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STORE&GO

Innovative large-scale energy storage technologies and power-to-gas concepts after optimisation

D8.5

The short, medium and long term perspectives of various dedicated market segments for 'green gases'

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Responsible	Catrinus Jepma, University of Groningen
Author(s)	Catrinus Jepma, Eise Spijker, Okkie den Boon
Reviewer	Simon Verleger, DVGW
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Executive Summary

As already shown in STORE&GO D8.1, (Jepma, 2017) for the next decade (2030) perspectives on substantial greening of the gas mix with renewable gases across the EU are in fact quite limited. On the one hand availability of green gas from anaerobic digestion (some 4% of the total EU uptake so far) may well be keep growing if markets and policy incentives remain favourable, but only a very positive set of developments will enable it to grow towards some 10% of overall uptake by 2030. At the same time gasification of biomass and power to gas technologies both are still in the pilot phase, so that substantial upscaling of production based on that technologies towards 2030 would seem not very likely. So an overall uptake of green gases in the order of 10-15% of EU gas uptake by 2030 would be in the range of optimistic scenarios.

Is it likely that a breakthrough towards a huge majority part of the EU gases uptake being green will be achieved towards 2050, when greening would need to be nearly completed. This report shows that this will be a formidable challenge that will need to be aggressively pursued by industry and policymakers working together starting as soon as possible, and will need to cover all major three technologies towards producing carbon-neutral gases: gases from biomass; natural gas ‘cleaned’ via CCS or CCU; or renewable gases from electrolysis and methanation with the help of green power. The fourth alternative, greening natural gas with the help of certificates, is considered to remain part of marketing the greening of gas in actual practice, but not as a fundamental source of green gas supply.

In the various scenarios developed the first set of key drivers of the overall volume of gases uptake are considered to be: the (speed of) phasing out of fossil solids, coal and lignite, as an energy source, because they cannot be greened; the reduction of the role of fossil liquids especially in mobility and the degree these can be replaced by liquid biofuels; the role of gas-fired power plants as back-up systems for intermittent renewable sources of energy; and the degree to which the EU and individual member states want to reduce import dependence on energy.

Another major driver of overall uptake of cases in the future EU energy system is the trend in electrification in the energy system. This trend is clearly upward, but it can be questioned if the upward movement of some 2 percentage point per decade during the last 4 decades (towards the current EU share of some 23%) will accelerate towards growth levels higher than some 5 percentage point during the next three decades towards 2050. If so, this would result to final uptake electrification levels between 35 and 40% by 2050, leaving the major part of energy uptake still to the liquid and gaseous, and hopefully carbon-neutral, energy molecules.

These drivers are influenced by a range of different social, economic, technological, institutional and other factors that either enable or frustrate progress. For example, certain technological hurdles can be in place that slow-down or even block the future uptake of gases, such as with long-range marine/road/air transport that require high energy dense fuels, or specific niches in the built environment that are more challenging to fully electrify. In other cases, a low level of social acceptance for specific energy options, or a lack of adequate skilled workers can frustrate an energy solution from upscaling.

For the reasons just outlined and based on a detailed disaggregation of the various gas uptake categories, it is expected in the central 2050 scenario that even if overall EU energy will likely decline primarily via energy efficiency and savings measures by possibly one third, the overall uptake of gases may well remain in the same ballpark order of magnitude of some 350-450 bcm. In line with the mitigation targets of the EU, the overwhelmingly major part of this will need to be green by 2050.

Given alternative uses of biomass (than for energy purposes), and given the physical and societal limitations expected to relate to the various CCS and CCU technologies, it seems not very likely that

much more than some half of the future uptake of gases can be ‘greened’ via the biomass and CCS/CCU options, which leaves a major role to play for power to gas to provide the ‘green gases the market will ask for. Electrolyser and fuel cell technology therefore will need to be brought to market maturity at relatively short notice given lead times of about a decade. After that decade their introduction is likely to be very substantial in order to produce the 150 bcm or more of green gases for the EU market (unless the EU chooses to rely on very substantial volumes on green gases to be imported from elsewhere).

The detailed country analyses included in this study adds a more disaggregated, context-specific, bottom-up perspective. The bottom-up analysis suggests that many top-down perspectives, could considerably overestimate the realistic speed of electrification, phase out of fossils, implementation of energy saving measures, and thereby underestimate future (renewable) gas demand. Various barriers are in place that frustrate the transition in many member states, including the need to manage/reduce energy import dependence, the adjustment of appliances / refurbishment of the building stock, the capability of the market to resolve back-up and grid balancing challenges due to intermittent energy supply, the low social acceptance for several technologies/options and also the lack of skilled workers to ‘build the transition’. All these factors add up to underestimation of the future demand for renewable gases.

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Summary

The energy transition in the European Union is now well underway. By 2050 the energy mix in the EU should mainly comprise carbon-neutral forms of energy, and most fossil fuel use needs to be phased out. While electrons are increasingly produced with the help of renewables, most molecules are still of fossil origin. Due to their relatively high carbon content, particularly the share of solid fuels (like coal and peat) and oil should be reduced first. Natural gas is often viewed as a transition fuel. However, by 2050 gas supplies should already predominantly be carbon-neutral if we aim to meet the Paris Agreement (UNFCCC, 2015) goal of 2 °C temperature increase (let alone the more ambitious target of 1.5 °C).

Our main finding in this study is that:

“We anticipate that future demand for (renewable) gases is often considerably underestimated and one therefore will have to anticipate that sufficient supplies of renewable gases need to be secured in time. Our assessment shows that particularly timely future power-to-gas production and supplies and deployment of CCS/CCU will need to be scaled up much more than currently anticipated in most energy scenario studies and Member State policies.”

Within this paper we discuss the role of renewable and conventional gases in the future European energy mix. We will reflect on supply and demand factors, both from a top-down perspective and from a country-specific bottom-up perspective.

In Figure 1, where the main approach has been outlined, we distinguish five different sectors where renewable gases can be used for different energy and non-energy purposes. They can be used for 1) power and heat generation (transformation sector), 2) as a feedstock in the (petro)chemical industry; as well as for final energy consumption in 3) industry, 4) transport, and 5) the built environment. Figure 1 also shows the four basic supply routes of renewable gases. We consider four different supply options, 1) conventional biogas, 2) biomass gasification, 3) power-to-gas and 4) climate-compensated gases, including carbon credits and carbon capture use and storage options.

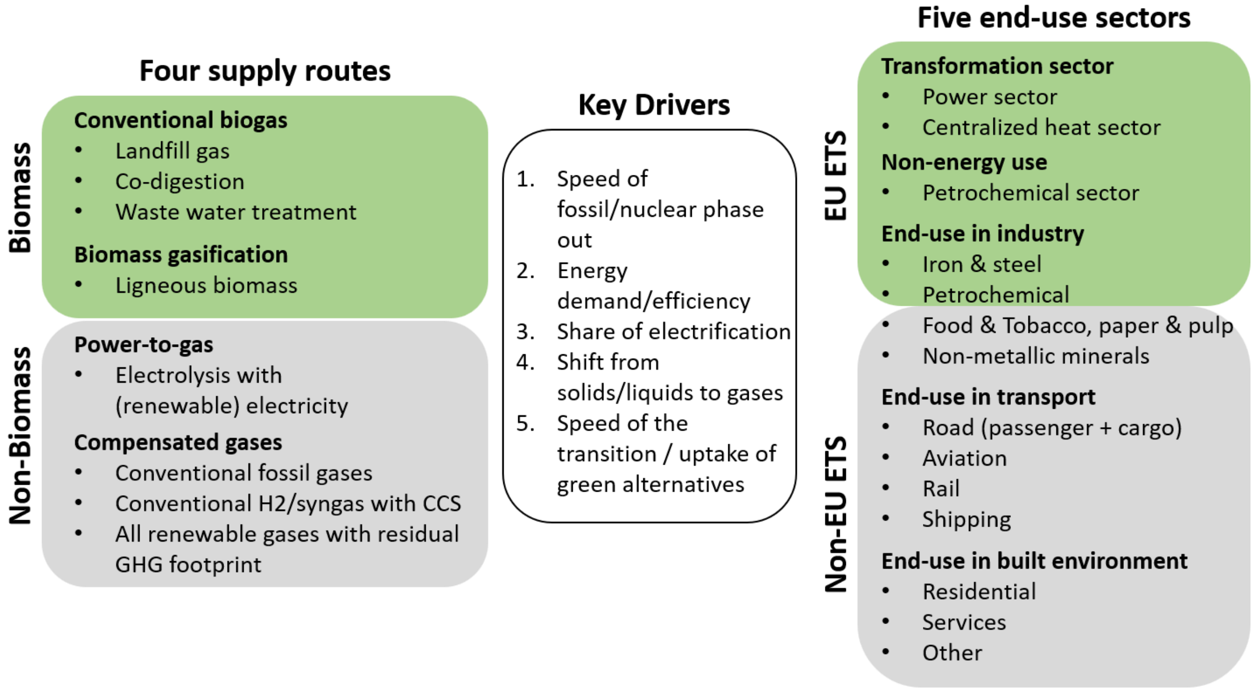


Figure 1: Four supply routes, five end-use sectors and key drivers influencing future demand for renewable gases

Within Figure 1 we also recognise that both conventional biogas and biomass gasification are two supply options that produce biomass derived renewable gases, while power-to-gas and compensated gases often do not involve the direct use of biomass. This is considered relevant since the use of biomass for (non-)energy is linked to a range of sustainability issues[1]. On the end-use side we recognise the relevance of the European Union Emissions Trading Scheme (EU ETS). The power and heat, (petro)chemical and part of the industry sectors fall under the scope of the EU ETS and are thus subject to specific EU ETS GHG accounting and compliance rules. Such considerations are relevant in light of meeting the climate change goals set in the Paris Agreement. In the centre section Figure 1 shows a number of key factors affecting future demand for carbon-neutral gases. We recognise five main factors.

1) The (desired / required) speed of the phase-out of fossil/nuclear energy is an important trigger for many EU countries to develop robust energy transition strategies. The phase-out itself can often be very costly and in some cases require buy-outs and decommissioning of old facilities.

2) The mirror-image to the phase-out, is the phase-in of the green alternatives, such as renewable electricity and gases. Also the increased uptake and implementation of these alternative forms of energy and their required infrastructure come at a considerable costs.

In between these two key factors there are three more specific factors that determine the balance between the share of gases vis-a-vis 3) the anticipated share of solids/liquids and 4) electricity in the aggregated future energy mix in light of 5) energy savings/efficiency improvements.

Top-down assessment of residual future gas demand in 2050

Current (2016) gas use in the EU is 383 Mtoe (or about 456 bcm) (EUROSTAT, 2018), which is about 23% of the total primary energy consumption. For 2030 the EU reference scenario (EC, 2016) anticipates that the share of gas demand will slightly increase to roughly 24%, equivalent to 371 Mtoe (about 442 bcm). For 2050, a modest increase to 25% of gross final energy is expected, which by then comprises about 379 Mtoe (or 451 bcm). Also Eurogas in their scenario study (Eurogas, 2018) indicates that 2050 gas demand can be up to 386 Mtoe (460 bcm). Eurogas also suggests that higher shares of gas in the energy mix can reduce overall energy transition costs.

Table 1: Top-down estimates for residual gas demand in 2050 (in Mtoe)

Transformation		100 – 106
Non-energy use		49
Industry		54
Transport		87
Built environment		65
Consumption of the energy branch and distribution losses		21
Total own top-down assessment		376 - 382
Other assessments		
	(EC, 2016)	379
	(Eurogas, 2018)	386

[1] https://ec.europa.eu/agriculture/bioenergy/sustainability_en

Our own top-down assessment (Chapter 1) of future residual (renewable) gas demand based on EU-28 energy balance data (EUROSTAT, 2018) and expectations of future developments – summarised in Table 1 – adds up to an estimated 376 – 382 Mtoe (or 448 – 455 bcm) gas demand in 2050, and is within the range of what (Eurogas, 2018) and (EC, 2016) estimate.

Bottom-up assessment of residual future gas demand in 2050

For the bottom-up assessment (see Chapters 2 and 3) we focussed on a subset of the EU-28 Member States, namely, Sweden, Poland, the Netherlands and Italy. For these four countries we reviewed national-level and sector-level energy and climate roadmaps, and policy documents to assess whether or not there are specific factors or developments that could cause a change in our expectations regarding the energy transition, and more particularly to identify key variables and key uncertainties that could have an impact on our estimated future gas supply and demand in the EU-28 at large. By performing this assessment we aim to validate and assess whether or not the envisaged trajectories may either over- or underestimate some of the key factors that influence the energy system transformation. In our case we will focus on the implications for potential future (carbon-neutral) gas demand as well as supply.

To get an even better disaggregated overview we will observe the phase-out / uptake trajectories for different energy sources for the various EU-28 Member States based on the EU reference scenario (EC, 2016). For example the reduction percentages in 2050 (relative to 2015) of the use of solid fuels (e.g. coal) range from -48% (Slovakia) to -100% (Portugal) (see Chapter 2 and Annex 1). The uptake percentages for renewables range from +17% for Latvia (relative to 2015) to +385% for Malta. For oil, gas and nuclear we see a more mixed picture, where some countries are considered to increase uptake, while others decrease. Anticipated gas uptake is particularly high in Malta, Cyprus, Sweden and Poland, while gas phase-out is considerable for Portugal, Estonia, Latvia, Spain and the United Kingdom. A full nuclear phase-out by 2050 is envisaged in Belgium, Germany and the Netherlands, while Finland, the United Kingdom, and a range of Eastern European countries are expected to increase nuclear capacity.

Table 2: Summary analysis of key factors influencing future gas demand in five EU Member States

Factors influencing (renewable) gas demand	The Netherlands	Sweden	Poland	Italy
Coal / nuclear phase out	Coal and nuclear phase-out anticipated	Coal phase-out anticipated, nuclear share decreasing and phase-out could occur	Nuclear will be introduced to reduce coal demand	Coal phase-out anticipant, no nuclear in energy mix foreseen
Speed of implementing energy efficiency/saving measures	Speed of refurbishing building stock is currently too low to meet 2050 target; likely to have shortages in skilled workers	Even if energy saving measures are not implemented at estimated speed and scale, sufficient renewable potential and nuclear back-up seems in place	Speed of refurbishing building stock is currently too low to meet 2050 target, however considerable (low-cost) energy saving potential remains, but funding and scaling is problematic	Progress on energy efficiency in many sector is made, but speed and scale are not fully in line with ambitions
Share and speed of electrification	Electrification ongoing, but unlikely to meet very high shares in final demand. Current electrification process does not (yet) have	Electrification of heating and road transport (including cargo) is increasing; however speed of electrification in	Electrification ongoing, but unlikely to meet very high shares in final demand. Current electrification process does not (yet) have	Electrification ongoing, but unlikely to meet very high shares in final demand. Current electrification process does not (yet) have

	enough speed and scale	transport might be an issue	enough speed and scale	enough speed and scale
Shift from solids/liquids to gases	Issues with phase-out of low calorific gas in industry and built environment, and unanticipated high potential gas demand from petrochemical sector envisaged; both result in high gas demand levels	Share of fossil gas is marginal, but renewable gases, mainly biogas share could slightly increase in industry, transport, and petrochemical sector; solid and liquid biomass are key options to fuel district heating systems and the transport sector	Coal phase-out is key issue in energy system transformation, with the slow phase in of nuclear and renewables, gas demand could spike in short-/medium term, and increase import dependency	Coal phase-out helps, but further reduction in use of liquids are challenge. Although introduction of NGVs is successful, and EVs are starting to gain market share, the speed and scaling required are enormous, while at the same time securing renewable/low-carbon gas supplies by 2050 will become an issue.
Speed of uptake of renewables	Currently not sufficient to meet intermediate targets, and likely insufficient to produce excess amounts of H2/SNG via power to gas to meet gas demand	High shares of renewables already obtained. Likely to overshoot intermediate targets, and adequate domestic renewable energy potential remains	Currently not sufficient to meet intermediate targets, and likely insufficient to produce excess amounts of H2/SNG via power to gas to meet gas demand, and reduce import dependence	Adequate, to date, in terms of meeting intermediate targets, especially on electricity (wind / solar uptake), however onshore wind/solar is starting to face spatial planning/public acceptance issues
Analysis	Higher than anticipated gas demand, as scale and speed of transition is too low	Marginal (if any) additional gas demand expected	Higher than anticipated gas demand, as scale and speed of transition is too low	High gas demand anticipated; securing renewable gas/low-carbon gas supplies likely to become an issue

A more detailed summary analysis of the factors that influence future gas demand in a diverse sample EU-28 Member States is provided in Table 2 (based on Chapter 3).

The analysis in Chapter 3 suggests that in Poland, the Netherlands, and Italy we estimate future renewable gas demand to be higher than anticipated in TD scenarios. In Sweden we consider that future gas demand is likely to remain a marginal fuel in the energy mix. Countries that both have to devote considerable time and resources on the phasing out of fossil and/or nuclear energy sources, and phasing in of renewable energy and implement energy saving measures could run the risk of not being able to implement the necessary transition at the required speed and scale. Depending on the country this can relate to poor transition economics and finance, the lack of sufficient skilled workers to actually ‘build the transition’ or an inadequate regulatory and institutional regime that provides a fair sharing of risks and returns along the value chain.

Matching future (renewable) gas demand with supplies

Based upon bottom-up (BU) assessment we conclude that there is considerable risk that several top-down (TD) scenarios could significantly underestimate the future demand for renewable gases in the EU-28. Even current TD assessment estimates by (EC, 2016) (Eurogas, 2018) may well be conservative given anticipated demand for renewable gases. Meeting this demand for both renewable and fossil gas can be done via the four main supply routes: 1) conventional biogas, from landfills and anaerobic digestion, 2) biomass gasification, 3) power-to-gas and 4) climate compensated gas including CCS/CCU and carbon credits/emission allowances.

Let’s set 2050 EU-28 gas demand at 380 Mtoe, and follow the suggestion by Eurogas (Eurogas, 2018) that by 2050 about 70% of that gas will be of renewable origin (266 Mtoe). Based on a literature review we estimate the potential 2050 future supply of conventional biogas and biomass gasification combined at 42 to 80 Mtoe. This leaves a ‘gap’ in carbon-neutral gas supplies of 186 – 224 Mtoe, which could be met via power-to-gas supplies or via CCS/CCU. Assuming that this ‘gap’ is fully covered with hydrogen/synthetic methane from power-to-gas plants, a lot of additional renewable/nuclear electricity is needed. Considering a conversion efficiency of electrolysis of around 60% (Götz, 2015), one would require about 1.6 times more Mtoe’s of electricity production, so around 298 – 358 Mtoe. This is roughly equivalent to about 790 – 949 GW of installed offshore wind capacity in 2050. To compare, Wind Europe (Wind-Europe, 2017) estimates in their scenario analysis that total installed wind capacity will be in the range of 256 – 397 GW by 2030, and estimates by (Wind-Europe, 2015) for 2050 go up to 600 GW installed wind capacity. Both Wind Europe estimates consider the wind production capacity, mainly to meet direct electricity demand for all sectors and uses, while our estimate of required incremental power production (to generate gases; green molecules) solely focusses on the electricity requirements to meet the needs for production of renewable gases alone. Given the magnitude of the required scale-up of renewable electricity it is unlikely that the EU power to gas option would single-handedly be capable of filling this ‘gap’. Here CCS/CCU is needed to decarbonize the remaining share of fossil gases in the energy system. This also includes the 30% of fossil gases that still remained in the 2050 gas demand (114 Mtoe). Below we provide a simple assessment for the required scale of CCS/CCU, if we only deploy CCS/CCU and/or climate compensated gases to decarbonize this remaining 30% fossil gas in the 2050 gas mix.

With the need to reduce EU aggregate GHG emissions by 80–95% by 2050 (relative to 1990), the remaining GHG emissions associated with fossil gas use could be compensated by purchasing project-based carbon offset credits (e.g. CDM) or EU emission allowances via the EU ETS (see Chapter 4). On top of that we also consider it likely that both fossil and renewable gases, by 2050 all footprint GHG emissions would need to be compensated and not only combustion-related GHG emissions: in the spirit of EU monitoring practices, life-cycle based GHG monitoring and compliance for EU ETS installations is then implemented. However, this deviates from the current practice of source-emission GHG monitoring and compliance under the EU ETS (see Chapter 5).

We estimate that to offset the GHG emissions associated with 114 Mtoe of fossil gases one would roughly require a total of about 325 Mt CO_2-eq. in terms of carbon credits. A substantial part of these carbon credits could be available in terms of emission allowances (EUAs) for gas combusted within the boundaries of the EU ETS system. Assuming that roughly about 54% of all gases is used under the EU ETS (46% non-ETS), this would imply that at least the combustion emissions associated with gas use under the EU ETS are covered. For the remaining part of the life cycle emissions, additional climate compensation would be needed. So, we estimate the need for additional (non-EU ETS) climate compensation at 154 – 178 million carbon credits in 2050. For compensating the GHG emissions for the remaining 30% fossil gases used by 2050, about 480 – 500 million carbon offset credits or EU allowances will be needed. This estimate excludes the possible need for additional footprint GHG compensation of renewable gases, many of which do not have a zero or net negative footprint (see chapter 4). This may well be rather complex, because it seems likely that by 2050 global supplies of carbon offset credits will be limited (Chapter 4), especially if and when the 2.0 °C or 1.5 °C degree temperature increase global GHG emission trajectories are being met.

With regards to the deployment of CCS/CCU we consider the gas combustion emissions falling under the EU ETS as most suitable. CO_2 captured from combustion of 114 Mtoe of natural gas requires an annual geological storage of about 325 Mt CO_2 by 2050. While studies suggest that there is adequate technical geological storage potential available, we anticipate a wide geographical mismatch within the EU between point source emissions and storage capacities. This is likely to frustrate

CCS economics and could ensure that CCS will remain a fall-back option that will not be implemented and scaled at the right time. Moreover, natural gas CCS alone could consume already a large portion of available cumulative geological storage capacity in the EU, while other point sources from coal or refineries might also want to claim storage space. Here CCU options that extract the carbon from methane in solid form (e.g. carbon black) could provide a better business case relative to carbon capture and geological storage. However, timely scaling this option will provide a great challenge.

1 Demand side for (renewable) gases

1.1 Current and future demand in EU-28 (top-down)

1.1.1 Current

In 2016, gross inland energy consumption in the EU-28 was 1,641 Mtoe (EUROSTAT, 2018), consisting of a mix of liquids, solids, gases, renewables and other forms of energy. A substantial share of that energy was transformed into a more suitable form of energy. This relates to conversion of solids and gases (mainly coal, natural gas, solid wastes and biomass) into heat and electricity, and to refining of liquids into transport fuels. Aside from that, the energy sector itself also consumes energy, and some distribution losses are recorded mainly for gases and derived heat. With regard to energy available for final consumption, one can distinguish between non-energy and energy uses. Non-energy consumption relates to the use of carbon containing feedstocks (mostly liquids and gases) for the production of chemical and petrochemical products (e.g. plastics, fertilizers). Final energy consumption relates to the use in various sectors, like industry, transport and the built environment (Table 3).

Table 3: Simplified energy balance of the EU-28 (in Mtoe)

	All forms of energy	Gases	Liquids	Solids	Renewables	Nuclear	Other[2]
Gross inland consumption	1,640,615	382,969	582,179	240,724	216,618	216,703	16,458
Transformation input	1.294.958	125,132	654,689	224,492	61,875	216,703	12,067
Consumption of the energy branch	80,128	19,028	33,402	636	654	-	26,408
Distribution losses	26,372	3,093	53	35	24	-	23,166
Final non-energy consumption	97,773	13,530	82,480	1,763	-	-	0
Final energy consumption	1,107,818	245,284	437,131	45,338	88,949	-	291,117
Industry	*276,823*	*86,242*	27,513	33,774	22,542	-	106,751
Transport	*367,272*	*3,284*	344,648	12	13,840	-	5,488
Other sectors (e.g. residential)	*463,723*	*155,758*	64,969	11,552	52,567	-	178,877

Source: (EUROSTAT, 2018)

Gases represent some 23% of the overall gross EU-wide inland energy consumption, whereas liquids and solids together represent some 50%, renewables some 13% and others the remaining 14%. As far as the use of gases is concerned (so far predominantly natural gas), the largest part is used for the built environment, followed by its use for power and heat generation in the energy (transformation) sector, and subsequently industry. This picture differs widely from one EU Member State to the other, depending on various factors such as the natural conditions, economic structure, and national policies and measures.

The question is how the demand for gas could evolve at the short (until 2023), medium (2030), and long term (2050), and specifically what this may imply for the future demand for renewable gases. In

[2] Other energy sources include energy derived from solid wastes, electricity and derived heat.

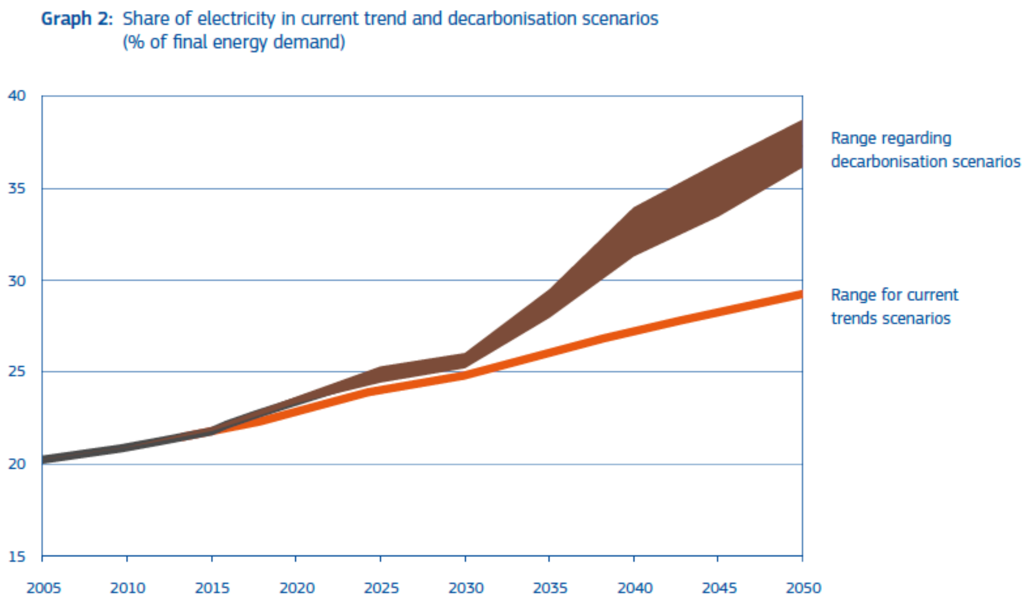
the following, we will discuss a number of factors that influence the future demand for gas in the EU (from a TD perspective) for the three time periods mentioned, sketching what the range of demand for renewable gas could look like in the various regions of the EU. Obviously, within all projections a host of assumptions will determine the outcomes. In subsequent chapters we will take a bottom-up perspective and will take into account as much as possible the current differences in gas uptake in the different sectors for a number of EU Member States in order to try to describe how future demand for (renewable) gases could develop and how this demand is met.

