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ELECTRICITY AND GAS COUPLING IN A DECARBONISED ECONOMY

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Definitions and abbreviations

- **Blue hydrogen:** hydrogen produced from fossil natural gas with CCS via steam reformation technologies (e.g., steam methane reformation, SMR, and autothermal reforming, ATR, technologies); carbon content of produced H_2 is 0; note that production of blue H_2 with CCS still emits CO_2, depending on assumed capture rate of SMR or ATR;
- **Green hydrogen or power-to-H_2:** hydrogen produced from renewable electricity via water electrolysis; carbon content of H_2 is 0;
- **Diesel:** fossil fuel based diesel;
- **e-gas:** synthetic methane produced by combining H_2 with CO_2 from bioenergy hence carbon neutral;
- **power-to-gas (PtG):** a group of technologies to produce carbon neutral CH_4 (e-gas) using hydrogen and CO_2 from biomass generation or biogas upgrading to biomethane;
- **e-liquids:** synthetic diesel produced by combining H_2 with CO_2 from bioenergy hence carbon neutral;
- **power-to-liquid (PtL):** a group of technologies to produce carbon neutral synthetic diesel (e-liquids) using hydrogen and CO_2 from biomass generation or biogas upgrading to biomethane;
- **P2X:** refers to either PtG or PtL as understood above;
- **Electricity network:** network to transport electricity;
- **EU:** where not explicitly mentioned, *EU* means aggregate of 27 member states of the European Union;
- **Gas network:** network to transport CH_4;
- **H_2 network:** network to transport hydrogen;
- **Natural gas:** natural gas of fossil origin;
- **Biomethane or renewable gas:** upgrading of biogas to the specification - 96% CH_4 and 3% CO_2 - allowing injection into existing gas grids. Biomethane is carbon neutral (i.e., its carbon content of is 0), just like biomass for power generation. In the process of upgrading biogas, the CO_2 in the biogas is captured and either stored (negative emissions) or used to produce carbon neutral PtG and PtL;
- **Europe** refers to EU27, UK, Switzerland and Norway.

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EXECUTIVE SUMMARY

Executive summary

The European Union is committed to a world-leading decarbonisation of its energy system. In the Paris Agreement in December 2015, the international community pledged to bring net emissions globally to zero by the second half of the 21st century. In November 2018, the European Commission (EC) announced its ambitious energy and climate strategy that set outs three policy scenarios for achieving 100% GHG emissions reduction by 2050 relative to the 1990 level. In the UK, in May 2019 the Committee on Climate Change (CCC), an independent non-departmental advisory body to the UK government, published its Net Zero report recommending stepping up UK ambitions, and the government quickly thereafter adopted a net zero target into law on 27 June 2019, followed two days later by France. Most Member State (MS) have now adopted net zero targets in domestic legislation and some countries have even earlier target dates (Finland (2035), Austria (2040) and Sweden (2045)). Norway, a member of the single market in energy, also has a net zero target. As evidence of its near-term commitment to net zero, in December 2020 the EU strengthened its 2030 target relative to 1990 from 40% to 55%.

While the prospects for electricity decarbonisation to 2030 are promising, the necessity of deep decarbonisation of the entire energy system by 2050 remains challenging. To be able to fully confront the challenges and trade-offs posed by deep decarbonisation, policy analysis will need to simultaneously examine both the long-time horizons needed to shift investment and the short time scales inherent in a system where variable renewables dominate. The EC 2030 energy package and the 2050 long-term energy and climate strategy were supported by PRIMES modelling. In the context of rising attention to so-called *"sector coupling"* in Brussels policy circles, recent energy modelling studies focused on the role of different energy carriers (e.g., natural gas, biomethane, hydrogen and electricity), corresponding infrastructure and sources of flexibility in meeting European deep decarbonisation targets by 2050.

While there are numerous energy system configurations to reach deep decarbonisation by 2050, any credible pathway to reach any of this ambitious design should take into account the current system that Europe and the EU has inherited. In this respect, the EU's current energy system is largely dominated by fossil fuels, especially in heating and transport. Although, tremendous progress has been achieved in reducing the GHG emissions by 23% (by 2018) relative to the 1990 level (total GHG emissions reduction totalled 1330 mt CO_{2e} in 1990-2018), mainly due to the RES penetration in power sector and energy efficiency, a huge task lies ahead, if we are to achieve net zero target of GHG emissions by 2050. This is just 30 years to reduce GHG emissions by a factor of at least 3 (3 x 1330 mt CO_{2e} = 3990 mt CO_{2e}) of the total reduction that we achieved in the past 29 years (1990-2018). That is, whatever we have done to date has to be done at roughly three times faster – a challenge that is only achievable with a joint effort on both electricity and gas system planning, integrating all energy-end use sectors and applications. One of the greatest challenges for such a jointly planned energy system is to build out flexibility and resilience to achieve net zero by 2050, taking into account the current state of the energy system and the demands it has to satisfy.

Studies on deep decarbonisation of economies abound in the academic literature. However, it is only relatively recently that selected studies have started to examine the flexibility requirements from an energy system integration perspective, stressing the importance of joint planning of energy vectors and supporting infrastructure for cost-effective deep decarbonisation of energy systems. Thus, this research project systematically analysed the sources of flexibility and complementary trends between various low-carbon energy vectors in EU's deep decarbonised energy system in 2050 using state of the art energy system optimisation model.

Our model offers spatial and temporal resolution of energy demand and renewables production across Europe to allow detailed modelling of the benefits of sector coupling. We model 12 European regions covering geographical areas of EU27, UK, Switzerland and Norway as well as modelling hourly time steps to include important intraday dynamics in supply and demand. On the demand side, our model covers buildings, road transport, industry and other sectors. We model power generation and storage technologies, main end-use technologies in buildings and transport, cross border trade in electricity, gas bioenergy, and petroleum products. In our model, primary supply sources include coal, uranium, natural gas, biomethane, hydrogen, e-gas and e-liquids. We also include CCS technologies in electricity generation and hydrogen production.

Using our model, we systematically analysed four scenarios – a core scenario which strives to reach net zero (NZ) GHG emissions by 2050 for Europe (EU, UK, Norway, and Switzerland) and three variants: (i) 90% GHG emissions reduction scenario, (ii) a NZ-e which favoured electrification, and (iii) a NZ-g which favoured gasification (NZ-g); both NZ-e and NZ-g reach net zero and are extreme versions of the core NZ scenario. These scenarios and detailed sensitivity analysis cover variations in network costs, system integration technologies and storage.

The modelling results both from the 90% and core NZ scenario suggest the central role of the electricity supply sector and electricity-based end-use technologies (e.g., EVs and heat pumps) to deliver deep decarbonisation. This conclusion is very consistent with other academic modelling studies and it is consistent with the EC' own scenario modelling conclusion (in its EC LTS) in that it is a no regret policy option to further support rapid roll-out of renewable generation and direct electrification to reach net zero by 2050. In particular, our NZ scenario shows a more than doubling of annual electricity production and a halving of methane demand in 2050. At the same time, our NZ scenario shows the emergence of a large hydrogen demand similar to the level of the methane demand in 2050. All three of our NZ scenarios show extensive electrification of surface transport, rising to 100% of cars and public transport and 60% of trucks under NZ-e.

To integrate a large share of variable renewable electricity (VRE) (at least 78% of total electricity production) in our NZ scenario, electricity is much more heavily traded across borders and cross-border transfer capacity is substantially increased by 2050. For example, in our NZ scenario, while final electricity consumption increases by ca. 50% (4,175 TWh vs 2.784 TWh in 2018) the total electricity trade in 2050 increases by ca. 208% (i.e., by a factor of 3) compared to total trade in 2018. An additional 2,600 TWh of electricity production are destined to be transformed to hydrogen and e-gas. This highlights the importance of cross-border electricity trade and market rules to complete EU's single market for electricity trading.

By contrast methane demand is significantly served by domestically produced biomethane and e-gas. Thus, to meet the NZ target we see a need to scale up biomethane production in the EU from the current level of 23 TWh (2018[1]) to 1,150 TWh by 2050 in our NZ scenario. Being domestically produced, cross-border methane transfers are significantly reduced - the total cross-border trade in CH_4 reduces by a factor of 4 compared to 2018. If we disregard fossil gas imports in NZ 2050 then the share of cross-border trade in biomethane and e-gas (the two fuels that are produced at "home") is quite marginal – 30% of final CH_4 consumption and is only a *quarter* of the value of cross-border electricity trade in NZ 2050. This is a complete reversal of the 2018 situation when we saw that cross-border trade (mainly due to huge import value) in gas exceeded that of electricity by a factor of 7 at least.

[1] https://mstreport.gasforclimate2050.eu/supply/

In relation to H_2, the role of cross-border trade could vary significantly, depending on the feasibility of deploying dedicated widespread RES capacity at scale in Europe, as well as the potential scope of local energy systems self-balancing. In our NZ 2050 scenario where local energy systems may be able to self-balance, the role of cross-border trade in H_2 might potentially be limited for a similar reason to the one we see for CH_4 cross-border trade: by using a combination of end-use and grid-scale flexibility solutions, cross-border H_2 capacity could be less needed to balance the fluctuations in supply and demand for H_2. However, if the timely deployment of the required additional RES capacity, as envisaged in our NZ 2050, was to be hindered by, say, administrative constraints, the role of cross-border trade in H_2 could gain relevance. In addition, if the costs of producing H_2 and RES-E developments in every EU MS vary substantially and/or imports of H_2 from outside the EU (from North Africa, Ukraine, Russia, for example) happens at scale, then in this context, the development of a single EU hydrogen market supported by significant cross-border H_2 trade would be key in reducing price spreads across countries. All in all, European market integration for home grown CH_4, H_2 and electricity will be of huge importance, with electricity gaining centre stage in the regulatory debate on further integrating energy markets.

While annual methane demand halves in NZ, peak methane demand only declines by 30% (relative to 2018), with methane use focussed in the distribution system and allocated to domestic use. In our NZ 2050, we see the emergence of H_2 transmission and distribution networks but the size of those networks are modest compared to the CH_4 network (the H_2 networks grow to 40% of the size of the CH_4 transmission network and 21% of CH_4 distribution). This disparity is because H_2 transmission will need to manage fluctuations in green H_2 production while the smaller H_2 distribution network is built mainly to serve transport and industry sector demand. As mentioned earlier, the size of H_2 networks also depends on the underlying assumptions on H_2 cross-border trade from other regions and within Europe, as well as on the feasibility of installing RES-E capacity at scale within Europe.

The electricity sector plays a central role in NZ. To deliver NZ, electricity networks need to expand by a factor of 3 relative to 2018. While the current European CH_4 system's capability is at least three and a half times larger than the electricity counterpart, in our main NZ scenario, the electricity network would grow to almost the same size as the CH_4 system in 2018 (just 13% smaller). Since the electricity system is expected to grow both in terms of energy flow as well as in terms of capacity, policy and regulatory provisions to support efficient expansion of both transmission and distribution capacity will become important as we increasingly rely on electricity system to decarbonise and reach NZ.

In end use, heavy-duty transport and industry decarbonisation drive the demand for hydrogen in our NZ scenario. This is because of our assumptions about the limits to electrification of road transport and the nature of our assumed costs. The 90% scenario still decarbonises the methane network with biomethane and e-gas. Electricity generation is only slightly lower than in the NZ scenario. However, in the 90% scenario there is much less hydrogen production and use, because gasoline and diesel remain significant in heavy-duty and road transport segments, as well as in the aviation and shipping sectors. CCS is utilised substantially in NZ and less so in the 90% scenarios: total CO_2 sequestration is 100 $mtCO_{2e}$ in our 90% scenario compared to 406 $mtCO_{2e}$ in NZ. The quantity of negative emissions (from biomass with CCS) is less than 10% of the NZ figure in the 90% scenario (20.7 $mtCO_{2e}$ in the 90% compared to 252.7 $mtCO_{2e}$ of negative emissions in the NZ scenario). The comparison between the NZ and the 90% scenario show that the incremental cost of achieving net zero over the 90% scenario is 85 bn Euro p.a., equivalent to a marginal carbon price of 148 Euro per tonne.

To check the robustness of our modelling results, we produced a range of sensitivity analyses for various technology and cost parameters. We also developed two extreme scenarios for net zero:

NZ-e where the assumptions favour electrification; and NZ-g where the assumptions favour gasification.

A key difference between the NZ-e and NZ-g "extreme" scenarios is the much higher production and use of electricity – by a factor of 2 – in NZ-e, with electrolysis covering 100% of hydrogen production. By contrast NZ-g mostly uses natural gas with CCS to produce the required hydrogen. Relative to NZ, total electricity generation is 25% higher in NZ-e and 30% lower in NZ-g.

Our sensitivity analysis suggests the limited extent to which capital costs of the electricity network, the methane network, the hydrogen network, electrolysers and P2X technologies impact the shares of different fuels in final consumption. Overall, under a binding net zero target the impact is generally small in aggregate within our quite wide but finite cost bounds.

Another conclusion that is emerging from this sensitivity analysis is that under a binding net zero GHG target, all energy vectors, traditional and new, complement each other either directly or indirectly. For example, by varying network cost assumptions, we found that CH_4 and electricity networks are complementary in the integrated energy system while CH_4 and hydrogen compete for direct final uses but are complementary in the primary supply sector. Further, we found that electricity and e-fuels are complements and that the role of green H_2, P2X and hybrid heat pump is to further integrate the energy system under net zero.

One conclusion that universally applies to all our modelling scenarios and sensitivity analyses is the increased need for both traditional and new forms of flexibility to support deep decarbonisation. In particular, spatial flexibility (investments in electricity grids and cross-border interconnections) is required to support rapid roll-out of VRE from local and remote locations (e.g., North Sea offshore wind), while traditional inter-seasonal flexibility is delivered by a combination of (i) traditional seasonal gas (CH_4) storage, and (ii) new forms of seasonal storage – green H_2 production and storage. The latter serves mainly to support the differences between winter and summer VRE production (in particular solar) to minimise potential curtailments, while the former supports seasonal variations in heat load and hence requirements to shift biomethane and e-gas supply to buildings.

Intraday flexibility in our NZ energy system is mostly delivered by:

1. electrical energy storage: both traditional storage solutions like hydro-based electrical storage and generation as well as new forms of intraday flexibility – V2G from EVs and electrical energy battery storage;
2. H_2-based intraday storage solutions, like pressurised H_2 tanks and liquid H_2 storage technologies;
3. and, hybrid heat pumps which allow for greater system flexibility associated with within day ramping requirements to meet heat loads during winter days.

To deliver the NZ target and advance direct electrification of final energy demand, seasonal flexibility is needed and it is largely delivered by gas-based solutions (e.g., H_2 production, storage and final demand and CH_4 underground storage) which help:

1. to provide seasonal flexibility during the spring/summer months when solar PV production typically exceeds electricity demand; and
2. to manage seasonal heat load when demand for heating is high during winter months relative to summer months.

Based on our modelling results, a number of high-level regulatory and policy recommendations emerge. We reaffirm the benefit of comprehensive and uniform pricing of electricity, gas and carbon across Europe. The single market in electricity, methane, hydrogen and carbon are essential to fully exploiting sector coupling in the pursuit of net zero.

We reconfirm the crucial role of zero carbon electricity in achieving net zero. Thus substantial expansion of low carbon renewables from today's level is at the heart of a zero carbon energy system. This suggests the need to continuing supporting the roll out of wind (onshore and offshore) and solar across Europe, the requirement to promote cross-border interconnection, the need to strengthen domestic transmission and distribution grids, the further extension of electrification of heating and transport and the use of zero carbon electricity in for conversion to mobile fuels.

We highlight the importance of the proper organisation of the gas system for net zero. In particular, we emphasise the need for co-ordination between gas and electricity TSOs (e.g. in system planning and operation) and DSOs to carry out joint testing of assets and appropriate funding mechanisms for gas network assets.

We identify the primary importance of fixed costs in driving underlying costs in the European energy system. Working out how to allocate fixed costs and to which consumers will be essential to the success of the decarbonisation of gas demand. This is because, in our modelling, current consumers of gas may have to finance new gas networks and conversion facilities in circumstances where the units of energy required will not be rising. Definitions will need to be standardised, in particular around green and blue hydrogen and power to gas, in order to underpin the single market. We highlight issues around the initial use of hydrogen.

We point out the potential benefits of the financial integration of electricity and gas sectors. This might involve harmonisation of regulated rates of return across the electricity and gas sectors, and, make use of green gas certificates similar to green electricity certificates. We note the fact that our net zero scenarios may depend on the actions of specific countries and developments outside of the EU and these need to be carefully watched for their impact on EU policy.

In terms of immediate next steps, we suggest that there is still scope for R&D and large-scale experimentation and extending carbon pricing and energy tax harmonisation, in ways which promote deep decarbonisation and sector coupling. As for near term policy, it should focus on a suite of options including: accelerating the deployment of RES-E, promoting electrification and power systems at its core meanwhile developing a plan for the decarbonisation of the economy in general, with an emphasis on the transport and heating sectors. Heating and transport sector decarbonisation can be promoted by appropriate intermediate year targets, stronger CO_2 price signals in these sectors, promotion of net zero heating and transport and heating technologies, expansion of cross-border electricity interconnection and distribution grids, digitalization in power grids and avoiding greenwashing solutions that do not actually put Europe on a path to net zero.

Overall, net zero remains an extremely technologically challenging policy goal, involving the roll out of multiple new technologies at scale within, as already mentioned, a 30 year time frame to achieve a level of decarbonisation around three times that achieved over the last 30 years. The wholesale failure to scale up any one of the key technologies on which our net zero scenarios depend – RES-E, biomethane, hydrogen or CCS – will block the path to net zero, necessitating a currently unforeseen technological break-through in the next 30 years.

01

INTRODUCTION

1. Introduction

The European Union is committed to a world leading decarbonisation of its energy system. In December 2015, the international community committed in the Paris Agreement to bringing net emissions globally to zero by the second half of the 21st century. In November 2018, the European Commission (EC) announced its ambitious energy and climate strategy (EC, 2018a) that set outs three policy scenarios for achieving 100% GHG emissions reduction by 2050 relative to the 1990 level. At Member State (MS) level, Sweden and Finland have all adopted net zero targets in domestic legislation. In the UK, in May 2019 the Committee on Climate Change (CCC), an independent non-departmental advisory body to the UK government, published its Net Zero report recommending stepping up UK ambitions, and the government quickly thereafter adopted a net zero target into law on 27 June 2019, followed two days later by France. Norway, a member of the single market in energy, also has a net zero target.

While the prospects for electricity decarbonisation to 2030 are promising, the necessity of deep decarbonisation of the entire energy system by 2050 remains challenging. To be able to fully confront the challenges and trade-offs posed by deep decarbonisation, policy analysis will need to simultaneously examine both the long-time horizons needed to shift investment and the short time scales inherent in a system where variable renewables dominate. The EC 2030 energy package and the 2050 long-term energy and climate strategy were supported by PRIMES modelling (see Capros et al, 2018; 2019).

In the context of rising attention to so-called 'sector coupling'[2] in Brussels policy circles, recent energy modelling studies (e.g., McKinsey, 2018; Navigant, 2019; Trinomics, 2019; DNV GL, 2020) focused on the role of different energy carriers (e.g., natural gas, biomethane, hydrogen and electricity), corresponding infrastructure and sources of flexibility in meeting European net zero target by 2050. Further, a number of national studies analysing deep decarbonisation by 2050 are worth mentioning - the UK's CCC Net zero analyses are based on a suite of modelling tools including the IWES model (Strbac et al., 2018) which builds on the WeSIM model (see Pudjianto et al., 2014); French Environment and Energy Management Agency (ADEME, 2018) produced a techno-economic feasibility assessment of 100% renewable gas in 2050 in France; German Energy Agency (dena) studied pathways to achieve 80-95% emissions reduction by 2050 in Germany (dena, 2018).

Academic literature on deep decarbonisation of energy systems is abound, primarily focusing on modelling *"pathways"* dynamics (see e.g., Capros et al., 2014a; 2014b; 2016; Fragkos et al., 2017; Davis et al., 2018), on the role of various supply-side technologies (see e.g., Evangelopoulou et al., 2019; Blanco et al. 2018a; 2018b), and on societal changes (see e.g., EC 1.5 LIFE scenario in EC, 2018b; Carmichael, 2019; 2020; Carmichael and Wainwright, 2020) and demand-side technologies (see e.g., Strbac et al., 2020; Elliot et al., 2020) required to reach deep decarbonisation pathways. Only relatively recently have selected studies started to examine the flexibility requirements from an energy system integration perspective (see e.g., Brown et al., 2018; Evangelopoulou et al., 2019; Victoria et al., 2019; Pavičević et al., 2020; Zhu et al., 2020; Bødal et al., 2020). While the focus of these recent studies are different in terms of geography, technology and sectors, and modelling methodologies, all stress the importance of joint planning of energy vectors and supporting infrastructure for cost-effective energy system decarbonisation.

[2] Sector coupling refers to linking the energy (electricity, gas and heat), transport and industrial infrastructures with a view to increase the penetration of renewable energy sources and decarbonise the economy, EC (2018b: pp 65-66)

Thus, this research project aims to answer the following research questions:

1. What are the sources of flexibility under gas and electricity sector coupling and their role in deep decarbonised energy systems;
2. What are complementary dimensions and trends between low-carbon electricity, renewables, and carbon-neutral gases for competitive and secure European energy system.

Also, our objective is to understand what regulatory and policy recommendations are available that would enable efficient gas and electricity sector coupling to deliver carbon neutral economy by 2050. The rest of this report is structured as follows. In Section 2 we briefly outline Europe's commitments on Clean Energy. In Section 3 we give a detailed overview of the EC's 2050 energy and long-term climate strategy (LTS) and main strategy and modelling work by European gas and electricity industry associations. Section 4 summarises the current state (in 2018) of the European energy system while in Section 5 we define sources of flexibility and their requirements in deep decarbonisation pathways. We then introduce our modelling and analytical framework and discuss main inputs and assumptions in Section 6. In Section 7 we present our modelling results and discuss policy and regulatory recommendations in Section 8 while the final section concludes our research.

02

EUROPE'S COMMITMENT TO CLEAN ENERGY

2. Europe's commitment to Clean Energy

In the 2050 Long-term strategy (EC, 2018a) *"A Clean Planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy"*, the European Commission (EC) has outlined seven strategic areas that would require joint action to achieve a climate neutral economy:

1. energy efficiency
2. deployment of renewables
3. clean, safe and connected mobility
4. competitive industry and circular economy
5. infrastructure and interconnections
6. bio-economy and natural carbon sinks
7. carbon capture and storage to address remaining emissions

The strategy envisages that energy efficiency measures should play a central role in achieving net-zero GHG emissions by 2050 reducing energy consumption by at least half compared to 2005. Further, in this strategy, the Commission sees that the European electricity system will have to reach complete carbon neutrality by 2050. A complete decarbonisation of the electricity sector will be achieved through large-scale deployment of renewables, in particular wind and solar power. Thus, by 2050 in some of its long-term scenarios, the vision for a carbon-neutral European economy is that 53% of final energy demand will be met by electricity; this is up to 2.5 times today's levels. The role of renewables will be central – at least 80% of electricity will come from renewables (with a combined share of VRE at 60%, including significantly increased offshore wind). Further, nuclear power will have 15% share in the 2050 European electricity generation; thus, these two sources will be forming a backbone of carbon-free European electricity system.

However, one of the biggest challenges of this 80%-15% renewables and nuclear power composition will be maintaining security of supply and affordability: it would require a highly flexible energy system to deal with intermittency of VRE and limited flexibility of nuclear power while keeping system costs at reasonable level for final end-users. From this perspective, both the Commission and European energy industry see opportunities for **'sector coupling'**, which the Commission elaborated in its recent **EU Energy System Integration Strategy** (EC, 2020a) along with its **EU Hydrogen strategy** (EC, 2020b). Other EC policy initiatives that are important in the context of deep decarbonisation and sector coupling include **EU Strategy on Offshore Renewable Energy** (EC, 2020c[3]), Offshore Strategy, the Renovation Wave (EC, 2020d[4]) and **Sustainable and Smart Mobility Strategy** (EC, 2020e[5]).

Sector coupling, although its definition varies, is commonly understood as integrating the energy consuming sectors (such as buildings, transport, and industry), and optimising them with the energy supply sector. By creating synergies that offer system flexibility, sector coupling can be an enabler reducing the overall energy consumption and allowing faster roll-out of renewables. Linking them all together in a more integrated energy system combining different energy vectors, starting with gas and electricity (but not only) is part of the

[3] https://ec.europa.eu/energy/topics/renewable-energy/eu-strategy-offshore-renewable-energy_en
[4] https://ec.europa.eu/energy/topics/energy-efficiency/energy-efficient-buildings/renovation-wave_en
[5] https://ec.europa.eu/transport/themes/mobilitystrategy_en

latest reflections within the EU to accelerate emissions cuts from transport, buildings and industry, which are considered hard-to-abate because they cannot be easily electrified.

In this research we assess and frame the concept of sector coupling (or sector integration) in the context of the new EU Green Deal adopted in December 2019 and the EU Strategy for Energy System Integration published in July 2020. As of today, the EU Green Deal remains a vast umbrella communication with non-binding targets, but it clearly states the commitment to tackle climate and environmental-related challenges as '*this generation's defining task.*'[6] Presented as the new '*growth strategy*', the document aims at '*transform[ing] the EU into a fair and prosperous society, with a modern, resource-efficient and competitive economy where there are no net emissions of greenhouse gases in 2050 and where economic growth is decoupled from resource use*'.[7]

This vision puts particular emphasis on the need to '*rethink policies for clean energy supply across the economy, industry, production and consumption, large-scale infrastructure, transport, food and agriculture, construction, taxation and social benefits*'[8] and sets out a wide range of policy initiatives, including a roadmap with key actions, to make Europe climate-neutral by 2050. Among those initiatives, the document highlights the important role of the clean energy transition and mentions in this context: '*the smart integration of renewables, energy efficiency and other sustainable solutions across sectors will help to achieve decarbonisation at the lowest possible cost*'.[9]

In July 2020, the EU Smart Sector Integration Strategy presented a first vision on '*how to accelerate the transition towards a more integrated system*' supporting a climate neutral economy at the least cost across sectors, while strengthening other important goals such as energy security, health, environment and innovation.[10]

It claims that today's energy system is built '*on several parallel, vertical energy value chains, which rigidly link specific energy resources with specific end-use sectors*' and warns that '*this model of separate silos cannot deliver a climate neutral economy*' and it is '*technically and economically inefficient, and leads to substantial losses in the form of waste heat and low energy efficiency*'[11].

Furthermore, the EU Energy System Integration Strategy offers a very comprehensive and wide definition of the concept: '*Energy system integration refers to the planning and operating of the energy system "as a whole", across multiple energy carriers, infrastructures, and consumption sectors, by creating stronger links between them with the objective of delivering low-carbon, reliable and resource-efficient energy services, at the least possible cost for society. It encompasses three complementary and mutually reinforcing concepts*'.[12]

The three mutually reinforcing concepts of an integrated energy system are summarised as follows:

1. A more efficient and 'circular' system, where waste energy is captured and re-used; in which the least energy intensive choices are prioritised, unavoidable waste streams are reused for energy purposes, and synergies are exploited across sectors;

[6] https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF, p.2
[7] https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF, p.2
[8] https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF, p.4
[9] https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF, p.6
[10] https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf, p.2
[11] https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf, p.1
[12] https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf, p.2

2. A cleaner power system, with more direct electrification of end-use sectors such as industry, heating of buildings and transport;
3. A cleaner fuel system based on the use of renewable and low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible.

For example, the Commission noted in the 2050 long-term strategy that the potential advantage of power-to-X is the 'storability' of synthetic fuels which could then be used in multiple ways across different economic sectors, especially those 'hard to decarbonise' sectors such as industry, heat and transport.

In practice, an efficient and tightly integrated energy system should therefore maximise the use of the already established gas and electricity networks while minimising the stranded assets and/or over-investments risks in both gas and electricity sectors.

All in all, in the 2050 long-term strategy, the EC analysed 8 scenarios[13] with a different degree of ambition towards achieving carbon-neutral European economy by the mid of this century and the Commission sees (i) rapid deployment of renewables as a no regret policy option, and (ii) in all options analysed the Commission expects that the energy system of the future relies on a secure and sustainable energy supply underpinned by a **market-based and pan-European approach.**

In parallel to the EU Smart Sector Integration Strategy, the European Commission adopted 'A Hydrogen Strategy for a climate neutral Europe' with the intention to boost clean hydrogen production in Europe and ensure hydrogen use as a feedstock, a fuel or an energy carrier and storage. The Commission defines hydrogen as the '*missing part in the puzzle to a fully decarbonised economy*'[14] and '*a key priority to achieve the European Green Deal'.*[15] The strategy outlines that "*in the integrated energy system of the future, hydrogen will play a role, alongside renewable electrification and a more efficient and circular use of resources*'.[16]

More particularly, the communication defines a strategic pathway towards an European hydrogen 'eco-systems' from 2020 to post-2030 in which hydrogen '*needs to become an intrinsic part of (EU) our integrated energy system, with at least 40 GW of renewable hydrogen electrolysers and a production of up to 10 million tonnes of renewable hydrogen in the EU'*.[17]

Moreover, the European Commission's economic recovery plan *'Next Generation EU'* to tackle the COVID-19 crisis highlights hydrogen as an '*investment priority*' to boost economic growth and resilience, create local jobs and consolidate the EU's global leadership.

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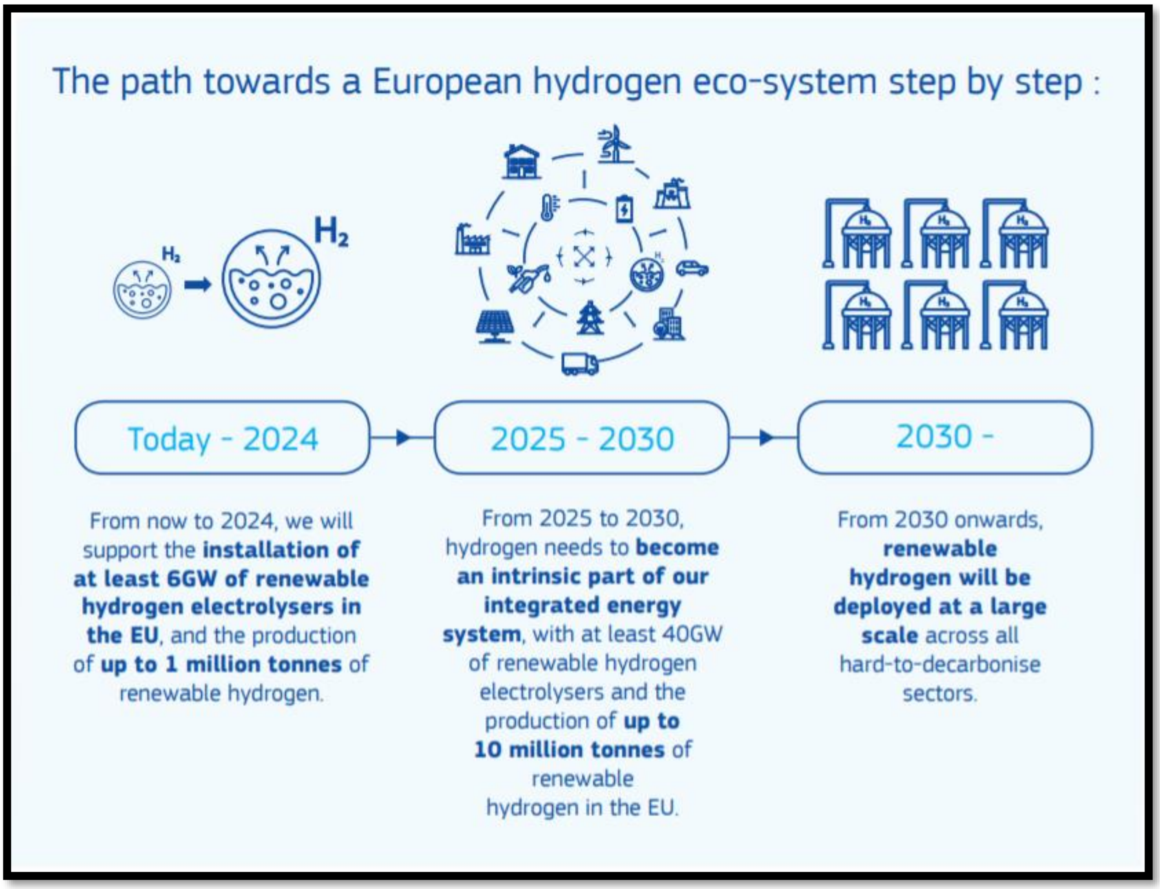
[13] https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_en.pdf, pp 6-7
[14] Source : https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_1257
[15] Source : https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf (Hydrogen Strategy)
[16] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, p.2
[17] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf, p.6



Source: EC (2020b, p. 1)

Thus, with all the above policy documents and strategy, the Commission reconfirms Europe's commitment to lead in global climate action and present a vision of a cost-efficient and socially fair transition pathways of its energy system towards net-zero GHG emissions by 2050.

03

EU'S PATHWAYS TOWARDS CARBON NEUTRALITY

3. EU's Pathways towards Carbon Neutrality

The 2050 Long-term Strategy (LTS) '*A Clean Planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy*' explores multiple pathways through which the EU can meet its Paris Agreement targets. It analyses eight scenarios, falling into three categories based on the level of emissions reduction achieved by mid-century. Each scenario varies in the sectoral options used to achieve decarbonisation. For the power and transport sectors, the options are mainly a reduction in the final energy consumption achieved through increased energy efficiency and changing demand patterns, and an increased adoption of carbon-neutral energy carriers, like renewable electricity, hydrogen or fuels produced using electricity (e-fuels). gives a summary of the scenario characteristics.

Table 1: EC's 2050 strategy

TABLE 1

EC'S 2050 STRATEGY

2050 GHG REDUCTION OVER 1990	SCENARIO	COMMON FEATURES	DEFINING ASSUMPTION	RELEVANT ENERGY SUPPLY TECHNOLOGIES
65%	Baseline	• 26% reduction in primary energy consumption by 2030 over 2005, 35% by 2050 • Energy production reduces by 28%, fossil fuel generation down by 88%, nuclear steady at ~10%, RE at 73% by 2050 • Transport sector remains largest CO_2 emitter at 41% of all emissions		
80%	ELEC	• Higher energy efficiency • Deployment of sustainable, advanced biofuels • Moderate transition to circular economy • Increased digitalisation across sectors • EU-level market coordina-tion for sustai nable infrastructure • Learning-by-doing for low-carbon technologies • Increased resource effi-ciency in the transport sector • No biomass associated carbon capture and storage un til 2050 in 80% reduction scenarios • Negative emissions by 2070, except 1.5LIFE	Shift to **renewable electricity** as carbon-neutral carrier	• Solar PV • Wind • Biomass (electricity +heat) • Hydropower • Ocean technologies • Nuclear • Biofuels (transport) • CCS, CCU (electricity + industry) • Li-ion • Power-to-heat/hy-drogen/gas/liquid/am-monia • CHP for distributed heating • E-gas (CH_4) and e-liquids obtained by reaction of H_2 with CO_2 • Green/blue H_2
	H2		Shift to **hydrogen** as carbon-neutral carrier	
	P2X		Shift to **e-fuels** (Power**2X**) as carbon-neutral carrier	
	EE		Deeper **energy efficiency** measures	
	CIRC		Transition to **circular economy**: higher resource and material efficiency	
90%	COMBO		Cost-effective **combination** of tech. from first 5 scenarios	
100%	1.5TECH		Higher use of **technology** to abate carbon	
	1.5LIFE		Larger **transition of business and consumption to circular economy**	

Source: Authors' summary based on EC (2018a).

Although the EU LTS predates the latest EU decarbonisation target of achieving net-zero emissions by 2050, they provide a mapping of the decarbonisation options available (economic, industrial and societal) and what the energy and other sectors would look like if each is pursued. Importantly, they provide the building blocks for the two net-zero scenarios. Two important conclusions that are common to all scenarios reaching at least 80% GHG emissions reduction target can be drawn:

I. All scenarios see a strong reduction in the primary energy consumption by 2050, driven by energy efficiency policies and penetration of efficient end-use technologies (e.g., EVs and electric heat pumps), from 22% in the P2X scenario to a maximum of 50% in the EE scenario, as compared to 2005. The sharpest reduction is seen in residential buildings due to improved building insulation and increased equipment efficiency, followed by the transport sector due to a transition to electric vehicles and stricter emission standards.

II. Electricity becomes the dominant energy carrier, ranging from a minimum 41% share of the final energy demand when it competes with e-fuels to a maximum of 53%. Further electrification of all sectors, i.e. residential, industry and most notably transport, takes place in all scenarios.

Thus, as per the LTS, economy-wide decarbonisation is generally characterised by electrification of end-uses and rapid deployment of renewables, particularly which of wind and solar power, as a 'no regret' policy option on the supply side. In all scenarios reaching at least 80% GHG reduction, 41% - 53% of final energy demand will be met by electricity, and 81% - 85% of electricity will come from renewables. Within renewables, wind energy could represent 51% - 56%, including significantly increased shares of offshore wind, while the share of solar reaches 15% - 16%, taking the combined share of VRE to 66% - 72%. Further, nuclear power will have a 12%-15% share in the 2050 EU electricity generation mix. Fossil oil and natural gas see a large reduction in their shares of final energy consumption provided, as their uses in power generation and particularly in transport, are replaced by carbon-neutral sources of energy. A major challenge to this power sector composition dominated by renewables and nuclear power, however, is system management: a highly flexible electricity system would be required to deal with the intermittency of VRE and inflexibility of nuclear power.

The LTS presents a more uncertain outlook for development of the gas sector in terms of the specific gaseous fuel that could become dominant. E-gases and biogas replace natural gas in its more traditional end-uses like space heating in buildings, diminishing the use of natural gas across scenarios. In scenarios where e-fuels, or power-to-X (P2X) technologies, develop as a viable option, they represent 7%-10% of the final demand by 2050, chiefly used in space heating. On the other hand, hydrogen, driven by adoption of consumption technologies, plays a large role in the transport sector (along with e-liquids) and in the industrial sector. Both, e-gases and hydrogen, also play important roles in electricity storage, along with the traditional storage method of batteries. The analysis suggests that in the case where e-fuels develop the most, they may provide up to 48% of all stationary electricity storage, i.e. storage not provided by vehicles.

Two scenarios lay a heavier emphasis on circular economy policies leading to behavioural changes and shifting consumption patterns. In industry circular economy measures include standardisation of recyclable material, improved waste collection and material substitution, resulting in shift of production from energy-intensive primary processes to less energy-intensive secondary production. Buildings become more resource efficient through sustainable design and usage (rational use of heating and cooling), and transport-as-a-service becomes a widespread usage model. COMBO also assumes a shift toward these trends but accompanied by technological changes. 1.5LIFE assumes a stronger adoption of these trends, with technology adoption but also large-scale lifestyle changes such as less carbon-intensive diets and preference for alternate modes of transport over air transport.

These changes are reflected prominently in the results, with the scenarios reporting some of the largest drops in fuel and energy consumption. CIRC scenario achieves a 45% reduction in primary energy consumption in 2050 compared to 2005, the largest after the EE scenario, while COMBO and 1.5LIFE scenarios achieve 35% and 42% respectively. CIRC sees final energy consumption in industry, transport and residential buildings reduced by 33%, 43% and 46% over 2005 levels respectively, while 1.5LIFE sees decreases of 41%, 50% and 57% in the respective end-use sectors, the largest across scenarios. Total gaseous fuel consumption drops by 47%, 43% and 32% over 2015 in CIRC, 1.5LIFE and COMBO respectively. While passenger road transport activity drops by 1%-5% across scenarios, aviation reduces by 3% in CIRC and a massive 18% in 1.5LIFE.

In totality, emissions from transport in 2050 over 2005 reduce by 91%, 76% and 71% in 1.5LIFE, COMBO and CIRC scenarios respectively. In the industrial sector, a consequence of reduced production in carbon-intensive industries is the late adoption of CCS. In all 80% decarbonisation scenarios, except CIRC, and COMBO CCS appears in 2045 and captures 60 $MtCO_2$ by 2050, while in CIRC only 44 $MtCO_2$ is captured. Higher carbon prices in the net-zero scenarios allow larger CCS capacities, with 71 $MtCO_2$ in 1.5LIFE and 80 $MtCO_2$ in 1.5TECH. Yet CIRC achieves the highest level of decarbonisation in industries at 77% by 2050 over 2015. Dietary changes also display considerable potential for non-CO_2 GHG mitigation. 34 – 110 $MtCO_2$eq. of emissions can be reduced through reduced consumption of milk, pig meat and poultry, representing 8-25% of emissions from agriculture in 2015.

Overall, the LTS points to a European energy sector in which energy efficiency and consumption trends reduce energy requirement, and the supply is likely to be dominated by VRE and nuclear energy for power generation. A large proportion of end-uses across residential, industrial and transport sectors as well as energy storage would be provided by gaseous fuels and associated infrastructure. Considering the results of the analysed scenarios, electricity and gas networks would be required to closely interact, providing mutual flexibility across end-uses and through storage. This necessitates a whole-system approach toward the future planning and analysis of the EU energy sector.

Another set of EU-level decarbonisation pathways is presented by the 'Eurelectric Decarbonisation Pathways' study (Eurelectric, 2018). It analyses three decarbonisation scenarios achieving 80%, 90% and 95% decarbonisation over 1990 levels respectively. Its remit covers the EEA countries in addition to the EU28 Member States. The model uses a multi-factor approach, including the costs of ownership and cost-competitiveness of decarbonisation technologies, and market, technological and regulatory developments. Whereas the 2050 LTS uses the PRIMES model (E3M Lab, 2018) to estimate the composition of energy supply and demand at the macroeconomic level, including LULUCF for carbon abatement, the Eurelectric study obtains the final energy consumption outputs by modelling more than 50 sub-sectors at the individual country level and excludes carbon abatement measures. The data for the bottom-up modelling in the Eurelectric study came from external stakeholders, including from sectors other than electricity. For the power sector, the model minimizes investments and operating costs constrained by emissions levels, cost curves, technology performance standards, levels of electrification and country-level policy decisions. These inputs vary by scenario, resulting in different cost-optimised power supply and generation mixes.

The different levels of decarbonisation achieved in the three scenarios result from varying assumptions of rate of technological development, deployment and adoption, supported by varying levels of regulatory intervention. For example, Scenario 1 (80% decarbonisation) assumes an acceleration of the current trends of technological development as the share of electric vehicles in the fleet grows from less than 1% in 2015 to 65% in 2050 and to 96% in Scenario 3 (95% decarbonisation). Apart from steep rates of adoption from consumers this is also supported by policy support for expansion of charging infrastructure. Similarly, energy efficiency and electrification in buildings is driven by adoption of heat pumps along with stricter building energy performance regulations.

This approach differs from the one taken in the LTS, which focuses on relatively faster development of a specific technology and energy carrier under each scenario. Hence, whereas "non-emitting fuels", i.e. P-to-X technologies and hydrogen provide 26%, 27% and 27% of the final energy demand in Scenarios 1, 2 and 3 respectively, in the LTS the share of e-fuels varies from 17% in P2X to 13% in 1.5TECH and 0% in ELEC. However, like the LTS, all Eurelectric scenarios are also underpinned by a direct electrification of the economy. Although other "non-emitting" fuels take a supporting role in reducing economy-wide emissions, an annual increase of 0.3 - 0.5% is observed in electricity demand for production of P-to-X fuels, including hydrogen for electrolysis. These fuels provide for 26% - 27% of the final energy consumption across the three scenarios, with remaining provided by "emitting fuels": 36% in Scenario 1 and 13% in Scenario 3. Critically, Scenario 3 depends on breakthroughs on currently nascent electric solutions across sectors, complemented with implementation of supporting regulation and consumer uptake at a global scale before 2040. This is reflected in the highest share of electricity in final energy consumption in any of the studies, particularly in the transport sector (Table 2). EU's 1.5TECH depends on a much larger CCS capacity, nearly 300 MtCO2, compared with less than 200 MtCO2 in Eurelectric's Scenario 3, which enables larger negative emissions and abatement of the final 5% of emissions.

Table 2: Comparison of Eurelectric scenarios with select

TABLE 2

COMPARISON OF EURELECTRIC SCENARIOS WITH SELECT EC 2050 LTS SCENARIOS

	EURELECTRIC PATHWAYS			EC 2050 LTS			
	SCENARIO 1	SCENARIO 2	SCENARIO 3	P2X	ELEC	COMBO	1.5TECH
2050 GHG TARGET	80%	90%	95%	80%	80%	90%	100%
ELECTRICITY IN FINAL ENERGY CONSUMPTION	38%	48%	60%	41%	53%	48%	50%
ELECTRICITY IN BUILDINGS	45%	54%	63%	S: 78% R: 53%	S: 83% R: 68%	S: 81% R: 63%	S: 80% R: 64%
ELECTRICITY IN TRANSPORT	29%	43%	63%	15%	26%	21%	26%
ELECTRICITY IN INDUSTRY	38%	44%	50%	54%	66%	63%	66%
E-FUELS AND H_2 IN BUILDINGS	34%	36%	32%	11%	0%	9%	10%
E-FUELS AND H_2 IN TRANSPORT	14%	18%	19%	32%	5%	22%	42%
E-FUELS AND H_2 IN INDUSTRY	26%	26%	29%				
FOSSIL FUELS IN BUILDINGS	21%	10%	5%	7%	9%	4%	2%
FOSSIL FUELS IN TRANSPORT	57%	39%	18%	41%	50%	39%	15%
FOSSIL FUELS IN INDUSTRY	36%	30%	21%				

Source: EC (2018a); McKinsey (2018). Notes: S – services; R – residential; Eurelectric scenarios do not quantify costs to society. Costs indicated here are annual capital investments only in the power sector.

Hence, the three scenarios in the Eurelectric study show a lower degree of variation in the share of the different energy carriers than the LTS, due to a larger overall focus on electrification. The power sector itself is 100% decarbonised by 2045 in all three analysed scenarios. The share of renewables in the final generation in the three scenarios by 2045 is 83%, 83% and 82% respectively. This is largely in agreement with the LTS scenarios. Eurelectric also finds that system reliability and flexibility in a totally decarbonised European electricity system is provided by other dispatchable sources. However, in divergence with the findings of the LTS, within dispatchable sources the largest shares are occupied by hydro and gas generation instead of nuclear energy. Hourly variations in VRE supply are managed through hydro, battery storage and demand-side response, whereas seasonal variations requiring larger reserves include P-to-X and hydrogen.

For its own assessment on net-zero pathways for the EU's energy system, Eurogas commissioned DNV GL to design pathways using the Energy Transition Outlook model (DNV GL, 2020). DNV GL has developed two pathways, each placing emphasis on gas and electricity as the primary energy carrier. These are called the 'Eurogas scenario' and '1.5TECH scenario' respectively, the latter being DNV GL's interpretation of the EC's 1.5TECH scenario in the LTS (DNV GL, 2020). Both scenarios achieve 100% decarbonisation of the energy system by 2050 over 1990 levels, as well as

2030 targets of 50-55% decarbonisation. In the Eurogas scenario natural gas, biomethane and hydrogen coupled with CCS provide the basis for decarbonisation of all end-use sectors, while in 1.5TECH gaseous fuels are limited to the "hard-to decarbonise" sectors. Overall, compared with the Eurogas scenario, 1.5TECH achieves a higher share of decarbonisation in the decades after 2030, but Eurogas's more gradual decarbonisation comes at 7% lower cost. This is due to EUR 300 billion saved in consumer subsidies for shifting from gas to electric heating, and a 35% lower capex in gas and electrical grids.

Neither scenarios put an emphasis on behavioural change, although the yearly reduction in final energy demand until 2050 is 1.2% in the Eurogas scenario, compared with 1.3% in Eurelectric's study. In the Eurogas scenario gaseous fuels and electricity respectively supply 32% and 36% of the final energy demand in 2050, while in the 1.5TECH scenario this split is 20% and 51%, respectively. Final energy demand from gaseous fuels increases by 16% by 2050 over 2016 levels in the Eurogas scenario and falls by almost a third in 1.5TECH. The share of electricity is similar to LTS's 1.5TECH scenario but lower than Eurelectric's most electrified scenario (60% in Scenario 3).

