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SECTOR COUPLING

Creating an interconnected decarbonized energy system benefiting industry, the power sector and society

SAFER, SMARTER, GREENER

SECTOR COUPLING

CREATING AN INTERCONNECTED DECARBONIZED ENERGY SYSTEM, BENEFITING INDUSTRY, THE POWER SECTOR AND SOCIETY

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DISCLAIMER
The insights presented in this paper are partly based on the DNV GL Smart Grid Scenario Model (DSSM), implementing basic market rules and generation dispatch. Implications of generator start/stop cost, part load behaviour, minimum load constraints, reserve capacity for scheduled maintenance of power units, value of ancillary services, grid constraints, differences in weather conditions for larger regions, etc. are not implemented. Although we are confident the trend behaviour is valid, the absolute numbers are not reliable enough for e.g. investment decisions. The central generation mix and variable renewables mix have a large influence on the electricity prices, as have other country specific characteristics. For investment decisions, a more detailed load/price forecasting study, dedicated to the specific country is necessary.

CONTENTS

1 – INTRODUCTION

- This report describes coupling between different economic sectors (e.g. industry, services, households and transport) as they transition towards the use of electricity and hydrogen as the dominant energy carriers.
- Traditionally, economic sectors are tied to specific energy carriers and energy carriers are tied to specific uses. For example, oil-derived fuels are mainly used in the transport sector. Electricity is mainly used for mechanical power, lighting and ICT, natural gas is (besides for electricity generation) mainly used as an industrial feedstock and for heating purposes.
- Electrification is a main enabler of the energy transition and a main aspect of sector coupling. Sectors that previously used various energy carriers will now compete for the same source: electricity.
- Sector coupling will lead to "market coupling", meaning that prices of energy will depend on its use in different markets. Market coupling may well have a positive effect on the business case for renewable electricity generation.
- Market coupling will lead to opportunities for industry, for example, using fuel switch to profit from the lowest commodity prices. This requires an optimized control and commodity purchase strategy.

SECTOR COUPLING AND MARKET COUPLING

Sector coupling is currently seen as an important enabler of the energy transition. Recent studies for the European Union[1, 2], investigated the techno-economical and regulatory barriers for sector coupling. They provide policy advice on how to enable and stimulate sector coupling. In this report we focus on another aspect of sector coupling, that could be called "market coupling[3]". This market coupling effect may well become an important driver to keep investments in renewable energy sources like solar PV and wind turbines economically feasible. Renewable generation suffers from cannibalization effects as the price they capture on the electricity market decreases with increasing penetration[4]. Sector coupling may prove itself to increase the value of renewable electricity during hours of high renewable production.

From an industrial point of view, sector coupling is an opportunity to reduce cost. A typical example is fuel switch for industrial heat/steam production.

In this study we aim to provide insight into the market coupling effect of sector coupling based on quantitative analyses of the impact of sector coupling on energy demand and energy prices. Because of sector coupling, taxation schemes meet and should be harmonized in order to create a level playing field. As in our previous white papers[4, 5, 6], we use a case study to quantify the effects of sector coupling and illustrate them.

WHAT IS SECTOR COUPLING?

Sector coupling is about the coupling of energy vectors (also referred to as energy carriers or energy value chains) between different end-users of energy. With respect to energy use, we recognize three major economic sectors:[7]

The industry sector is a large sector, including e.g. refineries, the (petro)chemical industry, the metal industry and the food & beverages industry. The built environment consists of households and services, including commercial services (e.g. trade, advisory, tourism, finance) and public services (e.g. healthcare, education and administration). The energy use of the services sector is mainly related to office use. For both households and services, energy use is for a large part due to space and water heating, ventilation and air conditioning. The transport sector includes road transport and transport by rail, ship and aeroplane, although, in this paper we will concentrate on road transport[8].

Other sectors, like agriculture, are generally much smaller in energy use, although, in individual situations like concentrated greenhouse cultivation, the impact may still be significant.

Generally, these sectors use three main energy vectors:

1. Electricity for mechanical power, ICT, lighting, electrochemical processes and specific industrial heating processes (e.g. induction furnaces). In some countries, e.g. countries with abundant hydropower, electricity is used for (space) heating purposes as well;
2. Natural gas as a feed stock for the industry and for generating low temperature heat (space heating, tap water heating) and high temperature heat (industrial processes);
3. Oil-derived motor fuels (diesel for heavy and light duty trucks, vans and passenger cars; and petrol mainly for passenger cars).

In this traditional picture, certain energy vectors are mostly tied to certain sectors (motor fuels to transport sector) or certain end-uses (natural gas for heating, electricity for mechanical power, lighting and ICT). In chapter two we will illustrate this based on an analysis of the energy use in Europe and some typical European countries.

ELECTRIFICATION AS MAIN ENABLER OF THE ENERGY TRANSITION

Electrification is seen as a major enabler of the energy transition[7]. This includes electrification of road transport by electric vehicles (EVs), made possible by battery development and electrification of heating of buildings by heat pumps. Electrification generally increases process efficiencies, as heat losses are typically reduced. A transition from fossil-based to renewable electricity will automatically result in an increased decarbonization of electrified processes.

Energy supply of different sectors, specifically industry, mobility and the built environment, are thus becoming more interconnected by using the same energy vector: electricity. And, through electricity, other energy value chains, such as for natural gas, oil and hydrogen, are more tightly connected, forming one large interconnected and increasingly dynamic energy system. Industrial ports, for example, are typical environments where these sectors come together[9].

Sector coupling and market coupling are not new. Energy value chains have always been connected one way or another. For example, power prices on wholesale markets are determined by the marginal running costs of power plants, which are directly coupled with the price of oil, coal and natural gas. Another example is combined heat and power generation (CHP). Combined heat and power plants are very efficient, because their 'waste' heat is their main product. Additional fuel used to generate electricity therefore can be fully converted to electricity with almost zero losses, because these losses are included in the heat production. This allows almost all the primary energy to be used. These are recognized ways of coupling in a well-defined area that are understood both from a thermodynamic process perspective as well as from a market perspective.

What will be different is both the scale on which energy vectors will be coupled and the dynamics of it. Sectors will rely more and more on electricity. Flexible demand will start to compete for low-priced renewable electricity[10], making demand price setting.

Additionally, hydrogen will become an important energy carrier[11]. Decarbonized (green) hydrogen will be mainly produced from renewable electricity and will serve applications in buildings, industry and the transport sector, and may also be used as a carbon-free fuel for (peak) power generation. Hydrogen production from electrolysis will, however, compete for low-priced electricity with other flexible energy consumption, such as transportation and heating.

THE NEED FOR STORAGE

The need for energy storage will increase as the amount of solar PV and wind power grows. Electricity storage, both short-term (typically to accommodate daily and weekly cycles) and long-term (to accommodate seasonal cycles)[6], will be added. This adds to the complexity of sector coupling as electricity storage will compete on the market for lower-priced electricity. Electric vehicles can also be used to provide storage services (vehicle-to-grid applications) and hydrogen can be used as an intermediate electricity storage medium. Figure 1 illustrates these interdependencies.

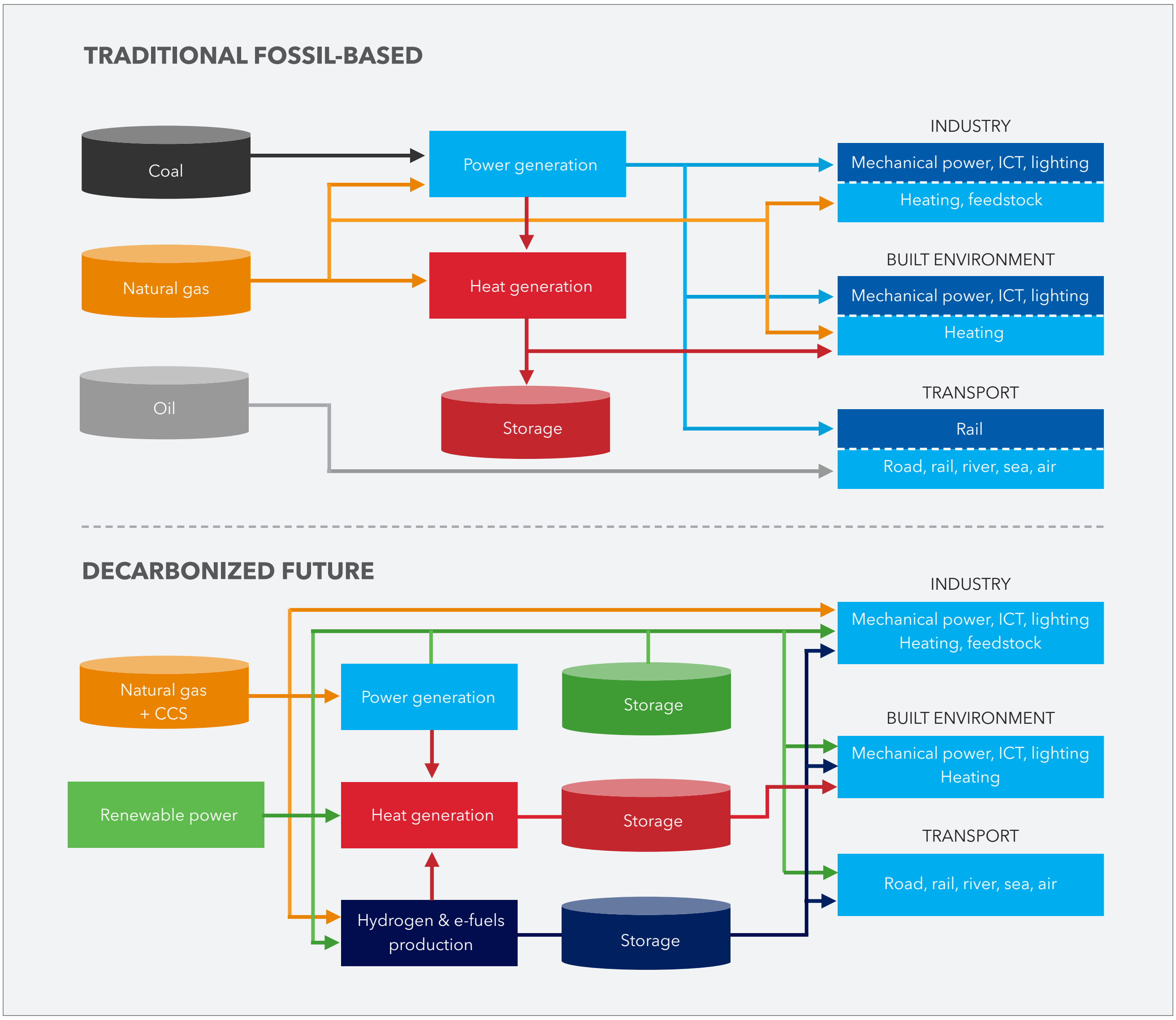


Figure 1 - Integration of key energy value chains towards an integrated decarbonized energy system

READING GUIDE

Market coupling will lead to more complex price forming. Especially when energy infrastructures are well developed and sectors have the opportunity of fuel switch (e.g. industrial heating from electricity, natural gas or hydrogen), this will become an important effect. It may help to increase the value of surplus electricity generated from solar PV and wind turbines, support the economic feasibility of variable renewable generation in the long run and mitigate risks of the energy transition.

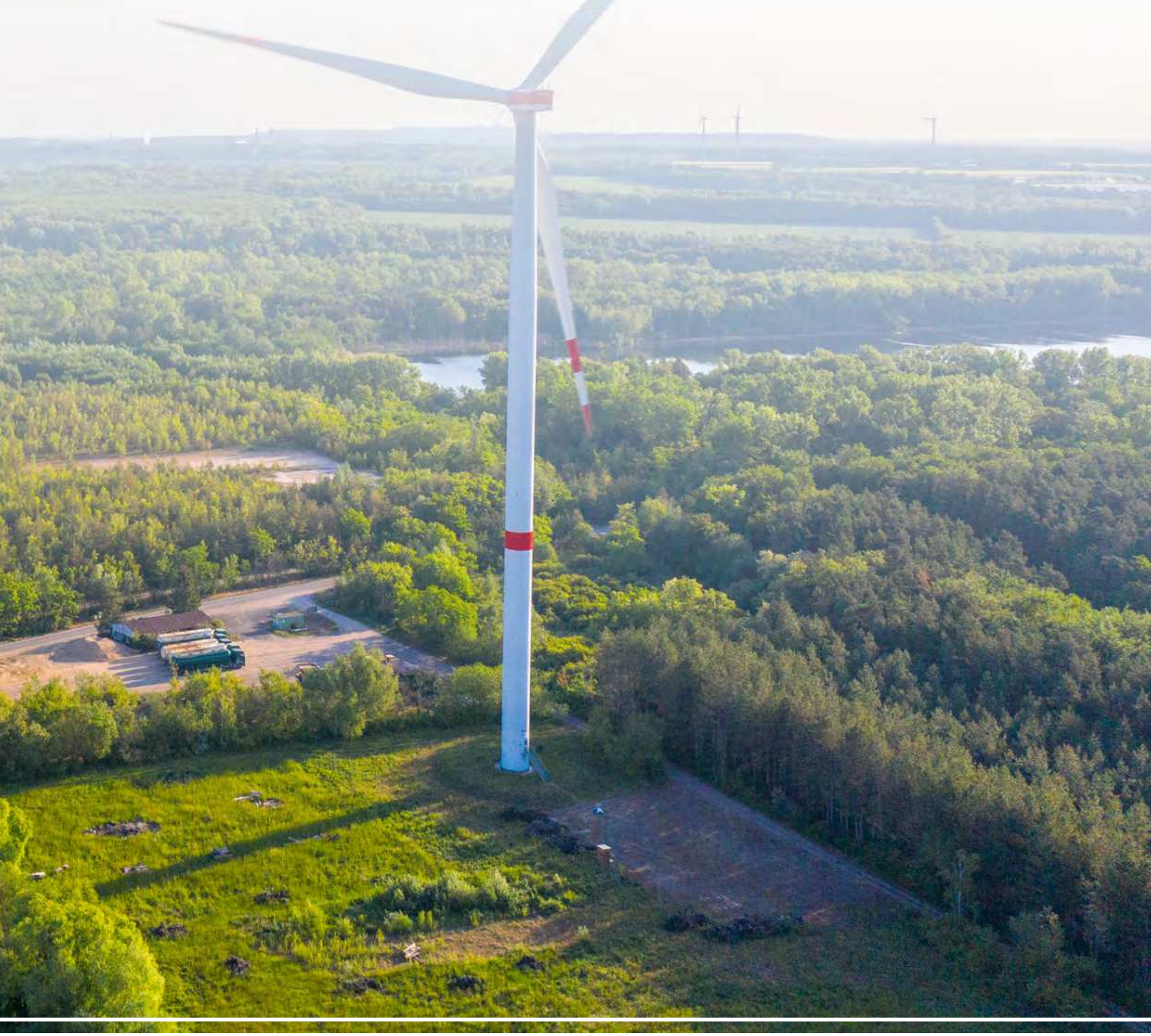
This paper aims to provide insights in the effect of sector coupling and market coupling. Chapter two analyses the use of the main energy carriers in Europe: electricity, natural gas and oil-derived fuels for road transport. It shows how energy consumption compares between those three energy vectors, both in absolute size and in daily and seasonal variation.

Chapter three provides insight into the effect of electrification of road transport. Based on a levelized cost calculation we show that EVs are on the road to becoming an economically feasible alternative to internal combustion engine cars. Therefore, EVs will significantly increase the demand for electricity resulting in potentially higher electricity prices. If EV batteries are used for vehicle-to-grid applications, both charging and discharging them to generate value on the electricity market will dramatically change traditional daily price patterns, both increasing and lowering the price.

In chapter four we look at the decarbonization of heat demand in the built environment, typically by using electricity (heat pumps, direct heating) or hydrogen (modified gas boilers). Chapter five does the same for the industrial sector but will focus on other areas of decarbonization potential away from heat demand alone. This chapter elaborates some more on the challenges and goals for emission reduction, on decarbonization options like energy efficiency, electrification and hydrogen and on opportunities for new renewable commodity markets.

Chapter six shows how sector coupling, discussed in the previous three chapters, will impact the electricity market and electricity prices. We show that sector coupling can become a price setting mechanism, increasing the value of renewable electricity.

Finally, in chapter seven we summarize our observations and conclusions from this study.



2 - ASSESSMENT OF THE MAIN ENERGY CARRIERS

2.1 Examples of current national energy use

- The consumption of motor fuels is (in energy units) similar to electricity consumption. Electrification of road transport can significantly add to the required volume of electricity.
- The same holds true for natural gas. Replacing (significant parts of) European natural gas use with electricity is a massive task and shift.
- An added challenge here is the large seasonal load swing in natural gas consumption, reflecting the variation in space heating demand. Electrification of this demand will introduce a significantly larger seasonal variation in electricity demand.

Sector coupling will go hand in hand with a fuel switch from fossil-based fuels to electricity and hydrogen. This has both volume issues and timing issues. Volume issues because fuel switch will lead to an increased need for electricity (and hydrogen), and timing issues because renewable electricity generation from solar PV and wind turbines doesn't automatically match (new) electricity demand.

To provide insight in the demand for energy, we analysed the national final energy consumption of two countries, the Netherlands and Italy, representing a Western-European and a Southern-European country[12].
Both countries have a well-developed natural gas infrastructure. We consider the natural gas consumption as a proxy for the demand for process and space heating.

Figure 2 and Figure 3 show the total consumption of natural gas (divided over large consumers directly connected to the transmission grid and consumers connected to the distribution grid), the total electricity load and the use of motor fuels for road transportation. This is not the final use as natural gas from the transmission grid will be partly used for power generation. Final energy use will be analysed on a European level in more detail in the last section of this chapter.

Both Figure 2 and Figure 3 provide valuable insights:

- The difference in the natural gas consumption profile between transmission and distribution grid consumers is obvious. Large transmission grid consumers show a fairly constant use with small day/night and seasonal variations. This suggests mostly industrial consumers and power generation.
- Gas distribution grid consumers show a much larger seasonal variation and a fairly constant use during late spring, summer and early autumn. This suggests a period with mainly space heating and tap water heating and small industrial consumers with an almost constant load profile. This is supported by an analysis of the distribution grid gas consumption and the outside temperature for the Netherlands which shows a significant correlation (see appendix A).
- The electricity use is also fairly constant with noticeable (but relatively small) day/night and seasonal variation. Overall, the electricity demand is significantly smaller than the natural gas demand.
- The use of mobility fuels is only publicly available on a monthly (Netherlands) or yearly (Italy) basis. The Dutch data suggests an almost constant profile throughout the year. A summer holiday peak or any seasonal variation is not noticeable from this data. In energy units, electricity use and road transport fuel use are close.