1.1.2 Generic factors impacting on the future demand for gases

Currently, still some three quarters of energy uptake across the EU consists of fossil sources, the predominant one being fossil liquids (primarily oil). Globally, this figure is even 86%. Although part of this primary energy is converted into power, molecules are still the backbone of today’s energy system, with a share in the order of 77% (globally 82% in 2015) against the remaining share of about 23% for the electron-based part of the energy system. This is illustrated by Figure 2 (EC, 2011a), which shows a clear trend towards electrification, particularly within the built environment, industry and transport. Globally, this electrification trend has been relatively slow so far, with an increase of just some 2 percent points per decade during the last four decades (Morgan Stanley, 2017).

In other energy applications, notably heavy transport, industry, and transformation for backup purposes, the role of molecules is likely to remain substantial. The EU projects the share of electrons to grow towards some 38% by 2050, which means that even if the transformation of the electricity system has more or less taken its shape, molecules still will dominate in satisfying final energy demand. In the following, the projected electrification trend as foreseen in the EU Roadmap will be accepted as a reasonable assumption. In other words, we will assume that by 2050 some 62% of final energy demand will be satisfied by molecules; by 2030 some 74%; against a current (2018) share of some 77%. Reasons why molecules will keep dominating final energy uptake also in the future are probably much similar to the ones explaining why molecules have dominated so far throughout the energy history: energy molecules can be transported, stored, and often implemented much cheaper and easier than electrons. The physical laws explaining this will not likely be overtaken by new technological developments.

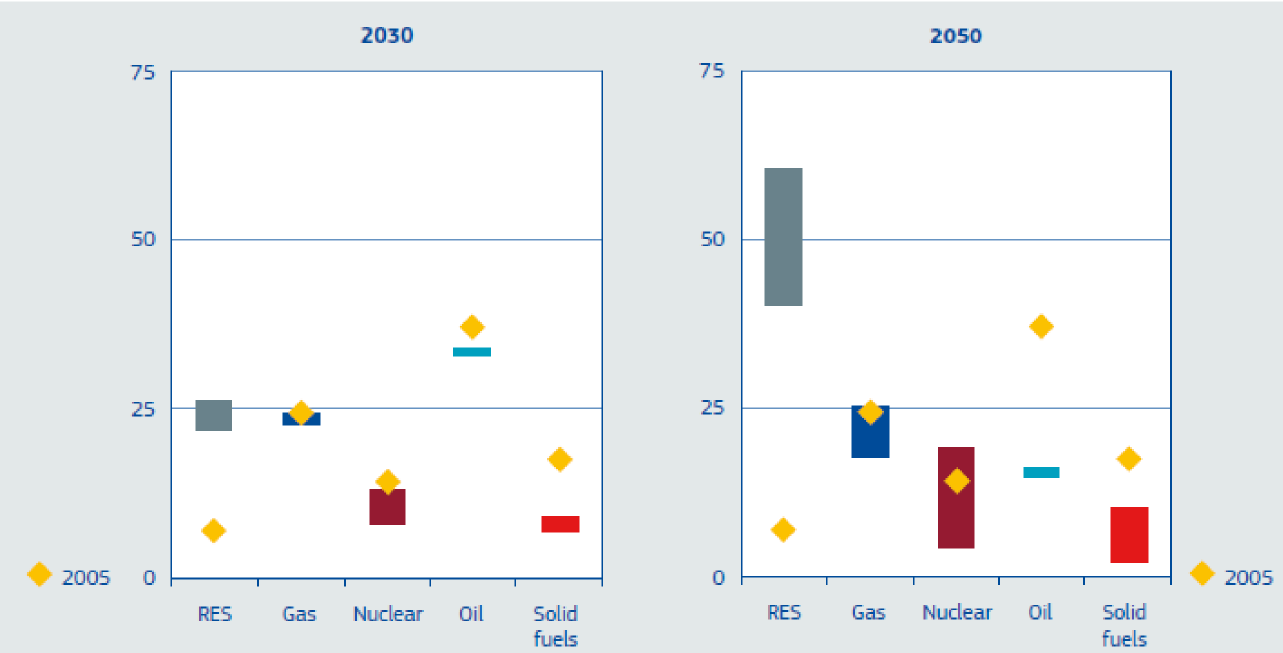
Figure 2. Share of electricity in current trend and decarbonisation scenarios, share of final energy demand



Source: (EC, Energy Roadmap 2050, 2011a).

Given the role of molecules in final energy demand, it is obvious that in order to comply with the Paris Agreement (UNFCCC, 2015) and subsequent Nationally Determined Contributions (NDCs) and other climate policy regime agreements, the future uptake of energy molecules will need to be green just as the electrons will need to be green. The EU energy and climate targets for 2030 and 2050 are quite clear on this: the EU’s 2030 Framework for climate and energy (EC, 2014) specifies for 2030 that at least 27% of energy consumption will need to be based on renewable energy, contributing to the 40% emissions reduction target compared to 1990 levels. For 2050, the EU (EC, 2011b) has set itself the goal to reduce greenhouse gas emissions by 80-95% compared to 1990 levels, which implies a significant increase of the share of renewable energy.

Figure 3. EU decarbonisation scenarios - 2030 and 2050 range of fuel shares in primary energy consumption compared with 2005 outcome



Source: (EC, Energy Roadmap 2050, 2011a).

The projections from the EU Roadmap 2050 for 2030 and 2050 are presented in Figure 3. They clearly show how renewables will take over the (2005) role of solid fuels (typically coal) and oil, whereas the role of gas is projected to remain roughly stable at the current level. The key question with respect to the projections is how they can be made compatible with the projection presented before on the share of molecules in the energy system of 75% (2030) and 62% (2050). Assuming that by 2030 all renewables and nuclear (together some 37%) are converted in (green) electrons and assuming net imports cannot compensate for this, there will be an oversupply of electrons and insufficient energy molecules. For 2050, the EU-picture gets even worse: renewables and nuclear together (roughly 50 to 75%) generate far too much electrons to satisfy the still significant (some 62%) share of demand that is focused on molecules. Even worse, by 2050, gas, oil, and solids (together some 25 to 50%) cannot deliver the green molecules that will be the bulk of energy demand given the EU mitigation targets, unless the EU embarks on very significant and large-scale CCS activity, or imports of green molecules.

In other words, already by 2030 there will be a clear shortage of (green) molecules, the problem of which gets even more serious if we move towards 2050.

In order to get to projections of the future uptake of green gases, depending on the scenario, the following assumptions have been made:

1. Overall gross energy demand, based on current policy initiatives, will decline somewhat relative to the current level of about 1800 Mtoe and will level off at around 1700 Mtoe by 2030 and remain relatively stable up to 2050; or, as a result of much more aggressive policies and measures towards decarbonisation, will decline to levels in the order of 1500 Mtoe by 2030 and 1200 Mtoe by 2050. See also (EC, Energy Roadmap 2050, 2011a), page 8.
2. The ratio of molecules vs. electrons will change gradually from the current 77/23 ratio to 75/25 by 2030 and 62/38 by 2050.
3. The share of renewables will increase from the current (2016) level of 13.2% towards much higher levels, some 24-27% by 2030 and some 40-60% by 2050.
4. The share of (fossil) gases will remain roughly the same throughout the period towards 2050, at levels anywhere between 20 and 25%.
5. The share of solid fossil fuels (specifically coal and lignite) will decline if not disappear almost completely; this process has already started by phasing out coal-fired power plants in some EU Member States, and will continue towards 2050. The share of liquid fossil fuels (specifically crude oil) will start to decline significantly only after 2030.
6. The electrons generated to satisfy energy demand will be green for about 60% by 2030, and virtually completely carbon-free by 2050. In order to comply with the EU targets, molecules will also need to be much greener than currently (a few percentages at most).
7. Low- to zero GHG emission molecules can be based on biomass or power-to-gas (i.e. physical renewable gases such as SNG or hydrogen), but it will be accepted that such low GHG molecules can also be based on fossil sources combined with CCS, or on fossil sources combined with emission reduction certificates.
8. The introduction of renewable gases on the short term (i.e. until 2023) will predominantly be based on the expansion of renewable gas supplies from anaerobic digestion and renewable gas based on certificates. Given the technology lead times, renewable gas production from industrial gasification of biomass and based on power-to-gas activity may expand in the course of the coming decade up to 2030 to further expand substantially after 2030 in order to provide the renewable gases needed in the energy system and in physical application. The same applies to CCS.
9. Typical areas where the use of physical renewable gases can expand are (heavy) transport, industry and perhaps non-energy applications. Sectors where a decline or consolidation of the use of gases can be foreseen are power generation and the built environment (residential sector). This is because these sectors have suitable switching options available that would not involve the use of (renewable or fossil) energy molecules.
10. In all scenarios, a gradually declining part of the greening of the energy molecules will be based on combining fossil energy sources with carbon certificates, either certificates based on the physical delivery of renewable gases, or certificates that just reflect carbon emission reductions elsewhere.

1.1.3 Future

Top-down estimate of the EU-wide future demand for renewable gases

Based on the above assumptions, a first top-down estimate can be made of the future EU demand for renewable gases for the short, medium and long term. These estimates obviously will be just crude figures, but may provide some indication of the orders of magnitude of demand for renewable gases that may evolve across the EU as a whole. In Chapter 2 and 3, these results will be confronted with a bottom-up exercise with the same purpose, i.e. to provide a picture of the future demand profiles for renewable gases across the EU. In this bottom-up approach, sectoral and regional data/information will be combined and eventually aggregated to also project how the demand profiles for renewable gases can develop given the current knowledge about specific factors influencing demand at the more disaggregated level. At the end of the report, the both approaches will be confronted to see if the top-down and bottom-up approach lead to comparable results or if there are any blind spots or under-/overestimated factors. In addition, we will reflect upon the question if and how future aggregate demand for renewable gases can be met, and via which supply options (Chapter 4) this is most likely?

Short term

On the short term, in the absence of any mandatory policies and measures to introduce the uptake of renewable gases rather than fossil gases, it seems fair to assume that demand for renewable gases will remain modest. Current supplies of renewable gases are almost completely based on anaerobic digestion of biomass, the major part of which (almost 90%) is put on the market by way of local biogas and only some 10% entering the grid as renewable gas with the same quality as fossil gas. As a result, less than 0.5% of the overall volume of gas offered via the public grid and consumed in the EU-28 consists of physical renewable gas. Insofar as renewable gas is provided by energy suppliers, a substantial part is currently based on carbon certificates, not on the physical delivery of renewable gas. Thus far, the price differential between renewable gas and fossil gas has remained fairly little, but even then actual demand for renewable gas, both from industry and households, has remained rather modest.

The same applies for the market of hydrogen, where virtually all hydrogen produced in the EU-28 stems from fossil energy sources (like coal and gas), and can therefore be considered ‘grey’. This is why current hydrogen production processes are a relatively substantial source of GHG emissions. Some initiatives to produce renewable hydrogen (i.e. based on renewable energy) or blue hydrogen[3] (i.e. decarbonised via CCS/CCU) are currently considered, but current production volumes of such carbon-neutral hydrogen are still negligible. Given the normal lead times in technology development, it seems fair to assume that the demand for renewable hydrogen will (can) not grow, mainly due to a lack of available supply in large quantities.

The only factors that could lead to a rapid short-term increase in market uptake of renewable gases seem to be short-term policies and measures that will force the uptake of renewable gases onto the market (e.g. policies requiring the transport and delivery of gases to specific destinations to contain a minimum percentage of renewable gas). Another example of short-term policy could be that some chemical products, e.g. fertilisers, can only be put on the market if the hydrogen used in the production process is ‘green’ or ‘blue’ for a certain percentage. A still other example could be that green agricultural products will lose their label, unless it can be proven that in the production process sufficiently green chemical fertilisers have been used, etc.

Medium term

Given the above assumptions, the total demand for energy across the EU is projected to be between 1500 and 1700 Mtoe per year by 2030. It is also projected that some 25% of this will be taken up by the market by way of electrons and the remainder as molecules. So, some 400 and 1200 Mtoe, respectively. Supply of energy is projected to be strongly affected by climate policies of the EU, such that by 2030, 25% of energy supply will be based on renewable energy sources. In STORE&GO

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[3] E.g. https://spectrum.ieee.org/energywise/energy/fossil-fuels/nuclear-to-coal-to-hydrogen-sheldon-station-blazes-a-trail?utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+IeeeSpectrum+%28IEEE+Spectrum%29

deliverable D8.1 (Jepma, 2017), the conclusion has been drawn that by 2030 anywhere between 4.5 and 14% of the gas supplies could be of renewable origin, which roughly corresponds to about 1 to 3.5% of the overall energy system. If we take the middle of the two figures as a reasonable ballpark figure, it implies that by 2030 roughly some 2% of the energy system can be 'green' thanks to the physical greening of gas.

Separate from the renewable gas that may come available on the market as sketched in (Jepma, 2017), there is another emerging source of renewable gases that is likely to be taken up by 2030, namely renewable gases that are generated as a result of the mismatch between the supply and demand levels of electrons vs. molecules. Overall, the increasing share of renewables as targeted by the EU will generate a substantial increase of green electrons, even if it is recognised that a part (probably some 10%) of the renewables consists of biomass that is converted into renewable gas. If the carbon-neutral electrons that will be provided by 2030 from nuclear power and renewable sources is combined, this will provide roughly a third of the overall energy uptake. If we assume that, instead, the market only absorbs a quarter of the overall available energy by way of electrons, the surplus of electrons can be put on the market in the form of green molecules, i.e. through power-to-gas technologies. This would substantially add to the uptake of renewable gases. If, to just give an example, some 8% of the overall energy supply would be converted into molecules because of the mismatch mentioned, this would correspond with roughly a quarter of the overall uptake of energy in a gaseous form, so that the overall market share of energy in gaseous forms increases from about 25% to about 35% of the energy system (25% natural gas, 8% from power-to-gas, and 2% from biomass).

Obviously, to the extent that electrification of society would proceed more rapidly than assumed above, will the share of demand for energy in gaseous form be less than the 35% of total uptake mentioned. Given, however, that the last four decades the increase of electrification amounted to 2 percentage points per decade only, it does not seem very likely that the increase in electrification up to 2030 will be such that the mismatch mentioned can be prevented. Power-to-gas therefore will need to be developed relatively quickly in order to address the upcoming issue of too many green electrons and too little green molecules.

Long term

On the long term, the picture is quite similar to the one sketched for 2030, but more pronounced in terms of its implications.

By 2050 of the energy molecules at least three quarters will need to be provided with a low to zero GHG footprint. The remaining non-renewable energy share could, for instance consist of oil and fossil gas, the carbon of which could be used in materials that could be recycled. If, however, by that time some 40-60 per cent of energy supply will consist of renewables, mainly wind, solar and hydro and therefore creating low-GHG emission electrons, and if there still would be some 10 per cent nuclear power creating another 10 per cent of energy supply of low to no GHG emission power, the mismatch between supply of and demand for electrons/molecules would even be larger than in the picture provided for 2030: whereas some 60% of EU energy demand would then be for primarily green molecules, some 40% of EU energy supply would consist of electrons. The required power to gas conversion needed to balance the system would need to be formidable indeed. Even if massive carbon capture use, storage and carbon recycling would be implemented, dealing with this mismatch would still require the conversion of about 20 per cent of overall energy supply into renewable gases.

Assuming that by 2050 the overwhelming part of gas taken up by the market would need to be virtually zero GHG emissions, and that the overall remaining share of solid and liquid fossil fuels would represent no more than some 20% of overall energy supply across the EU, the aggregate demand for all types of renewable gasses[4] will have grown to levels varying between some 400 and 500 Mtoe depending on overall trends in EU-wide energy uptake (varying from about the current levels to some one-third less).

In short, compared to the current very small numbers of renewable gas uptake, the next about 30 years will likely see a phenomenal growth in market demand for renewable gases. Part of this demand can also be satisfied by still fossil gas that is either turned into a low GHG source (e.g. blue hydrogen) via CCS (or possibly CCU to the extent politically accepted), or via combining it with carbon compensating certificates. Another part of this gas will be based on biomass either via digestion or gasification processes, and a part of this gas will consist of renewable hydrogen via P2G or derived SNG (e.g. via methanation or comparable technologies).

1.2 Transformation sector (power + heat)

The transformation of energy involves the production of so-called derived products like petroleum products and briquettes, as well as electricity and heat. Key inputs for this sector include solids (mainly coal), liquids (mainly oil), gases (mainly natural gas), and renewables (e.g. renewable electricity, biomass and wastes). Of all transformation energy inputs in the EU-28 about 49% is delivered to refineries and 28%, 17% and 2% to conventional thermal power plants, nuclear power plants, and district heating plants, respectively. Table 4 shows that refineries solely rely on oil as input, while nuclear power plants are 'fed' with nuclear heat to generate electricity. Conventional thermal power plants are predominantly fuelled with solids fuels (coal) and gas (natural gas) as well as renewables (mainly biomass, renewable share of wastes and biogas).

Table 4: Energy inputs in transformation sub-sectors (% of total)

	All inputs	Of which	Solid fuels	Oil (total)	Gas	Renewables	Nuclear	Other
	share in total transformation input	in %-point						
Refineries	49.4%	←	-	49.4	-	-	-	-
Conventional thermal power plants	27.7%	←	12.8	1.0	8.8	4.2	-	0.9
Nuclear power plants	16.7%	←	-	-	-	-	16.7	-
District heating	1.6%	←	0.3	0.1	0.7	0.5	-	-
Other[5]	4.5%	←	4.3	-	0.2	-	-	-

Source: (EUROSTAT, 2018)

[4] Probably by that time consisting of different mixtures of (synthetic) methane and hydrogen depending on transport facilities and applications.

[5] Other installations or transformation plants include: coke-ovens, blast furnaces, gas works, patent fuel plants, BKB / PB plants, coal liquefaction and gas to liquids plants, charcoal production plants.

If the EU-28 would phase-out coal, this would have a significant impact on the power generation / district heating (DH) industry as well as other industries like coke-ovens and blast furnaces which currently are most reliant on solid fuels.[6]

For our renewable gas uptake projections we assume that a full EU-28 nuclear and coal phase-out is not realistic in the short to medium term, but could be possible by 2045-50 considering the vintages of the latest coal and nuclear plants built in recent years. So, let's assume for the moment that nuclear power and the use of coal for power production will indeed be phased out almost completely (some 10% of current capacity remaining) by that time. What impact will this have on the demand for renewable gases for transformation into power by 2050, considering that by that time all electrons will need to be green and that some three quarters of power will come from other renewable sources than gases?

Since nuclear power provides energy equivalent to some 215 Mtoe, and coal for power some 175 Mtoe, the phase-out would reduce supply resources by some 75%. If we assume that by 2050 some three quarters of power will be produced with the help of the renewable energy sources wind, solar, and hydro, the remaining one quarter will have to be provided either on the basis of solid biomass that, after gasification (possibly in a former coal-fired power plant), is transformed into power (estimated at some 40 Mtoe), or on the basis of direct transformation of gases (estimated at 85 to 100 Mtoe), both of which is possible on the basis of relatively straightforward technology. The theoretical maximum demand for green molecules in the power sector could add up to 500-530 Mtoe.

In the trajectory towards 2050, the crucial factors determining the demand for renewable gases for transformation into power therefore are on the one hand the penetration speed of wind, solar, and hydro power, and on the other hand the speed at which nuclear and coal-fired power production will be phased out across the EU. Assuming that the rate of penetration of intermittent renewables and hydro in the power sector will reach up to 75% by 2050, residual gas demand for green gases for transformation into power could add up to some 120 Mtoe.

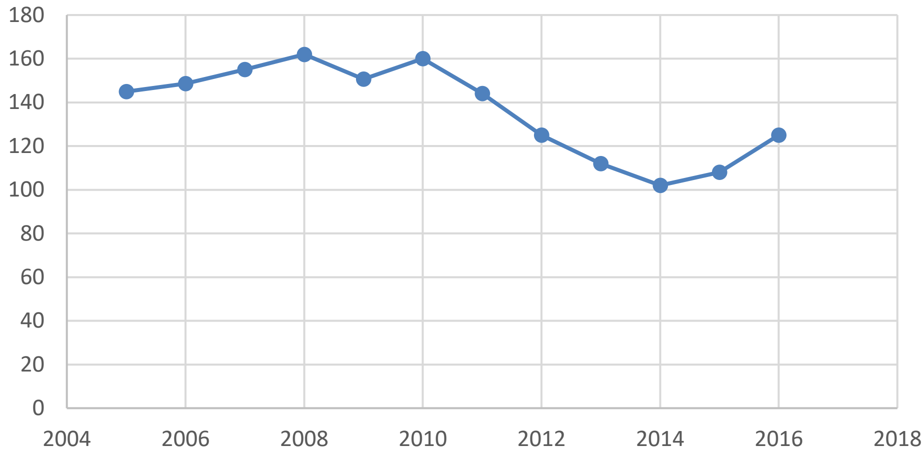
Short term

Currently (2016), the total volume of gas that is used in gas-fired power plants amounts to some 125 Mtoe, almost all of which is fossil. Insofar as greening of energy is taking place, this is at the demand side where suppliers of power and gases offer green energy primarily with the help of certificates. Demand for gas in the transformation sector (power and heat) across the EU has declined during the last decade typically as a result of the relatively low prices of coal.[7] In addition, gas-fired power plants have lost market share as a base-load solution due to the competition from low-cost marginal intermittent renewable power.

[6] We ignore the refinery sector here, since the use of oil is discussed in following sections in this chapter dealing with the transport, (petro)chemical and chemical sector.

[7] This is mainly the result of the US shale gas developments substantially reducing US demand for coal on the world market.

Figure 4: Gas demand for transformation sector in EU-28 per year (Mtoe)



Source: (EUROSTAT, 2018)

In fact, during the last decade substantial (some tens of GW capacity) gas-fired power capacity has recently been closed or mothballed across Europe. Although during the last few years mainly due to increasing power prices competitiveness of gas-fired power production, compared to the alternatives, has increased again somewhat, demand for gas for transformation has remained somewhat subdued (Figure 4). For the next few years, a possible relative price increase of coal vs. gas, the tendency to phase out coal-fired power plants, and a possible further rise of the EU ETS allowance prices may all contribute to enhance the competitiveness of the gas-fired power plants, and therefore the demand for gas for transformation. How this may affect the demand for renewable gas is very hard to predict, because most renewable gas so far is only used for local power and heat production, not for being provided via the public grid. So, even if demand for gas for transformation would increase, the impact on the demand for renewable gas at short notice is likely to be relatively small.

Medium and long term

The key variables determining future demand for renewable gases in energy conversion are on the one hand what the overall penetration rate of biomass and waste in power production eventually will be. The less such uptake will develop, the more likely the power sector will draw upon available renewable gases to meet power demand. On the other hand, slowing down or further postponement of the pace of nuclear phase-out or of decommissioning of coal-fired power plants will adversely affect the demand for renewable gases for converting into power. The second factor, however, is likely to be more dominant than the former, because, as Table 4 has shown, the current role of nuclear and coal in power production is some three times larger than that of gas: if these two sources would disappear for the major part, renewable gas would be virtually the only viable large-scale applicable alternative.

Table 5: Estimated share of renewable gas supply sources for the transformation sector

Supply source of renewable gas for power + heat sector in EU-28	Current	< 5 years	2030	2050
			Estimated share of demand	
Physical supply				
Anaerobic digestion	*≈3.5%*	*0-10%*	*0-10%*	*0-10%*
Biomass gasification	*0%*	*-*	*0-10%*	*5-20%*
Power to gas	*0%*	*-*	*0-5%*	*0-5%*

Administrative supply				
Climate compensated	*90-100%*	*90-100%*	*75-100%*	*65-95%*

Source: Own assessment

Given the expected supply/demand mismatch at the future market for renewable gases, it seems fair to anticipate that climate compensated gases will be one of the dominant supply routes for ‘low GHG emission’ gas supply for the power and heat sector in the EU-28 up until 2050 (see Table 5). Within the EU climate compensated gases (or other compensated fossil resources) for the conventional power sector installations will probably mainly relate to EU ETS CO_2 emission allowances, since most of these installations fall under the EU ETS, but other offset certificates will likely be used as well. It can be anticipated that even the increasing use of ‘physical’ renewable gases in this sector, will lead to a demand for carbon credits from offset projects around the world to compensate for GHG emissions related to the production of such renewable gases (e.g.. in case woody biomass or energy crops are used for this purpose any Indirect Land-Use Change (ILUC) impacts (EC, 2015) or process related GHG emissions might need to be compensated, etc.).

We consider that power-to-gas-to-power probably will be a less likely dominant future supply route for the power/heat sector. This is because this would entail a reconversion of molecules into electrons (which previously were electrons), and therefore significant energy conversion and thus financial losses. However, under specific conditions in which conversion to power technology is very flexible it could become a viable option for balancing the power grid. The same applies for offshore or distant onshore small standalone gas fields, that may become feasible to explore if the gas is converted on the spot (possibly with CCS) into (green) power, the so-called gas-to-wire option.