Within electricity generation the Eurogas scenario estimates a similar share of VRE in installed capacity as Eurelectric's 95% decarbonisation scenario (and LTS scenarios) at 84%, but a lower share in generation at 78%. A higher carbon price of EUR 350/tCO2 in 1.5TECH by 2050, compared with EUR 100/tCO2 in the Eurogas scenario, results in 38% higher generation by VRE. The higher share of VRE increases risk of curtailment in 1.5TECH, which results in a larger adoption of green hydrogen, at 68% of all hydrogen production by 2050, as against 54% in 1.5TECH. Manufacturing and buildings become the major adopters of hydrogen in both scenarios. Manufacturing in 1.5TECH also becomes a larger user of biomethane using 25% of biomethane (followed closely by power production at 24%), while under the Eurogas scenario industry largely shifts to hydrogen, making electricity generation the largest user of biomethane.

A distinct feature of these pathways is the massive reliance on carbon sequestration relative to both EC's and Eurelectric's scenarios, with both scenarios witnessing an annual growth rate of 20% between 2020 and 2050. CCS captures 895 MtCO2 and 1048 MtCO2 in the electricity and gas intensive scenarios, respectively. Despite the lower carbon price, the Eurogas scenario achieves more sequestration. In both scenarios manufacturing and electricity production deliver negative emissions due to dependence on hydrogen and biomass, respectively, coupled with CCS.

The buildings sector sees energy demand falling by 21% in 1.5TECH against 9% in the Eurogas scenario, on the back of a wider migration to higher efficiency electrical heating equipment. Electricity remains the largest energy carrier for buildings in both scenarios. The transport sector sees similar developments in both scenarios with a reduction in passenger vehicle fleet numbers (due to ride-sharing) but increased vehicle kilometres. In both scenarios about 18% of energy demand is provided by gaseous fuels. EVs, battery powered in the passenger segment and fuel-cell powered in the commercial segment, lead to road transport decarbonisation. Aviation remains unabated with bioliquids and oil providing 41%-55% of the energy demand. Maritime transport is powered by hydrogen/ammonia in the Eurogas scenario (31% of energy demand), while in 1.5TECH bioliquids cater to 57% of marine demand.

Overall, the 1.5TECH scenario presented by Eurogas achieves very similar results to the EC's 1.5TECH scenario across end-use sectors. The Eurogas scenario achieves 100% decarbonisation of the energy system through enhanced use of gaseous fuels, which none of the EC LTS (1.5 TECH/LIFE) scenarios achieves.

04

EU'S ENERGY SYSTEM OF TODAY

4. EU's Energy System of Today

While there are numerous pathways to reach carbon neutrality by 2050, it is important to understand our starting position – the EU's energy system of today.

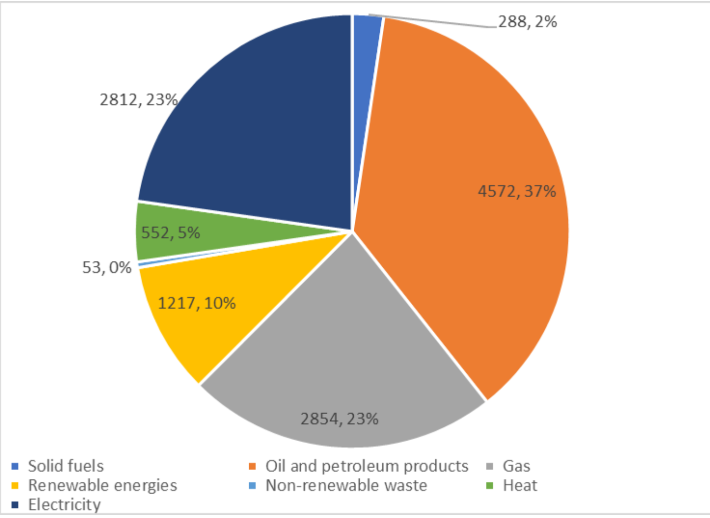
Figure 10 gives a snapshot of our energy system in 2018 in terms of energy flows: from primary sources to final consumption. The current system can be characterised as the one that is largely:

1. dependent on imports – gross imports accounts for ca. 66% of total primary energy supply[18], most of which are of fossil fuel nature - oil and petroleum products and natural gas.
2. dependent on fossil fuels – fossil fuels (oil and petroleum products and natural gas) accounts for ca. 60% of final energy consumption (Figure 1), with oil and petroleum products accounting for at least 37%, largely in the road transport sector; and the rest is natural gas, largely in buildings (for space and water heating) and in industry (as raw material and process heat);

In terms of final energy consumption, the single largest final energy consumer in 2018 is – the transport sector (Figure 10: 3.82 PWh[19], or 31% of final consumption); this is followed by households (3.29 PWh, or 27% of final consumption), industry (3.07 PWh, or 25% of final consumption), and services (1.76 PWh, or 14% of final consumption) with the rest consumed by agriculture, forestry, fishing and other sectors.

In terms of the fuel mix in the final energy consumption, as we noted, at least 60% comes from fossil fuels (gas and oil) but it is worth noting also that while electricity currently accounts for 23% the electricity generation sector it is not completely carbon free and electricity generation still heavily relies on fossil fuel (see Figure 3 and Figure 5).

Figure 1: EU+UK Final Energy Consumption Mix (TWh, % of total)



Source: Eurostat

[18] On the net basis (import – export), without accounting for transformation losses, this is lower – 42% of total primary supply
[19] 1 PWh = 1000 TWh

While electricity plays an important role in the final consumption (Figure 1, 23%), its role varies across final sectors: its share in the industry is 34% and in buildings - 31% (Table 3); but its role in the transport sector is rather limited (2%) in 2018. Natural gas plays a comparable role to electricity in the final energy consumption: its share in the industry is 34% and in buildings – 33%, but its role in the transport sector is only 1%. Oil and petroleum products are predominantly in the transport sector (92% of final energy consumption by the transport sector or 29% of total final consumption), as noted already. It is worth keeping in mind also that the share of natural gas in electricity generation was ca. 20% in 2016 (Figure 3), therefore, the role of gas in the current European energy economy is not insignificant overall.

Thus, total GHG emission in the EU+UK has been constantly reducing since 1990 (Figure 2) due to a number of factors: (i) policy push (e.g., via EU ETS, subsidies for RES, energy efficiency stimulus etc.), (ii) and as a result, a rapid decarbonisation of the electricity generation sector (e.g., due to coal-to-gas switching, phasing out coal-fired generation and RES supply uptake) (see Figure 3), (iii) progress in energy efficiency, de-linkage between GHG emissions and economic growth and between the later and energy consumption more generally (EC, 2018[20]).

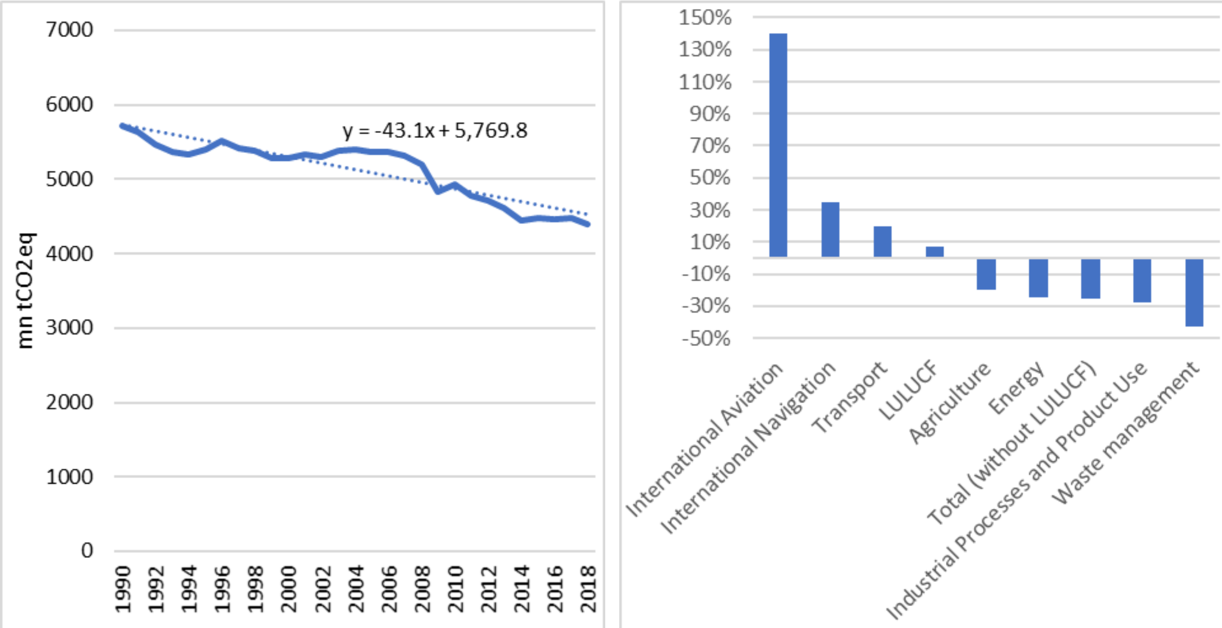
Table 3: EU+UK final energy consumption by sectors and fuels (2018)

	INDUSTRY		TRANSPORT		BUILDINGS*		TOTAL	
	TWH	%	TWH	%	TWH	%	TWH	%
Solid fuels	162	5%	0	0%	126	2%	288	2%
Oil and petroleum products	316	10%	3,521	92%	736	13%	4,573	37%
Natural Gas	1,032	34%	41	1%	1,781	33%	2,854	23%
Renewable energies	274	9%	195	5%	748	14%	1,217	10%
Non-renewable waste	50	2%	0	0%	3	0%	53	0%
Heat	183	6%	0	0%	369	7%	552	4%
Electricity	1,050	34%	64	2%	1,698	31%	2,812	23%
Total final energy consumption	**3,066**	**100%**	**3,822**	**100%**	**5,459**	**100%**	**12,347**	**100%**

Source: Eurostat
Notes: *Consumption in buildings is the sum of residential and services sector energy consumption and also include energy consumption in agriculture, fishing & other.

[20] EC LTS, page 19-20

Figure 2: EU+UK GHG emissions without LULUCF including indirect CO_2 (left panel) and sectoral changes in GHG emissions in 2018 relative 1990 level (right panel)

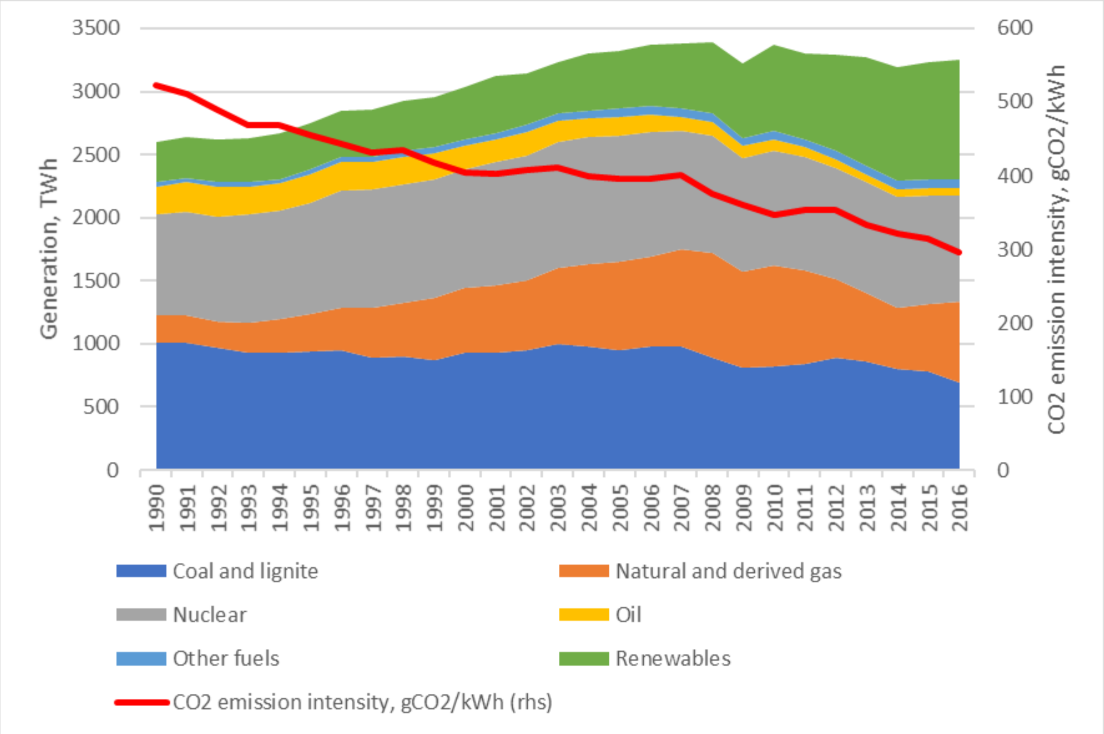


Source: EEA, based on the 2019 Member States' GHG inventories submitted to UNFCCC for the years 1990-2017 and proxy estimates for 2018.

Total GHG emission has been declining at an average rate of -0.92% p.a., or ca. 23% relative to the 1990 emissions level. Although much progress has been done in reducing GHG emissions, one can see that, on average, GHG emissions has been declining at a rate of 43.1 mn tCO2e p.a. and we would therefore miss the 2050 net zero target with this average historic rate, given the current level of emissions. As noted in the EC LTS, under the Baseline scenario (business as usual scenario) the GHG emissions will only be reduced by 65% in 2050 relative to the 1990 level.

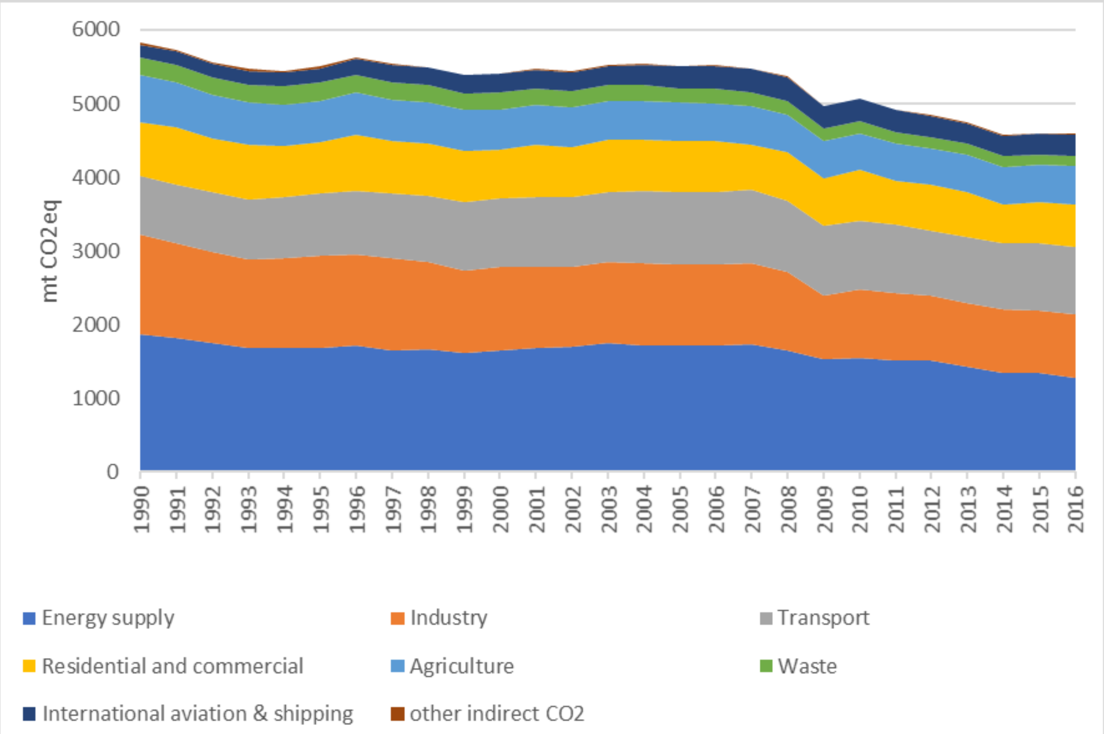
In terms of sectoral GHG emissions – we can see that GHG emissions from the transport sector including international shipping and aviation increased relative to the 1990 level while in all other sectors including energy there was a reduction in GHG emissions. Therefore, while the prospect of decarbonising energy supply and in particular the electricity generation sector is well on course, it is decarbonisation of the transport sector and energy use in the residential and commercial buildings as well as in industry and agriculture (Figure 4) that are required to reach ambitious climate change policy targets.

Figure 3: EU+UK Electricity generation and CO_2 emission intensity



Source: EEA

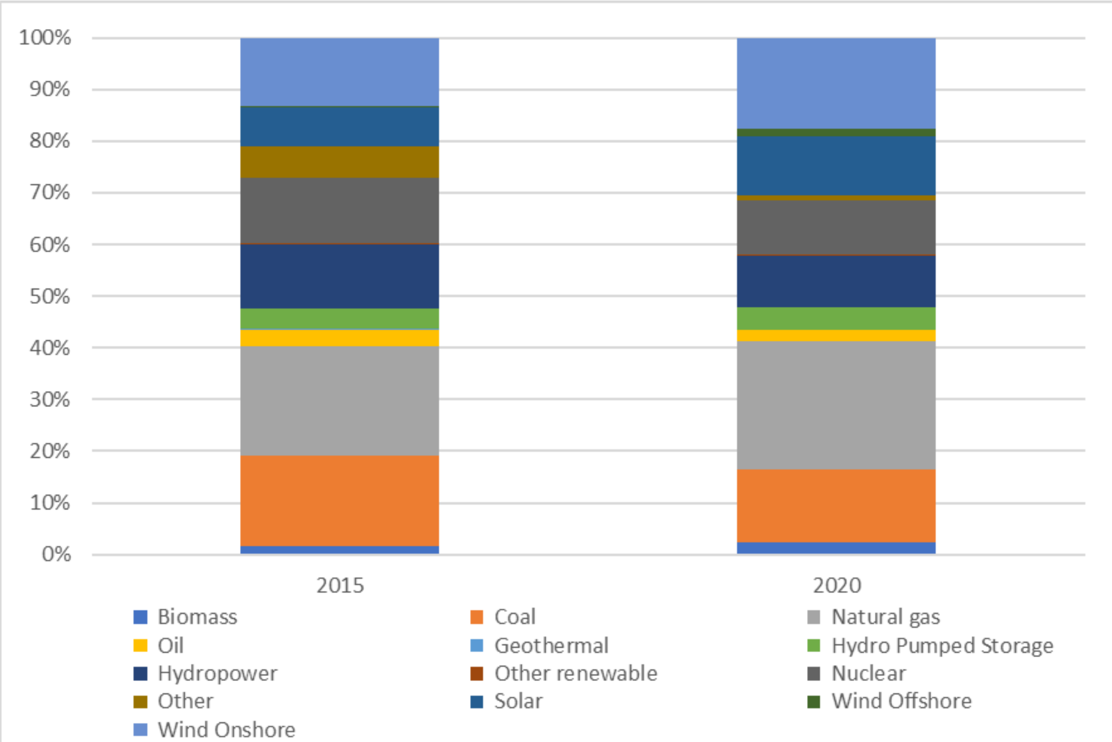
Figure 4: EU+UK Sectoral GHG Emissions



Source: EEA

Electricity generation sector decarbonisation, increasing usage of gas as well as energy efficiency in buildings and decoupling of economic activity from energy consumption more generally has led to a sustained fall in GHG emissions since 1990. In particular, the electricity sector developments in recent years in terms of market structure and regulation allowed integrating an increasing share of variable renewable energy (VRE) in the supply mix – combined share of wind and solar[21] has increased from 21% in 2015 to 31% in 2020 replacing mainly coal and oil capacity on the system (Figure 5); in the same period, we also see an increase in gas-fired generation capacity: from 21% in 2015 to 25% in 2020.

Figure 5: EU+UK Electricity Generation Mix: 2015 vs 2020

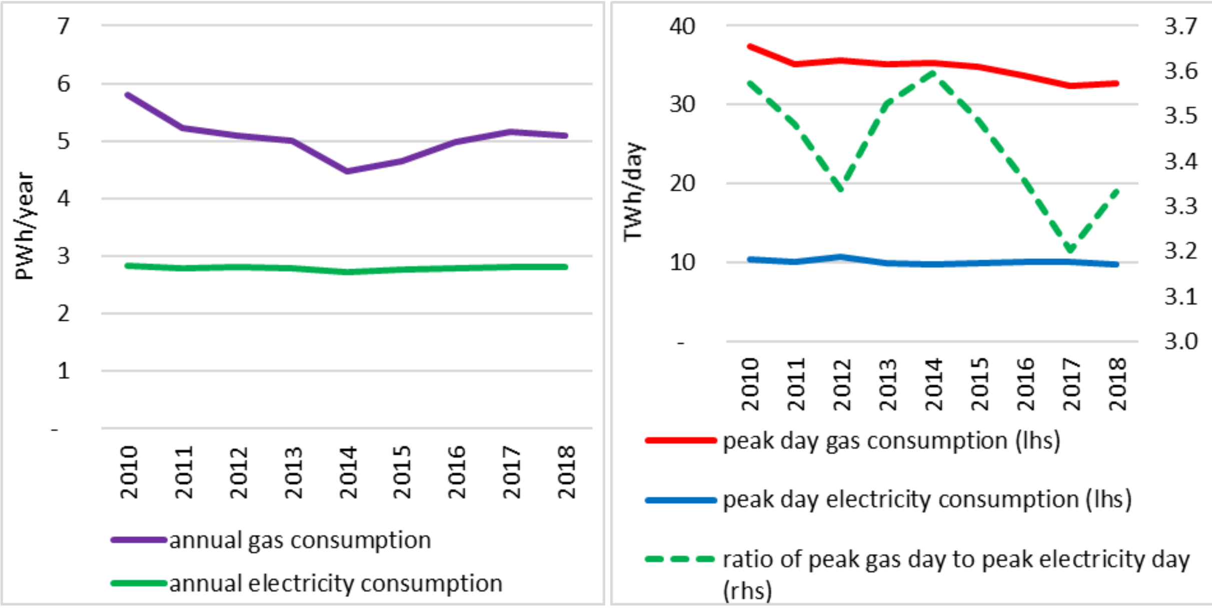


Source: ENTSO-E

To deliver the ongoing challenge of decarbonising the energy system both gas and electricity system capability (measured as peak hour and peak day electricity and gas demand recorded on the transmission systems) has evolved (see Figure 6 and Table 4).

[21] Note that the figure for solar from ENTSO-E might not include smaller scale installations; according to SolarPower Europe (https://www.solarpowereurope.org/wp-content/uploads/2019/12/SolarPower-Europe_EU-Market-Outlook-for-Solar-Power-2019-2023_.pdf?cf_id=7181) the solar PV capacity in EU28 in 2019 totalled 131.9 GW vs 101 GW reported by ENTSO-E.

Figure 6: Evolution of EU+UK Annual and Peak Day Electricity and Gas Demand



Source: Eurostat, ENTSO-E, ENTSO-G

While gas consumption is heavily influenced by temperature and hence year-to-year fluctuations, in Figure 6 (left panel) it is clear that gas consumption has been on decline at a greater pace (-12% in 2018 relative to 2010) than the decline in electricity consumption in the same period (-0.9%) which is consistent with the trends we discussed above. We see quite similar trends in peak day consumption – gas peak day consumption declined by 13% (2018 relative to 2010) while electricity peak day declined by 6% (2018 vs 2010) and electricity peak hour declined by 4% (see Table 4: 2018 vs 2010). Nevertheless, if we compare the capability of the two transmission system (using peak day delivery of gas and electricity consumption as a metric) then we clearly see that the current European gas system's capability is at least *three and half times larger* than the electricity counterpart (see Figure 6, right panel).

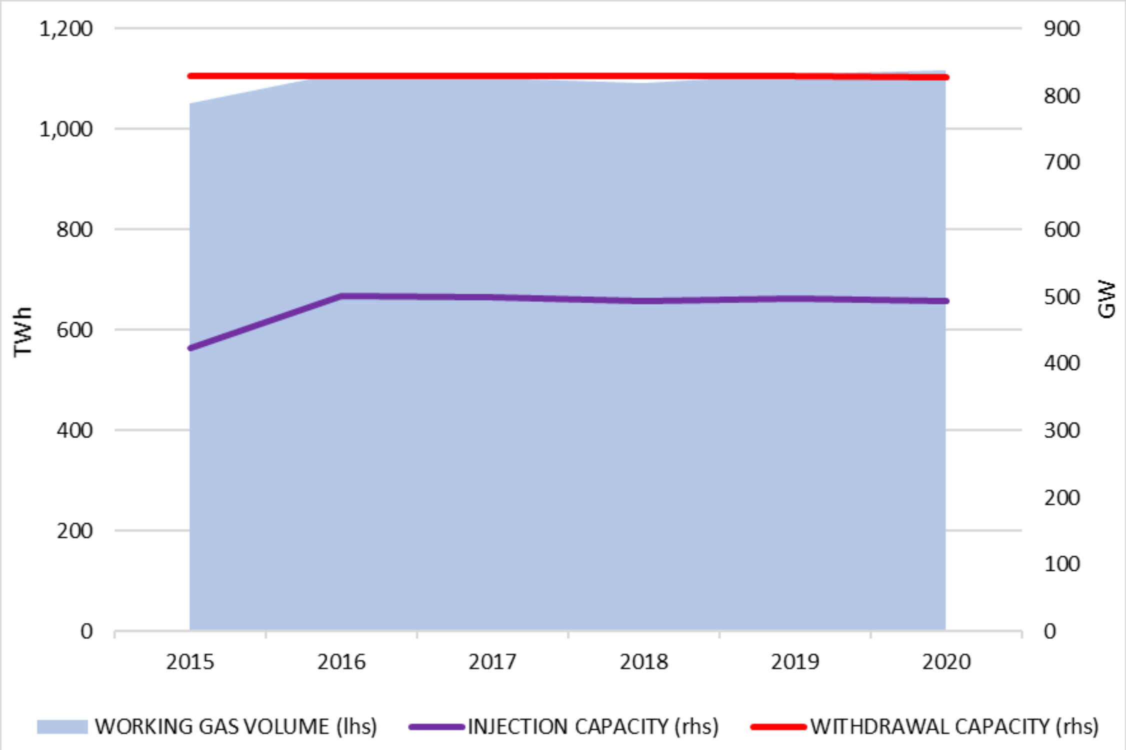
Table 4: EU+UK Peak Hour and Peak Day Electricity Demand

PEAK HOUR ELECTRICITY DEMAND		PEAK DAY ELECTRICITY DEMAND	
PEAK HOUR TIME	GWH	PEAK DATE	GWH
2010-12-15 17:00:00	496	2010-12-15	10,447
2011-01-27 17:00:00	475	2011-02-01	10,100
2012-02-08 17:00:00	496	2012-02-08	10,656
2013-01-17 17:00:00	470	2013-01-17	9,946
2014-01-29 17:00:00	465	2014-01-30	9,797
2015-02-05 17:00:00	471	2015-02-05	9,983
2016-01-19 17:00:00	476	2016-01-19	10,023
2017-01-18 17:00:00	477	2017-01-18	10,134
2018-12-13 17:00:00	463	2018-12-13	9,796
2019-01-22 17:00:00	474	2019-01-22	10,088

Source: ENTSO-E

While transmission network for gas and electricity deliver "instantaneous" energy and capacity across space, storage facilities delivers gas and electricity across time. Figure 7 shows evolution of EU gas storage capacity from 2015, while Figure 8 and Figure 9 show evolution of hydro-based electricity generation and capacity, including hydro pumped storage facilities.

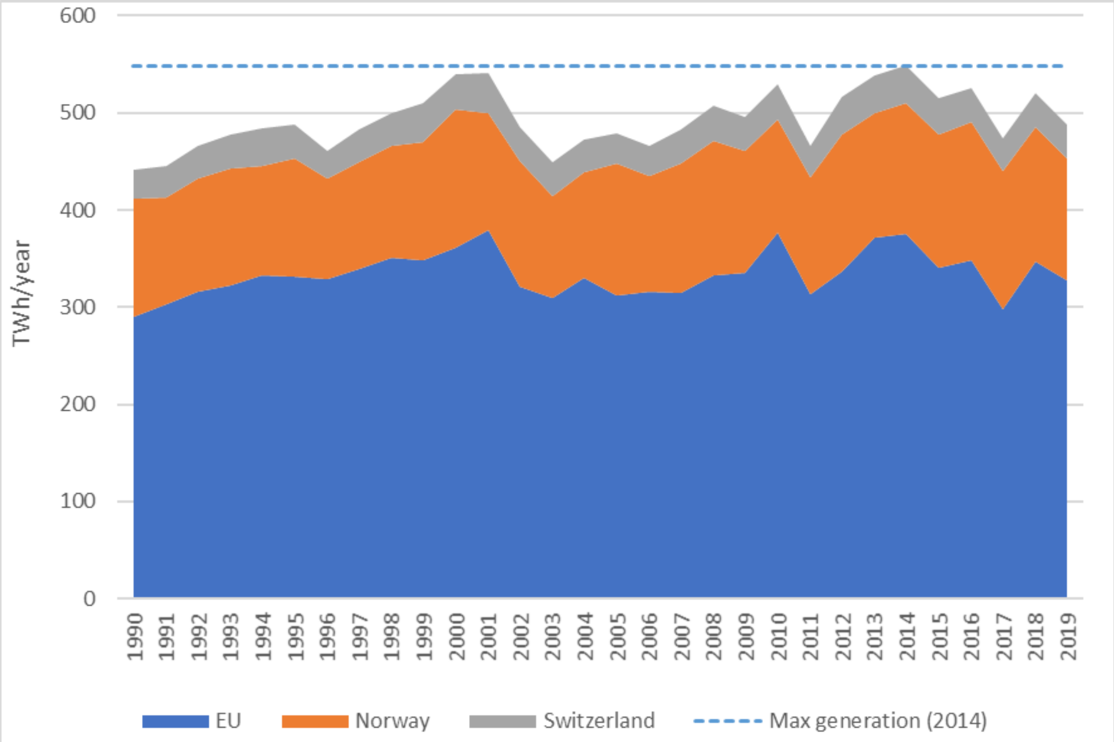
Figure 7: Evolution of EU+UK Gas Storage



Source: ENTSO-G

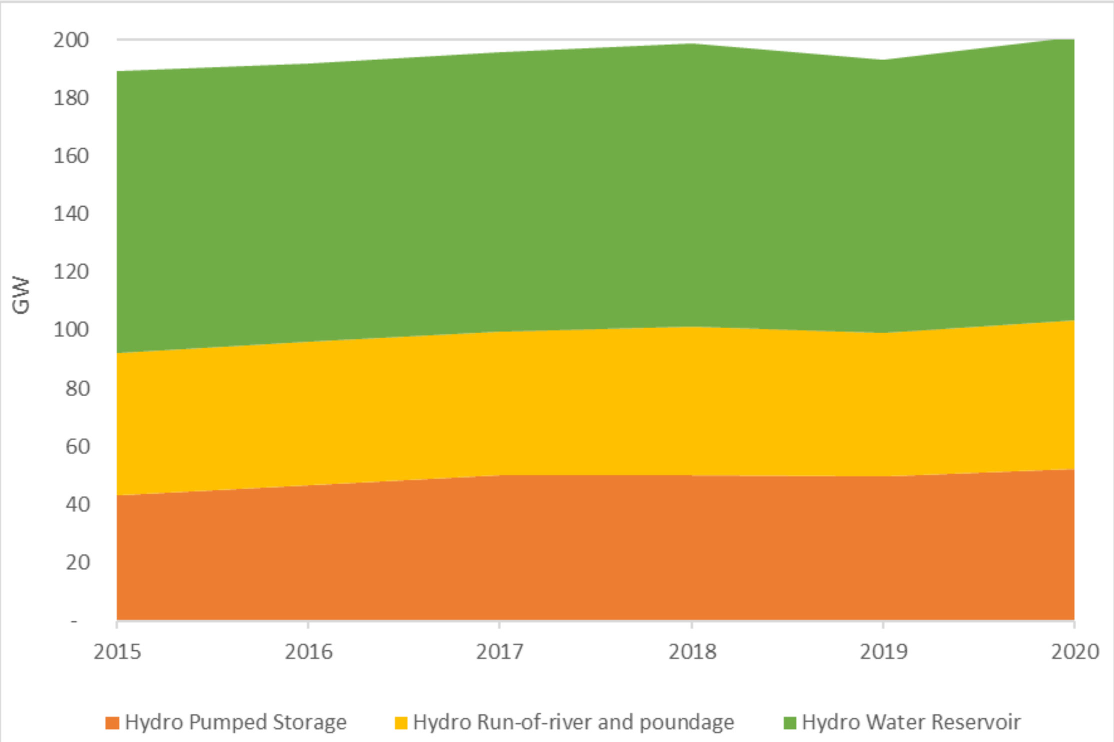
First, on the energy volume basis the current (2020) EU gas storage working volume (1117 TWh) can hold at least *twice* the energy content compared to the hydro reservoirs, even if we include huge hydro generation from Norway and Switzerland and consider the "best" hydrologic year (2014 when we saw the highest hydro electricity generation since 1990, 548 TWh - Figure 8).

Figure 8: Historic electricity production from hydro: EU, UK, Switzerland and Norway



Source: BP (2020)

Figure 9: Evolution of hydro capacity: EU, UK, Switzerland and Norway

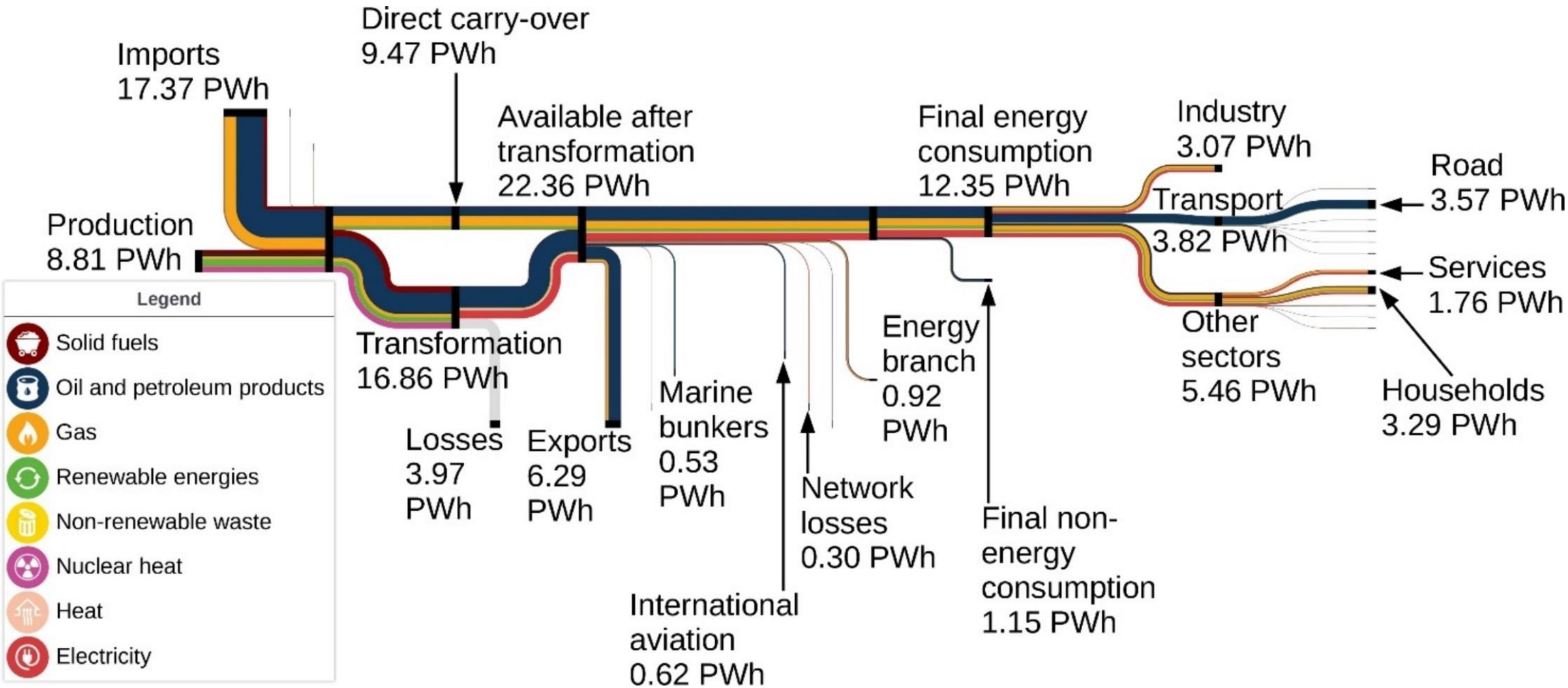


Source: ENTSO-E

Secondly the current deliverability of gas storage (withdrawal capacity, 829 GW) is at least *four times* the combined capacity of hydro pumped storage, hydro run-of-river and hydro dams of all EU, UK, Norway and Switzerland together (Figure 9). Although one should note that deliverability capacity of gas storage is a function of pressure and hence storage fill state (at 100% fill up the deliverability rate is 829 GW but will gradually fall as gas storage facilities are emptied); nevertheless, the difference in gas storage and hydro-based electrical energy storage and generation is striking, both in terms of energy volume and delivery capability. Also worth noting that, while gas storage are "controllable" in that both injection and withdrawal rate and time are manageable, hydro reservoirs, which currently provides most of bulk electrical flexibility, is "semi-controllable" in that rain and snow falls are weather-dependent and even in the past ten years (2010-2019) the difference between minimum and maximum generation were 83 TWh or 16% of the average in that period. Note that apart from peak hour gas consumption, there is also a substantial within day variations in road transport activities and hence decarbonisation of heat consumption in buildings **and** road transport might require a huge amount of flexibility (we come back to this in the next section).

All in all, the current energy system, and, in particular, electricity and gas systems have evolved in response to policy and technological changes we witnessed to date. Although, as we discussed above, tremendous progress has been achieved, particularly, in reducing the GHG emission by 23% relative to the 1990 level (total GHG emissions reduction totalled 1330 mt CO_{2e} in 1990-2018) a huge task lies ahead, if we are to achieve net zero target of GHG emissions by 2050. This is just 30 years to reduce GHG emissions by a factor of at least 3 (3 x 1330 mt CO_{2e} = 3990 mt CO_{2e}) of the total reduction that we achieved in the past 29 years (1990-2018). That is, whatever we have done to date has to be done at roughly three times faster – a challenge that is only achievable with a joint effort on both electricity and gas system planning, integrating all energy-end use sectors and applications. One of the greatest challenges for such a jointly planned energy system is to build out flexibility and resilience to achieve net zero by 2050, taking into account the current energy system that we inherited. We discuss this flexibility challenge in our next section with our simple quantitative example as well as thoroughly reviewing the academic literature on deeply decarbonised energy system and the role of flexibility.

Figure 10: EU+UK Energy Flow (2018)



Source: Eurostat

05

FLEXIBILITY REQUIREMENTS TO DELIVER CARBON NEUTRALITY

5. Flexibility Requirements to Deliver Carbon Neutrality

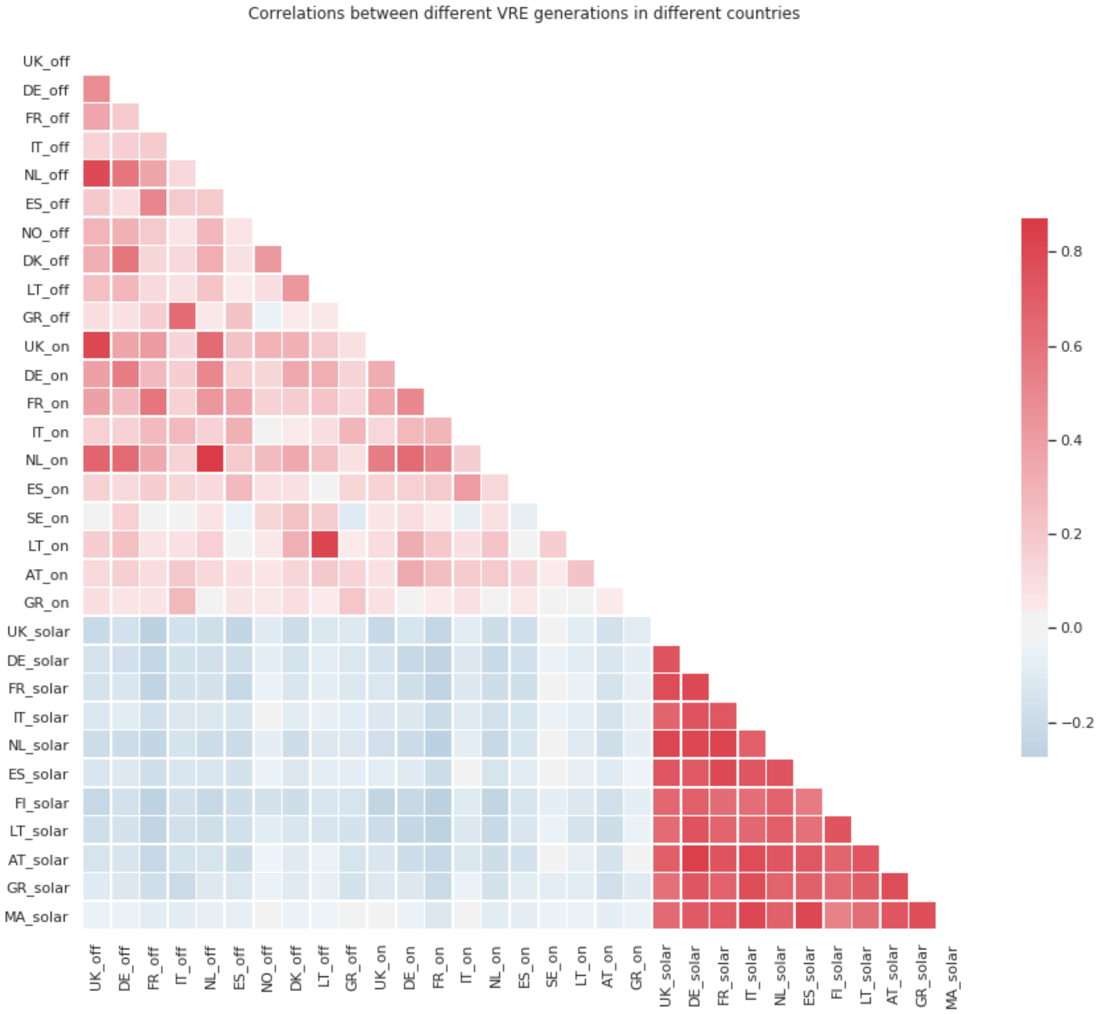
The EC LTS stresses the importance of sources of flexibility to decarbonise the EU energy system while ensuring security of supply: *"Energy storage emerges as a key enabling technology for addressing the flexibility requirements for integrating variable renewable electricity into the grid and for providing green electricity for electrified transport, industry and buildings sectors (and thus providing further rationale and helping the sectoral integration)."* (EC, 2018, p.38). While the EC LTS stresses the importance of electrical energy storage as a potential source of flexibility, it also mentioned hydrogen and e-fuels as another source of flexibility to reach carbon neutrality: *"Large amounts of variable RES can actually be stored in the form of hydrogen and e-fuels, capable of providing significant flexibility to the electricity system and decarbonising other sectors."* (EC, 2018, p.38). The rest of this section focuses on a rather simple quantitative example to outline the potential needs for flexibility in the EU energy system to reach carbon neutrality. We define flexibility requirements into three important areas to facilitate our understanding of potential infrastructure and system needs to reach net zero:

1. **Spatial flexibility** – this has been explored extensively in the energy policy and economics literature, particularly around integration of VRE resources through exploitation their negative covariances between geographical locations (see e.g., Schaber et al., 2012; Zeyringer et al., 2018) and hence minimising system integration cost of VRE. Potential to exploit negative covariances suggest further needs for interconnection between EU MS;
2. **Seasonal (temporal) flexibility** – this has been explored extensively in the literature in the context of meeting summer/winter heat loads and the role of natural gas seasonal storage (see e.g., Chaton et al., 2008; Chaton et al., 2009) and the literature on the role of P2G and gas network and storage (see e.g., Clegg and Mancarella, 2016; Blanco et al., 2018a). Large differences between summer and winter loads suggest further needs in technological advancements in long-duration electrical energy storage (see e.g., work by Mouli-Castillo et al., 2019 on CAES using saline aquifers as a proposed solution) or indeed reliance on CH_4 (see e.g., Clegg and Mancarella, 2016) and H_2 (see e.g., Amid et al., 2016; Tarkowski, 2019; Samsatli and Samsatli, 2019; Staffell et al., 2019) seasonal storage;
3. **Intraday (temporal) flexibility** – this has also been explored extensively in the electricity sector and in particular the role of electrical energy storage to facilitate integration of VRE on the intraday timescale (see e.g., Pudjianto et al., 2013; Steinke et al., 2013; Nijs et al., 2014; Weitemeyer et al., 2015; Zeyringer et al., 2018; Bistline et al., 2020). Intraday variations in demand and supply suggest trade-offs between intra-day electricity-based vs gas-based flexibility solutions.

5.1. Spatial flexibility

A relatively easy way to identify and to highlight potential benefits of further electricity interconnection between electricity markets to allow for more VRE resource integration is to examine their instantaneous correlations (Figure 17). One can see that while solar outputs are highly correlated with *each other* among the different countries due the earth's rotation, they are negatively correlated (some more than the others) with *all* the wind generations both on- and offshore. This reflects the importance of spatial flexibility of the EU energy system and calls for the need to have a highly interconnected electricity system across EU MS to allow high share of VRE. The case for geographical diversification of wind and solar outputs is highlighted by the grey and blue tiles in the upper triangle. For example, onshore wind in Sweden is uncorrelated or weakly negatively correlated with a number of offshore generations, namely in order of negativity, UK (0.02), Italy (0.002), France (-0.01), Spain (-0.05) and Greece (-0.10), as well as the onshore generations in the southern countries Greece (0.01), Spain (-0.06) and Italy (-0.07).

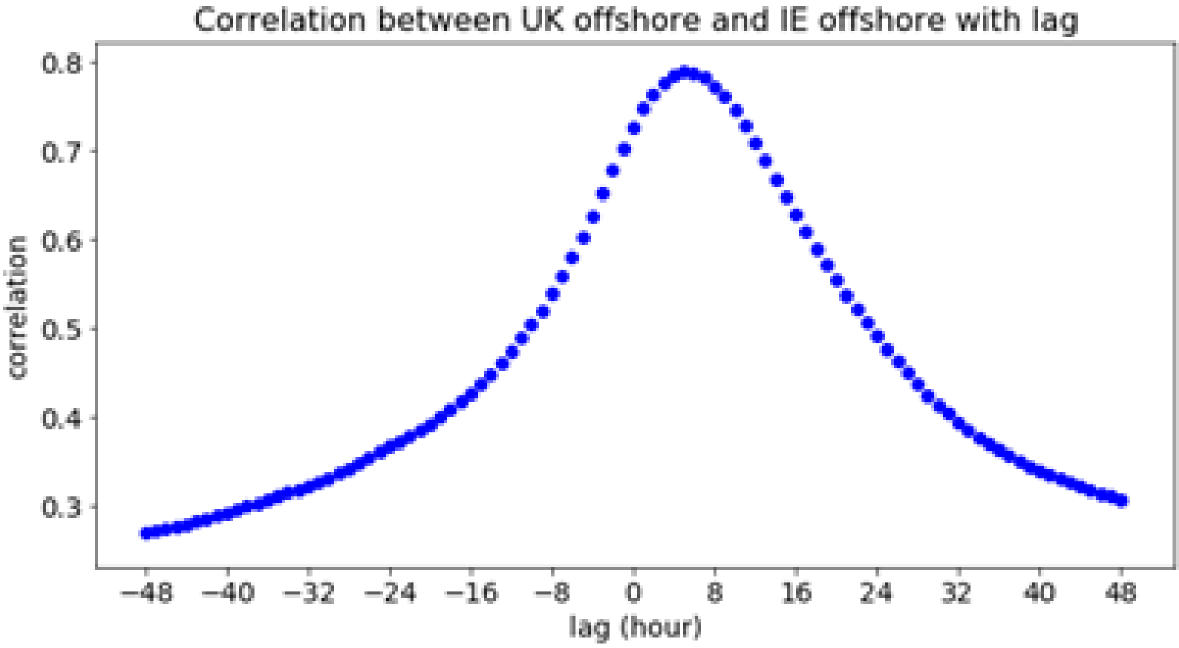
Figure 11: Instantaneous hourly correlations between different VRE generations in different countries



Note: Off=off-shore wind; On=on-shore wind
Source: own calculations based on https://www.renewables.ninja/

While the importance of having a highly interconnected electricity system to allow for a high share of VRE in the system is clear, especially to exploit negative correlations between wind and solar generation across space, temporal flexibility (or investments in storage technologies) might further complement investments in interconnections (see e.g., Steinke et al., 2013), given, for example, strong positive correlations between wind generation. Further, while correlations shown in Figure 11 is instantaneous correlation between wind and solar generation, we know that there are systematic lagged dependencies between wind speed in various part of Europe (see e.g., Malvaldi et al., 2017) – for example, Figure 12 shows the changing Pearson correlation by shifting the Ireland's offshore wind time series backwards and forwards by 2 days.