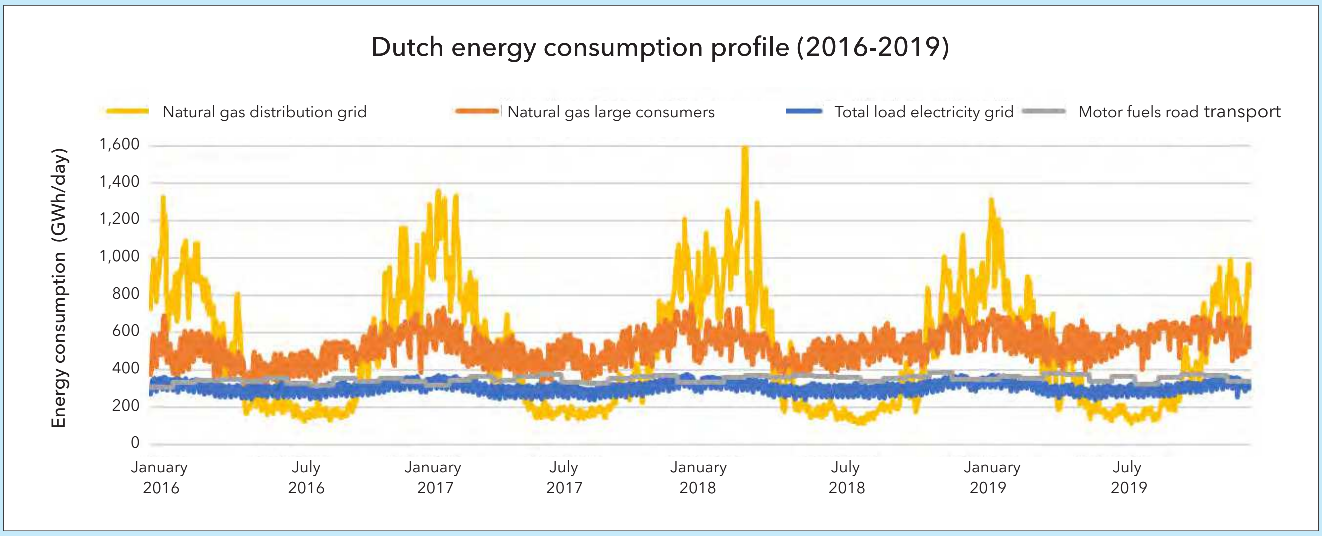


Figure 2 - Dutch energy consumption profiles for three main energy carriers

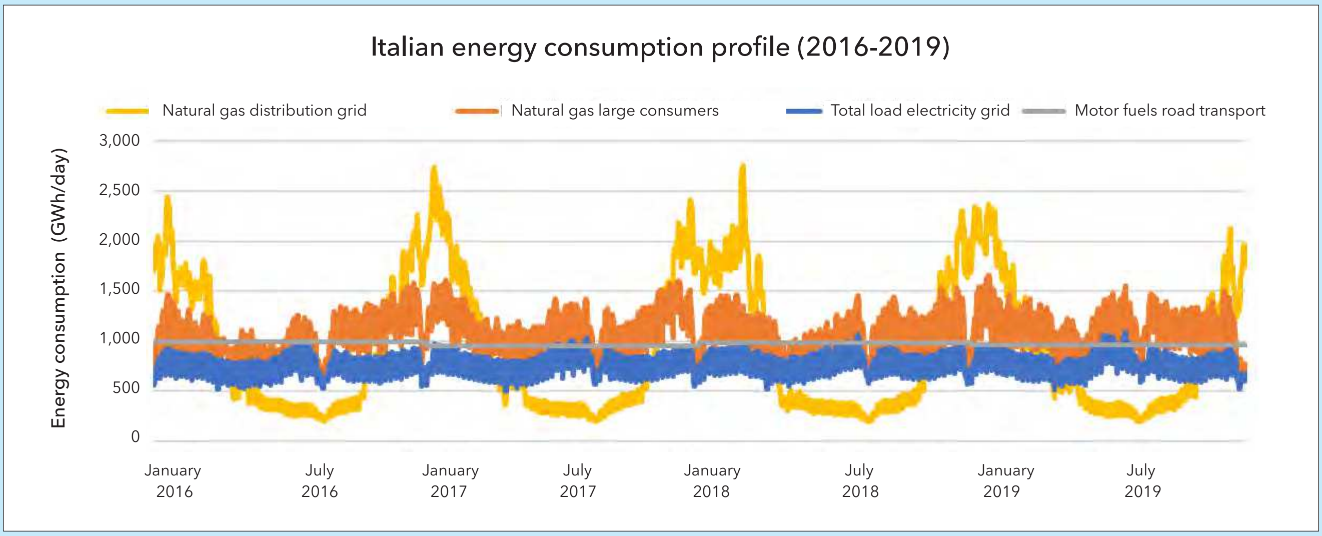


Figure 3 - Italian energy consumption profiles for three main energy carriers

A first conclusion from these graphs is that a full fuel switch to electricity would be a challenge. Even considering the higher efficiency factors for electric space heating (heat pumps) and electric mobility, electricity use will approximately double its current use and the seasonal load swing will increase dramatically. Seasonal storage will be an issue, as discussed in our previous position paper[6].

2.2 Total energy consumption in Europe

- The total energy consumption in Europe for electricity and road fuels is not seasonally dependent and in energy terms comparable in size.
- The natural gas consumption shows a high seasonal dependency.
- Electrifying the final natural gas and road fuel consumption will almost double the electricity demand and significantly increases the seasonal variations in electricity demand.

In the previous section, we discussed the consumption of natural gas, electricity and road fuels based on two typical countries. In this section we focus on Europe (27 countries as of 2020). Figure 4 presents the energy use in Europe for the three main energy carriers[13]. This is the total consumption including natural gas for electricity generation. Compared to the consumption for Italy and the Netherlands (shown in the previous section), the natural gas consumption is lower in comparison to the electricity consumption and the road fuel consumption.

The base load for all three energy carriers varies between 200 and 250 TWh per month. The electricity consumption and motor fuel consumption show no significant seasonal variation. This is different for the natural gas consumption. It shows a large seasonal variation. The load swing is lower than for the two cases in the previous study. This is most likely partly due to averaging out the natural gas consumption over all European countries and partly due to the sample frequency (monthly values versus daily values).

A thought experiment provides a first insight in the implications of fully electrifying the current final energy consumption as shown in Figure 4. Let's assume that:

- The current electricity demand stays the same.
- Approximately 40% of the natural gas demand is for electricity production and other non-final use. This is base-load demand that will not be electrified.
- The remaining base-load natural gas demand (summer months demand, 77 TWh per month average) is mainly industrial and will be electrified with direct electric heating (e.g. electric boilers). The efficiency ratio between a gas fired boiler and an electric boiler is assumed to be 1.
- The remaining natural gas demand is assumed to be for space and tap water heating. This demand will be electrified with heat pumps. The efficiency ratio is assumed 3.5[14].
- Electric vehicles (typically a mid-sized car) will realize a mileage of approximately 6 km/kWh. For a mid-sized petrol car this is approximately 20 km/litre. This results in an efficiency ratio of 3.4.

The resulting electricity demand is also shown in Figure 4. The electricity demand almost doubles and the seasonal demand variations become significantly higher. It shows that sector coupling potentially has a serious impact on the electricity consumption in Europe, both in volume and in timing. This is, however, a rough picture neglecting for instance the impact of a lower heat pump performance during cold days and the effect of district heating.

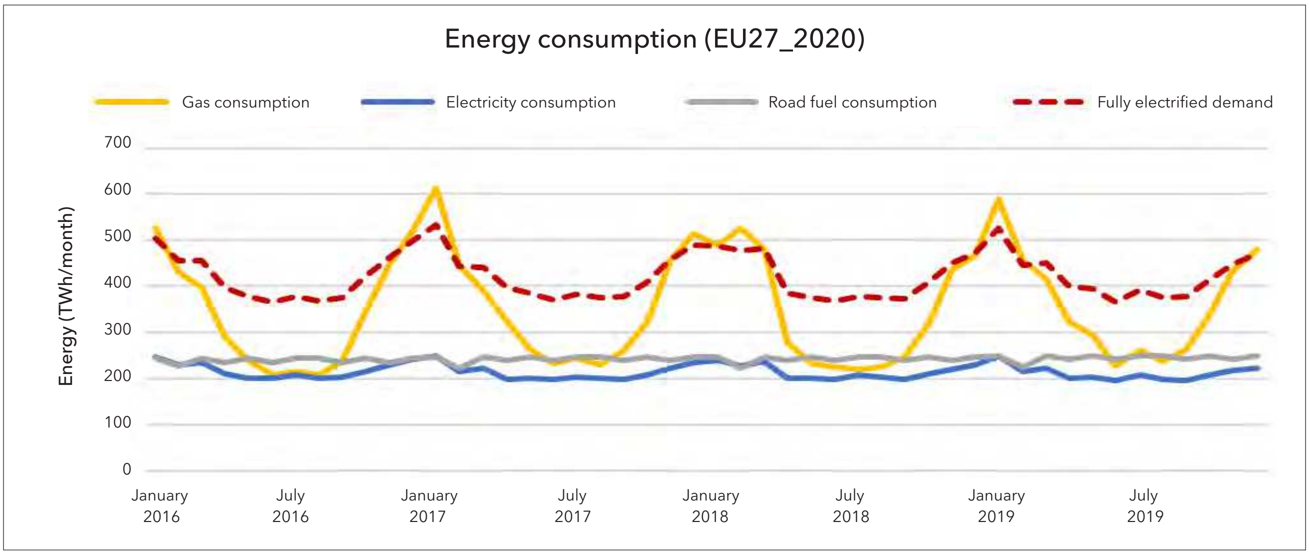


Figure 4 - Overview of energy consumption in Europe for three main energy carriers and the electricity demand assuming full electrification

2.3 Final energy consumption in Europe

- The final energy consumption is the energy consumption which reaches the final consumer's door, excluding for instance natural gas used for electricity production.
- More than 60% of the final energy consumption in 2018 was fossil-based, suggesting a significant potential impact of sector coupling when this demand is electrified.

The previous picture does not show the final energy demand in Europe for all energy carriers. This data is not publicly available on a monthly basis, only on a yearly basis[15]. The results of an analysis for 2018 are summarized in Figure 5 and Figure 6. Both figures show the same data but with a different cross section.

Figure 5 shows the final energy consumption per sector. The final energy consumption is the energy which reaches the final consumer's door and excludes that which is used by the energy sector itself[16]. Conversion from natural gas to electricity is thus not included in the final energy consumption. This explains the difference in natural gas volume between Figure 4 and the next two figures.

Heat supply in Figure 5 is based on supply by an industrial or district heating grid. All sectors make use of other fossil fuels, e.g. heating oil and motor fuels. Renewable energy comprises of biofuels, solar thermal and ambient heat (used by heat pumps)[17].

Industry, households and transport are comparable in energy use. The service sector energy use is half that of the other sectors individually. For the service sector, the heat demand (including natural gas, other fossil fuels and renewable energy[17]) is almost equal to the electricity demand. For industry and households, this share is much larger. The share of electricity and natural gas in energy consumption for road transport is negligible.

Figure 6 shows the final energy consumption per energy carrier. Fossil fuels are still the main energy carrier (more than 60% of the total final energy use), of which motor fuels for road transport is the largest. Approximately 40% of the total fossil fuels consumption is natural gas, the other 60% is mainly oil- and coal-based.

More than 60% of the final energy consumption in 2018 was fossil-based, suggesting a significant potential impact of sector coupling when this demand is electrified.

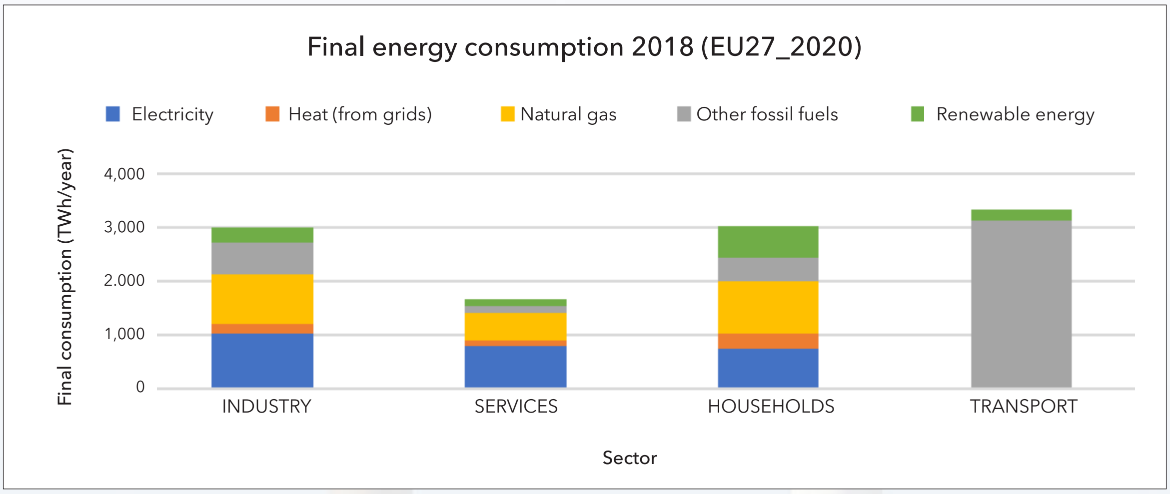


Figure 5 - Final energy consumption per sector

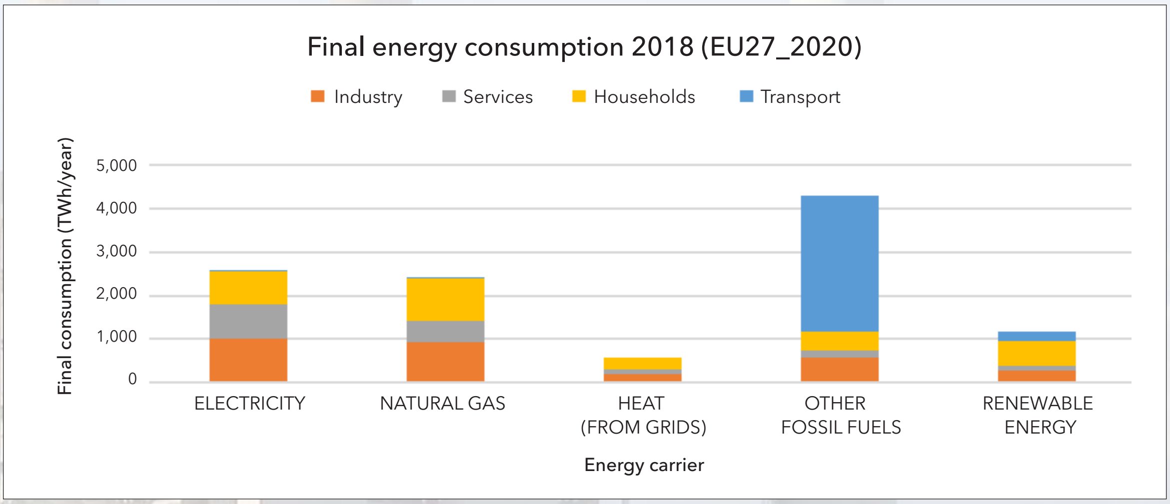


Figure 6 - Final energy consumption per energy carrier

3 - ELECTRIC MOBILITY

3.1 Trends in fuel consumption for motor transport

- Fuels for road transport are currently predominantly oil based.
- The total fuel consumption for road transport in Europe shows a steady increase from 2012 onwards, the share of electricity is however negligible.
- Approximately 6% of the road fuel in Europe is renewable (mainly blended biofuels).
- This picture differs per country: a country like Norway, with strong EV incentives, shows a decline in fossil fuel use for transportation.

Electric mobility has a potentially large sector coupling effect. As we have seen in the previous chapter, oil-based fossil fuels for road transport are the largest contributor to the final energy use in Europe. Historic data (Figure 7) shows that the road fuel consumption has increased steadily from 2012 onwards. Before 2012, it shows a gradual decrease. This is probably the combined effect of an increase in volume (car kilometres) and an improvement in average fuel efficiency. The share of renewables in the road fuels (predominantly blended bio petrol and biodiesels) has increased but is still small. The share of natural gas and electricity is negligible.

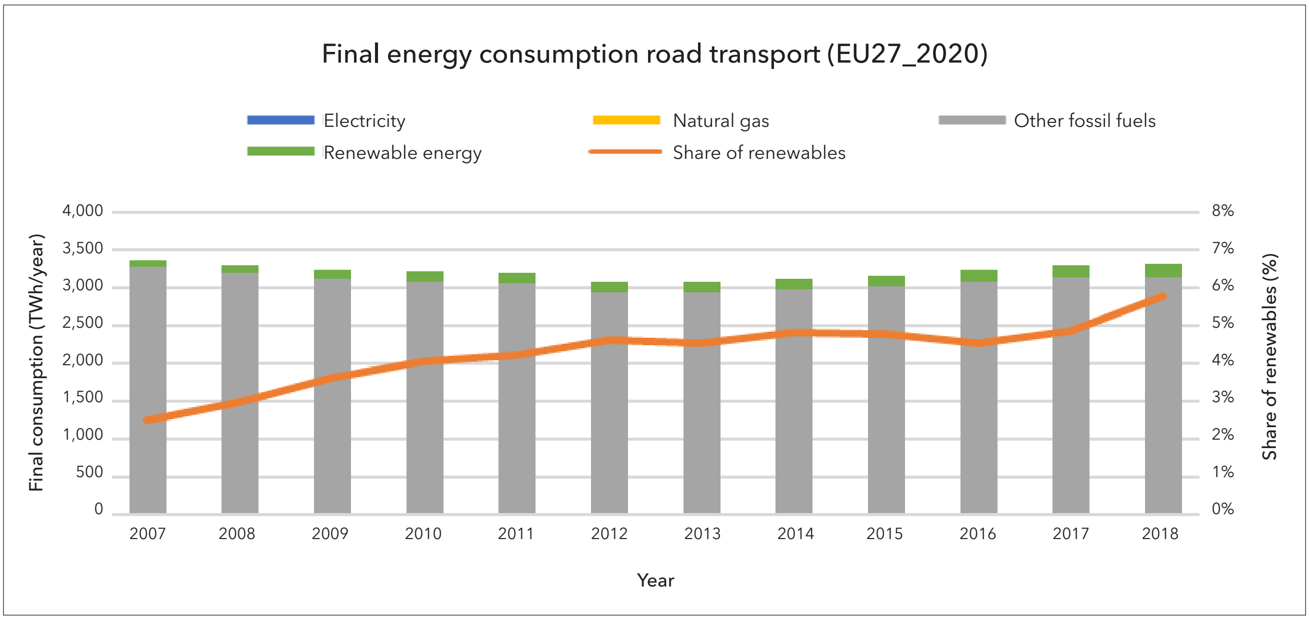


Figure 7 - Historic fuel consumption for road transport in Europe[18]

Although effects of electrification of transport do not seem to appear yet in European statistical data, in for example Norway, with strong incentives for EVs, a decline in fossil fuel use for transportation can be seen. Data (Figure 8) suggest a correlation with the share of privately owned EVs and plug-in hybrid electric vehicles (PHEV). The trend in total electricity consumption does not seem to reflect the additional electricity use for EVs. This is probably due to increased fuel efficiency for electric vehicles.

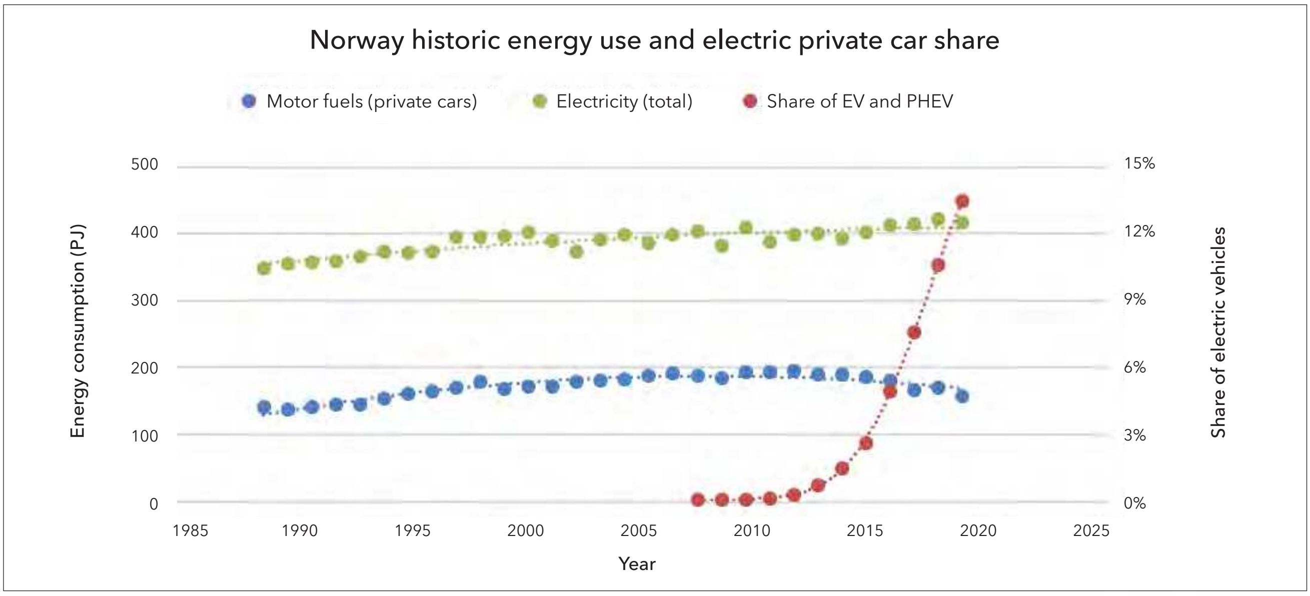


Figure 8 - Selected historic energy consumption in Norway and share of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs)[19]

3.2 Economic feasibility of electric vehicles

- Currently, the levelized cost of transport (LCOT), based on a case for an average mid-sized passenger car, are higher for an electric car than for a petrol car.
- From an LCOT-perspective, EVs will become the dominant passenger car. The difference in LCOT becomes more and more significant as EV-costs (and especially battery cost) decrease.
- Diminished range anxiety because of increasing range of EVs, available charging infrastructure and environmental awareness are other drives besides economics.