1.3 Final non-energy consumption

Final non-energy consumption involves the use of fossil fuels and other resources, mainly as feedstock for the production of non-energy products in various sectors.

Table 6 shows that the EU industry sector consumes about 96% of all resources in this category. Within the industry sector, the chemical/petrochemical industry sector is the largest consumer of energy feedstocks (77,5%). The industry (chemical/petrochemical) sector is heavily reliant on mainly oil and gas as key feedstocks and produces non-energy products such as chemical fertilizers and plastics.

Table 6: Energy inputs for non-energy use purposes in different sectors (% of total)

Non-energy use in:	All inputs	Of which	Solid fuels	Oil (total)	Gas	Renew-ables	Other
	share of total non-energy use	in %-point					
Transformation sector	0,0	←	0,0	0,0	0,0	0,0	0,0
Energy sector	0,0	←	0,0	0,0	0,0	0,0	0,0
Industry sector	95,7	←	0,0	81,9	13,8	0,0	0,0
of which in Chemical/Petro-chemical Industry	77,5	←	0,7	62,9	13,8	0,0	0,0
Transport sector	1,9	←	0,0	1,9	0,0	0,0	0,0
Other sectors	0,7	←	0,1	0,6	0,0	0,0	0,0
Industry, Transformation and Energy Sectors	1,7	←	1,71	0,00	0,02	0,00	0,00

Source: (EUROSTAT, 2018)

A future scenario where the EU-28 would phase-out oil would have a significant impact on the (petro) chemical industry sector. The most likely candidate for substituting oil in this sector would be natural gas, hydrogen or other (carbon containing) renewable gases. A switch to solid feedstocks like coal, lignite is not likely given the increasing desire to phase out coal due to its too high climate impact.

For our simple scenario assessment we assume that a full EU-28 phase-out of fossil oil is not realistic in the short, medium and long-term. For the short and medium term we consider that no significant reduction in the share of oil used will materialise. For the 2050 period, however, we consider its use will be reduced by about 10% due to conversion efficiency gains. Residual aggregate oil demand for non-energy purposes would then be 74 Mtoe. By that time we anticipate that the production of renewable gases via biomass gasification and power-to-gas has sufficiently matured. Substituting 50% of residual oil for non-energy use that with renewable gases would require 37 Mtoe. If we add to that the remaining use of fossil gases with renewable gases in the EU-28 (also corrected for a 10% conversion efficiency gain) an additional 12 Mtoe of gases would be needed in this sector (based on (EUROSTAT, 2018). Given that a dramatic switch to direct use of electricity is not realistic for this sector[8] we estimate aggregate renewable gas demand for this sector to rise to about (37 + 12=) 49 Mtoe by 2050.

Considering that this sector (predominantly the petrochemical sector) is anticipated to remain reliant on carbon containing liquids and gases up to the 2050 period, renewable gases are one of the few viable transition options available. Since the petrochemical industry has a higher added value relative to using renewable gases in the power sector, we expect that this sector should be able to better secure access to supplies of (physical) renewable gases. This can either be renewable gas supplied via anaerobic digestion, biomass gasification or power-to-gas value chains. For this sector we anticipate that power-to-gas supply options will provide the bulk of physical renewable gases as we come closer to 2050. We expect that this industry is likely to be one of the early adopters of large quantities of power-to-gas renewable gas supplies, particularly in the northwest European region where a high concentration of large petrochemical industries is located relative closely to large offshore wind parks in the North sea region. In case physical supplies of renewable gases cannot be secured the use of climate compensated fossil oils and gases can serve as a back-up, either via the use of emission allowances (EU ETS) or carbon credits.

Table 7: Estimated share of renewable gas supply sources for non-energy use purposes

Supply source of renewable gas for non-energy use in industry in the EU-28	**Current**	**< 5 years**	**2030**	**2050**
			Estimated share of demand	
Physical supply				
Anaerobic digestion	*0%*	*0-10%*	*0-10%*	*0-10%*
Biomass gasification	*0%*	-	*0-10%*	*5-20%*
Power to gas	*0%*	-	*20-40%*	*30-60%*
Administrative supply				
*Climate compensated oils and gases**	*90-100%*	*90-100%*	*20-80%*	*10-65%*

Source: Own assessment

[8] We consider that indirect use of electricity via power to hydrogen/SNG supplies is feasible.

**compensation needed to offset GHG emissions associated with E&P process of (un)conventional oil reserves and fossil gases; and perhaps for GHG emissions associated with the final use of non-energy petro-chemical products like chemical fertilizers*.

We anticipate that climate compensated gases is and will remain a dominant supply route for ‘renewable’ gases for the (petro-)chemical sector in the short- to medium term. Closer to 2050 we assume that sufficient supplies of (physical) renewable gases can be secured, mainly via power-to-gas, followed by biomass gasification (Table 7). The demand for climate compensation also is expected to rely on whether or not this industry (which mainly falls under the EU ETS) will (also) become liable for life-cycle GHG emissions that are linked to the feedstocks they use (e.g. GHG emissions related to exploration and production of oils and gases and/or GHG emissions related to the final use of petrochemical products, such as chemical fertilizers). In addition, there are also relevant life-cycle GHG emissions associated with the supply of ‘physical’ renewable gases via anaerobic digestion and biomass gasification (e.g. ILUC, methane leakage). For life-cycle emissions outside the scope of the EU ETS some form of climate compensation (via carbon credits) seems appropriate.

1.4 Final energy consumption

1.4.1 All sectors

Final energy consumption involves the use of fossil fuels and other resources for energy services in a wide range of sectors, including industry, transport, and other sectors. The ‘other’ sectors include the residential and services sectors as well as agriculture and fisheries, but mainly refers to energy use in buildings (we will refer to this sector as the ‘built environment’). In industry this typically relates to the provision of heating (or cooling), while in transport the energy is mainly used for fuelling trains, planes, trucks and cars.

Table 8 shows that in terms of final energy consumption oils, gases and electricity are dominant energy sources. The built environment is the largest sector of the three with 42% of final energy consumption, followed by transport (33%) and industry (25%) sectors.

Table 8: Energy inputs for energy use purposes in different sectors (% of total)

Final energy consumption in:	**All inputs**	**Of which**	**Solid fuels**	**Oil (total)**	**Gas**	**Renewables**	**Electricity**	**Other**
	share of total energy use	in %-point						
Total	100	←	4,0	39,5	22,2	7,9	21,7	4,7
Industry	25,0	←	3,0	2,5	7,8	2,0	7,9	1,8
Transport	33,2	←	0,0	31,1	0,3	1,2	0,5	0,0
Other (built environment)	41,9	←	1,0	5,9	14,1	4,7	13,3	2,9

Source: (EUROSTAT, 2018)

Given the diverse nature of these three energy end-use sectors, there are many different relevant energy transition options available. However, for these sectors we can assume that a phase-out of coal will not have a substantial impact on the energy systems and infrastructures, as alternative electricity supply options are available. A (gradual) phase-out of oil would have the largest impact on the transport sector. What role (renewable) gases will eventually play in these sectors is dependent on a large number of variables, one of the most significant ones being the level to which the various sectors can switch to electricity, or to the degree to which the built environment can switch to alternative heat supply (e.g. via district heating).

We will discuss the three sectors individually in more detail in the following sections.

1.4.2 Industry

The top-5 industry sectors that consume the largest amount of final energy are the (petro)chemical industry (19%), the iron and steel industry (18%), followed by the non-metallic minerals industry (12%), the paper and pulp industry (12%) and the food and tobacco production (11%). Although, electricity and gas are key energy sources used in the industry sector (about 2/3 share of total final energy in industry), there are specific industries that have a relatively higher dependence on solid fuels, such as the iron and steel sector, or already consume relatively high levels of renewable energy, such as in the pulp, paper and wood industries (Table 9).

Table 9: Energy inputs for energy use purposes in different industry sectors (% of total)

Final energy use in Industry	All inputs	Of which	Solid fuels	Oil (total)	Gas	Re-newables	Elec-tricity	Other
	share of total non-energy use	in %-point						
Iron & steel industry	17,7	←	8,3	0,2	5,3	0,0	3,6	0,2
Chemical and Petrochemical industry	18,6	←	1,1	2,7	6,3	0,2	5,6	2,7
Non-ferrous metal industry	3,5	←	0,1	0,1	1,2	0,0	2,0	0,1
Non-metallic Minerals (Glass, pottery & building mat. Industry)	12,2	←	1,5	2,4	4,6	0,6	2,1	1,0
Transport Equipment	3,1	←	0,1	0,1	1,0	0,0	1,7	0,2
Machinery	6,8	←	0,03	0,39	2,45	0,06	3,66	0,2
Mining and Quarrying	1,2	←	0,07	0,31	0,21	0,03	0,58	0,0
Food and Tobacco	10,7	←	0,44	0,71	5,01	0,41	3,63	0,5
Paper, Pulp and Print	12,2	←	0,37	0,27	2,45	4,68	3,60	0,9
Wood and Wood Products	3,1	←	0,01	0,08	0,23	1,82	0,77	0,2
Construction	2,5	←	0,01	1,22	0,63	0,04	0,62	0,0
Textile and Leather	1,6	←	0,02	0,09	0,75	0,01	0,64	0,1
Non-specified (Industry)	6,8	←	0,14	1,32	0,95	0,34	2,98	1,0

Source: (EUROSTAT, 2018)

A phase out of solid fuels will have the most profound impact on the iron and steel sector, but the sector could switch to electricity and/or (renewable) gases. A significant reduction in oil consumption for energy purposes in industry should be feasible for most industries in the EU-28, as it comprises a relatively small share of their total final energy use (≈10%) and adequate alternative energy supply technologies appear to be available. However, full electrification for all industrial sectors seems unlikely even in the long-term. In the short- to medium terms there should be good opportunities for most industries to consider electricity consuming technologies for upgrading residual/waste heat that is available on site, for example with heat pumps/exchangers.

One sector that should be capable to adopt a higher share of renewables in its energy mix is the food and tobacco sector. In many cases this would relate to the production of biogas via anaerobic digestion of food processing residues. One question for the food sector will eventually be if the produced renewable gas would be used by themselves for energy purposes, or will be supplied for a higher value purpose to another sector (e.g. the petrochemical sector for non-energy applications), or will aim to derive high value bio-based chemicals from their food crops. In case renewable gas supply to third parties is preferred, issues related to gas quality management, gas compression, transport and grid injection will become more important technical aspects in relation to anaerobic digestion.

The (petro)chemical industry already uses a relatively high share of gases in their energy mix, so should technically be able to make a quick transition towards renewable gases. An issue may be how this sector could make the best economic use of the renewable gases: since they can deploy it both for energy and non-energy purposes.

Considering a scenario where solid (fossil) fuels are fully phased out, half of the uptake of oil is replaced and gas use in this sector is 30% reduced relative to current levels, one can estimate the maximum remaining demand for renewables at (34 + 14 + 60=) 108 Mtoe. If about half of this energy demand can be supplied via green electricity and other renewables, estimated demand for renewable gases in this sector would amount to 54 Mtoe by 2050.

Since a substantial part of EU industrial sectors falls under the EU ETS, there is a suitable basis for implementing climate compensation on the short-term while still using conventional natural pipeline gas or imported LNG. On the short term the use of physical renewable gas (on the basis of anaerobic digestion) for energy purposes typically seems promising for the food and tobacco sector, while other industry sector may follow later by taking up physical renewable gases once significant biomass gasification and power-to-gas plants come online.

Table 10: Estimated share of renewable gas supply sources for energy use purposes in industry

Supply source of renewable gas for industry in the EU-28	Current	< 5 years	2030	2050
			Estimated share of demand	
Physical supply				
Anaerobic digestion	*0,2%*	*0-10%*	*0-10%*	*0-10%*
Biomass gasification	*0%*	*-*	*0-10%*	*5-20%*
Power to gas	*0%*	*-*	*20-40%*	*30-60%*
Administrative supply				
*Climate compensated**	*90-100%*	*90-100%*	*20-80%*	*10-65%*

Source: Own assessment

**compensation needed to offset GHG emissions associated with gas use and other life cycle emissions*

So to sum up, for the EU industry we anticipate that climate compensated gases will remain the dominant supply route for 'renewable' gases for the industry sector in the short- to medium term. Closer to 2050 sufficient supplies of (physical) renewable gases may be secured, mainly via power-to-gas, followed by biomass gasification (Table 10). The demand for climate compensation also relies on whether or not industry (which mainly falls under the EU ETS) will become liable for life-cycle GHG emissions that are linked to the feedstocks they use.

1.4.3 Transport

Within the transport sector road transport consumes most of the final energy (82%), followed by international aviation (13%). Other subsectors consume relatively small amounts of energy. While much public attention is paid to electrification of transport and transport systems, its current share in final energy use in transport is still fairly modest at around 1,5%, although the current role of gas in transport is even smaller. Oil still constitutes the bulk energy source for transport, with a share of about 95% of all final energy in transport (Table 11). For road transport, despite serious policy attention at the EU level, renewables (mainly biofuels) still have only a modest share in the energy mix. Considering the options for the different transport modes to switch towards biofuels (including low-GHG gases) road transport would seem to have the least technical and economic barriers. So, how could a scenario for a larger introduction of low-GHG gases in the transport sector look like?

Table 11: Energy inputs for energy use purposes in transport (% of total)

Final energy use in Transport	All inputs	Of which	Solid fuels	Oil (total)	Gas	Re-newa-bles	Elec-tricity	Other
	share of total	in %-point						
Rail	1,7	←	0,0	0,5	0,0	0,0	1,2	0,0
Road	81,7	←	0,0	77,5	0,5	3,8	0,0	0,0
International aviation	12,9	←	0,0	12,9	0,0	0,0	0,0	0,0
Domestic aviation	1,6	←	0,0	1,6	0,0	0,0	0,0	0,0
Domestic Navigation	1,2	←	0,0	1,2	0,0	0,0	0,0	0,0
Pipeline transport	0,5	←	0,00	0,00	0,41	0,00	0,04	0,0
Non-specified (Transport)	0,3	←	0,00	0,08	0,01	0,00	0,21	0,0

Source: (EUROSTAT, 2018)

A 50% phase out of oil scenario will have the most profound impact on road transport, international aviation and shipping. While road transport has realistic switching capabilities for all-electric, gas- and hydrogen fuelled systems, international aviation seems more locked in the use of liquid (bio)fuels. We anticipate that the partial phase-out of oil would be most feasible for rail and road transport, while aviation would lag behind. This means for road transport that - in addition to increasing electric/gas fuelled mobility of passenger vehicles - also long-distance road freight needs to make a faster transition (essentially to allow aviation to make longer use of oil-based fuels). There are several pathways (T&E, 2017) for decarbonizing the land freight. Solutions range from fuel efficiency enhancements, electric trucks[9] and e-highways (Siemens, 2015). Especially the latter one appears to be technically and practically the most feasible, but implementations of several auxiliary technologies (e.g. grid, charging, renewable power) is necessary to substantially lower CO_2 emissions by 2050 (T&E, 2017a). Power-to-jet, a synthesis jet fuel from both hydrogen and carbon dioxide could serve as an alternative fuel for long haul transport by air. Another option is the addition of processed biomass to the jet kerosene. Nonetheless, concrete plans and objectives are momentarily absent, but should be presented in the European Sustainable Aviation Fuel Vision and Roadmap[10]. For shipping, LNG driven vessels (LNG World Shipping News, 2018), but also hydrogen driven vessels are being developed and implemented (World Maritime News, 2018), but also there considerable infrastructure investments are needed and issues regarding fuel energy density in combination with (very) long-distance transport remain.

Considering a scenario where 50% of the oil currently used in transport is phased-out and fully replaced by renewable gases by 2050, we estimate the maximum demand for renewable gases at 173 Mtoe. Assuming that 50% of this demand is met via electricity and other renewables, we estimate net demand for renewable gases for the transport sector at 87 Mtoe by 2050 in the EU-28. For the short to medium term we consider only a marginal additional penetration of renewable gases in transport, due the fact that considerable fuel distribution networks have to be developed, and the existing car park needs to be replaced gradually as well.

[9] https://www.tesla.com/nl_NL/semi

[10] https://www.biofuelsflightpath.eu/index.php/strategy

Since only aviation falls under the EU ETS, there is no broad institutional basis for implementing climate compensation when using conventional transport fuels. Despite market initiatives to voluntary offset carbon emissions in aviation (Zelljadt, 2016) and road transport[11], the key incentive to switch to alternative fuels in transport within the EU stems from the mandatory use of biofuels in road transport. While the relevant EU policies to ensure the use of biofuels in transport also include monitoring and accounting rules to assess GHG emissions savings of fuels supplied to the transport sector, its primary focus is on securing physical supplies of biofuels for transport (i.e. blending). Such physical supplies do not exclude the use of physical renewable gases that are supplied via the gas grid or otherwise in the form of bio-CNG, bio-LNG, hydrogen. Considering that transport fuels have a higher economic value relative to energy use for power and heat generation the transport sector could be economically more attractive for renewable gas suppliers.

A key limitation for supply of renewable gases in transport is the roll-out and availability of suitable transport and distribution infrastructure (e.g. fuel stations), as well as sufficient vehicles that drive on renewable gases. Although physical supplies of renewable gases to the transport sector are preferred, the decentralised nature of the fuel distribution infrastructure would require the sector to also allow administrative transfer of renewable gases via the gas grid when a grid is available (instead of building a dedicated grid or using trucks for distribution). This can be enabled via the transfer of Guarantees of Origin for renewable gases (in combination with appropriate sustainability certification (e.g. ISCC EU, NTA8080 or the like) in case biomass is used as a resource.

Table 12: Estimated share of renewable gas supply sources for energy use purposes in transport

Supply source of renewable gas for transport in the EU-28	Current	< 5 years	2030	2050
			Estimated share of demand	
Physical supply				
Anaerobic digestion	*0,04%*	*0-10%*	*0-10%*	*0-10%*
Biomass gasification	*0%*	*-*	*0-10%*	*5-20%*
Power to gas	*0%*	*-*	*20-40%*	*30-60%*
Administrative supply				
*Climate compensated oils and gases**	*90-100%*	*90-100%*	*20-80%*	*10-65%*

Source: Own assessment

**compensation needed to offset GHG emissions associated with oil/gas use and other life cycle emissions*

Assuming that oil-based transport fuels will retain a large share of the transport market, we consider that climate compensation - mainly with offset credits[12] - for oils/gas use will remain the dominant supply route for 'renewable' energy for transport (Table 12). Closer to 2050 we consider that larger volumes of (physical) renewable gas supplies can be secured, mainly via power-to-gas. This will first enable the substitution of fossil gases, but indirectly can also trigger further expansion of gas-based mobility at the expense of oil.

[11] https://greenseat.nl/

[12] The use of EUAs from the EU ETS systems is less evident since only aviation falls under the scheme, and road transport does not.

1.4.4 Built environment)

Within the built environment most of the final energy (62%) is consumed in the residential sector, followed by the services sector (33%). The other subsectors consume relatively small amounts of energy (Table 13). Gas and electricity are the primary energy sources used with roughly two-thirds of all final energy. Especially, the share of renewables and electricity has grown steadily in the past two decades, while the use of solid fuels and oil has remained stable (or slightly declined). These trends are expected to continue. One of the key challenges for the built environment will be to secure alternative heat supplies. First and foremost this should be done via upgrading the energy performance of the entire building stock; but would also require a (partial) phase-out of natural gas in certain regions in the EU-28. On top of that increased electrification of heat provision is needed as well as expansion of district heating where possible.

Table 13: Energy inputs for energy use purposes in the built environment (% of total)

Final energy use in Transport	All inputs	Of which	Solid fuels	Oil (total)	Gas	Renewa-bles	Elec-tricity	Other
	share of total	in %-point						
Services	32,4	←	0,2	3,4	10,0	1,1	15,7	2,1
Residential	61,4	←	2,1	7,1	22,7	9,8	15,0	4,8
Agriculture / Forestry	5,2	←	0,2	2,8	0,7	0,5	0,9	0,1
Fishing	0,3	←	0,0	0,3	0,0	0,0	0,0	0,0
Non-specified (Other)	0,7	←	0,0	0,4	0,2	0,0	0,0	0,0

Source: (EUROSTAT, 2018)

A near complete phase-out of both solid fuels and oil in the built environment seems viable given the range of alternatives available. Ongoing electrification is also anticipated, but we estimate that this requires several decades before the entire EU-28 building stock is upgraded (e.g. properly insulated and adapted to work with low-temperature heating systems). Moreover, such a transition will be a major challenge because of technical and economic issues regarding the electrification of old (historical) buildings, particularly in large cities. In the intermediate period, (renewable) gases seem a valid transition fuel for this sector. However, we do not anticipate that full electrification of the EU-28 building stock is feasible by 2050 since there are specific regions or buildings (e.g. monuments, heritage sites, churches, etc.) that are not easy to make this transition. For those type of buildings renewable gases or compensated fossil gases appear a viable long-term option.

Considering a scenario where solid and oils are fully phased out in 2050 and gas use in this sector drops by 30% relative to current levels, there will be an energy supply gap for this sector of around 154 Mtoe. Assuming that renewables (e.g. solid biomass or geothermal based district heating systems) and electrification cover 60% of this supply gap, there will remain a need for renewable gases of climate compensated gases of around 65 Mtoe by 2050. This number could be smaller, depending on how ambitious and robust the energy efficiency policies and measures will be.

Since none of these subsectors falls under the EU ETS, there is no robust institutional basis for implementing climate compensation when using natural gas. On top of that, we anticipate that this sector will have difficulties in securing sufficient supplies of physical renewable gases relative to other sectors (e.g. petrochemical sector, transport and industry. This is because the economic value of energy for heating buildings is relatively low compared to other (non-)energy commodities.

Table 14: Estimated share of renewable gas supply sources for energy use purposes in the built environment

Supply source of renewable gas for the built environment in the EU-28	Current	< 5 years	2030	2050

			Estimated share of demand	
Physical supply				
Anaerobic digestion	*0,5%*	*0-10%*	*0-10%*	*0-10%*
Biomass gasification	*0%*	*-*	*0-10%*	*5-20%*
Power to gas	*0%*	*-*	*20-40%*	*30-60%*
Administrative supply				
*Climate compensated oils and gases**	*90-100%*	*90-100%*	*20-80%*	*10-65%*

Source: Own assessment.

**compensation needed to offset GHG emissions associated with gas use and other life cycle emissions also related to production of renewable gases*

Assuming that natural gas will remain a large option in the short- to medium term for the built environment, we consider that climate compensation – mainly with offset credits[13] – will be needed (Table 14). Closer to 2050 we consider that larger volumes of (physical) renewable gas supplies can be secured, mainly via power-to-gas. This will first enable the substitution of fossil gases.

[13] The use of EUAs from the EU ETS systems is less evident since only aviation falls under the scheme, and road transport does not.

2 Disaggregated impacts of the energy transition in EU-28 countries

2.1 Introduction

Although at the EU-28 level the uptake of renewable gases and electrification in the various sectors seems reasonable; such transition might be relatively more challenging on a country-by-country basis. Certain countries or regions in the EU might have a relatively higher dependence on solid fuels like coal, or nuclear and/or have less renewable energy production potential nearby. Hence, for those countries/regions the impact and challenges of the energy transition could be much more severe, and would not only affect their economic competitiveness, but could also increase their import dependence on third countries. In this chapter we will analyse in more detail the implications of the energy transition for various EU-28 countries that have a different profile. Where, for example, some countries will not have an extensive gas grid for easy distribution of renewable gases, others might have large petrochemical industries that serve other EU countries as well and require large supplies of renewable gases or other forms of energy.

The ‘recipe’ for greening of each of these individual economies will likely comprise out of the same ingredients, but these ingredients will probably not be used in a similar composition (i.e. will have a different transition trajectory). A detailed understanding of these country specific dynamic contexts is needed to develop an EU policy mix that is sufficiently harmonised, but also allows for enough flexibility to EU-28 countries to implement the transition trajectory that is most fitting to the specific context.

In the following section we will discuss the implications of certain aspects of the energy transition in the EU-28, and will briefly discuss the potential dynamics for a few EU member states.

2.2 Characterisation / grouping of EU countries

To get a more disaggregated overview we can observe the different phase-out / uptake trajectories for different energy sources for the various EU-28 Member States based on the EU reference scenario (EC, 2016) (Table 15).

The reduction percentages in 2050 (relative to 2015) of use of solid fuels (e.g. coal) range from -48% (Slovakia) to -100% (Portugal). The uptake percentages for renewables range from +17% for Latvia (relative to 2015) to +385% for Malta. For oil, gas and nuclear we see a more mixed picture, where some countries are considered to increase uptake, while others decrease. Anticipated gas uptake is particularly high in Malta, Cyprus, Sweden and Poland, while estimated gas phase-out is considerable for Portugal, Estonia, Latvia, Spain and the United Kingdom. A full nuclear phase-out by 2050 is envisaged in Belgium, Germany and the Netherlands, while Finland, the United Kingdom, and a range of Eastern European countries are expected to significantly increase their nuclear capacity.

Table 15: Envisaged phase-out / uptake of solids, oil, gas, nuclear and renewables in EU-28 counties in 2050 (in % relative to 2015), see also Annex 1.