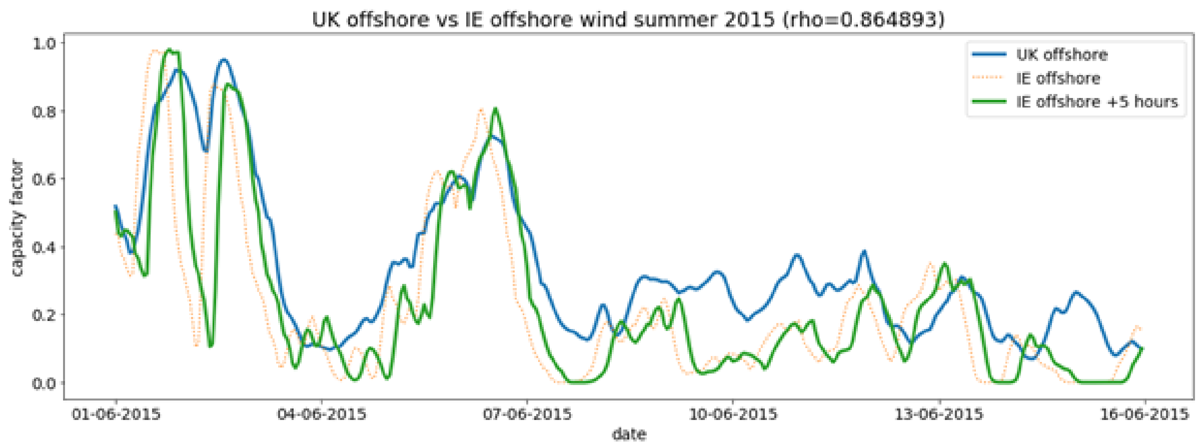
Figure 12: Correlation between UK Offshore wind and Ireland Offshore wind with lag



Source: own calculations based on https://www.renewables.ninja/

Without any shift, the Pearson correlation coefficient is 0.73 (as in Figure 11), which is already relatively high as the UK and Ireland are next to each other. But if we shift the Irish offshore wind series forward by 5 hours, the correlation increases to 0.79, which can be explained by the fact that the wind blows mostly from the Atlantic Ocean in the west, first to Ireland and then to the UK. Figure 13 gives an example of how by shifting the Irish offshore wind output by 5 hours, it matches more closely with the UK time series i.e. the green line matches better with the blue line than the orange dotted line.

Figure 13: UK Offshore wind and Ireland Offshore wind with a lag of 5 hours



Source: own calculations based on https://www.renewables.ninja/
Notes: calculations are in UTC

Another example highlighting this important systematic lagged correlations between offshore wind can be observed in Table 5 – accounting for time lag, we can see that, for example, the correlation between offshore wind output in Germany and Denmark is, on average, 0.85 compared to instantaneous correlation of 0.59; we can see similar improvement in correlation between Germany and the Netherlands when we account for a time lag. The time lag between Denmark, Germany, and the Netherlands, on average, is 2 hours: high wind speed in Denmark will likely mean high wind speed in Germany two hours later (hence -2) and then two hours later in the Netherlands (hence +2).

Table 5: Instantaneous and lagged correlation between offshore wind for Germany and selected countries

	UK	FR	NL	NO	DK
DE: instantaneous correlation	0.4741	0.1805	0.5844	0.3063	0.5882
DE: lagged correlation (hours)	0.6445 (9)	0.2304 (13)	0.7700 (2)	0.4223 (4)	0.8520 (-2)

Source: own calculations based on https://www.renewables.ninja/
Notes: calculations are in UTC

These systematic lags between offshore wind resources suggests even greater need to have storage technologies together with transmission capacity to integrate large amount of VRE, in particular offshore wind. Thus temporal flexibility is becoming increasingly important in a highly decarbonised energy system. We discuss two other forms of flexibility – seasonal and intraday flexibility – for managing a decarbonised energy system next.

5.2. Temporal flexibility

To understand the importance of temporal flexibility in a highly decarbonised (and electrified) energy system let us assume that all VRE are fully "dispatchable" such that 2018 total annual energy loads (in buildings, industry and transport sectors) can be in principle met from annual total production of energy coming from at least 85% of VRE (wind and solar) and 15% from nuclear. Fully dispatchability here simply means a potential combination of seasonal and intraday storage to move intermittent energy production from 85% of VRE to meet varying energy load while 15% of energy coming from nuclear is considered flat or baseload production in this simple example. This is a hypothetical example that is intended to show what sources of flexibility is needed and when these are needed to support a rapid electrification of the EU's energy system. Note that some of the EC LTS do suggest a move towards such a system; for example, in all 8 LTS analysed the EC stated that at least 60% of VRE and 15% of nuclear in the mix to be a no regret policy option. For a comprehensive review of the literature on high share of VRE in a deeply decarbonised electricity sector see work by Jenkins et al., 2018.

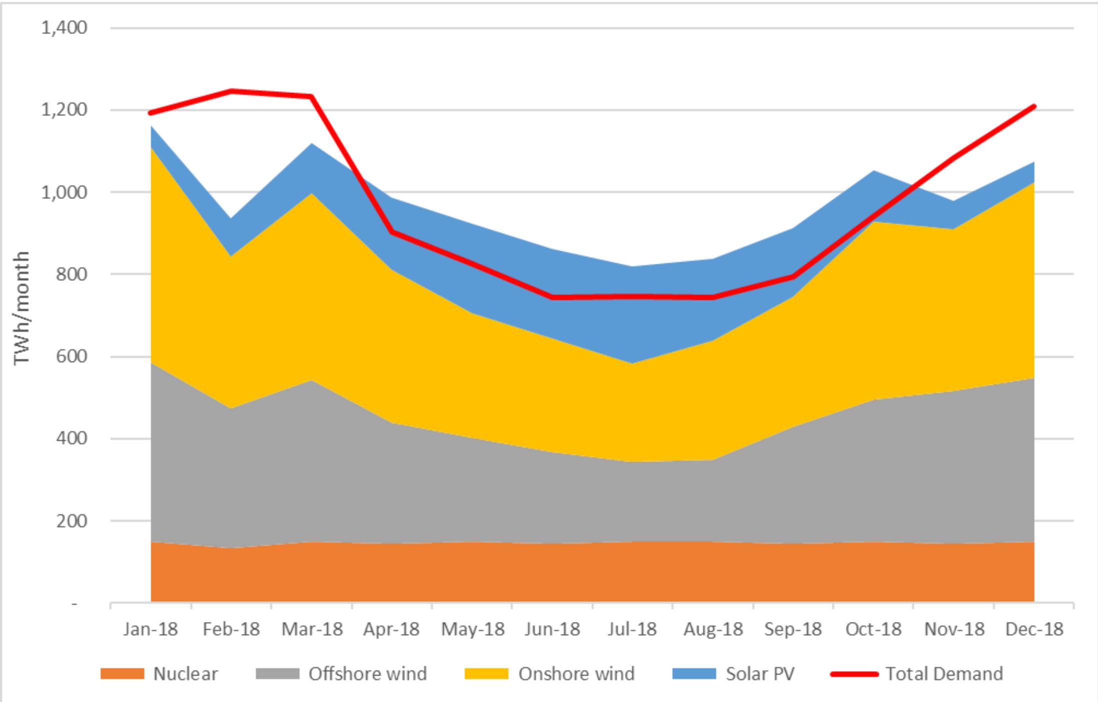
Thus, Figure 14 outlines monthly total demand and generation following the described simple hypothetical example above. One can see that, while solar generation is higher during the summer days than during the winter days (the ratio between trough and peak solar generation months is 22%), which is the opposite to the high winter and low summer energy demand (trough to peak ratio is 60%), wind does exhibit a very similar pattern to energy demand (trough to peak ratio is 45%). For example, total wind generation peaks in January (energy demand peaks in Feb) while it plunges in July (energy demand plunges in June).

As noted in the preceding section, wind and solar exhibit negative correlations and this can also be seen in Figure 14 – monthly solar PV generation peaks in July when output from wind is at its minimum point and output from Solar PV plummets in December when in general energy demand is at its high.

Thus, at the monthly resolution wind and demand has a rather strong positive correlation (+0.88) while solar generation exhibits a strong negative correlation with demand (-0.89) (see Table 6); and the combination of VRE generation and patterns of inter-year energy demand, therefore, has several important implications for planning a carbon-neutral energy system:

1. Although a large share of wind generation typically follows a similar intra-year pattern as energy demand, which helps to minimise a need for inter-seasonal (long-duration) electrical energy storage, some form of inter-seasonal storage will be required (on long-duration electrical storage see e.g., Henry et al., 2020; Ziegler et al., 2019; Albertus et al., 2020; Dowling et al., 2020; Bistline et al., 2020);
2. Dispatchability of VRE (i.e., a combination of storage and VRE) competes with not just firm power sources like CCGT and biomass (with CCS) and nuclear (on the role of firm power in deep decarbonisation of electricity sector see e.g., Sepulveda et al., 2018) as such, but more generally with energy "availability"; in other words, firm power capacity is a function of input fuel availability (methane, hydrogen, uranium, biomass etc.) and it is the flexibility of fuel input supply infrastructure and logistics (e.g., natural gas transmission capability and line pack services) that provides instantaneous power capacity or firm power to CCGTs.

Figure 14: E27+UK Daily Generation and Demand – a hypothetical example of 85/15 VRE and nuclear generation mix



Source: own calculations based on Eurostat; https://www.renewables.ninja
Note: this simple analysis assumes 85% of generation coming from offshore, onshore wind and solar PV with capacity levels such that to minimise annual absolute residual demand (or storage requirement); the rest of 15% generation is assumed to be from nuclear.

One can see that in our simple example (85/15 VRE and nuclear shares to electrify the 2018 EU energy demand) we can calculate the requirement to shift electrical energy from the summer season (excess of electrical energy) to the winter season (deficit of electrical energy) to be ca. 6% of total annual energy demand in 2018 (i.e., the sum of the mismatch area between demand and generation stack in Figure 14 divided by annual demand). Comparing this to the 2018 peak gas volume in all European gas storage (as % of total energy demand) reveals that inter-seasonal load shifting in this highly renewable-powered system is comparable to the current gas system – in 2018, peak volume of gas in storage facilities totalled 949.6 TWh[22], or 8% of total energy demand in 2018. It is worth noting that existing hydro pumped storage facilities in Europe have a combined power capacity of 52.42 GW and assuming 8 hours of duration (Simoes et al., 2013) this translates into 420 GWh of holding capacity or just 0.044% of the 2018 peak gas volume in storage facilities. Needless to say that this points to the challenge of and requirement for inter-seasonal electrical energy storage in a highly electrified, renewable-dominated energy system.

Note that this comparison is of course a simplification because the potential need for inter-seasonal storage in a highly electrified energy system will depend inter alia on technology composition of a low carbon system and assumptions about long-term relationship between economy and consumer behaviour etc. For example, there may be potential improvements in end-use efficiencies due to the penetration of technologies like heat pumps in buildings, and electric vehicles in road transport which reduce final energy consumption and hence lower inter seasonal modulation needs. On the other hand, new forms of seasonal technologies like H_2-based technologies might mean high overall energy requirement during the conversion processes. The exact requirement is a subject for rigorous energy system modelling, which is the primary objective of this research. Nevertheless, irrespective of how much in practice we might need inter-seasonal storage, the shapes of VRE production and energy demand will largely stay similar to what we have at the moment (see Figure 14), unless somehow we end up with a largely southern climate conditions such that our inter-year demand shape flattens out.

In addition to the need for inter-seasonal electrical energy storage to shift energy from summer to winter months (just what seasonal gas storage has been doing in the current energy system), intra-day flexibility options to manage and integrate a large share of VRE will be rather important. As we noted already, a vast literature exists on the importance of intraday electrical energy storage in decarbonised electricity sectors exist.

Nevertheless, the importance of intraday flexibility can be easily seen by looking at variability of total energy demand and VRE generation at different time resolution (from months to hourly). Table 6 outlines some summary statistics for demand and VRE generation for different time resolution. One can see that managing variability of VRE is important as we move from monthly variability to hourly time step – the coefficient of variation (CV) of VRE increases while the correlation between VRE and demand decreases i.e., we see a greater mismatch between VRE outputs and demand at hourly time scale.

[22] Note that this is 87% of total gas storage capacity (volume).

Table 6: Some Statistical Properties of EU+UK energy demand and VRE generation (2018), TWh

DEMAND/VRE TYPE	TIME STEP	MIN	MAX	MIN TO MAX RATIO	AVERAGE	STD. DEV	CV*	CORRELATION WITH DEMAND
DEMAND	Monthly	744,941	1,246,854	60%	972,105	198,816	20%	
	Daily	21,639	53,492	40%	31,960	7,322	23%	
	Hourly	434	2,775	16%	1,332	399	30%	
OFFSHORE WIND	Monthly	194,442	437,775	44%	311,918	78,562	25%	90%
	Daily	2,156	21,831	10%	10,255	4,252	41%	57%
	Hourly	17	416	4%	179	80	45%	36%
ONSHORE WIND	Monthly	239,559	523,874	46%	370,831	84,741	23%	84%
	Daily	4,907	27,298	18%	12,192	4,400	36%	52%
	Hourly	156	1,772	9%	758	294	39%	31%
SOLAR PV	Monthly	50,812	236,187	22%	143,540	64,474	45%	-89%
	Daily	662	9,442	7%	4,719	2,267	48%	-75%
	Hourly**	0.0004	777	0%	302	235	78%	-3%

Source: own calculations based on Eurostat & https://www.renewables.ninja/
Note: *CV is coefficient of variation and is calculated as std. deviation divided by the average; ** hourly solar calculations exclude zero entries, i.e., excluding hours when solar is not generating (e.g., night hours); including zero generation hours will further increase CV value.

Another point to mention is that, while there are some weak but positive hourly correlations between wind and demand, there is no correlation between hourly demand and solar PV (when it generates) (Table 6). This does imply a relative importance of intraday storage solutions to manage solar PV generation more than to manage wind. For example, Figure 15 shows hourly demand and supply for a summer period (15 June – 15 July) and we can see that excess supply coincides mostly with solar output and hence the importance of storage during summer times and the potential need for H_2 electrolysers to manage excess of supply, if this is cost effective against other flexibility options, including curtailments. Similarly, Figure 16 shows hourly demand and supply dynamics over a winter period (15 January to 15 February) and we can see that:

1. even in the winter period in some hours there is excess of supply coinciding with solar generation, and
2. also quite importantly that there is deficit of energy for a rather prolonged period of time (208 hours when demand exceeds supply), suggesting a clear need for long-duration storage technologies.

Figure 15: E27+UK Daily Generation and Demand – an example of a summer period (15 June-15 July) at hourly time step (x-axis)

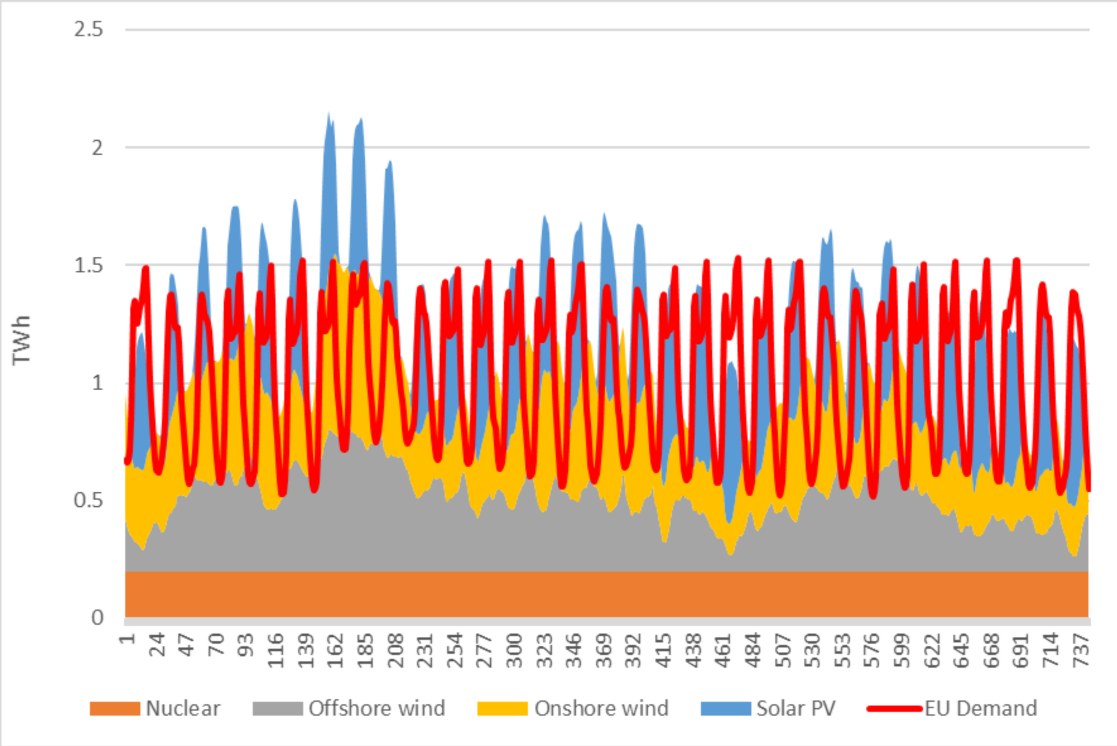
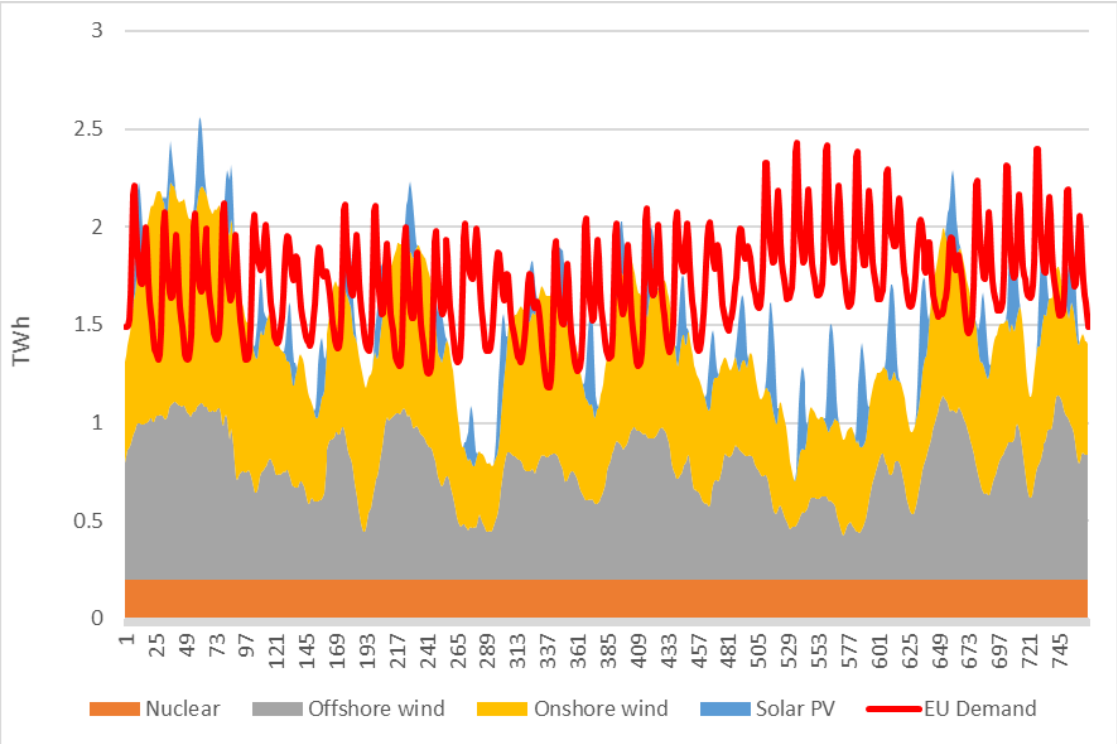


Figure 16: E27+UK Daily Generation and Demand – an example of a winter period (15 January - 15 February) at hourly time step (x-axis)



Source: own calculations based on Eurostat & https://www.renewables.ninja/

To summarise, even with this rather simple example[23] and the survey of the literature on the role of flexibility in net zero energy systems we can conclude that:

1. A highly interconnected European energy system is needed to reach deep decarbonisation goals;
2. A highly flexible intraday and inter-seasonal storage systems is needed to manage short and long-term security of supply in a deeply decarbonised European energy system.

In practice, the extent to which these flexibility solutions are needed in a cost minimal European net zero energy system depends on not just the underlying properties of hour-to-hour and month-to-month variations in demand and supply (extensively covered above) but also on four other **key** dimensions:

1. Costs of energy technologies in production to end-use value chains;
2. Technological limitations, including pace of innovation and scale up of new technologies;
3. Policy and institutional context in which the European energy system is embedded, and
4. Social acceptability of new technologies and system and behavioural changes needed.

In the academic literature, the issue of flexibility to support decarbonisation of the electricity sector through a very high share of VRE penetration has been explored and discussed *extensively* (for a review see e.g., Huber et al., 2014; Alizadeh et al., 2016; Kondziella et al., 2016; Cruz et al., 2018). The flip side of the need for flexibility is so-called *"system integration costs"* of VRE in the electricity sector (see e.g., Ueckerdt et al., Hirth et al., 2015; 2013; Heptonstall and Gross, 2020). While attention has been paid to the flexibility needs (and hence also understanding the nature of system integration costs) to support high share of VRE in the electricity sector, limited academic studies paid attention to the flexibility requirements in a deeply decarbonised energy system, taking into account possibility of a tightly coupled energy system – that is, from a *sector coupling* or *energy system integration* viewpoint. For example, Blanco and Faaji (2018) noted *"The more options considered to deal with intermittent sources, the lower the storage requirement will be. Therefore, future studies aiming to quantify storage needs should focus on the entire energy system including technology vectors (e.g. Power to Heat, Liquid, Gas, Chemicals) to avoid overestimating the amount of storage needed"*.

So far, most of the academic literature on modelling carbon neutral energy systems (see e.g., Capros et al., 2018; Capros et al., 2019; Weitzel et al., 2019) focuses on *"pathways"* dynamics (see e.g., Capros et al., 2014a; Capros et al., 2014b; Capros et al., 2016; Fragkos et al., 2017; Davis et al., 2018), on the role of various supply-side technologies (see e.g., Evangelopoulou et al., 2019; Blanco et al. 2018a; Blanco et al. 2018b), and on societal changes (see e.g., EC 1.5 LIFE scenario; Carmichael, 2019; Carmichael and Wainwright, 2020; Carmichael et al., 2020) and demand-side technologies (see e.g., Strbac et al., 2020; Elliot et al., 2020) required to reach deep decarbonisation pathways.

Recently, only selected studies started to examine the flexibility requirements from energy system integration perspective (see e.g., Brown et al., 2018; Evangelopoulou et al., 2019; Victoria et al., 2019; Pavičević et al., 2020; Zhu et al., 2020; Bødal et al., 2020). While the focus of these recent studies are different in terms of geography, technology and sectors, and modelling methodologies,

[23] In addition to the variability we model here across a single year, annual solar and wind demands also vary, adding another source of variability and requirement for storage in a low wind/solar output and high demand year.

all stress the importance of joint planning of all energy vectors and supporting infrastructure for cost-effective energy system decarbonisation.

From a modelling methodology perspective, this research paper advances further this emerging literature on modelling the energy system integration in at least two ways:

1. with the focus on understanding the flexibility (as defined here) requirements for a net zero energy system, our model has the right balance of temporal, spatial and technology-richness to capture wide range of flexibility sources – from large-scale, system level to end-use level[24];
2. in trying to strike this right balance, we employ sophisticated statistical methods (see Li et al., *forthcoming*) to capture the essence of hourly variability of both underlying demand and supply dynamics, in particular, generation from VRE; thus, avoiding "soft-linking" (see e.g., Zeyringer et al., 2018; Pavičević et al., 2020) between the various models with different time scales and horizons while ensuring tractability and solvability.

From an empirical and policy perspective, this is the first research to employ this sophisticated modelling framework to investigate the question of flexibility requirements in a net zero energy system. The model has many empirically innovative features such as (i) modelling key European countries with explicit cross-border interconnections capability, (ii) endogenous expansion of capacity and hourly operations of the system, and (iii) explicit considerations of trade-off between network and storage capacity and generation and end-use technologies.

[24] with the exception of the interannual flexibility need.

06

METHODOLOGY, ANALYTICAL FRAMEWORK AND SCENARIOS

6. Methodology, Analytical Framework and Scenarios

This section outlines a short summary of our research methodology and our modelling framework. It then describes our main baseline scenarios that we model and our sensitivity analyses.

6.1. Energy system model for policy analyses

Our energy system model is a partial equilibrium, linear programming optimisation model capable of representing our modern and future energy systems in great detail. It is an economic optimisation model and hence its objective is to minimise total energy system costs comprising of capital and operational costs in the various sectors while meeting projected end-use demands and GHG emissions and other constraints specified by the user (see Figure 17).

Figure 17: Energy system model for policy analyses

A detailed mathematical formulation of the model can be found in Chyong et al. (*forthcoming).* Our model is fundamentally similar to the well-known TIMES and PRIMES modelling tools but distinctively different from these in a number of advantageous ways:

- our model can capture both within day hourly and inter-seasonal variability. PRIMES and TIMES models use *timeslices* (usually 12 to 24) to represent rather coarsely intra-day variability without any ability to capture inter-seasonal operations of assets such as storages optimally.
- our model is based on fundamentals of microeconomics and can simulate welfare maximization under both perfect competition and imperfectly (Cournot) competitive commodity markets, for example.
- our model can simulate perfect or imperfect foresight with rolling horizon optimization algorithm.

Spatial and temporal resolution of the model

For this research project, the model represents 12 European market areas (Table 7) allowing for endogenous trade in main commodities (Figure 18 shows the interconnections we model).

Table 7: Spatial resolution of the energy system model

TABLE 7

SPATIAL RESOLUTION OF THE ENERGY SYSTEM MODEL

REGIONS IN THE MODEL	COUNTRIES & COMMENTS
UK	UK
Ireland	Rep. of Ireland
Nordic	NO, SE, FI, DK
BE	BE, LU
DE	DE
NL	NL
FR	FR
IT	IT
Baltics	LT, LV, EE
PL	PL
Eastern Europe	CZ, SK, HU
Central Europe	AT, CH, SL
SEE	BG, GR, HR, RO, MT, CY
Iberia	ES, PT
North Africa	Utility scale solar generation
North Sea	Offshore wind generation

The model covers **hourly dispatch** and operations of main technologies and **investment** in **capacities** of:

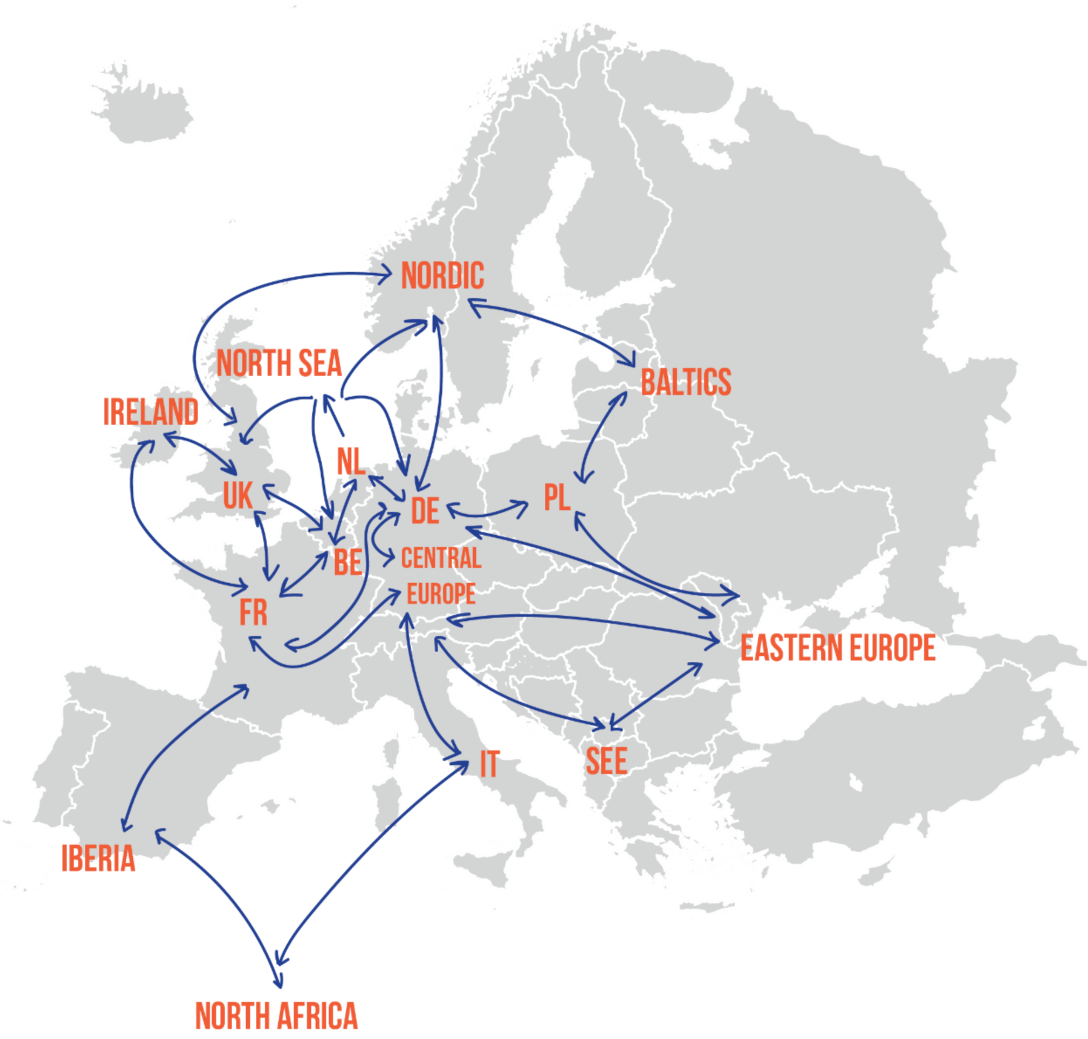
- Power generation technologies;
- heat technologies in buildings;
- road transport modes such as EVs, FCEVs, gas mobility and conventional road transport;
- H_2 production technologies: green H_2 via water electrolysis and blue H_2 via natural gas reformation with CCS;

- Synthetic fuels production: e-gas and e-liquids (methanation of H_2);
- Storage technologies for CH_4, CO_2, H_2, electricity, heat;
- Transmission and distribution networks;
- and interconnection capacity to allow endogenous cross-border trade in CH_4, H_2, electricity, CO_2, bioenergy and e-liquids.

The model allows for endogenous blending of H_2 into the CH_4 network (with an upper limit set by the modeller). For this project since we model an energy system of 2050 we do not allow blending of H_2. Therefore, we allow the possibility to have two separate CH_4 and H_2 networks in each modelled regions and scenarios, if it is cost optimal to do so.

Figure 18: Geographical coverage of the energy system model and interconnections

FIGURE 18 - GEOGRAPHICAL COVERAGE OF THE ENERGY SYSTEM MODEL AND INTERCONNECTIONS



Sectoral coverage

The model covers the main final consumption sectors – residential, commercial, transport and industry. For this research project we have aggregated final consumption as follows:

1. **Buildings** sector represents final consumption of residential, commercial and energy use in the agriculture sectors.
2. **Road transport** represents demand for road activities of passenger cars, public road transport and heavy goods vehicle (HGV).
3. **Industry** represents final energy consumption in the industrial sector.

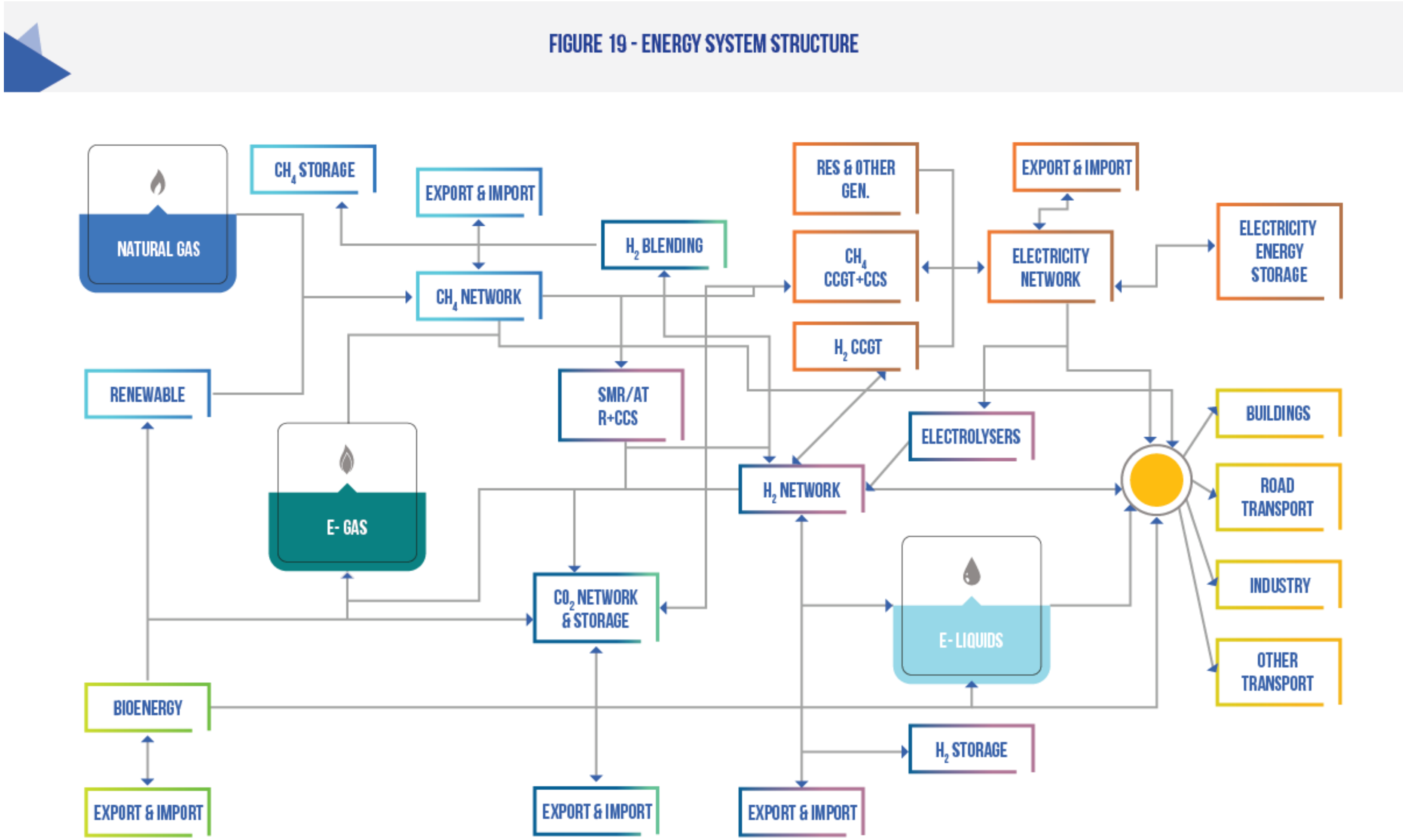
4. **Other transport** represents final energy consumption by aviation, inland navigation and rail transport activities.

In terms of supply and transformation technologies the model takes into account:

1. main power generation and storage technologies for the electricity sector;
2. and main end-use technologies in buildings and transport sectors;
3. cross-border trade in main commodities including via electricity transmission and gas pipelines;
4. primary supply sources include coal lignite and bituminous, uranium, biomass, natural gas, biomethane, e-gas, H_2, electricity, e-liquids.

The model also includes important emerging technologies such as hydrogen production as well as CCS, direct air capture, and renewable gases - Figure 19 highlights the structure of an energy system we implement in our model. Detailed description of assumptions and input data is given in Appendix 2.

Figure 19: Energy system structure



LEGEND

CH_4: methane
CCGT: combined cycle gas turbines
CCS: carbon capture and storage

CO_2: carbon dioxide
H_2: hydrogen
RES & other gen: Renewable electricity sources & other generation
SMR/ATR: steam methane reformation / auto-thermal reforming technologies

6.2. Baseline Scenario and its Variants

Our baseline scenario is *net zero ("NZ Scenario") GHG emissions European energy system by 2050*. This baseline scenario represents a very ambitious GHG emissions reduction strategy – the NZ scenario strives to achieve carbon neutrality by 2050 and it is closely aligned with the assumptions of the EC LTS 1.5 TECH (a summary of all EC LTS scenarios can be found in §2). For our NZ scenario, abstracting away from the policy credibility question, we assume:

1. Overall net zero GHG emissions target for the Europe (EU, UK, Norway and Switzerland) as a whole by 2050, and;
2. specifically for the UK, France, Denmark, and Hungary by 2050, in line with their national net zero legislation. Note that since Denmark and Hungary are part of regional groupings, net zero GHG emissions constraint is therefore applied to "Nordic" (Denmark is part of this grouping) and to "Eastern Europe" (Hungary is part of this grouping) regions; however, we acknowledge that in practice national net zero legislation (e.g., UK) allows for international offsets and trading of permits so in practice net zero GHG target by 2050 might not be binding on them physically. We leave this for future research and therefore assumes national net zero targets are binding targets without international offsets and trading of permits as such.

In addition to the NZ scenario, we also model three other baseline "variants" which differs along two important dimensions – (i) the level of GHG emissions reduction ambition, and (ii) the role of the electricity sector in deep decarbonisation. Thus, the first key baseline variant examines a lower GHG emissions reduction target, while the other two baseline variants look at the role of electricity in an extreme assumption scenario:

1. a deep decarbonisation pathways that strives to achieve a reduction of at least 90% GHG emissions relative to 1990 level; we call this 90% Scenario; this is closely aligned with the EC LTS COMBO scenario;
2. A net zero scenario which is heavily dependent on direct electrification; we called this NZ-e Scenario;
3. A net zero scenario which is heavily dependent on fossil methane, biomethane, hydrogen and negative emissions with limited reliance on direct electrification; we called this NZ-g Scenario.

The purpose of these three baseline variants is to understand:

1. The impact of the "last mile" on the energy system configuration; it is getting from 90% GHG reduction target to net zero that is deemed to be most challenging and hence we want understand implications on the energy system of this marginal 10% reduction;
2. Key drivers of electrification or gasification as potential solutions to get to net zero.

Following EC LTS (EC 2018, p.210), we assume a carbon price of €350/tCO2 in the ETS sectors in the NZ scenario and €250/tCO2 in the 90% scenario in 2050. It is worth noting that applying carbon pricing in the ETS sectors only might not lead to deep decarbonisation of other sectors such as buildings and transport sectors; therefore, in addition to the carbon pricing (in the ETS sector), we apply GHG emissions cap, in line with EC LTS assumption, for the buildings and transport sectors (Table 8).

Table 8: Caps on GHG emissions in buildings and transport sectors (mn tCO2e)

TABLE 8

CAPS ON GHG EMISSIONS IN BUILDINGS AND TRANSPORT SECTORS (MN TCO2E)

	90% SCENARIO	NET ZERO
RESIDENTIAL	19.3	11.8
TERTIARY	23	19.3
TRANSPORT	256.8	85.6

Source: PRIMES model & EC LTS

Table 9: Correspondence between modelled scenarios and those modelled in EC LTS

OUR SCENARIOS	EC LTS
NZ	1.5 TECH
90% Scenario	COMBO
NZ-e and NZ-g	1.5 TECH & authors' additional assumptions (see Table 10)

To the extent possible data inputs and assumptions for our NZ were based on inputs and assumptions made in the 1.5 TECH LTS; where data and assumptions were not made public by the EC LTS we source those from the academic literature, other public sources or sponsors' inputs. For details regarding our data inputs and assumptions see Appendix 1. Further assumptions were made to push our NZ to the two extremes: NZ-e and NZ-g (see Table 10). For details of the NZ baseline assumptions see Appendix 1.

Table 10: Additional Assumptions for NZ variants

NZ-E KEY ASSUMPTIONS	NZ-G KEY ASSUMPTIONS
All commodity prices to be increased by a factor of 2 (relative to the NZ baseline costs). These commodities are coal, natural gas, biomass, biomethane, diesel, gasoline, and uranium;	All commodity prices to be decreased by a factor of 2 (relative to the NZ baseline costs). These commodities are coal, natural gas, biomass, biomethane, diesel, gasoline, and uranium;
Capex of wind onshore, offshore and solar PV to be decreased by a factor of 2 (relative to NZ baseline costs);	Capex of wind onshore, offshore and solar PV to be increased by a factor of 2 (relative to NZ baseline costs);
Increase the upper bound for electrification of road transport – passenger cars, public transport and HGV – to 100% (% of total vehicle stock) in 2050. Note that under the NZ baseline, the upper bound were kept in line with EC 1.5TECH (see Appendix A.8);	Decrease the upper bound for electrification of road transport – passenger cars, public transport – down to 50% (% of total vehicle stock) while for HGV we keep the same as in the NZ baseline;
Country-specific upper bounds for wind offshore and onshore to be increased by a factor of 2 (relative to the NZ baseline upper bounds applied to wind offshore and onshore);	Country-specific upper bounds for biomass and biomethane availability to be increased by a factor of 2 (relative to the NZ baseline upper bounds applied to biomass and biomethane);
Electrification of industrial final energy demand to be increased to 85% compared to 60% assumed in the NZ scenario in line with 15 TECH.	Electrification of industrial final energy demand to be capped at 40%.

6.3. Research framework

While much previous academic work has focused on deep decarbonisation pathways and on how using a combination of technologies and societal transformations we can achieve these pathways (see our literature review in §4), limited academic work so far has assessed two inter-related and important questions:

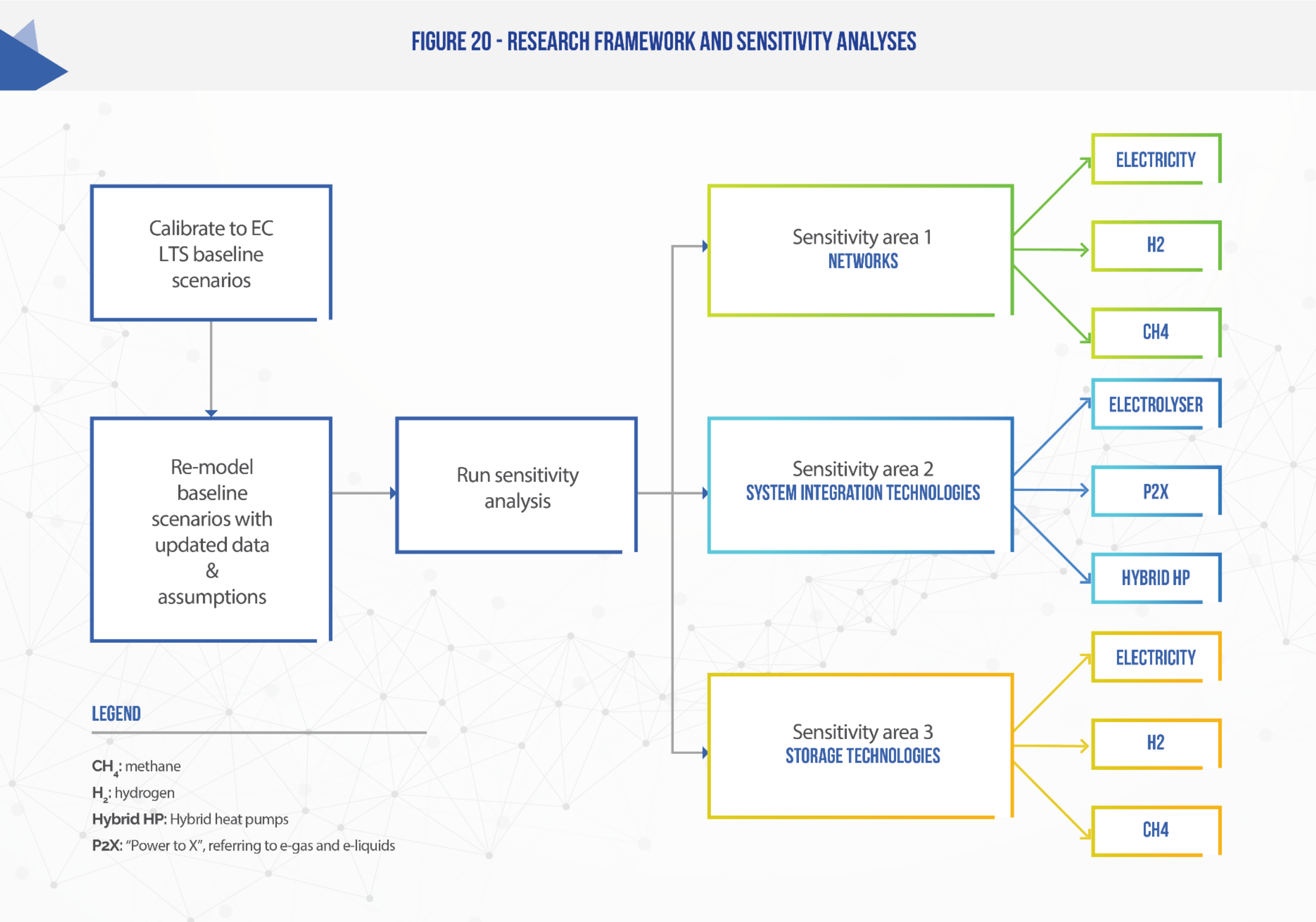
- What are the sources of flexibility under gas and electricity sector coupling and their role in deep decarbonised energy systems;
- What are complementary dimensions and trends between low-carbon electricity, renewables, and carbon-neutral gases for competitive and secure European energy system.

In order to address these research questions, our research framework consists of two parts: first, using our energy system model we simulate our baseline scenarios, and then secondly we conduct our sensitivity analyses (see Figure 20).

Based on our analysis discussed in §4, we can summarise the following key sources of flexibility in a deeply decarbonised energy system:

1. **Networks** – moving energy across space helping to integrate energy supply and demand sources;
2. **System integration technologies –** such as power-to-X helping to couple the different energy sectors and enabling efficient circular energy system as well as water electrolysis technologies coupling electricity and gas sectors at the upstream level and hybrid heat pumps coupling electricity and gas at the household level;
3. **Storage** – moving energy across time helping to modulate energy demand and supply.

Figure 20: Research framework and sensitivity analyses



For each of the key technologies we increase its projected cost by a small fraction and measure the impacts of these cost sensitivities on a tipping point when our energy system might switch to an alternative set of technologies. Thus, for each of the technology we listed in Figure 20, we change their projected costs by -50% to +200% from the baseline costs assumptions with the increments as shown in Table 11. Note that we consider H2-based technologies to be immature at present and hence our range of cost sensitivities parameters applied to these set of technologies are wider; this is intended to capture a potentially wider range of outcomes of H2-based technological innovation pathways by 2050.

Table 11: Cost parameters for sensitivity analyses

TABLE 11

COST PARAMETERS FOR SENSITIVITY ANALYSES

	ELECTRICITY- AND CH_4-BASED TECHNOLOGIES	H_2-BASED TECHNOLOGIES
SENSITIVITY 1 (S1)	+10% (relative to the baseline cost)	+50% (relative to the baseline cost)
SENSITIVITY 2 (S2)	+25%	+100%
SENSITIVITY 3 (S3)	+50%	+200%
SENSITIVITY 4 (S4)	-10% (relative to the baseline cost)	-10% (relative to the baseline cost)
SENSITIVITY 5 (S5)	-25%	-25%
SENSITIVITY 6 (S6)	-50%	-50%

For example, for the networks sensitivity analysis, we have done 18 sensitivities (3 x 6) for the Net Zero Scenario and hence 18 simulations in total for this set of technologies. This analysis is performed for all key technologies we listed in Figure 20. Apart from answering our research questions, the objective of this sensitivity analysis is at least two-fold:

1. To show the robustness of the model by showing "directional" impact;
2. and to facilitate transparency as to the model behaviour.

Such sensitivity analysis of key technologies for modelling a net zero scenario has not been carried out systematically in the recent modelling work on energy system integration nor it was carried out by the EC in its LTS study.

07

MODELLING RESULTS

7. Modelling Results

This chapter focuses on results from the NZ Baseline scenario (§7.1). It then discusses results from the baseline variants (§7.2), focusing in particular on the impact of lower GHG emissions reduction target and on the key drivers of the role electricity in delivering net zero target. Then we discuss how much it might cost to achieve deep decarbonisation (§7.3) and lastly we proceed to summarise key findings from the sensitivity analysis (§7.4).

