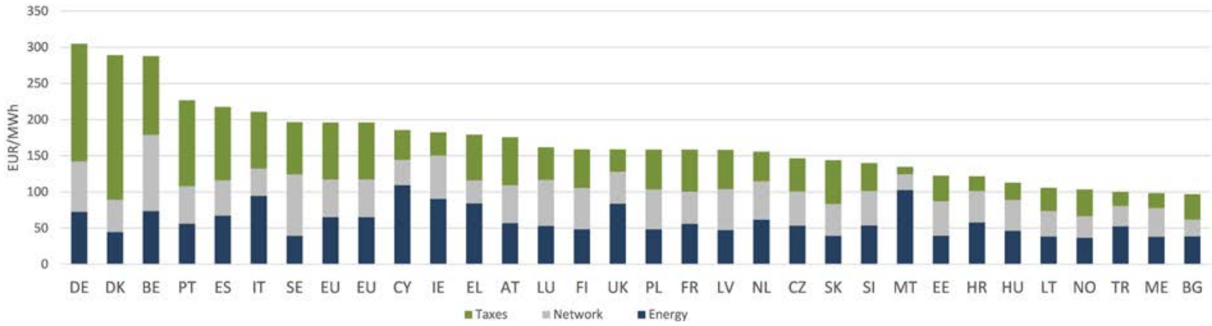


Figure 77: Cost components of the electricity end-user price for small consumer (EU Commission, 2019).

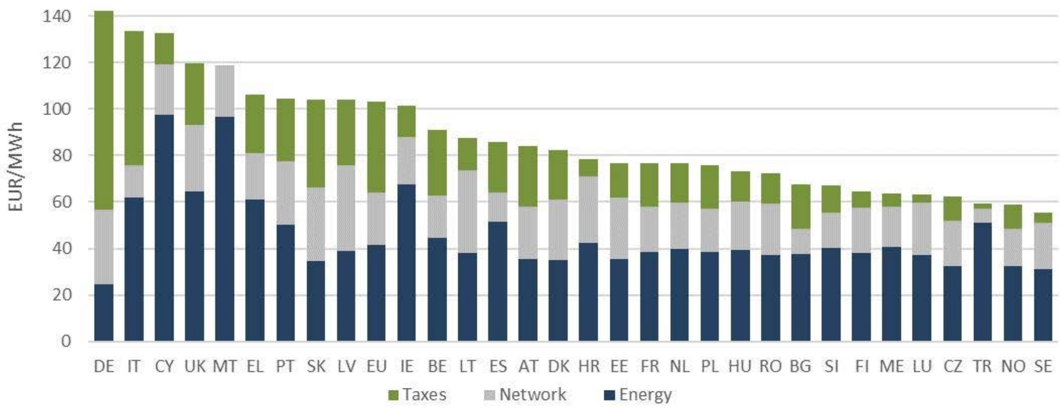


Figure 78: Cost components of the electricity end-user price for industrial consumer (EU Commission, 2019).

Figure 81 shows the development of the end-user price throughout the last decade, showing that the energy procurement cost is decreased, but the Taxes and Levies part is increased significantly, resulting in a total price increase.

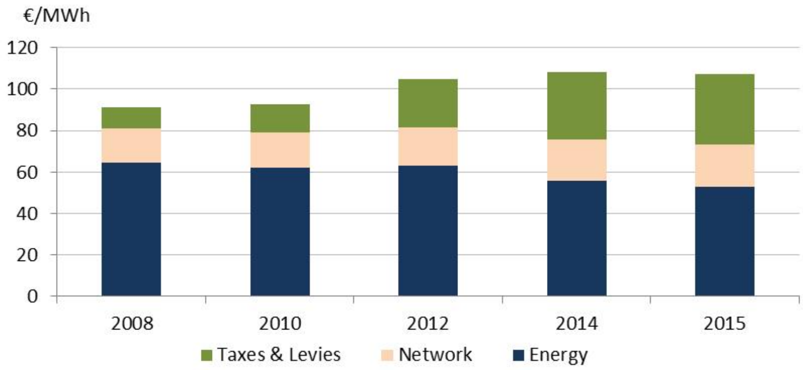


Figure 79: Development of cost components of the electricity end-user price (EU Commission, 2016).

Given the different shares of cost components throughout Europe and their development as described above, the following subsections go more into detail in each of the components and discuss the underlying costs and available data.

8.2.1 Power sector investments

Figure 82 shows the investments in the power sector for 2017 for different regions in the world. For Europe it can be observed, that the highest share are investments in generation from renewable energy sources and the second highest share in transmission and distribution networks. There only was a minor share of investments in fossil-based generation assets. This is in line with current European policies of a transition to a power system based on renewable energy sources and a stronger integration with the aim to establish an internal market for electricity in Europe.

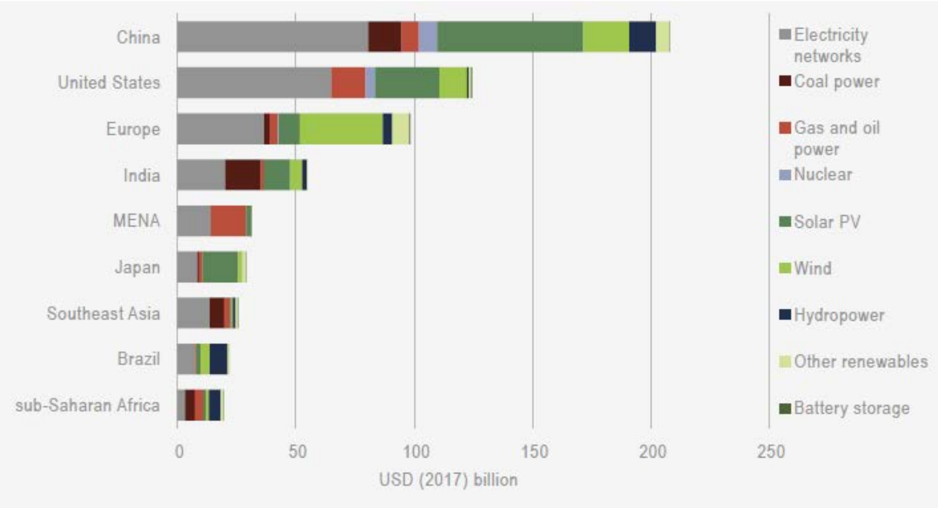


Figure 80: Global investments in the power sector (IEA, 2018a).