A large scale introduction of EVs will significantly change the demand for electricity. Most European governments have big ambitions for EVs. Generally, they stimulate EVs by providing incentives for the vehicles and charging infrastructure. These include[20]:

- Purchase grants (available in at least ten European countries, varying from 2,000 to 7,000 EUR);
- Tax benefits (lower or exemption from registration tax, road tax, company tax);
- Local benefits (free parking, reserved parking spots, use of taxi/bus lanes, access to limited circulation zones, exemption of toll charges, lower rates for ferries);
- Charging infrastructure benefits (low charging rates, subsidized charging infrastructure).

Except for the Netherlands, where only emission free cars may be registered from 2030 onwards, countries incentivize EVs but do no obligate them. Switching to an electric car is therefore mainly an economic decision (besides social aspects like range anxiety and environmental awareness of the buyer). To assess the sector coupling impact we first provide insight into the economics of an electric car compared to a petrol car. We use a case study modelled according to an average mid-sized passenger car. The parameters are estimated based on our *Energy Transition Outlook*[7] and a review of publicly available sources. The parameters reflect average European cost levels. Appendix B elaborates on the choice of parameter values and the sources used.

The economic comparison is made based on total costs of ownership. These costs are discounted and translated into the LCOT expressed in euros per km driven. This metric includes the effect of car purchase, fuel cost, maintenance, insurance, etc.

Figure 9 summarizes the results of the levelized cost calculations. The 2050 mid-size petrol car is for comparison only, it may not be a reasonable option anymore in 2050. The marginal cost (variable cost per km, fuel cost and CO_2-cost) are shown first and separated from the fixed yearly cost with a dotted line. This figure illustrates:

- The mid-sized electric vehicle is on average currently more expensive than a petrol car but, in the future, this is reversed
- This is mainly due to cost reduction in batteries
- The marginal (fuel) costs of electric vehicles are lower than those of a petrol car despite an expected higher service margin on electricity (public charging, fast charging). This service margin reflects the cost of a grid connection and the cost of charging equipment (for petrol, this service margin reflects the cost of distribution of fuel and fuelling equipment)
- Road tax exemptions/reductions for EVs will be cancelled in the future, but maintenance will still be lower than for a petrol car
- We expect the service margin on electricity (distribution, public charging, fast charging) to decrease because of more competition in the market. Also, both the battery size and the number of charging facilities may increase, reducing the need for expensive fast charging.

Marginal cost for the electric car (fuel cost) is lower than for the petrol car. The gap is expected to increase towards 2050 for reasons stated above. This will put pressure on fuel cost for petrol cars. In order to stay competitive, these fuel costs must decrease. Together with the diminishing demand of fossil-based road fuels, this will put pressure on the oil price and fuel taxation.

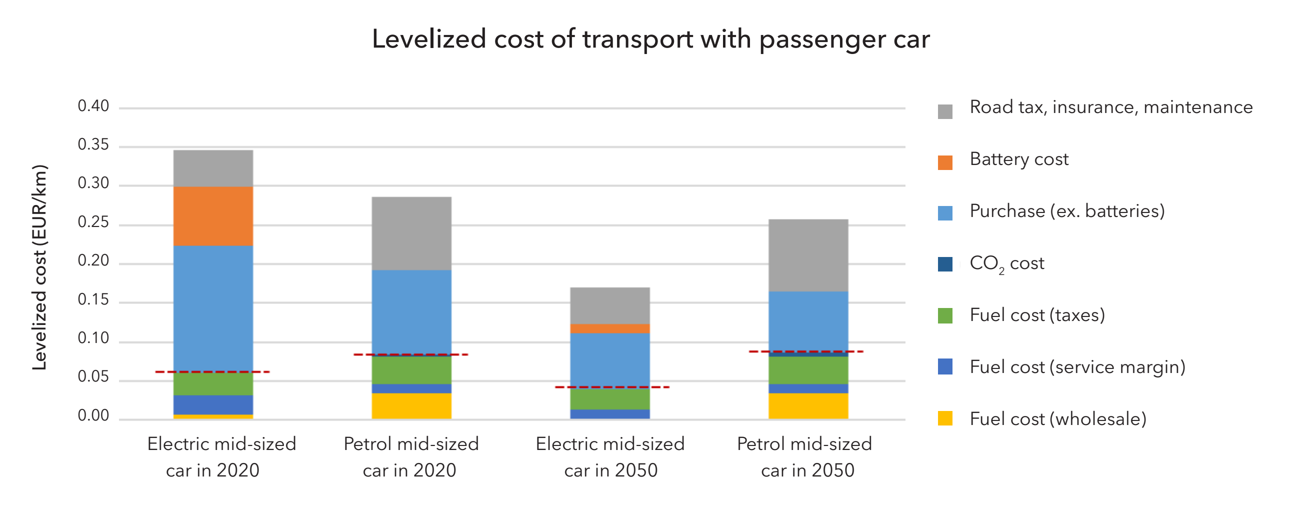


Figure 9 - Levelized cost of transport for four cases, current and future, for a mid-sized passenger car; costs below the dotted line are marginal cost (fuel cost)

To assess whether the differences in LCOT shown in Figure 9 are significant, we made a Monte Carlo calculation, assessing 32,000 different situations with input parameters varying randomly within the boundaries of an estimated uncertainty interval of 20% of the average value. For a fair comparison, we fixed the yearly mileage for each case on the mid value. The results are summarized in Figure 10 in a histogram, showing the distribution of the LCOT for each case.

The overlap of the curves for EVs and petrol cars is significant in 2020, suggesting that an EV can be the most cost-effective option, depending on the specific situation, but on the average, it is not. In 2050, this difference is much larger, and we may conclude that EVs are on average (based on a mid-sized car) the best option. Combined with national policies to ban fossil fuel-based cars, it is realistic that EVs will become the default option. This will lead to sector coupling and this effect will be discussed in the next section.

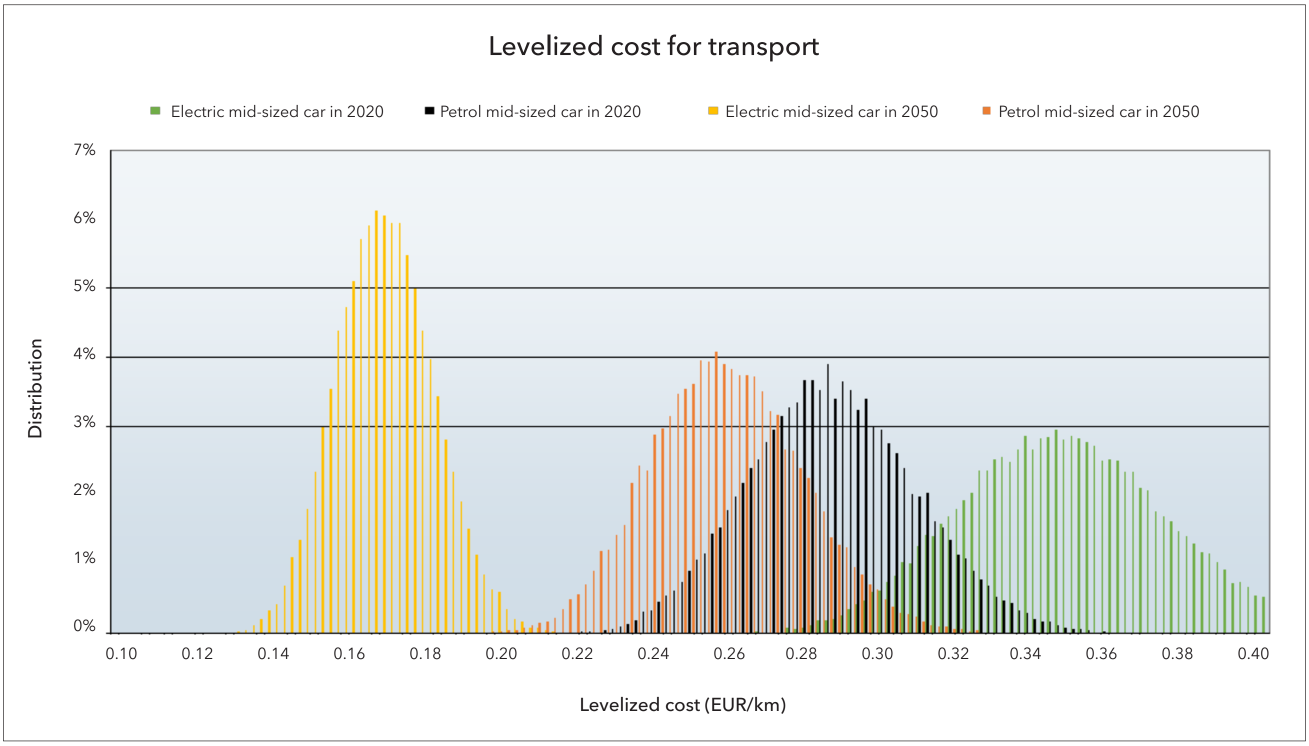


Figure 10 - Levelized cost distribution for each case, assuming a ±20% uncertainty interval for each input parameter

3.3 Sector coupling effects

- Sector coupling due to the large-scale adoption of EVs is realistic.
- It will impact the electricity system and other sectors in several ways.
- The increase in electricity demand may lead to an increase in the electricity price, leading to a more positive business case for renewable generation.
- The shift from Internal Combustion Engine (ICE) vehicles to EVs means a shift from opex to capex, offering opportunities for business models around ownership and risk, and integrating additional services.

The analysis presented in the previous section shows that large-scale adoption of electric transport will be very likely and that electrifying road transport (at least passenger transport) will therefore have an impact on sector coupling. But what does this mean?

Firstly, the demand for electricity will increase. This may increase the electricity price, as we discuss in chapter six. This has a positive effect on the business case for renewable generation but a negative effect on the business case for EVs themselves.

Secondly, this will impact the oil industry. When the costs of EVs go down, it will lead to an increased penetration of EVs and a decrease in oil demand. Decreasing the oil price to keep market share will be difficult, as the oil price is just a small part of the LCOT. To compensate for a relatively moderate decrease in, for instance, battery prices, a large decrease in oil prices is needed to maintain the same competitive cost level for a petrol car. This is an uphill battle that cannot be sustained for long.

Thirdly, the power sector will benefit from a significant volume of flexible demand. This may have multiple impacts, both on the demand and on the required transmission and distribution capacity. Generally, vehicles will follow a low-price charging strategy and so will help balance the electricity system during hours with high renewable generation. If EVs are massively used for vehicle-to-grid services, this may significantly flatten the daily load profile and price profile[21]. This is discussed further in chapter six. The impact on the transmission and distribution system depends on the local situation and may be both positive (peak load reduction) or negative (congestion).

Fourthly, this volume of flexibility may be used for ancillary services on the electricity market (vehicle-to-grid applications for, for instance, primary and secondary reserves). Assuming EVs will penetrate the market anyway, this is an almost no-capex service as the batteries are paid for already. The main costs involved are the (remote) control system, the conversion losses and a potential decrease in battery capacity. This abundance of flexible capacity may flood some current ancillary service markets resulting in a dramatic drop of revenues from these markets.

Furthermore, private car ownership may change. The capex component of EVs, especially the batteries, is currently large. Private owners may not wish to pay the initial cost of an EV, despite the lower marginal cost. This can be solved with financial construction like private lease and battery lease. We see these concepts emerging already. It fits within a general societal trend towards renting/leasing instead of buying.

Finally, new business models will emerge that will support the introduction of EVs. The shift from opex to capex poses a threat to companies that offer support services to cars, like maintenance and fuel, as their service potential diminishes. Integrating these supporting services through 'modular' lease contracts mentioned before offers a way out. These contracts can be tailored to address the specific needs and wishes of the client. Services such as providing a practical replacement car for the holidays, or a luxury sports car for special occasions can satisfy the different values a car has for the client, while offering the service provider a much closer relationship with the client, and the opportunity to tap into new value pools like offering flexibility services to the electricity system.

4 - HEATING IN THE BUILT ENVIRONMENT

4.1 Trends in energy use for heating

- Approximately 70% of the final energy use in the built environment in Europe is used for heating.
- Natural gas is the most important energy carrier for heating followed by heating oil and solid biofuels like wood pellets.

Figure 11 shows the final energy consumption for the built environment for households and services in Europe. Renewable energy is mainly primary solid biofuels (like wood pellets) and a small share of solar thermal heat and ambient heat for heat pumps. It does not distinguish between renewable electricity and fossil- or nuclear-based electricity[15,17].

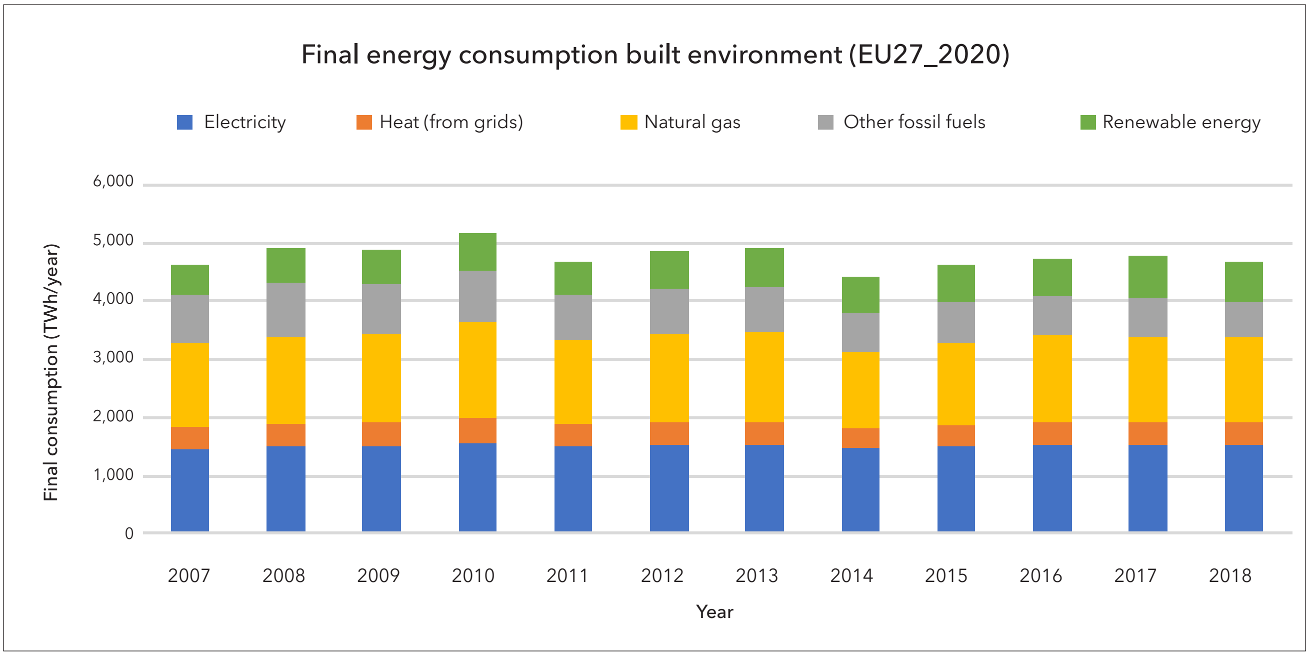


Figure 11 - Final energy consumption for sectors households and services

The total final energy use does not show a significant upward or downward trend, neither in the total consumption, nor in the share of individual energy carriers. Approximately 70% of the final energy consumption is used for heating purposes (neglecting electric heating and electric cooking).

The heat demand can be divided into three categories:

1	2	3
SPACE HEATING	HOT TAP WATER	COOKING

Space heating demand is the largest part (more than 80%, see Figure 12), hot tap water has a share of 14% and the remainder is for cooking. The space heating demand is forecasted to decrease significantly in the future due to better insulation of buildings.

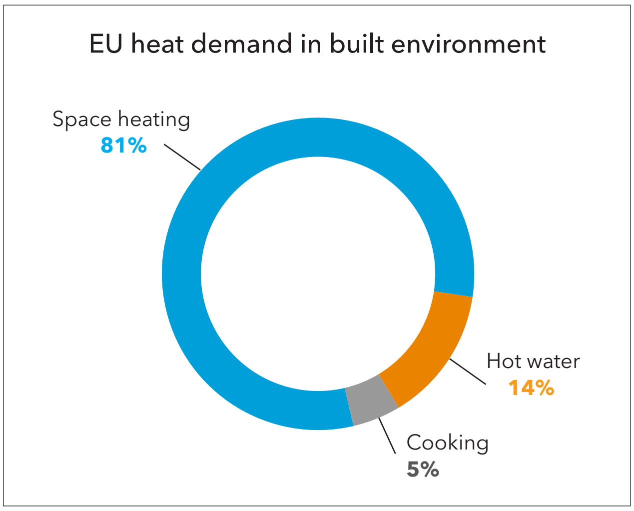


Figure 12 - Distribution of heat demand in Europe[22]

4.2 Electrification of heat demand

- There are multiple options to electrify heat demand.
- They differ in the flexibility they offer and the impact on the electricity market.
- The competitiveness of electric heating option, especially direct electric heating, suffers from relatively high fuel taxes.

The focus of this chapter is on electrification of space heating and tap water heating demand, as the main contributors of heat demand. Electricity use for cooking will most probably increase as well (ceramic, induction), but its share and impact on the power system is relatively small compared to the electrification of space and tap water heating.

Some options for electrification of heat demand are summarized in Figure 13. Within each option there are multiple variants.

The first option is individual direct electric heating. This was considered an inefficient option because electricity was generated from fossil fuels that could supply heat directly. It is an option when renewable electricity is available in abundance. Typically, with direct electric heating each dwelling (or office) has an electric boiler for tap water heating and electric radiators for space heating. Variants of direct electric heating include electric underfloor heating, infrared panels and storage heaters.

Given an approximate efficiency for electric heating of 100%, heat demand is transferred to electricity demand one-to-one. Even if this option is fuel inefficient compared to other solutions, economically it might be the most optimal solution for dwellings that have a limited heat demand, as it requires limited investments. Depending on the storage size of the storage heater or the hot tap water boiler, the demand is somewhat flexible and may accommodate part of the day-night demand cycle.