7.1. Net Zero Baseline

This section discusses the results from modelling the NZ baseline scenario, focusing in particular on energy system structure in terms of contributions of fuels and commodities in primary and final consumption of the key sectors and the changes required to get us from today's energy system (2018 as our starting point) to the 2050 NZ cost optimal energy system (§7.1.1.). Then, we discuss the impact of moving to the NZ target on sectors – buildings, industry and transport (§7.1.2.). After this, we analyse the energy system capacity and flexibility needed to meet the NZ target (§7.1.3.). Lastly, we focus on costs to achieve the NZ scenario (§7.1.4.).

7.1.1. Mind the Gap

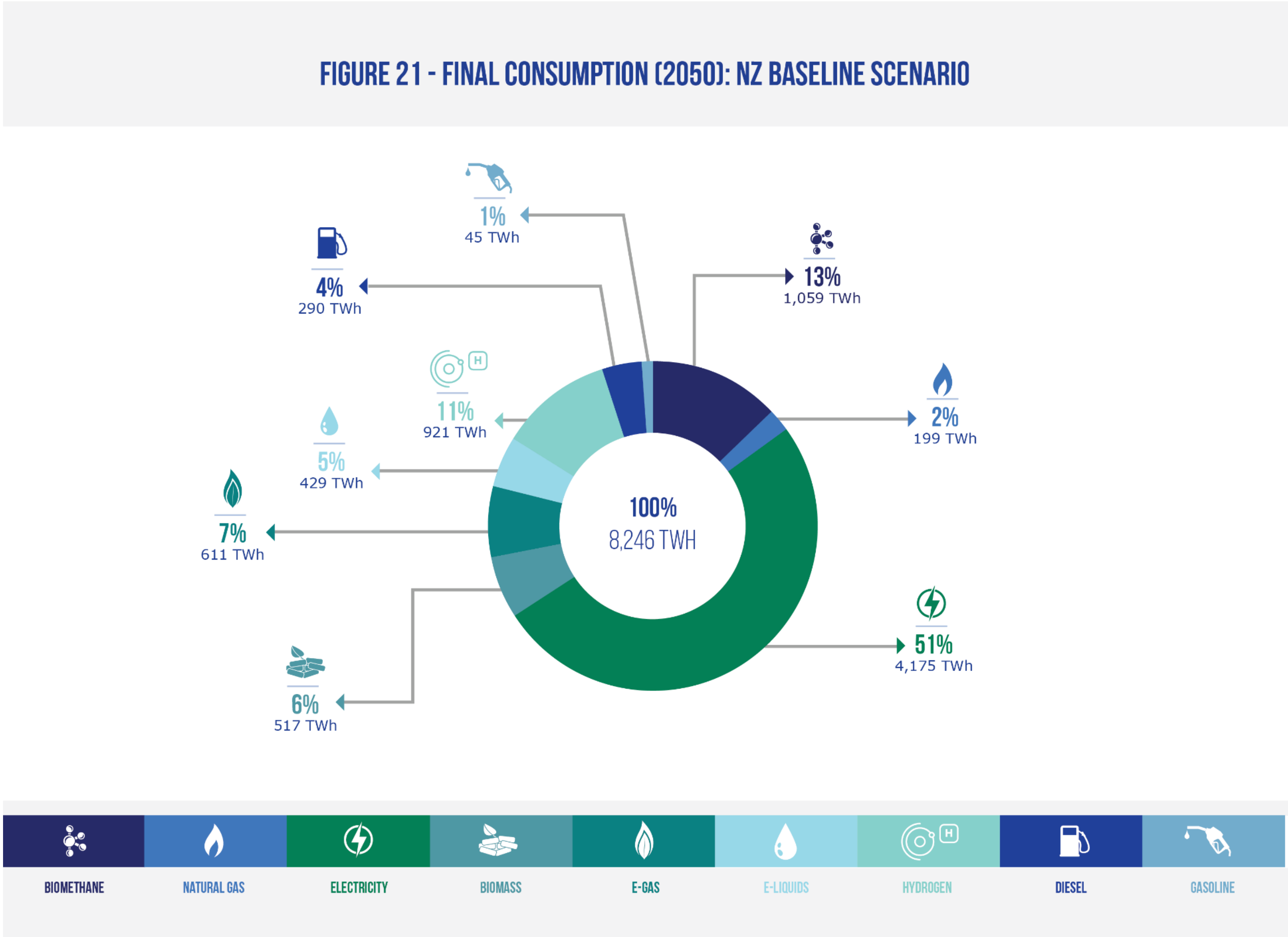
Figure 21 outlines projection of final consumption by fuels in the NZ baseline scenario that we model while energy flows and system balance can be seen in Figure 26. Our results suggest that final energy consumption reaches 8,246 TWh in 2050, which is consistent with the results obtained by the EC in its 1.5 TECH scenario (7,955 TWh in 2050). It represents 67% of final consumption in 2018 (compare Figure 21 and Table 3). This drop in energy consumption is driven primarily by direct electrification and in uptake of more energy efficient end-use technologies in the building sector (e.g., heat pumps) and in road transport sector (e.g., EVs) – we analyse sectoral impacts in more details later in §7.1.2.

The role of electricity in our NZ Baseline

First, at the system level, the results highlight the central role of electricity in NZ GHG emissions by 2050 in the EU. In the net zero scenario electricity in the final consumption reaches 51% (for comparison, the EC 1.5TECH predicts 50%). This is a very consistent set of results with both the EC LTS result as well as with many other academic studies: as reviewed by Jenkins et al. (2018; ***emphasis added***) *"Across global decarbonisation scenarios produced by **18 modelling groups**, for example, electricity demand increases 20%–120% by 2050 (**median estimate of 52%**) and 120%–440% by 2100;"*.

While electricity plays a central role in our NZ scenario, it is worth mentioning the role of other low-carbon energy sources, in particular, the role of biomethane, hydrogen and synfuels in the final energy consumption. Together, H_2, biomethane, e-gas and fossil gas contributes around 33% of to the final energy consumption in 2050. To put this in the context of our current (2018) energy system and energy flow, Table 12 shows changes in final consumption and primary supply position of electricity, CH_4 and H_2 in 2018 vs. 2050 NZ scenario. One immediate conclusion is that in terms of **energy throughput** requirements the flow of CH_4 will be reduced from 2854 TWh of delivery in 2018 to 1869 TWh in 2050 to final consumers, which is a reduction of 35% relative to the 2018 level; at the same time, we see a larger decrease of at least 50% in CH_4 flow at primary supply level – from 5396 TWh in 2018 down to 2672 TWh in 2050. There is no surprise in this trend because of potential decentralisation of CH_4 supply in the future as our NZ energy system will be dominated by "home grown” biomethane and synthetic gas at “local” level requiring less flow at primary supply level (or at transmission level). None of this, however, means less importance of transmission nor distribution network capability to deliver CH_4 in the NZ system; we come back to system capacity and capability below in Section 7.1.3.2. Further, one can see that the role of fossil gas will be reduced dramatically, from 2854 TWh to 199 TWh (just 7% of the 2018 supply level) in the structure of final consumption; however, at least at the distribution level, the CH_4 network will be smaller than it is in 2018 in terms of energy throughput, seeing a reduction of ca. 35% and supporting the throughput will be largely relying on a significant uptake of biomethane and synthetic gas in the CH_4 network.

Figure 21: Final consumption (2050): NZ baseline scenario



The second immediate conclusion to draw is the role of the emerging H_2 energy carrier and network in 2050 – hydrogen will have a comparable role in terms of energy flow as CH_4 network; its flow to final consumption reaches ca. 50% of the flow level of CH_4 in 2050 while at primary supply level the throughput of H_2 reaches 83% of the flow level of CH_4. As we shall discuss later it is not unimaginable to have two separate networks – CH_4 and H_2 – to deliver cost optimal net zero energy system. Clearly, this result is driven by the assumption that biogas (derived from waster wastewater treatment plans and landfill gas recovery systems) is both abundant and cheap, and upgraded to biomethane instead of being processed to hydrogen. Both processes are subject to great technological uncertainty, given that biomethane production today is close to zero and projected to increase to more than 1000 TWh per year in 2050. A sensitivity has been performed to explore a decarbonisation pathway where bioenergy is not abundantly available (see NZ-e scenario). Further research is needed to analyse how a transformation of bioenergy to hydrogen would impact energy infrastructure requirements and incorporate the potential economic impacts of competing uses of land for bioenergy production.

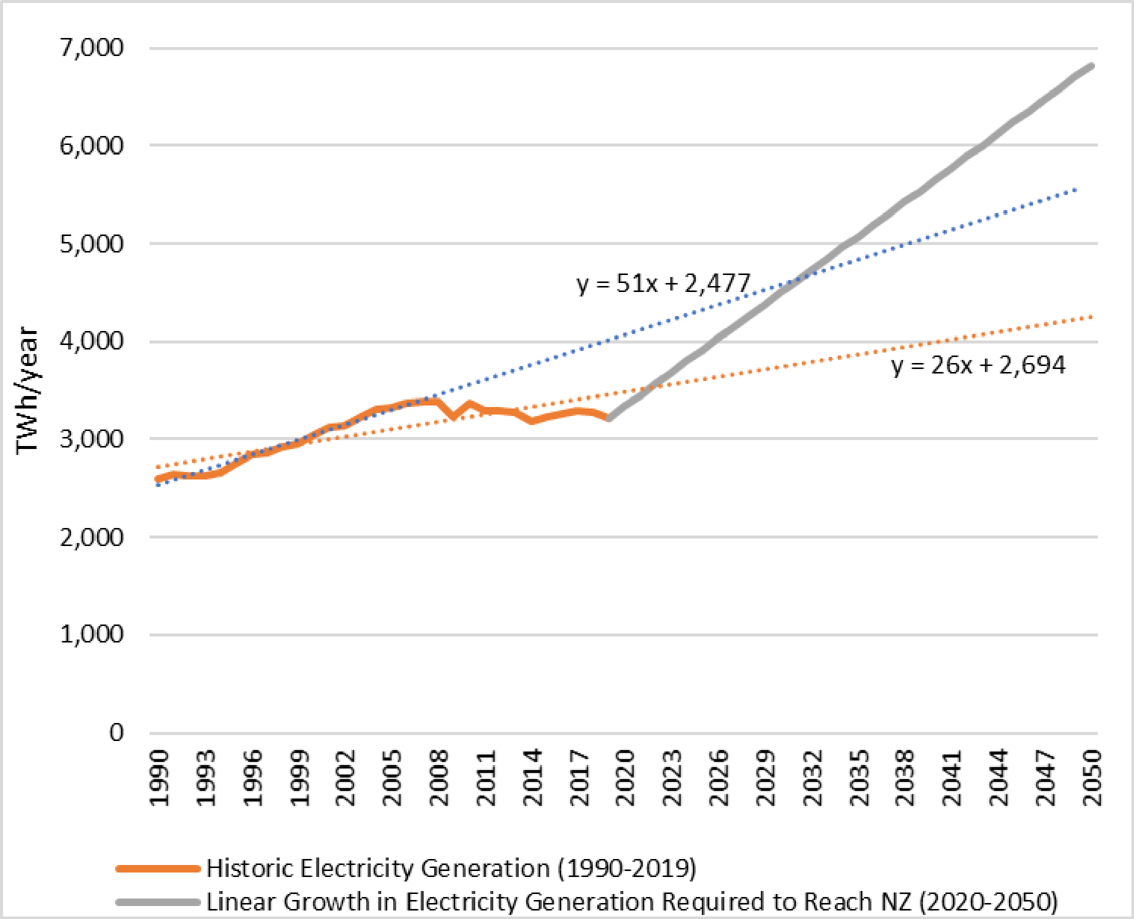
Table 12: Changes in final consumption for electricity and gases (TWh/year)

	FINAL CONSUMPTION		PRIMARY SUPPLY	
	2018	NZ 2050	2018	NZ 2050
Electricity	2,812	4,175	3,629	6,818
CH_4	2,854	1,869	5,396	2,672
Natural gas	2,854	199	5,396	907
Biomethane	-	1,059	-	1,150
E-gas	-	611	-	615
Hydrogen	-	921	-	2,228

Source: 2018 data is from Eurostat; NZ 2050 is our modelling results

Third conclusion that we can draw is that electricity flow to final consumption needs to be scaled up by at least 48% between 2018 and 2050 to serve as the main backbone of the NZ energy system. The scale up of electricity supply is even higher – 88% increase in supply relative to 2018 level (6818 TWh in 2050 vs 3629 TWh in 2018). While decommissioning of energy system capacity (in this example scaling down of CH_4 supply) is a challenge on its own in terms of policy support and sunk cost recovery, the scale up of electricity generation is not a lesser challenge either - Figure 22 shows the historic trend in electricity generation in the past 30 years and what is required to achieve the NZ electricity generation target in the next 30 years. One can see that the average expansion of electricity generation over the past 30 years was ca. 26 TWh/year, while before the 2008 financial crisis it was 51 TWh/year. However, to reach the target of 6818 TWh of electricity generation by 2050 an average growth rate of 116 TWh/year from 2020-2050 is required; this is almost *five times* the historic growth rate in generation that we have seen in the past 30 years but *not more than twice times* the growth rate before the 2008 financial crisis. Further, the challenge is not just scaling up the electricity system to meet future generation level but generation from a particular set of technologies.

Figure 22: Historic (30 years: 1990-2019) Expansion of Electricity Generation in EU and Required Growth to Meet the NZ Target by 2050



Notes: orange dotted line is linear growth fitted to 1990-2019 historic time series; blue dotted line is linear growth fitted to 1990-2008 historic time series.
Source: generation from 1990-2019 is from BP Statistical Review of World Energy (2020); 2020-2050 solid line is linear growth trend to reach our modelled electricity generation target by 2050.

To support deep decarbonisation of the European economies, the power generation sector should be low-carbon (see Figure 23). Thus, in terms of electricity generation mix, we can see that under the net zero GHG emissions scenario the mix consists of at least 78% variable renewable energy (VRE) and 12% nuclear, with hydro standing at 3% and the rest is dispatchable CCGT and biomass with CCS (with a combined share of just 7%) (see Figure 23). The NZ 2050 generation mix *is truly a zero-carbon electricity generation sector* because even fuels consumed by CCGT plants are low-carbon - they consume 95% biomethane and 5% e-gas, both of which are carbon free fuels.

Figure 23: Electricity generation mix (2050): NZ scenario

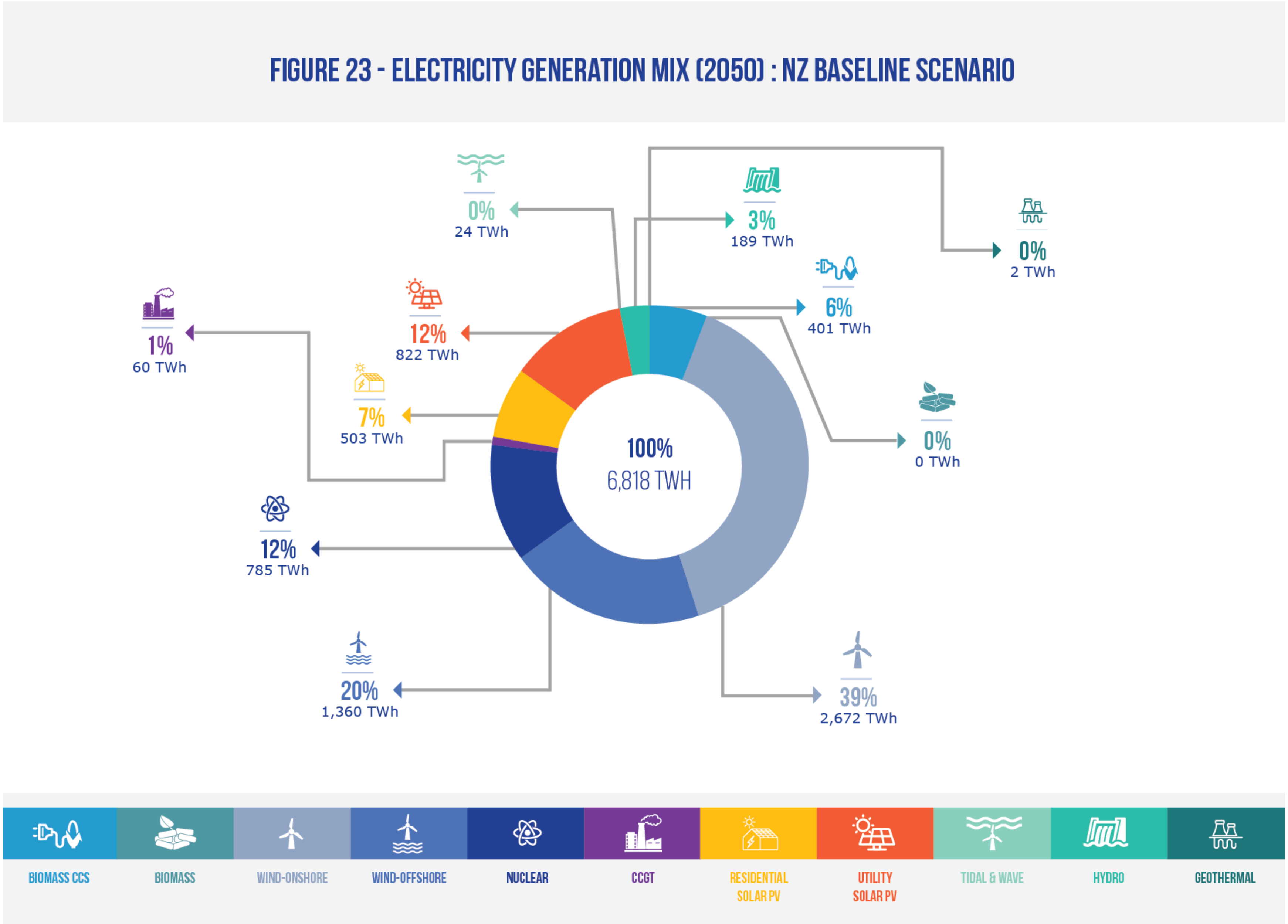
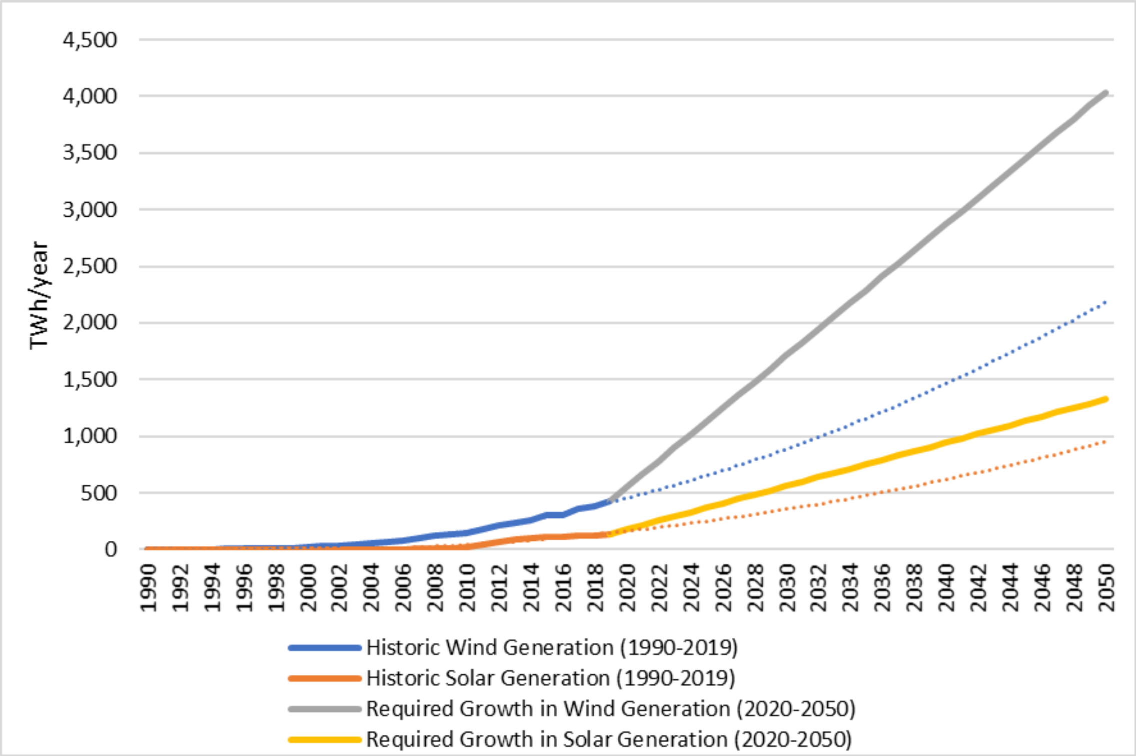


Figure 24 shows, again, historic electricity generation from wind and solar in EU over the past 30 years (1990-2019) and the required generation trend out to 2050 to meet our NZ target. First, we see the challenge is to scale up generation from wind sources because the historic (best fit) trend would get us to more than 2,000 TWh of generation by 2050 whereas under our NZ scenario we will need more than 4,000 TWh of wind generation by 2050; that is, we need to double our historic efforts in getting wind onto the energy system. In contrast, it does not appear to be a challenge to scale up generation from solar: based on historic trend we might only miss about 300 TWh of generation (historic extrapolation suggests we might have ca. 1,000 TWh of solar generation vs 1,325 TWh that we need for the NZ scenario).

Figure 24: Electricity Generation from Wind and Solar: Historic Trend and the Required Pathways to reach the NZ target by 2050



Source: generation from 1990-2019 is from BP Statistical Review of World Energy (2020); 2020-2050 solid lines are linear growth trend to reach our modelled electricity generation target by 2050.
Notes: dotted lines are polynomial growth trends fitted to historic (1990-2019) data.

All in all, it is important to note that the growth rate in electricity generation observed before the 2008 crisis (Figure 22: blue dotted line) was largely relying on wholesale market to finance (see Helm, 2002; Pollitt, 2012) and the expansion was largely in fossil-fuel based (such as gas-fired) generation (with low upfront cost but high variable running cost). That is, the current electricity market design was fit for purpose – it supported high rate of capacity expansion of conventional generation. However, we can see that the type of generation mix required under the NZ scenario are characterised by high fixed costs incurred upfront and low (almost zero) running costs (i.e., wind and solar generation in particular). Therefore, the deployment of RES-E generation likely at a rate as yet unmatched by historical development requires an overhaul of the electricity market design to allow investments (Chyong et al., 2019). It will be paramount to trigger investments in RES-E capacity through long-term price signals such as dedicated auctions and corporate PPAs (for a detailed discussion on market design principles under high RES-E see Newbery et al., 2018).

Since the 2050 electricity generation system should be largely zero-carbon we might expect large-scale decommissioning of the fossil fuel capacity that we have on the current energy system (Table 13 shows 2018 generation mix); in particular, in 2018, roughly 40% of generation mix comes from fossil fuels – oil (2%), natural gas (19%), and coal (20%). Albeit there might be opportunities, if cost optimal, to retrofit and repurpose some of the coal capacity to run on bioenergy (with or without CCS) (see our discussion below).

Table 13: 2018 Electricity Generation Mix in EU

	GENERATION, TWH	SHARES IN TOTAL
Oil	53	2%
Natural Gas	621	19%
Coal	644	20%
Nuclear energy	827	25%
Renewables	1048	32%
Other*	78	2%
Total	**3270**	**100%**

Source: BP Statistical Review of World Energy (2020)
Note: *Includes sources not specified elsewhere e.g. pumped hydro, non-renewable waste and statistical discrepancies (which can be positive or negative).

The role of bioenergy and CCS in our NZ Baseline

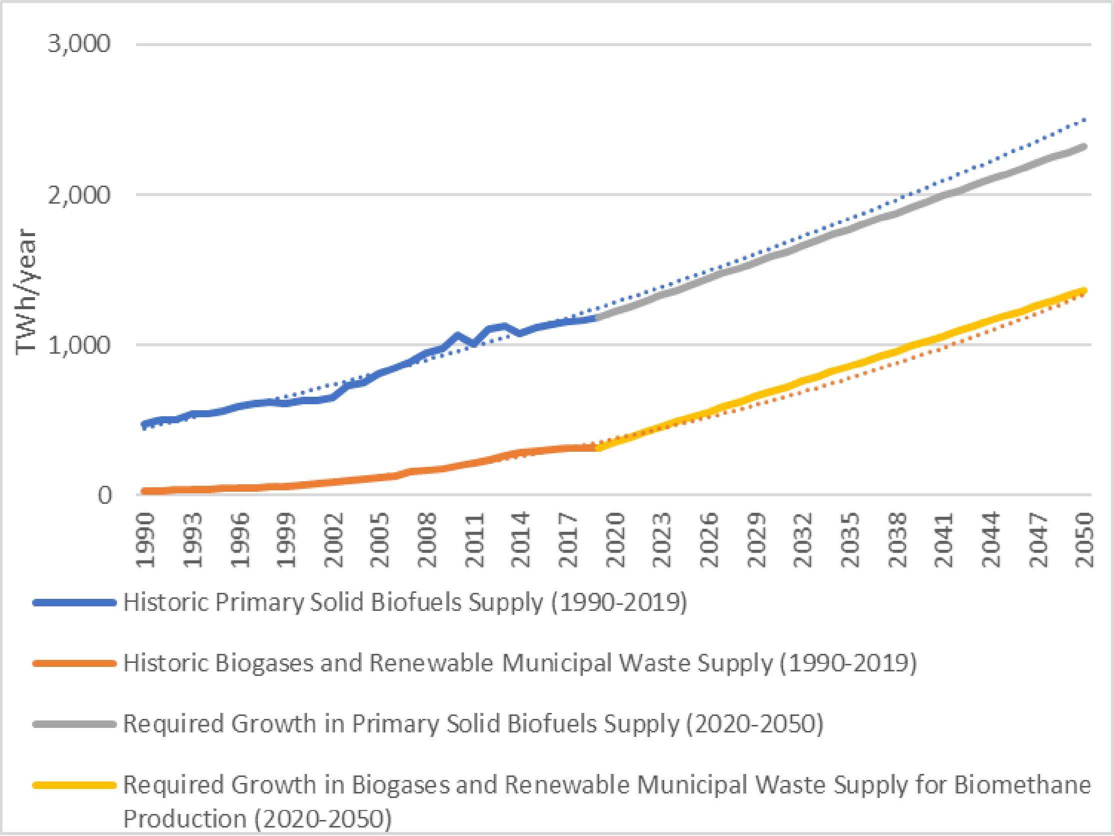
While electricity will become a backbone of our NZ energy system, the role of bioenergy and its derivatives in delivering the NZ target in our modelling is not insignificant – bioenergy and its derivatives[25] have a combined share of at least 32% in final energy consumption (Figure 21). Similar to the importance of supporting the tremendous scale up of investment in RES-E production (and hence transmission and distribution of electricity), the challenge of increasing supply of bioenergy to meet NZ target cannot be underestimated. Figure 25 shows historic supply of solid biomass and biogases and renewable municipal waste in EU+UK and their supply targets by 2050 to meet our modelled NZ scenario for European countries modelled. While we see that the required supply of solid biomass and biogases and renewable municipal waste is in line with the historic trend, the potential challenges might arise with scaling up of associated technologies for production of biomethane to the required level, in particular:

[25] Biomethane (13%), e-gas (7%), biomass (6%), and e-liquids (5%).

1. Proving that upgrading and methanation of biogas will work at the required scale: in 2018, only 23 TWh of biomethane was produced in the whole of EU+UK and most of this comes via upgrading of biogas produced from anaerobic digestion; to put this in the context, our NZ scenario requires 1,150 TWh of biomethane;
2. Thermal gasification is another promising technology to produce biomethane (with higher efficiency and more flexibility with feedstocks than upgrading of biogas), but not yet commercial at scale at the moment.

Therefore, the success in meeting our modelled NZ requires ambitious scale up of all key technologies from wind turbines and solar panels to ensuring sustainable bioenergy supply without negative impacts on competing land uses for other societal priorities.

Figure 25: Solid Biofuels and Biogas Supply: Historic Trend and the Required Pathways to reach the NZ target by 2050



Source: supply from 1990-2019 is from Eurostat; 2020-2050 solid lines are linear growth trend to reach our modelled electricity generation target by 2050.
Notes: dotted lines are polynomial growth trends fitted to historic (1990-2019) data.

In addition to the expansion of wind and solar generation as well as scaling up of supply and production of sustainable bioenergy to achieve our NZ scenario at least cost (given all inputs and assumptions, see Appendix 1) our modelling suggests that biomass with CCUS will have a share of 6% in the generation mix in 2050 NZ (see Figure 23) with a total installed generation capacity of 86.24 GW. In 2020, total biomass generation capacity in EU+UK was 19.85 GW, while hard coal generation capacity accounted for about 87 GW (lignite and brown coal capacity adds a further 37.2 GW of generation); given opportunities to retrofit some of the existing biomass-fired capacity with CCS and also converting coal-fired power stations to using biomass (see e.g., conversion of UK's Drax power station from coal to sustainable biomass[26]), the scaling up of generation capacity using biomass as such might not present an insurmountable challenge.

It is scaling up of a carbon capture technology (e.g., post-combustion capture technology) and associated pipeline and storage infrastructure to the required level that will be a challenge given limited success in large-scale demonstration of this technology so far. Thus, while for wind and solar we do have at least 30 years of evidence in terms of technology evolution and innovation, a big question mark is around scale up of CCS technology. Nevertheless, meeting our NZ scenario in a cost optimal way would require generation from bioenergy with CCS technology (see Figure 23). The importance of CCS in meeting net zero has been acknowledged and confirmed by the international community and academics. For example, according to the International Energy Agency's (IEA, 2020; page 13) Flagship report from September 2020: *'A net-zero energy system requires a profound transformation in how we produce and use energy that can only be achieved with a broad suite of technologies. Alongside electrification, hydrogen and sustainable bioenergy, CCUS will need to play a major role.'* In that report, IEA (2020; pages 13-14) identifies four main areas where CCUS can play an important role:

1. Tackling emissions from existing energy infrastructure;
2. A solution for some of the most challenging emissions;
3. A cost-effective pathway for low-carbon hydrogen production;
4. Removing carbon from the atmosphere.

To conclude, without doubt, the energy system faces triple challenges (i) scaling up the electricity system (e.g., networks) to meet the overall level of expected electricity generation (Figure 22) and bioenergy supply (Figure 25), (ii) scaling up carbon free and neutral generation sources (Figure 24), while (iii) at the same time decommissioning of carbon intensive generation assets (Table 13).

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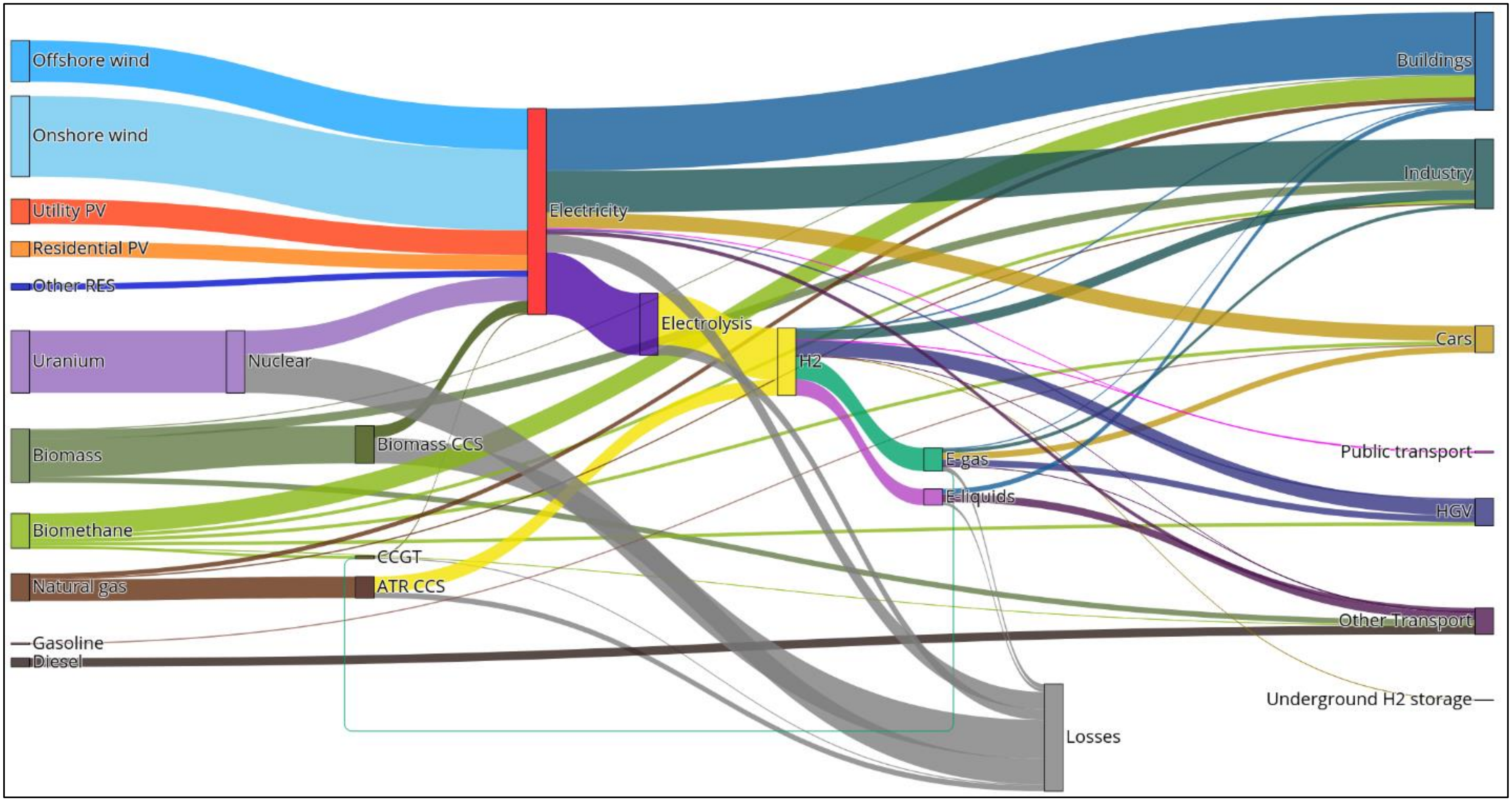
[26] https://ec.europa.eu/info/sites/info/files/iogp_-_report_-_ccs_ccu.pdf

Figure 26: Energy system balance – from primary production to final consumption: NZ baseline scenario



Note: Other RES includes: hydro, tidal and wave, geothermal

7.1.2. Impacts on Sectoral Final Consumption

This section discusses the impact of reaching NZ on main sectors – industry, transport and buildings – in terms of final energy consumption mix (see Table 14). If we compare the results for 2050 with the 2018 (Table 3) some important highlights should be mentioned:

1. final energy consumption in buildings drops from 5,459 TWh (2018) to 3,238 TWh (2050), or efficiency gain of 41%, driven by huge uptake of heat pumps and hybrid heat pumps;
2. the second largest energy efficiency improvement is in the transport sector – final energy consumption reaches 2,711 TWh (2050) which is 29% lower than the 2018 level (3,822 TWh); this is driven mainly up uptake of EVs in road transport (Table 15) which represents ca. 76% of entire vehicle stock;
3. decarbonisation of the industrial sector is reached by a combination of efficiency gains, higher uptake of electricity (1,050 TWh in 2018 vs. 1,381 TWh in 2050), and replacing usage of fossil gas (1,032 TWh in 2018) with a combination of biomethane (116 TWh), synthetic gas (124 TWh), and hydrogen (337 TWh).

Table 14: Europe final energy consumption by sectors and fuels in NZ 2050

	INDUSTRY		TRANSPORT		BUILDINGS*		TOTAL	
	TWH	%	TWH	%	TWH	%	TWH	%
Oil and petroleum products	0	0%	335	12%	0	0%	335	4%
Natural Gas	47	2%	0	0%	152	5%	199	2%
Biomass	291	13%	189	7%	38	1%	517	6%
Electricity	1,381	60%	731	27%	2,063	64%	4,175	51%
Biomethane	116	5%	232	9%	711	22%	1,059	13%
E-gas	124	5%	446	16%	40	1%	611	7%
Hydrogen	337	15%	517	19%	66	2%	921	11%
e-liquid	0	0%	260	10%	169	5%	429	5%
Total final energy consumption	**2,297**	**100%**	**2,711**	**100%**	**3,238**	**100%**	**8,246**	**100%**

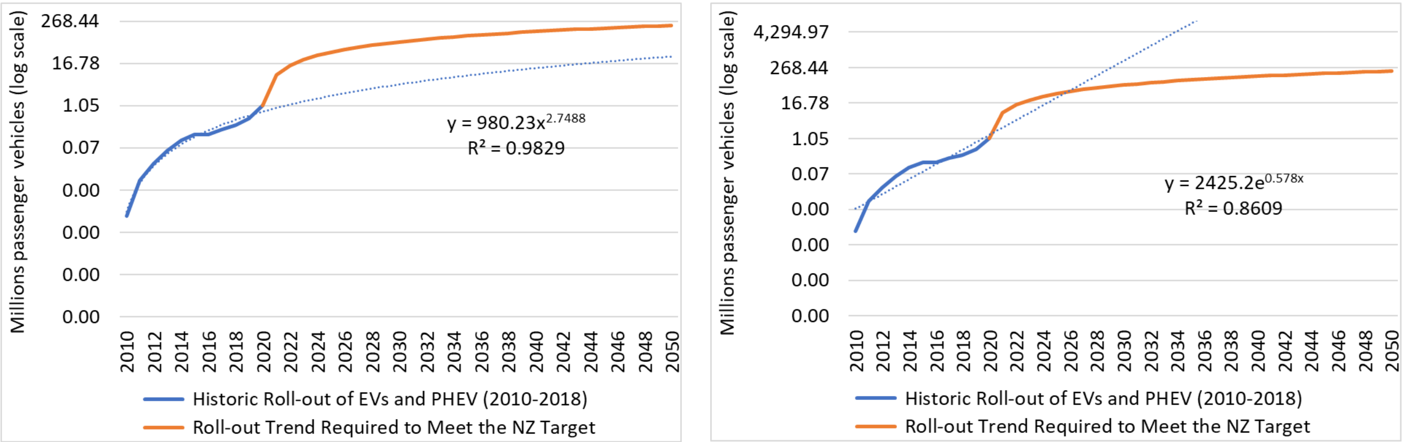
Notes: *Consumption in buildings is the sum of residential and services sector energy consumption and also include energy consumption in agriculture, fishing & other.

Table 15: Road vehicle stock (NZ 2050)

	MILLION VEHICLES	SHARES IN TOTAL
Passenger road transport		
EV Cars	204.30	80%
FCEV Cars	0.00	0%
Gas Cars	42.71	17%
Gasoline Cars	8.36	3%
Diesel Cars	0.00	0%
Total passenger transport	**255.37**	**100%**
Public road transport		
EV Public Transport	0.68	84%
FCEV Public Transport	0.13	16%
Total public transport	**0.81**	**100%**
Heavy goods vehicles (HGV)		
EV HGV	0.92	8%
FCEV HGV	7.60	64%
Gas HGV	3.38	28%
Total HGV	**11.90**	**100%**

In the transport sector we see a need for a complete system "redesign" if we are to reach NZ cost optimally – in 2018 the dominant fuel in the transport sector was oil and petroleum products, accounting for 92% (3,521 TWh, see Table 3) while in our NZ 2050 oil and petroleum products accounts only for about 12%, or 335 TWh (an almost 10 fold decrease relative to the 2018 level). The scale of challenge in the transport sector decarbonisation is particularly striking, if we put the results of our NZ modelling in the historic context of roll-out of passenger EV (and PHEV), for example. Figure 27 paints this challenge – based on historic (best fit: Figure 27 left panel) trend of roll-out of EV (and PHEV) by 2050 we might see ca. 26.6 mn cars on European roads vs 204 mn EV cars we need under our NZ by 2050 (Table 15). Therefore, whatever effort we have spent in the past 11 years we should accelerate our efforts by *7.7 times (204/26.6)* to support this required EV roll-out pace. That said, if roll-out of EVs were to follow exponential trend (and hence supporting infrastructure) (Figure 27 right panel) then we might hit the target by 2030; in other words, at some point between now and 2050 roll-out of EVs on our roads must be exponential to hit our modelled NZ target. This does suggest policy support is needed to achieve this ambitious road decarbonisation target that we have modelled.

Figure 27: Historic Roll-out of EVs and PHEV (2010-2018) vs. Roll-out Trend Required to Meet the NZ target.



Source: 2010-2018 is from EEA; 2019-2020 from ACEA 2020:
https://www.acea.be/statistics/tag/category/electric-and-alternative-vehicle-registrations

Looking at the results in the buildings sector, we see that electricity plays a central role in decarbonisation of our buildings energy demand – its share in final consumption in buildings is 64% (Table 14). However, due to the fact that energy demand in the buildings is very sensitive to external temperatures, especially for heating purposes during winters, biomethane and hydrogen as well as the supporting gases infrastructures, bring the much needed flexibility to cope with peak demand period. That way, gas infrastructures, while minimizing total system cost, provide this flexibility (see §6.1.3). Building sector offers a successful example of an efficient sector coupling, benefiting from the best of the two energy vectors: electricity grid providing large volumes of decarbonized energy and the gas grid offering its intrinsic power for a decarbonized flexibility management.

Decarbonisation of the industrial sector, and especially the energy intensive industries, is challenging. The three main factors affecting industrial emissions are process emissions, which are emitted as a result of the chemical and production processes carried out in industries (21%), emissions due to energy used in heating processes (70%), and space heating (9%). As we have already seen, space heating and low-temperature heat demand can be, in principle, electrified (and given that industrial heat demand is almost not sensitive to external temperatures) at reasonable costs. Therefore, challenges remain to decarbonise e.g., high temperature heat demand as well as non-energy use GHG emissions. Overall, electricity-based solutions could reach ca. 60% of final consumption in the industrial sector (Table 14) but nevertheless hard-to-decarbonise industrial processes and high temperature heat demands will require hydrogen and carbon neutral gas-based solutions.

7.1.3. Sources of Flexibility in the Net Zero Scenario

This section relates the results from our modelling back to the core discussions in Section 4 about the sources of flexibility to deliver a Net Zero scenario by 2050. We structure this analysis in line with our motivating analysis and literature review in Section 4. We start with examining the role of cross-border trade in our NZ scenario (Spatial Flexibility) and then the role of storage technologies to provide temporal flexibility. We end with a discussion on the role of "new" energy sources and technologies in managing flexibility we need for our NZ scenario.

Spatial Flexibility – Cross-border interconnections

Table 16 outlines historic (2009-2018) and our NZ 2050 cross-border trade in electricity, CH_4 and H_2. First conclusion to highlight is that the trend in electricity cross-border in NZ 2050 is quite in line with the historic trend we observed – as we electrify our economies the role of cross-border also increases: the share of total trade in final consumption doubles in NZ 2050 relative to 2018 (56% vs 27%). Importantly, it should be noted that while final consumption increases by ca. 50% (4,175 TWh vs 2.784 TWh) the total electricity trade in NZ 2050 increases by ca. 208% (i.e., by a factor of 3) compared to total trade in 2018. This highlights the importance of cross-border electricity trade and market rules to complete EU's single market for electricity trading.

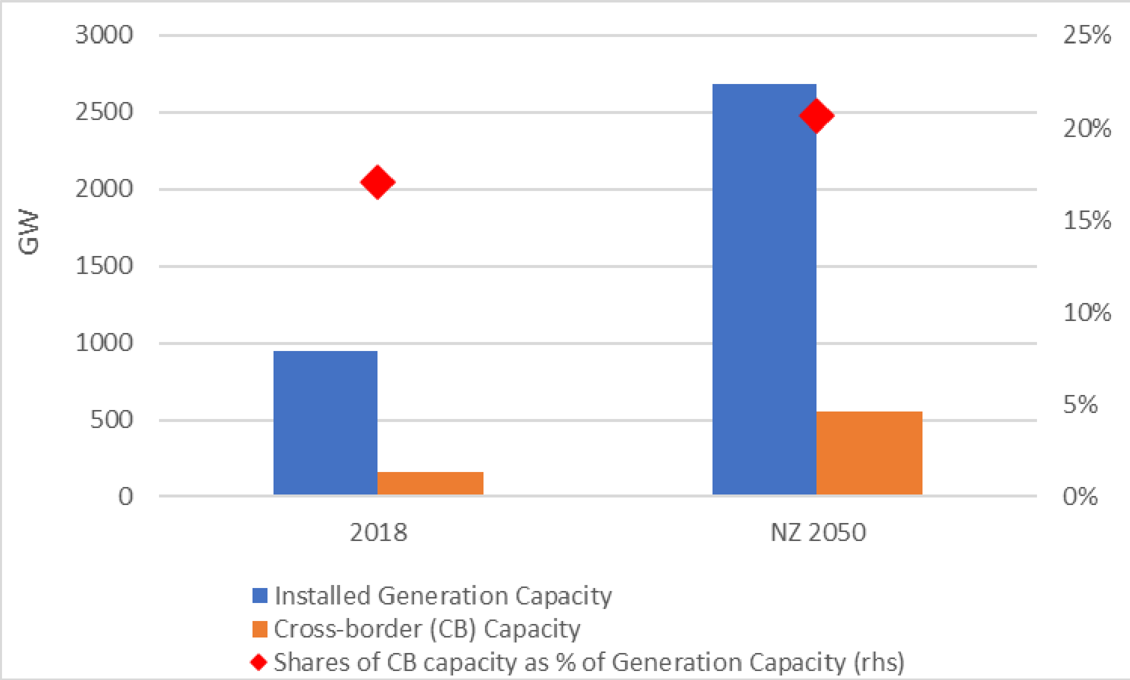
Table 16: Electricity, CH_4 and H_2 cross-border trade: 2009-2018 and NZ 2050

	ELECTRICITY				CH_4			
	IMPORTS	EXPORTS	FINAL CONSUMPTION	SHARES OF TRADE IN FINAL CONSUMPTION	IMPORTS	EXPORTS	FINAL CONSUMPTION	SHARES OF TRADE IN FINAL CONSUMPTION
2009	299	279	2,863	20%	4,519	1,062	5,621	99%
2010	299	291	2,813	21%	4,902	1,246	6,059	101%
2011	330	323	2,811	23%	4,775	1,232	5,469	110%
2012	363	345	2,786	25%	4,637	1,258	5,331	111%
2013	350	337	2,724	25%	4,645	1,356	5,242	114%
2014	387	371	2,768	27%	4,315	1,295	4,661	120%
2015	411	396	2,793	29%	4,609	1,371	4,822	124%
2016	383	364	2,814	27%	4,789	1,259	5,152	117%
2017	385	375	2,816	27%	5,307	1,360	5,409	123%
2018	394	366	2,784	27%	5,016	954	5,327	112%
NZ 2050	1,168	1,168	4,175	56%	1,190	283	1,869	79%
	HYDROGEN							
NZ2050	25	25	921	5%				

Source: 2009-2018 Eurostat; NZ 2050 from our modelling
Notes: Shares of trade in final consumption was calculated as sum of imports and exports divided by final consumption

This is in terms of energy flow. Figure 28 shows 2018 and NZ 2050 installed cross-border interconnection capacity as well as total generation capacity. Here, although we can see that to accommodate and integrate large share of VRE (at least 78% VRE in total installed capacity in NZ 2050) cross-border interconnection capacity needs to be increased by a factor of 3.43 relative to today's (2018) interconnection level, the proportion of such capacity is quite in line with the 2018. The share of cross-border capacity in total installed generation increases from 17% (2018) to 21% in NZ 2050. Such an increase is quite marginal and in line with an increase in overall share of electricity in our energy economies in NZ 2050.

Figure 28: Electricity Cross-border (CB) Interconnection and Generation Capacity for Europe: 2018 vs NZ 2050



Source: 2018 is from ENTSO-E; CB capacity for 2018 has been calculated by taking the maximum hourly flow (in 2015-2018) between every bidding zone, including Norwegian zones, and summing up these maximum hourly flow values; NZ 2050 is our modelling results

While the picture for the electricity cross-border trading and interconnection capacity requirements in NZ 2050 is in line with the rest of modelling results, confirming the growing importance of cross-border trading going forward, the status of cross-border trade in CH_4 in NZ 2050 is quite different from the 2018 status. We can see that, first the total trade in CH_4 reduces by a factor of 4. This is mainly due to the reduced requirement to import fossil gas from non-EU countries. Secondly, if we disregard fossil gas imports (totalling ca. 907 TWh) then the share of cross-border trade in biomethane and e-gas (the two fuels that are produced at "home") is quite marginal – 30% of final CH_4 consumption and is only a *quarter* of the value of cross-border electricity trade in NZ 2050. This is a complete reversal of the 2018 situation when we saw that cross-border trade (mainly due to huge import value) in gas exceeded that of electricity by a factor of 7 at least.