8.2.2 Electricity purchase prices / generation costs

In liberalised power markets, electricity is sold bilaterally (e.g. long-term contracts) or through markets with standard products (e.g. day-ahead spot market). The sale of electricity provides power generation companies with income to operate and finance their generation assets. The long-term wholesale price (for products such as futures) can be used as an indicator for the prospective power generation cost. The price gained for selling electricity, thereby not only needs to cover the marginal electricity generation costs, but also fixed and capital costs for the power generation assets.

Thus, the electricity purchase price/electricity procurement cost is defined the long-term cost for generating electricity up to the connection point with the power transmission grid. It comprises following cost components:

1. Investment/capital costs for the whole power generation infrastructure, including the power plant and the transmission infrastructure up to the connection point
2. Operation and maintenance costs, which occur during the whole lifetime of the generation asset
3. Fuel costs, which occur for power generation assets based on limited fossil/non-renewable energy sources
4. Carbon emission/carbon capture costs, occurring for CO_2 emitting power generation assets
5. Decommissioning costs at the end-of-life of power generation assets, which are most significant for large scale infrastructure, specifically for nuclear power plants

A way to express and compare this electricity procurement costs is the Levelised Cost Of Energy (LCOE) defined as:

$$LCOE = \frac{\sum[(Capital_t + O\&M_t + Fuel_t + Carbon_t + Decommission_t) \times (1+r)^{-t}]}{\sum[MWh \times (1+r)^{-t}]}$$

The LCOE expresses a constant monetary flow, which is necessary over the lifetime of the power generation asset for a break-even. Thereby, r is the discount rate. While, the capital, O&M and decommissioning costs are operation independent, the fuel and carbon costs depend as well as the actual produced energy depend on the utilisation factor of the power plant, which results from the actual power system dispatch. Hence in the following overview of LCOE, assumptions are made on the utilisation time of the different power plant technologies. Figure 83 and Figure 84 provide an overview of the range of LCOE for different fossil and renewable power generation technologies. The variation in LCOE is due to localisation and differences in the efficiency of the underlying specific technologies. As it can be observed, the levelised costs have a quite large range, as they significantly depend on the regional location of the asset. A more detailed analysis can be found in IEA (2015).

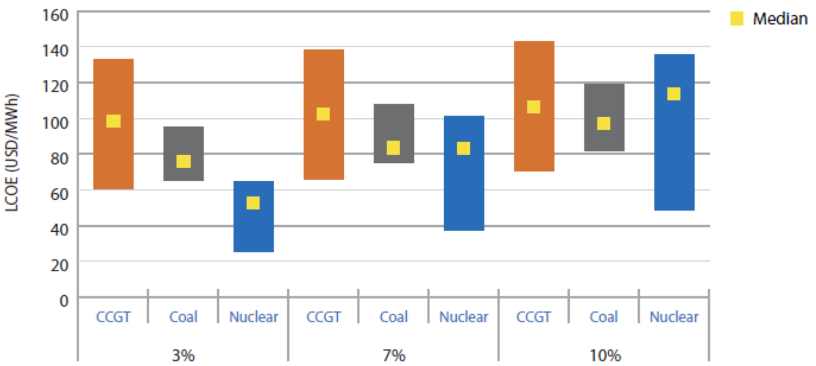


Figure 81: Levelised cost of energy for fossil-fueled power generation technologies (IEA, 2015).

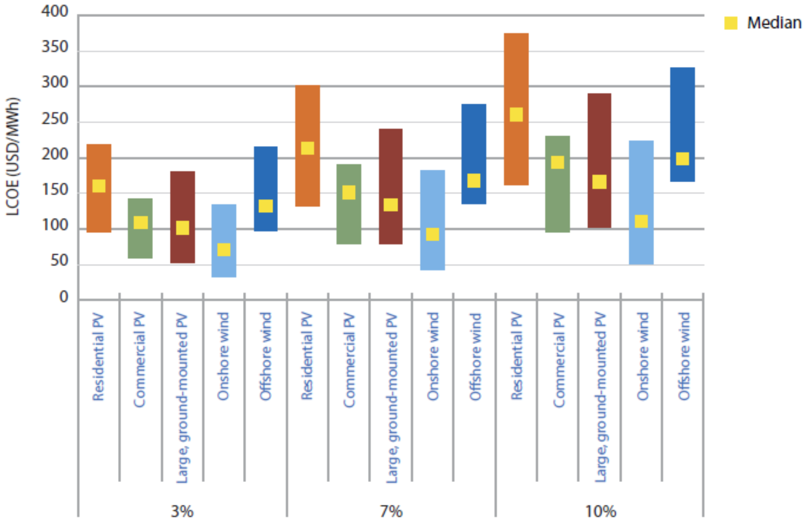


Figure 82: Levelised cost of energy for renewable power generation technologies (IEA, 2015).

The costs shown above are for three different discount rates. It can be observed, that there is a significant increase in LCOE for nuclear power production as well as for all of the RES technologies with an increasing discount rate. This is not the case for coal and specifically not for gas power generation. The reason is, that the former technologies are rather capital intensive. This means, that a large part of costs occurs upfront (investment costs), while the operational costs are rather low. However, the higher share of capital costs also incurs a higher investment risk, which normally results into applying a higher, risk adjusted discount rate for financing the asset.

Figure 85 illustrates the share of fixed to variable costs for fossil-based power generation vs. wind and solar power generation, pointing to the significant share of fuel costs for the fossil power plants, which do not need to be financed upfront, but are significantly affected by fuel prices.

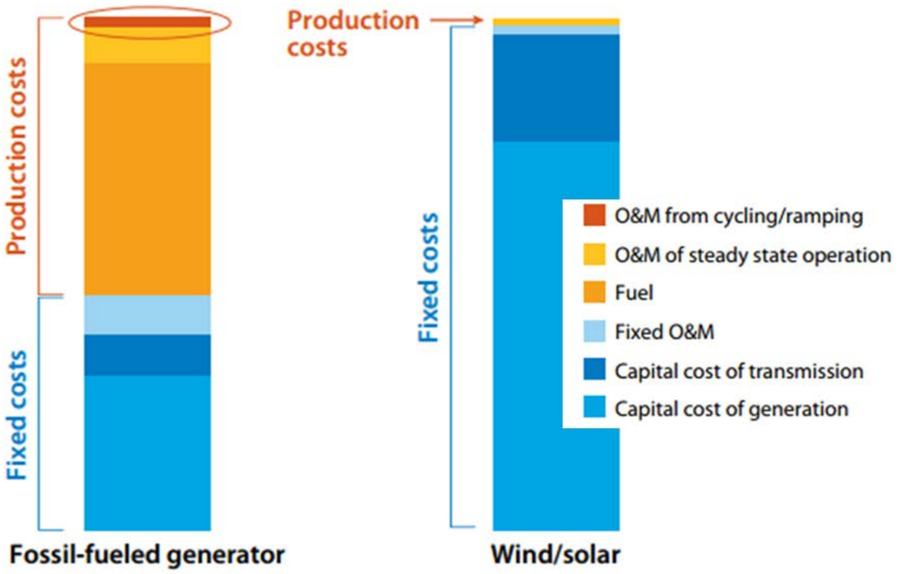


Figure 83: Fixed and variable (production) cost share of fossil vs. renewable power generation (Lew et al., 2011).