The second option is an individual heat pump per dwelling or building. Heat pumps concentrate heat with ambient temperature to useful heat of a higher temperature. Ground source heat pumps use ambient heat from a subsurface source, like an aquifer. Their coefficient of performance (COP, the ratio of useful heat delivered and electricity used) varies typically between 3 and 5. It depends on the ambient temperature and the delivery temperature. Air source heat pumps use outside air as a heat source. Their COP is lower

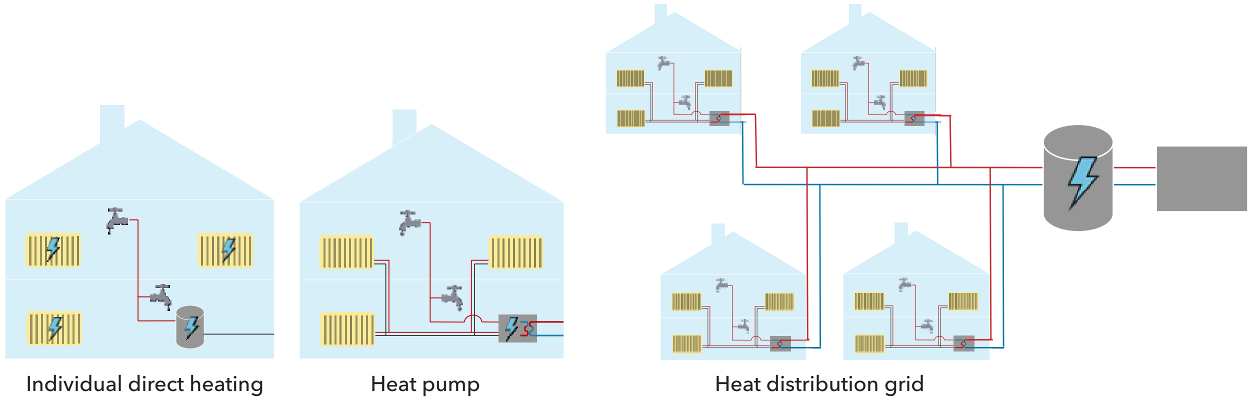


Figure 13 - Some options for electrifying space heating and tap water heating

(typically 2-4) and may decrease below 1.5 in severe freezing conditions[23]. The picture shows conventional radiators, but heat pumps are often combined with special low-temperature radiators or underfloor heating, allowing for a lower water temperature and higher heat pump COP. The electricity demand is lower than the heat demand because of the COP is greater than one. The demand is somewhat flexible as many heat pumps are equipped with hot water storage.

The third option is a district heating option. Water is centrally heated and distributed to buildings and dwellings for space heating and tap water heating. Figure 13 depicts a large electric boiler combined with other potential sources (industrial waste heat, biomass boiler, natural gas boiler, industrial heat pump, geothermal energy, etc.). Generally, there will be different heating source for base load demand and peak load demand. An industrial heat pump, for instance, is typically a base load unit as it requires a large specific investment (per kW of heat power) but has a high efficiency. An electrode boiler is typically for peak load and for opportunity heating. It is used during peak heat demand and when electricity prices are low (opportunity heating, assuming a heat pump, if used, is operating already). Assuming large heat buffers are also installed, this option provides demand flexibility and additional fuel switch flexibility if, for instance, an additional gas-fired or biomass-fired boiler is installed.

The feasibility of the three options depends, amongst other things, on the type of dwelling or building and its thermal insulation. Generally, heat pumps are better for well insulated buildings that allow for low temperature heating. Direct electric heating is generally a convenient retrofit option due to its low required investment and easy installation.

Indirect electrification of heat demand via hydrogen is not considered here. Compared to a heat pump, the energy chain efficiency is much lower. Hydrogen generation is discussed in chapter five.

The feasibility of electric heating is discussed in our paper *'Hydrogen in the electricity value chain'*[5]. Assuming low-priced renewable electricity is available, electric heat pumps and electric boilers become a competitive option for a gas-fired boiler if more than a few hundred operating hours can be realized. This analysis is based on a wholesale price comparison. For a more detailed analysis, we must look at actual prices.

Figure 14 shows the actual consumer energy prices for different consumption bands. The network costs are generally capacity based. Supply (purchase excluding transportation cost) and energy taxes are generally based on a kWh-tariff. VAT is a fixed percentage but generally not included in commercial business cases. For household consumers, the supply cost is 30-50% of the total cost.

From a marginal cost perspective, excluding VAT and network cost, a heat pump is still a competitive alternative (neglecting other fixed cost, see discussion in next paragraph). Given a COP of more than 3 and assuming a gas boiler efficiency of 100%, the marginal electricity cost per kWh can be at maximum three times the marginal natural gas cost to be competitive from a fuel cost perspective. This seems not to be the case for the electrode boiler. Energy taxes are generally absolute (in euro/kWh), and they do not change with the energy supply cost. Zero electricity wholesale prices still lead to a non-competitive electricity price. On a per kWh basis, natural gas taxes are significantly lower than electricity taxes, hampering the business case for electric heating.

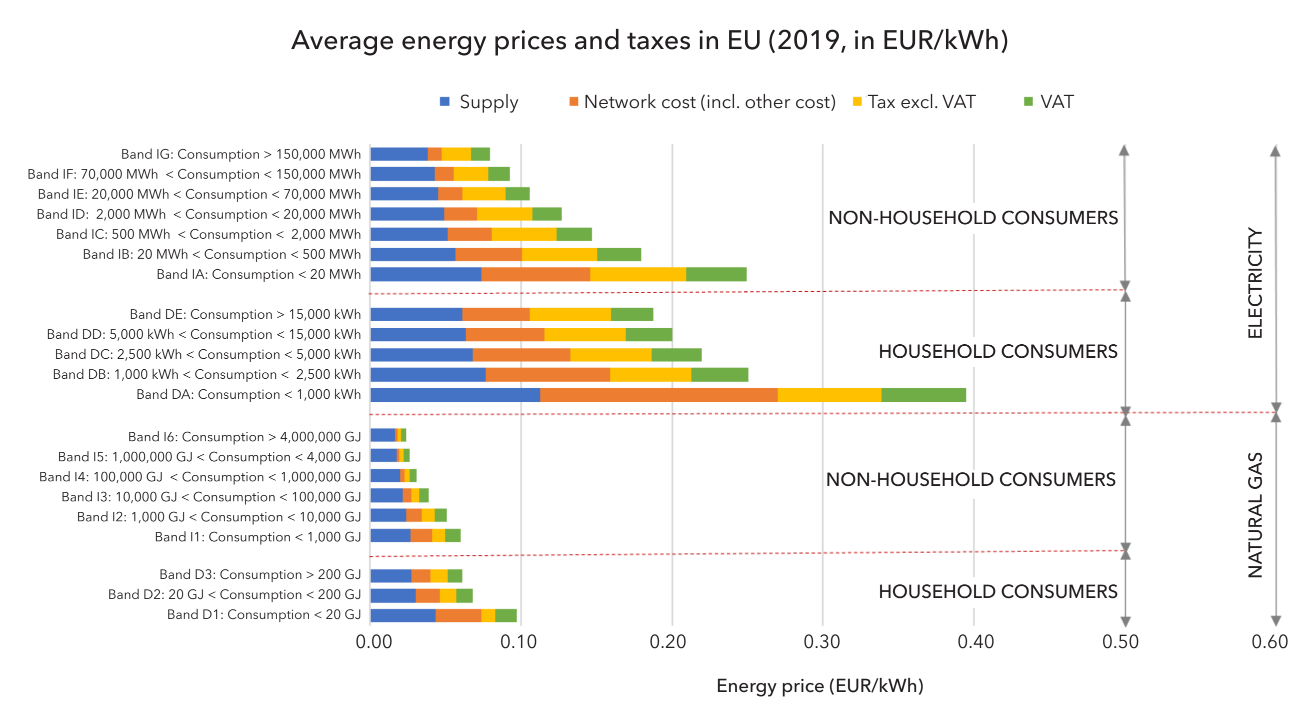


Figure 14 - Average energy prices per kWh in Europe for different consumption bands and consumer groups[24]

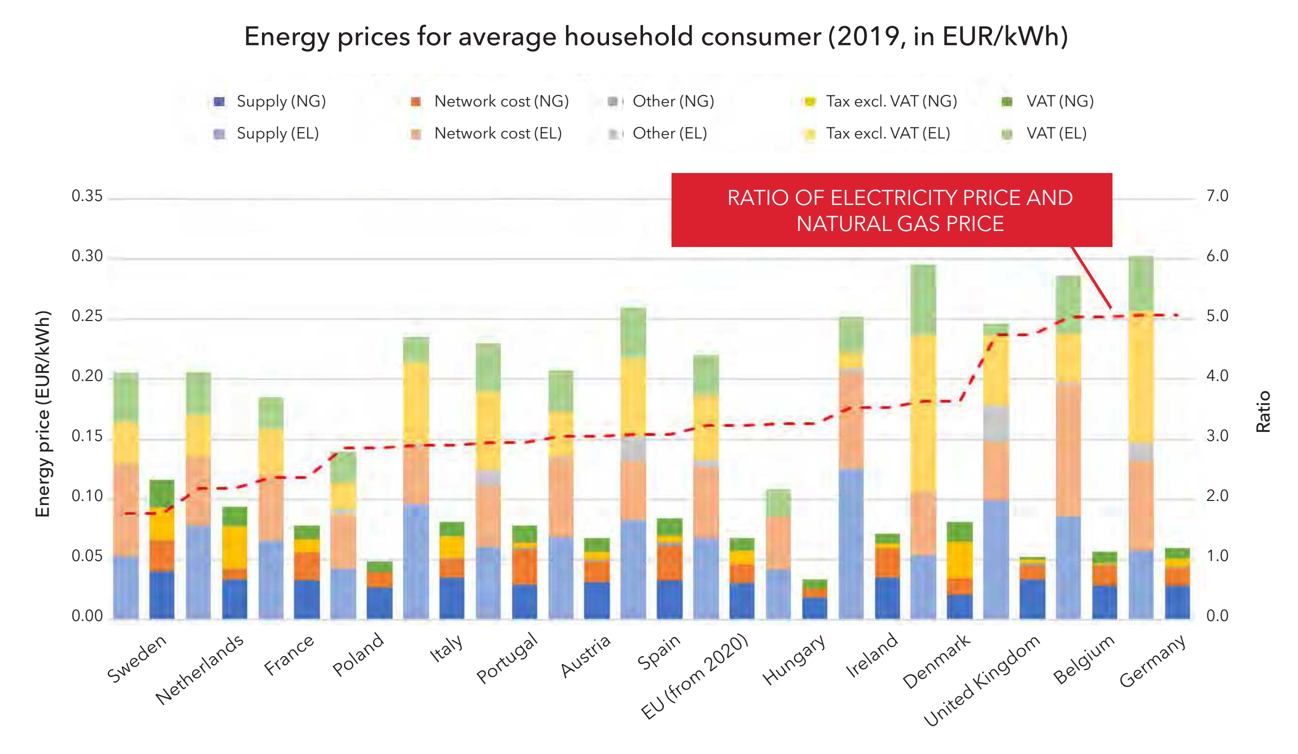


Figure 15 - Average energy prices for 2019 in Europe for an average household consumer (EL = electricity, NG = natural gas)[24]

The impact of taxation for some selected European countries is illustrated in Figure 15. It summarizes the composite energy prices for an average household consumer (electricity consumption 2500-5000 kWh/year, natural gas consumption 20-100 GJ/year[25]) for some relevant European countries. It illustrates the significant contribution of taxes to the total energy cost and the large variation per country. Note that these costs represent total cost including e.g. metering cost, fixed grid connection costs, fixed supply services fees and fixed rebates. These fixed costs may differ significantly from country to country.

From a sector coupling perspective, the ratio of the marginal electricity price and the marginal natural gas price is of interest as it determines the marginal cost of electric or natural gas heating. This ratio cannot be determined from the available statistical data as it includes both marginal and fixed cost. Due to sector coupling the volume of electricity demand can easily double, resulting in a potentially significant decrease in network cost per kWh[26]. Sector coupling analysis needs to take all details of marginal and integral pricing into account.

Currently available statistical price data from EuroStat is not suitable for assessing the marginal cost of electric heating versus natural gas fired heating on a country basis. What we can conclude from the data in Figure 15 is that on average, the total cost of natural gas per kWh is more than three times lower than the costs of electricity. This differs significantly per country, but on average, natural gas has a significant preferential tax position from a cost-per-kWh perspective. Taxation in this case is the key to sector coupling.

4.3 CASE STUDY: District heating in Denmark

- Denmark is known for its high contribution of wind energy. It has also a very strong history of coupling electricity and heat: 65% of its population is connected to district heating, fed by combined heat and power generation.
- The Danish government recognizes this connection and removes legislative and tax barriers for integrating electricity and heat demand.
- This will benefit both the heat and wind sectors in Denmark, as the opportunity cost of avoiding using natural gas in district heating may set a bottom price for wind energy during surplus production.

Denmark is an interesting case regarding the integration between renewable electricity generation and heat production. Denmark is known for its large amount of wind energy. Figure 16 shows that in 2018 more than 66% of the electricity generated in Denmark came from renewable sources, of which almost 70% was from wind energy (46% of total generation).

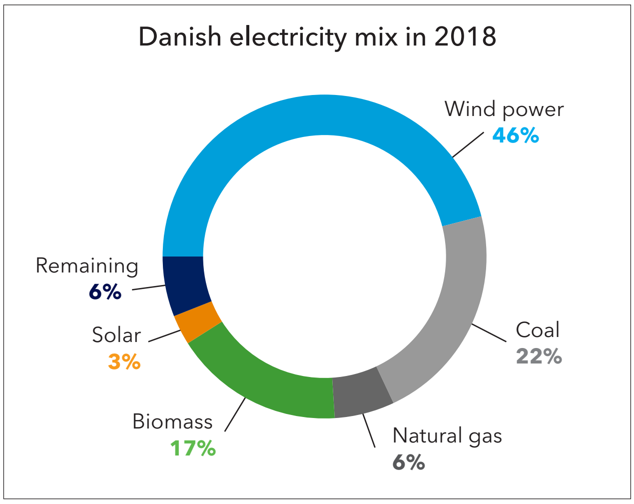


Figure 16 - Danish electricity mix in 2018[27]

Additionally, 65% of the Danish population is connected to district heating. Denmark has an extensive history of district heating systems that started in 1903 using the heat from waste incineration and electricity generation in the 1920's and 1930's. The district heating system got a boost after 1973 as a result of the oil crises of the 1970's[28]. The first energy plan made by the government in 1976 ('Dansk Energi 1976') promoted, among other things, the use of waste heat from power plants (combined heat and power) and district heating to increase fuel efficiency and reduce the dependency on energy import.

From Figure 17 we can see that the traditional dispatchable capacity mainly consists of large (and small scale) combined heat and power generation (CHP) units, indicating that the Danish district heating infrastructure is physically tightly connected to the electric infrastructure.

Figure 17 also shows that the installed capacity of wind (and solar) has already surpassed the installed capacity of dispatchable generation. The periods with oversupply will increase. Currently, oversupply is exported to neighbouring countries, but as these countries increase their share of renewables, the value of this export is diminishing. Alternatively, this electricity can be used to generate heat at the nodes where the electricity and heat infrastructures meet: the location of CHP units.

Assuming that the average CHP produces one to two times as much heat as it produces electricity, the capacity of the electric connection of the CHPs might be the most limiting factor for using oversupply of renewable electricity for direct electric heating. Still, Figure 17 gives a rough indication that this heating capacity will have the potential to absorb an installed capacity of variable renewables of the same magnitude as the current installed capacity. Therefore, assuming export conditions for electricity do not change, Denmark will be able to approximately double its installed wind capacity without the need to curtail production significantly, if it is able to further integrate its electricity and heat infrastructure.

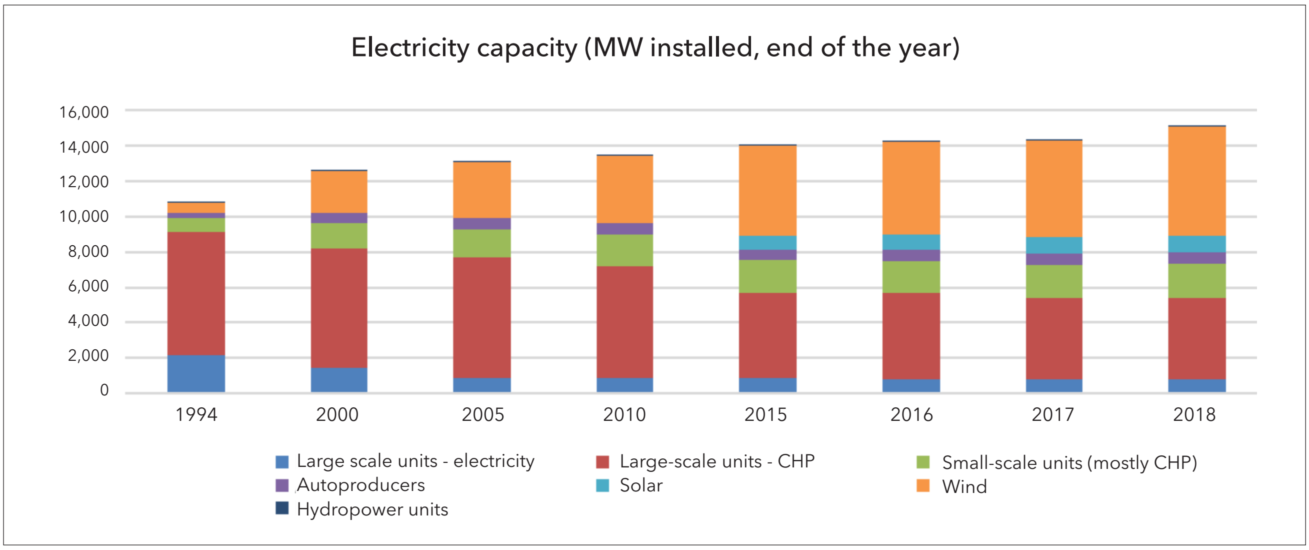


Figure 17 - Installed electric generation capacity in Denmark[29]

As mentioned in the previous paragraph, it does not make sense to produce extra electricity by using natural gas or biomass in CHP units at times of electricity oversupply. It does make sense to use this oversupply of electricity to produce heat, using the existing infrastructure at these locations in combination with relatively cheap electric boilers.

This is recognized by the Danish government, which in June 2018 established a political agreement to improve legislation and remove tax barriers in order to create 'the most integrated, market-based and flexible energy system in Europe'. This agreement includes the following intentions[30]:

- Reduced electricity taxes for heating purposes
- Termination of the mandatory use of natural gas in small CHP units (brændselsbinding – mandatory fuel use) and of the co-generation of heat and electricity (kraftvarmekrav – mandatory cogeneration)
- Increased competition with individual heat sources through the lifting of a mandatory connection to district heating systems for consumers in district heating areas
- Regulatory 'sandboxes' – free zones for testing new regulations
- Dynamic electricity taxes.

The effects of this new legislation will prove to be beneficial to the large wind sector in Denmark. As the production of wind power increases, electricity market prices will drop. If they drop below the marginal cost of heating using natural gas, electric heating will be both cheaper and have a smaller carbon footprint. This makes direct electric heating an attractive option, assuming low electricity prices occur often and long enough to cover the relatively low, but necessary investments in electric heating equipment.

Given the amount and possibilities to implement direct electrification in the district heating infrastructure, the 'oversupply' of wind energy might be completely absorbed at a price level close to the marginal cost of natural gas fired heating. This makes this form of direct electric heating, based on avoiding natural gas, price setting for the electricity market. How this effect can create a 'bottom market price' is described in more detail in chapter six.

4.4 Sector coupling effects

- Electric heating will give rise to sector coupling and market coupling.
- The effects are partly the same as for electric vehicles.
- An additional dimension is the effect of opportunity heating based on fuel switch between e.g. natural gas and electricity for heating purposes.