Lastly, we can also conclude that the role of cross-border in H_2 might be limited in our NZ 2050 (see Table 16), for quite similar reason to the one we see for CH_4 cross-border trade – the fact that H_2 is locally produced (predominantly from electricity – see Figure 33 in every EU country and the fact that local energy systems can self-balance using a combination of end-use and grid-scale flexibility solutions (see next two sections) mean that cross-border capacity might be less needed to balance the fluctuations in supply and demand for H_2. That said, if costs of producing H_2 and RES-E developments in every EU MS vary substantially and imports of H_2 from outside the EU (from North Africa, Ukraine, Russia, for example) happens at scale, then in this context, the development of a single EU hydrogen market supported by significant cross-border H_2 trade would be key in reducing price spreads across countries.

Similar conclusion applies to CH_4 cross-border trading in NZ 2050 – system flexibility at local (MS) level is such that there is minimal need to have huge interconnection capacity in CH_4. Therefore, relating back to the recent discussions by the EC as part of its "Quo Vadis" Gas Study, integration of fossil gas markets across EU MS remain of importance to minimise cross-border price spreads in the short to medium term. If we are to gradually move away from fossil gas then the discussion around market integration for home grown CH_4, H_2 and electricity will be of importance with the later (electricity) gaining the centre stage in the regulatory debate on further integrating the electricity markets.

Spatial Flexibility – Energy Networks

As we discussed in Section 3 the current European gas (CH_4) system's capability is at least *three and a half times larger* than the electricity counterpart (see Figure 29). Nevertheless, in NZ 2050, as the result of dramatic system changes (discussed above), the capability of the two systems may change:

1. We will see a reverse when electricity transmission capacity is at least 25% larger than the CH_4 transmission capacity; in fact, electricity transmission capacity expands by a factor of 3 relative to 2018 and is just 13% smaller than the CH_4 system in 2018;
2. That said, at the distribution level we see that CH_4 distribution network capability is similar to transmission (1,118 GW distribution capacity vs. 1,134 GW transmission capacity) capability; further, CH_4 distribution network is ca. 30% larger than the electricity distribution network;
3. Under certain assumptions about the feasibility of widespread deployment of RES capacity at scale in Europe, as well as the potential scope of local energy systems self-balancing, both CH_4 transmission and distribution networks may be relatively smaller (of up to 30%) than present levels.

Further, we also see the emergence of H_2 transmission and distribution networks but the size of those networks are small compared to the CH_4 – transmission for H_2 is 40% of the CH_4 transmission capacity while at distribution level the H_2 network is just 21% of the CH_4 distribution network. This can be explained by the fact that H_2 transmission is served to manage fluctuations in green H_2 production while a small H_2 distribution network is mainly to serve transport and industry sector demand (see Table 14). This does suggest that two "parallel" gases networks might be quite realistic and manageable – at transmission level we might see H_2 backbones to connect large electricity generation sources with electrolysers and H_2 distribution centres and at the distribution level we might see small H_2 distribution networks to deliver H_2 to fuelling stations or steel factories. Our modelling does not suggest we have a separate H_2 network to serve heat loads in buildings, where we might see a large network (see Table 14); as already noted, energy demand in buildings are still served largely by CH_4 network as well as electricity network. It is interesting also to note that the combined transmission capacity of both CH_4 and H_2 is 1,594 GW; this is just 2% smaller than the CH_4 system capacity in 2019.

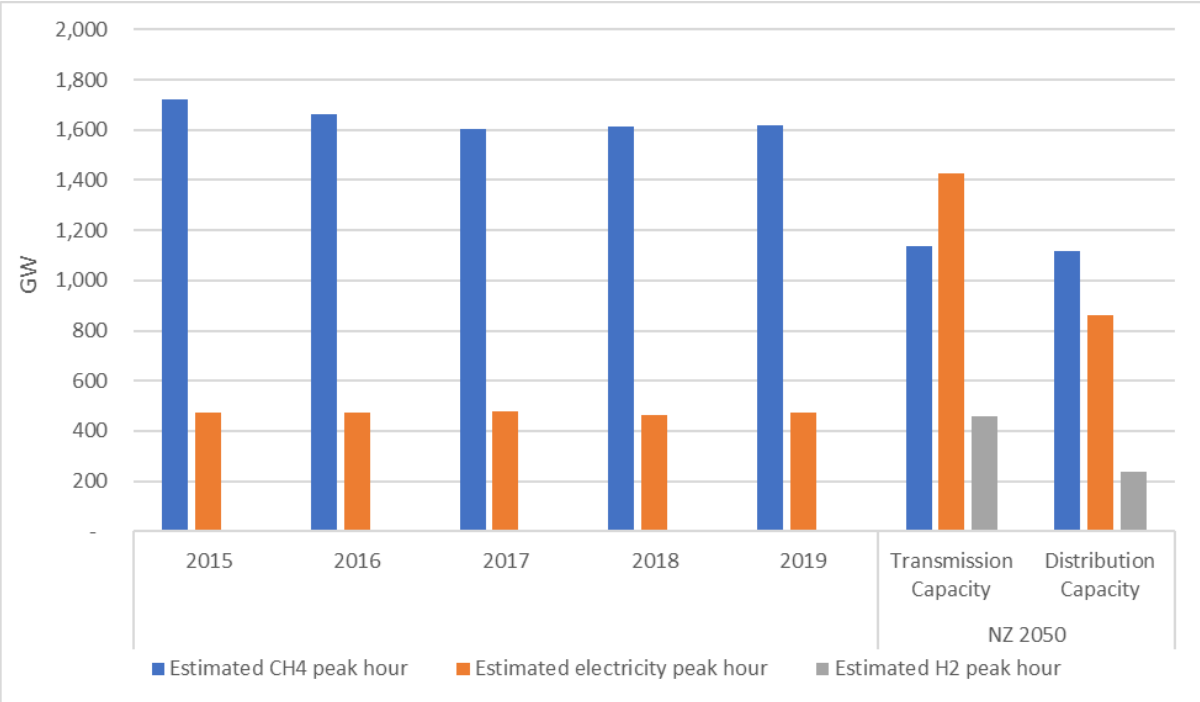
Several important conclusions can be made:

1. In line with our discussion in Section 7.1.1, and particularly under the caveats that there would be no issue of timely deployment of RES-E at scale in Europe, no material differences in the cost of production of H_2 and RES-E across EU MS over time and importing green and blue H_2 would not materialise at scale, both CH_4 distribution and transmission system might see a reduction of energy flow by at least 35% and 50% compared to the current situation (2018). While this might seem substantial, the CH_4 networks will still be important in terms of delivering system security because in our NZ 2050 scenario we see that the overall CH_4 network capacity needed to meet peak demand during winter time will be just 30% less compared to today;
2. The associated potential divestment in CH_4 system capability may largely be due to reduced requirement for imports of fossil gas from non-EU countries and this might indeed

help the problem of sunk cost recovery and streamlining cost-reflectivity of gas charging arrangements between internal and cross-border flows of CH_4 going forward (see ACER's recent consultation on this subject[27] and the EC Quo Vadis gas study[28]);

3. At the distribution level, CH_4 network capability may be important due to the provision of ramping requirements coming from the heat load (hybrid heat pumps, see Section 6.1.3.4., Figure 35);
4. Since the electricity system grows both in terms of energy flow as well as in terms of capacity regulatory provision to support efficient expansion of both transmission and distribution capacity will become important as we increasingly rely on electricity system to decarbonise and reach NZ.

Figure 29: Estimated Electricity, CH_4 and H_2 network capacity for Europe



Source: 2015-19 is from ENTSO-E and ENTSO-G.

Temporal Flexibility

In Section 5 we made a distinction between inter-seasonal and intra-day flexibility requirements in moving to a carbon neutral energy system. Table 17 outlines storage system capacity for electricity, H_2 and CH_4 in our NZ 2050 scenario. It is immediately clear that inter-seasonal flexibility in the NZ scenario is provided by CH_4 long-duration storage (traditional underground gas storage).

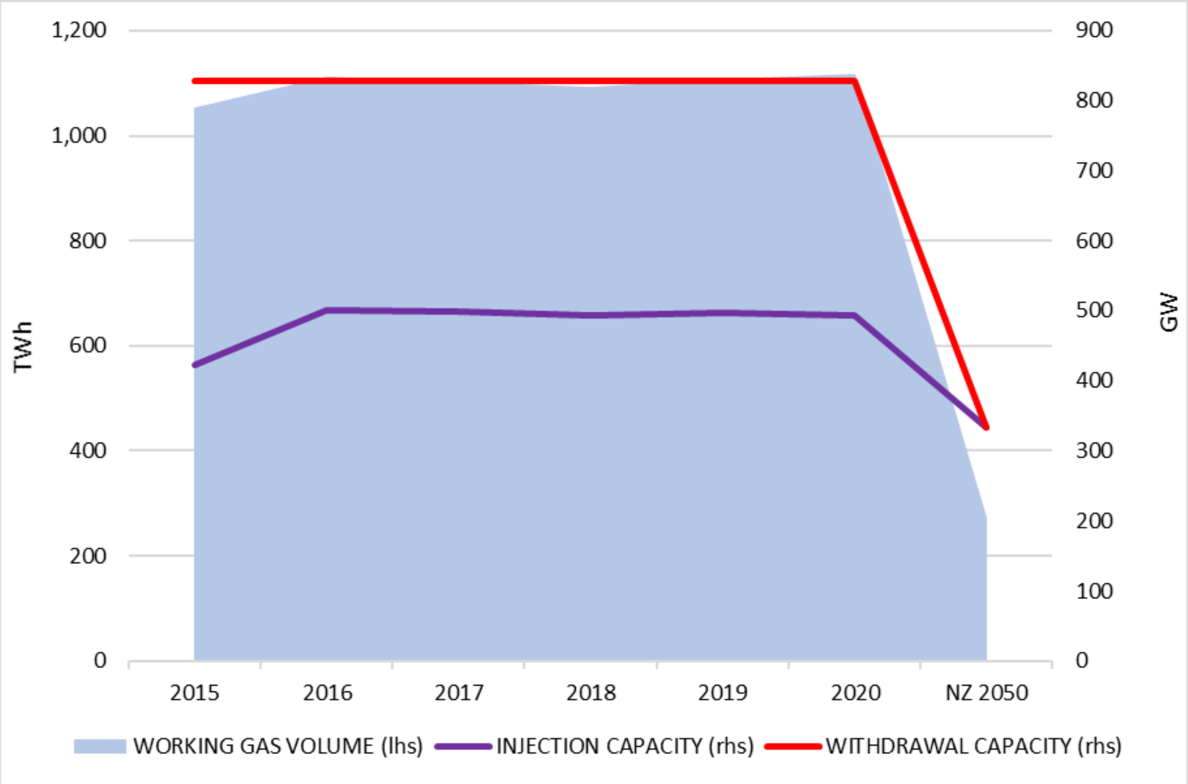
[27] https://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2020_G_19_.aspx
[28] https://ec.europa.eu/energy/studies/study-quo-vadis-gas-market-regulatory-framework_en

Table 17: Electricity, CH_4 and H_2 Storage Capacity in NZ 2050

	ELECTRICITY	H_2	CH_4
Volume, GWh	461	8,306	272,735
Power, GW	99	671	334
Average storage system duration, hours	5	12	816

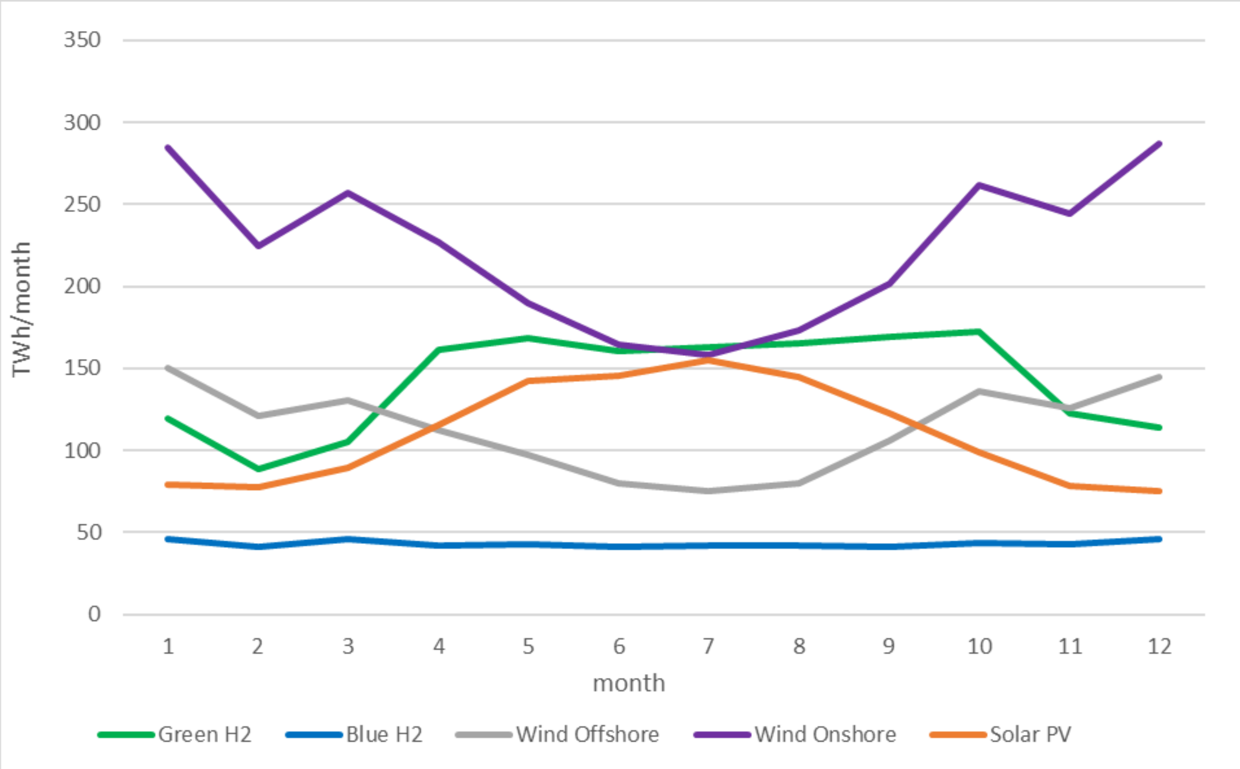
With the reduced requirement for CH_4 in the buildings sector (predominantly for heat load) less inter-seasonal storage capacity will be required in NZ 2050. Figure 30 compares the evolution of seasonal gas storage capacity in 2015-2020 with the storage capacity in NZ 2050 – we can see that in terms of CH_4 storage volume needed to move energy from summer to winter season will reduced by a factor of 4 (from the existing storage volume of 1,117 TWh to 272.7 TWh in NZ 2050). While CH_4 seasonal storage serves seasonal variations in energy demand in buildings, green H_2 production serves as a "virtual" seasonal storage to manage seasonal variations in VRE production, especially solar output. Figure 31 shows how green H_2 production follows closely the monthly solar generation. Green H_2 is indeed an important sector coupling technology helping to efficiently integrate VRE.

Figure 30: Evolution of Europe Gas Storage from 2015 to NZ 2050



Source: 2015-2020 is from ENTSO-G; NZ 2050 is our modelling

Figure 31: Monthly H_2 production and outputs from wind and solar in NZ 2050



When it comes to intraday flexibility in our NZ energy system, it is delivered by a combination of:

1. electrical energy storage: both traditional storage solutions like hydro-based electrical storage and generation as well as new forms of intraday flexibility – V2G from EVs and electrical energy battery storage;
2. from H_2-based intraday storage solutions, like pressurised H_2 tanks and liquid H_2 storage technologies;
3. And, hybrid heat pumps which allow for greater system flexibility associated with within day ramping requirements to meet heat loads.

While there are 99 GW of hydro pumped and electrical energy storage systems, intraday electricity flexibility could be provided by some EVs. In NZ there are 268 million vehicles, of which 204 million, are private EV passenger cars. With the assumed 40 kWh battery capacity per passenger EV this means that theoretically there are 8172 GWh of electrical energy storage on the system; however, most of EV cars will be used during the day. Therefore, in practice, we only see 120 GWh of peak hour V2G output from passenger EVs in our NZ modelling, or 1.47% of total EV battery capacity. Nevertheless, it is relatively significant source of intraday electricity flexibility.

It is also quite interesting to note that intraday flexibility is also provided by H_2-based storage technologies (e.g., pressurised H_2 tanks and liquid H_2 storage technologies) to manage intra-day variations in VRE output and green H_2 production; H_2-based storage power capacity is the largest – 671 GW – amongst the three storage systems.

The role of "new" energy sources and technologies in a smartly integrated net zero GHG emissions energy system

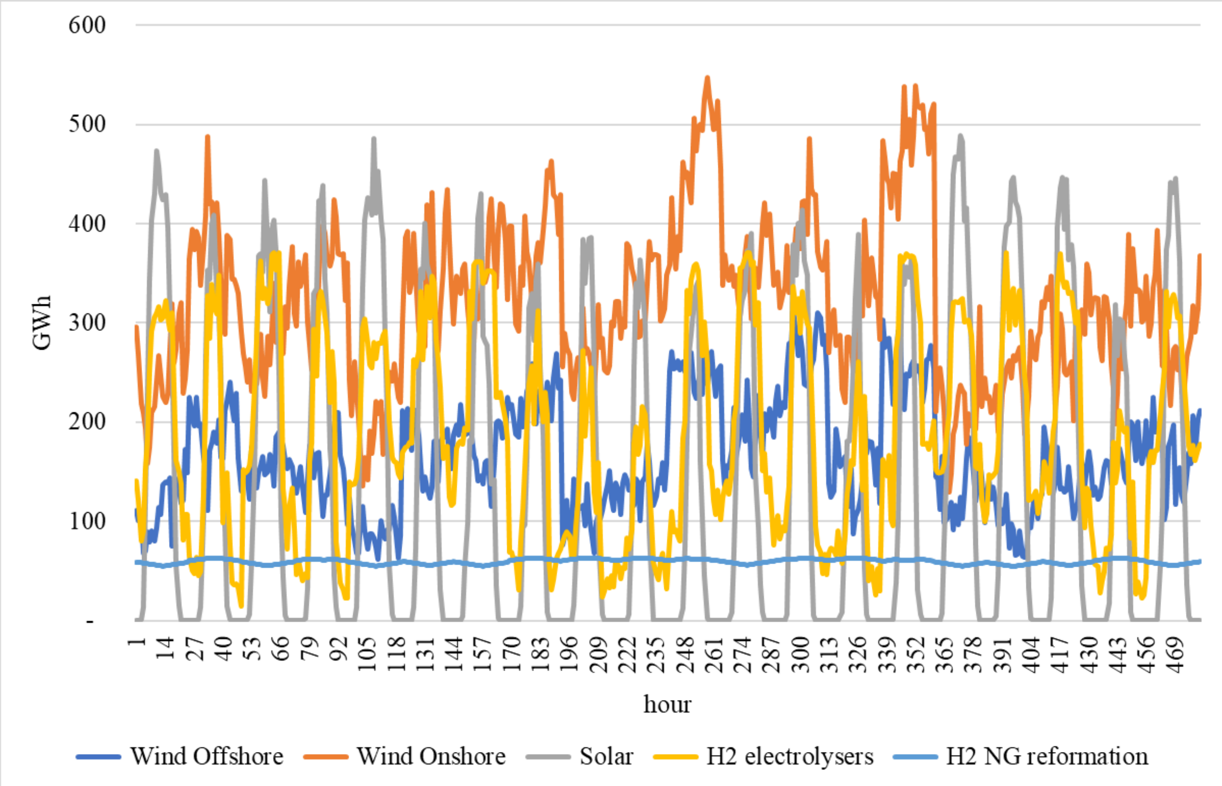
It is impossible to decarbonise our economies without low carbon energy sources which would permit decarbonisation of hard-to-abate sectors (e.g., transport and industry) at lowest cost and not allow smart energy system integration. This section outlines the role of hydrogen, synthetic fuels and end-use technologies in helping to smartly integrate our energy system towards the net zero GHG emissions by 2050. It focuses on results of our NZ scenario.

Smart energy system integration is focused on at least three inter-related areas:

1. Upstream integration between electricity and gas sectors using H_2-based technologies like water electrolysis;
2. Downstream integration at household level with enabling technologies like hybrid heat pumps (HHP) linking both electricity and gas supply;
3. Circular energy system with smart utilization (re-utilization) of energy and materials resources; for example, utilization of CO_2 emissions from sustainable and short cycle CO_2 sources (bioenergy) to produce carbon neutral H_2-based fuels.

At the upstream level, there has been anticipation that hydrogen production from electrolysis could potentially allow a much greater quantity of variable renewable energy (VRE), such as wind and solar, to be efficiently integrated while meeting climate goals at minimum cost (and curtailments). This is true. Figure 32 shows a sample of hourly production of electricity from renewables and H_2 production facilities. It is immediately clear that solar generation and H_2 production from water electrolysis are highly correlated (positively, with a correlation coefficient of ca. 90%); green H_2, therefore, helps to integrate at least 780 GW of solar energy capacity in the system, a six-fold increase relative to today's total EU solar PV capacity.

Figure 32: Samples of hourly electricity generation from renewables and H_2 production plants



Note: hourly correlation between offshore, onshore wind, solar and H_2 electrolysers are respectively -0.01, 0.00 and 0.82

This is not to say that H_2 production from electrolysers does not facilitate further integration of wind energy production – if we look at the hours when solar PV is not producing (i.e., at evening and night hours) we see a much improved hourly correlation (positive) between wind energy production and H_2 production (see Figure 33). There are even some night hours in a winter day when there is a clear pattern of higher wind speed increase H_2 electrolysers production (see Figure 33, hours 131-146, for example). The thesis that green H_2 helps to integrate solar generation is indeed a matter of arguing about the merit order of solar, onshore and offshore wind. In fact, if we assume that solar generation is first in the merit order and offshore wind is last in the merit order then indeed green H_2 production helps to minimise curtailment of offshore wind. Nevertheless, from the energy system perspective, the curtailment of wind in the absence of green H_2 production will be highly correlated with the solar generation patterns.

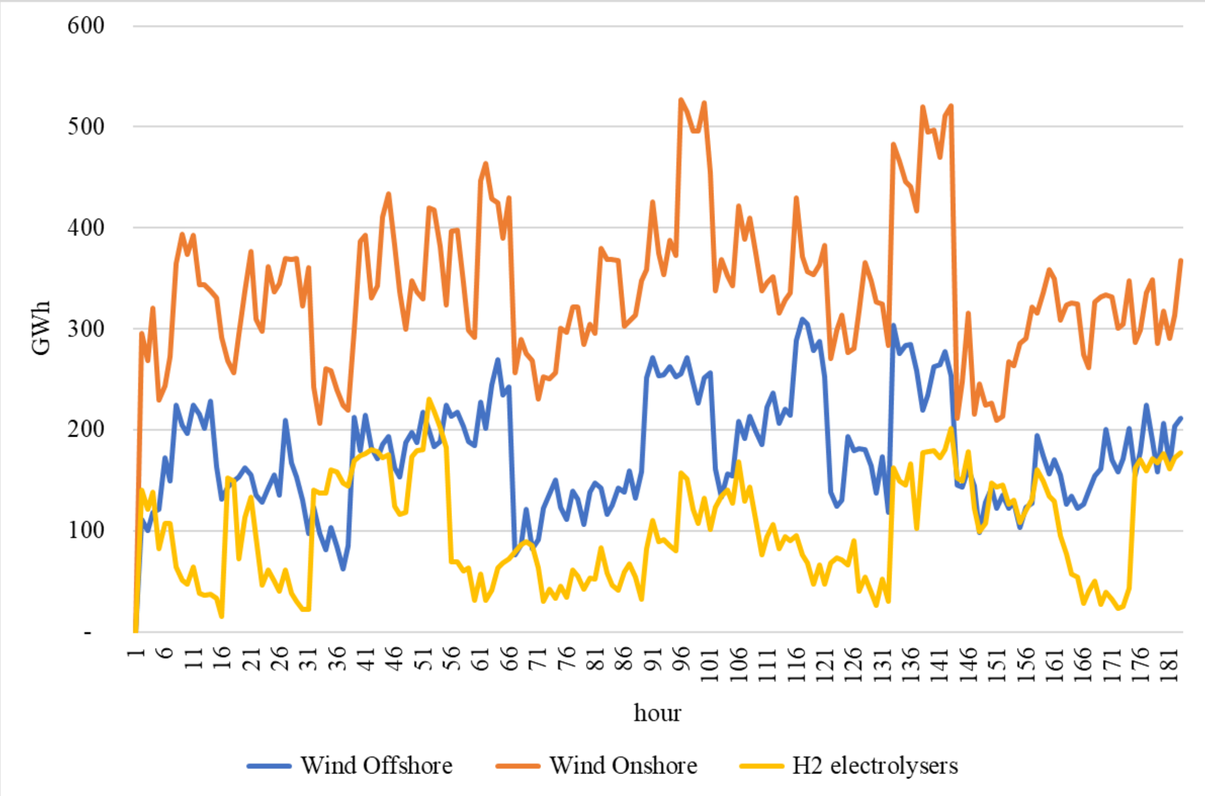
Further, the argument that green H_2 production helps to integrate solar generation does not exclude emerging "business models" of investing in a dedicated offshore wind farm and produce H_2 entirely based on electricity output from that wind farm (see Ørsted, 2020[29]) – the business case for this venture is entirely dependent on the outlook for H_2 demand and economics of selling H_2 to final customers versus direct electrification and taking electricity from the wind farm and selling on spot power exchanges. That is, the central "commercialisation vehicle" should be market institutions – spot markets – to guide where the electrons should end up being used. That said,

[29] https://orsted.com/en/media/newsroom/news/2020/05/485023045545315

vertical integration might be justifiable from technology demonstration perspective given the well-established outside value of electricity (spot markets).

It is worth remembering that the diurnal flexibility in the electricity system has been fulfilled by traditional technologies like hydro pumped storage whereby excess of overnight electricity production is used to pump water up a hill, and then during the day when electricity is needed draw water down the hill to generate electricity back to the grid. Round trip efficiency of hydro PS is 75%. The efficiency of H_2 production from electricity (see Appendix A.2.2) are currently 72% but expected to reach 82-95%; hence, H_2 production from electricity, as a flexibility option, is no different to such traditional technologies like hydro PS, but potentially more efficient and importantly more valuable because H_2, as a versatile zero-carbon energy carrier, can be used in hard-to-abate sectors like industrial high heat temperature or in long-haul trucks and potentially aviation, where direct electrification is not possible.

Figure 33: Samples of hourly electricity generation from offshore and onshore wind and H_2 production plants when solar is not generating (evening and night hours)



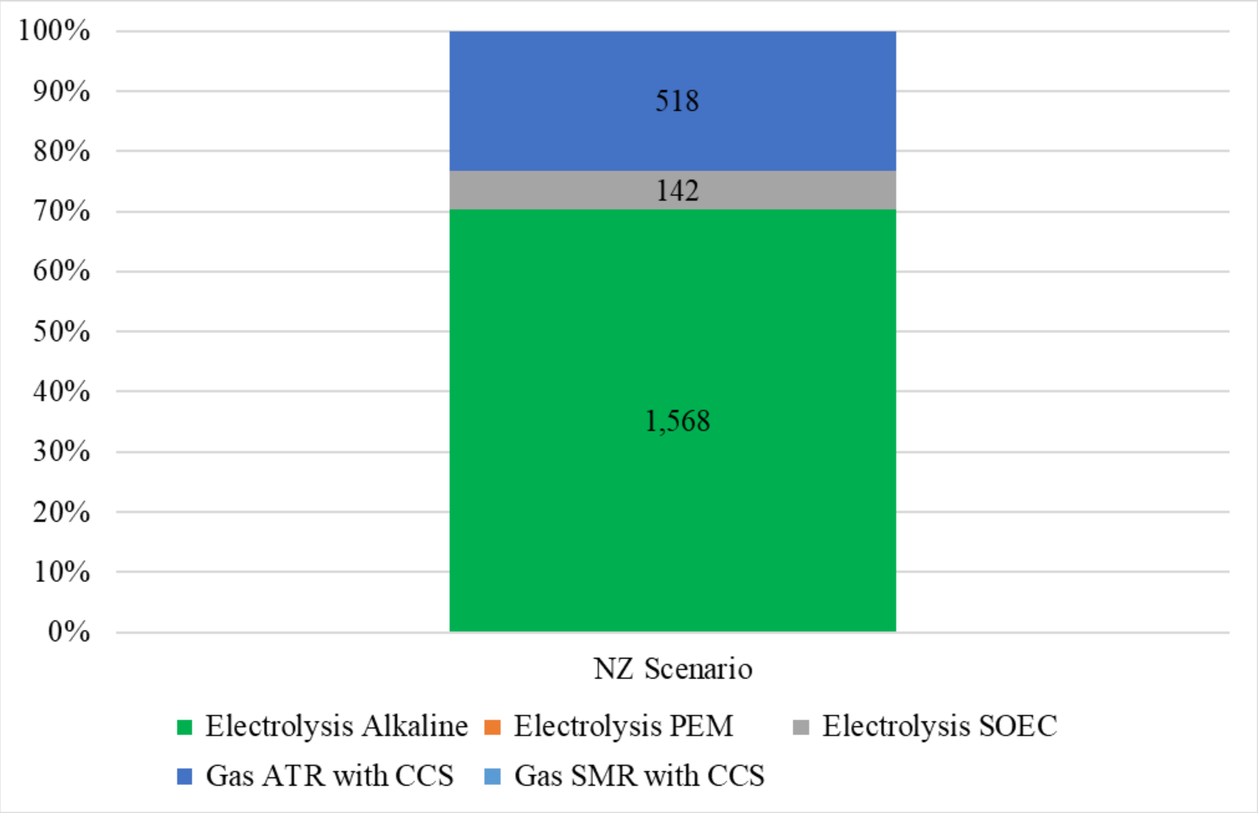
Note: hourly correlation between offshore, onshore wind and H_2 electrolysers are respectively -0.17, 0.18

It is worth noting that H_2 from natural gas reformation plays a rather marginal role in the NZ scenario (its production share is 23% while green H_2 is 77%, see Figure 34). In fact, H_2 from gas reformation does not have a similar (system integration) role like green H_2. Therefore, the place of blue H_2 in our future energy system will be limited to:

- the economic competitiveness of both feedstock fossil gas prices and cost reduction potential of advanced steam reformers;
- potential increase in CO_2 capture rate as there will still be residual CO_2 emissions from these reformers, unless techno-economic potential of advance reformers suggests a possibility of 100% capture rate;

- lastly, CO_2 pipelines and storage liabilities and public acceptance.

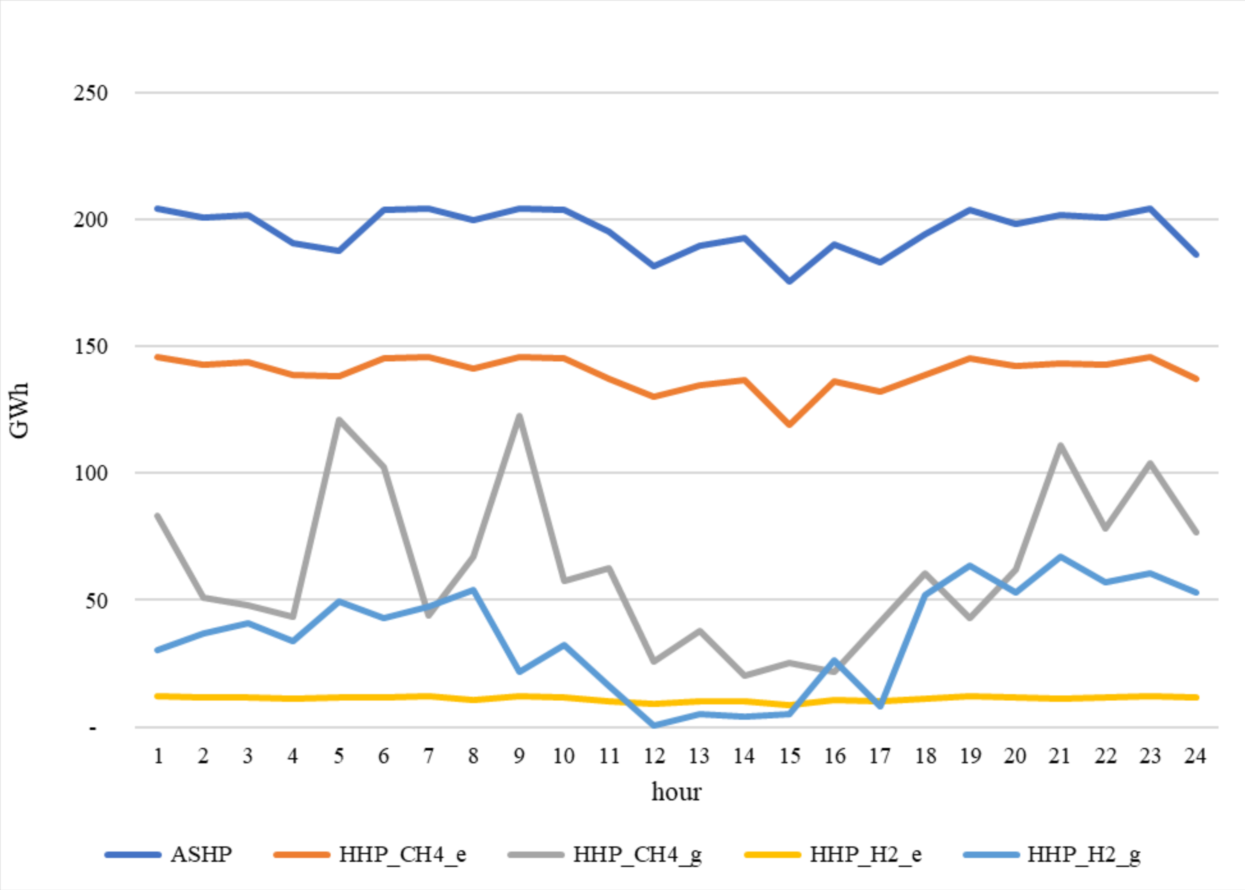
Figure 34: Supply Volumes and Market Share of Green and Blue H_2 in the NZ scenario



Note: numbers in the chart represent production of H_2 in TWh.

At the downstream level, we find that such technologies as hybrid heat pumps allow for greater system flexibility associated with within day ramping requirements to meet heat loads. Thus, both gas (biomethane) and electricity couples in the deep decarbonisation pathways at the downstream level via end-use technologies using hybrid heat pumps. This technology allows for system flexibility at end-use level and allows for potentially rapid electrification of buildings demand while minimizing overall system costs. This can be seen in the Figure 35 where an example of hourly operations of heating solutions in buildings on a winter day (aggregate of all regions in the model) – electricity-based heat technologies run smoothly as baseload solution to provide heat while gas-based technologies provide ramping needs during morning and evening peak load. Figure 35 shows heat generation in aggregation, thus, in some instances electrical part of HHP might run continuously throughout the day with minimal ramping needs from the gas part of HHP.

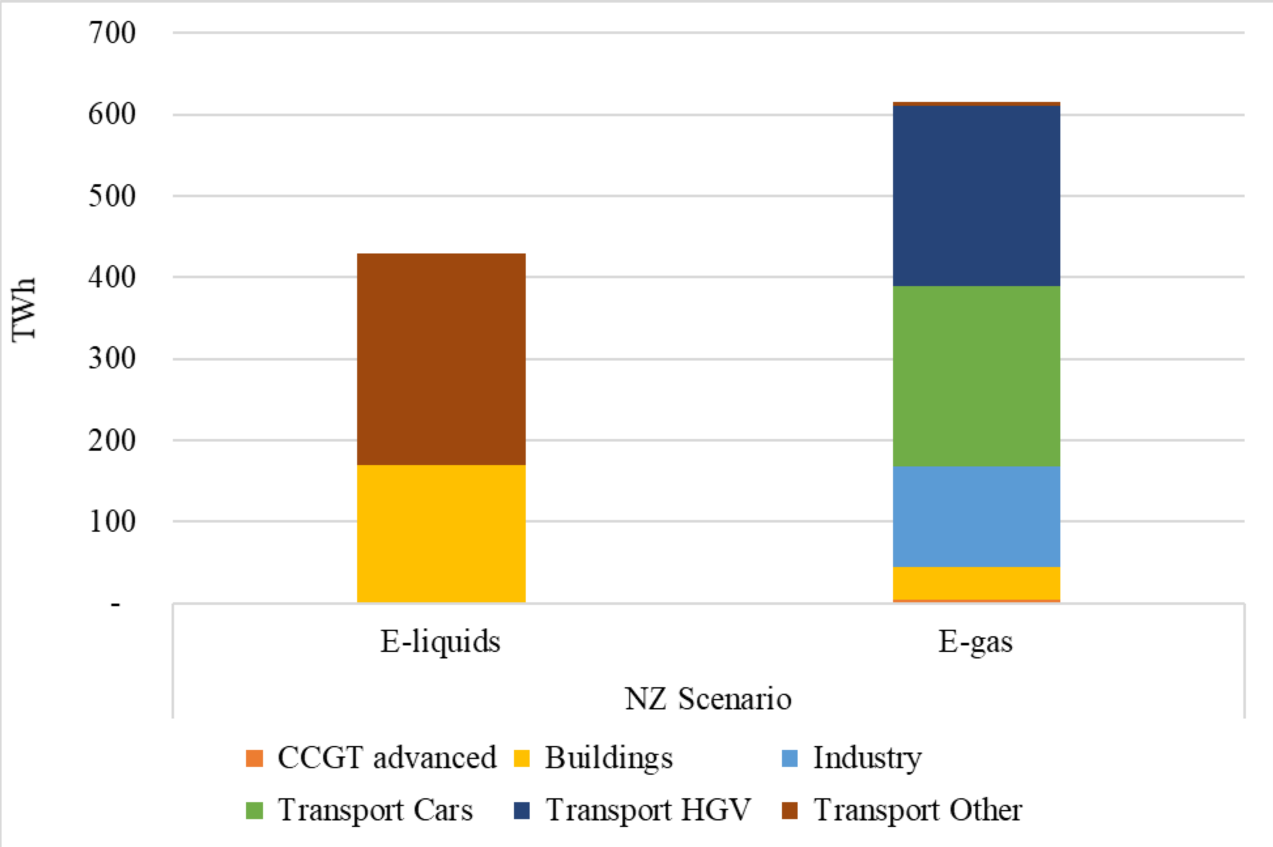
Figure 35: Aggregate hourly operations of heating technologies in buildings on a winter day across all regions in the model



Notes: ASHP – air sourced heat pumps, HHP – hybrid heat pumps (e – electricity based unit, g – gas based unit).

Another pillar of a smartly integrated energy system is efficient utilization of resources and materials and exploitation of synergies between them. In this regard, potential economic benefit of using carbon-neutral H_2-based synfuels in deep decarbonisation pathways could be primarily utilization of mature and existing (end-use) technologies and associated existing infrastructure at relatively low cost (e.g., internal combustion engines or existing gas boilers). Figure 36 shows the role of carbon-neutral synfuels in our two baselines – we can see that the usage of synfuels are concentrated mostly in transport and industry where it would be hard either to directly to electrify or much costlier. We should note that since we modelled agriculture energy demand as part of 'buildings' sector e-liquids consumption in this sector represent replacement of traditional diesel consumption in the agriculture activities (machinery etc.).

Figure 36: Carbon neutral synfuels consumption in the NZ scenario



7.2. Baseline Variants

Here, we summarise our findings in terms of the impacts of reaching NZ from 90% GHG reduction level (§6.2.1.) and then sensitivities of the electrification pathway (§6.2.2.).

7.2.1. Impacts of the Last GHG Emissions Reduction "Mile"

Table 18 compares final energy consumption structure in the NZ and 90% scenarios. First, we can see that biomethane supports decarbonisation: its share stays roughly the same at 12-13% in the final energy consumption, irrespective of GHG emissions reduction target being either 90% or net zero. Hydrogen plays a more prominent role in the final consumption when we need to achieve the net zero target, as its share increases from 3% under the 90% GHG emissions reduction scenario to 11%, predominantly to serve road transport demand.

Table 18: Final Energy Consumption (TWh) in NZ and 90% Scenario

	NET ZERO		90% SCENARIO	
	FINAL CONSUMPTION	SHARES IN TOTAL	FINAL CONSUMPTION	SHARES IN TOTAL
Biomethane	1,059	13%	1,040	12%
E-gas	611	7%	647	8%
Electricity	4,175	51%	4,093	49%
Hydrogen	921	11%	210	3%
Natural gas	199	2%	323	4%
Gasoline	45	1%	305	4%
Diesel	290	4%	661	8%
Biomass	517	6%	508	6%
E-liquids	429	5%	582	7%
Total	**8,246**	**100%**	**8,369**	**100%**

Overall, allowing for some residual GHG emissions to remain in the system under the 90% reductions target, we still see at least 12% of gasoline (cars) and diesel (HDV) in the final consumption mix, predominantly to serve the road transport demand. Therefore, these results do suggest that residual GHG emissions are indeed focused in hard-to-abate sectors like transport. One can see that, for example, in the 90% GHG reductions scenario there are 56 mn gasoline cars and 5.9 mn diesel cars (see Table 19) but in the net zero scenario we only have 8.4 mn gasoline cars while the rest switched to gas mobility (running on biomethane and carbon-neutral e-gas); similarly, the switch between gas mobility and H_2-driven and electricity-based HGVs also happens between 90% and net zero scenarios, suggesting sensitivity of low carbon solutions in the HGV sector.

Table 19: Road vehicle stock in NZ and 90% Scenarios (million vehicles)

TABLE 19

ROAD VEHICLE STOCK IN NZ AND 90% SCENARIOS (MILLION VEHICLES)

	NET ZERO	90% SCENARIO
DIESEL CARS	0.00	5.86
EV CARS	204.30	204.30
EV HGV	0.92	0.01
EV PUBLIC TRANSPORT	0.68	0.68
FCEV CARS	0.00	0.00
FCEV HGV	7.60	0.00
FCEV PUBLIC TRANSPORT	0.13	0.15
GAS CARS	42.71	0.00
GAS HGV	3.38	6.23
GASOLINE CARS	8.36	56.34
TOTAL	268.09	273.58

If we compare (see Table 20) the electricity generation mix in the two deep decarbonisation scenarios we see that is largely similar with the exception that fuels consumed by CCGT plants are low-carbon under the net zero scenario - they consume 95% biomethane and 5% e-gas, both of which are carbon free fuels. However, under the 90% emissions reduction scenario the fuel mix for CCGTs consists of 90% fossil natural gas and 10% e-gas. Obviously, allowing for some residual GHG emissions in the system (10%) would permit some plants to run on fossil fuels. Further, under the net zero scenario, electricity generation increases by 7.3% in absolute terms; therefore, deeper decarbonisation pushes further electricity generation for both direct electrification of end-use sectors as well as in transformation sectors, in particular the usage of electricity to produce hydrogen and synthetic fuels.

Table 20: Electricity generation (TWh) Mix in NZ and 90% Scenarios

	NET ZERO		90% SCENARIO	
	GENERATION	SHARES IN TOTAL	GENERATION	SHARES IN TOTAL
CCGT	60	1%	67	1%
Hydro	189	3%	242	4%
Nuclear	785	12%	790	12%
Residential Solar PV	503	7%	453	7%
Biomass	0	0%	17	0%
Biomass CCS	401	6%	301	5%
Tidal & Wave	24	0%	24	0%
Utility Solar PV	822	12%	733	12%
Wind Offshore	1,360	20%	1,122	18%
Wind Onshore	2,672	39%	2,601	41%
Geothermal	2	0%	3	0%
Total	**6,818**	**100%**	**6,353**	**100%**

Table 21 shows electricity consumption by activities for both baselines – while growth in the final consumption is ca. 2% between the net zero and the 90% GHG reduction scenario, the major growth in electricity consumption is in the transformation sector – we see 17% growth in electricity consumption in the net zero scenario compared to the 90% GHG reduction scenario, primarily to produce more green H_2. This suggests an important role for green H_2 in the net zero scenario to further decarbonise the energy system where direct electrification is less suitable. What is also interesting to note is that under the net zero scenario we see uptake of less mature electrolysis technologies (and more costly) such as solid oxide electrolyser cell (SOEC) which is expected to be more efficient than the alkaline technology. Therefore, pushing our system towards net zero GHG emissions target seems to suggest a need for more technological efficiency in green H_2 production, perhaps, due to limited availability of incremental renewables capacity or costly incremental expansion of the electricity system.

Table 21: Electricity consumption (TWh) by end-use activities in NZ and 90% Scenarios

TABLE 21

ELECTRICITY CONSUMPTION (TWH) BY END-USE ACTIVITIES IN NZ AND 90% SCENARIOS

	NET ZERO		90% SCENARIO	
	CONSUMPTION	SHARE IN TOTAL	CONSUMPTION	SHARE IN TOTAL
TRANSFORMATION	2,085	33%	1,780	30%
ELECTROLYSIS ALKALINE	1,910	31%	1,780	30%
ELECTROLYSIS PEM	0	0%	0	0%
ELECTROLYSIS SOEC	150	2%	0	0%
DIRECT AIR CAPTURE	25	0%	0	0%
FINAL CONSUMPTION	4,175	67%	4,093	70%
BUILDINGS	2,063	33%	2,079	35%
INDUSTRY	1,381	22%	1,351	23%
TRANSPORT CARS	507	8%	507	9%
TRANSPORT PUBLIC	35	1%	35	1%
TRANSPORT HGV	60	1%	0	0%
TRANSPORT OTHER	129	2%	120	2%
TOTAL	6,260	100%	5,873	100%

Table 22 outlines projected GHG emissions, storage and utilization in the two baseline scenarios. First, one can see that removing the residual 10% emissions (i.e., net zero target) requires a four-fold increase in permanent CO_2 sequestration, of which at least more than half is negative emissions, relative to the level of sequestration under the 90% reduction target scenario. Under the net zero scenario, the emissions are higher in the transformation sector, predominantly from the residual emissions in the process of blue H_2 productions from advanced gas reformers as well as from burning bioenergy.

It is worth mentioning an interesting result that CO_2 utilization for production of synfuels are higher under the 90% scenario than under the net zero baseline. The main reason for this is higher economic value of having more negative emissions in the net zero scenario, i.e. production of carbon neutral synfuels competes with alternative use (permanent sequestration) of CO_2 from bioenergy to create supply of CO_2 emissions permits. Looking at the results in Table 22, we can see that increment of negative emissions (252,692 less 20,676 ktCO2e) accounts for about 41% of total residual CO_2 emissions in the 90% reduction scenario – therefore, achieving the net zero target requires essentially abating another 59% of the 572,652 ktCO2e which was achieved with a combination of higher direct electrification as well as higher usage of H_2 and renewable gases.

Finally, we calibrated our input dataset to the EC LTS and therefore for the 90% scenario we used EC LTS's overall GHG emissions – 620,100 ktCO2e (line [9] in Table 22) as the emissions cap in our modelling of that scenario. But one can see that the constraint was not binding as our total projected emissions under the 90% reduction scenario is 572,652 ktCO2e (vs 620,100 ktCO2e); that said, if we compare our projected total residual emissions with the 1990 level then this projection is ca. 10.6% of the 1990 level; therefore, it is unclear why the EC LTS COMBO has GHG emissions which is 11.46% of the 1990 level. Finally, EC's 1.5 TECH is actually not a net zero scenario – it is a scenario that achieves 99.5% reduction of CO2e emissions over 1990 level (see EC LTS, p. 198).