The upper Figure 85 does not include a cost for CO_2 emissions. However, the carbon emissions can make up a significant share of the cost, which come on top of the fuel cost/production cost part. Figure 86 shows an overview of the carbon footprint for various power generation technologies. It depicts the levelized CO_2 equivalents for the lifecycle of the different power plants. In the case of CCS, a 90 % capture of CO_2 is assumed.

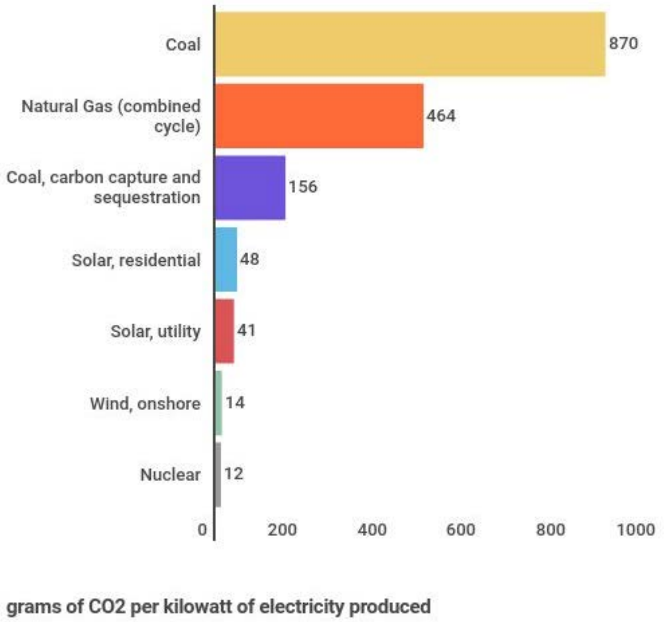


Figure 84: Estimated carbon (lifecycle) footprint of power generation technologies in kg CO_2/MWh (Energy Institute, 2018).

Fuel costs

Figure 87 shows the relative development of wholesale price for the fossil fuels coal, gas and oil. It shows a significant increase until around 2010 and a continuous decrease afterwards, point to a relative lower demand for these fuels compared to the available supply. Further data for fuel costs are available from IEA (2015) and (2018b).

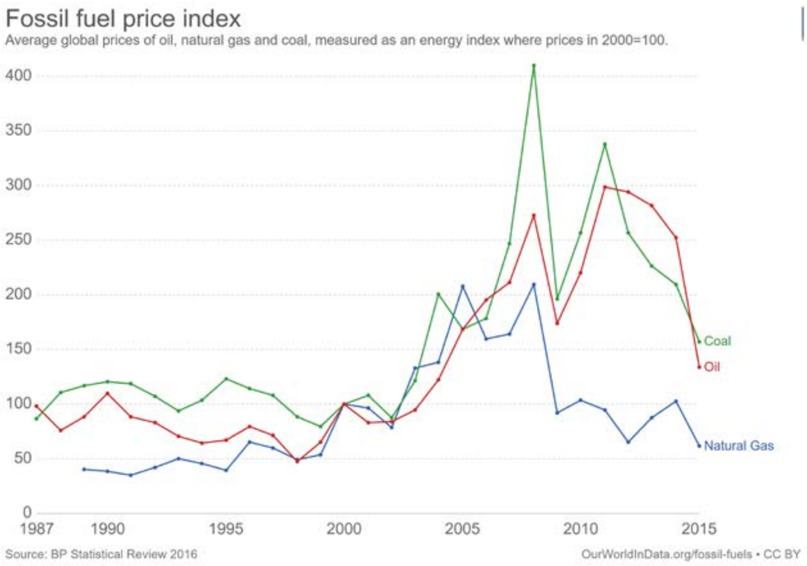


Figure 85: Relative development of wholesale fuel prices for fossil fuels[29].

[29] https://ourworldindata.org/fossil-fuels#fossil-fuel-prices

Renewable energy sources costs

Figure 88 shows the development of levelized costs of electricity for realised projects for renewable generation technologies during the last decade (IEA, 2015). While there was no substantial decrease in costs for traditional power generation technologies (such as biomass, geothermal and hydropower) there was a dramatic decrease for solar and wind power. This decrease resulted in, that the LCOE for most of the RES technologies lie within the same range, equal to the costs for fossil fuel technologies. However, the figure also shows, that there still is a large span of costs for solar and wind power projects. Further information and detailed data can be found at (IEA, 2015) and (IRENA, 2018).

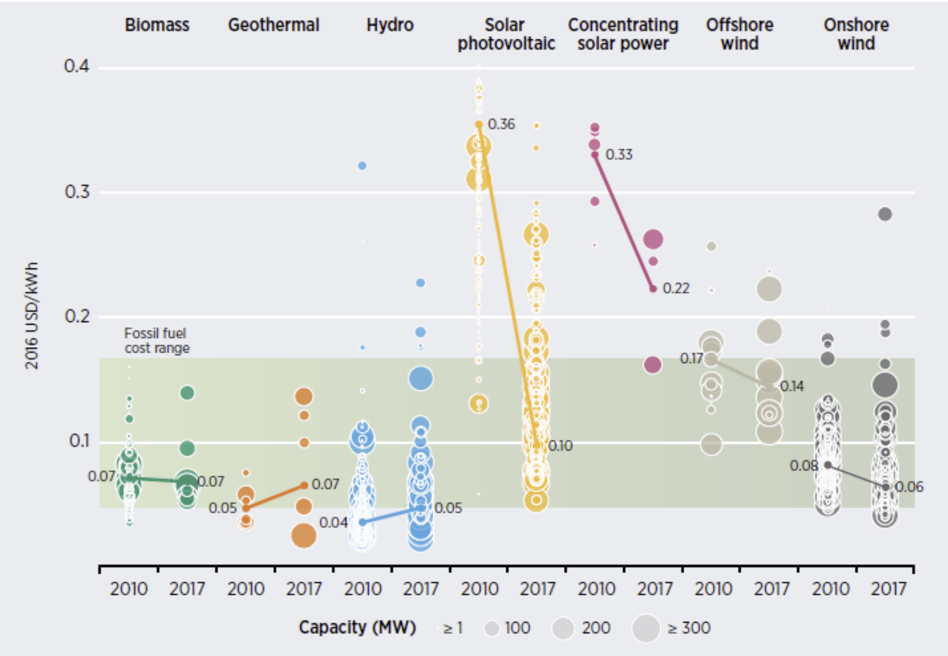


Figure 86: Development of the Levelised Cost Of Energy for power generation based on renewable energy sources (discount rate of 7.5 %) (IRENA, 2018).