	GFI	SOLIDS	OIL	GASES	NUCLEAR	RENEWABLES
EU28	-10	-70	-16	-2	-23	83
AT	-3	-64	-13	21	-	25
BE	-4	-68	-6	33	-100	82
BG	-7	-53	-7	1	14	98
HR	0	-97	-13	20	-	71
CY	5	-79	-35	>300	-	167
CZ	-2	-63	9	-1	78	63
DK	2	-96	-13	-12	-	97
EE	-22	-55	-7	-25	-	67
FI	-5	-78	-27	-16	55	20
FR	-19	-76	-16	-14	-49	111
DE	-21	-52	-28	-8	-100	76
EL	-28	-99	-33	21	-	129
HU	17	-90	21	3	82	132
IE	3	-93	1	-6	-	214
IT	-9	-90	-27	4	-	79
LV	4	-81	3	-6	-	17
LT	13	-88	-19	-22	>300	70
LU	36	-92	24	66	-	132
MT	22	-	-42	>300	-	385
NL	-11	-88	-9	-12	-100	231
PL	8	-62	8	86	>300	126
PT	-17	-100	-13	-44	-	39
RO	12	-65	7	10	103	58
SK	12	-48	8	0	60	99
SI	-1	-99	-16	45	52	60
ES	-16	-96	-9	-19	-100	121
SE	3	-79	-14	271	-3	20
UK	-10	-94	-19	-17	99	145

Source: (EC, EU Reference Scenario 2016 - Energy, Transport and GHG Emissions Trends to 2050, 2016)

2.3 Nuclear phase-in and phase-out

From an energy systems transition perspective a nuclear phase-out will be most problematic for countries with very high shares of nuclear like Sweden and France. But also a range of Eastern European countries, like Bulgaria, Slovenia, Slovakia, Hungary, Estonia, Romania and the Czech Republic will face a considerable challenge (EUROSTAT, 2018). Finland the United Kingdom and Belgium also appear to be strongly committed to continuing the use of nuclear, similar to a range of Eastern European countries that are considered to expand their nuclear capacities. One of the key political challenges if and when pursuing a (partial) nuclear phase-out in the EU-28 will be to also convince countries with substantial nuclear capacity to follow this, as the energy transition for both the electricity system and the supply of renewable gases (via power to gas), as well as the electrification of various end-use sectors is vital to the success of future decarbonisation actions. For example in Sweden, a (partial) nuclear phase-out, with its associated buy-out, decommissioning, clean-up and afterlife costs, valuable (economic) resources might be diverted away from investments in other sectors, such as the electrification of (heavy) road transport. Also with nuclear having a relatively low GHG impact, it will likely be perceived as an interesting 'Paris Agreement friendly' supply source of electricity.

2.4 Phase out of solid fuels

Based upon current shares of solid fuels (mainly coal) in gross inland consumption in the EU-28 countries, we anticipate that a phase-out strategy will be most challenging (from a technological, economic and political perspective) for a range of Eastern European countries, including Estonia, Poland, Czech Republic, Bulgaria, Slovakia, Slovenia, Romania (EUROSTAT, 2018). In these countries the use coal is often associated with energy security of supply and employment. Making a switch to natural gas will be challenging in this region which is already has a high level of import dependence. Also securing adequate supplies of renewable gases instead will be challenging in this region as the capacities of intermittent power generation – which can be used to generate renewable gases - are lagging behind with the other regions in the EU-28. Statistics (2016) from Wind Europe (WindEurope, 2017) indicate that the North sea country region alone hosts about 75% of total installed wind capacity in the EU-28. This lag reduces the scope for quickly upscaling the use of power-to-gas as a supply option in that region. And with several North sea countries like Germany and the Netherlands already aiming for a coal phase-out, and a L-gas phase-out in the Netherlands, and with sizable petrochemical industries we anticipate no shortage in demand for renewable gases in the North sea region. As a result those countries would likely 'block' excess supplies of renewable electricity or derived renewable gas supplies to Eastern Europe to reduce/alleviate their import dependence of natural gas. Sticking to coal might therefore be perceived as the most secure political strategy. One other alternative for, most Eastern European countries would be to increase supplies of renewable gases by means of gasification of biomass. Most Eastern European countries have a relatively good position in terms of domestic availability of solid biomass which can be used for gasification instead of direct co-firing of solid biomass. However, due to local availability of cheap coal and related infrastructures, developing a viable business case for biomass gasification will very challenging and is likely to require additional support.

In similar fashion, a phase-out of solid fuels in Finland and Ireland is also challenging due the fact that these two countries make considerable use of domestically produced peat (resp. 30% and 36% of total solid fuels). Both countries consume little over 90% of all peat in the EU-28. We consider that those EU-28 countries with a small (>5% of gross final energy demand) of solid fuels should be capable of fully phasing out coal before 2030. Quite a few of the EU-28 countries with a modest share of coal in their energy mix (>5% - 13%), such as the Netherlands, United Kingdom, Portugal, Denmark, Spain, Croatia,[14] also appear to be countries with relatively modest domestic biomass potentials, but would have good access to nearby offshore wind, and thus would have a better position to switch quicker to renewable gases from power-to-gas.

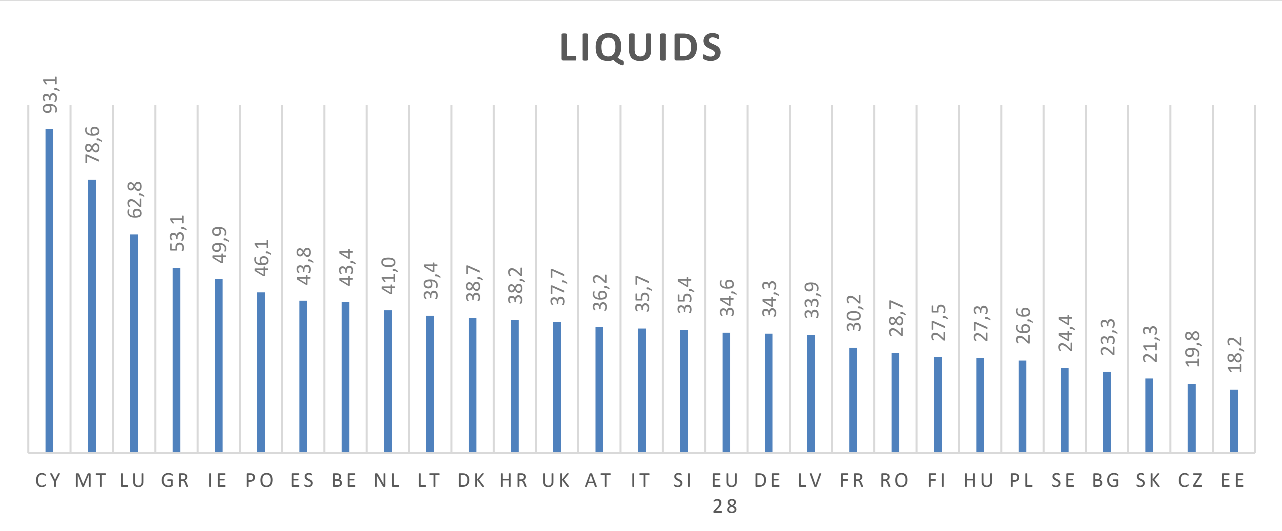
[14] With land locked countries Austria and Hungary perhaps being the exception.

2.5 Partial phase out of oil

A partial phase-out of oils in the transport sector (both for road transport and aviation) can be considered a generic challenge with similar impacts throughout the EU-28 countries. However, substitution of oil in other non-transport sectors, like the petrochemical sector, industry and the built environment will have a more country-specific impact.

Current shares of oil in gross final energy consumption shows that particularly Cyprus, Malta and perhaps some of the Greek Islands would be challenged with a partial phase-out of oil (Figure 5). This is because these economies are less diversified and their energy systems are still often mainly rely on imported oil for provision of heat and power in the industrial sector and the built environment. Important design question for the energy systems for these countries is if their transport system should fully switch to non-liquid (e.g. all-electric options), while their current power and transport system still is dedicated to liquids. Either going all-electric in all sectors at once might makes sense of going for all (bio-)liquids could also be an option. The scope for renewable gases in those countries seem dependent on nearshore availability of offshore natural gas production and transport infrastructure.

Figure 5: Share of oil in gross final energy in EU-28 member states (2016)



Source: (EUROSTAT, 2018)

There is also a range of countries in the EU-28 that would have a greater challenge to reduce the use of oil for non-energy use in their petrochemical sector. These are countries that currently have low shares of gases used in this sector, and rely heavily liquid and solid fuels might not be able to make a fast transition. This is partly because the current low use of gases in this industry would require substantial additional (infrastructure) investments to enable the use of renewable gases. These countries include: Cyprus, Denmark, Estonia, Ireland, Latvia, Luxembourg, Malta and Portugal. Of these countries, particularly Cyprus, Estonia, and Malta do not have a significant domestic gas sector, as their share of gas in gross inland consumption is very low (<7%). The other countries mentioned should be considered capable to (partially) redirect gas flows from for example the built environment to the petrochemical sector (via a partial phase-out of gases).

A subset of mainly Eastern European countries appear very well suited to further phase out the use of oil in the petrochemical sector, as their current shares of gas is already quite high (>24%). These countries include: Bulgaria, Croatia, Greece, Hungary, Lithuania, Poland, Romania and Slovakia. The key challenge for this sector in these countries will be to secure sufficient supplies of (renewable) gases since they have only limited indigenous gas resources available (and electrification of this sector is not a realistic option).

The remaining EU-28 countries, which mainly includes countries from the north, west and southwest of European countries, do also have a foothold for expanding the use of gases in this sector (2–17% gas share), but are considered to be faced with the problem of securing sufficient supplies of renewable gases. This subset of countries includes the top-7 EU-28 countries with the largest refinery throughout 2017. These include Germany, Italy, Spain, the Netherlands, France, the United Kingdom, and Belgium. The sheer size of the petrochemical sector in these countries makes the transition towards renewable gases so challenging.

2.6 Gas consumption

Based upon current shares of gases in EU-28 countries (EUROSTAT, 2018) we can assume that most EU-28 countries have at least some level of domestic expertise and experience with building, maintaining and operating gas infrastructure and related technologies. Although future gas consumption in the EU-28 is considered to remain at current levels, the energy transition is likely to cause a shift in (renewable) gas demand levels per sector. With indigenous gas production declining and increasing imports from non-EU countries there will be a driver to better rationalise gas use in the EU. Particularly low-economic value, high volume uses of (renewable) gases, such as for heating in the residential sector or power generation are likely to be scrutinised as valid alternatives for heat and power are available.

Already in some EU country regions in the EU-28 that are importing considerable volumes of low-calorific (L-gas) from the Netherlands, are developing plans for a (partial / full) phase-out of L- gas used in certain industries and the built environment. This is a direct result of the declining production of natural gas from the large Groningen gas field, which is declining faster than initially anticipated as a result of a government decision. Rational use of limited indigenous or imported supplies of gas will provide a common challenge to virtually all EU-28 countries (except for Cyprus, Malta and other small islands) to limit the use of gas for low value – high volume end uses such as for space heating and power generation. In addition to that there will be a common need to expand the use of (renewable) gases in the transport and petrochemical sector. Overall the share of gases in transport in EU-28 countries is still very low, but countries like Slovakia, Bulgaria, Italy, Austria, Poland, Hungary, Spain, Czech Republic and Germany have already developed a considerable niche market for gases in this sector. This experience should enable these countries to more swiftly scale-up gas use in this market relative to other EU-28 countries.

2.7 Phase-in of renewables

The renewable share of gross inland consumption differs substantially across the EU-28 countries ranging from 3.4% for Malta to 37.1% for Sweden (Table 16). The countries that already a substantial share of renewable energy, such as Sweden, Latvia and Finland (>30%) are characterised by having access to solid biomass and often also have significant hydro power potential. Denmark, Poland, Croatia and Lithuania’s gross inland consumption is for between 20%-30% composed of renewables. Followed by Romania, Italy, Slovenia, Estonia, Spain, Germany, Hungary, Greece, Bulgaria and the Czech Republic. Interestingly, foremost Italy, but also Slovenia, use a substantial amount of renewable energy originated from geothermic sources. Alternatively, Greece and Spain source a significant share of their renewable energy from solar thermal. Hungary consumes relatively large amounts of bio gasoline, whereas Germany consumes by far the largest amount of biogas, which is roughly 8 Mtoe. The remaining countries display a relatively low share of renewable energy in their gross inland consumption (<10%).

Table 16: Share of renewables in gross final energy consumption and estimated increase in renewables in 2050 relative to 2015 (in%)

	Current share (2016) of Gross final energy	Increase % in 2050 relative to 2015
EU28	13.2	83
AT	29.7	25
BE	6.3	82
BG	10.7	98
HR	23.3	71
CY	6.3	167
CZ	10.3	63
DK	28.7	97
EE	15.5	67
FI	30.1	20
FR	9.9	111
DE	12.3	76
EL	10.9	129
HU	11.7	132
IE	7.5	214
IT	16.8	79
LV	37.0	17
LT	20.8	70
LU	5.3	132
MT	3.4	385
NL	4.7	231
PL	8.8	126
PT	24.1	39
RO	19.1	58
SK	9.6	99
SI	16.5	60
ES	14.3	121
SE	37.1	20
UK	8.1	145
Source	(EUROSTAT, 2018)	(EC, 2016)

Based on the EU reference scenarios data (EC, 2016)(Table 16), there are a range of EU-28 countries with sizable economies, such as France, Spain, the Netherlands, the United Kingdom, Poland, and Ireland that require to increase their renewable energy output in 2050 with triple-digit growth rates relative to 2015. Also some smaller EU countries like Malta, Cyprus, Luxemburg, Bulgaria and the Slovak Republic face such a challenge. The envisaged energy transition and phase-in of renewables will particularly be challenging for EU countries with smaller land-mass, and low indigenous hydro-power and biomass potentials. For such countries intermittent renewables will preferred options, although these have considerable spatial implications.

3 Disaggregated impacts of the energy transition selected EU Member States

3.1 Introduction

In this chapter we explore from a more disaggregated level (i.e. bottom-up perspective) the implications and dynamics of the energy transition on future demand for (renewable) gases for a selection of EU Member states. The following four EU countries are considered: the Netherlands, Poland, Sweden, and Italy. This sample of EU countries were selected due to their different energy profiles, natural resource endowments, while trying to obtain a sufficient geographical spread.

3.2 The Netherlands

3.2.1 Current and theoretical future energy demand for (renewable) gas

The gross inland energy consumption (2016) in the Netherlands amounted to 79 Mtoe (EUROSTAT, 2018). Some 38% of the gross inland consumption was met with fossil gases which is fairly compared to the EU-28 average (23%). In the National Energy Scenarios study (‘Nationale Energieverkenning’) (ECN, 2017) anticipates that due to both energy efficiency and policy measures, final energy consumption decreases with more than 4% in 2020, and nearly 8% in 2030 (compared to 2016 levels). This implies a gross inland energy consumption of 68 mtoe in 2030.

Netherlands currently still is a net exporter of gas, but this is expected to change in the near future due to declining domestic gas reserves and the 2018 decision on gas production from the Groningen field (EZK, 2018) to terminate gas production from the large Groningen gas-field (resulting from increasing occurrence of induced earthquakes in the Province of Groningen). Demand for gas is currently predominantly met through domestically produced natural gas (36,5 Mtoe produced in 2016). However, declining domestic production (12,7 Mtoe indigenous gas production anticipated in 2030) the Netherlands is expected to substantially increase its gas imports in the coming two decades (34,6 Mtoe imports in 2030 anticipated) (ECN, 2017).

In an overall declining domestic gas market, it will be challenging to increase the uptake of renewable gases. This is particularly challenging for the use of gases (Table 17) for electricity production (-69% reduced use of gas), as well as gas use for energy purposes in industry and the built environment (-22% gas use) where policies are in place to phase-out the use of low-calorific gas from the Groningen gas field. Given that the National Energy Scenario’s study (ECN, 2017) estimates that the Netherlands is expected to become a net exporter of electricity by 2023, we can assume that there are high ambitions (and scope) for increased electrification of heating, particularly in these two sectors for 2030. The only sector where the (ECN, 2017) expects an increase in gas use is in the petrochemical sector (+7% gas use by 2030).

Table 17: Current and future demand of gas in the Netherlands (in Mtoe)

	Current (2016)	Future (2030)	Reduction
Gross inland consumption	79	68	-14%
Total gas consumption	30	19	-37%
Gas used for electricity production	9,4	2,9	-69%
Gas used for non-energy purposes	2,1	2,2	+7%
Gas used for final energy use	16,5	12,9	-22%

Source: (ECN, 2017)

3.2.2 Transformation sector (power + heat)

The power and heat sector is one the sectors where the energy transition is most advanced, with at least triple digit growth rates for gross renewable electricity production in the 2000-2016 period (+525%). Particularly wind and solar have grown rapidly in that period (Table 18).

Table 18: Past and required growth rates for renewable electricity generation (in mln. kWh)

	2000	2016	2000-16 past growth	2016-30 growth needed*
Biomass	2019	5068	+251%	+200%
Wind	744	8384	+1122%	+842%
Solar	8	1555	+19.438%	+891%
Renewable electricity	2871	15069	+525%	+575%

Source: (CBS, 2017)
**to meet (ECN, 2017) scenario*

However, despite this considerable growth, according to the (ECN, 2017) scenarios also triple digit growth rates are needed to meet 2030 policy objectives. Key challenges resulting from this ambition are linked to the anticipated increase in use of biomass for electricity generation[15], as well as the expansion of onshore wind and solar pv, which already face increasing social opposition due to their spatial impact. Offshore wind power appears to have the ‘best cards in hand’ to enable future expansion of renewable electricity production in the Netherlands (and thus to ensure minimal use of natural gas in this sector). While (ECN, 2017) assumes a modest overall reduction in final electricity consumption (-2,2% for the 2016-30 period), the more recent National Climate Agreement (‘Klimaatakkoord’) considers an increased use of electricity due to electrification of various sectors ranging from 12 to 38 TWh up to 2030 (or 1 and 3,3 Mtoe resp.). A failure to meet these growth rates would not only result in an increased demand for (renewable) gas in the power sector, but also would reduce any potential for upscaling future renewable gas supplies via the power-to-gas route.

3.2.3 Final non-energy consumption

While electrification of energy use makes sense in many other sectors, the sectors where energy commodities are used to produce products, like plastics and fertilizers will remain reliant on (renewable) molecules. While (ECN, 2017) anticipates a modest increase in the use of gas in this sector it also estimates that oil will remain the dominant fuel used in the petrochemical sector (84%), followed by gases (15%) and coal (1%). This 2030 projection is more or less consistent with the current situation where final non-energy use in the Netherlands accounts for 14 Mtoe (EUROSTAT, 2018), which predominantly relates to the (petro)chemical industry. It is composed of 86% oil and 14% gas, making it a sizable sector of the fossil energy use in the Netherlands. This all is a sign that – at least according to the (ECN, 2017) scenario studies – it is unlikely that there will occur a radical transition within this sector.

[15] There is aimed for closure of less-efficient coal-fired plants. Yet, another controversial CO_2 reducing option, is the substitution of coal by (solid) biomass in conventional power plants. However, the extent to which biomass is allowed to play a role in the renewable energy goals, is 25 PJ (roughly 1.4 percentage point in the 14% renewable energy objective in 2020). Simultaneously, this is the maximal amount that conventional power plants receive subsidy for. Balanced against alternatives, CE Delft (2016) concluded that co-firing of biomass is not a favorable option.

If we look at the VNCI roadmap for 2050 (Ecofys, 2018) the report considers a combination of three basic development options as part of their transition strategy. The preferred transition pathway involves a combination of 1) the use of ‘circular and bio-based’ feedstocks, 2) ‘electrification’ (i.e. hydrogen produced based on electrolysis with renewable electricity mainly from offshore wind), and 3) ‘carbon capture reuse and storage’. This pathway (Table 19) would require the use of 6,7 Mtoe (280 PJ) of biomass, and 4,1 Mtoe (170 PJ) renewable electricity to produce 1,72 Mtoe (or 72 PJ) of hydrogen in 2050 (and 3,34 Mtoe / 140 PJ of biomass in 2030).

Table 19: Use of biomass and renewable electricity in VNCI 2050 roadmap

	2030	2050
Non-energetic use		
Use of biomass	140 PJ	280 PJ
Use of renewable or GHG-free electricity	-	170 PJ*
Energetic use		
Renewable energy; electric boilers	0 PJ	35 PJ
Renewable energy; geothermal	0 PJ	30 PJ

Source: (Ecofys, 2018)
**Corresponds to 11,4 GW of offshore wind, is equivalent to 72 PJ or 600 Kton of* H_2

This preferred pathway suggests that the use of renewable electricity for H_2 or SNG production is anticipated to develop only after 2030. Current (2016) use of biomass and electricity in this sector is around 0,02 Mtoe (1PJ), and 1 Mtoe (42 PJ) resp. (EUROSTAT, 2018), but this largely relates to its use for energy purposes. (ECN, 2017) considers its use by 2030 to increase to 0,14 Mtoe (6 PJ) and 0,93 Mtoe (39 PJ) resp.

The numbers particularly on biomass use (but also when biomass and electricity are combined) show a considerable gap between (ECN, 2017) projections and (Ecofys, 2018) projections for both 2030 and 2050. Where (ECN, 2017) considers a total aggregate biomass use in the Netherlands of a little over 3,1 Mtoe (130 PJ) for all applications, the (Ecofys, 2018) VNCI preferred pathway alone would require the use of 3,34 (140 PJ) of biomass for the petrochemical sector alone by 2030. It will be no surprise that this will ensure considerable competition for scarce biomass resources, which in the case of the Netherlands will require massive biomass imports.

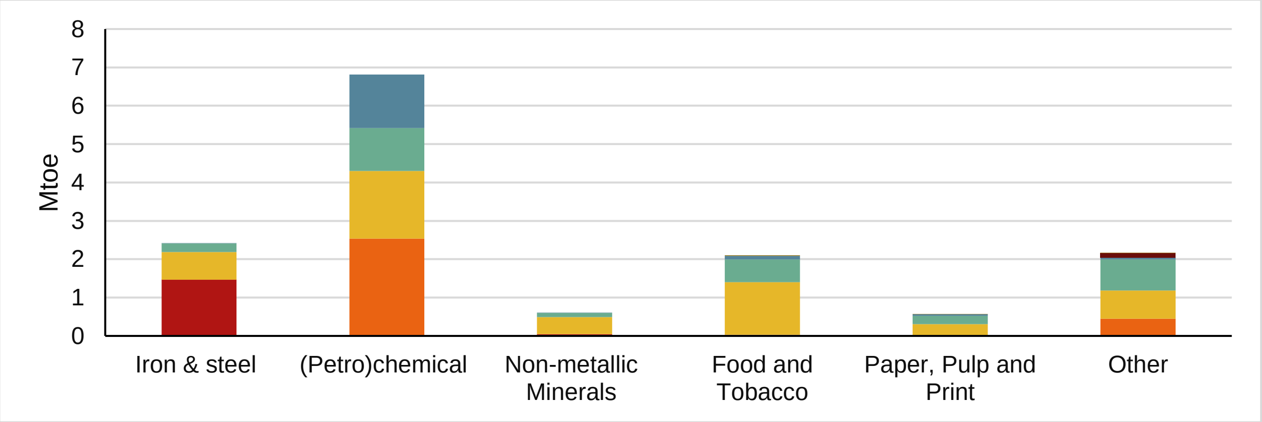
One way to reduce the pressure on the increasing use of biomass will be to more rapidly develop and expand the power-to-gas option. As (ECN, 2017) considers that by 2023 the Netherlands is expected to become a net exporter of electricity, these net exports can also be used to supply the petrochemical sector extra renewable H_2 / SNG already by 2030. The key challenge here will be that the power-to-gas option will have to mature and reach commercial status well before 2030. Speeding up power to gas would also require a fast-track or increase in ambitions for the power sector. (ECN, 2017) currently considers gas demand in this sector to expand by about 0,1 Mtoe (4 PJ) in 2030 relative to 2016. However, expanding this to a level that matches for example of 50% of anticipated biomass use for non-energy purposes by 2030 in the VNCI scenario would be a massive effort, considering that this would imply that an additional power-to-gas of 1,67 Mtoe (or 70 PJ) would be needed, which in terms of electricity generating capacity would be even more, considering conversion losses in the electrolysis process.

3.2.4 Final energy consumption

3.2.4.1 Industry

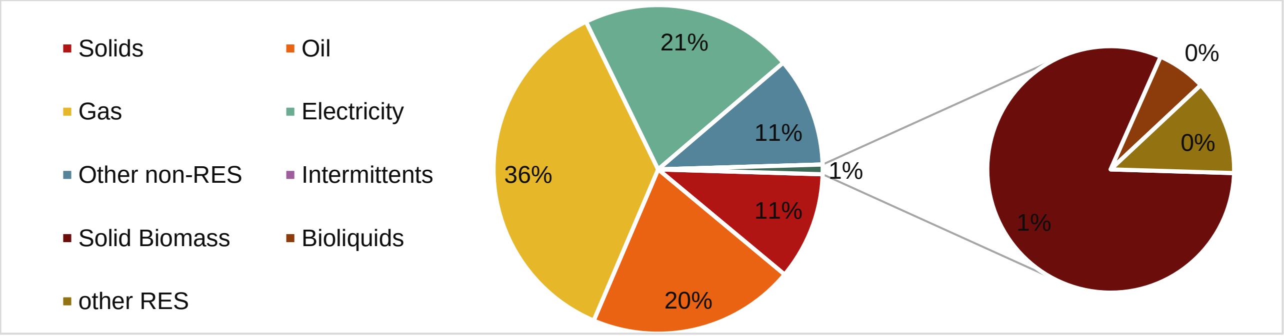
The industry sector currently (2016) accounts for roughly 20% (15 Mtoe) of gross inland energy consumption in the Netherlands (EUROSTAT, 2018). For energy purposes this sector makes most use of natural gas (36%), followed by electricity, oil and other non-RES, such as heat (Figure 7). The share of electricity in the industrial final energy consumption (21%), is relatively low compared to the EU-28 average (31%), while its use of oil is still relatively high (20%) compared to the EU-28 average (10%). This should provide scope for increasing the share of electricity use while reducing the share of oil used for energy purposes in industry (mainly relates to the petrochemical industry). There is also scope for substituting solid fuels (i.e. less coal, more electricity) in the iron and steel sector as they have a relatively high share of coal used (61%) relative to EU-28 average (47%), while current share of electricity (10%) is low relative to the EU-28 average (20%).