Table 22: GHG emissions balance in the NZ and 90% Scenarios, mtCO2e

TABLE 22

GHG EMISSIONS BALANCE IN THE NZ AND 90% SCENARIOS, MTCO2E

		NET ZERO	90% SCENARIO
[1]	**Stock Change**	**-406,2**	**-100,3**
[1.1]	Underground storage: non neutral emissions	-153,5	-79,6
[1.2]	Underground storage: negative emissions	-252,7	-20,7
[2]	**Transformation**	**612,0**	**457,4**
[2.1]	Gas-fired electricity generation	19.44	21.76
[2.2]	Hydrogen production from natural gas CCS	144.75	83.77
[2.3]	Bioenergy electricity generation	0	15.44
[2.4]	Bioenergy electricity generation CCS	447.84	336.44
[3]	**CO_2 utilization**	**-229,4**	**-276,3**
[3.1]	Synthetic methane production	-121.76	-146.01
[3.2]	Synthetic liquids production	-107.70	-130.30
[4]	**Final Consumption**	**510,9**	**822,1**
[4.1]	Buildings	173,5	171,1
[4.2]	Industry	109,8	175,6
[4.3]	Transport Cars	79,8	76,2
[4.4]	Transport Public	0.0	0.0
[4.5]	Transport HGV	69,3	255,8
[4.6]	Transport Other	78,5	143,5
[5]	**CO_2 neutral emissions**	**-518,0**	**-427,2**
[6]	**LULUCF CO_2 emissions**	**-306,6**	**-240,5**
[7]	**Non CO_2 GHG emissions**	**337,4**	**337,4**
[8]	**TOTAL 2050** (this research)	**0**	**572,7**
[9]	**TOTAL 2050 (EC LTS)**	**26,1**	**620,1**
[10]	**TOTAL 1990***	**5,408,8**	

Notes: [8]=[1]+[2]+[3]+[4]+[5]+[6]+[7]; * Total CO2e, including indirect CO_2, with land use, land-use change and forestry; Stock Change means CO_2 storage; CO_2 neutral emissions are emissions from combustion of bioenergy; non CO_2 GHG emissions are primarily methane, nitrous oxide and fluorinated gases.

7.2.2. Don't Put All Your Eggs in One Basket

We can see from our modelling results that meeting net zero requires the roll out of multiple new technologies at scale with a wide range of uncertainties around their costs and associated resource availability. Therefore, the model results are highly dependent on assumptions regarding availability (and costs) of these key technologies. For example, availability of negative emissions has been long recognised as a source of controversy, as discussed by Anderson and Peters (2016) and by Fuss et al. (2014). Ultimately, the volume of negative emissions available will inevitably depend on accounting methodologies, sustainability of the biomass feedstock and acceptability of biomass use at scale. Thus, to understand how these key sources of uncertainties could drive our results, we model two net zero variants with a wide range of key parameters representing these uncertainties (see Section 6.2. for more details).

Thus, this section summarises key drivers of electrification and gasification of the energy system under the net zero GHG emissions target by 2050.

Table 23 outlines structures of the final energy consumption in the two NZ variants that we modelled as a result of changing key assumptions of the NZ baseline (see Table 10). As we would expect the set of 3 key dimensions that we vary produces a wide range of results in terms of share of electricity (electrification of final demand) in final consumption – from **36% (NZ-g) to 68% (NZ-e)**:

1. Future evolution of commodity prices, including importantly prices of fossil gas and bioenergy **and** availability of sustainably sourced bioenergy;
2. Investment costs of wind and solar technologies **and** resource availability;
3. Technological innovation in industrial processes allowing further direct electrification of industrial demand and further innovation in road transport modes and supporting infrastructure to allow higher uptake of EVs in all road segments.

Results of the final consumptions structure reveal some interesting insights:

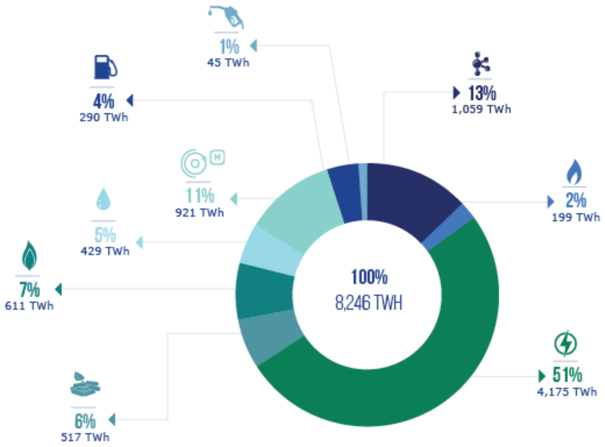
1. While electricity shares swing from 36-68%, we can also see that the role of biomethane swing from 4-22%, suggesting that the role of biomethane in final consumption is much more sensitive to our key set of assumptions than electricity; similar conclusion applies to synthetic fuels (e-gas and e-liquids) as their shares varies widely from 5-16% for e-liquids to 2-7% for e-gas;
2. The role of hydrogen, although marginal at 8-11%, is very stable in final consumption structure, suggesting its prominent importance in delivering net zero target; this result seem to suggest that hydrogen is simply insensitive to such a wide variations in key input assumptions. Similar conclusions apply to other very marginal fuels which are quite insensitive to changes in key inputs – fossil gas, gasoline, diesel and biomass.

The fact that direct usage of hydrogen in final consumption sectors is not sensitive to our key inputs does not mean that its supply volume does not change in the NZ energy system as we move from one extreme to another one (from NZ-e and NZ-g). We can see changes in primary supply of all fuels and commodities in Table 24. Hydrogen supply volume changes by almost a factor of two between the two NZ extremes. What is interesting to note in the NZ-g variant is that the primary supply volume of CH_4 (fossil gas, biomethane and e-gas) totals 7,049 TWh – this is 31% higher than the supply volume we saw in 2018. Thus, in this hypothetical NZ-g variant not only we meet the GHG reduction target but we might also see an expansion of CH_4 supply sector – of this CH_4 supply volume, 41% is carbon neutral (renewable) gas while the rest is imported fossil gas to generate blue hydrogen.

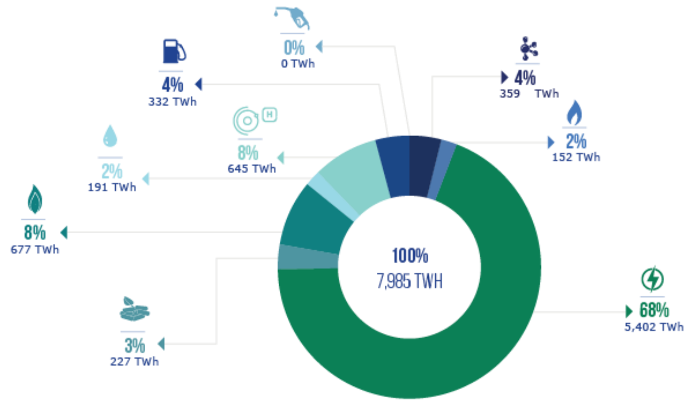
Table 23: Final Energy Consumption (TWh) in the NZ Scenario and its Variants (NZ-e and NZ-g)

	NZ SCENARIO		NZ-E SCENARIO		NZ-G SCENARIO	
	FINAL CONSUMPTION	SHARES IN TOTAL	FINAL CONSUMPTION	SHARES IN TOTAL	FINAL CONSUMPTION	SHARES IN TOTAL
Biomethane	1,059	13%	359	4%	1,936	22%
E-gas	611	7%	191	2%	597	7%
Electricity	4,175	51%	5,402	68%	3,229	36%
Hydrogen	921	11%	677	8%	731	8%
Natural gas	199	2%	152	2%	199	2%
Gasoline	45	1%	0	0%	35	0%
Diesel	290	4%	332	4%	300	3%
Biomass	517	6%	227	3%	517	6%
E-liquids	429	5%	645	8%	1,399	16%
Total	**8,246**	**100%**	**7,985**	**100%**	**8,943**	**100%**

NET ZERO BASELINE SCENARIO



NET ZERO-E SCENARIO



NET ZERO-G SCENARIO

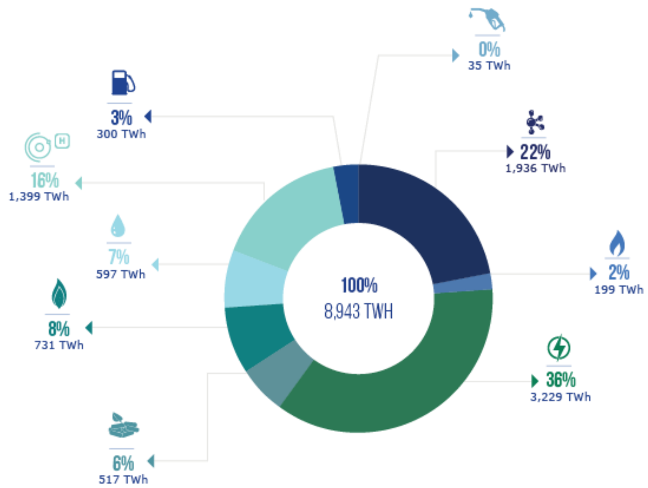


Table 24: Primary Supply (TWh) Mix in the NZ Scenario and its Variants (NZ-e and NZ-g)

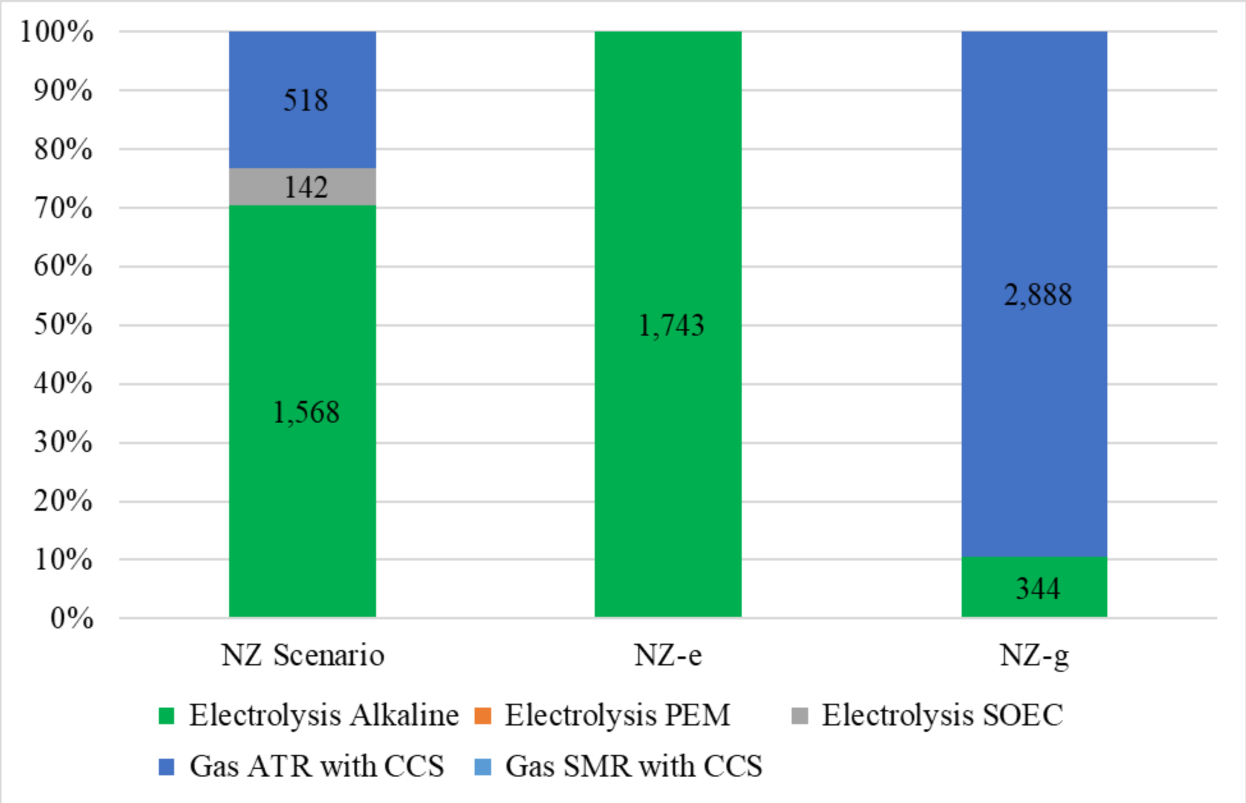
	NZ SCENARIO		NZ-E SCENARIO		NZ-G SCENARIO	
	SUPPLY	SHARES IN TOTAL	SUPPLY	SHARES IN TOTAL	SUPPLY	SHARES IN TOTAL
Biomethane	1,150	8%	359	3%	2,300	12%
E-gas	615	4%	191	1%	600	3%
Electricity	6,818	48%	8,309	63%	4,176	21%
Hydrogen	2,228	16%	1,743	13%	3,232	16%
Natural gas	907	6%	152	1%	4,149	21%
Gasoline	45	0%	0	0%	35	0%
Diesel	290	2%	332	3%	300	2%
Biomass	1,769	12%	1,375	10%	3,538	18%
E-liquids	429	3%	645	5%	1,399	7%
Total	**14,251**	**100%**	**13,107**	**100%**	**19,729**	**100%**

As we might also expect, these two extreme NZ variants produce diametrically opposite results in terms of hydrogen supply sources and technology reliance (see Figure 37) – in the NG-g variant due to our assumption of low energy commodity prices (both bioenergy and fossil) as well as abundance of bioenergy (to offset residual emissions from blue hydrogen production via ATR-CCS route) 90% of hydrogen production comes from gas ATR-CCS route (blue hydrogen). The fact that we still see 10% of green hydrogen in this gas-dominated NZ scenario suggests a robust competitive position of green hydrogen even in such an unfavourable set of electricity assumptions (high costs of wind generation and very low cost of gas commodity and abundance of negative emissions to offset residual GHG emissions).

Similarly, if we look at another extreme (NG-e) we see that hydrogen is in fact 100% produced from electricity (green hydrogen) and this reinforces our conclusion that blue hydrogen is very sensitive to:

1. Fossil gas commodity prices;
2. Availability of bioenergy with CCS (negative emissions) to offset the residual emissions from ATR-CCS in the context of binding net zero constraint.

Figure 37: Supply Volumes and Market Share of Green and Blue H_2 in the NZ Scenario and its Variants



Note: numbers in the chart represent production of H_2 in TWh.

Coming back to the role of electricity in delivering NZ, we can conclude that even in the extreme gasification scenario (NZ-g) we should still expect the electricity supply industry to grow (albeit of course marginally) by at least 15% compared to the 2018 supply situation while under the electrification extreme (NZ-e) the electricity supply should expand by a factor of 2.3. Indeed, if we look at the electricity generation mix under the extreme electrification scenario (see Table 25) we should expect that at least 85% of electricity supply coming from VRE (wind and solar) with the other 10% coming from nuclear and dispatchable renewables (e.g. hydro). However, what is striking is that, even in this highly electrified scenario, we still see ca. 4% of generation coming from biomass CCS suggesting that to meet NZ even with 90% zero carbon electricity we need negative emissions to offset GHG emissions in hard-to-abate sectors such as aviation and industrial processes. That is, even with such relatively unfavourable assumptions (high cost of bioenergy and its low availability coupled with low cost of VRE and its high availability) it is still cost optimal to have some negative emissions to reach NZ under high electrification pathway.

Table 25: Electricity Generation (TWh) Mix in the NZ Scenario and its Variants (NZ-e and NZ-g)

	NZ SCENARIO		NZ-E SCENARIO		NZ-G SCENARIO	
	GENERATION	SHARES IN TOTAL	GENERATION	SHARES IN TOTAL	GENERATION	SHARES IN TOTAL
CCGT	60	1%	0	0%	231	6%
Hydro	189	3%	94	1%	274	7%
Nuclear	785	12%	763	9%	806	19%
Residential Solar PV	503	7%	523	6%	503	12%
Biomass	0	0%	0	0%	265	6%
Biomass CCS	401	6%	367	4%	754	18%
Tidal & Wave	24	0%	0	0%	36	1%
Utility Solar PV	822	12%	281	3%	251	6%
Wind Offshore	1,360	20%	2,180	26%	639	15%
Wind Onshore	2,672	39%	4,100	49%	413	10%
Geothermal	2	0%	1	0%	3	0%
Total	**6,818**	**100%**	**8,309**	**100%**	**4,176**	**100%**

Abstracting away from the details of the modelling results from these two extreme NZ scenarios one key policy conclusion emerges. While the future commodity prices are so uncertain to predict even for the next 12 months and largely out of our control, the four other key areas are largely in our hands – such as investing in R&DD to drive down costs and increasing availability of low-carbon energy resources and new end-use technologies. Thus, policy support at early stage for all key set of technologies that could jointly deliver us NZ should be pursued at early stage and none should be excluded if we are to achieve the NZ target at least cost while tackling many uncertainties on our way to the target.

7.3. Total Energy System Costs to Achieve Deep Decarbonisation

This section focuses on total energy system costs and investment needs to achieve two deep decarbonisation scenarios that we modelled – net zero (NZ) scenario and 90% GHG emissions reduction scenario (90% Scenario) and reports annual energy system costs for the two baseline scenarios in 2050 (Table 26).

Table 26: Annuitized total energy system cost for NZ and 90% scenarios in 2050 (bn €)

TABLE 26

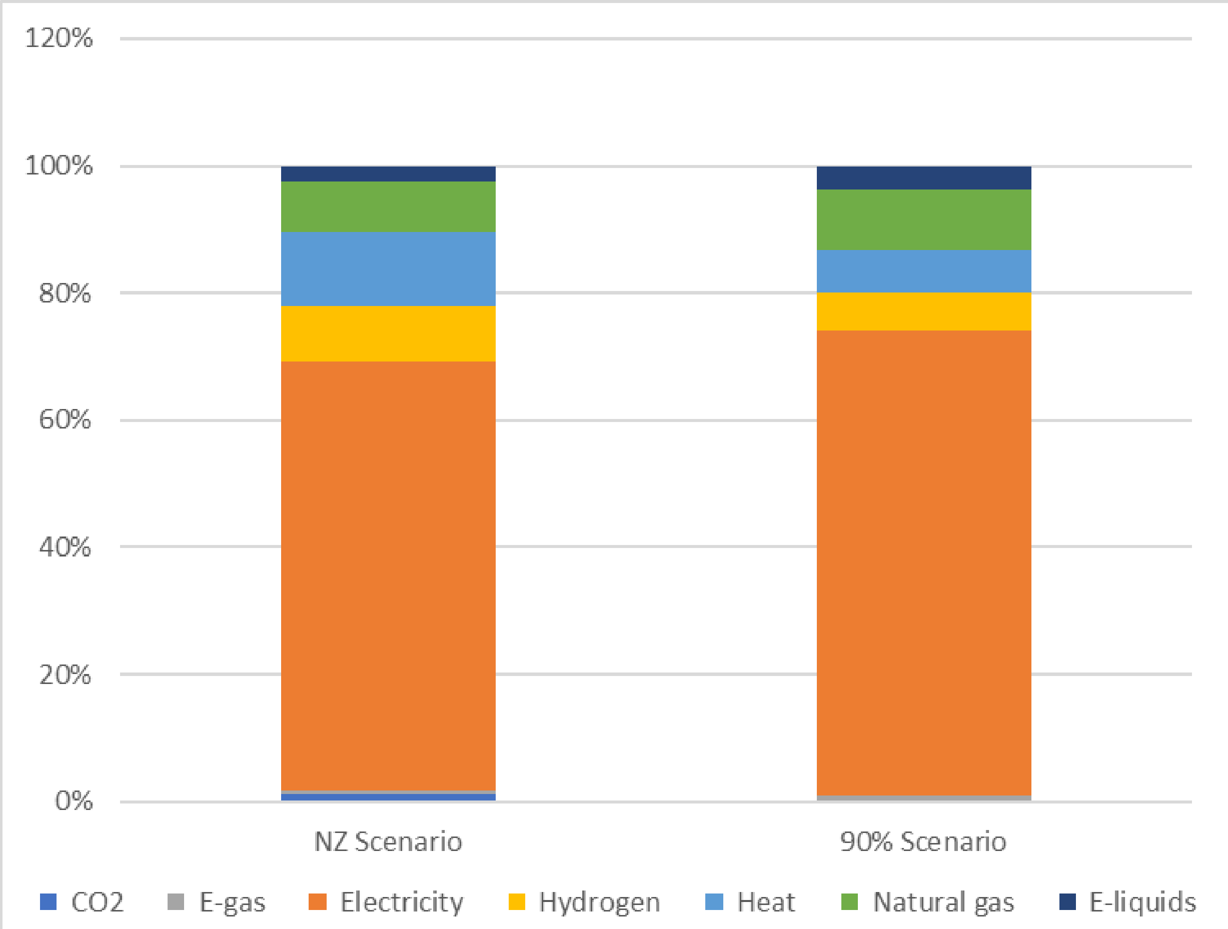
ANNUITIZED TOTAL ENERGY SYSTEM COST FOR NZ AND 90% SCENARIOS IN 2050 (BN €)

	NET ZERO						
	OPEX			CAPEX		TOTAL	AS % IN TOTAL
	Conversion & Storage	Networks	Commodity cost	Conversion & Storage	Networks		
CO_2	9.0	1.7	0.0	1.2	0.2	12	1%
E-GAS	1.8	0.0	0.0	3.1	0.0	4.9	1%
ELECTRICITY	63.5	2.2	49.8	322	159.8	597.2	66%
HYDROGEN	7.4	11.4	28.1	22	11.7	80.6	9%
HEAT	0.0	0.0	51.7	49.4	0.0	101.1	11%
NATURAL GAS	0.0	36.1	0.0	0.8	35.6	72.5	8%
E-LIQUIDS	16.7	0.0	0.0	3.8	0.0	20.5	2%
ROAD TRANSPORTS FUEL*	0.0	0.0	16.3	0.0	0.0	16.3	2%
TOTAL	98.4	51.4	146	402.2	207.3	905.3	100%
	90% SCENARIO						
CO_2	0.1	0.6	0.0	0.0	0.10	1.1	0%
E-GAS	2.0	0.0	0.0	3.5	0.0	5.6	1%
ELECTRICITY	57.9	2.2	39.9	299.4	154.2	553.7	67%
HYDROGEN	5.7	6.4	16.3	13.4	4.6	46.3	6%
HEAT	0.0	0.0	48.6	49.3	0.0	97.9	12%
NATURAL GAS	0.0	34.9	0.0	0.9	36.6	72.3	9%
E-LIQUIDS	22.6	0.0	0.0	5.1	0.0	27.7	3%
ROAD TRANSPORTS FUEL*	0.0	0.0	16.1	0.0	0.0	16.1	2%
TOTAL	88.3	44.1	120.9	371.9	195.4	820.7	100%

Notes: * non-electricity fuels; total system cost excludes carbon cost (in NZ it is 35.4 bn EUR and in 90% it is 46.7 bn EUR) because, like any, tax it is a transfer that is recycled back to the system

Comparing the two scenarios, we can see that the incremental cost of achieving the net zero target is ca. €84.6 bn p.a. (€905.3 bn p.a. - €820.7 bn p.a.), or €147.8/tCO2, on average between 90% and the net zero target. Since electricity sector plays a central role in delivering the deep decarbonisation targets, its share in total system costs approaches ca. 67-73% of the total annual system cost (see Figure 38).

Figure 38: Share of costs by energy carriers and commodities



In terms of break down by electricity supply chain, we can expect that investment in electricity generation will dominate the electricity total system cost with ca. 54% of the total costs (see Figure 39) while variable and commodity cost supporting electricity generation is only ca. 17-19%, hence, electricity system shifts to the one dominant by capex.

While Table 26 shows investments needs to achieve our modelled NZ, a potential way to allocate these costs might be to charge total annuitized system costs to final usages. Based on economic principles, activities that are not final consumption (which includes storage, conversion and intermediate transformation activities) should not be charged with the fixed cost of infrastructure but only with the variable cost which is then passed on to final consumers. For example, under our NZ scenario electricity system provides not just opportunity to directly electrify final energy consumption but also provide substantial services to 'gases' sector to produce H_2 and synthetic fuels. Hence, in theory total annuitized system cost should be paid directly by consumers to avoid potential distortion of market price signals. Table 27 shows these allocations to final consumption by energy carriers.

Figure 39: Electricity system cost structure

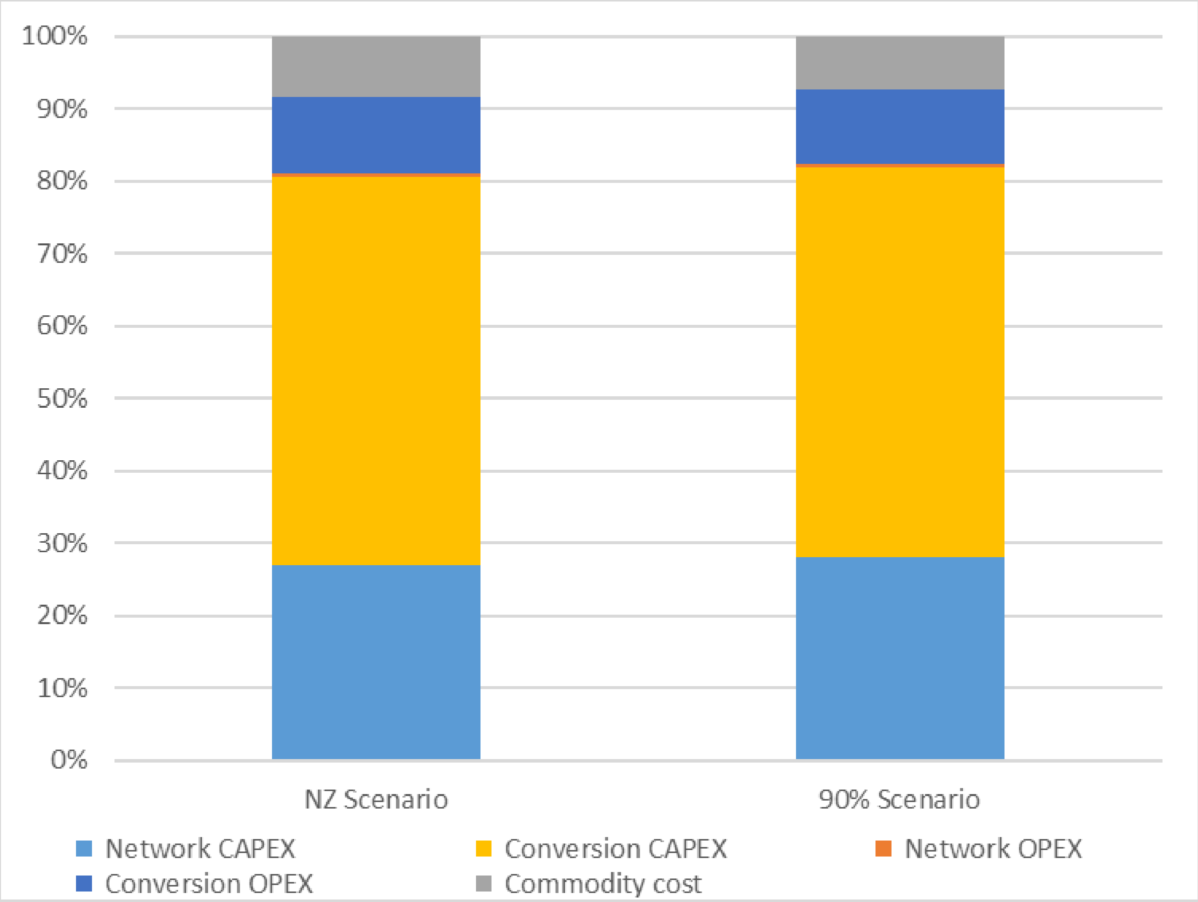


Table 27: Allocation of annuitized total energy system cost to final consumption in our NZ and 90% scenarios in 2050

	NET ZERO		90% SCENARIO	
	FINAL CONSUMPTION, TWH	EUR BN	FINAL CONSUMPTION, TWH	EUR BN
Biomethane	1,059	116	1,040	102
E-gas	611	67	647	63
Electricity	4,175	458	4,093	401
Hydrogen	921	101	210	21
Natural gas	199	22	323	32
Gasoline	45	5	305	30
Diesel	290	32	661	65
Biomass	517	57	508	50
E-liquids	429	47	582	57
Total	**8,246**	**905**	**8,369**	**821**

7.4. Sensitivity Analysis

As we discussed in the research methodology section (§6) we performed several sensitivity analyses to understand the impacts of key assumptions on our results. For each of the key technologies we increase its projected cost by a fraction and measure the impacts of these cost sensitivities on the structure of final consumption. Thus, for each of the technology we listed in Figure 20, we change their projected costs by a fraction from the baseline costs assumptions (see Table 11). Here, we describe the impact of electricity, hydrogen and CH4 network capex on the structure of final consumption and fuel mixes. In the second part of this section we report our sensitivity analysis for system integration technologies (detailed results are reported in Appendix 3). Examining the sensitivity results reveals some very interesting insights regarding potential complementarities between our key energy carriers – electricity, hydrogen, synfuels (e-gas and e-liquid), biomethane and natural gas.

7.4.1. Electricity network

Varying electricity network capex between +/-50% from the baseline does not change its share in the final consumption very much relative to other energy carriers, suggesting a robust and central role of the electricity network in delivering deep decarbonisation targets. It also suggests that our assumptions regarding electricity network costs do not impact the conclusions when net zero target is a binding constraint and that the modelling results are robust because of the correct "directional impact" – higher (lower) electricity network costs does decrease (increase) its share in the final consumption but marginally. Further, these rather insensitive results towards electricity network costs can be explained by the fact that electricity network costs constitute 27-29% of total electricity system costs (see §7.3). As we have seen in Figure 39, the electricity cost structure is dominated by costs of generation technologies.

In terms of complementarities and coupling with other energy carriers, one can see that for example, lower electricity network costs have a positive impact on the position of e-gas and marginally negative impacts on the role of biomethane and hydrogen in the final consumption. This is because electricity-based end-use solutions seem to compete with biomethane and hydrogen but not with e-gas. This could suggest that there is secondary and indirect effect whereby cheaper electricity displaces both biomethane and hydrogen from end-use but then hydrogen is used more to produce synfuels.

7.4.2. Hydrogen network

Our sensitivity analysis with respect to H_2 network seem to suggest that the position of H_2 in the final consumption sectors is relatively sensitive to the costs assumptions (if we compare this with the electricity network costs sensitivity results) – its consumption can vary between -22% and +11% relative to the baseline in responses to changes in the H_2 network costs. While we see that there are complementarities between electricity and synfuels in the final consumption sectors (and hence indirectly with H_2, actually), there are less complementarities between H_2 and other energy carriers. It seems that in the final consumption sectors, H_2 competes the most with e-gas and less so with electricity and biomethane.

7.4.3. CH_4 network

The results from changing the costs of the CH_4 network show that the role of biomethane and e-gas in the final consumption sectors do depend on the costs of the gas network, as expected, but it is somewhat less sensitive relative to the sensitivity of H_2 network costs. What is interesting to note is the complementarities between gas and electricity networks – for example, a higher (or lower) cost of CH_4 network relative to our baseline assumption decreases (or increases) the biomethane and e-gas consumption in the final sectors but the increased gas network costs also decreases electricity consumption in the final sectors (albeit marginally, -0.2% relative to the baseline consumption). Thus, gas and electricity are complementary in the integrated energy system while gas and hydrogen competes for direct final uses. Worth mentioning that CH_4 network costs have a rather large impact on the position of transport fuels – diesel, e-liquids, gasoline – if gas network costs were to be 50% higher than the baseline assumption then this would negatively impact the role of gasoline but positively impacts the role of carbon neutral diesel (e-liquid). A possible explanation is higher costs of the CH_4 network reduces competitiveness of biomethane and e-gas in the final consumption and hence reducing the carbon offsetting of gasoline emissions.

Lastly, the cost of the gas network has asymmetric impacts – for example a 50% higher gas network cost sensitivity reduces the consumption of e-gas by 28% while a 50% lower gas network cost sensitivity increases the consumption of e-gas only by 7% suggesting a limit of gases in the final consumption sectors which are independent of costs of gases.

7.4.4. Electrolysers

The role of green H_2 in integrating different energy vectors is examined in this sensitivity analysis by changing the costs of green H_2 technologies – alkaline, PEM, SOEC. First, while an increase of 200% (relative to the baseline assumption) of total costs of electrolysers does reduce the share of H_2 by 3.3% in the final consumption, a decrease of 50% of electrolysers' cost increases the share of H_2 by the same amount: +3.3% (see Table A. 30); hence, a marginal reduction in green H_2 cost has far greater impact on its competitive position then a marginal increase in its cost.

It is rather obvious that green H_2 competes with biomethane in the final consumption sectors (e.g., increasing costs of green H_2 technologies reduces its share in the final consumption while at the same time we see higher shares of biomethane, see Table A.30, Appendix 3); what is less obvious is the relationship between green H_2 and synfuels – when costs of electrolysers are increased this mainly reduces the consumption of e-gas, but a decrease in the cost of green H_2 seems to benefit e-liquid but not e-gas. This does suggest that cheaper green H_2 will have an important role in transport sector – it allows synthetic diesel (carbon neutral) to displace gasoline, e-gas and biomethane.

Overall, the evolution of the cost of electrolysers to 2050 does seem to have an impact on various energy carriers but it seems that the cost of H_2 infrastructure (pipelines) have far greater impact on the position of green H_2 than the cost of H_2 production.

7.4.5. P2X technologies

The cost of P2X technologies seem to be even more important than the costs of electrolysers – lower (than in the baseline) costs of P2X allows both carbon neutral and fossil diesel to increase their shares in the transport sector at the expense of e-gas and gasoline. A reason for this is that diesel-based transport can use both synthetic and fossil diesel and in general these are more efficient than either gas or gasoline-based transport modes. An increase in costs of P2X (relative to the baseline cost) reduces the role of e-gas in the final consumption. Thus, cost evolution of P2X technologies has rather asymmetric and different effects on the position of input fuel (H_2) as well as output products (e-gas and e-liquids) – when P2X costs are very high we see more direct usage of H_2 in the final consumption sectors displacing mostly e-gas and marginally biomethane and electricity.

All in all, P2X creates an additional channel through which energy system can become more integrated – from offshore wind to car fuel stations.

7.4.6. Hybrid heat pumps

While green H_2 and P2X technologies allows integration of low-carbon energy vectors at the upstream level, hybrid heat pump (HHP) systems allows integration of two important energy vectors – electricity and gas – at household level. The impacts of varying costs for HHP does not seem to have a dramatic shift in final consumption mix; thus, the cost of HHP themselves might play a marginal role in the overall system cost; for example, increasing the cost of HHP by 50% (relative to the baseline cost) only reduces consumption of biomethane by 2.7% but increasing the cost of the CH_4 network by the same 50% reduces biomethane consumption by 8.2%; thus, cost of HHP have smaller impacts but the value it provides to manage system peak is rather important (see §7.1.3.4.).

7.4.7. Storage Technologies

On storage capex sensitivities, the modelling results suggest that there are complementarities between electricity-based storage and CH_4 storage: if capex for electricity-based storage increases it would reduce the share of electricity in final consumption but this also reduces CH_4's (biomethane and e-gas) share as well. Similarly, reducing electricity storage capex would increase shares of both electricity and CH_4 (biomethane and e-gas) in final consumption. At the same time, we also see that electricity storage competes with H_2-based storage: increasing (reducing) electricity storage capex increases (reduces) share of H_2 in the final consumption.

What is less intuitive is the observed directional impact of changing capex for H_2 and CH_4 storage technologies. For example, we observe that higher (than in the baseline) capex for H_2 storage would actually increase the share of this energy carrier at the expense of reducing the shares of biomethane and e-gas in the final consumption. The reason for this is H_2 storage helps to integrate intermittent renewables and when H_2-based storage capex is higher we observe lower overall VRE electricity generation and higher generation from other sources such as gas (biomethane), nuclear, hydro, and tidal resources; thus, it seems that under very high H_2-based storage capex it is cost optimal to use more H_2 in final consumption and CH_4 and e-gas is diverted away from final consumption towards electricity generation (transformation sector).

Similarly, we observed that higher (than in the baseline) capex of CH_4-based storage actually increases the shares of biomethane and e-gas while reducing the share of H_2 in the final consumption. Comparing the energy balances suggests similar pattern to the H_2-based storage: increasing CH_4-based (seasonal) storage primarily affect (negatively) production of blue H_2 and its position in buildings and HGV transport sector, where seasonal (and daily) balancing of H_2 is needed. This negative impact on H_2 in buildings and HGV transport has knock on (positive) impact on biomethane, e-gas and electricity in buildings and road transport.

While this reshuffling has marginal impact (relative to baseline) on fuels shares in final consumption, the overall impacts of changing CH_4 and H_2 storage capex has *no net impact on total final consumption.* But changing CH_4 and H_2 storage capex does nevertheless reveals a complex interactions between gases-based storage, green and blue hydrogen production and P2X. Further, it is important to note also that relative to H_2 and CH_4 storage technologies, electricity-based storage technologies are more important because changing its capex results in overall net changes in total final consumption whereas changing capex of gases-based technologies would result in 'reshuffling' of fuels in the final total consumption only.

08

POLICY AND REGULATORY RECOMMENDATIONS

8. Policy and Regulatory Recommendations

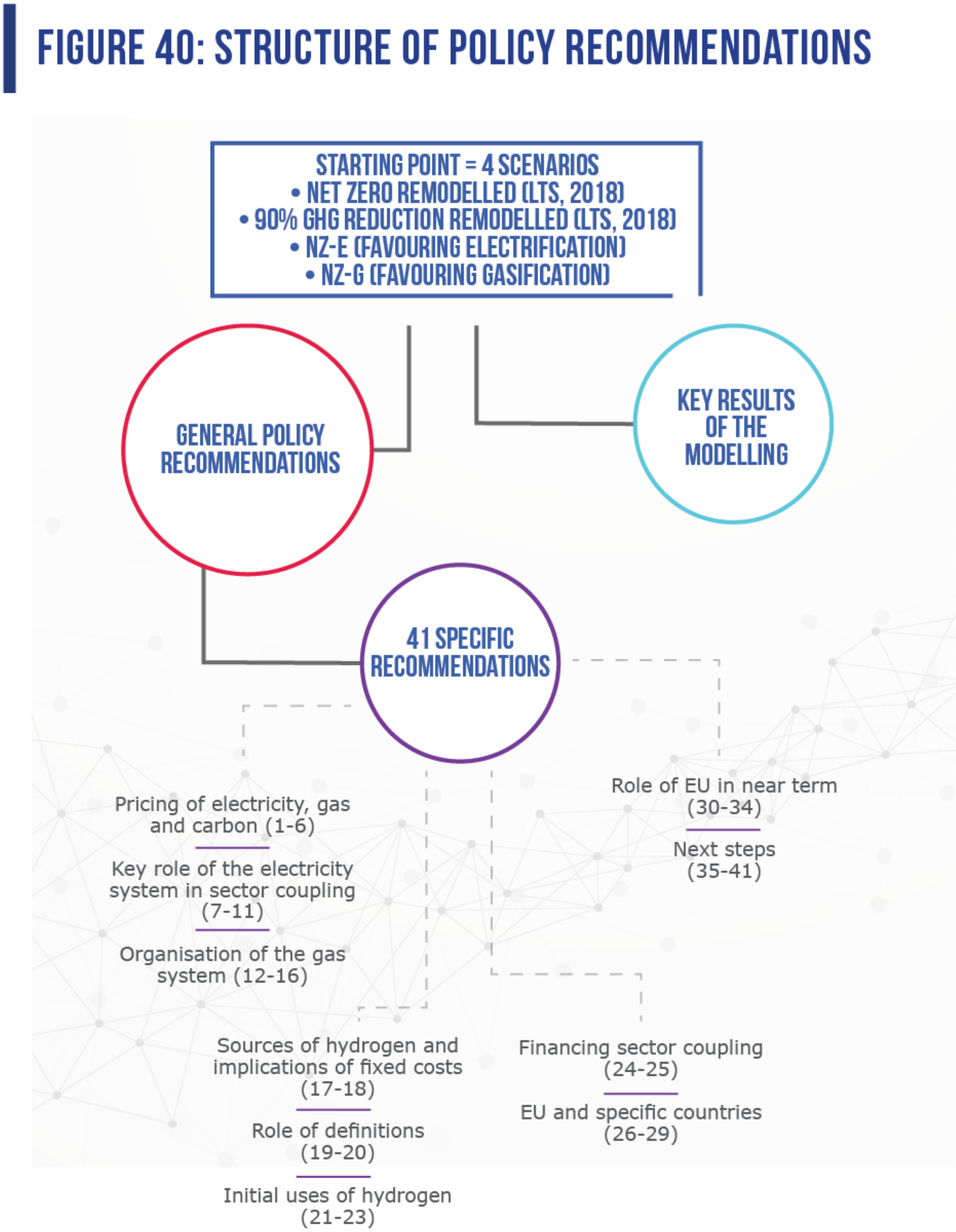
8.1. Starting points

The starting point for our recommendations is that we have remodelled both the COMBO and 1.5TECH (labelled as 90% and NZ) scenarios of the European Commission and have then produced new extreme scenarios which emphasise assumptions which would favour electricity (NZ-e) and gas (NZ-g). See Figure 40 below.

It is important to emphasise at the outset that all four of our scenarios are extreme relative to now and in particular that the two net zero scenarios that we modelled focusing on electricity (NZ-e) and gases (NZ-g) are one step further and based on a set of rather unrealistic and extreme assumptions. As with all scenarios, none are predictions about the future, and we are not saying a priori that any of these scenarios is absolutely likely to come about or that the one is more likely than another. All of them would represent very significant changes to the European energy system relative to today. We are however saying that they each represent an internally consistent quantification of a potential future and have value as such. They allow the potential magnitudes of future electrification, use of hydrogen, use of biomethane and the extent of CCS to be explored. They also produce magnitudes for the amount of sector coupling which we take to mean power-to-H2, e-gas and e-liquids.

We have also undertaken sensitivity analysis to show how sensitive the modelling results are to some of the underlying cost assumptions that lie behind the scenarios. Much of the modelling shows relatively little sensitivity to key cost parameters, given the constraint to meet the overall deep decarbonisation target, but some costs do exhibit significant sensitivity, and these are significantly around the extent of sector coupling and the use of electricity to produce other fuels. Moreover, results strongly depend on the actual availability of wind, solar and bioenergy resources as well as associated costs and the extent of CO_2 capture technology deployment at scale by 2050 and CO_2 transport and underground storage availability and associated costs.

Figure 40: Structure of the Policy Recommendations



8.2. Key results from the modelling

Total electricity production is significantly higher than today in 2050 (except in the extreme NZ-g scenario where it is only modestly higher) and this is achieved by large increases in electricity from wind, solar, nuclear and biomass. The continuing roll out of RES-E is essential to any deep decarbonisation scenario and the required rate of roll out of wind is much higher than has previously been achieved.

A striking consequence of the increased reliance on a RES based electricity system is that a substantial increase in electricity trading is envisaged and a somewhat higher level of cross border transmission capacity. The detailed modelling results show large roles for offshore wind, in particular, from the North Sea. Together with huge increase in onshore wind and solar PV generation, this suggests that the single electricity market and substantial interconnection across Europe (in addition to the strengthening of underlying electricity distribution grids) will be necessary to integrate at least 78% of generation from VRE in our Net Zero Scenario.

While we see that final electricity demand should at least double relative to today in the NZ scenario, there is also a substantial amount of electricity which is transformed into hydrogen, e-gas and e-liquids. This suggests that direct electrification of transport in our scenarios, while significant, is not the biggest contributor to demand growth. This result is also due to the very high efficiency of electric vehicles compared to combustion engines. Depending on relative costs and the depth of decarbonisation, electricity is required to be transformed into gaseous or liquid fuels, which implies significant transformation losses compared to the route of direct electrification. Our NZ scenarios give rise to four sets of activities which will be on a massively increased scale: the production and distribution of hydrogen; the conversion of hydrogen to synthetic methane; the creation of synthetic liquid fuel from electricity; and widespread use of carbon capture with and without the use of storage.

The modelling suggests the need to increase biomethane production and the replacement of natural gas with synthetic methane in the existing gas network; the need to create a separate hydrogen network; for large investments in electrolysis, e-liquids and e-gases; and investments in carbon capture with storage. To the extent that some of these technologies are prevented from taking off due to excessive cost or regulation, this will necessarily limit options and increase the costs of achieving decarbonisation targets. NZ scenarios vs 90% differ primarily in transport and industry, where moving from 90% to NZ replaces liquid petroleum and diesel with hydrogen and other synthetic fuels in the heavy-duty and “other transports” segments. This emphasises the key role of hydrogen and biomethane in each of our NZ scenarios, given our currently available/envisaged technologies out to 2050, provided that the large increase in biomass availability turns out to be sustainable.

In our central NZ scenario the methane network is 50% smaller than today by annual TWh delivered but peak demand and capacity are only 30% smaller. By contrast the hydrogen network capacity is almost three times smaller than the methane network in 2050, and it is relatively focussed on transmission (to serve gas SMR/ATR injections), with a less extensive distribution system (to distribute to HGV transport and industry).

Fossil fuel prices do continue to make potentially significant differences in our model. Low methane prices favour the use of methane with CCS to make blue hydrogen vs the use of green hydrogen from renewables in our NZ-g vs NZ-e extreme scenarios. High methane prices combined with low costs of wind and solar can completely eliminate the use of methane in the production of hydrogen.

8.3. General points about policy recommendations

Our modelling emphasises a key point about NZ scenarios relative to today. Namely, that while the nature of today's energy system has been shaped by the relative availability and price of fossil fuels, the future energy system will only partially depend on relative fossil fuel prices. Instead, the successful scale-up of multiple technologies supported by appropriate policies will be critical for the achievement of any our Net Zero scenarios. The evolution of the relative costs of wind and solar energy, biomethane, hydrogen related technology, CCS and alternatively fuelled vehicle technologies which will enable NZ remain subject to the influence of R&D and experimentation and to policy support. Our scenarios assume that certain technologies (e.g. CCS and biomass at the scale required) are both politically and economically feasible.

EU wide (and near neighbour) policy and MS policies towards energy do both conflict and dynamically interact. Member States want to promote particular technologies within their own borders even if this does create negative externalities at the level of the EU. Sector coupling is likely to be a good example of this: while harmonisation of rules and incentives might well be desirable at the EU level, Member States can and will pursue their own interests. Such conflict may however produce valuable learning for the whole of the Europe. Often common rules restrict the ability to learn from experimentation, especially where this is pointing to the evolution of existing pan-European rules. Our recommendations cannot help but reflect this, where they both encourage learning from experimentation and harmonisation of arrangements across the EU.

Timing in energy policy is important, but especially on the path to Net Zero. Some policy recommendations must reflect the reality of where we are now and hence likely to be in the next few years. The truth is that we do not know which technology is best at scale (even if some technologies have more favourable starting points) or what the eventual path to net zero might be. Anyone who says they know this is simply mistaken. What our NZ scenarios show is that some massive scaling up of currently nascent technologies – e.g. hydrogen, CCS, biomethane - is part of each of our three scenarios. The future cannot be known with certainty. Equally there are some things, such as co-ordination on whatever the 'final' pathway to net zero is, which one can say would be necessary in the longer run. So some of our recommendations are for now (and not for later) and some are more desirable at some later point in the medium run.

In energy, as in the economy more generally, there is always competition for scarce resources. There is no getting away from the reality that choices will have to be made which will exclude some technological options. These can be either the result of market forces or government decisions to back one technology over another. The fact is that high priced resources will be allocated by the market to their most valuable use first. And that individual governments will have choices to make over which technologies to adopt in their domestic energy sectors, given that one cannot simultaneously back a multiplicity of energy vectors for every type of customer. A good example of this would be that while we show scenarios with both a hydrogen and a methane gas network, not every existing methane customer – at the residential level - will have access to the hydrogen network. While differences relative costs are important, they are not necessarily critical to the feasibility of achieving net zero. However the complete failure to develop certain technologies - such as hydrogen and CCS - will lead to critical problems in the achievement of net zero; indeed our models illustrate the critical role they play in our net zero scenarios, rather than a 90% target. It is difficult to see how NZ can be achieved without them given the other available technologies, range of costs and constraints that we model.

As with any modelling of net zero, it is large scale policies that matter. It is important to remember that small amounts of blending and recommendations around these are not going to achieve net zero (so blending of hydrogen up to say 20% in the existing gas system at today's scale is not consistent with any deep decarbonisation scenario we look at). **While there may be lots of small**

injections of locally produced hydrogen, this is not enough on its own in any of our net zero scenarios. Allowing for this, means these technologies will then compete with much larger scale ones within any of our scenarios. Indeed our detailed modelling assumes that there are **separate methane and hydrogen networks in 2050.** We emphasise that we are only modelling net zero in 2050 and not modelling the equally (or indeed more) difficult pathway to net zero, which may involve the emergence of a separate hydrogen network at some point after the initial scaling up and use of hydrogen leveraging on repurposing of part of methane network.

There is a difference between a closed local energy system and the use of the public energy network. Business models may make more sense at one location than in making use of any public network. For instance, it is often assumed that power-to-gas (P2G) is about integrating the whole of the gas and power networks. It would be possible to produce gas from electricity via an electrolyser, store it at that site and burn it in a hydrogen powered power plant on site. This would be P2G and it would arbitrage gas and power prices, but it would not make use of any of the existing gas network. This is economic coupling of gas and electricity but it is hardly sector coupling as we understand it in this project.