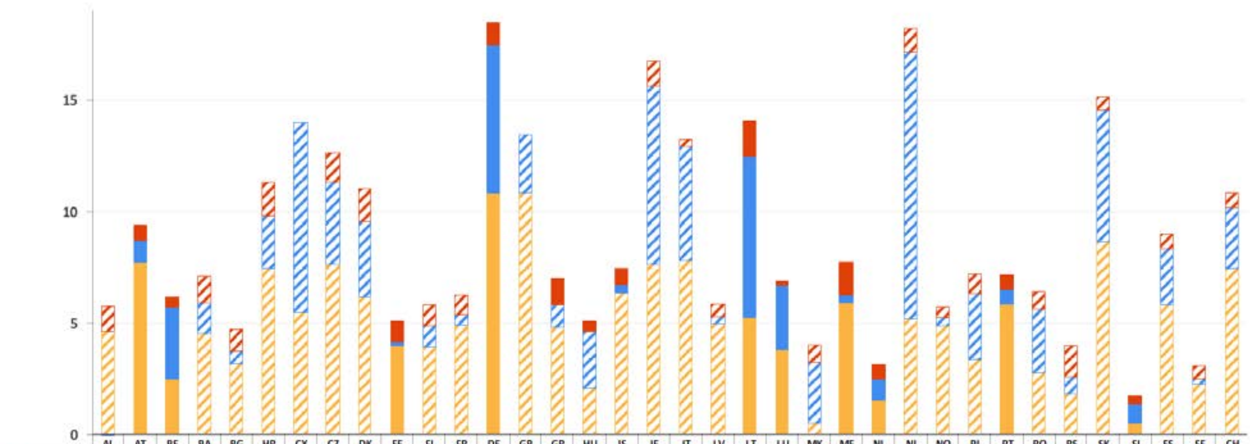
Comparing the power generation costs for fossil-fuelled power generation and renewable energy sources shows some clear differences. While RES power generation has a high share of capital costs and very low operational costs, fossil-fuelled power plants have substantial fuel costs. This is due to the fact that renewable power generation relies on unlimited (renewable) energy sources, such as wind, solar and to some extend hydro. On the other side fossil power plants rely on limited resources, which have to be extracted, such as coal and gas to generate power. Hence, using the latter energy source incurs an additional cost.

However, electricity generation based on RES has to happen at the location, where the energy source is available, while fuels such as coal or gas can be transported to the power plants, which often is more effective than transporting electricity. This means, that power systems based on renewable energy sources are larger with possible connections to remote areas, where the renewable energy sources are available, while fossil-fuelled power plants can be established rather near to electricity demand centres.

8.2.3 Network charges/Transmission costs

Based on the last point due to the differences in fossil-based and renewable power generation, the required power transmission grid is important for the transport of power from the generation source to the demand locations. The costs for transmitting/delivering the electricity are usually handled by the system operators (TSO – transmission system operator/DSO – distribution system operator) in Europe, which normally get reimbursed through network tariffs. In addition to this reimbursement, the costs for the TSOs are partly covered by congestion rents, occurring on transmission corridors, which connect market areas with different electricity prices.

The network charges comprise the infrastructure costs (investment and maintenance of the transmission and distribution grid), transmission losses and other system services, such as reserve capacity, balancing energy, congestion management and voltage stability. Figure 89 provides an overview of the shares, which are part of the transmission tariffs of the TSOs in Europe.



	AL	AT	BE	BA	BG	HR	CY	CZ	DK	EE	FI	FR	DE	GB	GR	HU	IS	IE
Losses	1,12	0,72	0,44	1,19	1,00	1,46	0,00	1,30	1,52	0,94	0,90	0,87	0,99	0,00	1,21	0,46	0,70	1,10
System Services	-0,14	0,98	3,22	1,36	0,56	2,42	8,50	3,67	3,34	0,19	0,94	0,48	6,62	2,64	0,99	2,57	0,39	8,00
Infrastructure	4,66	7,73	2,51	4,55	3,17	7,43	5,50	7,64	6,19	3,99	3,95	4,91	10,88	10,84	4,82	2,08	6,35	7,64

	IT	LV	LT	LU	MK	ME	NL	NI	NO	PL	PT	RO	RS	SK	SI	ES	SE	CH
Losses	0,36	0,55	1,61	0,18	0,78	1,47	0,65	1,10	0,46	0,85	0,66	0,83	1,42	0,59	0,36	0,67	0,58	0,68
System Services	5,10	0,33	7,23	2,86	2,72	0,37	0,92	11,96	0,40	2,98	0,62	2,83	0,73	5,89	0,83	2,50	0,23	2,74
Infrastructure	7,80	4,97	5,26	3,82	0,54	5,90	1,55	5,19	4,85	3,36	5,87	2,77	1,85	8,68	0,53	5,81	2,27	7,45

Figure 87: Network charges for end-consumers per country in Europe (EUR/MWh) (ENTSOE, 2018).

While the figure above shows some average value for the different countries, the actual tariffs vary significantly for various consumers depending on their size and consumption patterns.

Losses in the transmission system are covered by the TSO, through direct contracts or by purchasing extra power in the power market. The system services are acquired by the TSOs through bilateral contracts or through the purchase of standard products in markets that are usually run by the TSO, such as the balancing market. The topic of system services is rather large, and the actual resulting costs are very much depending on the underlying market design and the real-time operation of the power system. These both issues are not in the focus of this report and hence will not be discussed more throughout. Further information on the development can be found in ACER's / ENTSO-E's framework guidelines and network codes[30].

There is a difference in the location of generation assets depending on the utilisation of fossil fuels or renewable energy sources. The difference is if power generation assets are/can be located near demand centres or need to be locate near the energy resource. The required expansion to utilise the energy sources has a significant effect on the socioeconomic outcome for the development of the system.