Figure 6: Final energy consumption in industrial sectors



Source: (EUROSTAT, 2018)

Figure 7: Final energy consumption by energy source, in all industry sectors



Source: (EUROSTAT, 2018)

Expanding the use of natural gas or renewable gases should also be feasible in Dutch industry, but from a climate change mitigation perspective it is expected that both the iron and steel and the pet-rochemical sector would have a stronger interest to start phasing out solid and liquid fossil fuels first. However, the other industrial sub-sectors (including food and tobacco, paper and pulp, as well as non-metallic minerals), which have a relatively high dependency on natural gas (Figure 6), are even more prone to exercise demand for renewable gases in the short term. It is these sub-sectors where considerable quantities of low-calorific gas (L-gas) from the Groningen gas field are still used.

A recent (2018) letter from the Minister of Economic Affairs and Climate (EZK, 2018) calls upon the phase out of use of L-gas already by 2022 at about 200 industrial companies.[16] L-gas intake in industry comprises about 4,62 Mtoe (5,5 bcm), which – according to the Ministerial Letter should be phased-out (i.e. replaced) by 2022. In the short run (<5 years) this will most likely comprise a switch from L-gas to high-calorific gas (H-gas) blended with nitrogen to meet the technical specifications of the L-gas grid and combustion appliances. A fast-track phase-in from low-calorific renewable gases would also be possible, but it is unlikely that such volumes of biogas will come online already before 2022. To compare current (2016) total domestic biogas production in the Netherlands comprises 0,31 Mtoe (13.000 TJ) (CBS, 2017)[17], which is considerably less than the 4,62 Mtoe needed by 2022.

While the food and tobacco and the pulp and paper industry appear to have a somewhat better position for switching to resp. biogas and solid biomass[18] (and perhaps increase the use of electricity for recycling and upcycling of waste heat), the non-metallic minerals industry (e.g. including bricks, roof tiles, glass, etc.) appears to have little viable short-term alternatives to L-gas use. For example, the brick and tile factories (i.e. there are about 30 ceramics factories in the Netherlands) - which are mainly located in the Eastern to Southeastern part of the Netherlands - require carbon containing (renewable) gases in their combustion processes (so pure hydrogen would not suffice). Securing supplies of H-gas blended with nitrogen would be a viable short-term solution. Direct supplies of H-gas are not viable on very short term, since dedicated H-gas pipeline and distribution infrastructure would need to be constructed. Supplies of carbon containing renewable gases at L-gas specifications would be a good alternative, provided sufficient volumes can be produced and supplied in time. The last resort strategy would be to terminate the ceramics industry within the Netherlands that currently provides 2.000 direct jobs; but that could result in ‘carbon leakage’ as the ceramics industry could grow in another country.

Table 20: Implications of change in energy mix in industry by 2030 (in Mtoe)

	Current energy use	Assumed change in use by 2030	2030	L-gas phase out
Gas use	5,5	-22%	4,1	-4,1 (already in 2022)
Solid fuels	1,5	-100%	0	
Liquid fuels	3	-50%	1,5	
Electricity	3	+100%	6	
Others	2,2	+50%	3,3	
Total	15		14,9	10,8

[16] https://www.ftm.nl/artikelen/dit-zijn-de-200-grootgebruikers-van-gronings-gas?share=1

[17] This includes biogas from landfills, waste- and sewer water treatment facilities, manure co-digestion, and digestion of organic wastes and food processing residues.

[18] The food and tobacco sector in the Netherlands is one of the largest producers of biogas or biomethane. This biogas is produced with the help of anaerobic digestion of food processing residues. However, most of that biogas is not consumed within industry, but used for space heating in the build environment. The main reason for the sector to not self-consume more of their produced biomethane is due the principles of the feed-in premium subsidy scheme (SDE+) which demands the energy produced to be injected into the public grid. On top of that combining the SDE+ subsidy scheme with receiving EU allowances for free under the EU ETS (as many of these industries are deemed exposed to a significant risk of carbon leakage), is problematic from a state aid perspective.

Considering Table 20 we see that gas use for energy purposes in is dominant with 5,5 Mtoe. Of this 5,5 Mtoe, about 4,6 Mtoe is L-gas which is expected to be phased out by 2020. Even if we consider that gas use for energy purposes in industry will reduce with 22% by 2030 according to (ECN, 2017) (see Table 14), and we consider that electrification (a 100% increase relative to current levels) and derived heat (‘other’ +50%) will fill in the ‘gap’ resulting from the phase-out of coal (-100%) and oil (-50%), there still remains a short term gap of 4,1 Mtoe of L-gas demand that need to be substituted before 2022.

3.2.4.2 Transport

The transport sector is traditionally heavily reliant on liquid fuels, particularly oil. An increasing, but still modest share of biofuels is observed as a result from EU level biofuels policies (EC, 2009). About 1.8% of the transport’s energy demand in the Netherlands is satisfied by biofuels, which is significantly below the EU-28 average of 3.7%. About 69% of energy demand in this sector comprises road transport, and 27% of energy demand in aviation (EUROSTAT, 2018). Rail and other transport sub-sectors make for the remaining 4% final energy use. Currently, aviation in the Netherlands is 100% dependent on fossil oil derived fuels. Road transport still has a share of oil-based fuels of 97%, but aside from liquid biofuels (which are only used in road transport) also some other alternatives are entering the road transport market (electricity 0,25%, and natural gas 0,43%), although they are still small niche markets.

Concrete goals for the transport sector were established in the Energy Agreement (SER, 2013), such as, that all cars sold after 2035 should be capable of zero emission performance. Significant enhancements have to be made in order to comply with the goal of 40% less fossil fuel use in 2050 (EC, 2011). For now, electrification of the long distance transport, either by air, road or water, is considered as unfeasible (EZK, 2017). Hence, biofuels will be needed in the heavy road transport, as well as in aviation and the shipping sector as described above. As opposed to passenger transport, buses and other urban logistics, which are eligible for electrification. Complying with the prescribed objectives of the Energy Agreement means that there should be approximately 3 million zero-emission vehicles in use by 2030 (SER, 2014). Another promising technology is driving using hydrogen as a fuel. The first fuel-cell powered electric vehicles are appearing, together with hydrogen filling stations, and could be a long term viable solution. Final energy consumption in domestic transport is expected to be 486 PJ (EZK, 2017) in 2030, whereas it is 771 PJ for international transport by air and sea. This implies that domestic transport’s energy consumption will slightly decrease, while international transport’s energy use will increase.

The shipping sector aims at a transition towards LNG and sustainable biofuels for short-sea and inland shipping (KNVR, 2012). Until 2030, the shipping sector expects to primarily use biodiesel, after which LNG possible can be substituted by bio-LNG towards 2050. In the rail sector, a similar transition is desired, mainly by greening the railways that are not electrified yet. Furthermore, the upper voltage was raised from 1.5 KV to 3 KV. This paves the way for intensifying rail use, more efficient energy use and hints on further expansion of sustainable electricity use. Alternatively, hydrogen can be used by trains in areas where the rail is not electrified yet.[19] Aviation can benefit from improvements in technological, operational and infrastructure areas. Furthermore, bio-kerosene, a mixture between conventional kerosene and biomass, could be a promising fuel alternative for airplanes. Several projections have been made regarding future biofuel use in aviation, among which a 26% forecast in 2050 (IEA, 2010). The road sector has several options for deep decarbonization,

[19] https://www.spoorpro.nl/materieel/2018/05/31/waterstoftrein-rijdt-begin-2019-tussen-groningen-en-leeuwarden/

such as electrification, hydrogen, biofuels and biogas. The latter one refers to bio-LNG, power-to-gas methane, power-to-gas Synthetic (SNG), but also bio-LPG.

The Energy Agreement (SER, 2013) – in which both private and public actors active in the transport took part – resulted in a strategy for sustainable fuels in transport ('Duurzame Brandstofvisie') (SER, 2014). This strategy aims for the implementation of alternative fuels in road, rail, shipping and aviation. Relevant alternative fuels for the transport sector include, electricity, liquid biofuels, LNG, renewable gases, and hydrogen.

Table 21: Assessment of alternative future energy options in transport

	Road (heavy)	Road (passenger)	Rail	Shipping (inland / coastal)	Aviation
Mtoe energy use (2016)	3,46	6,44	0,17	0,95	3,9
Alternative fuel option preferences					
Electricity	++++	++++	++	+	-
Liquid biofuels	++++	++++	++	++	+++
LNG	+++	-	++	+++	-
Renewable gases	++*	++*	+	+++	-
Hydrogen	++++	++++	++	+	-

Source: Based on (SER, 2014)

**Renewable gases in road transport are perceived as a transition fuel, before hydrogen fuel cells enter the market in combination with electric vehicles.*

Table 21 is an own assessment based on the vision documents prepared by the various 'fuel tables' (included tables on hydrogen, electricity, renewable gases, and biofuels) that provided input to the sustainable fuels in transport strategy (SER, 2014). Table 21 also shows current energy use in the various subsectors (in Mtoe). Aside from pilot and experimental projects, aviation appears to have an interest to expand the use of liquid biofuels, as not much other alternative fuels are considered. Heavy road transport appears suitable for a broad range of alternative fuels, while passenger vehicles currently are mainly using biofuels, the share of electricity and hydrogen is anticipated to increase. However, only a modest role for renewable gases (other than pure hydrogen) in Dutch mobility is foreseen, with renewable gases in road transport labelled as a temporary or intermediary solution; and shipping being considered as a more robust long-term end-use market for non-pure H_2 renewable gases. In relation to hydrogen, the 'hydrogen table' stakeholders indicated that the 2020-25 period will focus on (early) introduction of hydrogen vehicles, and required auxiliary hydrogen distribution infrastructure. They intend to initially target niche markets, such as buses and special purpose vehicles (e.g. garbage trucks, street sweepers, vans, urban distribution trucks). The 2025-30 period would focus on full scale market introduction, also for hydrogen fuel cell vehicles.

Despite these ambitions and strategies we anticipate that demand for renewable gases including hydrogen in transport up to 2030 will remain limited. Also after that (up to 2050), the Dutch road transport sector seems headed towards using a mix of mainly biofuels, electricity and hydrogen (in volume terms). Carbon containing renewable gases appear only viable in a few niche markets, such as shipping and long-distance road cargo transport.

3.2.4.3 Built environment

This sector comprises several sub-sectors, but mainly comprises energy use in commercial, public or private buildings (20,5 Mtoe in 2016). Natural gas used for space heating and cooking consumes most of this energy (12,5 Mtoe), followed by electricity (5,8 Mtoe) use for lighting/appliances and cooling. The remaining 2,2 Mtoe comprises a mix of diesel, solid biomass, derived heat, and LPG

(ECN, 2017). Most buildings in the Netherlands are connected to the L-gas grid, and have appliances suitable only for low-calorific gas. With the decision of the central government to terminate L-gas production from the Groningen gas field no later than 2030 (EZK, 2018), this sector is confronted with a high ambition not to just reduce the use of gas, but to gradually phase-out the use of L-gas and switch to alternative forms of energy.

Specific measures to reduce the use of L-gas in the built environment include (EZK, 2018a):
- New builds will no longer be connected to the gas grid
- 30-50.000 existing buildings per year will be disconnected from the L-gas grid as per 2021, and after 2021, 200.000 buildings per year will be disconnected
- Initiative to phase-out the sale of gas boilers

The Netherlands Environment Assessment Agency (PBL), estimated that – based on implementing all cost-effective measures – to get to a 49% CO_2-reduction, the built environment could reduce its consumption of L-gas by 0,34 to 1,51 Mtoe by 2030 (EZK, 2018a). With a current overall L-gas demand of 12,5 Mtoe in this sector, we can observe that natural gas will remain the dominant energy carrier until (at least) 2035, despite the increased importance of heat pumps, which are estimated to consume 0,33 Mtoe (14 PJ) of electricity by that time (ECN, 2017). In total, it is estimated that there will remain a demand of approximately 6,93 Mtoe (290 PJ) of gas, 5,02 Mtoe (210 PJ) of electricity and 0,6 Mtoe (25 PJ) of heat in 2035 for the built environment (ECN, 2017). Gas supplies by 2030-35 will predominantly be H-gas converted to L-gas specifications, and a modest share of renewable gases. A positive development in this context is that hydrogen might also be considered as a recent study (KIWA, 2018) indicated that the Dutch natural gas distribution infrastructure can be refurbished / upgraded (at relatively modest costs) to also transport 100% hydrogen or biomethane. However, this would also entail that all end-use appliances also need to be converted to be able to run on pure hydrogen, other (or fluctuating) gas qualities.

To illustrate the challenge of the energy transition in the built environment, the Taskforce Building Agenda ('Bouwagenda')[20], published a progress report (Bouwagenda, 2018) indicating that there are only 8.000 working days left to improve/refurbish 7.5 million houses and about 500.000 public and office buildings, shops and schools by 2050. The aim is to make have an energy neutral building sector by 2050. However, this ambition implies that on average about 1.000 buildings per day (or over 350.000 buildings per year) need to be improved[21], while the current daily 'production' is only a few dozen buildings.[22] On top of that, the building and construction sector in the Netherlands, currently already is facing shortages of skilled labor. According to UWV[23] by the end of 2018, there number of vacancies in the building sector will have increased from a 48.000 vacancies in the building and construction sector, while the share of employers in the sector experiencing difficulties in recruiting new staff increased sharply from close to 0% in 2016 up to 18% in 2018. We consider that if such ambitious daily building renovation rates are not met, the built environment will remain a

[20] The Taskforce Building Agenda ('Bouwagenda') was initiated in 2016 by the Ministries of Economic Affairs, Housing and Infrastructure together with a wide range of actors from the building sector. Together this public-private partnership developed an agenda for improving the sectors' performance in terms of sustainability, resource use (circular) and customer satisfaction (link).

[21] This number is considerably higher than is estimated in the Coalition Agreement (EZK, 2018b), which indicates that each year until 2050 about 200.000 houses and other buildings will need to be disconnected from natural gas.

[22] At current daily production rates that target will only be met in the year 2350.

[23] https://www.uwv.nl/overuwv/Images/Factsheet-Bouw.pdf

considerable user of natural gas or renewable gases well after 2030. Such unanticipated future gas demand will put more pressure on the electricity sector to generate more power for produce SNG/hydrogen.

3.2.5 Analysis

If we take a look at the dynamics of the energy transition within each sector in the Netherlands, we can observe that renewable gases in transport remain a niche option until 2030-35, but will have to expand rapidly in the 2030-50 period when hydrogen in transport matures. The three sectors, electricity, industry, and the built environment are supposed to reduce demand for gases as a result from government policies and/or ambitions. The anticipated short-term phase-out of L-gas in industry and the built environment is an important driver in this transition that provides a momentum to initiate short-term action. However, phasing out L-gas in these three sectors is not an easy task, particularly in industry and the built environment where there are major (and often costly) barriers in place that slow down or can even block L-gas phase out. We consider that particularly converting the building to non-gas solutions will be challenging. This is mainly because full-electric solutions would also require large investments by households in complete house refurbishment, including roof, wall, floor insulation and installment of low-temperature heating systems. The challenge to scale-up and speed-up this process is formidable as the sector currently is short on skilled staff. A failure or slow-down in the transition process in all mentioned sectors will likely put additional demand for (renewable) gases in the market.

Our analysis of sector reports/strategies and ambition papers also suggests that particularly the petrochemical industry bears a considerable potential demand for renewable gases as an alternative to oil as a petrochemical feedstocks. This potential extra demand for (renewable) gases currently seems not to be fully recognized in the Dutch energy scenarios (ECN, 2017). If we add this up, we anticipate that demand for renewable gases will greatly outstrip supplies. Such demand will likely be met with increased imports of H-gas on the short term, but shall increasingly be met via power-to-gas supplies. However, this requires a massive additional expansion of renewable electricity generation, on top of existing growth trajectories.

3.3 Poland

3.3.1 Current and theoretical future energy demand for (renewable) gas in the Poland

Poland's gross inland energy consumption in 2016 totaled 99.9 Mtoe (or 4184 PJ) (EUROSTAT, 2018). Coal plays a crucial role in Poland's gross inland consumption with a share of roughly 50%. Oil and gas account for another 40%, whereas renewables have a 9% share, which mainly exists of solid biomass and some wind energy. Most of oil and gas consumption is imported. Reducing energy import dependency in combination with the need to reduce coal consumption provides a great challenge for Poland.

According to the EU reference scenario (EC, 2016) coal use in Poland is estimated to decrease with close to 60% in 2050 relative to 2016 coal demand levels. This is equivalent to roughly 29 Mtoe, and mainly affects power and heat sector (CHP plants, district heating) and its use in coke ovens. Both nuclear and renewables are considered to fill this 'gap' in future power generation. Gas use is also estimated to increase substantially, but will deployed also outside the power and heat generation sector.

Projections haven been made up until 2030 by the Ministry of Economy in 2009 in the 'Energy Policy of Poland until 2030' (Ministerstwo Gospodarki, 2009). Gross inland consumption is expected to rise to 118.5 Mtoe in 2030, which is considerably higher than estimated in the EU reference scenario (107 Mtoe). Based upon the energy mix shares for 2030 primary energy are estimated by the Polish Ministry of Economy (Ministerstwo Gospodarki) we can make a comparison with the EU reference scenario. Aside from a large deviation in terms of final inland consumption, it shows that the EPP anticipates that the first nuclear power plants will be operational by 2030. By 2030, it is projected that gas will have a 14.5% share in the primary energy demand, which is similar to 2016 levels (Ministerstwo Gospodarki). Solids' share will be reduced to 39.2% and nuclear fuels are introduced (6.3%) (Table 22).

Table 22: Current and future demand of energy in Poland (in Mtoe gross inland consumption)

	Current (2016)	Future (2030)	Future (2030) *EPP	Future (2050)	Future (2050) *EPP	Change (2016-50)
Gross inland consumption	99,9	106,8	*118,5*	109,9	87,9	+10%
Total solids	49,1	43,3	*46,45*	20,2	29,3	-59%
Total gas consumption	14,6	20,5	*17,18*	24,5	15,8	+68%
Total nuclear	0,0	0,0	*7,46*	14,8	10,3	+>300%
Total oil	26,5	27,4	*31,05*	27,9	21,5	+5%
Total renewables	8,8	15,5	*14,7*	22,3	13,7	+153%

Source: (EUROSTAT, 2018); (EC, 2016); (Ministerstwo Gospodarki, 2009); (Ministerstwo Gospodarki, 2015)

To reduce gas import dependency from Russia, Poland has been actively engaged in enhancing and diversifying gas supplies. Although, domestic shale gas appears to have potential, after the initial interest and investments by shale-gas companies, the option (to date) has largely failed due to combination of high production costs and unsuitable concession / production licensing conditions.[24] The LNG terminal in Świnoujście has the capacity to satisfy almost half of Poland's current gas demand (IEA, 2016). Although, the terminals current capacity (5 bcm or 4.2 Mtoe/y) is not fully utilized - its current utilization rate (60-65%) is amongst the highest in Europe[25] - there are already plans to increase its capacity to 7.5 bcm (or 6.3 Mtoe/y) per year. This alone could satisfy little over 40% of the country's (2016) gas demand. Despite this the increasing future gas demand will also likely imply an increase in imported pipeline gas, complemented by imports from Lithuania (LNG terminal in Klaipeda) via the GIPL pipeline.

Table 23: Current demand of gases in Poland (in Mtoe)

	Current (2016)	Share of total energy for specific purpose
Gross inland consumption	99,9	-
Total gas consumption	14,6	14,6%
Gas used for electricity production	3,2	4,2%
Gas used for non-energy purposes	2,1	37,6%
Gas used for final energy use	9,6	14,5%

Source: (EUROSTAT, 2018)

Current (2016 gas demand mainly stems from the residential and services sector (5.4 Mtoe), industry (3.8 Mtoe) as well as the power/heat sector (3.2 Mtoe). About 2.1 Mtoe of gas is used for non-energy purposes (Table 23).

[24] https://oilprice.com/Energy/Energy-General/Is-The-Polish-Shale-Gas-Industry-Set-For-A-Comeback.html

[25] https://www.lngworldnews.com/polish-lng-terminal-boasts-highest-utilization-rate-in-europe/

3.3.2 Transformation sector (power + heat)

Current (2016) gas use in power and heat sector is 3,2 Mtoe (134PJ). Coal use in Poland for electricity generation purposes have been historically high, but have decreased from 56 Mtoe in 2000, to 44 Mtoe in 2016. Gas use for electricity production in Poland is limited to about 4% of total, while coal has an 80% share (EUROSTAT, 2018). However, also the lion's share of heat generation's demand is met by coal. More than half of Poland's gross consumption of coal is absorbed by the power and heat generation. With regards to the district heating network, Poland has one of the largest in Europe and 200 PJ of heat reached approximately half of the population (IEA, 2016). This shows that there is an enormous challenge for this sector to realize the 62% coal reduction by 2050 as projected by the EU reference scenario. On top of that, according to the Polish transmission system operator (PSE), a substantial part of coal-fired power plants is old and are in need of replacement (between 16 GW and 23 GW) (IEA, 2016). With a domestic coal mining sector that loses its international competitiveness, there is a renewed interest for coal imports. This could further increase the country's energy import dependency (IEA, 2016). Nonetheless, an increase in the carbon price and dependence on the Polish newly implemented capacity market pose a risk for investments in new and more efficient coal plants[26]. Eventually, this could deteriorate the business case so dramatically, that calculations of a negative net present value of 1.7 billion euros for the new Ostrołęka coal power plant C have been made (Carbon Tracker, 2018).

Due to electrification in transport and in the heating sector, electricity demand is expected to rise with 1.4% per year, reaching a level of 175 TWh (15,0 Mtoe) in 2030 and 220 TWh (18,9 Mtoe) by 2050 (Forum Energii, 2017). The EU reference scenario (EC, 2016) expects slightly higher generation values of 203 TWh (17,5 Mtoe) and 245 TWh (21,1 Mtoe) respectively. In the Forum Energii, three alternatives are outlined: diversified with nuclear energy, diversified without nuclear energy and a RES scenario.

In 2030, coal is expected to remain the dominant fuel used in electricity generation (>50%), with an increasing share of renewable energy and roughly 8% is satisfied by gas (50 PJ) (Forum Energii, 2017). From 2050 on, renewable energy production will rise substantially in each scenario and is predominately composed of Wind (~148 PJ/3,5 Mtoe in 2030, ~331 PJ/7,9 Mtoe in 2050) and PV, but also biogas (~40 PJ/1,0 Mtoe in 2030, ~80 PJ/1,9 Mtoe in 2050). The renewable share in electricity generation differs dependent on which of the scenarios is followed, but ranges between approximately 40% and 70%. The remaining electricity demand is either fulfilled by gas (~143 PJ – 198 PJ/3,4 Mtoe – 4,7 Mtoe), nuclear, coal or is imported (~16 PJ – 80 PJ/0,4 Mtoe – 1,9 Mtoe), again depending on which scenario is followed. The outcome of the EU reference scenario with regards to electricity generation is heavily dependent on the successful development and installation of nuclear energy. By 2050, nuclear energy is estimated to be the largest source of electricity generation, followed by solid fuels (~228 PJ/5,5 Mtoe), gas (~150 PJ/3,6 Mtoe) and wind power (~162 PJ/3,9 Mtoe). Especially in the latter energy source, a large discrepancy is observable between the forum energii projections and the EU reference scenario.

The potential incremental demand for gas in this sector is substantial given the anticipated decrease in use of coal. However, given the resulting increase in import dependence the country would have

[26] http://ieefa.org/ieefa-europe-polands-pge-would-do-well-to-accelerate-plans-to-diversify-away-from-coal/

an interest to maximize the share of nuclear and renewable power first and keep the share of gas fired power plants limited, for example for grid balancing purposes.

The development and installation of nuclear power, is seriously considered and concrete implementation plans are in place as is described in the EPP 2030 (Ministerstwo Gospodarki, 2009). With the first nuclear power plant yet to be built, a slowdown in the scaling of nuclear power in Poland would increase future demand for gas and slow-down the phasing out of coal. Nonetheless, these expectations are still upheld, but government officials are pushing for a quick decision on this[27].

Wind power production has grown from 0,1 Mtoe in 2000 to 1 Mtoe in 2016. The wind and solar power capacity in Poland has to scale up considerably in the efforts to phase-out coal. This initially will come from onshore wind and solar pv[28] capacity, but increasingly also from offshore wind parks. McKinsey estimates that by 2030 about 6 GW of offshore wind capacity will be installed in Poland (McKinsey, 2016). Depending on the speed of scaling up nuclear, wind and solar, a temporary increase of gas use for power and heat generation to replace coal can be envisioned in the period up to 2040. After that renewables, nuclear, remaining coal will likely dominate the power sector and gas will be used for balancing purposes.

We consider that the efforts to rapidly increase nuclear, solar and wind power capacity face several obstacles / barriers (e.g. onshore wind park developments near Natura 2000 areas, oversupply of green certificates) in the 2020 to 2045 period. As the phase-in of these options is not as fast as anticipated, gas demand could be (temporarily) higher than currently anticipated.

3.3.3 Final non-energy consumption

Final non-energy use totalled nearly 5,6 Mtoe in 2016, with oil (3.4 Mtoe or 61%) and gas (2.1 Mtoe or 37.5%) as the main energy sources. This total demand is expected to rise gradually towards 2050 to 8,5 Mtoe (EC, 2016). The current use of solid biomass in this sector is zero. Given that the energy transition in Poland, mainly targets a phase-out of coal, and thus mainly affects the power sector, we consider that the increasing the share of gas in this sector, at the expense of oil is unlikely. While there is scope for a fuel switch to biomass (the country has considerable domestic solid biomass resources) and despite the fact that there are several bio-based economy clusters active within the country (Biconsortium, 2018), the Polish petrochemical sector has not (yet) launched plans / strategies for large-scale uptake of biomass within (or renewable gases) within the sector. On top of that, in an effort to decarbonise the country's energy system, phasing out coal is likely to be more effective. Hence, for this sector we anticipate that the increased use of energy as feedstock will largely remain comprising oil and gas in similar proportions in the run up to 2050.