The consideration of the possibility of extreme solutions is part of any serious consideration of energy policy for net zero. We cannot shy away from acknowledging that they are possibilities. Thus it is a fact that some countries (e.g. the UK) are considering switching off all or part of their natural gas networks; to not say this is an option would be undermining the credibility of the study. Quite frankly, no one would take a decision like this lightly and given the history of telecoms, post and rail networks which all exhibit similar options for radical closure of parts of the network, which have not been adopted, one has to say it is unlikely that any set of elected politicians would take such a decision. Indeed, these one-zero decisions are not what we have assumed in our modelling, because that is not the best use of a modelling exercise such as ours which can test sensitivities to prices and impose minimum and maximum values on certain technologies.

Simply arbitraging – even with harmonised carbon and network charges - between the existing power and gas networks does not correctly signal the future value of maintaining a decarbonised gas network._This is because it would only be as the gas network declined and demand switched over to electricity that the flexibility value of gas would rise and the inflexibility cost of electricity would increase. This is why whole system modelling is required to establish the relative cost different mixes of the two systems.

8.4. Specific recommendations

The pricing of electricity, gas and carbon

1. Harmonisation of taxes/charges across energy vectors is an essential pro-decarbonisation tax reform (e.g. most obviously uniform carbon pricing of electricity and gas sectors, where direct consumption of gas is outside the current EU ETS). Sector coupling requires the greenhouse gas (GHG) prices (arising from both carbon taxes and the EU ETS) to be harmonised across electricity and carbon markets. GHG price harmonisation reduces leakages which encourage restrictions of trade. The net result of harmonisation of gas and electricity carbon charges would be to encourage green gas in the gas network and increase the arbitrage opportunities from electricity to gas, if green electricity can be used to produce green gases, to substitute for

methane. Such 'tax' harmonisation would also promote direct electrification of demand currently served by gas, where this was cost effective.

2. Sector coupling immediately raises the question of how the EU ETS should be extended to include heating as a way of promoting harmonisation of taxation of carbon[30]. There are serious inconsistencies in the treatment of the electricity and gas sectors within the current EU ETS. Serious sector coupling needs these issues to be addressed. Extension would increase the financial coupling between the electricity and gas sectors and reduce the current distortion that exists been the heavily taxed electricity sector and the lightly taxed gas sector. However this would substantially raise the price of gas (by around 0.45c /KWh @ 25 Euro per tonne CO_2). Alternatives to extension of the EU ETS, such as raising MS gas taxation, result in a lack of real time harmonisation - such as is provided by joint inclusion in the EU ETS - will limit the role of P2G in ancillary services and distort its role in energy markets.

3. Energy efficiency with respect to current gas use remains a critical policy for net zero. Reduction of underlying demand for gas is the most desirable and cost efficient way of reducing GHG emissions from methane. All of our scenarios imply a high price for energy delivered by gas and significantly increased energy efficiency in the use of gas, relative to the current price of a TWh delivered by natural gas, for the marginal TWh delivered through either the methane or hydrogen network. Thus improvements in heating energy efficiency of boilers and buildings are important. Ambitious plans to reduce gas demand need to be factored into any projection for greening the gas grid. A net zero policy applied to gas implies that other policies such as energy efficiency measures now become more valuable. For example, renovating poorly insulated buildings and encouraging switch to hybrid heat pumps could significantly reduce gas demand and improve energy efficiency of buildings. The easiest conceptual way to think of this is that energy efficiency in gas use is a competing zero carbon gas technology. Before incurring high marginal cost conversion of the gas network to hydrogen, one would want to look again at energy efficiency in gas use. Reducing gas conversion fixed cost requirements is a key part of reducing the costs of net zero.

4. The completion of the single market in methane, with appropriate tariffication methodology that ensures cost-reflective tariffs between internal and cross border gas flows, is made more important by sector coupling, even though in the long run methane may be less heavily traded across borders in Europe. The single market in gas is far from complete (see Chyong, 2019) due to the emergence of cross border gas tariffs pancaking. A lack of gas market integration reduces the benefits of coupling within the more extensive single market in electricity. P2G is more about complementing and supporting high RES-E where direct electrification of final demand is hard or cost inefficient to achieve and less about arbitraging between the electricity and gas markets as such. However to make this work efficiently the arbitraging within the electricity and the gas markets needs to be completed. An obvious use of CO_2 free gas is to replace methane imports consumed by the Russian gas dependent EU periphery. In the near term investments in cross-border electricity and 2-way gas transfer capacity to strengthen the single markets are likely to be more efficacious than any integration investments between electricity and gas. It will be important not to make the same mistakes in the creation of a genuine single European hydrogen market

[30] We discuss the rationale for EU ETS extension to heating and transport at length in Pollitt and Dolphin (2020).

that were initially made in the single European natural gas market, both in terms of a failure to achieve price arbitrage and to offer shared supply security to all countries.

5. If electricity and gas networks are going to be coupled to much greater extent than in the past, it is extremely important that the pricing of the use of electricity and gas networks reflects the value of flexibility. Thus attention to double charging of the use of storage assets and the ultimate incidence of network charging must be made. This will be important to encourage optimal provision of power-to-H_2, power-to-gas and power-to-liquids and correctly incentivising the best use of RES, storage and conversion facilities. The evolution of network charging in a way that does this is a work in progress in electricity, with respect to renewables integration.[31]

6. The market design of the electricity market needs to support continuing substantial investment in RES-E. A substantial expansion of renewable electricity is still required and this needs a market framework providing long-term price signals for investments facilitated through long-term contracts. This is in addition to the streamlining of RES permitting. All our scenarios envisage a further very large expansion of RES-E. It is still not clear that electricity spot markets are fit for purpose (see Newbery et al., 2018; Chyong et al., 2019) with respect to supporting the substantial (and increased) level of long-term investment that is required.

The key role of the electricity system in sector coupling

7. The continuation of the deep decarbonisation of the electricity system remains central to our Net Zero scenarios. Even in our NZ-g scenario the electricity demand is at least as large as it is today and it is completely decarbonised. This still implies a very large increase in RES-E relative to today. **The continuation of a supportive policy environment towards the roll-out of RES-E is critical to net zero.**

8. Zero carbon electricity is important in transport in each of our net zero scenarios and it is important as a source of green gas and carbon neutral liquids for heating and transport. Thus the infrastructure required to make these uses possible is also important for net zero. Heavy electrification of transport will require the supportive policy environment towards the rapid uptake of electric vehicles to be continued and extended.

9. Electricity transmission and distribution networks will need to be substantially strengthened in order to support the increased end use of electricity. We envisage peak hour transmission and distribution system demand to be significantly higher under net zero than today. This will require significant and sustained increases in network investment.

10. While our modelling shows that there may be significantly less gas being traded across borders relative to now, our net zero scenarios also show a substantial increase in the cross-border trading of electricity. The transmission infrastructure to make this possible will need to be financed, in circumstances where overall electricity demand increases due to the direct electrification of heat and road transport but total final energy demand may not have increased.

11. **The overarching task facing the electricity sector in supporting net zero remains challenging.** Our model results incorporate the need to balance the system

[31] For a discussion of the complex issues in network charging, see Pollitt (2018).

in each hour of the year in the face of intermittency of RES-E and demand fluctuations. This requires a change to the existing European electricity system (which was only around 55% zero carbon in 2018) which is at least as great as some of the challenges associated with gas decarbonisation that we seek to address below.

The organisation of the gas system

12. Co-ordination between gas and electricity DSO and TSO would seem to be paramount in promoting sector coupling to achieve net zero. The real time operation of P2G assets will require integration between the relatively sophisticated electricity system and the less sophisticated gas system. It will also require physical interconnection of electricity and gas assets. Such co-ordination needs to **take place around the location of the P2G assets and their operation (including data coordination).** The likelihood is that such assets will be adjacent to existing gas assets, given that the safety, security and size of the gas assets will drive P2G asset location.

13. There may be a need for joint testing of P2G assets by electricity and gas network operators. This has been suggested in Italy by ARERA (DCO 39/2020). This is because the safe and efficient operation of such assets requires such co-operation. This joint testing could be carried out by a third party, consistent with a desire to unbundle potentially competitive activities.

14. Sector coupling may thus be promoted by a stronger cooperation between gas and electricity system operators. It might be that existing system operator coordination bodies such as we have seen in electricity across multiple member states through regional reliability co-ordinators, such as CORESO, could be organisational vehicles for improved co-ordination. Certain governments might promote coordination via joint ownership, as was suggested by the Labour Party in the UK[32], where this does not currently exist.

15. How the gas network is priced is very important for sector coupling. Equality of treatment of gas to power and power-to-gas on network charges (assuming costs the same) should be aimed for. The treatment of network costs for gas and electricity being transmitted in and out of P2G assets will be crucial for the efficient arbitrage across the two sectors, but this will be a significant overall determinant of the viability of such arbitrage. **Clearly, network costs do need to be recovered for both networks. There is a significant payment issue for users of gas, because in our scenarios methane demand falls but capital costs to support peak flow remains relatively high**. **Meanwhile, the achievement of net zero in our scenarios requires the build out of the hydrogen and CO2 networks. This needs to be organised and financed, most likely by existing gas network owners, building in anticipation of rising demand.** This also raises the question whether it is efficient to maintain three gas networks (methane, hydrogen, and CO_2). Alternative decarbonisation pathways where bioenergy is not converted to biomethane but to hydrogen with CCS or is used more directly could be explored in future modelling work, so that there might be limited (or no) need to maintain both a hydrogen and methane network in the long run.

16. In our currently analysed decarbonisation scenarios we envisage separate methane and hydrogen networks, thus creating a new network monopoly industry. This would likely

[32] See Labour Party (2019).

need to be regulated, certainly in the longer run once customers had committed to using the hydrogen network. Deep decarbonisation does not in our NZ scenarios involve mixing hydrogen and natural gas in the same network, because a feasible CH_4/H_2 mix does not meet the 2050 net zero target. This implies new laws/regulations to define and regulate hydrogen network assets and their owners at the MS level, as these are not necessarily covered by existing network regulation applying to natural gas. While individual member states might not have a hydrogen network, those that did would need to amend and update their regulations appropriately.

Sources of hydrogen and implications of fixed costs

17. Our scenarios envisage alternative sources of hydrogen – cracking of methane (with CCS) and electrolysis of different types – both being utilised. Thus these sources would compete with each other. The extent of the use of different sources of hydrogen requires the creation of a level playing field in order to allow the most economically and environmental efficient combination of technologies to be used. There must be a level playing field between power-to-H_2, steam reformation of methane with CCS and biomethane where the underlying costs (in terms of wholesale production costs and environmental externalities – in terms of carbon and CCS) are reflected in pricing. On the other hand, it is important to point out that blue hydrogen does not represent a sector coupling technology and would therefore not provide flexibility to power grids.

18. CCS, gas, power and other infrastructures have fixed costs and attention must be paid to the impact of fixed cost recovery on the relative attractiveness of different options. Our scenarios show the rising importance of fixed costs in all parts of the energy system as units distributed decline. Attention needs to be paid to not overbuilding networks and unnecessary impositions of fixed costs on regulated energy consumers. A particular issue might emerge with the existing gas network, our NZ scenario shows gas demand on the methane network down by 50% but the network is still 70% of its current size by 2050, ceteris paribus this would suggest a 40% rise in unit network costs[33].

Role of definitions

19. The definition of green, blue, purple and grey gas is important, especially if targets are set around these. We have discussed the following. Green gas = biomethane, methane from anaerobic digestion, landfill gas, gasification of bioenergy. Green hydrogen = hydrogen from electrolysis of renewables. Blue hydrogen = Hydrogen from reformation of methane with CCS. Other definitions exist (e.g. blue hydrogen from nuclear power) and need to be clearly articulated and regulated on. Definitions have the potential to vary across Europe. Hydrogen could be deemed to be green if it has been produced from a certain percentage of renewables (e.g. 80% in Germany). This suggests a role for the European Commission in specifying definitions for gas that is traded across MS borders.

20. How methane and H_2 storage is treated with the regulatory system raises similar to issues to those around electricity storage and whether it is treated as load or source of supply. For instance, the treatment of local hydrogen storage facilities raises similar

[33] i.e. If initially demand is at 100 and the network fixed cost is 100, the unit fixed cost is 1. If demand drops to 50 and network costs drop to 70, then the unit costs are now 70/50 = 1.4, indicating a 40% rise in unit fixed costs.

issues in gas networks to those raised in the treatment of electrical energy storage in electricity. In that latter case, the issue has been how conversion/arbitrage assets - which act as both supply and demand - should be charged for using the electricity network (as a generator or as a load or as both?). Ideas from how conventional methane storage pays for the network may be helpful. This is being discussed within the Council of European Energy Regulators (CEER).

Initial uses of hydrogen – sector coupling is not just about electricity and gas

21. Our scenarios are for 2050 and envisage separate methane and hydrogen networks. Even at 90% decarbonisation, a methane network is maintained because it is assumed that bioenergy is cheap, sustainable and abundant, and not converted to hydrogen but to biomethane. A hydrogen network is developed because blending with conventional methane is not consistent with deep decarbonisation in the longer term even if it might be a convenient way to use small initial quantities of hydrogen. Further research is needed to analyse whether this configuration is indeed cost-optimal.

22. Our Net Zero scenarios envisage the replacement of liquid fossil fuels in light duty transport by electricity and in heavy duty transport by hydrogen and hydrogen derivatives. Thus, in the initial stages power-to-H_2 could concentrate on industrial and transport heavy-duty uses of hydrogen, rather than on injection into the gas grid. This is because our modelling suggests that by 2050 it will be heavy-duty transport and industrial demand that will drive the use of hydrogen and it will be distributed via a dedicated hydrogen grid. A good economic argument for this is because use of pure hydrogen directly in industry or heavy-duty transport will command higher willingness to pay than in mixing with methane in the gas grid.

23. Obligations on heavy trucking and mass transport to use hydrogen (or an equivalent zero carbon fuel) could help spur growth in the use of hydrogen, in sectors where modelling suggests the use of hydrogen makes clear sense. This is because the use of hydrogen as a mobile fuel is a premium use of energy.

Financing sector coupling

24. Our modelling suggests that much capital will be invested in large assets connected to the existing networks and the costs of capital will be significant in determining overall costs. There would seem to be a need to allow power-to-H_2 and power-to-gas facilities to be built at regulated rates of return in the medium run. This is because these conversion facilities will likely be large and dependent on policies to support deep decarbonisation and therefore not cheaply financed as unregulated assets. One way to do this would be to allow electricity and gas distribution and transmission companies to build, own and operate such assets. For example, gas and electricity network companies could take shares in power-to-gas and power-to-H_2 facilities where these are providing services to the network, such as back-up storage. Notwithstanding the current restrictions (e.g. Art. 36 and 54 of Directive 2019/944) on ownership of storage assets by electricity and gas network companies, in the early stages of development of the P2G sector, there may be large advantages to joint ownership. P2G is an early stage technology facing high capital and financing costs. Similar technologies have benefited from integrated ownership (e.g. battery storage) in the past. This support

could take the form of temporary derogations from internal market rules to allow testing of the scalability of P2G test plants.[34]

25. Certificates of origin of green gas may help with financing green gas. They should be transferable across Europe and potentially apply to all imports of gas. We envisage significant expansion of 'green' gas thus suggesting a parallel with 'green' electricity. Green gas certificates are similar to renewables obligation certificates for electricity. Green gas raises the issue of the appropriate financial support mechanism. Ten European countries in total already have a green certificate system for gas and it is being considered at the European level.

Developments at the EU level may depend on the actions of specific countries

26. Currently, only Germany, France, Norway and the UK are making financially significant hydrogen investments and their role will likely be crucial in terms of having the incentive to push the technology and implementation forward. New industries need to be created to support the 2050 scenarios we have developed and the value added in these industries will likely not be evenly distributed across Europe. This raises the issue of how to fairly divide up payment and responsibility between the countries that might disproportionally benefit and the rest of the EU for the development of these new industries.

27. With respect to sector coupling the technology emphasis is different between different Member States. Thus in Germany there is currently a big emphasis on power-to-H_2 and injection of hydrogen into the gas grid. However in France the emphasis is on the production of power-to-gas and biomethane coupled with flexible end-use technologies like hybrid heat pumps (to couple electricity and gas at household level). The different emphases of different countries may have implications for which policies get adopted at the EU level and where new industries are concentrated across Europe.

28. EU should watch closely developments in Australia, Japan and Nigeria, who have significant interests in developing a global green gas market, as participating in the global market may have significant benefits for the EU. Japan was the first country with a 'Basic Hydrogen Strategy' (2017) focussing on power and mobility to 2030. Japan wants to see the internationalisation of the hydrogen market. Australia shares similar interests and has a 'National Hydrogen Strategy' and wants to participate in the global supply chain. Germany recently signed a deal with Nigeria to collaborate on hydrogen production in West Africa.

29. Europe has options on the use of imports to support the achievement of deep decarbonisation targets. These should be developed and kept open. We explicitly model the possibility of direct imports of solar and green hydrogen only from North Africa and we do not assume imports of hydrogen or biomethane from any other non-EU regions. However hydrogen could be produced outside the EU and imported via pipelines (e.g., from Russia and North Africa) and in liquid form (e.g., from Middle East), if this was cost effective. This is true for biomethane as well. The possibilities in the long and the short term are different with more likelihood of international trading in hydrogen in the long-run with implications for LNG terminal repurposing and domestic production of

[34] For a discussion of current rules, see ACER-CEER position paper at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/SD_The%20Bridge%20beyond%202025/The%20Bridge%20Beyond%202025_Conclusion%20Paper.pdf

hydrogen in the short-term to kick start the internal market in hydrogen. The EU is likely to benefit from global trading in zero carbon fuels given potential disparity between costs of "home-grown" zero carbon fuels vs. imported zero carbon fuels.

Role of EU in near term

30. An EU plan on sector coupling is necessary. Our scenarios suggest that deep decarbonisation implies the greening of methane and the creation of a hydrogen network. Four new industries need to be supported in our scenarios: the production and distribution of hydrogen; the conversion of hydrogen to synthetic carbon neutral fuels (e-gas and e-liquids); the creation of synthetic liquid fuel from electricity; and widespread use of carbon capture, with and without the use of storage. These industries need to be promoted now to achieve scale by 2050. We are approaching the stage at which attention to gas sector decarbonisation is going to be required to have any hope of keeping on track for net zero by 2050. These are in addition to the substantial effort the EU is making on electricity decarbonisation with renewables.

31. The decarbonisation of electricity with renewables has substantially benefited from the RES-E targets. These have been very important and successful in promoting the strategic roll-out of renewables and have resulted in substantial learning benefits (Newbery, 2018). The result of this has been a significant fall in cost of renewable electricity. Consideration should be given to equivalent RES-G targets, as these could have an important role to play in kick starting decarbonisation of the gas sector with zero carbon gas. Such targets would not need to specify which zero carbon gas is to be favoured.

32. Our net zero modelling suggests that zero carbon transport solutions are important drivers of sector coupling. All four of scenarios suggest key roles for electric vehicles and for the use of hydrogen and biomethane and e-gas in heavy-duty transport. A major driver of the development of the supply side around our net zero scenarios will be the changing nature of demand. It is also the case that strong policy support for vehicle technology change will unlock customer investments in the energy transition and the high willingness to pay for private low carbon transport.

33. Expansion of cross-border transmission infrastructure in electricity will be important in achieving net zero. We find that cross-border flows of electricity substantially increase in our scenarios. The EU has a role to play in encouraging projects of common interest in electricity networks to support the growth of the single market in low carbon electricity.

34. The EU needs to be careful to prevent greenwashing in the area of sector coupling. There is the potential to use coal to produce hydrogen, or to undertake steam reformation of methane without CCS. Hence the role of proper definitions and carbon pricing that we have emphasised above. The EU should be careful to avoid incentives to take partial steps towards sector coupling which do not actually bring us closer to net zero.

Next steps

35. Sector coupling and development of power-to-gas and power-to-H_2 require large scale experiments/clusters to demonstrate their viability. These experiments will need significant blocks of funding at both national and potentially EU level. Our NZ-e and NZ-g scenarios reveal the wide range of future outcomes that still depend on technologies which are impacted by R&D and experimentation. Explicit large scale innovation projects will need to be encouraged and funded through customer levies and/or general

taxation. Thus we may need to see large scale demonstration projects, and significant funding in line with such things as the Network Innovation Competition in Great Britain or the Nice Smart Valley Interflex in France.

36. At least initially there can and should be a large amount of MS variation in power-to-gas and power-to-H_2 policy, not least because different countries (e.g. Germany and the Netherlands) will have different industrial policy goals around the technology, with export potential outside the EU. This is to be encouraged as it will motivate significant public and private investment in the countries that wish to lead, say on hydrogen. Some companies are keen to use the EU as a testbed for the roll out of zero carbon gas technologies.

37. National TSOs and DSOs in gas should be encouraged to participate in power-to-gas and power-to-H_2 solutions, but there must be open access on injection rights, so that particular projects are not favoured. This implies a lack of discrimination against particular technologies on the terms and location of access to the existing gas grid. An open access injection right might involve the right to inject gases of different origins and quality to the main network. There will, however, have to be restrictions to prevent the mix of hydrogen exceeding the relevant technical maximum – this will need to be managed via market based incentives. This is not well worked out at the moment and hydrogen injection rules vary between Member States.

38. There is a role for national regulators and their gas TSOs and DSOs in proposing ten year plans for conversion of gas networks towards zero carbon, or mandating their inclusion in both gas and electricity transmission system ten year statements. Indicative planning for gas networks should be lined up with power networks in terms of their extent, clarity and consistency.

39. There may be opportunities within the upcoming revision of the Energy Taxation Directive and in the debate around extending the EU ETS to heating and transport to harmonise gas and electricity taxation and promote sector coupling as suggested in this report.

40. Net zero can be supported by the preferences of large energy consuming companies, with deep pockets. Companies such as Amazon and Google have committed to decarbonisation of their own energy consumption and signed power purchase agreements (PPAs) accordingly. It is at least possible that this trend will continue and actually extend to decarbonisation of their heating and transport demand. This could provide a further spur to both electrification of transport and the use of zero carbon gases, especially in the near term, in line with some of developments envisaged in our net zero scenarios.

41. COVID-19 will have a profound effect on the energy sector with implications for sector coupling policy. Energy demand has declined substantially since 2019 and more importantly there are profound implications for GDP growth and for particular sectors such as air transport. In addition, there may be a desire to promote green investment and growth. **COVID-19 related developments may significantly affect the nature of demand and hence the ability to pay for large upfront net zero investments for many years into the 2020s.**

09

CONCLUSIONS

9. Conclusions

Ensuring that the energy system is flexible is important to meet deep decarbonisation of the entire economy at minimal cost. In this research we have tried to systematically assess and quantify sources of flexibility using a state of the art energy system model. This took into account spatial, intraday and seasonal variability of energy production and demand across the main countries in Europe. The model also explicitly takes into account existing (e.g., fossil fuels, bioenergy, renewables, electricity) as well as new energy vectors (e.g., H_2, e-fuels, and infrastructure) of a tightly integrated energy system. Using this model, we systematically analysed four scenarios – a core scenario which strives to reach net zero (NZ) GHG emissions by 2050 for the Europe and three variants: (i) 90% GHG emissions reduction scenario, (ii) a NZ-e which favoured electrification, and (iii) a NZ-g which favoured gasification (NZ-g); both NZ-e and NZ-g reach net zero and are extreme versions of the core NZ scenario.

The modelling results from the core NZ scenario (and its variants) suggest the central role of electricity supply sector and electricity-based end-use technologies (e.g., EVs and heat pumps) in delivering deep decarbonisation. This conclusion is very consistent with other academic modelling studies and it is consistent with the EC LTS conclusion in that it is a no regret policy option to further support rapid roll-out of renewable generation to reach net zero by 2050.

While electricity plays the key role to deliver net zero, it is worth mentioning the role of other low-carbon energy sources, in particular, the role of biomethane, hydrogen, synthetic e-fuels and bioenergy with CCUS. We found that sector coupling occurs not just at the supply level (e.g., via P2X technologies) but also potentially at end use level (e.g., via hybrid heat pumps in buildings). In this respect, the building sector offers a successful example of an efficient sector coupling, benefiting from the best of the two energy vectors: the electricity grid providing large volumes of renewable energy and the gas grid offering flexibility to deal with the seasonality of heat demand in colder regions of Europe.

Overall, we reaffirm the importance of sector coupling in all stages of the value chain in a future deeply decarbonised energy system. The modelling results reveal that green hydrogen from electricity has a role in each of our scenarios and that even in a scenario where technological cost developments favour electrification, this facilitates hydrogen production by electrolysis for use in a hydrogen network to supply the heavy transport sector and industry. Technological cost and gas commodity price developments which favour gasification, result in more use of gas as hydrogen is produced by reformation of methane with CCS.

We find that our net zero scenarios result in the continuation of the methane network running on biomethane and syngas and the separate emergence of a hydrogen network which has a relatively extensive transmission capacity but much less extensive distribution capacity. However, the relative size of the hydrogen network in our scenarios is significantly affected by whether the overall GHG emissions reduction target has to go from 90% to net zero. Also, further research is needed to understand if both a hydrogen and methane network are to be kept, should biogas be converted to hydrogen instead of being upgraded to biomethane, as currently assumed in the modelling.

What the modelling results also show is that electrification of transport is crucial to reach the carbon neutrality. However, moving from 90% to net zero is both costly and mostly distinguished by the elimination of fossil fuels in the heavy road, air and maritime transport sectors and their replacement by hydrogen.

One conclusion that universally applies to all our modelling scenarios is the increased need for both traditional and new forms of flexibility to support deep decarbonisation. As we set out at the beginning, our two basic research questions were:

1. What are the sources of flexibility under gas and electricity sector coupling and their role in deep decarbonised energy systems?
2. What are complementary dimensions and trends between low-carbon electricity, renewables and carbon-neutral gases for a competitive and secure European energy system?

On question 1, in Section 5 we defined energy system flexibility as including (i) spatial, (ii) intraday, and (iii) seasonal flexibility and discussed the potential requirements in a future energy system reaching deep decarbonisation targets. Our modelling results for NZ scenario clearly shows the importance and need of both temporal and spatial flexibility. In particular, spatial flexibility (investments in national electricity transmission and distribution grids and cross-border interconnections) is required to support rapid roll-out of VRE from local and remote locations (e.g., North Sea offshore wind), while traditional inter-seasonal flexibility is delivered by a combination of (i) traditional seasonal gas (CH_4) storage, and (ii) new forms of seasonal storage – green H_2 production and storage. The latter serves mainly to support the differences between winter and summer VRE production (in particular solar) to minimise potential curtailments, while the former supports seasonal variations in heat load and hence requirements to shift biomethane and e-gas supply to buildings.

Intraday flexibility in our NZ energy system is mostly delivered by:

1. electrical energy storage: both traditional storage solutions like hydro-based electrical storage and generation as well as new forms of intraday flexibility – V2G from EVs and electrical energy battery storage;
2. from H_2-based intraday storage solutions, like pressurised H_2 tanks and liquid H_2 storage technologies;
3. And, hybrid heat pumps which allow for greater system flexibility associated with within day ramping requirements to meet heat loads.

On question 2, we have conducted extensive sensitivity analysis to understand complementarities between low-carbon electricity, renewables, and carbon-neutral gases. A conclusion from this sensitivity analysis is that under a binding net zero GHG target, all energy vectors, traditional and new, complement each other either directly or indirectly. For example, by varying network cost assumptions, we found that CH_4 and electricity networks are complementary in the integrated energy system while CH_4 and hydrogen could have different roles in the final consumption sectors depending on costs and availability assumptions. Further, we found that electricity and synfuels are complements and that the role of green H_2, P2X and hybrid heat pumps is to further integrate the energy system under net zero.

Lastly, our modelling emphasises six high level policy points. First, the deployment of RES-E generation likely at a rate as yet unmatched by historical development underpins the achievement of net zero: this requires an overhaul of the electricity market design to allow investments. It will be paramount to trigger investments in RES-E capacity through long-term price signals such as dedicated auctions and corporate PPAs, but also through more lean permitting procedures. Second, electricity is expected to reach a 51% share in final energy demand in our baseline NZ scenario and could cover up to 68% in the NZ-e sensitivity. Policy can greatly accelerate this transformation process, as shown by the most recent Commission Regulation on emission standards for vehicles. This has triggered a surge in electric vehicle registrations in 2020, despite the overall downward trend of the passenger car sector during the Covid-19 crisis. It should be evaluated whether similar performance standards can also be applied to new heating technologies and whether stronger CO_2 price signals can be given to existing heating technologies, via for example the extension of the EU ETS to include heating. Third, gas as methane or hydrogen remains a significant part of the European energy system, helping both to keep costs down and to balance the inherent variability of a wind and solar based electricity system. Fourth, our net zero scenarios require the use of hydrogen in heavy-duty road transport and industry and hence the development of hydrogen production and hydrogen network. Fifth, net zero as modelled here requires some significant use of CCS. While the quantities vary substantially between scenarios, the increase relative to today is significant. Sixth, there is a substantial variation in the likely outturn quantities of electricity, hydrogen and green methane arising from technological cost developments. Hence R&D and large scale experimentation is both desirable and necessary.

Overall net zero remains an extremely technologically challenging policy goal, involving the roll out of multiple new technologies at scale in a 30 year time frame. It requires policy to deliver three times the carbon reduction achieved in the last 30 years. The wholesale failure to scale up any one of the key technologies on which our net zero scenarios depend – RES-E, biomethane, hydrogen or CCS – will block the path to net zero, necessitating an a currently unforeseen technological break-through in the next 30 years.

In terms of possible major extensions of our modelling, we suggest six.

First, a future study might focus on the impact on Europe of global developments in hydrogen and CCS and hence how these might affect the path to net zero. A global hydrogen market or massive scale up of negative emissions elsewhere might allow Europe to avoid higher costs at home and/or purchase emissions allowances from abroad.

Second, energy efficiency in buildings, demand side flexibility and the role of energy and carbon prices and taxes could be further investigated as using them to manipulate demand in a helpful way could promote low carbon technology adoption and helpful behavioural change.

Thirdly, more rigorous analysis of other hydrogen production pathways should be carried out; in particular, bioenergy to hydrogen with CCS and pyrolysis of methane to produce hydrogen and solid carbon (thus avoiding CCS chain entirely) should be included in the modelling.

Fourth, we have not modelled the potential impact of different climate change and weather variability scenarios on energy demand and renewable energy supply. Different potential climate outcomes, together with already observed annual variations in VRE generation could significantly impact on our model results, and would be a worthwhile stand-alone exercise.

Fifth, systematic analysis of pathways between now and 2050 to reach our NZ, NZ-e and NZ-g scenarios at both EU and national member state (MS) level should be undertaken, including rigorous assessments of the techno-economic potential of resource availability (e.g., RES-e and bioenergy at the EU and MS level) and system cost implications of reaching any of these NZ scenarios.

Finally, we have focussed on techno-economic modelling and the overall technology mix and cost of net zero. The substantial question of how these costs can and should be allocated across vectors, end-use sectors, European countries and between individual consumers remains.

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APPENDIX 1

Appendix 1 – Data inputs and assumptions

This appendix outlines data calculations, processing and assumptions that were used in the modelling. It covers the following:

1. How we derive input data from EC LTS and calibrate our model to model our own scenarios.
2. Sources for techno-economic parameters for modelling (e.g., ramp rate, efficiency of power stations etc.).
3. Other supply and demand projections.

We start from the demand side, then we cover the supply side and finally we discuss networks and storage solutions.

A.1. Demand side

A.1.1. Buildings

We derive thermal energy services demand in buildings based on EC JRC TIMES input database for every country in our model. The following thermal energy services demand categories were considered for residential and commercial buildings:

1. Cooking thermal energy services demand.
2. Cooling thermal energy services demand.
3. Space heating thermal energy services demand.
4. Water heating thermal energy services demand.
5. Lighting and appliances and specific electricity uses demand.

Further, agriculture energy demand has been included into the 'buildings' demand category, following EC PRIMES modelling convention (see (EC, 2016)). In our modelling, we do not consider explicitly end-use technology options for agriculture final energy demand (e.g., different farming machine drives) so we use historic fuel mix from the EC JRC TIMES model (2010) with some adjustments as follows:

1. Diesel consumption is assumed to be carbon-neutral e-liquids.
2. Natural gas consumption is assumed to be carbon-neutral biomethane.

A.1.2. Transport

Road transport activities demand projection for every country that we model is based on European Commission's 2016 Reference scenario (EC, 2016) results adjusting for growth rates projected by EC LTS modelling work (Table A. 1 and Table A. 2).

Table A. 1: Passenger transport activity

	Baseline			relative to Baseline**	
	'95-'15	'15-'30	'30-'50	COMBO	1.5TECH
Road	1.00%	0.70%	0.60%	-1%	-3%
Rail	1.20%	2.10%	1.20%	5%	2%
Aviation	2.80%	2.30%	1.60%	-3%	-3%
Inland navigation	-0.50%	1.20%	0.50%	5%	3%

Notes: * average growth rates per year; ** % changes to the Baseline in 2050

Table A. 2: Inland freight transport activity

Baseline*				relative to baseline**	
	'95-'15	'15-'30	'30-'50	COMBO	1.5TECH
Road	1.80%	1.50%	0.80%	-3.20%	-4.80%
Rail	0.50%	2.50%	1.30%	8.30%	4.40%
Inland navigation	1.30%	1.70%	0.70%	5.50%	2.40%

Source: EC LTS
Notes: * average growth rates per year; ** % changes to the Baseline in 2050

Projections for passenger transport demand activities are based on passenger-km, while freight transport demand activities are based on tonnes-km. Therefore, to model potential energy demand further assumption is needed in terms of average occupancy of various modes of transport. We use EC TIMES data (2019) which used real data on occupancy of main transport modes at EU MS level. We took an average of MS level data and within main transport modes (public road transport, passenger cars, HGVs) and use the following to inform our modelling:

1. Public transport – 20.8 passengers/vehicle
2. Passenger cars – 1.58 passengers/vehicle
3. Heavy goods vehicles (HGV) – 5.40 tonnes/vehicle

Further, calculations of travel mileage for the above transport were also based on EC TIMES (2019) dataset:

1. Public transport – 45,743 km/vehicle/year
2. Passenger cars – 17,440 km/vehicle/year
3. HGV – 42,808 km/vehicle/year

Note that travel mileage could be further disaggregated down to MS level data as well as by transport mode but for this research project we have decided to use averages as our main focus. Further research on the impact of transport modes on energy system could use detailed MS and transport mode level data.

Other transport modes include aviation, rail and inland navigation which we do not model explicitly in the research paper (i.e., our modelling does not take into account end-use transport modes for aviation, rail and inland navigation) and hence we calibrate final energy consumption from these other transport modes to EC LTS. *Table A. 3* outlines projections for aviation final energy consumption, according to EC LTS.

Table A. 3: Aviation fuels mix (2050), mtoe

	jet fuels	e-liquids	liquid biofuel	electricity
Baseline	63.2	0	1.8	0
COMBO	44.6	3.3	11.9	0.4
1.5TECH	23.9	19.8	13.7	1.2

Source: EC LTS

Projection of final energy consumption for rail and inland transport is based on the following methodology. First, we use annual growth rates of energy consumption for rail and inland navigation from the EC LTS (Table A. 4) and use the historic energy consumption for the year 2005 to calculate total energy consumption in 2050 for the respective scenarios. The EU28 total final energy consumption for rail transport sector was 8,553.1 ktoe and for inland navigation transport sector was 6,838.9 ktoe in 2005, according to Eurostat (Eurostat, 2020).

Table A. 4: Change in final energy consumption per transport mode in 2050 compared to 2005

	Total	road	Rail	air	inland navigation
Baseline	-24%	-35%	22%	30%	-7%
COMBO	-38%	-50%	25%	21%	-3%
1.5TECH	-45%	-58%	20%	17%	-6%

Source: EC LTS

Finally, the fuel mix for 2050 was then calculated using the projections from EC LTS as follows –the net zero GHG scenario sees 95% electricity and only 5% diesel in the fuel mix for the rail transport sector, while for the inland navigation electricity constitute 3%, hydrogen – 2%, liquid biofuels – 40%, e-liquids – 40%, e-gas – 5%, biomethane – 1%, diesel – 9%. We use this fuel mix projections for the COMBO scenario as well. Further sensitivity analysis will be carried out regarding this assumption.

Disaggregation of fuel mix down to the EU MS level follows the results of the EU Reference scenario 2016 (EC, 2016).

A.1.3. Industry

Final energy demand in the industrial sector was calibrated to the results of EC LTS (see Table A. 5) because the current modelling version does not look at end-use technologies in the industry sector and as such out of scope of this research. That said, the projection of final fuels consumption impacts the choices further "upstream" (e.g., electricity or gas network expansion to meet expected industrial loads).

Table A. 5: Final energy consumption in industry (2050), mtoe

	Electricity	Natural gas	Biogas & biomethane	Hydrogen	E-gas	Biomass	others
Baseline	102	64	5	0	0	38	83
COMBO	116	10	15	15	17.2	26	37
1.5TECH	119	4	10	29	10.7	25	32

Source: EC LTS

Since EC LTS did not publish results at EU MS level, a careful disaggregation by country is based on the following methodology.

In the Industrial sector the focus of the Long-Term Strategy is again on reducing the overall emissions. The three main factor affecting industrial emissions are process emissions, which are emitted as a result of the chemical and production processes carried out in industries (21%), emissions due to energy used in heating processes (70%), and space heating (9%). Indirectly, the emissions are caused by the volume of output from energy-intensive industries causes the emissions. Apart from modifying production processes and improving energy efficiency, if the output of these industries can be reduced, indirectly the emissions would also be reduced. However, maintaining production, or even increasing it is important to sustain economic growth.

The total industrial energy consumption is derived for the scenarios using the percentage change of industrial energy consumption over the Baseline scenario in each scenario.

EU Reference scenario 2016 (EC, 2016) provides a disaggregation of industrial energy consumption between energy-intensive industries (EIIs) and other industrial sectors. For the LTS Baseline scenario the share of the two kind of industries within the total industrial final energy demand is assumed to be the same as given in the Reference scenario 2016. However, since the LTS does not provide such a disaggregation it is important to understand the characteristics of the two industrial sub-sectors and how their final energy demand is affected within each of the considered scenarios to be able to discern the disaggregation for each scenario and subsequently each MS.

There are ten industries classified as EIIs[35]:

1. Iron and steel,
2. Cement,
3. Chemicals and fertilizers,
4. Refineries,
5. Non-ferrous metals,
6. Ferro-alloys and silicon,
7. Pulp and paper,
8. Ceramics,
9. Lime, and
10. Glass

Apart from using non-emitting chemical processes and material substitution, the main source of decarbonisation in industries is energy efficiency and fuel-switching of heat and steam production either to clean fuels like biomass, hydrogen and e-fuels, or electrification, assuming that the electricity provided can be decarbonised. Other options include increasing resource efficiency, reducing and reusing the raw materials used in the production cycle, and carbon capture and utilisation (CCU) to store capture carbon from production processes and storing it in materials.

Only the circular economy scenarios (CIRC and 1.5LIFE) in the LTS assume reduced output from certain industrial sub-sectors and a greater production of secondary materials replacing production of primary materials, which are less energy intensive. ELEC focuses on electrification of industrial heat and processes. Electric heating is less efficient than thermal heating methods for high-temperature heating requirements, while also reducing the potential for heat recovery. Although electricity is more efficient than thermal heating for low temperatures, the percentage of demand for low-temperature heating applications is much smaller than high-temperature heating. Hence, in 2050 in the ELEC scenario, industrial energy demand is the same as in the Baseline, while emissions are reduced mainly via substitution of natural gas and other fossil fuels by electricity and biomass. Hence, we assume that the sub-sector share in the final energy demand also remains the same as in Baseline (57% EIIs and 43% other industries), since the overall energy efficiency of the sector increases by 10% of the eventual 11% in 2050 over 2015, because of heat recovery applications between 2020 and 2030. However, there is no evidence provided of a redistribution of production activity or final energy consumption between EIIs and other industries.

A similar reasoning can be applied to the P2X scenario, where natural gas and fossil fuels are replaced by e-gases, hydrogen and biomass, without reductions in output and a restructuring of production activity among the two sub-sectors.

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[35] Industrial Value Chain: A Bridge Towards a Carbon Neutral Europe: https://www.ies.be/files/Industrial_Value_Chain_25sept_0.pdf

On the other hand, the COMBO and 1.5TECH scenarios achieve energy demand reductions of 24.4 Mtoe and 32.7 Mtoe respectively, through circular economy measures, or shifting of production activity from energy-intensive primary materials to less intensive secondary production. This amounts to 80% of the entire final energy demand reduction achieved in COMBO compared to Baseline, and 84% in 1.5TECH. This is combined with energy efficiency for the remaining final energy demand reduction, and fuel substitution and CCS for further decarbonisation. The eventual reduction in final energy demand in these scenarios is comparable, at 19% and 22% in COMBO and 1.5TECH respectively. Thus, given that the production activity decreases in EIIs and increases in other industries, to achieve the aforementioned 'total reduction' in output through shifting of production activity, EII output must reduce by *at least* an equivalent amount, while production in other industries will increase by some amount. Therefore, to re-calculate the share of EII and other industries we assume that the entire reduction in output is attributed to EIIs, and adjust the final energy demand of 'other industries' to match the total energy demand, thus, redistributing the *percentage share* of the two in the final energy demand.

Doing this calculation, we find that the share of EIIs in the total energy demand of the industrial sector falls from 57% in Baseline to 54% in COMBO and 52% in 1.5TECH, while the balance is attributed to the 'other industries' sub-sector.

The above reasoning is true if we hold another assumption that secondary production takes place only in 'other industries', while primary production takes place only in EIIs. This is a reasonable assumption to make as the distinguishing factor between primary and secondary production is its energy intensity. If the energy intensity of production falls considerably, regardless of the nature of the output, it may no longer be classified as an EII.

A.2. Supply side

A.2.1. Traditional energy sources

This section describes main assumptions for the supply of traditional energy sources. First, we outline assumptions for bioenergy, then for other commodities and finally we discuss CO2 emissions associated with these energy carriers.

The supply availability of bioenergy is taken from the EC LTS for the two respective baselines that we model: in 2050 under the 1.5TECH the projection of bioenergy availability is 2919 TWh and under the COMBO scenario it is 2640 TWh. To disaggregate this total EU level bioenergy supply we use the shares of bioenergy calculated from the Trinomics study for the European Commission (Nuffel et al., 2019[36]). For the 1.5 TECH, in line with the Trinomics study, we assume that the availability of biomethane is 1150 TWh while the rest is biomass (1769 TWh). For the COMBO scenario we keep this proportion and scale it with the total bioenergy supply projected by the EC LTS for the COMBO scenario (2640 TWh). Cost of biomethane is based on the Trinomics study while the cost of biomass is based on Navigant (2019) study but to calculate MS level cost we scale this cost using the Trinomics study numbers.

Table *A*. 6 shows the results of these calculations and calibration process.

[36] Nuffel, Luc van; Dedecca, João Gorenstein; Yearwood, Jessica; Smit, Tycho; Bünger, Ulrich; Altmann, Matthias; Fischer, Christian; Michalski, Jan; Raksha, Tetyana; Zerhusen, Jan; De Vita, 2019

Table A. 6: Supply and cost of bioenergy (2050)

	Biomethane			Biomass		
	Cost, €/GWh	Supply, TWh/yr		Cost, €/GWh	Supply, TWh/yr	
		1.5TECH	COMBO		1.5TECH	COMBO
Central Europe	64,394.1	24.0	21.7	26,654.1	36.9	33.39
BE	68,104.6	13.2	12.0	28,190.0	20.4	18.41
SEE	75,009.3	133.9	121.1	31,048.0	206.0	186.30
East Europe	74,581.0	69.1	62.5	30,870.7	106.3	96.13
Nordic	59,624.3	137.5	124.4	24,679.8	211.6	191.35
Baltics	68,355.9	36.7	33.2	28,294.0	56.4	51.01
FR	72,500.0	184.4	166.7	30,009.4	283.6	256.50
DE	71,400.0	133.9	121.1	29,554.0	206.0	186.30
Ireland	65,200.0	10.2	9.2	26,987.7	15.7	14.20
IT	67,800.0	88.3	79.8	28,063.9	135.8	122.83
NL	67,700.0	19.2	17.4	28,022.5	29.5	26.71
PL	73,600.0	91.3	82.5	30,464.7	140.4	126.98
Iberia	69,791.6	138.7	125.4	28,888.3	213.4	192.97
UK	71,000.0	69.7	63.0	29,388.5	107.2	96.91

Source: own calculations based EC LTS; Trinomics (2019); Navigant (2019)

Apart from bioenergy, the model takes into account the main energy commodities. Supply and costs assumptions are reported in Table A. 7. We assume unlimited supply availability but in practice the model will constrain the usage of these commodities due to GHG emissions constraints and high carbon cost associated with usage of these technologies. Cost of coal and natural gas for 2050 is based on Navigant (2019) while cost of diesel and gasoline is based on EU Reference scenario 2016 (EC, 2016). Cost of uranium is based on Word Nuclear (2020).

Table A. 7: Cost and CO_2 intensity of energy commodities in the model

Energy carrier	Cost (2050), €/GWh	CO_2 intensity, ktCO2e/GWh
Coal bituminous	9,000	0.32611
Coal lignite	8,100	0.37638
Natural gas	30,000	0.20444
Diesel	58,333	0.27000
Gasoline	52,500	0.25000
Uranium	3,588	0
Biomass	See Table A. *6*	0.35777
Biomethane	See Table A. *6*	0.20444

Source: for cost: own calculations based Navigant (2019); (EC, 2016); World Nuclear Association (2020); for CO2 intensity: based on BEIS, EIA, Fachbuch Regenerative Energiesysteme and UBA

Note that although combustion of bioenergy for end-use services results in CO_2 emissions but because in the process of growing feedstock the same quantity of CO_2 is captured from the atmosphere in the photosynthesis process the feedstock has short carbon cycle. IPCC guidelines suggest, therefore, that CO_2 emissions from combusting bioenergy should count as zero emissions as the carbon stock embodied in the fuel is already counted in Agriculture, Forestry and Other Land-Use (AFOLU), and Waste (IPCC, 2019[37]).

Moreover, if CO_2 emissions from combustion of bioenergy is captured and permanently stored in underground storage formations then this result in "negative" emissions and can be used to offset emissions of CO2 from hard-to-decarbonise activities. It is also worth noting that in the process of producing biomethane from biogas short carbon cycle CO_2 is captured and the economic value of biomethane is not just carbon neutrality but also that CO_2 as a by-product has an economic value – either as negative emissions, if captured and permanently stored, or utilised, for example, to produce carbon neutral e-fuels.

Various methods could be used to produce biomethane that can be used in the existing gas grid (Navigant, 2019):

1. Anaerobic digestion (AD),
2. Thermal gasification (TG), and
3. Biological methanation[38]

In this research we do not explicitly model technological processes of biomethane production and hence have we assumed country-specific costs and supply availability (see Table A**. 6**) without looking into the economics of various biomethane production methods. Therefore, to estimate the potential for negative emissions from the upgrading of biogas produced from AD we follow Navigant's (2019) assumption that ca. 64% of all biomethane supply by 2050 (*Table A***. 6**) is produced from AD while the rest is from TG process. The calculation assumes:

1. Efficiency of 54% for converting biogas to biomethane; that is, to produce 1 TWh of biomethane, 1.852 TWh of biogas with 55% CH_4 content while the rest is short carbon cycle CO_2 is needed.
2. Therefore, to produce biomethane at the required specification (96% CH_4 and 3% CO_2) to inject into the existing grid, 42% of CO_2 contents should be removed from the biogas mixture. This results in 138.72 ktCO2/TWh being captured when biomethane is produced from biogas AD.
3. Since only 64% of biomethane is produced from AD process while assuming that only 90% of CO_2 can be captured, the useful CO_2 captured is 80.257 ktCO_2/TWh.

In our modelling, we take this potential CO_2 capturing from AD process upgrading to biomethane explicitly. We allow the model to use this CO_2 captured either to store permanently in underground storages resulting in negative emissions or to be utilised with H_2 to produce carbon neutral e-fuels.

[37] https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html
[38] Ecofys & Imperial College, 2017. Assessing the Potential of CO2 Utilization in the UK. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/799293/SISUK17099AssessingCO2_utilisationUK_ReportFinal_260517v2__1_.pdf

A.2.2. Hydrogen and Power-to-X

This section outlines our techno-economic assumptions for hydrogen and power-to-X production technologies.

We model two main routes for hydrogen production – water electrolysis and natural gas steam reformation with CCUS. We further model production of synthetic methane (e-gas) and synthetic diesel (e-liquid) using hydrogen and carbon dioxide from sustainable sources (e.g., biomass with CCS or biogas upgrading to biomethane) so that those e-fuels are carbon neutral.