The impact of electric heating is comparable to the impact of electric vehicles. The electricity demand will increase, and a significant volume of flexible demand will become available, although this flexibility is limited to a few hours.

An additional dimension is opportunity heating, made possible by fuel switch. Both an electric boiler and a natural gas boiler are low-capex options for heating. Installing both and switching between fuels depending on the electricity price and the natural gas price provides opportunities to minimize the production cost of heat. This opportunity heating has an additional effect; it can become price setting in the electricity market. The willingness to pay for electricity will be slightly less than the natural gas price times the boiler efficiency ratio. If the amount of electricity generated with a lower marginal cost than the willingness to pay is sufficient to satisfy traditional demand, but not enough to satisfy the demand for opportunity heating, then electric boilers competing for this electricity will drive the electricity price to its willingness to pay. To put it more simply, in this case opportunity heating is price setting. This is an additional effect of sector coupling and will be explained in more detail in chapter six.

Using oversupply of renewable electricity for heating is an attractive prospect, both to provide a 'bottom price' to variable renewable electricity generation as well as to avoid natural gas consumption by replacing it with renewable electricity. However, current legislation and taxation prove to be large hurdles in grabbing this opportunity. Besides financing governments, most energy tax regimes are meant to encourage energy savings and are based on primary energy. So historically, tax on electricity is typically two to three times as high as tax on natural gas, as it compensates for the conversion losses in electricity generation.

With the increase of other renewable electricity sources this logic becomes more and more flawed, leading to undesired effects, like wind power being curtailed because of high taxes, instead of using it to temporarily replace natural gas for heating. This will lead to an increasing pressure on the tax regimes to change.
That this is possible is demonstrated by the ambition of Denmark and by Spain, which already implemented an 'ad valorem' energy tax (tax based on the value of the electricity, similar to VAT) in 1992[31]. A low electricity price results in a similar low tax and therefore taxation will not be blocking the use of low-priced electricity.

5 - DECARBONIZATION OF INDUSTRY

5.1 Introduction and challenge

- Industry is very heterogenic, ranging from heavy energy intensive bulk chemistry to fine mechanical precision equipment manufacturing.
- For all industry, decarbonizing requires increasing energy efficiency and decarbonizing its energy carriers.
- The main energy carriers currently supplying industry are natural gas and electricity, followed by liquid fossil fuels.
- Decarbonizing these energy carriers lead to increased sector coupling

Industry comprises many different sectors that can be vastly different, ranging from chemical bulk industries, to fine mechanical manufacturing of small equipment. Industry is one of the largest energy users in most countries and decarbonizing this heterogenous industry will be a huge challenge. Because of the heterogenous character of industry we mainly discuss emissions from energy use and not from feedstock[32].

Energy efficiency plays an important part in reducing this challenge, but eventually fully decarbonizing industry implies decarbonizing its energy supply. The main energy carriers that are used for supplying industry are electricity, natural gas, and to a lesser extend liquid fossil fuels and waste (Figure 18). The use of other energy carriers, such as biomass and heat from other nearby industries is minor.

Electricity is gradually being decarbonized by replacing fossil fired power generation with renewable generation, predominately solar and wind energy. Electricity generation by solar and wind is characterized by its variability due to its dependency on weather conditions. This means that during times when there is insufficient wind and solar power, an alternative carbon-free source of electricity is needed. Alternatively, during times of oversupply, wind and solar collectively produce more electricity than demand can absorb, and possibly need to be curtailed. Competition between power generators will lead to lower electricity prices and new opportunities in industry to use this cheap carbon free energy[4].

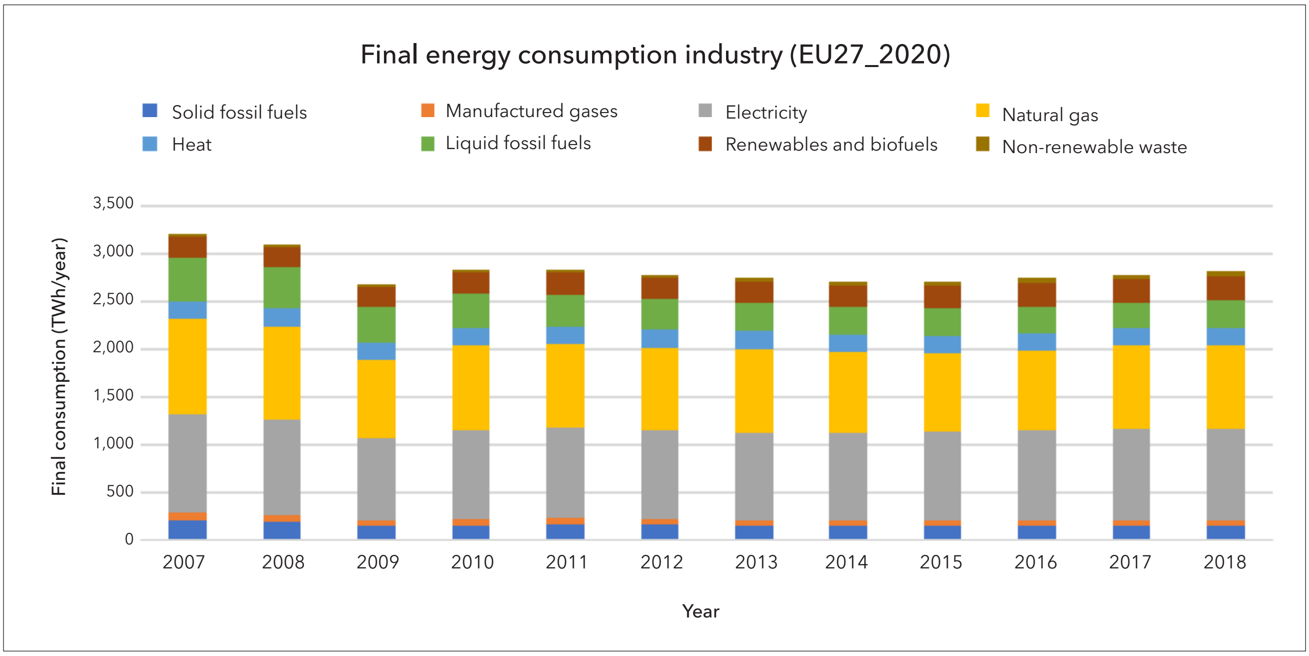


Figure 18 - Final energy consumption of industry per energy carrier[15]

Decarbonizing energy use based on natural gas has its own challenges. Replacing natural gas with electricity one-on-one will have consequences for the required electric infrastructure. A direct route to decarbonize gas is to take out the carbon from the methane (or another hydrocarbon) and use the resulting hydrogen instead. The carbon should be captured and stored to avoid it being released to the atmosphere (CCS: carbon capture and storage). While the resulting hydrogen is carbon free, this route still uses fossil fuels. Alternatively, hydrogen can be produced from electricity and water by electrolysis. A third route for decarbonization is to use biomass, either directly in the form of biogas, or to synthesize methane from hydrogen and carbon from biomass.

Decarbonizing other fossil fuels either involves biomass, such as bio-oil, bioethanol and biocoal. Sometimes the energy carrier can be replaced by another in the long run, like replacing cokes with hydrogen as a reduction agent in steel production. And finally, assuming there are no other alternatives, these fuels can be produced from hydrogen, possibly in combination with a renewable carbon source.

Both an increased use of electricity and decarbonization of natural gas use will lead to increased connectivity and interaction between value chains, and therefore increased sector coupling. This is discussed in the following sections after discussing the goals to reduce greenhouse gas emissions in industry.

5.2 Goals for reduction of greenhouse gas emission

- The EU has two main tools to set targets for industry:
  - The European Emission Trading System (ETS)
  - Binding national targets set by the Efford Sharing Decision (ESD).
- Industry needs to increase its efforts beyond the current reduction trend in order to meet the ambitious EU decarbonization targets.

The main regulatory tool to reduce greenhouse gas emissions in power generation and heavy industry is the EU ETS (European Union emission trading system). It covers 11,000 installations and aviation[33] in the EU member states as well as Iceland, Liechtenstein and Norway.

All sectors included in the EU ETS will need to reduce their carbon dioxide emissions by 43% in 2030 (as compared to 2005). Between 2021 and 2030 the total number of allowances issued will be reduced annually by 2.2% to reach this target. Each allowance gives the right to emit one tonne of CO_2 or an equivalent amount of other greenhouse gasses. Participants of the EU ETS can trade these allowances between each other. They must do so ensuring that the most cost-efficient measures to reduce carbon emissions are taken.

Sectors that are not included in EU ETS, meaning all other sectors, have to reduce greenhouse emissions by 30% compared to 2005. This has been translated into binding national targets through the Effort Sharing Decision (ESD).

Overall, this must ensure a total emission reduction of at least 40% in 2030 compared to 1990. Figure 19 shows that additional effort and measures are necessary to reach these targets by 2030[34]. So, it will be likely that carbon prices will increase if industry does not pick up its speed of decarbonization. Part of the European Green Deal is a proposition to increase this 40% target to at least 55% and to increase the number of participating installations in the ETS scheme[35]. This will put even more pressure on the carbon price.

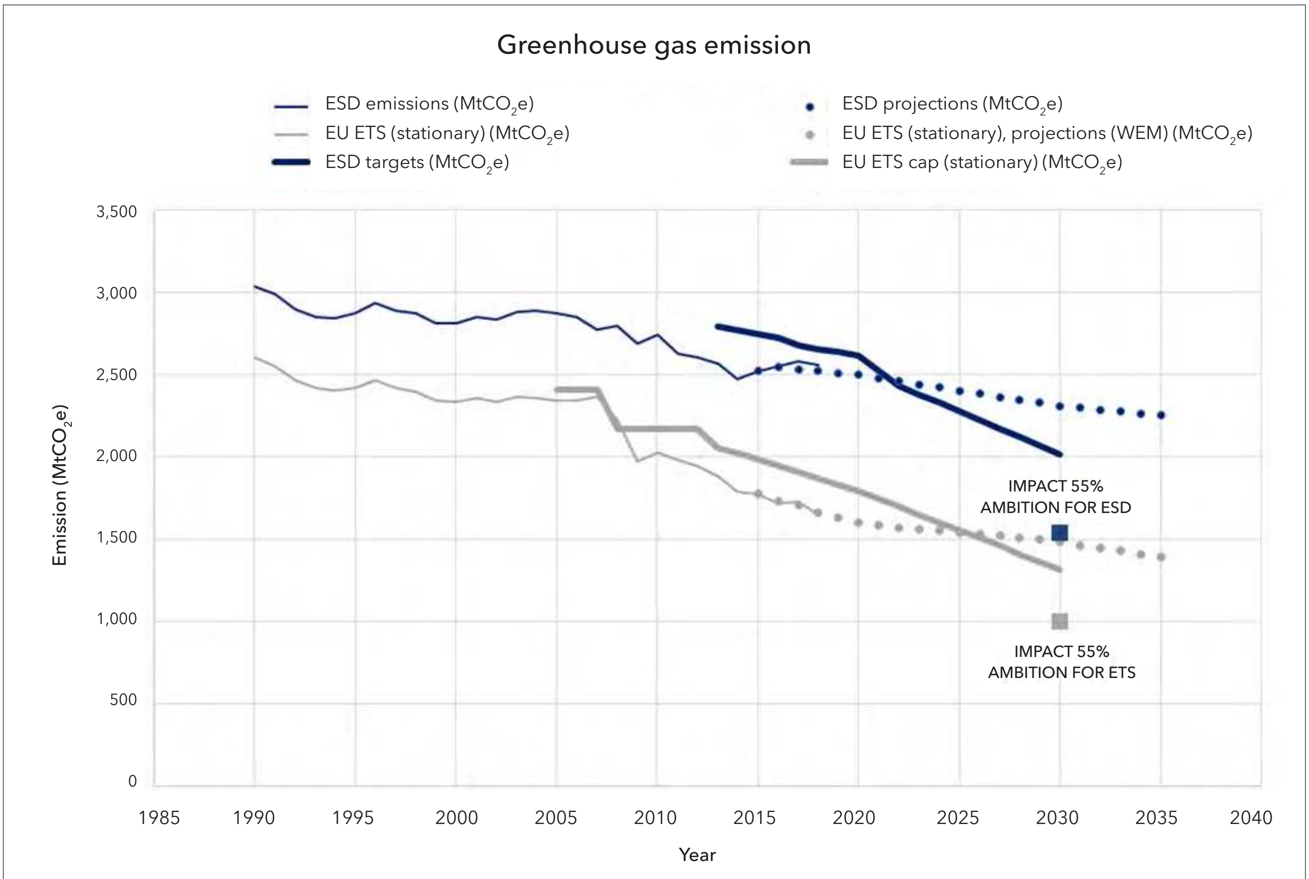


Figure 19 - Forecast of greenhouse gas emissions EEA with existing measures (WEM)[36]

5.3 Decarbonization opportunities in industry

The main routes to decarbonize industry are clear:

- Energy efficiency and energy savings. This involves process integration, utilization of waste heat and developing and applying efficient equipment;
- Electrification and benefiting from renewable electricity generation;
- Decarbonization of energy supply through replacement of natural gas, for example, using blue and green hydrogen.

5.3.1 ENERGY EFFICIENCY

Energy efficiency will be essential in reaching the targets set for greenhouse gas emission reduction. Reduction of energy consumption leads to reduction of greenhouse gas emissions, either directly through reducing the use of fossil energy, or indirectly because the saved renewable energy can be used elsewhere where it replaces fossil energy (at times when there is no excess renewable generation).

Energy savings can be accomplished in several ways. Foremost by using more efficient equipment and devices, and designing more efficient processes, often involving the integration of process steps (process intensification). Especially of interest for this paper is that this trend is not confined by the boundaries of organizations. Heat integration, using waste heat from neighbouring industries, smarter logistics, and aligning processes between companies, will have significant contributions to reducing carbon emissions.

Many industries have already implemented energy efficiency measures. The main drawback of increased implementation of energy efficiency measures within companies is that most 'quick wins' have already been taken and the remaining opportunities will often come at high cost and expensive equipment. Opportunities might still exist when looking beyond the boundaries of individual companies, though this often leads to increasing risks caused by increasing interdependency between companies.

5.3.2 ELECTRIFICATION

Electrification is often mentioned as a trend in industry. In Figure 18 at the start of this chapter, the total energy consumption of the industry in Europe in the last decade is shown, as well as by what energy carrier this energy is supplied. This graph does not show a clear indication of electrification in the last ten years. The graph does show a limited gradual reduction in energy use during these years, a trend broken by a significant reduction in 2009, likely due to the credit crisis. The coronavirus crisis in 2020 is expected to result in an even larger decline of energy use. Our *Energy Transition Outlook 2020* forecasts a 6-8% decline in energy demand in 2050 due to COVID-19[37].

Figure 19 however indicates that industry needs to increase its efforts to decarbonize in order to meet its future targets, though this graph does not consider the effects of COVID-19 on emissions. Electrification is a major tool for decarbonization. Many energy efficiency measures imply electrification and will result in replacing fossil fuels with electricity. An example is the use of electric heat pumps in combination with ambient heat replacing natural gas boilers for the supply of (low temperature) heat.

Industry that electrifies implicitly rides along with the decarbonization of the power sector, though it might need to claim this decarbonization by purchasing guarantees of origin. In chapter six we see that this increase of variable renewable generation in the electricity mix has major implications for the power system as well as the electricity market. These implications will impact industry as well.

The main opportunities to decarbonize that will drive electrification in industry are[9]:

- An increased focus on heat integration and use of ambient heat (from water, soil and air) using heat pumps (leading to a growth in electricity consumption)
- The use of electricity for carbon capture, storage & utilization (CCS&U) and hybrid hydrogen production (electrolysis)
- On-site power generation by solar, wind, hydro, geothermal
- Replacement of fossil-based boilers, furnaces and steam producing equipment by electricity powered alternatives.

So while the need to electrify will increase, Figure 18 shows that electrification is still to gain traction. This is because there are still significant barriers, such as[9]:

- High costs and lack of a level playing field. Electrification is currently leading to high investments and therefore relatively long payback times compared to other investments. If not compensated by efficiency gains electrification currently often leads to higher energy bills through higher grid tariffs, energy prices and energy taxes, compared to gas.
- Lack and/or cost of capacity of the electricity infrastructure. A further expansion of the electricity network to distribute the extra needed electricity is expensive, especially in densely industrialized areas. The process of permitting, planning and implementation is long, up to 10 years in some countries. The impact of this barrier may be partly mitigated because electrification of industrial processes may include an efficiency improvement as well. Therefore, less electric capacity is needed than gas-fired capacity.
- Reliability of electricity supply and loss of flexibility compared with the current situation. The cost of (battery) storage of electricity (as a back-up) is still very high compared to storage of gas or oil.

While electrification will likely be a major contributor to the decarbonization of industry, electricity has significant weaknesses, such as the costly electric infrastructure needed to supply high temperature heat in large quantities, or the cost and relative low energy density of electricity storage with batteries. Many believe that this leaves room for another, molecule based, low carbon energy carrier: hydrogen.

5.3.3 HYDROGEN AND THE DECARBONIZATION OF NATURAL GAS

As mentioned, electricity is being decarbonized by building renewable generation on a large scale, harnessing solar, wind, water, geothermal, and bioenergy. Still, challenges remain, such as the amount of storage needed to cope with the variability of solar and wind energy[4,6]; the need for increased capacity of the electricity grid; and ways to decarbonize difficult-to-electrify sectors, such as aviation, shipping and some industrial sectors. These challenges can be met by complementing electricity with one or more alternative low-carbon energy carriers, most notably hydrogen or carriers produced from hydrogen, such as ammonia and methanol.

Hydrogen is a carbon-free energy carrier and can be produced from electricity and water, by splitting water into hydrogen and oxygen in a process called electrolysis; or by thermally breaking up hydrocarbons in the presence of steam or oxygen, a process called steam (methane) reforming (SMR), respectively partial oxidation (POX)[38]. Being produced almost exclusively from hydrocarbons, hydrogen is widely used as feedstock for industries such as (petro-)chemical and fertilizer.

In a future energy system hydrogen can complement electricity in three ways:

- Hydrogen can be used as a potential replacement of natural gas to supply industry with high-temperature, high-volume heat, in the long run avoiding excessive investments in the electricity infrastructure that otherwise would be necessary to supply this industry with energy.
- Hydrogen from renewable electricity can be used as feedstock to produce low-carbon liquid fuels for difficult to electrify sectors, such as aviation and shipping, and possibly some industrial sectors. Possible fuels include ammonia and 'synthetic' hydrocarbons, such as synthetic natural gas, methanol and formic acid; using biomass or carbon dioxide as carbon source.
- Hydrogen can also be used to store energy for longer periods, covering seasonal variations in renewable energy supply and energy demand by converting it back to electricity (see also chapter two).
- Hydrogen can be used to transport energy in large volumes over large distances more efficiently than electricity.

Hydrogen can also be used to avoid investments in distribution grids as a result of relatively small-scale local renewable generation with solar and wind, by converting locally generated renewable electricity to hydrogen and transporting this in a pressure vessel by truck. However, for this option to become feasible, the relative high cost because of a lack of economies of scale, and high cost for hydrogen compression and logistics[5] needs to be covered by the benefits of avoiding additional investments in the electricity grid for this hydrogen to compete with green hydrogen produced on a much larger scale.

Hydrogen will likely have an important role in the energy system of the future, including a role in supporting the electricity system. While it might not completely replace natural gas, its role might already start in the next few years by gradually decarbonizing natural gas, for example, by mixing hydrogen with natural gas in the grid. And starting from 2030/2035, green hydrogen might start playing an increasingly important role in industrial hydrogen feedstock, partly replacing hydrogen from fossil fuels during times when electricity prices are low because of high renewable generation and low demand, as is discussed in chapter six.