3.3.4 Final energy consumption

3.3.4.1 Industry

Poland has a sizable energy intensive industry and its final energy demand in 2016 totalled almost 16 Mtoe (EUROSTAT, 2018). The final energy demand in industry exists predominately of electricity (4.4 Mtoe), solids (3.8 Mtoe) and gas (3.8 Mtoe). All three represent a share of roughly 25% and offers arguably a good starting position for greening this sector. The iron and steel, (petro)chemical

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[27] https://emerging-europe.com/news/poland-speeds-nuclear-power-plans/

[28] Energy generated from PV is still relatively small and only accounted to 0,1 Mtoe in 2016.

and the non-metallic minerals are the largest industries and all account for roughly 3 Mtoe. Other large industries are the food, tobacco, paper and pulp industries.

The industrial sector is expected to grow to a total final energy demand of 17,5 Mtoe in 2050 (EC, 2016).The iron, steel and (petro) chemical industry are mainly responsible for the use of solid fuels (i.e. coal). Solid fuels usage can be drastically reduced by for example replacing the cokes that are used in the iron and steel industry by means of a new production process such as HYBRIT[29]. Also some subsector in the non-metallic minerals sector (e.g. glass) have good prospects to become all-electric by 2050, so could both contribute to reducing the share of coal and gas within industry. Naturally, this would have consequences for the electricity demand in Poland, which would increase. Similar developments of increasing electrification and gas use in the non-metallic industry can be achieved. The pulp and paper industry has potential to make a further switch to using solid biomass or partial electrification, while the food and tobacco industry – which is heavily dependent on gas – has considerable technical potential (estimated at 5 bcm/y or 4.2 Mtoe) to switch to biogas (Biogas Action, 2016).

Considering the options for further electrification, use of solid biomass and biogas, we anticipate that the share of natural gas is not expected to increase much in industry in the industry sector in the coming decades and might even slightly reduce depending on biogas developments. However, as biogas is mostly combusted in CHP plants (Biogas Action, 2016), it could also increasingly be used as an alternative energy source for Polish district heating systems.

3.3.4.2 Transport

Transport’s final energy demand is expected to rise from 19,4 Mtoe in 2016 to 22,4 Mtoe by 2050. Given the traditional nature of the energy mix (94% oil) in transport, this poses a real challenge to adhere to the energy transition proposed in the EPP 2030 (Ministerstwo Gospodarki, 2009). One of the goals outlined is to have a 10% share of biofuels involved in this sector already by 2020, which is quite ambitious given the current situation (2016) of just under 4% of renewables in transport (Central Statistical Office Poland, 2017). The EU reference scenario predicts a slightly lower implementation trajectory with 7,1% for biofuels, together with a share of 0,2% of electric vehicles by 2030 (EC, 2016). This latter projection seems to be achievable, considering that EV market share quadrupled between 2016 and 2018 (from 0,06% to 0,24%)[30]. This correspondents to a current passenger car stock of approximately 50.000 EV. The Polish government is pursuing growth in the EV stock and is investing in expanding the charging stations network (Financial Times, 2017). Furthermore, the minister mentions in the same news article that 41 cities and municipalities signed to electrify their bus fleet by 2020. This could have very beneficial results for the air environment in certain cities where coal use for heating purposes is relatively high.

Finally, Poland attracts investments from Korea, China and Germany for producing batteries. The idea is that Poland can provide an environment that is a good breeding place for developing relatively cheap EVs, despite the fact that Poland does not have a national car manufacturer. These developments hints at high ambitions to electrify the transport sector. On top of that the Polish government is pursuing also an expansion in the use of CNG/LNG in the Polish transport sector. “The Polish Ministry of Energy forecasts that by 2025, there will be more than 50,000 natural gas vehicles on Polish

[29] http://www.hybritdevelopment.com/

[30] http://www.eafo.eu/content/poland#country_pev_market_share_graph_anchor

roads (currently about 3,600) and more than 100 fuelling points.” (The Polish Institute Of International Affairs, 2017)

3.3.4.3 Built environment

Poland’s build environment is characterized by high use of coal, around 30% of final energy use in the residential and services sector stems from coal. Throughout the whole of Europe (EU-28), 11,5 Mtoe of solid fuels, mainly bituminous coal, was used in the build environment. A substantial share of this amount, roughly 70%, was used in Poland (EUROSTAT, 2018). The high levels of residential coal use in combination with poorly insulated houses, low quality coal and absence of quality norms lead to smog in several regions (Euroheat News, 2018). A possible solution for this problem could be the investment in a comprehensive coverage of the district heating network in densely populated areas, thereby avoiding inefficient heating systems in houses. Already 41% of the heat demand in Poland was satisfied by district heating in 2015 (Euroheat, 2017). Most district heating plants (heat only and CHP) are fueled with coal accounting for over 80% of energy use in district heating systems (EUROSTAT, 2018). Several alternatives for coal use in district heating systems are available. Several initiatives are taken to drastically reduce coal use in the residential sector, both for improving air quality, as well as reducing CO_2 emissions. The Polish government is currently exploring the possibilities of implementing an incentive scheme for renewable energy sources in district heating (Solar District Heating News, 2018). Another option is the installation of solar PV on houses’ roofs, as Switzerland has financed between 2012 and 2017 in the southern region of Poland. Other alternatives include the use of natural gas, biogas CHP, solid biomass, and electric heating systems. However, first and foremost a key first step here is to improve the energy performance of buildings in Poland by better insulation.

BPIE conclude that (BPIE, 2016): *“Poles live in homes that are inadequately insulated against heat loss. Heating technology is outdated and the most popular fuel is highly polluting coal, burned in old coal-fired boilers. It is estimated that more than 70% of detached single-family houses in Poland (3.6 million) have no, or inadequate, thermal insulation. Only 1% of all houses in Poland can be considered energy efficient, primarily those that have been built in the last few years.”* While this shows that there is sufficient low-cost scope for improving the energy performance of buildings it also shows that in absolute terms major investments in upgrading the building stock are needed. Given the magnitude of this challenge we anticipate that by 2050 the building stock is not yet fully upgraded to modern energy performance standards. As a result energy demand from this sector will remain relatively high. If renewable alternatives for heating are not sufficiently maturing, this will likely imply in an increased use of natural gas in district heating systems.

3.3.5 Analysis

Poland is a relatively large country with high energy consumption. Coal has been the dominant energy carrier for decades and has become interconnected with Poland’s economy. A shift away from coal will therefore be difficult, but necessary in order to comply with the goals set by the EU. However, phasing out coal almost immediately increases the country’s import dependence on natural gas, both in power generation, but as well in district heating and the residential sector where most coal is used. We consider that natural gas demand in Poland will see a temporarily sharp rise in the period up until 2030-2040, and after that could decrease considerably (up to 2050 levels envisaged in the EU reference scenario) as markets for intermittent renewables, nuclear and biogas have overcome the first main barriers[31], have matured and become more cost-competitive. The higher import dependency will then likely serve as an important incentive for continued efforts for the Polish energy transition. In case either the development of solar PV or wind power is hampered or the projected capacities are not reached, then the demand on gas as an alternative becomes larger. Nonetheless, due to energy dependency issues, this might not be the most favourable solution. We anticipate that close to or beyond 2050 other options, such as power-to-gas, hydrogen use or CCS/CCU will become more relevant for Poland. While power-to-gas / hydrogen production could be pursued domestically with increasing capacities of intermittent wind, solar pv and increasing shares of nuclear power, the country will likely be dependent on third countries (e.g. Russia) when it comes to CCS/CCU deployment as it lacks sizable geological storage capacity in hydrocarbon reservoirs.[32/33]

3.4 Sweden

3.4.1 Current and theoretical future energy demand for (renewable) gas in Sweden

Sweden’s gross inland energy consumption totalled 49 Mtoe in 2016. Only 30% of the gross inland energy consumption was met by means of fossil energy carriers, of which oil was the most predominant one. Natural gas only accounted for roughly 2% (0,8 Mtoe) of gross final energy demand and was entirely imported. The remaining 70% of gross inland energy consumption was fulfilled by means of nuclear energy and renewables originating from hydro, wind and solid biomass sources.

The EU reference scenario estimates that gross inland consumption in Sweden in 2050 will remain stable at 48 Mtoe, and the use of fossil gas is estimated to rise to a level of 2.5 Mtoe in 2050. Final energy consumption was 33 Mtoe in 2016 (EUROSTAT, 2018). The IVL scenario (IVL, 2011) forecasts a total final energy consumption of 22 Mtoe by 2050, whereas the Swedish Energy Agency (SEA, 2016) estimates it to be between 32 Mtoe and 21 Mtoe. These forecasts are more optimistic than the EU reference scenario, which estimates the final energy consumption to be 33 Mtoe by 2050 (EC, 2016).

The government of Sweden agreed on a long term energy policy in 2016 prescribing zero net CO_2 emissions by 2045 (Swedish Government, 2016), where after negative emissions can be reached. Currently, fossil fuel use is virtually zero in the built environment and also little fossil energy is used in industry. Gas can still be found in industry, electricity/heat generation and non-energy use. The largest challenge will be encountered in the transport sector, where final energy consumption consists mainly of oil (80%/7,4 Mtoe). One of Sweden’s approaches towards this challenge appears to be intensive electrification of the car stock (IEA, 2018).

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[31] Despite the efforts being made, it is forecasted that Poland will fall some 1.2 to 5 percentage points short of meeting its RES target of 15% of final energy in 2020 (PV Magazine, 2017).

[32] Including geological storage capacity in aquifers, Poland could store its total national CO_2-emissions domestically only for about nine years. Excluding aquifers this would be 3.5 years (see chapter 4)

[33] The first research and pilot projects around the world for large-scale production of hydrogen as a ‘by-product’ from carbon black extraction from methane by using plasma-reactors are already underway (link)

3.4.2 Transformation sector (power + heat)

Between 2000 and 2016, shares of power types in the electricity production have been relatively stable, as well as the total produced electricity. In 2015, 81% of the total electricity production existed of hydropower and nuclear power (SEA, 2018). The total electricity production amounted to 159 TWh (13,7 Mtoe). Additionally, 10% originated from wind power and the remaining 9% from combustion-based production in combined heat and power plants. There are nine nuclear reactors active in Sweden of which three are scheduled to be taken out of service by 2020. This is in line with the decreasing trend in the nuclear energy production capacity which has fallen with 1,4% between 2000 and 2015 (EC, 2016). While the EU reference scenario estimates that by 2050 nuclear will provide 13.9 Mtoe of gross inland energy consumption, there are already several scenario studies (IVL, 2011) and other sources (Nuclear Engineering International Magazine, 2017) (Forbes, 2015) that indicate a full nuclear phase-out in Sweden by 2040 – 2050.

In case of such a phase-out more renewable and a combination of electricity storage and gas fired power plants would be needed to fill this gap. Wind power generation experienced a significant increase from 2000 (0,5 TWh) onwards (15,5 TWh in 2016). This sharp increase is also visible in the installed wind power capacity of nearly 6.6 GW (Wind Europe, 2018). Electricity derived from PV sources is still marginal with an installed capacity of roughly 0,2 GW. PV only accounted for 0,06 per cent of the total electricity production in Sweden by 2015.

Finally, gas turbines have a production capacity of 1,6 GW, which is fairly high considering the minor input (0,4 Mtoe/4,6 TWh) of gas used in this sector in 2016 (EUROSTAT, 2018). This implies that gas turbines are mainly used to meet peak demand. In the future, however, gas use in the power sector could also be completely phased-out as there seems good potential for power-to-heat (Schweiger, Rantzer, Ericsson, & Lauenburg, 2017) options to balance the electricity grid given the extensive nature of the Swedish district heating system.

Considering district heating, 62 TWh of energy was used in 2016 (SEA, 2018). This was predominately originating from biomass (38,3 TWh) and other fuels, such as peat. The share of heat pumps is steadily decreasing (7,5 TWh in 2000 to 4,5 TWh in 2016) and electric boilers have disappeared almost completely. Also gas plays only a minor role in the generation of heat with an energy input of roughly 2 TWh in 2016. Interestingly, industrial waste heat is actively used and is injected in the district heating network. This cogeneration product from industry amounted to 5 TWh in 2016.

The Swedish Government (Swedish Government, 2016) agreed upon the goal of 100% renewable electricity production by 2040. In the same document, it is explicitly stressed that this goal does not necessarily imply the political banning of nuclear power plants. In turn, this is supported by the tax on thermal output of nuclear power plants, which will be gradually abolished over a two-year period. On the other hand, investment in hydro plants is supported by means of reducing the property tax. Moreover, it is considered to eliminate marine-based fees for offshore wind power plants. Scenario studies (IVL, 2011) (SEA, 2018) forecast a relatively similar electricity production capacity in the future and there appear to be no concrete plans from out the government to substantially increase the generation capacity.

However, it is likely that by 2050 nuclear energy could be phased out and predominately replaced by intermittent sources. However, the EU reference scenario (EC, 2016) predicts a substantial increase in both the total electricity generation (210 TWh in 2050), as well as an expansion of nuclear energy generation. The same scenario studies predict a shift from biomass use in district heating plants towards surplus energy (e.g. from biofuel production) and surplus heat from industry. In this way, biomass can be used for other, higher added-value, purposes (e.g. transport). This is in line with projections from the Nordic Carbon Neutral Scenario (NER, 2016).

3.4.3 Final non-energy consumption

The non-energy consumption in Sweden is not particularly high. It accounted for 2,2 Mtoe in 2016 and was mainly consumed by the (petro)chemical sector (1,7 Mtoe). This is substantially below the EU-28 average, which implies that Sweden's (petro)chemical sector is relatively small and hence the demand for raw materials is not extremely high. However, most of the oil and gas required in this sector has to be imported.

The share of oil in the total non-energy consumption is relatively high with 94% and gas relatively low with 6%. This makes it challenging to completely phase-out the use of oil (Swedish Government, 2006) in this sector. Nevertheless, if Sweden wants to realize its target of zero net emissions in 2040, non-energy consumption has to be greened. If projections of the EU reference scenario were to be followed, the use of energy carriers for non-energy purposes is expected to rise to 2,6 Mtoe by 2050. This would imply more pressure both electricity and biomass to meet the increased non-energy demands.

Given the country's vast indigenous biomass resources a shift to biorefining could be feasible for the (petro)chemical sector in Sweden. Such increased demand could be matched, as "the Swedish Forest Agency states in its recent report (RISE, 2015) that the potential additional extraction of forestry residues for the period 2020-2029 is between 20-30 TWh/y (1.7-2.6 Mtoe/y)." On top of that, particularly increased gas imports, but also the use of biogas will be feasible and realistic alternatives. Current natural gas supplies for large-industrial users mainly comprise pipeline gas imported from Denmark. All pipeline gas is supplied via the Dragör pipeline that is connected to the Danish Tyra gas field. The current gas import capacity is around 22TWh (1.9 Mtoe) per annum (Energimarknads inspektionen, 2012), which is sufficient to cover current national usage of gas (0.8 Mtoe). A small-/mid-scale LNG import facilities are already operational in Lysekil and Nynäshamn, and one is anticipated to open in Göteborg in 2018. LNG is used for different purposes, for industry, transport (road and shipping) as well as for heating. The Lysekil LNG regassification terminal also targets LNG use in the petrochemical sector, where naptha and butane will be replaced (Ship Technology News, 2014).

Given the above we anticipate that for this sector, a considerable share of oil can be phased-out by 2050, while mainly the use of biomass, but also the use of (imported) gas via pipeline and LNG will gradually expand.

3.4.4 Final energy consumption

3.4.4.1 Industry

Final energy consumption in the industrial sector was 142 TWh (12 Mtoe) in 2016 and appears to be slowly decreasing since 2000 (153 TWh). This is mainly due to more efficient industrial processes and minor changes within the industrial sectors (SEA, 2018). By far the largest industry is the paper and pulp industry which totalled a final energy use of 5,7 Mtoe. Other fairly large industries in Sweden are the iron and steel industry and the (petro)chemical industry, but their size is not comparable to the paper and pulp industry. As a result, the energy mix used in the industrial sector is significantly different from the EU-28. Electricity and biomass were the dominant energy carriers, with a share of roughly 75%, in the industrial sector. Solid fuels were the main fossil fuel energy carriers, and were predominately used in the iron & steel industry.

This industry, the iron and steel industry, is responsible for 10% of the total CO_2 emissions and is thereby one of the largest emitters in Sweden. In turn, this is because this industry consumes almost half of all the coal that is being consumed in Sweden. To ensure the future of the iron and steel industry in Sweden, while complying with the national environment targets poses great challenges. Even the more because global steel demand is expected to almost double in size by 2050. The ore-based steelmaking process starts at the mine, after which the iron ore is processed in a pellet form (pelletizing). Then the pellets are transformed into hot liquid metallic iron by means of a coke blast furnace. Alternatively, this step can be executed by the direct reduction method, which requires gas instead of cokes and electricity for melting purposes. For Sweden, this is not a viable option since gas is not abundantly available and a fossil fuel anyway. Therefore, three Swedish companies (Vattenfall, SSAB and LKAB) started HYBRIT[34], a joint venture which is partly financed by the SEA. HYBRIT develops a steelmaking production process which makes use of hydrogen and eliminates 85% to 90% of the total carbon dioxide emissions in the value chain. The viability of the business case will be dependent on the price of coking coal and the price of electricity. If the pilot phase (2018-2024) is fruitful and the demonstration trials (2025-2035) successful, then full implementation can be pursued. This has large implications for the electricity demand for this industry, which will rise to an amount of 15 TWh (54 PJ) (Vattenfall, 2017).

The use of electricity in the paper and pulp industry is high. In the EU-28 the average share of electricity in final energy consumption in this sector is 37%, while it is almost double that in Sweden. A similar observation can be made for the use of solid biomass in this industry, the EU-28 average is 38% and in Sweden close to 67%. Nevertheless, a decrease in electricity consumption is visible, which can be partly explained by the development of less mechanical pulp production which is relatively electricity-intensive (SEA, 2018). With regards to the biomass, the typical biomass that is used, is black liquor. This is the remainder of the pulp boil and can be burned in recovery boilers, after which the recovered energy can be used in several industrial processes. The way forward for this industry appears to be even more energy efficient, upgrade by-products to value-added stream of products and using recovered heat for the district heating network (CEPI, 2017). Especially the latter development is vital for relocating the valuable biomass to district heating plants, so that other sectors, such as transport or industry, can benefit from these non-fossil energy carriers. In addition, if pulp mills would become more energy efficient, less biomass (e.g. black liquor) would be required for this industry and could be used alternatively.

The IVL scenario (IVL, 2011) predicts an overall final energy demand of an estimated 120 TWh in 2050, given a consistent production mix. In this scenario, oil is completely phased out by 2050. This gap is expected to be filled by respectively biogas, biofuels and bioenergy originating from solid biomass. The Swedish Energy Agency (SEA, 2016) is slightly more conservative, and predicts a final energy demand between 120 and 170 TWh (10-14.6 Mtoe) in 2050. The EU reference scenario (EC, 2016) considers final energy use in this sector to stabilize at around 11.3 Mtoe. We consider it unlikely that by 2050 oil and fossil gasses have disappeared in the industrial sectors. However, there is sufficient potential for alternatives, like renewable gases, including hydrogen and biogas to for example replace coke and other solid fuels in the iron and steel industry. Moreover, it is expected that the industrial sector has access to 3 TWh (0,3 Mtoe) of biogas (Energigas Sverige, 2018), which would already satisfy more than half of the current gas demand in industry.

Given the specific nature and characteristics of the Swedish industry sector we consider a large (unexpected) increase in the use natural gas unlikely. Renewable alternatives to satisfy energy demand in this sector are adequately available and also show sufficient technical potential. Renewable gases such as biogas and hydrogen are likely to be developed and used, but we expect that the main options remain solid biomass use and further electrification in industry.

[34] http://www.hybritdevelopment.com/

3.4.4.2 Transport

Sweden's transport sector is heavily reliant on fossil energy carriers, as oil satisfies 83% of the final consumption in transport. However, compared to the EU-28, the transport sector is already quite green when considering the large share of liquid biofuels (13%). This relatively large amount of bio liquids is exclusively used in the road sector, which is also the case for the use of electricity, which account for 3% of the final energy consumption in transport.

Road transport is also the largest sector within the entire transport sector and is responsible for 86% of the consumed energy. In total, the transport sector consumed 380 PJ (9.1 Mtoe) of energy in 2016. According to the EU reference scenario (EC, 2016), 2050 energy demand in Swedish transport will be somewhat lower at 8.1 Mtoe. The largest demand for energy in the transport sector will be comes from private cars.

Looking at the development over the past couple of years, it is observable that battery electric vehicles (BEV) and plug-in electric hybrid vehicles (PEHV) are gaining substantial shares. Their share increased from around 1,5% in 2014 to 6,5% in 2018, representing close to 300.000 (partly) electric cars[35]. On the other hand, the expansion of natural gas vehicles (NGV) has stabilized, and even slightly declined in recent years. It is, however, interesting to observe that – although current (2016) gas use in transport is only still minimal (0.132 Mtoe) – around 75% originates from biogas (EUROSTAT, 2017). After Italy, Germany and Austria, Sweden has the largest number of CNG filling stations within the EU-28 (i.e. 163 CNG filling stations).[36]

Furthermore, Sweden is actively exploring the possibilities of electric roads, mainly for reducing the dependency of heavier vehicles on fossil fuels (CNN News, 2018). These could be established by either conductive transmission via overhead lines, transmission via rails or an energetic field. Transmission by rail and overhead lines is now implemented and tested actively (Scania News, 2016). Another viable option is expanding and improving the rail network, which would contribute to the further reduction of CO_2 (Swedish Government, 2017). This could result in doubling freight traffic, and even triple passengers transport by 2050. Hydrogen as a renewable energy carrier is also being investigated closely, and gradually hydrogen stations are popping up across the country. This technology is mainly promoted by the Scandinavian Hydrogen Highway Partnership[37], which is a transboundary initiative between the Scandinavian countries.

Also the use of biofuels is soaring, and grew from around 4 TWh in 2007 to more than 12 TWh in 2016 (SEA, 2016). The increase in biofuels and EVs is largely due to the directives and regulations that Sweden has implemented. Originally consumer were stimulated to buy an environmental friendly car by means of the 'super green car premium' (SEA, 2018). From 2018 onwards, this system was replaced by a bonus-malus scheme that ensures that high carbon emission cars are taxed heavier than relatively clean cars. According to the EU reference scenario (EC, 2016), these policies result in a biofuel share of 14% in transport (now around 11%). Furthermore, it is forecasted that final energy demand drops slightly to 8,1 Mtoe.

There appears to remain a role for gas use in transport in Sweden. Biomass derived gases are expected to be the third largest fuel for transport by 2050, after liquid biofuels and electricity (IVL, 2011). The IVL scenario also estimates that by 2050 mainly biofuels, renewable electricity as well as renewable gases (biogas and SNG from biomass gasification) will provide all energy required in

[35] http://www.eafo.eu/content/sweden

[36] http://www.eafo.eu/infrastructure-statistics/natural-gas

[37] http://www.scandinavianhydrogen.org/

transport. They estimate that gas use mainly comprises public buses and passenger vehicles. There seems to be sufficient potential to cover anticipated future biogas demand. The proposal for a 'National Biogas Strategy 2.0' from the Swedish Gas Association (Energigas Sverige, 2018) suggests a realistic biogas potential of 15 TWh (1.3 Mtoe) biogas supply by 2030, while other estimates indicate a higher biogas potential for Sweden of around 22 TWh (1.9 Mtoe).

For this sector we consider that by 2050 fossil gases will no longer be used in transport, but that after liquid biofuels and electricity, biogas will serve a significant share of the public bus fleet and a smaller share of the passenger vehicle market.

3.4.4.3 Built environment

In 2016, the final energy consumption in this sector totalled 12,1 Mtoe. More than 95% of this demand is met by means of electricity, derived heat (district heating) and renewables. Only small shares of oil and gas use remain. Within Sweden there are ample alternatives available to provide heating for buildings in the residential and services sector to become (nearly) climate neutral by 2050 or even well before that. The question remains if oil and gas can be fully phased-out in this sector as there might be very small niche applications that remain in remote areas or specific applications.

The development of 'passive houses' is ongoing (Rohdin, Molin, & Moshfegh, 2014) which could considerably contribute to reducing energy demand in this sector. Overall, these houses are very well insulated and can be functionally heated by means of mere human movement and electric appliances.

Government sets the standard by obliging all newly build public buildings to be these nearly zero-energy buildings (Swedish Government, 2016). A loan scheme for energy efficient investments in houses is also investigated in order to promote energy efficiency in the build environment. Moreover, the Swedish government aims to lower taxes for excess self-produced electricity in order to stimulate the self-produced capacity. Nevertheless, the European Reference scenario (EC, 2016) predicts a one Mtoe increase in the residential sphere and also for the built environment overall. According to the four future scenario, households are expected to be completely fossil-fuel free by 2050 (SEA, 2016). Depending on the scenario (SEA, 2016), energy demand will range between 360-490 PJ (8.6-11.7 Mtoe).

3.4.5 Analysis

Sweden is progressing rapidly towards a society without any CO_2 emissions. High goals were set that even exceed the ambitions that were portrayed in the EU reference scenario (EC, 2016). In order to be truly fossil free by 2040, large challenges has to be faced, especially in the transport sector. Nevertheless, Sweden is on pole position to be one of the green leader in Europe. It is likely that gas will not be completely phased out by 2050, as it remains necessary in areas sector, such as cooking, transport, but also for industrial processes. However, because of initiatives taken, such as by the Energigas Sverige, it is expected that by 2050 any remaining gas use is from renewable origin and mainly used in transport and industry (the latter both for energy and non-energy purposes).