Table A. 8 outlines our cost assumptions for these emerging technologies, based on the Asset (2018) project.

Table A. 8: Cost of producing new energy carriers

	Investment cost per unit of capacity (€/kW-output)			Fixed O&M costs (€/kW-output)			Variable, fuel and emissions cost per unit of output (€/MWh-output or per tCO2)		
	2015	2030	Ultimate	2015	2030	Ultimate	2015	2030	Ultimate
Hydrogen from natural gas SMR - Large Scale with CCU	900	850	800	36	34	32	0.00015	0.0002	0.000153
Hydrogen from natural gas ATR - Large Scale with CCU	1241	1069	984	36	34	32	0.00015	0.0002	0.000153
Hydrogen from low temperature water electrolysis PEM centralised	1400	340	200	49	15	10	0	0	0
Hydrogen from low temperature water electrolysis Alkaline centralised	1100	300	180	28	14	9	0	0	0
Hydrogen from high temperature water electrolysis SOEC centralised	1595	804	600	55.8	36.2	39	0	0	0
Methanation: e-gas	1200	633	263	42	22	9	1	1	1
Methanation: e-liquids	1000	620	364	50	31	18	7	10	94
Capture CO2 from air (per 1 tCO2)	1015	771	506.5	35.5	27	17.7	0.15	0.15	0.2

Source: De Vita et al. (2018)[39] *; others*

Table A. 9: Water electrolysis technical parameters

[39] De Vita, A., Kielichowska, I., Mandatowa, P., Capros, P., Dimopoulou, E., Evangelopoulou, S., Fotiou, T., Kannavou, M., Siskos, P. and Zazias, G., 2018. Technology pathways in decarbonisation scenarios. *Tractebel, Ecofys, E3-Modelling: Brussels, Belgium*.

	2020	2030	2050
PEM electrical efficiency (HHV)	72%	79%	82%
AE electrical efficiency (HHV)	77%	80%	82%
SOE electrical efficiency (HHV)	85%	91%	95%
Water consumption (tap water) of electrolysers, litres/kWh H_2 HHV	0.45-0.55		
footprint AE, m2/kW H_2 HHV	0.136		
footprint PEM, m2/kW H_2 HHV	0.074		
footprint SOE, m2/kW H_2 HHV	0.136		
minimum load factor	none		
ramp rate PEM, full capacity	seconds		
ramp rate AE, full capacity	minutes		
ramp rate SOE, full capacity	hours to one day		
Stack lifetime AE, operating hours (thousands)	60-90	90-100	100-150
Stack lifetime PEM, operating hours (thousands)	30-90	60-90	100-150
Stack lifetime SOE, operating hours (thousands)	10-30	40-60	75-100

Source: various

Table A. 10: Hydrogen from natural gas technical input parameters

	SMR	ATR
Efficiency with CCS (kWh-th H_2 HHV/kWh-th NG HHV)	73.80%	73.10%
CO_2 capture rate	90%	95%
NG emission factor, kg CO2e/kWh-th HHV	0.184	0.184
H_2 emission factor, kg CO2e/kWh-th HHV	0.249	0.252
CO2 captured, kg CO2e/kWh-th HHV	0.2244	0.2391
CO2 emitted, kg CO2e/kWh-th HHV	0.0249	0.0126
Footprint m2/kW H_2 HHV	0.107	0.055
Raw water requirement, litres/kWh H_2 HHV	0.12	0.18
Sea water requirement, litres/kWh H_2 HHV	30	0
Waste water litres/kWh H_2 HHV	0.06	0
Return sea water litres/kWh H_2 HHV	30	0
minimum load factor	70%	70%
ramp rate, %/hour	0.417%	0.417%

Source: various

Table A. 11: Hydrogen to e-fuels technical input parameters

H_2 to e-gas efficiency	80.000%
CO_2 required, tCO_2/kWh(methane)	0.000198
H_2 to e-liquid efficiency	79.900%
CO_2 required, tCO_2/kWh(PtL)	0.000251

Source: Agora (2018)[40]

A.2.3. Power sector

This section reports our main assumptions for power generation technologies we used in our modelling. Note that we also consider CCGT running on H_2 and have assumed the same techno-economic parameters for H_2-based CCGT as "Gas combined cycle advanced no CCS" in the tables below.

Table A. 12: Power generation techno-economic input parameters

Power generation technologies	Overnight investment cost, EUR/kW				Fixed O&M, EUR/kW/yr				Variable O&M, EUR/MWh			
	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Pulverised Lignite Supercritical CCS post combustion	3600	3420	3250	3200	68.6	65.0	61.6	60.6	6.24	6.02	4.28	4.04
Integrated Gasification Coal CCS pre combustion	3550	3350	3250	3150	69.8	65.9	63.9	61.9	7.74	7.44	7.17	6.91
Integrated Gasification Lignite CCS pre combustion	3950	3750	3650	3550	77.6	73.6	71.6	69.6	6.38	6.15	5.95	5.75
Pulverised Coal Supercritical CCS oxyfuel	3400	3150	2890	2850	75.5	64.7	55.5	53.9	6.06	5.86	5.64	5.59
Pulverised Lignite Supercritical CCS oxyfuel	3800	3550	3350	3300	72.6	67.6	63.6	62.6	6.94	6.70	4.76	4.50
Gas combined cycle advanced no CCS	820	770	750	750	15.00	15.00	15.00	15.00	1.99	1.90	1.81	1.73
Gas combined cycle CCS post combustion	1750	1625	1500	1500	41.0	38.2	35.0	34.3	3.10	2.99	2.88	2.78
Gas combined cycle CCS oxyfuel	2013	1820	1650	1628	46.3	42.1	38.0	36.8	3.45	3.34	3.20	3.07
Steam Turbine Biomass Solid Conventional	2000	1800	1700	1700	47.5	40.1	39.2	38.4	3.56	3.56	3.56	3.56
Steam Turbine Biomass Solid Conventional w. CCS	3800	3450	3090	3000	81.5	69.1	63.0	61.4	5.99	5.91	5.82	5.80
Nuclear III gen. (no economies of scale)	6000	6000	6000	6000	120.0	115.0	108.0	105.0	6.40	7.40	7.60	7.80
Wind onshore*	1483	1343	1260	1213	14.0	14.0	13.0	12.0	0.18	0.18	0.18	0.18
Wind offshore (with transmission)*	2612	2061	1632	1203	42.0	31.0	29.0	28.0	0.39	0.39	0.39	0.39
Utility scale Solar PV*	718	494	364	308	12.6	10.8	10.0	9.2	0.00	0.00	0.00	0.00
Residential Solar PV*	1306	989	765	606	24.0	17.0	15.0	13.0	0.00	0.00	0.00	0.00
Tidal and waves	6100	3100	2025	1975	39.6	33.3	28.0	23.5	0.10	0.10	0.10	0.10

[40] Agora_2018_The Future Cost of Electricity based fuels

Run of River	2450	2400	2350	2300	8.9	8.2	8.2	8.1	0.00	0.00	0.00	0.00
Geothermal Medium Enthalpy	4970	4586	3749	3306	95	95	92	92	0.32	0.32	0.32	0.32

*Source: Asset (2018); *BNEF*

Table A. 13: Power generation techno-economic input parameters (continued)

Power generation technologies	Electrical efficiency (net)				Self-consumption of electricity, %				Technical lifetime, years	Capacity Factor (equivalent full load operation), %			
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**		**2020**	**2030**	**2040**	**2050**
Pulverised Lignite Supercritical CCS post combustion	0.32	0.33	0.34	0.35	33%	30%	28%	28%	40	80%	80%	80%	80%
Integrated Gasification Coal CCS pre combustion	0.37	0.39	0.4	0.41	32%	27%	25%	25%	30	80%	80%	80%	80%
Integrated Gasification Lignite CCS pre combustion	0.34	0.37	0.38	0.39	35%	29%	26%	26%	30	80%	80%	80%	80%
Pulverised Coal Supercritical CCS oxyfuel	0.36	0.37	0.38	0.38	32%	27%	24%	24%	40	80%	80%	80%	80%
Pulverised Lignite Supercritical CCS oxyfuel	0.32	0.33	0.34	0.35	34%	28%	25%	25%	40	80%	80%	80%	80%
Gas combined cycle advanced no CCS	0.60	0.61	0.62	0.63	2.0%	2.0%	2.0%	2.0%	30	35%	35%	35%	35%
Gas combined cycle CCS post combustion	0.43	0.46	0.48	0.49	34%	18%	16%	16%	30	80%	80%	80%	80%
Gas combined cycle CCS oxyfuel	0.4	0.46	0.49	0.5	27%	19%	15%	14%	30	80%	80%	80%	80%
Steam Turbine Biomass Solid Conventional	0.35	0.39	0.4	0.4	10%	10%	10%	10%	40	80%	80%	80%	80%
Steam Turbine Biomass Solid Conventional w. CCS	0.27	0.31	0.32	0.32	34%	29%	27%	26%	40	80%	80%	80%	80%
Nuclear III gen. (no economies of scale)	0.38	0.38	0.38	0.38	5%	5%	5%	5%	60	85%	85%	85%	85%
Wind onshore*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30	based on 30 years of hourly			

Wind offshore (with transmission)*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30	data from JRC EC study			
Utility scale Solar PV*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30				
Residential Solar PV*	1.00	1.00	1.00	1.00	0%	0%	0%	0%	30				
Tidal and waves	1.00	1.00	1.00	1.00	0%	0%	0%	0%	80	24%	33%	36%	36%
Run of River	1.00	1.00	1.00	1.00	0%	0%	0%	0%	50	22%	22%	22%	22%
Geothermal Medium Enthalpy	0.1	0.1	0.1	0.1	0	0	0	0	30	45%	45%	45%	45%

*Source: Asset (2018); * BNEF*

A.3. Networks

In our model, we have a simplified representation of networks in that we do not consider engineering details which would make this economic model intractable due to the level details we model in other areas. Instead, we treat transmission and distribution networks for each of markets/countries we model as "copper plate". This simplification is necessary given the scope of sectors and technologies. This section outlines our cost assumptions for the networks we model.

Costs for CH_4, H_2, CO_2 networks (distribution and transmission) are based on ASSET 2018 project for EC (see Table A. 14). Clearly, these values represent academic estimates and have not been benchmarked with actual cost data, mainly because the real cost of building and running a hydrogen or CO2 network is subject to great uncertainty. Note that the ASSET project did not have costs information for electricity networks.

Table A. 14: Gases network costs

	Investment cost per unit of capacity (€/kW-output)			Fixed O&M cost per unit of capacity (€/kW-output)			Variable cost €/MWh		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
CH_4 Transmission Network	126	126	126	5	5	5	0.7	0.7	0.7
CH_4 Distribution Network	552	552	552	22	22	22	3.2	3.2	3.2
H_2 Transmission 60bar	178	173	166	7	7	7	1	1	1
H_2 Distribution 10 bar	723	723	723	29	29	29	4.1	4.1	4.1
CO_2 Transmission network (per tCO_2)	23	23	23	1.3	1.3	1.3	1	1	1

Source: Asset (2018)

An alternative approach was developed for electricity networks whereby we estimate recognised cost for existing electricity transmission and distribution networks and apply historic (2015) "de-rated"[41] peak flow to calculate "per peak unit" (GW) cost. Where data on recognised cost is not available we use Eurostat electricity network cost component to scale with the recognised costs that we have gathered from NRAs. Note that we remove the cost of capital from the recognised cost base and then apply 4% interest rate to get to the uniform cost of capital for all network types and countries in our model.

Table A. 15 shows results of our calculations with 4% interest rate applied.

Note also that the two sets of costs (Table A. 14 and Table A. 15) are not directly comparable as such because electricity network include all costs components (such as capex and opex) while the gases network costs have an explicit break down in terms of costs components. Further, while the electricity costs in Table A. 15 is annuitized costs, gases network costs are total costs over the life

[41] Assuming a 10% margin above the historic peak flow to account for electricity system security margin in electricity network planning

time of a gas network. For example, we assume 50 years of life time for all networks and therefore with 4% interest rate, annuity factor applied to the gases network cost is ca. 0.04655; therefore, taking CH_4 transmission (ultimate cost) capex and fixed O&M costs as an example, we have 0.04655 x (126 + 5) = 6.098 €/kW/year for CH_4 transmission network costs which is still not very comparable to the electricity costs as we still have to account for variable O&M costs for gases network, which is "flow-based" cost component.

Table A. 15: Electricity network costs (€/kW/year)

	Transmission	Distribution
UK	53.79	101.62
Ireland	28.44	171.41
Nordic	20.91	148.33
BE	22.49	194.78
DE	34.59	151.90
NL	29.62	135.04
FR	31.14	120.04
IT	22.68	113.70
Baltics	54.38	114.31
PL	36.95	135.46
Eastern Europe	64.66	149.01
Central Europe	25.48	149.63
South East Europe	27.36	92.13
Iberia	27.45	132.15

Source: own calculations based on Eurostat, ARERA, EC JRC TIMES datasets

Further, the cross-border electricity interconnection costs have also been taken into account because the model expands capacity also for cross-border trade in CH_4, H_2, electricity, and CO_2. For CH_4, H_2 and CO2 this is based on costs in Table A. 14. For cross-border electricity interconnection we rely on EC JRC TIMES costs which different between three types of interconnection depending on distance as follows:

1. Short distance interconnection: 57,500,000 EUR/GW
2. Medium distance interconnection: 414,000,000 EUR/GW
3. Long distance interconnection: 828,000,000 EUR/GW

A.4. Storage

This section outlines our techno-economic assumptions for storage technologies.

Table A. 16: Energy storage costs

	Investment cost per unit of energy stored per year (€/MWh)			Fixed O&M costs (€/kW)			Variable, fuel and emissions cost per unit of stored energy (€/MWh)		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
Compressed Air Energy Storage	125,000	112,500	110,931	39	35	34	-	-	-
Flywheel	1,750,000	1,575,000	1,553,029	52.5	47.3	46.6	0	0	0
Large-scale batteries*	563,522	156,741	126,886	40.5	15	13.1	0	0	0
Small-scale batteries*	767,846	248,174	194,061	16.9	6.3	5.5	0	0	0
Pumping	100,000	90,000	88,745	22.5	20.3	20	0	0	0
Underground Hydrogen Storage	5,340	3,936	3,821	0	0	0	0.6	0.7	0.8
Pressurised tanks - Hydrogen storage	6,000	4,800	4,659	0	0	0	0.6	0.7	0.8
Liquid Hydrogen Storage - Cryogenic Storage	8,455	6,800	4,000	0	0	0	0.7	0.9	1
Metal Hydrides - Hydrogen Storage	12,700	11,430	11,271	0	0	0	0.5	0.7	0.8
Thermal Storage Technology	100,000	90,000	88,745	100	97.2	95.8	0	0	0
LNG Storage Gas	135	135	135	0	0	0	0.6	0.7	0.8
Underground NG Storage	33	33	33	0	0	0	0.6	0.7	0.8

*Source: Asset (2018) ; * BNEF*

Table A. 17: CO_2 storage costs

	Investment cost per ton CO2 stored per year (€/tCO₂)			Investment cost per ton CO2 (€/tCO₂)			€/tCO₂ liquefaction cost		
	2015	**2030**	**2050**	**2015**	**2030**	**2050**	**2015**	**2030**	**2050**
Liquid CO_2 storage tank	1000	1000	1000	15	15	15	3.18	3.18	3.18
Underground CO_2 storage*	33	33	33	-	-	-	1	1	1

*Source: Asset (2018); * our own assumption*

A.5. Buildings end-use heat technologies

Table A. 18: Purchase cost of building heat technologies

	Purchasing cost, EUR/kW						
	Current	2030			2050		
		from	A	to	From	B	to
Boilers condensing gas	195	191	224	273	171	210	237
Heat pump air source	784	603	835	1080	267	673	1030
Hybrid heat pump*	600	510	855	1200	226	689	1144
Boilers condensing H_2**		191	224	273	171	210	237

*Source: Asset (2018); * GRDF; **our own assumption*

For our modelling of 2050, we use purchase cost in column B (Table A. 18).

Table A. 19: Efficiencies of building heat technologies

	Efficiency						
	Current	2030			2050		
		from		to	From		to
Boilers condensing gas	0.87	0.89	0.93	0.96	0.90	0.98	1.03
Boilers condensing H_2*		0.89	0.93	0.96	0.90	0.98	1.03

*Source: Asset (2018); *our own assumption*

We use 0.98 as an efficiency of condensing boilers (both for gas and H_2-based boilers) for modelling a 2050 energy system. Performance of heat pumps depends on outside temperature with the following relationship[42]: **Heat pump efficiency = 0.07T + 2.07,** where T is outside temperature; thus, for example, when outside temperature is 0 C° heat pump's efficiency is 2.07.

A.6. Road transport technologies

For the road transport modes, we the following (ultimate) values for costs and efficiencies (Table A. 20 Table A. 21).

Table A. 20: Technical and economic assumptions for transportation means

	Fuel	Purchasing cost			Fixed O&M costs		
		EUR/vehicle			**EUR/vehicle/year**		
		2015	**2030**	**2050**	**2015**	**2030**	**2050**
Diesel Public road transport	Diesel	277,090	282,107	293,908	8,857	8,857	8,857
NGS Public road transport	Gas	301,283	304,418	309,122	9,557	9,557	9,557

[42] Zhang, X., Strbac, G., Teng, F., & Djapic, P. (2018). Economic assessment of alternative heat decarbonisation strategies through coordinated operation with electricity system–UK case study. *Appl. Energy*, 222, 79-91.

Electric Public road transport	Electricity	351,517	310,375	312,790	14,054	10,831	10,831
H_2 Public road transport	Hydrogen	377,386	344,376	322,856	16,397	11,934	11,934
Diesel Private cars	Diesel	22,795	22,869	24,942	1,450	1,450	1,450
Gasoline Private cars	Gasoline	19,403	20,077	22,623	1,300	1,300	1,300
NGS Private cars	Gas	21,484	22,891	24,704	1,380	1,380	1,380
Electric Private cars	Electricity	48,010	25,956	24,685	1,650	1,272	1,272
H_2 Private cars	Hydrogen	82,130	38,729	28,616	1,718	1,250	1,250
Diesel Heavy duty vehicles	Diesel	105,926	111,777	134,001	6,527	6,527	6,527
NGS Heavy duty vehicles	Gas	118,980	124,830	147,054	7,034	7,034	7,034
Electric Heavy-duty vehicles	Electricity	230,600	151,929	157,320	10,180	7,846	7,846
H_2 Heavy duty vehicles	Hydrogen	240,372	193,252	172,662	10,780	7,846	7,846

Source: Asset (2018)

Table A. 21: Technical and economic assumptions for transportation means (cont-d)

	Fuel	Variable Non-fuel Cost			Specific energy consumption		
		EUR/vehicle-km			**kWh/vehicle - km**		
		2015	**2030**	**2050**	**2015**	**2030**	**2050**
Diesel Public road transport	Diesel	0.89	0.89	0.89	3.49	3.22	2.85
NGS Public road transport	Gas	0.89	0.89	0.89	3.89	3.72	3.47
Electric Public road transport	Electricity	0.89	0.89	0.89	1	0.97	0.96
H_2 Public road transport	Hydrogen	0.89	0.89	0.89	2.3	2.04	1.93
Diesel Private cars	Diesel	0.09	0.09	0.09	0.47	0.32	0.27
Gasoline Private cars	Gasoline	0.09	0.09	0.09	0.56	0.38	0.31
NGS Private cars	Gas	0.09	0.09	0.09	0.52	0.48	0.45
Electric Private cars	Electricity	0.09	0.09	0.09	0.19	0.13	0.12
H_2 Private cars	Hydrogen	0.09	0.09	0.09	0.38	0.3	0.28
Diesel Heavy duty vehicles	Diesel	0.59	0.59	0.59	2.74	2.28	1.89
NGS Heavy duty vehicles	Gas	0.59	0.59	0.59	3.39	2.83	2.34
Electric Heavy-duty vehicles	Electricity	0.59	0.59	0.59	1.32	1.29	1.28
H_2 Heavy duty vehicles	Hydrogen	0.59	0.59	0.59	1.88	1.64	1.55

Source: Asset (2018)

A.7. GHG emissions

This section outlines GHG emissions assumptions in this model.

Table A. 22: GHG emissions for the baseline scenarios from EC LTS

	Baseline	COMBO	1.5TECH	Endogenous
Non-CO_2 other	205.5	60.5	60.5	No
Non-CO_2 agriculture	404.2	277	276.9	No
Residential	129.6	19.3	11.8	Yes
Tertiary	77.7	23	19.3	Yes
Transport	666.9	256.8	85.6	Yes*
Industry	483.6	175.6	109.8	No
Power	246.3	61.9	37.5	Yes
LULUCF	-236.3	-248	-316.9	No
Carbon Removal Technologies	0	-6	-258.4	Yes*

Source: PRIMES model & EC LTS

Table A. 23: Share of CO_2 emissions in EU28 total (2017)

	Agriculture non energy	Industry non energy	LULUCF
Baltics	2%	1%	3%
BE	2%	5%	1%
Central Europe	2%	5%	2%
DE	15%	17%	10%
Eastern Europe	4%	9%	5%
FR	17%	12%	11%
UK	9%	8%	4%
Iberia	11%	10%	11%
Ireland	4%	1%	-1%
IT	7%	9%	8%
NL	4%	3%	-2%
Nordic	6%	4%	21%
PL	7%	7%	13%
South East Europe	8%	10%	14%

Source: European Environment Agency (2019) "Annual European Union greenhouse gas inventory 1990–2017 and inventory report 2019" (https://www.eea.europa.eu/publications/european-union-greenhouse-gas-inventory-2019/annex-v-summary-tables.zip/view)

A.8. EU level and regional/country specific constraints

This section outlines lower and upper bounds that we have implemented for various energy resources and technologies in all our scenarios (NZ and 90% scenarios), primarily to:

1. Reflect resource constraints (such as how much sustainable bioenergy is available or how much offshore wind capacity can be installed in various locations etc.);
2. Reflect capacity build rate and implicitly reflecting also supply chains for various traditional as well as emerging energy technologies

We start with EU level constraints and then proceed with country-specific bounds imposed in our modelling.

Thus, upper bounds for power generation capacity at EU aggregate level was implemented for the following technologies, based on EC 1.5 TECH results:

1. Tidal and wave (11.9 GW); geothermal (5.04 GW); hydro (227.9 GW);
2. Battery storage (69 GW); Hydro pumped storage (52.4 GW).

Similarly, the upper bound for uptake of EVs in 2050 (in line with EC 1.5 TECH) was implemented for the total EU vehicle stock as follows:

1. 80% of total passenger car stock;
2. 83.5% of total public transport vehicle stock;
3. 8% of total HGV stock.

At the EU MS level we have implemented both lower and upper bounds (for 2050) for electricity generation technologies. The lower bound on electricity generation reflects the installed capacity to date (2020). The reason for imposing this lower bound is that we assume a 2050 electricity system will not start from scratch but will at least have capacity mix in line with today's system. This does not however reflect any potential policy changes in respect of nuclear generation closure. Other than nuclear, all other technologies that we consider to have lower bounds are all renewables and hence power system will have to be largely decarbonised the lower bounds shown in Table A. 24 will not be binding in practice. It is however important to reflect sunk capacity of such large installations as hydro in the Nordic countries, Central and Southern Europe as lower bounds.

Table A. 24: Lower bounds for electricity generation capacity in 2050 for 1.5 TECH and COMBO scenarios (GW)

	Nuclear	Wind Onshore	Wind Offshore	Utility Solar PV	Residential Solar PV	Tidal &Wave	Hydro	Geothermal	Hydro Pumped Storage
UK	8.21	12.84	10.37	5.84	10.84		1.88		4.05
Nordic	11.38	17.12	1.70	0.39	0.89		48.79		
BE	5.93	2.25	1.67	0.05	4.83		0.18		1.31
NL	0.49	3.97	1.71	1.23	5.94		0.04		
FR	63.13	15.66		5.03	6.54	0.24	19.23		5.02
Eastern Europe	7.88	0.65		1.79	2.81		2.77	0.00	2.09
Central Europe	3.67	3.14		0.10	1.92		15.32		9.97

South East Europe	3.30	7.57		3.55	2.56		13.05	0.01	1.84
Iberia	7.12	29.63		8.91	2.24		24.67		8.47
Ireland		1.92					0.22	0.02	0.29
DE		53.40	7.71	15.27	43.10		5.26	0.04	9.42
IT		10.22		1.22	4.91		14.90	0.87	7.28
Baltics		0.92		0.10	0.18		1.68		0.90
PL		5.95		0.35	1.30		0.60		1.78

Table A. 25 outlines upper bounds for electricity generation applied to our countries and regions in the two baseline scenarios. For Italy, Germany, France, and Belgium the bounds were given by the sponsors of this project while for all other countries and regions the bounds were derived from either EC JRC ENSPRESSO study or as the highest historical build rate of more than 20 years of capacity expansions.

Table A. 25: Upper bounds for electricity generation capacity in 2050 for 1.5 TECH and COMBO scenarios

	Biomass	Biomass CCS	Wind Onshore	Wind Offshore	Tidal & Wave	Hydro
UK			24.56	103.61		
Ireland			45.59	0.99		
Nordic			223.67	79.61		
BE		0.50	9.00	13.00		
DE			210.00	64.00		
NL			48.87	47.75		
FR			80.00	80.00	13.24	
IT	9.00	10.00	31.00	17.00	3.00	22.00
Baltics			235.05	19.19		
PL			105.31	12.31		
Eastern Europe			270.73			
Central Europe			21.77			
South East Europe			76.89	11.31		
Iberia			131.74	0.66		

APPENDIX 2

Appendix 2 – Detailed modelling results – Baseline scenarios

This appendix outlines detailed modelling results for the two baselines – NZ and 90% scenarios – we modelled. It tabulates energy and GHG emissions balance for NZ, 90%, NZ-e and NZ-g scenarios (Table A. 26, Table A. *27*, Table A. 28, Table A. 29).

Table A. 26: Energy and GHG emissions balance: NZ baseline scenario

	Biomass	Biomethane	CO2	E-gas	Electricity	Hydrogen	Natural gas	Diesel	Uranium	E-liquids	Coal bit	Coal lignite	Gasoline
Ar_primary_supply	**1769**	**1150**	**0**	**0**	**0**	**0**	**907**	**290**	**2065**	**0**	**0**	**0**	**45**
Ar_Export_flow	**-566**	**-207**	**-63**	**-76**	**-1168**	**-25**	**0**	**0**	**0**	**-392**	**0**	**0**	**0**
Ar_Import_flow	**566**	**207**	**63**	**76**	**1168**	**25**	**0**	**0**	**0**	**392**	**0**	**0**	**0**
Ar_StockChange	**0**	**0**	**-406**	**0**	**0**	**-1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Underground_CO2_Stor	0	0	-154	0	0	0	0	0	0	0	0	0	0
Underground_CO2_Stor_negative	0	0	-253	0	0	0	0	0	0	0	0	0	0
Ar_Transformation	**-1252**	**-91**	**383**	**611**	**4733**	**922**	**-708**	**0**	**-2065**	**429**	**0**	**0**	**0**
CCGT_advanced	0	-91	19	-4	60	0	0	0	0	0	0	0	0
CCGT_advanced_H_2	0	0	0	0	0	0	0	0	0	0	0	0	0
CCGT_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
CCGT_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrolysis_Alkaline	0	0	0	0	-1910	1568	0	0	0	0	0	0	0
Electrolysis_PEM	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrolysis_SOEC	0	0	0	0	-150	142	0	0	0	0	0	0	0
Hydro_RoR	0	0	0	0	189	0	0	0	0	0	0	0	0
IG_Coal_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IG_Lignite_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
NG_ATR_CCS	0	0	145	0	0	518	-708	0	0	0	0	0	0
NG_SMR_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear_Gen3	0	0	0	0	785	0	0	0	-2065	0	0	0	0
Residential_SolarPV	0	0	0	0	503	0	0	0	0	0	0	0	0
SC_Coal_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0

SC_Lignite_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
SC_Lignite_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0
ST_Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0
ST_Biomass_CCS	-1252	0	448	0	401	0	0	0	0	0	0	0	0
Tidal_Wave	0	0	0	0	24	0	0	0	0	0	0	0	0
Utility_SolarPV	0	0	0	0	822	0	0	0	0	0	0	0	0
Wind_Offshore	0	0	0	0	1360	0	0	0	0	0	0	0	0
Wind_Onshore	0	0	0	0	2672	0	0	0	0	0	0	0	0
H_2_Methanation_eliquids	0	0	-108	0	0	-537	0	0	0	429	0	0	0
H_2_Methanation_egas	0	0	-122	615	0	-769	0	0	0	0	0	0	0
DAC	0	0	0	0	-25	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	2	0	0	0	0	0	0	0	0
Ar_FinalConsumption	**-517**	**-1059**	**511**	**-611**	**-4175**	**-921**	**-199**	**-290**	**0**	**-429**	**0**	**0**	**-45**
Buildings	-38	-711	173	-40	-2063	-66	-152	0	0	-169	0	0	0
Industry	-291	-116	110	-124	-1381	-337	-47	0	0	0	0	0	0
Trans_Cars	0	-114	80	-221	-507	0	0	0	0	0	0	0	-45
Trans_Public	0	0	0	0	-35	-12	0	0	0	0	0	0	0
Trans_HGV	0	-118	69	-221	-60	-504	0	0	0	0	0	0	0
Trans_Oth	-189	-1	78	-4	-129	-1	0	-290	0	-260	0	0	0
Ar_CO2_neutral_emissions	**0**	**0**	**-518**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Ar_LULUCF_CO2_emissions	**0**	**0**	**-307**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Ar_non_CO2_emissions	**0**	**0**	**337**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table A. 27: Energy and GHG emissions balance: 90% baseline scenario

	Biomass	Biomethane	CO2	E-gas	Electricity	Hydrogen	Natural_gas	Diesel	Uranium	E-liquids	Coal_bit	Coal_lignite	Gasoline
Ar_primary_supply	**1492**	**1040**	**0**	**0**	**0**	**0**	**829**	**661**	**2078**	**0**	**0**	**0**	**305**
Ar_Export_flow	**-417**	**-158**	**-62**	**-12**	**-1049**	**0**	**0**	**0**	**0**	**-454**	**0**	**0**	**0**
Ar_Import_flow	**417**	**158**	**62**	**12**	**1049**	**0**	**0**	**0**	**0**	**454**	**0**	**0**	**0**
Ar_StockChange	**0**	**0**	**-100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Underground_CO2_Stor	0	0	-80	0	0	0	0	0	0	0	0	0	0
Underground_CO2_Stor_negative	0	0	-21	0	0	0	0	0	0	0	0	0	0
Ar_Transformation	**-984**	**0**	**181**	**647**	**4573**	**210**	**-505**	**0**	**-2078**	**582**	**0**	**0**	**0**
CCGT_advanced	0	0	22	-11	67	0	-96	0	0	0	0	0	0
CCGT_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
CCGT_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrolysis_Alkaline	0	0	0	0	-1780	1462	0	0	0	0	0	0	0
Electrolysis_PEM	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrolysis_SOEC	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro_RoR	0	0	0	0	242	0	0	0	0	0	0	0	0
IG_Coal_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
NG_ATR_CCS	0	0	84	0	0	300	-410	0	0	0	0	0	0
NG_SMR_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear_Gen3	0	0	0	0	790	0	0	0	-2078	0	0	0	0
Residential_SolarPV	0	0	0	0	453	0	0	0	0	0	0	0	0
SC_Coal_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0
SC_Lignite_CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
SC_Lignite_CCS_oxyf	0	0	0	0	0	0	0	0	0	0	0	0	0
ST_Biomass	-43	0	15	0	17	0	0	0	0	0	0	0	0

ST_Biomass_CCS	-940	0	336	0	301	0	0	0	0	0	0	0	0
Tidal_Wave	0	0	0	0	24	0	0	0	0	0	0	0	0
Utility_SolarPV	0	0	0	0	733	0	0	0	0	0	0	0	0
Wind_Offshore	0	0	0	0	1122	0	0	0	0	0	0	0	0
Wind_Onshore	0	0	0	0	2601	0	0	0	0	0	0	0	0
H_2_Methanation_eliquids	0	0	-146	0	0	-728	0	0	0	582	0	0	0
H_2_Methanation_egas	0	0	-130	658	0	-823	0	0	0	0	0	0	0
Geothermal	0	0	0	0	3	0	0	0	0	0	0	0	0
Ar_FinalConsumption	**-508**	**-1040**	**822**	**-647**	**-4093**	**-210**	**-323**	**-661**	**0**	**-582**	**0**	**0**	**-305**
Buildings	-38	-633	171	-51	-2079	-21	-207	0	0	-169	0	0	0
Industry	-302	-174	176	-200	-1351	-174	-116	0	0	0	0	0	0
Trans_Cars	0	0	76	0	-507	0	0	0	0	0	0	0	-305
Trans_Public	0	0	0	0	-35	-13	0	0	0	0	0	0	0
Trans_HGV	0	-232	256	-393	0	0	0	-130	0	-344	0	0	0
Trans_Oth	-168	-1	143	-4	-120	-1	0	-530	0	-68	0	0	0
Ar_CO2_neutral_emissions	**0**	**0**	**-427**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Ar_LULUCF_CO2_emissions	**0**	**0**	**-240**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Ar_non_CO2_emissions	**0**	**0**	**337**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table A. 28: Energy and GHG emissions balance: NZ-e scenario

	Biomass	Biomethane	CO2	E-gas	Electricity	Hydrogen	Natural_gas	Diesel	Uranium	E-liquids	Coal_bit	Coal_lignite	Gasoline
Ar_primary_supply	**1,375**	**359**	**-**	**-**	**-**	**-**	**152**	**332**	**2,007**	**-**	**-0**	**0**	**0**
Ar_Export_flow	**-568**	**-111**	**-81**	**-25**	**-1,486**	**-25**	**-0**	**-**	**-**	**-601**	**-**	**-**	**-**
Ar_Import_flow	**568**	**111**	**81**	**25**	**1,486**	**25**	**0**	**-**	**-**	**601**	**-**	**-**	**-**
Ar_StockChange	**-**	**0**	**-195**	**0**	**-0**	**-19**	**0**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_Transformation	**-1,148**	**-0**	**211**	**191**	**6,185**	**696**	**-**	**-**	**-2,007**	**645**	**-**	**-**	**-**
CCGT_advanced	-	-0	-	-0	0	-	-	-	-	-	-	-	-
CCGT_advanced_H2	-	-	-	-	-	-0	-	-	-	-	-	-	-
Electrolysis_Alkaline	-	-	-	-	-2,123	1,743	-	-	-	-	-	-	-
Electrolysis_PEM	-	-	-	-	-0	0	-	-	-	-	-	-	-
Electrolysis_SOEC	-	-	-	-	-0	0	-	-	-	-	-	-	-
Hydro_RoR	-	-	-	-	94	-	-	-	-	-	-	-	-
Nuclear_Gen3	-	-	-	-	763	-	-	-	-2,007	-	-	-	-
Residential_SolarPV	-	-	-	-	523	-	-	-	-	-	-	-	-
ST_Biomass_CCS	-1,148	-	411	-	367	-	-	-	-	-	-	-	-
Tidal_Wave	-	-	-	-	0	-	-	-	-	-	-	-	-
Utility_SolarPV	-	-	-	-	281	-	-	-	-	-	-	-	-
Wind_Offshore	-	-	-	-	2,180	-	-	-	-	-	-	-	-
Wind_Onshore	-	-	-	-	4,100	-	-	-	-	-	-	-	-
H2_Methanation_eliquids	-	-	-162	-	-	-808	-	-	-	645	-	-	-

H2_Methanation_egas	-	-	-38	191	-	-239	-	-	-	-	-	-	-
DAC	-	-	-	-	-1	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	1	-	-	-	-	-	-	-	-
Ar_FinalConsumption	**-227**	**-359**	**323**	**-191**	**-5,402**	**-677**	**-152**	**-332**	**-**	**-645**	**-**	**-**	**-0**
Buildings	-38	-315	98	-67	-2,181	-338	-152	-	-	-169	-	-	-
Industry	-	-	43	-	-1,959	-337	-	-	-	-	-	-	-
Trans_Cars	-	-	-	-	-633	-	-	-	-	-	-	-	-0
Trans_Public	-	-	-	-	-42	-0	-	-	-	-	-	-	-
Trans_HGV	-	-43	103	-121	-457	-0	-0	-42	-	-216	-	-	-
Trans_Oth	-189	-1	78	-4	-129	-1	-	-290	-	-260	-	-	-
Ar_CO2_neutral_emissions	**-**	**-**	**-370**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_LULUCF_CO2_emissions	**-**	**-**	**-307**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_non_CO2_emissions	**-**	**-**	**337**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Table A. 29: Energy and GHG emissions balance: NZ-g scenario

	Biomass	**Biomethane**	**CO2**	**E-gas**	**Electricity**	**Hydrogen**	**Natural_gas**	**Diesel**	**Uranium**	**E-liquids**	**Coal_bit**	**Coal_lignite**	**Gasoline**
Ar_primary_supply	**3,538**	**2,300**	**-**	**-**	**-**	**-**	**4,149**	**300**	**2,121**	**-**	**0**	**0**	**35**
Ar_Export_flow	**-1,634**	**-181**	**-43**	**-1**	**-643**	**-0**	**-0**	**-**	**-**	**-496**	**-**	**-**	**-**
Ar_Import_flow	**1,634**	**181**	**43**	**1**	**643**	**0**	**0**	**-**	**-**	**496**	**-**	**-**	**-**
Ar_StockChange	**-**	**0**	**-1,215**	**0**	**-0**	**-0**	**0**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_Transformation	**-3,021**	**-364**	**1,494**	**597**	**3,757**	**731**	**-3,951**	**-**	**-2,121**	**1,399**	**-0**	**-0**	**-**

CCGT_advanced	-	- 364	75	- 3	231	-	- 0	-	-	-	-	-	-
CCGT_advanced_H2	-	-	-	-	0	- 0	-	-	-	-	-	-	-
CCGT_CCS	-	- 0	0	- 0	0	-	- 0	-	-	-	-	-	-
CCGT_CCS_oxyf	-	- 0	0	- 0	0	-	- 0	-	-	-	-	-	-
Electrolysis_Alkaline	-	-	-	-	- 419	344	-	-	-	-	-	-	-
Electrolysis_PEM	-	-	-	-	- 0	0	-	-	-	-	-	-	-
Electrolysis_SOEC	-	-	-	-	- 0	0	-	-	-	-	-	-	-
Hydro_RoR	-	-	-	-	274	-	-	-	-	-	-	-	-
IG_Coal_CCS	-	-	0	-	0	-	-	-	-	-	- 0	-	-
IG_Lignite_CCS	-	-	0	-	0	-	-	-	-	-	-	- 0	-
NG_ATR_CCS	-	-	808	-	-	2,888	- 3,951	-	-	-	-	-	-
NG_SMR_CCS	-	-	0	-	-	0	- 0	-	-	-	-	-	-
Nuclear_Gen3	-	-	-	-	806	-	-	-	- 2,121	-	-	-	-
Residential_SolarPV	-	-	-	-	503	-	-	-	-	-	-	-	-
SC_Coal_CCS_oxyf	-	-	0	-	0	-	-	-	-	-	- 0	-	-
SC_Lignite_CCS	-	-	0	-	0	-	-	-	-	-	-	- 0	-
SC_Lignite_CCS_oxyf	-	-	0	-	0	-	-	-	-	-	-	- 0	-
ST_Biomass	- 663	-	237	-	265	-	-	-	-	-	-	-	-
ST_Biomass_CCS	- 2,358	-	844	-	754	-	-	-	-	-	-	-	-
Tidal_Wave	-	-	-	-	36	-	-	-	-	-	-	-	-
Utility_SolarPV	-	-	-	-	251	-	-	-	-	-	-	-	-
Wind_Offshore													

	-	-	-	-	639	-	-	-	-	-	-	-	-
Wind_Onshore	-	-	-	-	413	-	-	-	-	-	-	-	-
H2_Methanation_eliquids	-	-	-351	-	-	-1,751	-	-	-	1,399	-	-	-
H2_Methanation_egas	-	-	-119	600	-	-750	-	-	-	-	-	-	-
DAC	-	-	-	-	-0	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	3	-	-	-	-	-	-	-	-
Ar_FinalConsumption	**-517**	**-1,936**	**1,032**	**-597**	**-3,229**	**-731**	**-199**	**-300**	**-**	**-1,399**	**-**	**-**	**-35**
Buildings	-38	-1,073	242	-13	-1,844	-202	-152	-	-	-169	-	-	-
Industry	-291	-271	256	-279	-919	-492	-47	-	-	-	-	-	-
Trans_Cars	-	-508	197	-296	-316	-0	-0	-1	-	-87	-	-	-35
Trans_Public	-	-0	0	-0	-21	-36	-	-0	-	-0	-	-	-
Trans_HGV	-	-83	259	-6	-0	-0	-	-8	-	-883	-	-	-
Trans_Oth	-189	-1	78	-4	-129	-1	-	-290	-	-260	-	-	-
Ar_CO2_neutral_emissions	**-**	**-**	**-1,341**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_LULUCF_CO2_emissions	**-**	**-**	**-307**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Ar_non_CO2_emissions	**-**	**-**	**337**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

APPENDIX 3

Appendix 3 – Detailed modelling results – Sensitivity analyses

This appendix outlines detailed results of our sensitivity analyses. It focuses on the impacts of changing costs assumptions of key energy technologies on final consumption mix. We outline the impact of sensitivities on final consumption mix for our NZ Scenario (Table A. *30*)

Table A. 30: Impact of energy technologies costs on final consumption structure: NZ scenario (2050)

	Biomethane	Diesel	E-gas	Electricity	E-liquids	Gasoline	H_2	CH_4	Total
NZ Baseline, TWh	**1,059**	**290**	**611**	**4,175**	**429**	**45**	**921**	**199**	**8,246**
S1 H_2 Network	1.4%	0.0%	5.5%	0.6%	0.0%	0.0%	-8.7%	0.0%	-0.1%
S2 H_2 Network	1.9%	0.0%	9.5%	1.0%	0.0%	0.0%	-14.7%	0.0%	-0.2%
S3 H_2 Network	3.6%	0.0%	20.0%	1.2%	0.0%	0.0%	-22.5%	0.0%	0.0%
S4 H_2 Network	-0.1%	0.0%	-1.2%	-0.2%	0.0%	0.0%	2.5%	0.0%	0.1%
S5 H_2 Network	-0.4%	0.0%	-2.3%	-0.4%	0.0%	0.0%	5.5%	0.0%	0.2%
S6 H_2 Network	-1.7%	0.0%	-3.1%	-1.0%	0.0%	0.0%	11.2%	0.0%	0.3%
S1 Electricity Network	0.6%	0.0%	-0.9%	-0.2%	0.0%	0.0%	1.7%	0.0%	0.1%
S2 Electricity Network	0.4%	0.0%	-2.3%	-0.8%	0.0%	0.0%	5.8%	0.0%	0.1%
S3 Electricity Network	-1.0%	0.0%	-4.4%	-1.5%	0.0%	0.0%	11.0%	0.0%	0.0%
S4 Electricity Network	-0.3%	0.0%	1.3%	0.2%	0.0%	0.0%	-1.7%	0.0%	0.0%
S5 Electricity Network	-0.8%	0.0%	3.9%	0.5%	0.0%	0.0%	-5.4%	0.0%	-0.2%
S6 Electricity Network	-1.3%	0.0%	9.5%	1.3%	0.0%	0.0%	-12.3%	-5.7%	-0.3%
S1 CH_4 Network	-1.4%	0.1%	-1.1%	0.1%	0.2%	-0.9%	1.1%	0.0%	-0.1%
S2 CH_4 Network	-3.9%	5.3%	-11.3%	-0.1%	9.8%	-36.7%	3.6%	0.0%	-0.5%
S3 CH_4 Network	-8.2%	13.6%	-27.9%	-0.2%	24.9%	-94.3%	8.0%	-1.1%	-1.1%
S4 CH_4 Network	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	-1.9%	0.0%	0.1%
S5 CH_4 Network	3.5%	0.0%	3.9%	0.0%	0.0%	0.0%	-5.2%	0.0%	0.2%
S6 CH_4 Network	5.4%	0.0%	7.0%	0.1%	0.0%	0.0%	-9.6%	0.0%	0.2%
S1 Green H_2	1.0%	0.0%	-1.0%	0.1%	0.0%	0.0%	-1.5%	0.0%	-0.1%
S2 Green H_2	1.5%	0.0%	-1.6%	0.1%	0.0%	0.0%	-2.5%	0.0%	-0.2%
S3 Green H_2	2.6%	0.0%	-3.0%	0.1%	0.0%	0.0%	-3.3%	0.0%	-0.2%
S4 Green H_2	-0.4%	0.0%	0.6%	0.1%	0.0%	0.0%	-0.2%	0.0%	0.0%
S5 Green H_2	-1.1%	0.3%	1.0%	0.1%	0.5%	-1.8%	-0.2%	0.0%	0.0%
S6 Green H_2	-1.7%	1.9%	-3.7%	-0.4%	4.5%	-13.0%	3.3%	0.0%	-0.1%
S1 P2X	-0.3%	0.0%	-2.1%	-0.1%	0.0%	0.0%	1.8%	0.0%	0.0%
S2 P2X	-0.3%	0.0%	-3.1%	-0.1%	0.0%	0.0%	2.4%	0.0%	-0.1%
S3 P2X	-0.2%	0.0%	-3.9%	-0.2%	0.0%	0.0%	2.9%	0.0%	-0.1%
S4 P2X	0.1%	0.0%	0.5%	0.0%	0.0%	0.0%	-0.4%	0.0%	0.0%
S5 P2X	0.0%	2.5%	-3.7%	-0.1%	5.9%	-17.2%	-0.8%	0.0%	-0.1%
S6 P2X	-0.5%	9.7%	-14.8%	-0.2%	20.6%	-67.0%	-2.1%	-2.8%	-0.5%
S1 HHP CH_4	-0.5%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%
S2 HHP CH_4	-1.3%	0.0%	-0.5%	0.1%	0.0%	0.0%	1.0%	0.0%	-0.1%
S3 HHP CH_4	-2.7%	0.0%	-0.7%	0.2%	0.0%	0.0%	1.4%	0.0%	-0.2%
S4 HHP CH_4	0.8%	0.0%	0.4%	0.0%	0.0%	0.0%	-0.5%	0.0%	0.1%
S5 HHP CH_4	1.2%	0.0%	0.8%	0.0%	0.0%	0.0%	-1.5%	0.0%	0.0%
S6 HHP CH_4	0.3%	0.0%	2.2%	0.4%	0.0%	0.0%	-5.2%	0.0%	-0.2%
S1 H_2 Storage	-0.7%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.2%	0.0%	0.0%
S2 H_2 Storage	-0.7%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%
S3 H_2 Storage	-0.5%	0.0%	-0.7%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%
S4 H_2 Storage	0.8%	0.0%	0.5%	0.0%	0.0%	0.0%	-1.4%	0.0%	0.0%
S5 H_2 Storage	2.6%	0.0%	2.7%	0.0%	0.0%	0.0%	-3.4%	0.0%	0.1%
S6 H_2 Storage	2.5%	0.0%	4.9%	0.2%	0.0%	0.0%	-6.6%	0.0%	0.0%
S1 Electricity Storage	-0.2%	0.0%	-0.1%	-0.1%	0.0%	0.0%	0.1%	0.0%	-0.1%
S2 Electricity Storage	-0.4%	0.0%	-0.1%	-0.2%	0.0%	0.0%	0.2%	0.0%	-0.1%
S3 Electricity Storage	-0.5%	0.0%	0.0%	-0.3%	0.0%	0.0%	0.1%	0.0%	-0.2%
S4 Electricity Storage	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	-0.4%	0.0%	0.1%
S5 Electricity Storage	0.3%	0.0%	0.2%	0.3%	0.0%	0.0%	-0.5%	0.0%	0.1%
S6 Electricity Storage	0.3%	0.0%	0.2%	0.3%	0.0%	0.0%	-0.5%	0.0%	0.1%

S1 CH_4 Storage	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	0.0%	0.0%
S2 CH_4 Storage	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.2%	0.0%	0.0%
S3 CH_4 Storage	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%	-0.4%	0.0%	0.0%
S4 CH_4 Storage	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
S5 CH_4 Storage	-0.1%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%
S6 CH_4 Storage	-0.1%	0.0%	-0.2%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%

Note: there was no impact on the final consumption of biomass so it was not reported here for clarity purpose.

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