5.4 Sector coupling effects

- The cost to seize the opportunities for industrial decarbonization comes at the cost of increased interdependency.
- Dependency on variable renewable electricity requires either storage or the opportunity to switch to an alternative supply to ensure continuous production.
- The optimal position of storage in the production chain depends on multiple factors: earlier in the process storage will be more expensive, but the utilization of the remaining steps will be better.
- The option of switching between supply at different steps in the production chain might lead to increased sector coupling and eventually to new renewable commodity markets, like for renewable hydrogen, green synthetic natural gas or renewable e-fuels, reducing the risks of interdependencies.

5.4.1 GENERAL EFFECTS OF SECTOR COUPLING

Decarbonization, especially by introducing energy saving measures and decreasing the dependency on fossil fuels, has been happening in industry for decades, and companies have already taken many individual measures. Opportunities to decarbonize industry still exist across value chains and involve a closer interaction with other stakeholders and sectors, resulting in increased energy chain efficiencies and better utilization of renewable electricity. This is one of the main aspects of sector coupling and, besides the increased use of electricity, includes closing material loops by using waste material from other sectors, and using waste energy streams (mostly heat) as input for other processes or industries.

An important effect of sector coupling is an increased interdependency between industry and other stakeholders. An important aspect of sector coupling is therefore also managing the risks caused by this interdependency, for example, by making sure that there are multiple suppliers (or customers) for the exchanged commodities. In the following paragraphs some of the risks and consequences of increased electrification and increased dependency of renewable electricity are highlighted.

5.4.2 ELECTRIFICATION OF HEAT AND HYDROGEN PRODUCTION

As mentioned in the previous paragraphs, electrification predominately means replacing natural gas for heating by electricity. The required investments to electrify heating depends on the temperature and the amount of energy required. While electricity can provide very high temperatures, for example, using plasmas, this is capital intensive, and electrification of high quantities of heat can be severely hindered by capacity constraints in the electricity infrastructure. Still, as is discussed in chapter four, investments to electrify low (<100°C) and even medium (<400°) temperature heat through electrode boilers are relatively low, assuming the electric infrastructure has sufficient capacity.

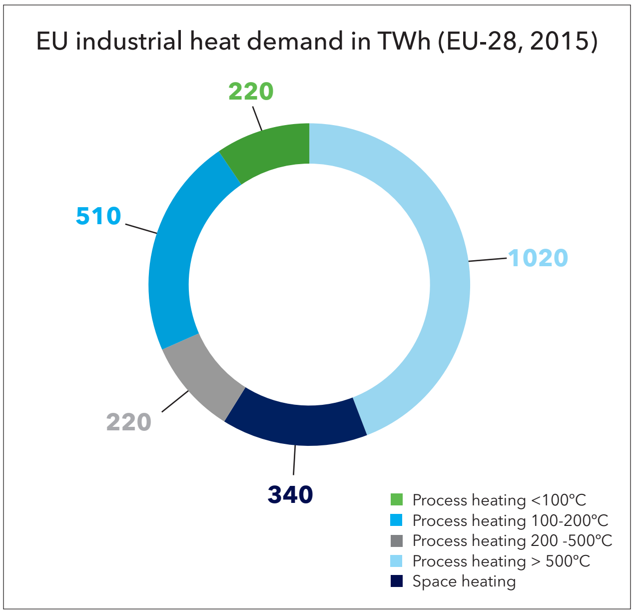


Figure 20 - Industrial heat demand in the European Union[22]

The potential for electrifying heat demand is illustrated in Figure 20. Based on 2015 data, the total industrial heat demand in the EU is more than 2.3 PWh. Assuming a constant demand, this equals to 260 GW of heat generating capacity. Although this is only an order-of-magnitude approach, it suggests that electrifying heat demand can absorb a considerable amount of surplus renewable electricity.

The operational cost of electric heating depends on the electricity price. The electricity price is very volatile and depends on the momentary balance between generation and demand. The cost of electric heating, using electricity from the wholesale market, is therefore very time dependent. Because of the low investments, with an available grid connection, it becomes beneficial to build two parallel heat production facilities. One using electricity, that is used during times when electricity prices are low, and one (usually already existing) facility using natural gas, that is used when electricity prices are high. The additional benefit of being able to switch between energy carriers ('fuel switch') is that these parallel heat production facilities function as each other's emergency back-up.

This does not only apply to low-temperature heating, such as district heating, but also to high-temperature heating, such as for high pressure industrial steam networks. Because of the higher investments needed compared to low-temperature heating, and because of the lack in storage capacity in steam networks, the operation requires more careful interaction and forecasting of electricity markets. The risks of applying fuel switch in high-temperature heating are significantly higher and specialized knowledge and expertise is essential.

The same reasoning applies for hydrogen production for industrial feedstock, where electricity is also an alternative to natural gas. Electrolysis requires significantly higher investments than electric boilers, but if the electricity price remains low long enough, these investments can be justified. In a previous study[5] it is argued that these investments can become profitable before 2035, assuming the current growth of variable renewable electricity production does not slow down.

5.4.3 OPERATION: STORAGE AND FUEL SWITCH

Similar to using electricity to produce heat, the production of hydrogen using cheap variable renewable electricity follows the variability of the renewable energy generation. As heating was addressed in chapter 4, we focus on hydrogen production in the remainder of this chapter, though many concepts introduced here apply to renewable heat as well.

To ensure a continuous supply of hydrogen there are two options:

1) Apply storage in the production chain , and
2) using and switching between alternative sources (fuel switch).

Figure 21 gives an overview of the options for a carbon free hydrogen production chain and its application as feedstock, for example, to produce renewable fuels that can be more easily handled and stored as a liquid.

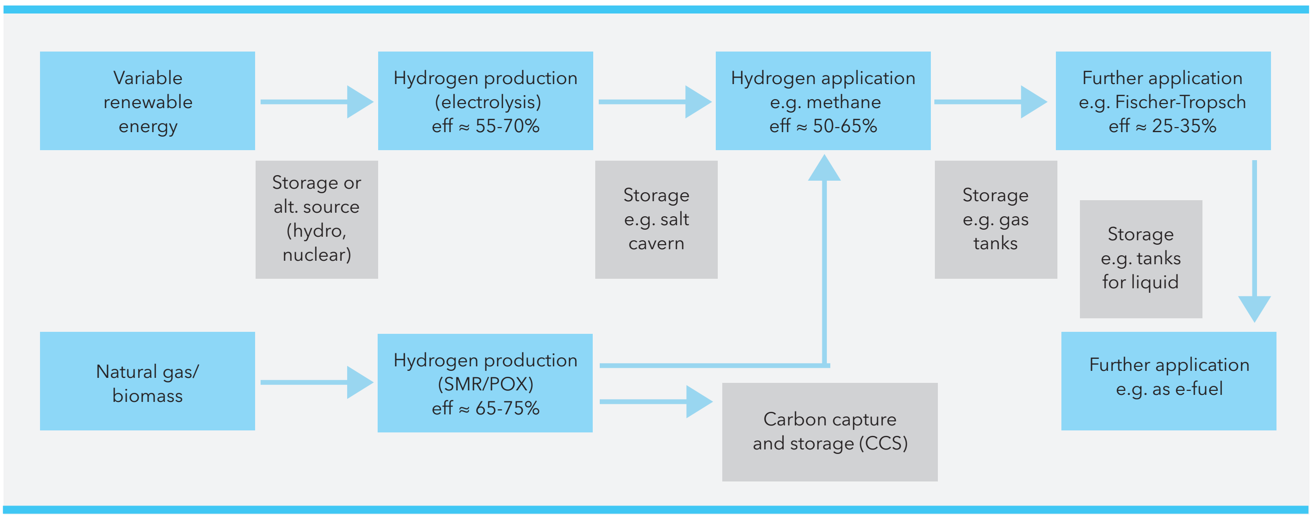


Figure 21 - Carbon neutral e-fuel production from renewable electricity requires storage in the production chain or the option to switch between alternative sources

During times of low electricity prices, production of hydrogen from renewable electricity is most cost effective. This supply can be supplemented by hydrogen production from biomass and/or natural gas in combination with carbon capture and storage. Depending on the electricity price, the process switches between both pathways, ensuring a continuous supply of hydrogen. The main advantage of this fuel switch is that the electrolysis pathway, using renewable electricity can be implemented parallel to the existing process using natural gas, and electricity will gradually replace natural gas as the share of variable renewables in the electricity mix increases.

Hydrogen produced only from variable renewable electricity requires storage to ensure a continuous supply of hydrogen. The production capacity of the process step before buffering needs to be sufficient to supply the total demand within the time frame set by the variable renewable generation. Using mostly surplus renewable electricity, this means that the capacity needs to be three to four times the capacity needed if it would be utilized all the time. This excess capacity is needed to fill the buffer that is providing hydrogen supply when the production is not feasible because of lack of renewable electricity or when electricity prices are high.

This means the earlier storage is included in the process, the lower the required investments for the next steps will be. However, because each process step has efficiency losses, the earlier in the process the buffering, the higher its energy content needs to be to compensate for these losses. Another significant aspect is that after each process step, the product becomes easier to handle and store. The logistics and storage of liquid fuels or methane is cheaper than the logistics of hydrogen, which in turn is cheaper than the logistics and storage of large amounts of electricity.

To summarize, the earlier buffering is applied in these value chains, the higher the utilization of the rest of the value chain and the smaller the necessary investments. On the other hand, the earlier the buffer in the value chain, the more difficult and expensive storage will be in general, and the larger it needs to be in order to compensate for conversion losses further in the value chain.

The optimal choice depends on many aspects, such as:

- regulation and acceptance of carbon capture and storage
- the amount and capacity factor of renewable electricity sources
- the efficiency of each of the steps in the value chain
- the cost to increase throughput for each of the process steps in the chain and,
- the cost to buffer the intermediate products between the process steps.

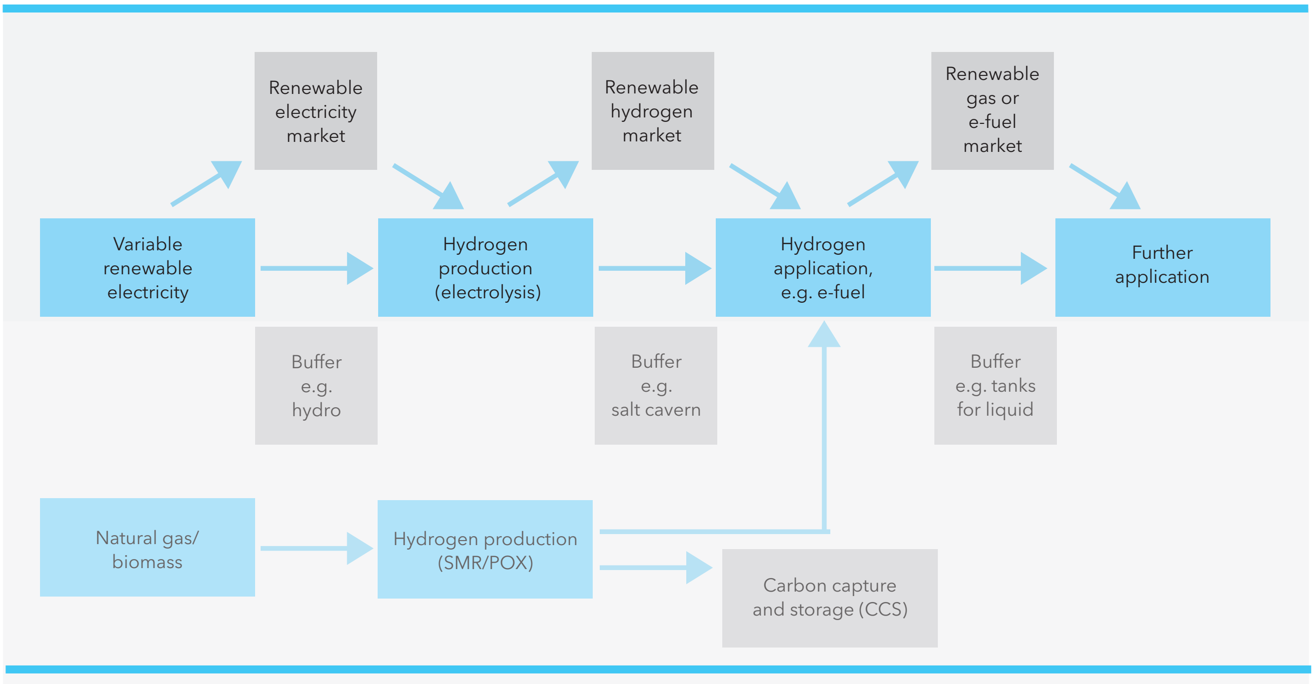


Figure 22 - Opportunities for new renewable commodity markets

5.4.4 NEW ENERGY COMMODITIES

The discussion on the position of buffering in a hydrogen value chain in the previous paragraph demonstrates the considerations that need to be made in establishing such a value chain. On the other hand, it is also exemplary of a linear way of designing value chains, that does not consider opportunities given by sector coupling.

Each of the intermediate products in the value chain might be available from other sectors, or instead might be supplied to other sectors or stakeholders. As multiple stakeholders struggle with the same issues, it is likely that they will start cooperating and maybe individual stakeholders will specialize in one of the process steps, depending on others for the other steps. As this cooperation matures, this process might eventually lead into new commodity markets that, when having sufficient size, reduce the risk of companies becoming dependent of only one or a few suppliers.

Fuel switch, switching between natural gas (with or without CCS) or biomass, and variable renewable electricity to produce green hydrogen are examples of this and each of the energy carriers that can be buffered between process steps in principle has the potential to grow into a commodity market, as shown in Figure 22.

A prerequisite for these energy carriers to grow into a liquid commodity market is a suitable infrastructure with relatively low cost compared to the price of the carrier, that can be used to exchange the commodity between the participants in such a market.

Such infrastructure for renewable commodities will facilitate sector coupling and will be essential for fully decarbonizing industry. While for most of these potential commodity markets there already is an infrastructure for the traditional equivalent that can be utilized, in most cases this will require a new proper way to separate the traditional commodity and the renewable variant.

In ‘Appendix C: Prerequisites and consequences of new commodity markets’ this is discussed in more detail.

5.5 EXAMPLE: Ports and the industrial energy transition

- Ports are logistical hubs where different energy consumers physically come together. This makes ports ideal landing places for large-scale offshore wind and inland solar.
- Port-based industry has a competitive advantage through the use of low-cost surplus power since ports can create an energy ecosystem that makes use of the strengths of the different energy carriers (heat/steam, natural gas, electricity, hydrogen, synthetic fuels).
- Port electric infrastructure can be designed using the implicit redundancy in opportunity demand instead of being redundant itself. This requires that the benefits can be shared between the grid operator and industrial stakeholders, or by ports owning their own 'private' energy infrastructure, including heat, hydrogen and electricity networks.

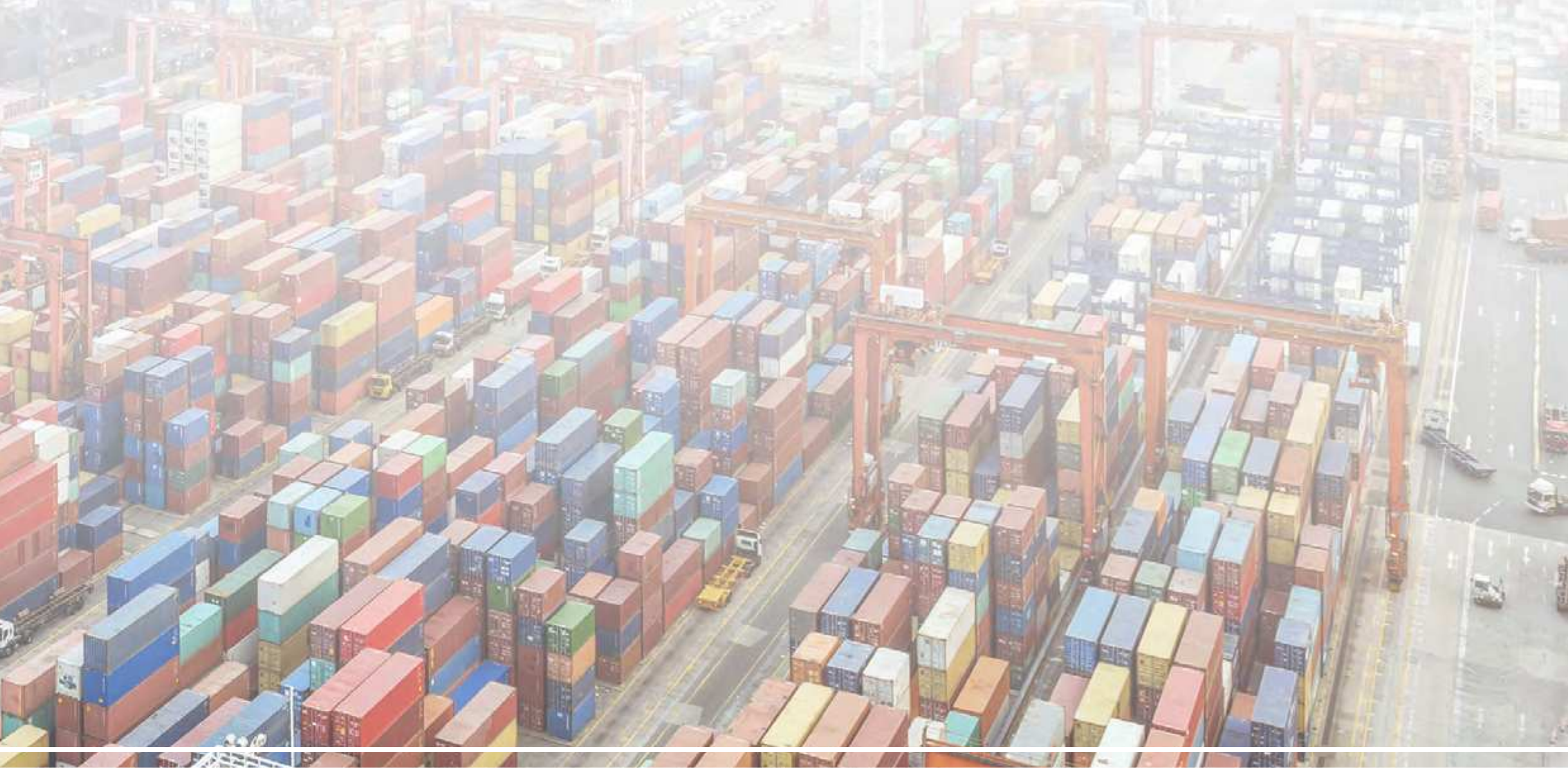
Industrial ports are an interesting case that can be used to demonstrate the developments described in this chapter and the importance of sector coupling. They are logistical hubs, already coupling sectors together, and because of this, industry conglomerates around them. These industrial areas have a strong energy infrastructure, making them the preferred spots for landing offshore wind power or large inland solar power. The production scale of these variable renewable energy sources will be immense, causing temporary overproduction in these areas that cannot be exported to the main electricity grid. The scale of this problem will be orders of magnitudes larger than in other parts of the grid, because of the huge amounts of solar and wind that is being planned around ports, especially in areas in the North Sea.

Industry at these locations has the option to use this power locally, if it is cheap enough, thereby avoiding excessive and under-utilized infrastructure upgrades that would be necessary to export this excess power outside the industrial port area. Using this electricity for generating heat or producing hydrogen can be combined with traditional heat and hydrogen generation, using carbon capture and storage facilities to mitigate carbon emissions from using natural gas; and using the local industrial heat and/or hydrogen infrastructure to distribute energy in other ways than electricity.