3.5 Italy

3.5.1 Current and theoretical future energy demand for (renewable) gas in Italy

Italy's gross inland consumption totalled 155 Mtoe in 2016 (EUROSTAT, 2018). Roughly 38% (EU-28 average: 23%) of the gross inland consumption was satisfied by gas, 36% (EU-28 average: 35%) by oil and 7% by coal (EU-28 average: 15%). Italy has no nuclear power in their energy mix and total final energy demand was 122 Mtoe in 2016. Italy imports almost their entire fossil fuel demand, with 79% of the energy coming from abroad.

Ambitious goals have been established in the Strategia Energetica Nazionale (NES) 2017 (Italian Government, 2017), which sets the target of 28% share of renewables in gross inland consumption by 2030. This is an ambitious goal considering the current share of renewables in gross inland consumption, which was 17%. Furthermore, the NES considers a reduction in final energy consumption to a level of 112 Mtoe by 2030.

In the previous version of the Strategia Energetica Nazionale (2013) (Italian Government, 2013), gas was described as having a “key role of gas for the energy transition” until 2050, despite “a reduction of its weight both in percentage and in absolute value in the span of the scenario”. Moreover, the opportunity was considered to become a Southern European gas hub in order to facilitate gas in- and outflows.

The EU reference scenario (EC, 2016), forecasts residual gas usage in gross inland consumption in Italy of 58.5 Mtoe both in 2030 and 2050, and total gross inland consumption to be 150 Mtoe and 145 Mtoe resp. in 2030 and 2050. Although the NES 2017 has no official scenario background analysis, based on preliminary results from ENEA[38] we can assume a considerable role for natural gas of around 45-50 Mtoe in 2030. Particularly with regards to estimated gas use in 2030, a difference between to scenario estimates of over 8 Mtoe (or 9.5 bcm) is substantial. The NES 2017 for example, anticipates investments in new gas import pipeline infrastructure and a phase-in of natural gas (derived from LNG regasification) on Sardinia to phase-out the use of LPG. The latest NES also considers the phase-out of coal by 2025 and outlines measures to diversify energy supplies, such as diversifying the natural gas supply sources. Another measure are large investments in research and development of clean-energy technologies (€ 444 million in 2021), of which power-to-gas would be an important factor in reducing overall import dependency.

3.5.2 Transformation sector (power + heat)

Total electricity consumption in 2015 in Italy totalled 328 TWh (or 28.2 Mtoe) (Terna, 2018) of which 46 TWh (3.9 Mtoe) was imported. According to (EC, 2016), in 2015 about 33% of all electricity consumed originated from renewable sources. This share has to increase to 55% by 2030 (Italian Government, 2017). Natural gas is the main conventional fuel used for power generation with 111 TWh (or 9.5 Mtoe). Also already about 1.9 Mtoe of biogas is already used to generation electricity. Other renewables predominately originated from hydro sources (18%) and were followed by wind, solar and other bio energy. Geothermal energy, represents 5,6 Mtoe in the gross inland consumption and is almost used entirely for the generation of electricity. Overall, the power generation mix in Italy is relatively suitable for accommodating intensive electrification in an environmental responsible way (Enel, 2018), as the CO_2 emissions intensity of 325 tCO_2/GWh is below the sustainability threshold of 600 tCO_2-eq./GWh of emissions.

With a full coal phase-out by 2025 and an at least 55% share of renewables in the electricity mix (Italian Government, 2017) (renewable) gases are likely to more and more provide a balancing function in the power sector. At the same time, the EU reference scenario (EC, 2016) predicts the electricity generation to be nearly 418 TWh (35.9 Mtoe) in 2050, suggesting an about 100 TWh (8.6

[38] https://iea-etsap.org/workshop/madrid_may2017/11_Gaeta_ENEA.pdf

Mtoe) increase in electricity generation by 2050 relative to current production levels. This expansion is expected to be mainly accommodated by a substantial increase in wind, but mainly in solar. By 2050, the EU reference scenario expects that Italy hosts 26 GW wind capacity (9 GW in 2015) and 57 GW pv capacity (20 GW in 2015).

Key issues identified by (IEA, 2018), that could hamper the further expansion of wind power relate to:

- Uncertainty about the rules of the future incentive mechanism,
- Short construction and installation times for tender winners,
- Slow offshore wind expansion
- Spatial planning and social acceptance issues regarding on- and offshore wind

The upscaling of solar pv appears quite successful in Italy with solar pv already covering a 10% share of the power mix in several months per year.[39] However, the upscaling required to meet the estimated share of solar in 2050 according to the EU reference scenario (EC, 2016) is still substantial. Already, in some regions policy measures are taken to limit / better manage the (uncontrolled) upscaling of solar pv, especially for onshore solar (and wind) parks as they increasingly have an impact on the landscape.[40] We anticipate that any setback in upscaling solar and wind, will result in an increased use of natural gas use in Italy to satisfy an anticipated growing demand for electricity in other sectors such as heating and transport. In fact, for the 2017-35 period (SNAM, 2017) considers gas demand for power generation to grow 1.5% average each year to a level of 31.2 bcm (26.2 Mtoe) in 2035. This demand grow is likely to come also from the transport sector, which had a 2% electricity share in its final energy consumption, but the electricity share is forecasted to be between 5% and 8% by 2030 (Enel, 2018). Similar projections have been made for industry and the built environment, but are less extreme than in the transport sector.

3.5.3 Final non-energy consumption

The use of energy sources for non-energy use in Italy is quite high. It accounted for 6,3 Mtoe in 2016 and was mainly consumed by the (petro)chemical sector (4,1 Mtoe) (EUROSTAT, 2018). This use is above the EU-28 average and implies that this sector is fairly large. The composition of the non-energy use is conventional (90% oil and 10% gas) and is slightly below the EU-28 average. We anticipate that there is significant potential to increase the share of (renewable) gases at the expense of oil, but also biomass would be a suitable candidate considering the developments in the Italian bio-economy where several biorefineries (pilot, demo and industrial scale) plants are operational[41]. If the feedstock that currently exists of fossil energy carriers would be replaced by renewable alternatives, than either biomass demand or electricity-based hydrogen/SNG demand will rise substantially. Given that Italy has a sizeable domestic biomass potential (see (Elbersen, 2012), we consider that potential incremental future demand for (renewable) gases in this sector are estimated to remain moderate.

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[39] https://www.pv-magazine.com/2018/06/18/residential-commercial-pv-drives-solar-demand-in-italy/

[40] https://www.pv-magazine.com/2018/05/16/italy-new-q1-pv-additions-total-89-mw-sicily-introduces-moratorium-on-large-scale-solar/

[41] http://www.agenziacoesione.gov.it/opencms/export/sites/dps/it/documentazione/NEWS_2016/BIT/BIT_EN.pdf

3.5.4 Final energy consumption

3.5.4.1 Industry

Italy's industry is relatively energy intensive and had a final energy consumption of 26 Mtoe in 2016 of which 8.6 Mtoe natural gas (EUROSTAT, 2018). Other key fossil energy sources include solid fuels (1.6 Mtoe), oil (2.6 Mtoe), but electricity (9.7 Mtoe) and derived heat (2.7 Mtoe) combined provide close to 50% of energy demand for industry. Most electricity is consumed in; iron and steel, (petro) chemical, machinery and the food industry. Nearly 15% of all coal used in Italy is transformed into cokes and consequently used in the iron and steel industry for melting purposes. Gas is mainly used in the non-metallic minerals, iron & steel, machinery, food & tobacco, the petrochemical industry and for glass and pottery manufacturing. In order to facilitate the estimated decrease of oil (-26% rel. to 2015) and coal (-19% rel. to 2015) in gross inland consumption by 2050), the industry sectors have to implement energy saving measures as well as to shift towards alternative fuels.

(SNAM, 2017) estimates that in the 2017-35 period gas (natural gas and biomethane) consumption in industry "is expected to fall by 1.2% year-on-year" due to an efficiency recovery exceeding the growth dynamics associated with economic growth"; starting from gas demand of 14.6 bcm (12.2 Mtoe) in 2016 dropping to 11.6 bcm (9.7 Mtoe) in 2035. While within industry sectors there is scope for introducing renewable gases, given overall anticipated demand decline we consider that introduction of biogas (e.g. in food & tobacco or petrochemical sector) or hydrogen would directly substitute natural gas use.

3.5.4.2 Transport

Transport in Italy consumed 39 Mtoe of energy in 2016 and is a typical oil intensive sector. However, when compared to the EU-28 the oil's 92% share in the final energy consumed is rather low. This is caused by relatively large shares of electricity (2,4%) and gas (2,8%) in the final energy use. Especially the latter one is significantly different from the 0,9% average in the EU-28. There currently are over a million natural gas vehicles[42] (NGV) and close to 1.200 gas filling stations in Italy (NGVA, 2018). In 2016, there were 900.000 NGV in Italy, implying an increase of 10% over a time span of two years. Nevertheless, Italy's total vehicle population only exists of 2% NGV and the number of new registrations have dropped from over 72.000 per year in 2013 to 33.000 in 2017[43]. However, (SNAM, 2017) anticipate "a considerable growth of 7.9 billion cubic meters in 2035 of CNG for the private transport (+6.8 billion cubic meters compared to 2016), favoured by more stringent emission constraints from 2020 for engines and by development of LNG as fuel for heavy road transport and maritime transport". On top of that considerable investments in expansion of NGV fuelling infrastructure is planned by SNAM.[44]

On the other hand, new registrations of battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) are gaining market share and the number is almost growing with double digits (0,25% in 2016, 0,45% in 2018). Currently, there are roughly 16.000 electric, either fully or partially, vehicles on the Italian roads[45]. If the ambitious target of one million EV's by 2022 (Bloomberg News, 2018) wants to be reached, tremendous growth has to be ignited fuelled by heavy subsidies. Despite the fact that NGVs have a head-start relative to EVs, we anticipate that, especially for passenger

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[42] http://www.iangv.org/current-ngv-stats/

[43] http://www.eafo.eu/content/italy

[44] http://www.ngvglobal.com/blog/massive-natural-gas-filling-station-expansion-planned-for-italy-0807

[45] http://www.eafo.eu/content/italy

vehicles there NGVs could face considerable competition from EVs in the short to mid-term. The key question for the long-term is if the NGV sector in Italy would also be capable to make the switch to 100% renewable gas use, via biomethane as well as hydrogen and/or syngas.

While currently, in absolute terms, the use of biofuels in transport in Italy still is somewhat higher than natural gas, some estimate that liquid biofuel use in Italy will remain rather stable up until 2030.[46]

3.5.4.3 Built environment (other sectors)

This sector consists of various sub-sectors, of which services (e.g. commercial buildings) and residential, both public and private, are by far the largest. In total, 51 Mtoe of energy was consumed in the build environment in 2016. The main source of energy is gas (23.8 mtoe; (EUROSTAT, 2018)), and accounts for almost half of the total energy consumption in the build environment. Electricity is another large part and covers one third of the final energy demand, followed by oil and solid biomass. The latter on is predominately used for (space) heating in private houses and offers a sustainable alternative for space heating by means of gas.

Final energy consumption in the build environment is expected to remain roughly at the same level by 2050 as in the current situation (EC, 2016). Moreover, the situation of the build environment in Italy is relatively similar to that of the Netherlands. Both countries use relatively a large amount of gas in this sector, and the consumption of derived heat by means of a district heating network is only minor. This implies that Italy faces similar challenges as the Netherlands, but the approach appears to be different. However, while the Netherlands is anticipating a phase-out of low-calorific gas, Italy is anticipating a combination of natural gas expansion (e.g. in Sardinia to replace LPG use) and energy efficiency measures in the built environment. (SNAM, 2017) anticipates gas use in the residential and commercial sector to decline from the current level to around 20 Mtoe (23.8 bcm) by 2035. To enable this there are support schemes in place, such as the Energy Efficiency Tax Rebate Programme (IEA, 2016) that promote energy efficiency measures, such as thermal insulation and the installation of solar panels. This is also underlined by the NES (Italian Government, 2017) outlining the potential of highly efficient heat pumps in the heating and cooling sector. Furthermore, the NES aims at exploring the potential of expanding the district heating network significantly.

Given the combination of energy efficiency measures and further local expansion of gas use for heating we anticipate that future gas demand in the built environment in Italy will remain rather stable, which is in line with the EU reference scenario estimates (EC, 2016).

3.5.5 Analysis

Italy is highly energy import dependent, meaning that the transition towards renewable energy can cut two ways. There appears to be an intensive focus on energy efficiency and a goal of decarbonizing the power sector. The latter one should be achieved by phasing out coal by 2025, as is described in the NES (Italian Government, 2017). The energy transition in the power sector seems well under way, and Italy should be able to meet its RES-E ambitions, mainly with the help of solar and wind power and gas-fired power as a flexibility source. We anticipate that Italy is and will likely remain a considerable gas user. As a result we see a need for increasing supplies of renewable gases in order to decarbonise the gas system. While significant biomass and biogas potential is present within the country, meeting the country's potential demand for green molecules with biogas/biomethane is

[46] https://www.statista.com/statistics/863042/biofuel-demand-in-italy/

unlikely. To meet that demand, alternatives such as power to gas (i.e. hydrogen) or decarbonised natural gas (i.e. CCS/CCU) are needed for heating in the built environment, the petrochemical sector as well as within transport, for example to increase H_2 content in natural gas to fuel NGVs, see for example (Nanthagopal, 2011).

4 Supply side for (renewable) gases

4.1 Conventional biogas and biomass gasification

Conventional biogas comprises various subcategories, such as biogas extraction from landfill, the anaerobic digestion of organic wastes and animal manure as well as biogas production in waste/sewer water treatment plants. Biomass gasification involves the use of ligneous (or woody) biomass in a gasification process to produce synthetic natural gases. There are various studies that have tried to estimate the potential supply of biogas – derived from biomass – in the EU. These often cover conventional biogas only, but in several cases also biomass gasification. Table 24 provides an overview of supply potential estimates from different sources.

Table 24: Future supply potential for biomass-derived renewable gases in EU for 2020, 2030 (in Mtoe)

	Current (2016)	2020	2030	
Eurostat	16.6			Conventional biogas
(EBA, 2017)*		20.58	42	Conventional biogas and gasification
			16.8	*Gasification*
(CE-Delft, 2016)		19 – 23.5	28.8 – 40.2	Conventional biogas
NREAPs (Scarlat, 2015)		21.19		Conventional biogas
(AEBIOM, 2010)**		39.5		Conventional biogas
DBFZ (Scarlat, 2018)***			126 – 206	Conventional biogas and gasification
			55	*Gasification*

**EBA also includes SNG produced via biomass gasification*
***AEBIOM scenario study assumes large contribution from energy crops and considers a technical potential of 65.5 Mtoe*
****Refers to an estimate of the technical potential (not the economic potential)*

According to (EUROSTAT, 2018), EU-28 production of conventional biogas is at 16.6 Mtoe, which is about 1% of gross inland energy consumption. For the year 2020 the biogas supply potential range from 19 to 39.5 Mtoe. This mainly comprises conventional biogas, as biomass gasification is only still at pilot and demonstration scale. For the year 2030 this range for all biomass-derived biogas is about 29 – 206 Mtoe, and 17 – 55 for biomass gasification. We can observe that the various estimates show great variation and can differ by a factor four or five.

For 2050, there are few, if any, robust scenario or modelling studies available that estimate the supply potential of biomass derived renewable gases in the EU-28. Hence, we perform an own simplified calculation by using a simple multiplier factor based on some crude assumptions (see Table 25). We assume that there is not much additional potential for expanding conventional biogas, as only limited additional land used for food, feed, fibre and forest will be converted for producing energy crops. There still is some expansion possible in the area of wet manure digestion in the 2030-50. If we combine these assumptions we use a multiplier of 1.5 for conventional biogas. We consider biomass gasification to expand 2.5 its estimated 2030 supply potential as the technology matures in the 2030-50 period.

Table 25: Future supply potential for biomass-derived renewable gases in EU for 2050 (in Mtoe)

	2030	2050 (own estimate)	
(EBA, 2017)*	42	79.8	
	25.2	*37.8*	Conventional biogas
	16.8	*42*	Gasification
(CE-Delft, 2016)	28.8 – 40.2	42.3 – 60.3	Conventional biogas

DBFZ (Scarlat, 2018)**	126 – 206	244 - 364	
	71 - 151	*106.5 – 226.5*	Conventional biogas
	55	*137.5*	Gasification

**EBA also includes SNG produced via biomass gasification*
***Refers to an estimate of the technical potential (not the economic potential)*

4.2 Power to gas

There are hardly any future supply potentials studies available for power-to-gas. Most reports and studies focus on the techno-economic feasibility of power-to-gas supply chains, including large-scale electrolyser and hydrogen/SNG storage systems. Many of those 'business case' studies focus on using excess electricity (or avoided curtailed electricity) as a key input for electrolysis. However, the capital expenditure required for such facilities requires higher load factors to be economically viable, and thus also require more (renewable / nuclear) electricity to be generated.

Due to the lack of such assessments and studies, we will make an estimate based on relevant top-down demand estimates for gases in 2050. We consider here that power-to-gas will play only a small role in the gas mix in the EU up to 2030. According to the EU Reference scenario (EC, 2016), natural gas consumption in the EU is expected to remain relatively stable in the coming decades – varying somewhere between 400 and 450 bcm (336 – 378 Mtoe) in 2050. Eurogas[47] has come up with a similar estimate in their scenario study with the PRIMES model. They estimate that aggregate "gas demand can be up to [386 Mtoe] 460 bcm in 2050". (Eurogas, 2018) also estimates that 70% of will be supplied in the form of renewable gas.

If we consider that end-users will have a strong preference for having access to physical renewable gases, we can estimate aggregate demand for renewable gases in 2050 somewhere between 235 and 270 Mtoe. If we subtract the potential supply of biomass-derived renewable gases from that estimated demand we can estimate the required supply of power-to-gas (see Table 26).

Table 26: Estimated required aggregate supply of power-to-gas in 2050 (in Mtoe)

	Aggregate supply potential of biomass derived renewable gases	Required aggregate supply of power-to-gas in 2050	Aggregate demand for renewable gases in EU in 2050
	2050 (own estimate)		
(EBA, 2017)*	79.8	155.2 – 190.2	235 - 270
(CE-Delft, 2016)	42.3 – 60.3	174.7 – 227.7	
DBFZ (Scarlat, 2018)**	244 - 364	0	

**EBA also includes SNGs produced via biomass gasification*
***Refers to an estimate of the technical potential (not the economic potential)*

Considering that the DBFZ supply potential for biomass-derived renewable gases is a technical potential, we consider the EBA and CE Delft estimates a more realistic estimate. As a result 155 to 228 Mtoe of renewable gas from electrolysis needs to be produced.

To produce the required Mtoe of power-to-gas, electricity is needed. Assuming a conversion efficiency of electrolysis of around 60% (Götz, 2015), one would require about 1.6 times more Mtoe of electricity production, so around 258 – 380 Mtoe. This is roughly equivalent to about 683 – 1006 GW of installed wind capacity. To compare, Wind Europe (Wind-Europe, 2017) estimates in their scenario analysis that total installed wind capacity will be in the range of 256 – 397 GW by 2030. And estimates by (Wind-Europe, 2015) for 2050 go up to 600 GW installed wind capacity. However, both

[47] https://gaswindandsun.eu/

estimates consider the production of electricity to meet electricity demand for all sectors and uses, while our estimate of required power-to-gas focusses on the electricity requirements to meet the needs for production of renewable gases alone. Of course, these calculations are crude and based on several assumptions, but the envisaged gap is considerable and illustrative for the challenge to meet the demand for physical renewable gases in the future.

As an alternative means to make gas supplies greener there is also the possibility to remain using a higher share of fossil gases and compensate for their climate impact by buying carbon credits.

4.3 Climate compensated gases

4.3.1 Administrative compensation

Climate compensated gases involves the continued use of fossil gases (e.g. pipeline gas, LNG, industrial gases, shale gas), but offset their GHG emissions by buying carbon credits. Such credits can compensate for the full life cycle emissions associated with producing, processing and using fossil gases (e.g. venting, leakage, boil-off, combustion emissions).

If we follow the estimates made by (Eurogas, 2018), there still is about 101 – 116 Mtoe of fossil gases are being used in 2050 (30%). The ambition shall be to reduce the GHG impact of fossil gases by implementing a series of mitigating measures. However, as the footprint of fossil gases will never be zero or negative, some level of climate compensation might be needed.

To offset the GHG emissions associated with 101-116 Mtoe of fossil gases one would require a total of about 285 – 330 Mt CO_2-eq. in terms of carbon credits (With an assumed life cycle emission factor of 68 gCO_2-eq./MJ of natural gas) / A substantial part of these carbon credits will be available in terms of emission allowances (EUAs) for gas combusted within the boundaries of the EU ETS system. Assuming that roughly about 54% of all gases is used under the EU ETS (46% non-ETS), this would imply that at least the combustion emissions associated with gas use under the EU ETS are covered. For the remaining part of the life cycle emissions, additional climate compensation would be needed. Assuming that roughly 15% of the life cycle emissions of natural gas are not related to gas combustion the total amount of (non-ETS) carbon credits required in 2050 to offset GHG emissions related to gas use in the EU would add up to about 154 – 178 Mt CO_2-eq., which is equivalent to an annual purchase of 154 – 178 million carbon credits in 2050. To compare the total annual cap of the EU ETS (in 2013) was set at 2.084 million emission allowances (EUAs).[48]

In today’s global carbon offset market sourcing this amount of (non-ETS) carbon credits should be feasible as the potential supply and technical scope for developing GHG offset projects around the globe is nearly unlimited. However, if we compare this with the expected additional average annual issuance of offset credits (CERs) from the current project pipeline of the Clean Development Mechanism (CDM), which is roughly 100 mln. CERs per year in the 2013-20 period, we can observe that abundant supplies of carbon offset credits are not guaranteed. Also the annual average number of CERs issued during the Kyoto Protocol period 2008-2020 would add up to 197 million CERs being issues each year (UNEP, 2018). This alone would be just enough to meet the GHG offset demand for the remaining fossil gas use in the EU, but does not cover offsetting remaining fossil energy use related GHG emissions in other sectors. Of course, in addition to the CDM, there are also a broad range of other GHG offset schemes and markets, like the Voluntary Carbon Standard, the Gold standard that could supply the required volumes of carbon credits. However, one major uncertainty is what potential supplies of carbon credits will be there in 2050, within a decarbonizing world? The

[48] https://ec.europa.eu/clima/policies/ets/cap_en

1.5 °C and 2.0 °C degrees temperature increase pathways require total global remaining annual emissions to be resp. 8 and 23 $GtCO_2$-eq. by 2050 (UNEP, 2016). To compare, current global GHG emissions are around 50 $GtCO_2$-eq. (PBL, 2017), and with the current policy trajectory we are likely to already reach about 60 $GtCO_2$-eq., by 2030.

If Paris 1.5 °C degree ambitions in 2050 are being met, the remaining global scope for offsetting GHG emissions will be more limited. This will be particularly challenging as several sectors would have to focus on achieving negative emissions. If we consider that the CDM is the largest global GHG offset scheme, which has been able to ‘produce’ around 200 mln. carbon credits per annum, this captures roughly only 0.4% of the global GHG emissions. If we would add all global offset schemes together we might consider that the altogether the global carbon offset schemes will be able to capture roughly 1% of the global (remaining) GHG emissions. For 2050 this would imply a potential supply of carbon offset credits of 80 million carbon credits under the 1.5 °C degree pathway and 230 million credits under the 2.0^0 degree pathway. However, current (I)NDC trajectories show that we will not meet the 1.5 or 2.0 degree trajectories, which would only expand the future potential for carbon offsetting.

Aside from offsetting non-ETS and remaining life cycle emissions of fossil gases, there are also a range of renewable gases that do not have a zero or negative life cycle footprint. For example, using energy crops for biogas production could also involve life cycle GHG emissions related to energy use in machinery, but also (indirect) land use change related GHG emissions. If there would be a requirement that remaining life cycle GHG emissions from renewable gases would also need to be compensated, this would also generate additional demand for carbon offset credits from the gas sector.

4.3.2 Carbon capture use and storage

As an alternative to acquiring emission allowances or carbon offset credits, carbon capture reuse and geological storage can also be applied to reduce the GHG impact of fossil gases. To offset the GHG emissions associated with 101-116 Mtoe or remaining fossil gases by 2050 one would require to capture and/or compensate a total of about 285 – 330 Mt CO_2-eq. If we consider that only the source emissions (combustion emissions) of natural gas are eligible for CCS, about 15% of the total GHG footprint emissions of natural gas (68 gCO_2-eq./MJ of natural gas) still remains. This would bring the minimum annual CO_2 storage requirements at 242 to 280 Mt CO_2 by 2050. If we assume a linear increase from zero storage in 2030 to an annual storage of 242 – 280 Mt CO_2 by 2050, cumulatively geological storage capacity would add up to 2.4 – 2.8 Gt. This estimate excludes any underground storage capacity requirements for remaining CO_2 emissions from refineries, coal use, biomass use or other processes. For example, if we consider that by 2050 all CO_2 emissions related to the use of the remaining share of solid fuels (e.g hard coal, lignite) in the EU (82.8 Mtoe according to (EC, 2016) has to be captured and stored, that would roughly require a cumulative storage capacity of 3.4 Gt[49] for the 2030-50 period.

[49] With an assumed emission factor anthracite is 26.8 tC/TJ (44/12 ratio to convert C to CO_2), and assuming a start linear increase of coal-CCS from 0 Mt stored in 2030 to 342 Mt stored in 2050.