Figure 90 illustrates the cost range for overhead lines with single/double circuit based on their dimensioning voltage, showing a significant variation in costs. Thereby, the 400kV transmission lines have much larger transmission capacity than 220kV lines.

[30] https://www.entsoe.eu/network_codes/

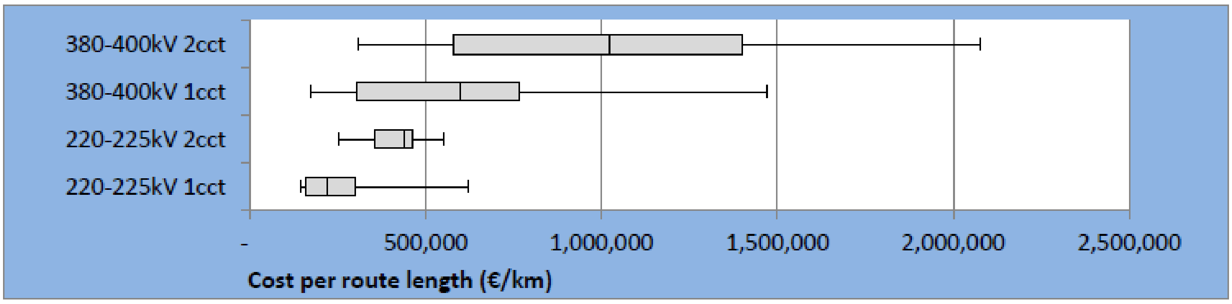


Figure 88: Costs for overhead lines per kilometre (ACER, 2015).

Figure 91 shows the same data for subsea cables, indicating that, the cost for DC cables is much lower.

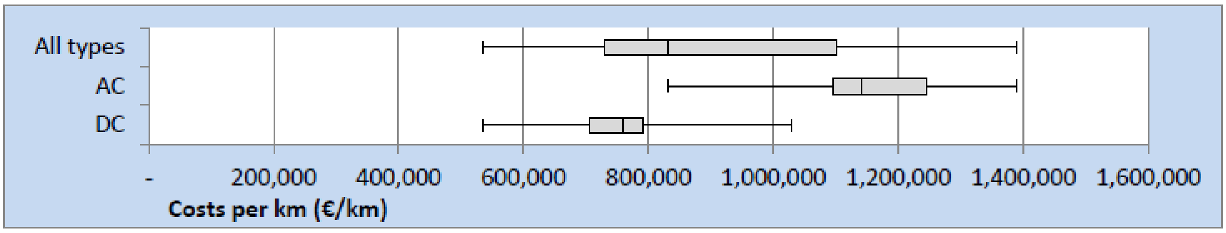


Figure 89: Costs for cables per kilometre (ACER, 2015).

However, the figures do only take into account the actual transmission line/cable and not the additional equipment, that is necessary, such as transformers or inverters. Especially in the case of DC lines, the costs for the inverters (terminal costs) contribute to a large share of the total costs of the transmission infrastructure. Thus, the investment in DC is only beneficial above a certain transmission distance (usually around 600km), see Figure 92.

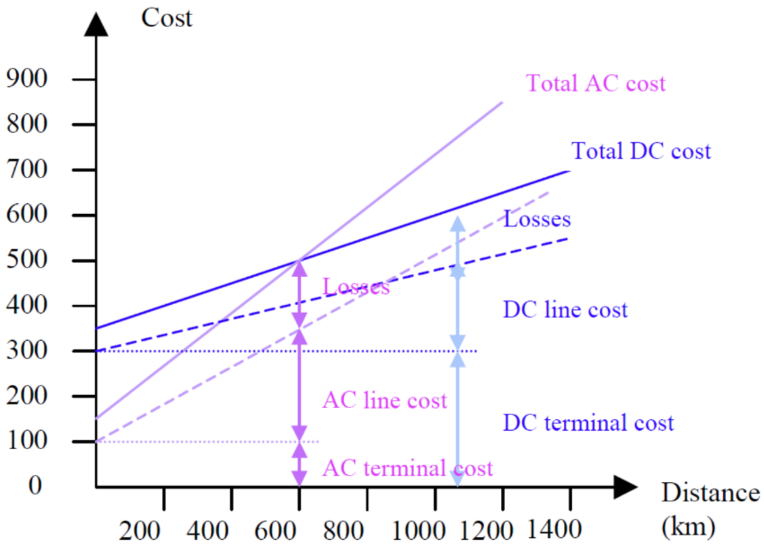


Figure 90: Figurative transmission investment cost based on distance for AC vs. DC (Larruskain et al., 2005).

The variation of the costs per kilometre are among others due to the location of the transmission infrastructure, including the type of landscape Table 12 gives an overview on the impact of the landscape on the infrastructure cost, defined by a cost multiplier (Andrade et al., 2016). It can be seen, that the construction of lines in mountainous, forested and urban areas is rather expansive.

Table 12: Effect of landscape on the transmission infrastructure costs, adopted from (Andrade et al., 2016).

Terrain	Terrain Multiplier
Desert	1.05
Scrub/Flat	1.00
Farmland	1.00
Forested	2.25
Rolling Hille (2-8 % slope)	1.40
Mountain (>8 % slope)	1.75
Wetland	1.20
Suburban	1.27
Urban	1.59

More detailed cost data on the transmission system can be found at ENTSO-E's Ten-Year Network Development Plan[31] or the Realisegrid project[32].

When new generation assets based on RES are constructed, there often is a need to also build a connection to the existing, as the renewable energy sources can be located in rather remote places. Above a certain distance, this grid connection costs can make up a significant share of the investment cost, see Figure 93 for an example of onshore wind. In case of offshore wind, this share might be much higher, as indicated in Figure 94.

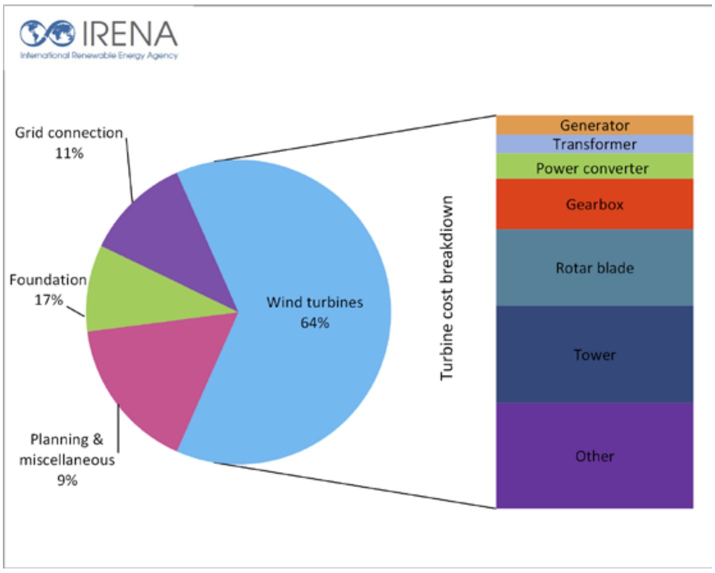


Figure 91: Cost components for onshore wind power installations[33].