Because industry needs to decarbonize, and the pressure to do so is increasing, industry needs to cooperate to create an ecosystem that makes use of the strengths of the different energy carriers. There are numerous examples of the synergy that can be achieved in such an ecosystem. For example:

- Because of the implicit redundancy in fuel switch for heating or hydrogen production, the electric infrastructure can be designed using this redundancy instead of being redundant itself. Heat and hydrogen production using natural gas acts as a back-up for production from electricity and vice versa. The redundancy in the electric infrastructure that is legally required for the power grids, can be implemented at the demand side, making the connection for opportunity demand even cheaper, assuming the grid operators and industry find a way to share the benefits, or ports start to build their own dedicated networks.
- The industrial port area can act as a buffer between the variable infeed of offshore wind power (or alternatively inland rural solar) and the main national power system, drastically increasing the utilization of the transmission infrastructure between the port and the main national power system. To do so it can use opportunity demand, as well as on-site dispatchable generation (for example, using natural gas with CCS) together to manage the variability of large renewable generation, and so provide a stable electricity supply to the main national power system, again assuming stakeholders in port areas can share in the benefits.
- To relieve the local electricity grid in industrial port areas, a parallel heat/steam network and/or hydrogen infrastructure can be built within ports. Heat and hydrogen can be produced centrally in the industrial area and distributed to the users. This would help in establishing the benefits discussed in the previous points, without the need to strengthen the local electric distribution grid.
- Hydrogen production, switching between electrolysis and steam reforming, and dispatchable electricity generation both use natural gas. Both share the benefits from the available natural gas and electric infrastructure, and both could benefit from the development in offshore CCS facilities (for example, in Rotterdam, Oslo, Bergen).

Eventually the electric and hydrogen infrastructure and logistics would benefit the production of synthetic fuels that can be used for bunkering international shipping and supplying airports.



6 - IMPACT OF SECTOR COUPLING ON THE ELECTRICITY MARKET

6.1 Summary of impact per sector

- Due to sector coupling, electricity demand will change in magnitude and nature; it may double with significantly more seasonal variability.
- Traditional demand (no flexibility) is currently already supplemented with responsive demand, meaning demand that can be shifted in time as response to e.g. a price signal.
- With sector coupling, a new type of flexible demand arises: opportunity demand. It arises because consumers have a choice between different energy carriers for the same energy service.

In the previous chapters we discussed sector coupling caused by:

We argued that, from a technical and economic perspective, these are realistic developments and that the energy volumes involved will potentially double the electricity consumption in Europe and introduce significant more seasonal variability. This will have a significant impact on the electricity market. We want to argue that, from an electricity market perspective, sector coupling leads to different types of electricity demand, offering different kinds of flexibility that will be explained in more detail in the next paragraphs:

FIXED DEMAND	RESPONSIVE DEMAND	OPPORTUNITY DEMAND

FIXED DEMAND

Fixed demand is electricity demand that is unresponsive to market prices. This includes most traditional demand and is generally used for applications that have much higher (perceived) value than the price of electricity. Because it is inelastic, except for the most extreme price peaks, there are no systems in place to control this demand.

RESPONSIVE DEMAND

Responsive demand is electricity demand that has some flexibility in time of use. It is based on some sort of explicit or implicit energy storage capability. This includes charging electric vehicles and operating heat pumps.

Electrification of passenger vehicles (traditionally mainly fuelled by oil-derived fuels) will lead to an increased volume of responsive demand. Part of this electricity demand is shiftable in time but still requires a fixed volume at a specific time, necessary for driving. Another part of the EV battery is less bound by external factors and in principle can be used freely for market arbitrage, within the boundaries set by the car owner, discharging electricity when prices are high enough to compensate for e.g. battery degradation.

While individual heat pumps for space heating are not capable of feeding electricity back to the grid, they have a similar effect on the electricity market. Due to the thermal mass of buildings and the boiler that is often there to store hot tap water, electricity demand can be shifted but only within a limited time interval. Responsive demand is comparable to demand response (DR) and electricity storage. Incentives to respond, i.e. to charge or discharge, come from relative differences in the electricity price over time.

OPPORTUNITY DEMAND

Opportunity demand is electricity demand for applications that can switch between different energy carriers depending on price. This includes electric heating and hydrogen production installations build parallel to gas installations to seize the opportunity to benefit from low electricity prices.

The most illustrative example is opportunity heating applicable in industry of district heating grids. In this situation, a dual fuel facility is installed. An electric boiler complements a traditional natural gas fired boiler. Depending on price or congestion signals, a fuel switch is made between natural gas and electricity. From an electricity market perspective, the opportunity cost is equal to the natural gas price. This will couple the market price for electricity and the market price for natural gas. In situations with abundant production of renewable electricity, this will support the price for renewable electricity, as discussed in next section.

Hydrogen production from electrolysis as an alternative for the conventional production of hydrogen from natural gas with steam methane reforming (SMR) is also opportunity demand. There will probably be more technical issues with switching between electricity and natural gas and the investments required (mainly the electrolyser) are higher than for opportunity heating. Still, if forecasted electricity prices are low enough for a sufficiently long duration, typically due to abundant production of solar PV and wind turbines, opportunity hydrogen production will become economically feasible[5].

Responsive demand and opportunity demand behave differently in the electricity markets. Responsive demand reacts to relative electricity price fluctuations, while opportunity demand is triggered when the electricity price is below a price that is determined by the opportunity cost of switching to the alternative fuel.

6.2 Impact on electricity market

- Traditionally or principally, the electricity price in the day-ahead market is set by a clearing price based on the generation unit with the highest marginal cost that is scheduled to operate in a time period.
- Sector coupling adds different forms of flexibility to the power system. Next to the traditional fixed demand this is responsive demand and opportunity demand.
- Responsive demand is capable of absorbing large fluctuations within a short timeframe.
- Opportunity demand adds an additional dimension to the price forming mechanism as this demand can become price setting based on the marginal cost of the alternative.

Price forming on the day-ahead market is discussed in detail in our previous white paper about future-proof renewables[4]. Economic theory dictates that in 100% competitive markets producers of electricity bid at marginal production cost. These are the cost to generate an additional MWh of electricity and are mainly determined by the fuel cost and the plant efficiency. All bids for a given time interval are accumulated and sorted (merit order) and the production unit with the highest bid price that will still need to operate to meet the demand in this time interval sets the price (clearing price). Every production unit lower in the merit order will get the same price[39].

Responsive demand can be considered demand shift from expensive times towards times when electricity is less expensive. Demand response with heat pumps and electric vehicles has the potential and capacity to absorb large amounts of variable renewable electricity by shifting demand towards high renewable production. However, it is limited by its storage capacity. Responsive demand is well suited to absorb short fluctuations of minutes to hours. The storage capacity of electric vehicles that are capable to discharge electricity to the grid (V2G) can offer a storage capacity that is capable to cover a few days, thus is very suited to the day and night cycle of solar energy. The available storage capacity of vehicles that only respond in charging is much smaller, because on average it can only charge the amount of energy that is used by driving, in many cases much less than the full battery capacity.

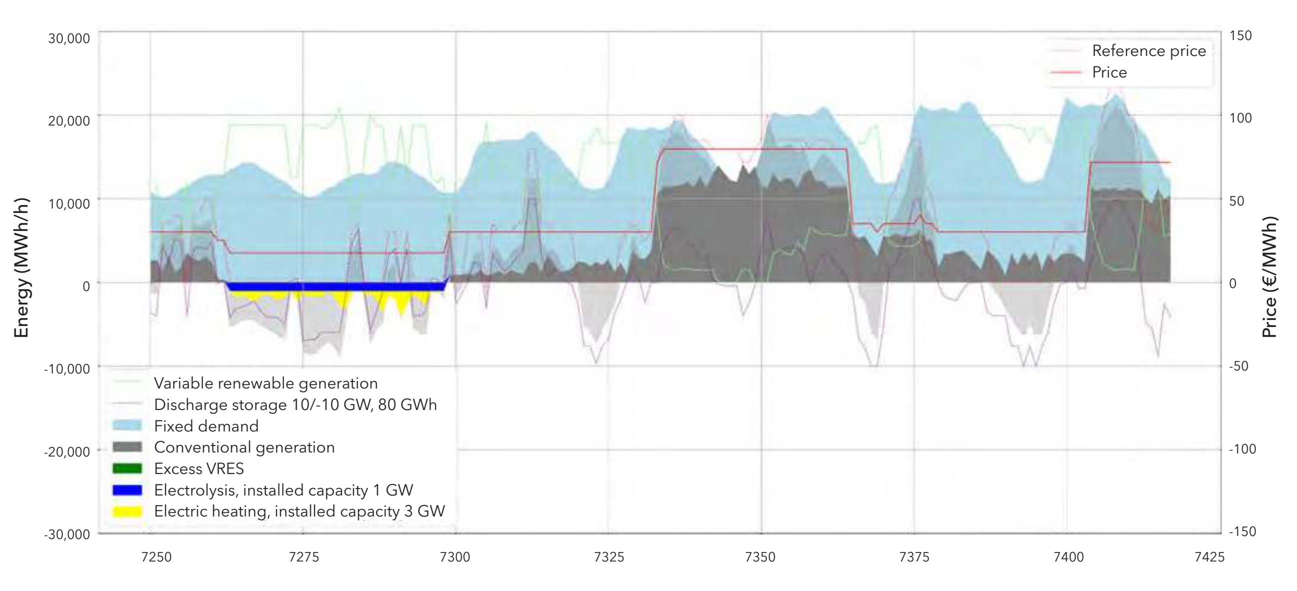


Figure 23 - A huge amount of responsive demand (1 million of V2G capable EV's in a system with a 24 GW peak fixed demand and 36 GW VRES) can create price 'plateaus' of a couple of hours. It also shows opportunity demand (electrolysis and electric heating) creating a 'bottom' in the market price.

Responsive demand is less capable of absorbing renewable electricity with longer cycles, because it will run into limitations of its storage capacity. When the total charge/discharge capacity is large enough to become price making, this creates 'plateaus' in price, whose length is determined by the size of the storage capacity.

In Figure 23 these price plateaus are shown for the Netherlands where one million V2G capable EVs offer a total of 80 GWh of storage capacity with a charge/discharge capacity of 10 GW.

Opportunity heating adds another dimension to this price forming mechanism. This is illustrated in Figure 24. To the left, a merit order is shown based on a significant amount of renewable production at almost zero marginal cost. The demand line (normally a flexible demand but for simplicity reasons assumed fixed) is the total load of the system. The clearing price (p_1) follows from the intersection of the merit order and the total load.

The picture on the right-hand side shows the situation with two blocks of opportunity heating. Depending on the electricity price this heating demand will be met with an electric boiler or (for instance) a natural gas boiler. The willingness to pay for electricity for the first block (p_3) is also shown. It is based on the natural gas price and the boiler efficiency ratio. Due to the opportunity demand, the electricity price increases. This price lies between the electricity price if the opportunity heating is not dispatched (p_1) and the price if it was fully dispatched (p_2). The effect is an increase in electricity price. All production units lower in the merit order (including renewable production) profit from this price increase.

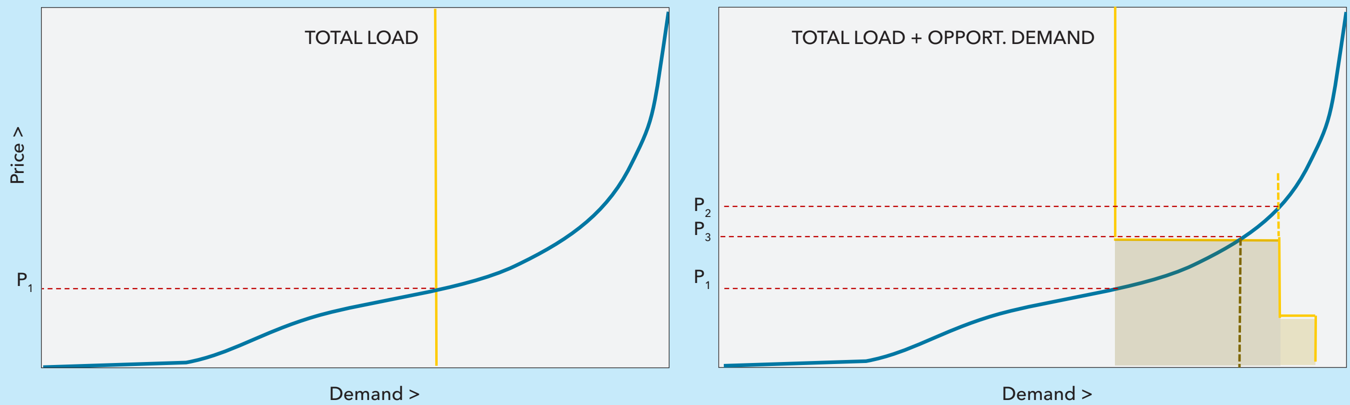


Figure 24 - Illustration of the effect of opportunity heating on the clearing price

Bids based on opportunity demand do currently exist so the market can cope with this. If not blocked by legislation and taxation, it is the size of the demand that will create a difference.

The impact on the residual load curve is illustrated in Figure 25. It shows the effect on the residual load for the Netherlands in a situation with high penetration of renewables[4]. The red dotted curve represents the residual load without opportunity demand and the black curve the same load including opportunity demand (in this case 6 GW of opportunity heating and 7 GW of opportunity production of hydrogen). The bid price for the opportunity demand is high enough to keep electricity production units (shown as bands in the graph) low in the merit order operating. In this case, nuclear capacity with low marginal cost runs to meet the opportunity demand. The price is set by the willingness to pay for the opportunity demand, not by the marginal production cost for the nuclear unit.

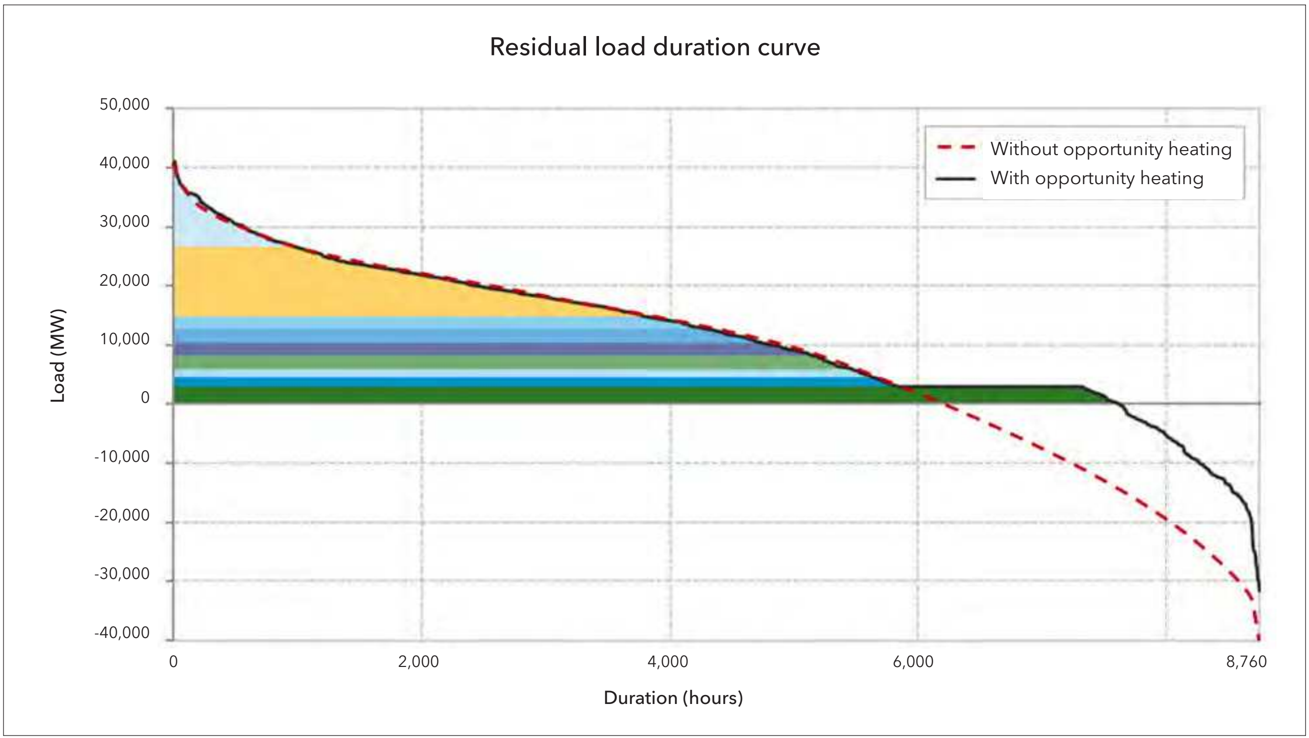


Figure 25 - Illustration of the effect of opportunity heating on the residual load[40]

6.3 Combined effect of sector coupling

- The effects of opportunity demand and responsive demand strengthen each other. Opportunity demand creates a bottom price for responsive load, which increases the duration this bottom price applies.
- This bottom electricity price is very beneficial for renewable electricity generation, as it avoids a price drop to zero when there is no dispatchable power generation.

Sector coupling will have a huge effect on the electricity system and market. Electrification of transport and residential heating, together with electrification of industrial heating and hydrogen production will potentially double the European electricity demand. Besides the increase in electricity demand, the combined effect of responsive demand and opportunity demand do strengthen each other.

The potential of both is huge and they will have a major impact on the energy market, provided barriers such as fixed taxes on electricity are removed. Opportunity demand creates a plateau in the price curve, where it absorbs renewable electricity until the electricity price reaches the opportunity cost, determined by the gas price. Responsive demand flattens the residual load duration curve, shifting demand from the peak to the valley. As discussed in more detail in *'The Promise of Seasonal Storage'*[6], this effect is limited by the inherent storage capacity and is only be capable to shift energy use for a couple of days.

The effects of responsive and opportunity demand do strengthen each other. Both forms of flexible demand compete for the same low-cost electricity. Responsive demand reacts to relative price differences and will charge to their maximum extent when prices are at the bottom price that is set by opportunity demand. This maximum is often determined by the storage capacity (in GWh) that is taken at the end of the period, and not by the charging capacity (in GW).

If responsive demand would increase at a moment when prices are set by opportunity demand, then part of the opportunity demand will switch back to natural gas to restore the price at the opportunity cost. From the point of view of responsive demand, the price plateau that is caused by opportunity demand, acts as a reference price that is quite insensitive to the price making effect of responsive load. So responsive demand limits the amount of opportunity demand that is necessary to create a bottom price in the market, by basically acting as an amplifier of the effect of opportunity demand in the market.

The combined effect of both forms of flexibility is shown in Figure 26. It shows that even a relatively small amount of opportunity demand (4 GW of opportunity heating and 1 GW of opportunity hydrogen production in a system of 24 GW peak fixed demand) already has a very significant effect on creating a price plateau for more than 1,000 hours. This has a tremendous positive effect on the revenues and merchant risk of variable renewable generation, especially when realizing that at these times they produce the most energy.