Table 27: Total estimated geological CO_2 storage capacity in the EU (in Mton)

Country	Annual total CO_2 emissions	Annual CO_2 emissions from large point sources	in deep saline aquifers	in hydrocar-bon fields	in coal fields
Slovakia	46	23	1716		
Estonia	21	12			
Latvia	4	2	404		
Lithuania	18	6	30	7	
Poland	325	188	1761	764	415
Czech Republic	128	78	766	33	54
Hungary	79	23	140	389	87
Romania	74	67	7500	1500	
Bulgaria	52	42	2100	3	17
Albania	0	0	20	111	
FYROM	6	4	390		
Croatia	23	5	2710	189	
Spain	423	158	14000	34	145
Italy	212	140	4669	1810	71
Slovenia	20	7	92	2	
Bosnia-Herze-govina		9	197		
Germany	864	465	14900	2180	
Luxemburg					
The Netherlands	180	92	340	1700	300
France		131	7922	770	
Greece	110	69	184	70	
United Kingdom	555	258	7100	7300	
Denmark	52	28	2553	203	
Norway		28	26031	3157	
Belgium		58	199		
Total		1893	95724	20222	1089

Source: (Vangkilde-Pedersen, 2009)

(Vangkilde-Pedersen, 2009) estimates total aggregated (aquifers, gas and oil reservoirs and coal fields) geological CO_2 storage potential in the EU at 117 Gton (

Table 27). If we assume that aquifers will be considered as least preferred storage option (i.e. due to potential leakage concerns), and consider that there will be a preference to store CO_2 in offshore hydrocarbon fields, this cumulative EU potential is reduced considerably to about 10 Gt. So by 2050 already more than 60% of this storage capacity would already be used for coal- and gas-CCS. This potential can be even further reduced due to potential spatial mismatches between onshore CO_2 point sources and offshore geological storage sites throughout the EU, which would put serious limits on both the technical, but also the economic potential of CCS in the EU.

5 The GHG performance of renewable gases: footprints and fossil comparators

5.1 Introduction

This report tries to estimate the future market uptake of renewable gases across the EU in the near future and by 2030 and 2050, but what are renewable gases, what varieties do we have or more specifically can we expect any differentiation in terms of environmental or sustainability performance be expected to develop in the market? In this chapter we focus on the GHG emissions associated with renewable and fossil gases, and current GHG accounting and compliance systems.

One way to distinguish between varieties of (renewable) gases is to identify their overall life cycle GHG footprint. As will be discussed below, there are several existing EU policy frameworks in the EU that are specifically including accounting rules based on life cycle analysis, in an effort to firmly establish more transparent and harmonized approaches to GHG accounting for (renewable) energy. As we can anticipate an ongoing and increasing need to decarbonise our energy systems, a focus on life cycle GHG footprint accounting will eventually have implications for the GHG emission reduction performance premium (or penalty) for a given unit of (renewable) gas or any other form of energy for that matter. We also briefly explore the differences of life cycle based GHG accounting and the current GHG accounting system under the EU emissions trading system (EU ETS). We argue that each specific type of (renewable) gas has its own unique GHG life cycle footprint impact.

5.2 Life cycle or source emission based GHG accounting?

Climate policy making in the EU dates back to the 1990s. The IPCC’s first assessment report (IPCC, 1990) stimulated the political debate on climate change and resulted in actions promoting the use of renewable energy and energy efficiency and savings in order to reduce greenhouse gas emissions. However, only after adoption of the Kyoto Protocol in 1997 (UNFCCC, 1998), which included implementation of quantified national emission limitation and reduction commitments for industrialised countries, climate change policies and actions at the EU member state level became more firmly established. These national emission reduction commitments not only demanded member states (as well as the EU as a whole) to mitigate by 2008-2012 a quantified share of their national GHG emissions compared to the 1990 levels, but also required countries to maintain a national accounting inventory system that keeps track of greenhouse gas emissions in the various sectors.

In the same year that the Kyoto Protocol (KP) was ratified (2005), the EU also launched phase I of the EU-wide Emissions Trading Scheme (EU ETS). The EU ETS targets the CO_2-emissions of the about 11,000 installations of the energy-intensive industries and power sector,[50] and applies a so-called source-emissions accounting system to monitor compliance. This system therefore requires monitoring of CO_2 emissions that occur at the installation level.[51] The underlying EU ETS Directive (EC, 2003) was adopted in 2003.

In 2009, the EU Renewable Energy Directive (EC, 2009) was adopted. This directive also put in place an obligation for EU member states to blend a certain percentage of biofuels with conventional

[50] And more recently included also aviation.

[51] Article 3: "‘installation’ means a stationary technical unit where one or more activities listed in Annex I are carried out and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution”

fuels in an effort to reduce GHG emissions from transport. EU Member States are also required to report on a number of sustainability impacts related to the use of biomass for biofuel production, including the climate change impact. For this reporting, article 4 of (EC, 2009) specifically states that a “life-cycle perspective of biofuels and other renewable fuels” should be applied. Annex V of (EC, 2009), established specific rules for calculating the GHG impact of biofuels, bio liquids and their fossil fuel comparators (FFC). These rules also consider the life cycle perspective, and include several life cycle emission sources, as well as potential emissions saving categories, including sinks.

Table 28: Key features of three different GHG accounting systems

	National Accounting	**EU ETS**	**Transport**
Legal basis	Kyoto Protocol	EU ETS Directive	RED and FQD Directives
Reporting via:	National Inventory Report (NIR)	Verified Emission Report (VER)	Registry Energy and Transport
Submits to:	UNFCCC	National Emission Authorities	Competent national authority on energy & transport
Relates to:	Source emissions and sinks within national borders	Source emissions at installation level	All life cycle related emissions and sinks within defined system boundary
Inclusion of indirect emissions?	No. Indirect emissions outside own borders are excluded	No. Indirect emissions occurring outside installation borders are excluded	Yes. Up to limits of system boundary set, but ILUC Directive applies
External GHG emission compensation allowed?	Yes. Has been the case with the use of CDM/JI credits used for national compliance	Yes. Has been the case with the use of CDM/JI credits allowed via EU ETS Linking Directive	N.A.
GHGs included	CO_2, CH_4, N_2O, PFCs, HFCs, SF_6	CO_2, N_2O and PFCs	CO_2, CH_4, N_2O, PFCs, HFCs, SF_6

The GHG accounting rules and methods, of the Kyoto Protocol, the EU ETS, and in EU transport all have their own key features. Table 28 shows the key features of these accounting systems. One of main differences is that the life cycle based approach (applied for fuels in transport) deviates strongly from source-emission accounting systems, like in the EU ETS and the national GHG accounting system. Currently, the EU ETS has no provisions in place mandating ETS installations to also cover full life cycle GHG emissions and/or indirect emissions related to up- and downstream activities. For example, upstream emissions can relate to the extraction and transport of fossil fuels; and downstream emissions can be related to the use of chemical fertilizers on land.

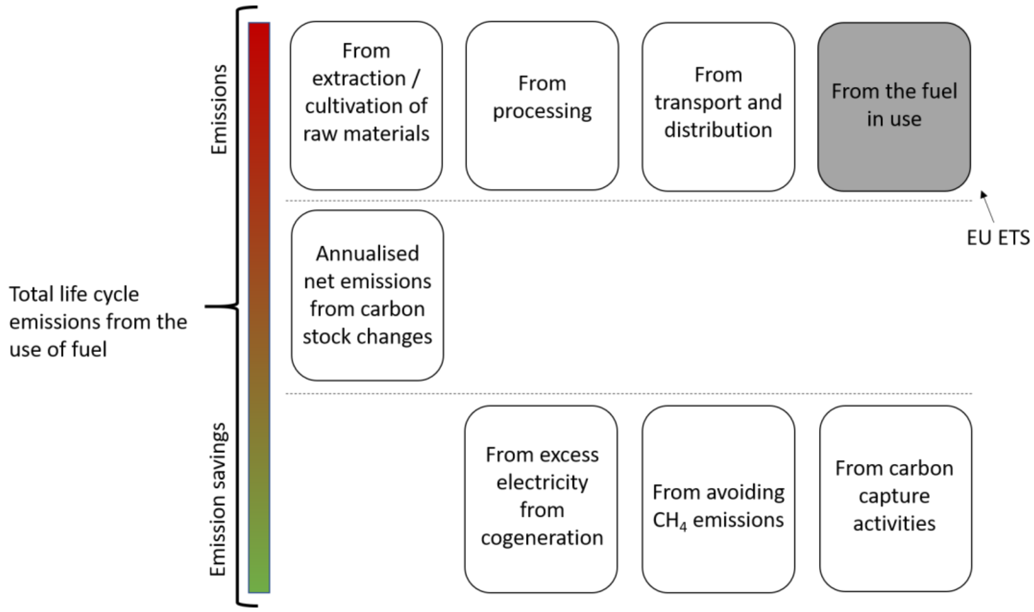
In contract, within the EU transport sector, fuel suppliers have to monitor and report life cycle GHG emissions for both biofuels and fossil fuels supplied to the sector. Under the EU ETS, these criteria currently only apply to the use of liquid biofuels at the EU level, while in some EU Member States GHG accounting and sustainability criteria also apply to non-liquid bioenergy.[52] For solid and gaseous biomass the EC decided not to introduce binding sustainability criteria for solid / gaseous biomass at the EU level (EC, 2014). The EU, however, did issue non-binding recommendations for this to Member States for stationary heat/power installations with a nameplate capacity of ≥1 MW_{th}. This allows EU Member States to voluntarily implement national sustainability certification schemes for

[52] In real practice, this mainly pertains to the use of solid biomass for electricity and heating, like wood chips and pellets; but also refers to renewable gases, like biomethane.

biomass use. Article 26 of the proposed directive (EC, 2017) suggests that a minimum level of sustainability criteria should also formally apply to "biomass and biogas for heating, cooling and electricity generation." The Directive also explicitly refer to the need for life cycle based GHG accounting.

So where most of the biomass sustainability certification schemes (e.g. ISCC, RSPO, Red Cert)[53] include a GHG criterion that applies life cycle based GHG accounting, many fossil fuels used in EU, particularly those used under the EU ETS, currently are only subject to source-emission GHG emission monitoring, reporting and compliance at the installation level; and thus do not cover the full life cycle. This distinction in scope and coverage of GHG accounting is illustrated in Figure 8. It provides a simplified overview of GHG emission sources, sinks and savings categories, relevant for life cycle based GHG accounting. Emission source categories include emissions from processing and transport of the energy commodity. Emissions savings categories include avoided GHG emissions from production of excess electricity, carbon capture and storage and/or avoided methane emissions from manure / digestate storage facilities or via gas flaring. Carbon stock changes (in forests or soils) can both be positive or negative, depending on the specific process and fuel under consideration.

Figure 8: The scope of source emission and life cycle based GHG accounting



While the EU ETS does not apply full life cycle accounting of GHGs, final use of energy (e.g. combustion) typically comprises the largest share (typically 60–100%, depending on fuel type, production process and origin) of total life cycle GHG emissions. On top of that other relevant emission categories have recently been added to life cycle based accounting. The ILUC Directive (EC, 2015) , which was adopted in 2015, for example includes specific accounting rules for calculating the annualised emissions from carbon stock changes caused by land-use change.

5.3 The impact of fossil fuel comparators on net GHG savings in different sectors

The distinction with regards to GHG accounting mentioned in section 5.2 is relevant for exploring the future dynamics in demand for renewable gases that will be exercised by the different sectors. If, for

[53] See: https://ec.europa.eu/energy/en/topics/renewable-energy/biofuels/voluntary-schemes

example, upstream life cycle emissions from renewable gases are not accounted for (i.e. do not count for EU ETS compliance purposes), EU ETS installations would be indifferent about what type of renewable gas is supplied (e.g. biogas from AD or from power-to-gas), whereas other sectors, that are subject to full life cycle GHG accounting, would have an interest in securing supplies of renewable gases with the lowest GHG footprint. Another important aspect of GHG accounting is what FFC is applicable, or what fossil fuel is substituted by the renewable gas. Does it substitute coal, oil, natural gas or an average unit from the electricity grid?

If we assume that life cycle based GHG accounting will become standard practice for all forms of (renewable and fossil) energies, it will be interesting to consider the specific life cycle GHG footprint for renewable energies (including renewable gases) as well of their FFCs. Comparing GHG footprints will help in determining whether or not a certain feedstock, process of making renewable gas is in line with global climate ambitions. We can anticipate that hydrogen derived from coal with CCS will have a different GHG footprint, relative to SNG generated with renewable electricity and renewable carbon.

Aside from that we can anticipate that within each end-use sector, a unit of renewable will substitute different types and mixes of fossil energy. In transport, a mix of diesel and gasoline will be substituted, whereas in the power sector a mix of coal, gas and nuclear is substituted. If we consider that each end-use sector has a different FFC, a single unit of renewable gas can – in principle – achieve three different emission reduction performances. To illustrate this, we start from a renewable gas with a typical GHG footprint of 25 gCO_2-eq./MJ of final energy. We assume that the technical infrastructure is in place so that this renewable gas can be used in a range of different sectors, including:

- Transformation sector; power generation
- Transport sector, as transport fuel
- Built environment or industry, for heating and cooking, and
- Petrochemical sector, as feedstock.

Currently the EC applies default FFCs for electricity, transport and heating.[54] Table 29 provides an overview of the life cycle emissions savings. This illustrates that the highest GHG savings for renewable gas currently can be achieved within the power sector. The final column also shows the difference between life cycle based GHG accounting and source emissions accounting under the EU ETS. Since the EU ETS does not cover any up- or downstream GHG emissions associated with the production and/or end-use of the energy used in their process, the footprint emissions of the renewable gas itself (25 gCO_2-eq./MJ) are not accounted for. This also implies that the electricity sector and industries that fall under the EU ETS, would in principle be indifferent to what type of renewable gas is consumed, as any kind will suffice for mitigation and compliance purposes.

Table 29: Life cycle based FFCs for different sectors (in gCO_2-eq./MJ)

	GHG footprint renewable gas	Default FFC	Net life cycle GHG emission savings	GHG saving under EU ETS
Power sector (EU-ETS)	25	183	-158	-183
Non-energy use (EU-ETS)	25	N.A.	25	0
Transport	25	94	-69	-
Built environment	25	80	-55	-

[54] These fossil fuel comparators are subject to change/updates, as the baseline energy mix in the EU and its Member States changes over the years.

Currently, there are no official FFC values for energy commodities that are used for non-energy purposes, such as oil used in the petrochemical industry for production of plastics. This might seem logical since that energy commodity is not combusted, and hence there are no GHG emissions emitted at the installation level. However, even such processes have life cycle emissions which should be accounted for. But under the EU ETS there would be a low incentive to replace oil with renewable gas in this sector, as substituting those would not lead to a reduction in installation level emissions. In fact, these installations in this sector would have a greater incentive to use renewable gases for basic energy (heating) purposes, as this would count as a net GHG reduction at the installation level under the EU ETS. However, for future reference it would seem appropriate to start considering full life cycle GHG emissions under (or linked) the EU ETS, as it currently could distort the overall quantities offered and supplied to a given sector. Such emissions could also include the postponed (or delayed) GHG emissions associated with petrochemical products such as plastics and chemical fertilizers.

5.4 Different FFCs for fossil energy

Where the EU currently applies default FFC for basic energy services (electricity, transport and heating), we could also differentiate even further and focus on fuel specific emission factors within one sector. The current default FFC for transport (94 gCO_2-eq./MJ), essentially is based on a weighted average of the specific life cycle emissions of diesel and petrol. Table 30 shows the life cycle GHG intensities of a range of transport fuels.

Table 30: Life cycle GHG intensity of different transport fuels (in gCO_2-eq./MJ)

Raw material source and process	Fuel placed on the market	Life cycle GHG intensity
Coal	Compressed Hydrogen in a fuel cell	234,4
Coal-to-Liquid	Petrol	172
Coal-to-Liquid	Diesel or gasoil	172
Oil shale	Diesel or gasoil	133,7
Oil shale	Petrol	131,3
Natural bitumen	Diesel or gasoil	108,5
Natural bitumen	Petrol	107
Natural gas using steam reforming	Compressed Hydrogen in a fuel cell	104,3
Conventional crude	Diesel or gasoil	95
Natural Gas-to-Liquid	Petrol	94,3
Natural Gas-to-Liquid	Diesel or gasoil	94,3
Conventional crude	Petrol	93,2
Waste plastic derived from fossil feedstocks	Petrol, diesel or gasoil	86
Natural Gas, EU mix	Liquefied Natural Gas in a spark ignition engine	74,5
Any fossil sources	Liquefied Petroleum Gas in a spark ignition engine	73,6
Natural Gas, EU mix	Compressed Natural Gas in a spark ignition engine	69,3
Coal with Carbon Capture and Storage of process emissions	Compressed Hydrogen in a fuel cell	52,7

Source: (EC, 2015)

The numbers show that using renewable gas (or renewable electricity/fuels) to substitute coal[55], oil shale and/or natural bitumen derived transport fuels makes most sense from a climate change mitigation perspective. Substituting the use of natural gas derived transport fuels with renewable gas would result in the lowest climate benefits per unit of energy. So, even within a specific sector there is scope to trigger the market to substitute the most GHG intensive fuels first.

For promoting the use of renewable gases in transport (and other sectors), one of the key questions is what the appropriate FFC will be. If one reasons from a more technical point of view, renewable gases would simply take the place of fossil gases in transport. Hence, in that case natural gas (EU-mix) could be the FFC. However, we already observed that substituting natural gas has a relatively low emission reduction performance. However, if we take a broader energy transition perspective we aim to gradually reduce the dependence of oil in transport, hence any additional unit of renewable gas used in transport comes at the expense of liquid fuels. With a higher FFC value for liquid fuels we would also achieve a higher net GHG saving and would provide a stronger incentive to supply more quantities of renewable gas to the transport sector. The European Biogas Association (EBA, 2016), confirms this by stating that “natural gas, a low-carbon fossil fuel and an alternative fuel, cannot be used as the FFC of biomethane”. (EBA, 2016) also suggests to use an average default fossil comparator for all biofuels in transport and reject the idea of using natural gas as the FFC in transport. We do like to note that, although the use of an average default FFC seems fair from a level playing field perspective within the transport sector; it is unlikely that an average default fossil fuel comparator will be agreed upon and applied for all economic sectors. The latter observation might be relevant in light of a potential distorting of market demand and competition between end-use markets. We anticipate that sector specific fossil fuel comparators will remain in place and thus will likely affect the future supply-demand dynamics for renewable gases in all sectors for electricity, heating/cooling, transport and/or non-energy use; simply because higher net GHG saving can be achieved in another sector relative to the other (by definition of different FFCs used).

5.5 Comparing GHG Footprints of renewable gases

The previous section shows that the level of an FFC can determine in which sector the highest net GHG savings can be achieved. The general logic of phasing out the most GHG intensive fuels first applies here. However, due to life cycle based accounting principles, we will also be able to distinguish one unit of renewable from another in terms of their GHG footprint. A renewable gas with a low GHG footprint, will achieve higher net GHG savings compared to a high GHG footprint renewable gas. By differentiating in this manner there is also scope for differentiating in the price of renewable gases (i.e. one unit of renewable energy will have a higher climate benefit relative to the other).

Table 31 provides an overview of typical GHG footprints for various renewable gas supply chains. Particularly, the anaerobic digestion of wet manure for production of renewable gas has a beneficial (and even) sometimes negative GHG footprint. Such a negative footprint mainly results from CH_4 emissions avoided during manure storage, and provides a considerable competitive advantage relative to other renewable gases in terms or GHG performance benefits to the end-user. Table 31, also shows two electrolysis based (e.g. power-to-gas) processes for the production and supply of compressed renewable gases. Both processes have only a marginal GHG footprint. Processes for anaerobic digestion of biowastes generally have a lower GHG footprint relative to food crops (maize)

[55] Perhaps, except when a large share of the associated GHG emissions is captured and stored (CCS).

used for biogas production. This is mainly due to additional GHG emissions for food crops associated to cultivation / harvesting and/or indirect land use change.

Table 31: Life cycle GHG intensity of different renewable gases for different end-uses (in gCO_2-eq./MJ)

Raw material source	Process	Fuel placed on the market	DEFAULT life cycle GHG intensity
Wet manure	Biogas for biomethane(4) - closed digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	-100
Wet manure	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - close digestate	Electricity and/or Heat	-89
Wet manure	Biogas for electricity - Case 1 (Electricity and heat from CHP) - close digestate	Electricity and/or Heat	-84
Wet manure	Biogas for biomethane(4) - closed digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	-79
Wet manure	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - close digestate	Electricity and/or Heat	-78
Wet manure	Biogas for biomethane(4) - open digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	1
Renewable energy	Sabatier reaction of hydrogen from non-biological renewable energy electrolysis	Compressed synthetic methane in a spark ignition engine	3,3
Wet manure	Biogas for electricity - Case 1 (Electricity and heat from CHP) - open digestate	Electricity and/or Heat	3,4
Wet manure	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - open digestate	Electricity and/or Heat	9
Renewable energy	Electrolysis fully powered by non-biological renewable energy	Compressed Hydrogen in a fuel cell	9,1
Wet manure	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - open digestate	Electricity and/or Heat	10
Biowaste	Biogas for electricity - Case 1 (Electricity and heat from CHP) - close digestate	Electricity and/or Heat	13
Biowaste	Biogas for biomethane(4) - closed digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	14
Biowaste	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - close digestate	Electricity and/or Heat	21
Wet manure	Biogas for biomethane(4) - open digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	22
Biowaste	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - close digestate	Electricity and/or Heat	22
Maize whole plant	Biogas for electricity - Case 1 (Electricity and heat from CHP) - close digestate	Electricity and/or Heat	28
Maize whole plant	Biogas for biomethane(4) - closed digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	30
Maize whole plant	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - close digestate	Electricity and/or Heat	35
Biowaste	Biogas for biomethane(4) - closed digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	35
Maize whole plant	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - close digestate	Electricity and/or Heat	38
Biowaste	Biogas for electricity - Case 1 (Electricity and heat from CHP) - open digestate	Electricity and/or Heat	44
Maize whole plant	Biogas for electricity - Case 1 (Electricity and heat from CHP) - open digestate	Electricity and/or Heat	47
Biowaste	Biogas for biomethane(4) - open digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	50
Maize whole plant	Biogas for biomethane(4) - closed digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	51
Maize whole plant	Biogas for biomethane(4) - open digestate - off gas combustion	TRANSPORT FUEL (mix) or fossil gases	52
Biowaste	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - open digestate	Electricity and/or Heat	52
Maize whole plant	Biogas for electricity - Case 2 (Electricity from grid heat from CHP) - open digestate	Electricity and/or Heat	54
Biowaste	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - open digestate	Electricity and/or Heat	57
Maize whole plant	Biogas for electricity - Case 3 (Electricity from grid heat from boiler) - open digestate	Electricity and/or Heat	59
Biowaste	Biogas for biomethane(4) - open digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	71
Maize whole plant	Biogas for biomethane(4) - open digestate - no-off gas combustion	TRANSPORT FUEL (mix) or fossil gases	73

Source: (JRC, 2017) and (EC, 2015a)

To illustrate this dynamic more clearly, if one MJ of renewable biomethane from wet manure (at footprint -100 gCO_2-eq./MJ) avoids the use of one MJ of transport fuel (default comparator -94 gCO_2-eq./MJ), this would result in a net GHG emission reduction performance of -194 gCO_2-eq./MJ. To compare, the use of biomethane from maize would ‘only’ result in a net life cycle GHG emission reduction of (-94 + 73 =) -21 gCO_2-eq./MJ. This shows that it matters a great deal where a transport fuel supplier - that has to reduce the GHG emissions of its fuel supply portfolio – sources its renewable fuels/gas from. We therefore anticipate that in future markets, where life cycle GHG accounting and compliance based systems are in place, price differentiation will be applied between renewable gases with different GHG footprint performances. However, under the current GHG accounting rules of the EU ETS such differentiation is not likely to occur, as the buyer will not be affected by life cycle emissions in terms of its compliance under the ETS scheme.

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Annex 1

Table 32: Energy use in EU-28 countries, solids, oil, gas, nuclear and renewables in EU-28 countries (in Mtoe)

	GFI		SOLIDS		OIL		GASES		NUCLEAR		RENEWABLES	
	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050
EU28	1667	1492	278	83	580	488	388	379	213	164	206	379
AT	33	32	3	1	12	11	6	8	0	0	10	12
BE	55	52	3	1	23	22	15	20	7	0	4	8
BG	16	15	6	3	4	3	2	2	4	4	2	4
HR	8	8	1	0	3	3	2	3	0	0	1	2
CY	2	2	0	0	2	1	0	1	0	0	0	0
CZ	41	40	15	6	9	10	8	8	7	12	4	6
DK	17	17	2	0	7	6	4	3	0	0	4	7
EE	6	5	4	2	1	1	1	1	0	0	1	2
FI	34	32	4	1	9	7	3	2	6	9	11	13
FR	256	208	9	2	80	67	39	33	109	56	24	52
DE	323	256	78	37	112	80	74	68	24	0	39	69
EL	26	19	7	0	13	9	3	4	0	0	3	6
HU	23	27	3	0	6	8	8	8	4	7	2	4
IE	14	15	2	0	7	7	4	4	0	0	1	4
IT	159	145	16	2	61	45	56	59	0	0	22	39
LV	4	4	0	0	1	2	1	1	0	0	2	2
LT	7	7	0	0	2	2	2	2	0	2	1	2
LU	5	6	0	0	3	4	1	2	0	0	0	1
MT	1	1	0	0	1	0	0	0	0	0	0	0
NL	84	75	9	1	35	32	34	30	1	0	4	13
PL	102	110	53	20	26	28	13	25	0	15	10	22
PT	23	19	3	0	11	9	3	2	0	0	5	7
RO	33	37	6	2	9	9	10	11	3	6	6	10
SK	17	19	3	2	3	4	5	5	4	6	2	3
SI	7	7	1	0	2	2	1	1	1	2	1	2
ES	125	104	16	1	54	49	25	20	14	0	16	35
SE	47	48	2	0	12	10	1	3	14	14	19	23
UK	200	179	31	2	71	58	68	56	16	31	13	31

Source: (EC, EU Reference Scenario 2016 - Energy, Transport and GHG Emissions Trends to 2050, 2016)