[31] https://tyndp.entsoe.eu/
[32] http://realisegrid.rse-web.it/
[33] https://www.irena.org/costs/Charts/Wind

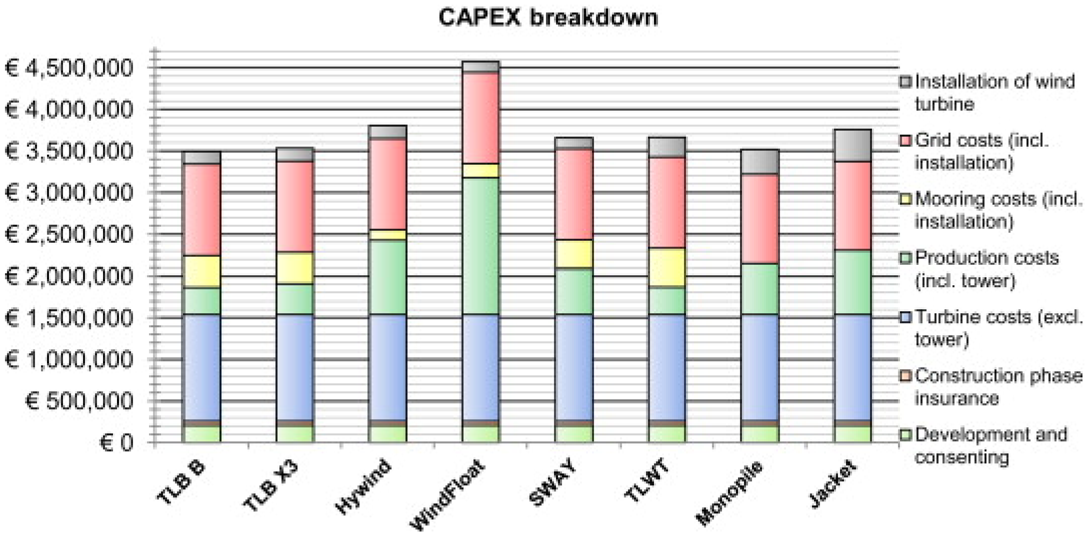


Figure 92: Cost components for selected offshore wind park projects (Myhr et al., 2014).

Based on various policies in the countries, the responsibility for the grid connection lies with different stakeholders, depicted in Figure 95 and Figure 96. In the first case, the grid connection lies at the offshore inverter station and the TSO is responsible for the construction of the offshore cable. In the second case the grid connection lies onshore, which means that the wind power producer is responsible for constructing the cable to the onshore grid connection point. However, this construction can be subsidised, and the responsibility might be given to some other private stakeholder.

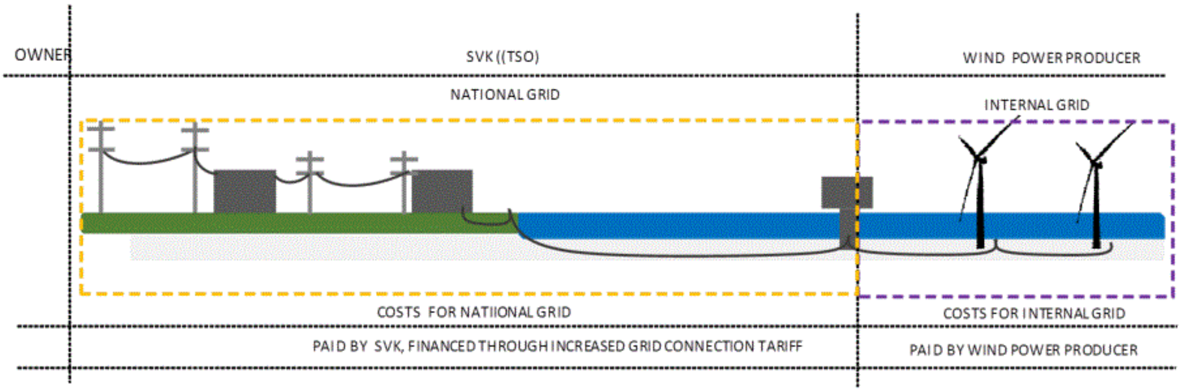


Figure 93: Investment responsibility for grid connection offshore[34].

[34] http://www.energimyndigheten.se/en/news/2018/two-models-for-removing-grid-connection-costs-for-offshore-wind-power/

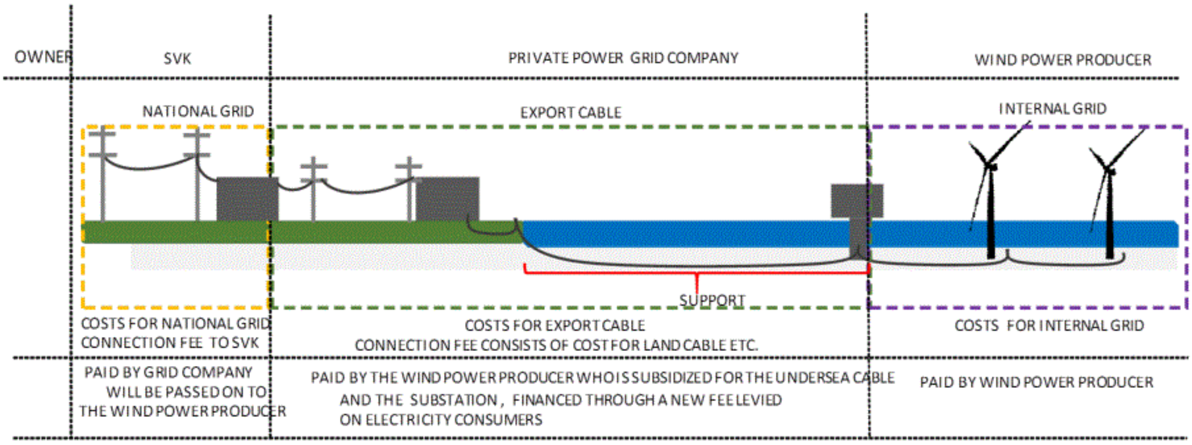


Figure 94: Investment responsibility for grid connection onshore [Source: http://www.energimyndigheten.se/en/news/2018/two-models-for-removing-grid-connection-costs-for-offshore-wind-power/].