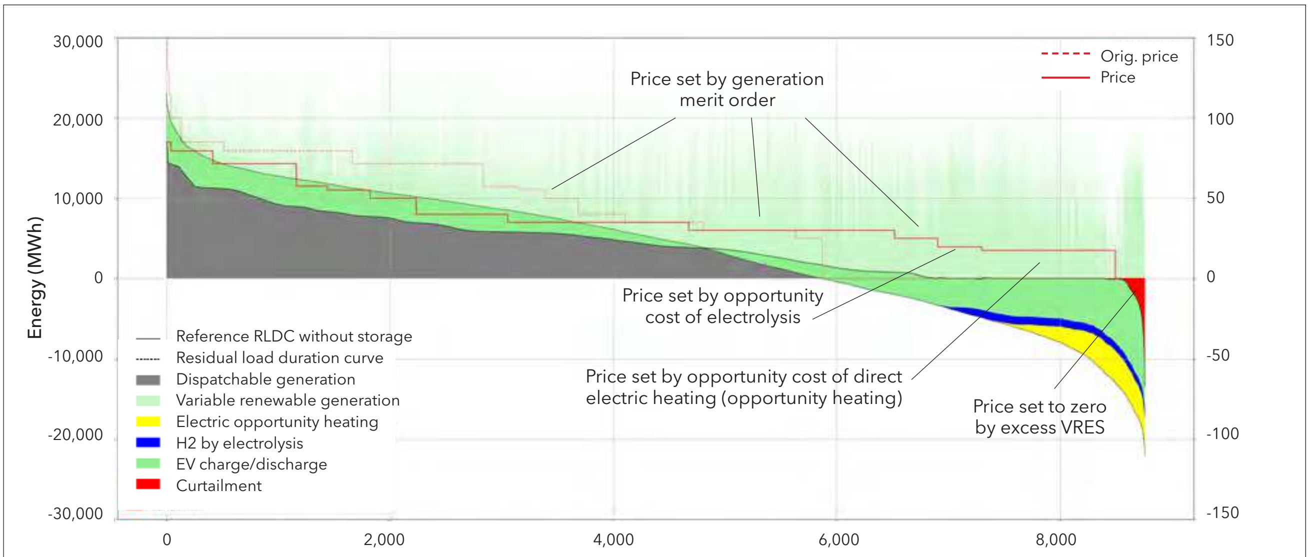


Figure 26 - Combined impact of EV and opportunity demand on the electricity market (variable renewable generation excl. the part used for flexible demand and curtailment)

7 – OBSERVATIONS & CONCLUSIONS

- The first opportunities for sector coupling in industry point towards heating.
- Sector coupling implies market coupling and energy price coupling.
- Sector coupling will have a positive impact on the business case of renewables.
- Our energy taxation scheme is not fit for the energy transition.
- The size of the new electricity demand in industry, transport and for buildings requires new rules regarding energy infrastructures and connection to the grid.

THE FIRST OPPORTUNITIES FOR SECTOR COUPLING IN INDUSTRY POINT TOWARDS HEATING

Sector coupling will have a large impact on industry. The technical impact is clear. Processes will need to be changed or redesigned to allow for electrification. Additionally, industries will have to manage a much more dynamic energy sourcing portfolio that will consist of, for instance, hydrogen, natural gas and electricity, in order to grasp its opportunities. Sourcing electricity at the wholesale markets needs more involvement than, for instance, sourcing of natural gas. The electricity market is more complex and has more short-term elements. Managing energy sourcing will become an increasingly important aspect for industry.

The first opportunity for sector coupling in the industry point towards opportunity heating. Investing in a low-capex electric boiler integrated into an existing steam grid will allow industries to switch fuels (electricity, natural gas) based on actual fuel prices. Opportunity production of hydrogen is another option. Industries must be aware of competition for low-priced (renewable) electricity, e.g. from storage and electric vehicle charging.

Given the current projections for the energy transition and the penetration of solar PV and wind, it seems wise to be aware of sector coupling effects when considering current investments. The impact on energy prices and of the missed opportunities mentioned, may be large.

SECTOR COUPLING IMPLIES MARKET COUPLING AND ENERGY PRICE COUPLING

Sector coupling is driven by the cross-sector application of energy carriers. It means a coupling of markets and energy prices. This is not a new phenomenon. In the past, electricity prices were strongly coupled to natural gas prices as gas-fired power plants were often the marginal, price-setting unit. This gave rise to combined heat and power (CHP) production that hedged against high natural gas prices. High natural gas prices meant high electricity prices which balanced the business case for CHP with the additional benefit of the delivered heat. With the rise of renewable energy, the coupling between natural gas prices and electricity prices weakened as did the business case for CHP.

Sector coupling will lead to new mechanisms of market coupling and price coupling. The huge potential of opportunity demand will impact electricity market prices and become price setting in times of abundant renewable generation. Markets and prices will be coupled as opportunity demand develops. It will have a balancing effect between energy markets, eventually leading to greater economic prosperity.

SECTOR COUPLING WILL HAVE A POSITIVE EFFECT ON THE BUSINESS CASE FOR RENEWABLES

A large penetration of non-dispatchable renewable generation, such as solar PV and wind turbines, may lead to a significant number of hours with zero (or even negative) electricity prices. This happens when the total production capacity of non-dispatchable renewables is larger than the demand. It has an adverse effect on the business case for solar PV and wind and may lead to curtailment of renewable electricity. Sector coupling has two advantageous effects:

1. It increases the volume of electricity required. This may lead to higher electricity prices as the price setting power generation unit will be higher in the merit order. This additional demand is partly responsive demand (e.g. because electric boilers and electric vehicles have storage capabilities). This added flexibility will help to mitigate the effects of the increased volume.
2. More important will be the opportunity demand based on fuel switch. Some industrial processes, like process heat generation and hydrogen production, can utilize fuel switch to produce with the cheapest fuel. This means, industry is willing to pay a price for electricity that is slightly under the cost of the alternative fuel (typically natural gas). The potential volume of opportunity demand is large and with sufficient volume, the opportunity demand will become price setting therefore increasing the electricity price, especially of surplus electricity that would normally be zero priced.

Both effects may increase the electricity price, especially during hours of surplus production, and thereby helping the business case for non-dispatchable renewable electricity generation.

OUR ENERGY TAXATION REGIME IS NOT FIT FOR THE ENERGY TRANSITION

Due to increasing volumes of electricity production through solar, wind and hydro, electricity becomes less a conversion product and more like a primary fuel. Energy taxation regimes are historically based on the concept of electricity production from fossil fuels and independent value chains, leading to high electricity taxation rates to account for conversion efficiencies and efficient use. Due to sector coupling and the changing nature of electricity, it becomes evident that the taxation should be harmonized per energy unit for the different energy carriers. For example, in the heating sector, the average EU tax per kWh on electricity is four times higher than on natural gas. Natural gas, therefore, has a high preferential position; customers are encouraged to use fossil fuels over renewable electricity. This taxation regime is not fit for the energy transition and it is obvious that there will be pressure to increase fossil taxes and/or lower the (renewable) electricity taxes to stimulate the use of renewable electricity. Due to market coupling, electricity taxation might become the benchmark and oil and gas taxation should be adjusted in the coupled markets. With the production of renewable electricity through solar and wind, the availability becomes time dependent. Sometimes there is a shortage of renewable power, sometimes there is a surplus. The future taxation scheme should adapt to make sure that it is economically feasible for opportunity demand to use surplus power. Fixed, high electricity taxes will have an adverse effect. Special regimes or an ad valorem taxation could solve this elegantly.

In the case of transport fuels, the taxation regime is based on captive customers (that will drive anyway, regardless of the fuel price) and on political goals. Due to the cost reduction of EVs there will be tremendous pressure on the fossil fuel product price and taxation to reduce in order to compete with the total cost of ownership of EVs. In the case of international competitive industry, cost and regulations are continuously benchmarked with other countries. This reduces the options local governments have.

In general, due to sector coupling, taxation needs harmonizing, both in magnitude of the taxes and in taxation schemes.

THE SIZE OF THE NEW ELECTRICITY DEMAND IN INDUSTRY, TRANSPORT AND FOR BUILDINGS REQUIRES NEW ENERGY INFRASTRUCTURE RULES

The huge size of demand to be electrified combined with the changing nature of the demand towards more responsive and opportunity demand will put a tremendous strain on our electricity infrastructure and system operation. The EU-wide electricity demand will potentially more than double and the power system will see larger seasonal variations compared to today, both from the generation and demand side. The character of the energy use will change in order to benefit from low-cost surplus power. We have to reconsider current grid rules, for example, allowing for non-redundant connections, include the potential of responsive and opportunity demand in grid rules and tariffs and allow for other quality standards in industrial grids. Industries should share the benefits from avoided grid investments resulting from redesign of grid rules and tariffs. A doubling of the electricity use in 30 years (2020-2050) is equivalent to an annual growth of 2.5%. While capacities will need to increase more, this seems doable with proper long-term planning and timely anticipation in grid investments and rule development.

APPENDIX A

ANALYSIS OF TEMPERATURE DEPENDENCY OF NATURAL GAS CONSUMPTION

Our hypothesis is that natural gas use for large consumers, connected to the gas transmission grid, is mainly electricity generation and heavy industrial use (process heating, feedstock). Natural gas delivered to the distribution grid is mainly used for space heating and hot tap water.

The validity of this hypothesis is supported by an analysis of the temperature dependence of natural gas use. We use available hourly data for the Netherlands from the ENTSOG-platform and the Dutch Royal Meteorological Institute from 2015-2019. The results are shown below in Figure 27.

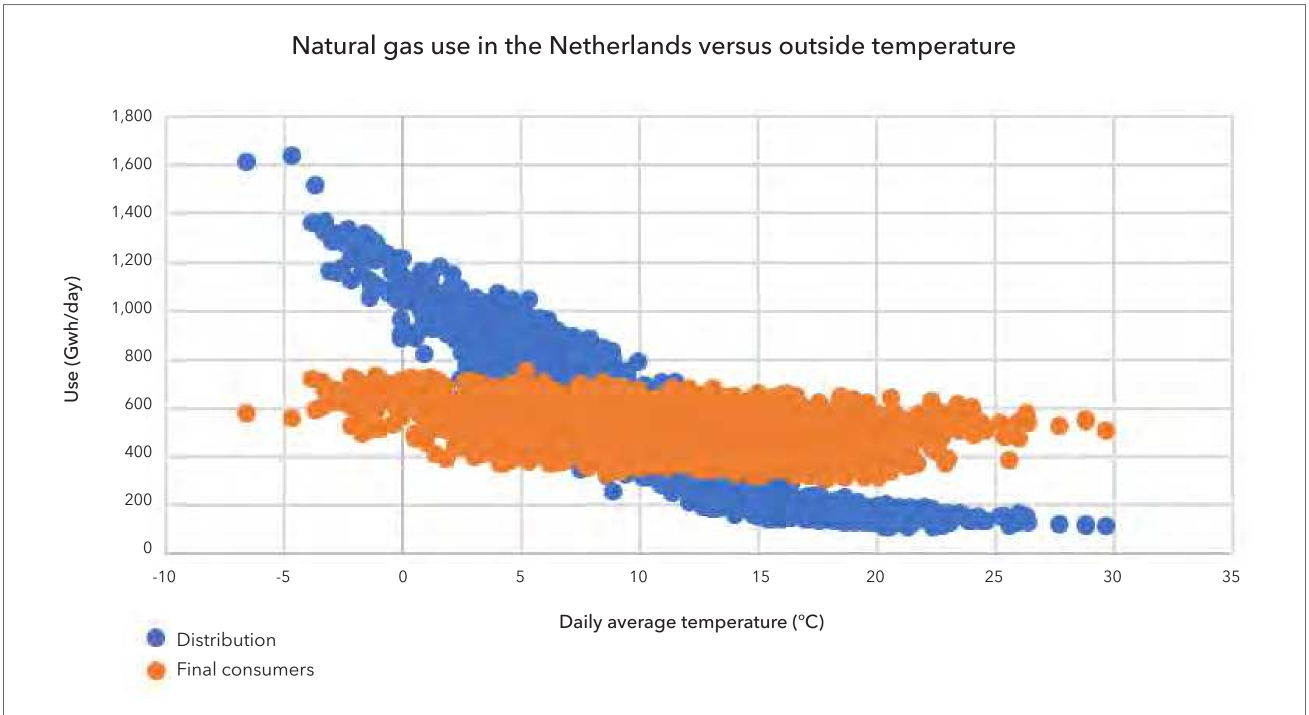


Figure 27 - Relation between outside temperature and natural gas use

Figure 27 is consistent with our hypothesis regarding natural gas use. The dependency for large consumers connected directly to the transmission grid (final consumers) shows a small linear correlation to the outside temperature. The correlation for consumers connected to the distribution grid (distribution) is more distinct. It is consistent with an almost constant demand (assumed mainly hot tap water heating) at an average hourly temperature greater than 15 °C. At lower outside temperatures, the demand increases linearly with the outside temperature, suggesting a space heating demand. This graph also suggests that, on average, the space heating demand is significantly larger than the tap water heating demand.

APPENDIX B

LEVELIZED COST OF CARS IN EUROPE

For a comparison between electric vehicles and petrol vehicles (assuming diesel is currently not a realistic option because of particles and NOx-emission) we make assumptions regarding the cost of the car, tax levels, mileage etc. This appendix summarizes assumptions and sources they are based on. We emphasize this comparison is made to provide insight in the main cost factors for cars and in the difference to be expected in the future, not as a precise cost calculation. Therefore, some parameters are based on a reasonable estimate without extensive literature review. Table 1 summarizes the parameters used in the levelized cost calculation.

Purchase cost for electric cars and petrol cars (including battery cost and subsidies) are based on our *Energy Transition Outlook* (ETO)[37]. The same for non-fuel cost (road tax, insurance, maintenance) and travel distance. Our ETO forecasts a significant decrease in battery cost per kWh, which is partly offset by an increase in battery size for electric vehicles. The yearly travel distance increases significantly due to an expected increase in shared vehicle use. Carbon costs are also based on our ETO (23 EUR/ton in 2020 and 56 EUR/ton in 2050. We assume an ETO-based discount rate of 10%.

Fuel costs are split into pure energy costs (based on wholesale prices), a service margin for cost of a grid connection and charging equipment (electricity) or distribution of fuel and fuelling equipment. These data are based on an estimate of wholesale prices, a review of fuelling cost based on European consumer organizations[41] and an analysis of European road taxes (based on EUROSTAT data). For electric vehicles in 2050 we assume a flexible charging strategy that uses electricity during low-priced hours. The share of renewable fuel is based on current EU-data and a linear trend towards 2050.

VALUE	UNITY	ELECTRIC MID-SIZED CAR IN 2020	PETROL MID-SIZED CAR IN 2020	ELECTRIC MID-SIZED CAR IN 2050	PETROL MID-SIZED CAR IN 2050
Net purchase price ex batteries	EUR	19,600	14,100	17,200	17,400
Battery size	kWh	63	0	115	0
Battery cost	EUR/kWh	146	146	26	26
Road tax, insurance, maintenance	EUR/year	730	1,460	1,450	2,900
Vehicle lifetime	year	15.60	18.60	15.70	13.20
Travel distance	km/year	15,600	15,600	31,100	31,100
Average mileage	km/kWh-liter	6.0	18.0	6.5	18.0
Fuel cost (wholesale)	EUR/kWh-liter	0.0400	0.6300	0.0100	0.6300
Fuel service margin	EUR/kWh-liter	0.1500	0.2100	0.0750	0.2100
Fuel taxes	EUR/kWh-liter	0.1700	0.6200	0.1700	0.6200
Share of renewable fuel	%	29.0%	6.0%	80.0%	25.0%

Table 1 - Overview of parameters used for the calculation of levelized cost of transport

APPENDIX C

PREREQUISITES AND CONSEQUENCES OF NEW COMMODITY MARKETS

RENEWABLE ELECTRICITY MARKET

A well-functioning and liquid electricity market does exist, and while a separate renewable electricity market exists through guarantees of origin (GoO) and power purchase agreements (PPAs), this is implemented on an administrative level based on monthly generated total volumes that are issued with hindsight. According to the European Revised Renewable Energy Directive (REDII)[42], this renewable electricity through GoOs cannot serve the production of green or carbon-neutral hydrogen, because additional requirements for the electricity are needed.

For hydrogen to be called green or carbon-neutral a temporal and geographical correlation between renewable electricity and hydrogen production needs to be established, as well as a guarantee that its production does not cause greenhouse gas emissions, also not indirectly through replacement. While it is still under discussion, this regulation is meant to avoid that non-excess renewable electricity is taken from the electricity market (or prevented to be traded on the electricity market), and thus causes other electricity demand to use grey electricity.

For industry to claim the reduction of carbon emission for hydrogen production resulting from replacing natural gas with electricity, this electricity should be 'additional' according to REDII. This implies that this electricity should not have been produced if the electrolyser would not be there, i.e. from renewable generation that otherwise would be curtailed (for example, because there is excess renewable generation, or the grid connection is insufficient).

While the intent in REDII is admirable, it might have undesired overall effects. It intends to stimulate investments in additional renewable power generation and use of excess power of existing generation. However, also if this generation was built specially to produce 'green' hydrogen, its electricity still might be put to better use displacing a gas turbine than a steam methane reformer (SMR) in case there is no global excess[43].

While a market for 'real time' renewable electricity (which is not the same as a real time market for renewable electricity) can ensure an efficient system for green hydrogen production, as long as the requirement for 'additional' renewable electricity remains in place, such a market needs to guarantee this exclusivity in some way, to ensure that it remains additional. Guaranteeing this by building a separate dedicated infrastructure might be feasible locally on a project scale, but not on a national scale. For this, such a dedicated renewable electricity market would require the use of the main electricity grid, and the exclusivity needs to be guaranteed contractually. Administrative systems that support a real time renewable market have been demonstrated in multiple peer-to-peer pilot projects, often using blockchain technology. An example of this is discussed in this conference paper[44].

RENEWABLE AND CARBON FREE HYDROGEN MARKET

As mentioned in the previous part, a 'real time' renewable electricity market can be instrumental in establishing a renewable and/or carbon free hydrogen market, that possibly is supplemented with renewable hydrogen from biomass.

If, and how, a potential market for renewable or carbon free hydrogen will evolve, depends strongly on the cost of the needed transport and distribution network. If the demand for hydrogen is sufficiently large to support a (semi-)public distribution grid consisting of pipelines, pricing of hydrogen will be strongly linked to the instantaneous production cost of hydrogen. This in turn is strongly determined by the variable prices of the electricity needed to produce it. It would mean that hydrogen market prices might fluctuate by the hour, dampened by the availability of hydrogen storage.

Similar to electricity, this infrastructure might be used for hydrogen produced in other ways as well, for example, blue hydrogen and low carbon hydrogen from nuclear power. The different kinds of hydrogen should be distinguished and traced by guarantees of origin, as proposed in REDII. If a large enough portion of hydrogen would be produced from variable renewable sources, all other variants of hydrogen would be subject to the same price fluctuations, based on supply and demand, while the price of the hydrogen guarantees of origin will remain stable.

However, if only a small number of large hydrogen producers and users are connected, it is unlikely that such a liquid hydrogen market will evolve. Instead the market will be characterized by long-term bilateral contracts based on levelized cost of hydrogen and supported by a dedicated infrastructure that grows from the current existing hydrogen infrastructure that exists within and between some industrial areas. While major parts of this infrastructure will consist of pipelines, also large-scale shipping might be part if this, including supporting facilities such as hydrogen terminals.

Hydrogen demand outside industry will likely remain relatively small and dispersed, and for this a hydrogen network will not be feasible. Small-scale distributed use of hydrogen will be generated on-site or distributed in pressurized vessels by trucks or ship, comparable to liquid fuels. Because the cost to pressurize and store hydrogen in vessels is relatively high, the price of this hydrogen will be determined more by logistics than its production costs, and will be fairly stable.

RENEWABLE E-FUELS MARKET

To transport renewable energy efficiently on a small scale it needs to be converted into renewable fuels, such as ammonia, or a carbon-based fuel like methane, methanol or formic acid, using biomass as carbon source. This fuel will be expensive to produce, as it needs to pay for the whole value chain. On the other hand, the costs of storage and logistics are small, as these fuels can be economically shipped by ship and truck. The limited need for a (fixed) infrastructure makes trading e-fuels very feasible, and it is likely that a market for e-fuels service in difficult-to-decarbonize sectors like aviation will evolve as the overall cost of using e-fuels and fossil fuels are converging as a result of cost reductions and of incentives and penalties.

A market for biofuels already exists, because of the obligation to mix road-transport fuels with 10% renewable fuel. Aviation however is part of the EU ETS. This makes it likely that aviation will be decarbonized only after the emission rights for easier-to-decarbonize sectors have been fully used. For industry that falls under the ETS scheme, this means that the pressure to decarbonize will eventually be increased because of aviation needing the same carbon emission rights.

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