8.2.4 State-regulated components/Taxes and levies

In addition to the costs for electricity generation, transmission and distribution, there is a significant additional part consisting of taxes and levies that are regulated and normally paid to the state. The EU Commission (2016) divided these state-regulated components into the 10 following parts:

1. Support for renewable energy sources and combined heat and power;
2. Social levies (vulnerable consumers, social tariffs, island system tariff equalisation, last resort supply, pension funds, employment policies);
3. Support to the nuclear sector;
4. Energy efficiency;
5. Security of supply, not directly connected to the operation of the power system (security of supply policies, support for indigenous electricity generation/fuel production, emergency stockpile fees);
6. Concession fees (mostly for the occupation of public land);
7. NRA & Market (financing of the national regulator authorities or market operators);
8. Other levies (includes R&D, deficit annuities and public television fees);
9. VAT;
10. Other taxes (excise duties (taxes for electricity, natural gas, energy, final energy consumption, environment) and taxes such as distribution, transmission and greenhouse gas emission).

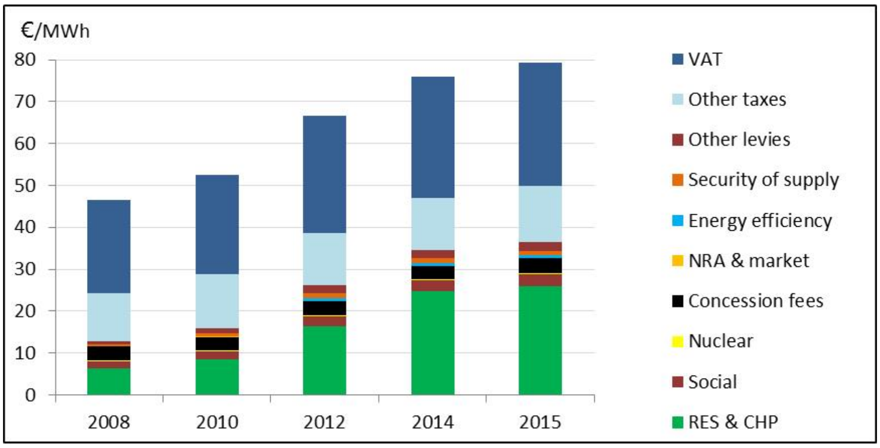


Figure 95: State-regulated components of the end-user electricity price (European Commission, 2016).

The above Figure 97 shows the development of the additional costs in the EU for household customers (including VAT). In most European countries, there is a difference in these additional costs for different end-consumer, depending on their size. Furthermore, VAT is normally excluded for commercial power consumption. It can be observed, that the RES support was the part increasing most during the last decade and amounting up to about 30 % in 2015.

8.2.5 Data for power system optimisation

When assessing the costs for electricity a number of components as described above have to be taken into account, as illustrated in Figure 78. However, when going a bit more in detail of this single components, it can be seen, that not all of the components in the final electricity procurement price are directly driven by costs for the generation, transmission and distribution of electricity.

For an optimisation from a socioeconomic standpoint, the underlying costs for the LCOE are of interest, such as capital, O&M as well as fuel costs. For the transmission system these are the capital costs for the transmission infrastructure, such as overhead lines, cables, substations and inverters. In addition, comes the costs for the operation of the power system, including losses and system services.

All other components are not directly related to the expansions and the operation of the power system but will have an impact on the strategic investment and operational decisions of the various stakeholders in the power system.

8.3 Societal barriers for infrastructure projects

Both the development of hydrogen and carbon dioxide network as well as a power network will require extensive upgrading of existing and building of new infrastructure. This may face public opposition, especially for necessary long-distance transport. The discussions surrounding the planning of the high-voltage direct current line from northern Germany to southern Germany can be seen an example of the public opposition[35]. Hence, when detailed planning for the development of the necessary infrastructure commences, it is crucial to include the public.

However, infrastructure projects on a European level have a reduced spatial resolution, and hence, it is not possible to include societal barriers in the analysis. Furthermore, these barriers are difficult to integrate into energy systems analysis as they are non-deterministic.

[35] https://www.dw.com/en/germany-protesters-oppose-suedlink-wind-energy-cable/a-48437451, accessed 25.04.2019

8.4 Existing energy system models

Table 13 provides an overview on existing energy system modelling tools in the power, heat and gas sector with a focus on Europe or selected European countries that are known to us. The listed tools are mostly available and can be applied in the main study assessing the potential of hydrogen within the future framework of the power, gas and heat sector.

Table 13: Overview over energy system models within the European power, heat, and gas sector.

			Sectors					
Model name	**Institution**	**Open**	**Geo**	**Electricity**	**Heat**	**Gas**	**Transport**	**Description**
powerGAMA	SINTEF	es	EU	x				Power system simulator based on an optimal power flow model (DC) methodology. The mod-el is implemented in Python and open available. It is developed by SINTEF Energy Research in the EU-project EuroSunMed based on a predecessor model, which was used in several Norwegian and European research projects.
Ramona	SINTEF	o	EU			x		Long-term investment model for natural gas infrastructure. The model has a rich representation of the natural gas transportation system and can consider operation of the system on a short-term basis in addition to find an optimal long-term investment plan. The Ramona model can also handle uncertainty on both a strategic and an operational level in the same analysis. This is handled with multi-horizon scenario trees.
Elegancy	SINTEF/ Imperial College London	es				x		A value-chain investment tool for hydrogen and CCS infrastructure is currently developed in the ERA-Net Cofund ACT project **ELEGANCY**[36], led by SINTEF Energy Research. This tool utilizes GIS data for the separation of the investigated regions into grid cells and uses a multi-horizon approach for decision-making related to where and when to invest in new hydrogen production facilities. Furthermore, it includes transport of the produced hydrogen and CO_2 to the required sinks. A first prototype of the model was made available to the project partners in March 2019 and can be used for initial investment decisions.
MESMERISE-CCS	Imperial College London							Multi-scale Energy Systems Modelling Encompassing Renewable, Intermittent, Stored Energy and Carbon Capture and Storage

[36] https://www.sintef.no/elegancy/

OSeMOSYS	Community project	es	Scala-ble	x	x		x	OSeMOSYS is an open source modelling system for long-run integrated assessment and energy planning. It has been employed to develop energy systems models from the scale of continents (African Power Pools, South America, EU28+2) down to the scale of countries, regions and villages. It is specifically designed as a tool to inform the development of local, national and multi-regional energy strategies and support them with capacity building activities. In mathematical terms, it is a deterministic, linear optimisation, long-term modelling framework. Mixed-integer linear programming may be applied for certain functions, like the optimisation of discrete power plant capacity expansions.
REMES	NTNU	es	EU	x	x		x	Computable General Equilibrium model developed for the Norwegian Economy. REMES takes as input a Social Accounting Matrix and a set of industry-specific elasticities of substitution. Based on that it calculates the economic equilibrium of a system, and possible outcomes once a shock has been introduced, such as simple tax increases or policies that are more complex. The model can run either as a one-year economic evaluation, or as a succession of years in which the results from one run impact the following (Werner et al, 2016) [37]
eTransport	SINTEF	o	Scale-able	x	x	x	x	Planning of local energy systems where different energy carriers and technologies are considered simultaneously. Optimization model for planning of local energy systems where different energy carriers and technologies are considered simultaneously. The current version can optimize the construction of infrastructure for most relevant energy carriers; electricity, heating, cooling, gas, waste and biomass, including conversions between these. (Bakken et al., 2008)
EMPS	SINTEF	o	EU	x				Fundamental model for the power market, specifically suited for hydro-thermal power systems. The total system is divided into a set of areas that are connected by transport corridors. The market equilibrium is calculated for each area and time-step on the basis of demand-, supply and transmission options. All power generation technologies can be represented. The problem is solved as a system optimization including SDP, LP and heuristics. The stochastic variables include all climate variables such as inflow to reservoirs, temperatures, and intermittent generation (wind-power, and solar-power).

[37] Regpoll – Regional Effects of Energy Policy - http://www.sintef.no/en/projects/regpol-regional-effects-of-energy-policy-/

FANSI	SINTEF	o	EU	x				Optimal dispatch of hydrothermal power systems taking into account stochastic climate variables such as wind, solar and inflow to hydropower reservoirs (Helseth et al., 2007). Formal optimisation model that include individual water values and power flow constraints.
EMPIRE	NTNU/ SINTEF	es		x				Capacity expansion model for the European power system, formulated as a multi-horizon stochastic program. The objective is to minimize system cost of the European power system including investment cost and expected operational costs. The model represents load and RES generation under short-term uncertainty, hence hourly variations and their correlations are considered. (Skar et al., 2016)
PyPSA	KIT	es	Scala-ble	x	x	x	x	PyPSA is a free software toolbox for simulating and optimising modern power systems that include features such as conventional generators with unit commitment, variable wind and solar generation, storage units, coupling to the natural gas, hydrogen, heat, and transport sectors, and mixed alternating and direct current networks. PyPSA is designed to scale well with large networks and long time series. PyPSA itself is written in Python and uses the Pyomo library. The source code is hosted on GitHub and is also released periodically as a PyPI package.
EXIOMOD 2.0	TNO	es	Global	x	x	x	x	EXIOMOD 2.0 (Bulavskaya et al., 2016) is a multisector multi region computational general equilibrium model that is able to measure the environmental and economic impacts of policies. It can provide comprehensive scenarios regarding the evolution of key economic variables such as GDP, value-added, turn-over, (intermediary and final) consumption, investment, employment, trade (exports and imports), public spending or taxes. Thanks to its environmental extensions, see www.em-plus.eu, it establishes the link between the economic activities of various agents and the use of a large number of resources and negative externalities (greenhouse gases, wastes).
MES-SAGEixGLO-BIOM	IIASA	es						Integrated Assessment Model for long-term energy system planning and policy analysis in the context of climate change and sustainable development. The IIASA IAM framework consists of a combination of five different models or modules - the energy model MESSAGE, the land use model GLOBIOM, the air pollution and GHG model GAINS, the aggregated macro-economic model MACRO and the simple climate model MAGICC. See http://data.ene.iiasa.ac.at/message-globiom for a more information. (Fricko et al., 2017)

MESSAGEix EU	IIASA	es						Version of the MESSAGEix-GLOBIOM including more regional disaggregation to allow a better focus on implementation of policies by the EU and EU member states.
TEPES	Comillas	es	EU+	x				Electricity network modelling and analysis of the impact of the implementation of specific energy policies on the development of the transmission network[38]
SCOPE	FhG IEE	o	EU	x	x	x	x	Scenario development for energy system transformation towards decarbonisation (Trost et al., 2017)
HERO	TU Wien	es	Any	x	x	x	x	Optimal capacity allocation and dispatch (distributed generation and battery storage) under special consideration of sector coupling on distribution grid level (electricity, heating/ cooling and gas grid) for meeting the energy services needs of local energy communities. (Fleischacker et al, 2017)
OSCARS	TU Wien	es	National/Regional	x	x			Optimal utilization of small battery storages and flexible loads on prosumer level under various operation strategies. References: Project LEAFS: Integration of Loads and Electric Storage Systems into Advanced Flexibility Schemes for Low Voltage Grids. Project MBS+: Development of Battery Storage Clusters Minimizing Schedule Deviations. Both Projects are ongoing, Refer to summary at Austrian Climate/Energy Fund[39]
GENeSYS-MOD	TU Berlin	es	EU	x	x	x	x	The Global Energy System Model (GENeSYS-MOD) is a cost-optimizing linear program, focusing on long-term developments of the energy system, with a detailed approach to sector coupling of the sectors electricity, heat, and transportation. It specifically targets the developments with regard to the global low-carbon transition.
Plan4RES	EDF	es	EU	x				The plan4eu[40] modelling suite (from plan4res H2020 project), focused on the electricity system, comprises i/ a capacity expansion model which finds the best optimisal compromise between generation/storage investment and transmission/distribution expansion for a given long-term horizon, ii/ a seasonal storage valuation tool and iii/ a european operational dispatch model. All 3 models include uncertainties, a realistic accounting of all technical costs and constraints including system services, for all kinds of centralised and distributed assets. It includes an aggregated modelling of transmission and distribution networks.

[38] https://www.iit.comillas.edu/aramos/TEPES.htm
[39] https://www.energieforschung.at/projekte/intelligente-netze
[40] https://www.plan4res.eu,https://www.plan4res.eu/wp-content/uploads/2018/06/plan4res_D3.1_Description_of_model_interconnections.pdf

FRESH:COM	TU Wien	es	Local	x			x	FaiR Energy SHaring in Local COMmunities: Multi-objective optimization tool for optimal local renewable technology portfolio dimensioning/design and consideration of the individual actors' sharing allocation preferences in different local energy community configurations. (Finna et al., 2018)

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