

The role of interconnection and storage for the integration of renewable energy in the Netherlands

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I am eager what the future will hold for me.

Sander Meerman

Abstract

The urge in the European Union to become less reliant on fossil fuel for its energy provision becomes increasingly important. Global warming and self sufficiency are key drivers for the Netherlands to deploy large numbers of variable renewable energy sources. However, integrating these variable energy sources in the existing energy system poses complex challenges, and requires a change of thinking in how energy is transported and used in time. Amongst the expansion of the electricity grid, alternative energy carriers including hydrogen are widely being considered. Linking electricity with hydrogen production impacts several aspects of the power system, including curtailment of renewable generation and electricity prices. Using a linear optimal energy system model that allows for integrated expansion, the role of interconnection and storage for the integration of renewable energy in the Netherlands is assessed. The expansion of interconnection of electricity and hydrogen transmission develops from 2030 onward. Hydrogen storage enables for long term energy storage, but the degree of hydrogen storage for the integration of renewables, and in particular offshore wind, is strongly dependent on geographical location and rate of electrification of demand.

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List of abbreviations

EU	European Union
BE00	Belgium
BEV	Battery electric vehicle
CAPEX	Capital expenditure
CCGT	Combined Cycle natural gas turbine
CNG	Compressed natural gas
COP	Coefficient of performance
CY	Climatic year
DE	Distributed energy
DE00	Germany
DHW	Domestic hot water
DK00	Denmark
DSO	Distribution system operator
FOM	Fixed operational and maintenance
GA	Global ambitions
GJ	Giga Joule (10^9)
GW	Giga Watt
GWh	Giga Watt hour (10^9)
H2CCGT	Hydrogen combined cycle gas turbine
H2OCGT	Hydrogen open cycle gas turbine
HP	Heat pump
HVAC	High voltage alternating current
HVDC	High voltage direct current
J	Joule
kJ	kilo Joule (10^3)
kV	kilo Volt
kW	kilo Watt
kWh	kilo Watt hour (10^3)
LCP	Low carbon pathway
LNG	Liquefied natural gas
MJ	Mega Joule (10^6)
MW	Mega Watt
MWh	Mega Watt hour (10^6)
NEA	Dutch emission authority, 'Nederlandse emissie autoriteit'
NL11	Groningen
NL12	Friesland
NL13	Drenthe
NL21	Overijssel
NL22	Gelderland
NL23	Flevoland
NL31	Utrecht
NL32	Noord Holland
NL33	Zuid Hollan
NL34	Zeeland
NL41	Brabant
NL42	Limburg
NO00	Norway
NUTS	Nomenclature of terrotorial units for statistics
OCGT	Open cycle natural gas turbine

PJ	Penta Joule (10^{15})
PV	Photo voltaics
SIC	Standard industrial classifications
T	Temperature
TAP	Temperature dependent profile
TJ	Tera Joule (10^{12})
TOP	Temperature independent profile
TSO	Transmission system operator
TWh	Tera Watt hour (10^{12})
TYNDP	Ten year network development plan
UK00	United Kingdom
V2G	Vehicle to grid
VOM	Variable operational and maintance
VRES	Variable Renewable Energy Sources
Wh	Watt hour

1 Introduction

1.1 A changing European energy landscape

Energy is heavily integrated in the economy of the European Union, and current days the energy used in the European Union used as, or originated from fossil fuels. The European energy sector is responsible for 75% of the European green house gas emissions in 2021 (EC, 2022a). A sector-wide adaption to the proposed EU renewable directive is therefore crucial to limit green house gas emissions. The renewable energy directive is the legal framework for the development of renewable energy across the European Union, and originates from 2009. The energy landscape is undergoing one of the largest transitions in modern human history. In 2020, 22.1% of the final energy consumption was renewable, originating from 10.3% in 2009 (Eurostat, 2022). The target is to reach 32, or even 40% of renewable final energy consumption in 2030 and is critical for the trajectory towards reaching climate neutrality in 2050 (EC, 2022a,b). Additional to the aforementioned goals, an increase in energy efficiency, direct electrification and promotion of clean fuels are pillars for the decarbonization strategy of the European Union (EC, 2020).

Rather than treating the decarbonization of sectors separately, an energy system integration approach is proposed by the European Union. Energy system integration ensures that the system is planned and operated whilst linking different energy carriers, infrastructure and end-users. This is often referred as 'sector coupling'. An integrated energy system aims to enable connected and flexible system to be more efficient and resilient, whilst reducing costs for society. Examples of sector coupling are electric mobility, electric heating of the built environment and utilisation of green hydrogen for steel and ammonia. A visual representation of sector coupling can be found in figure 1.

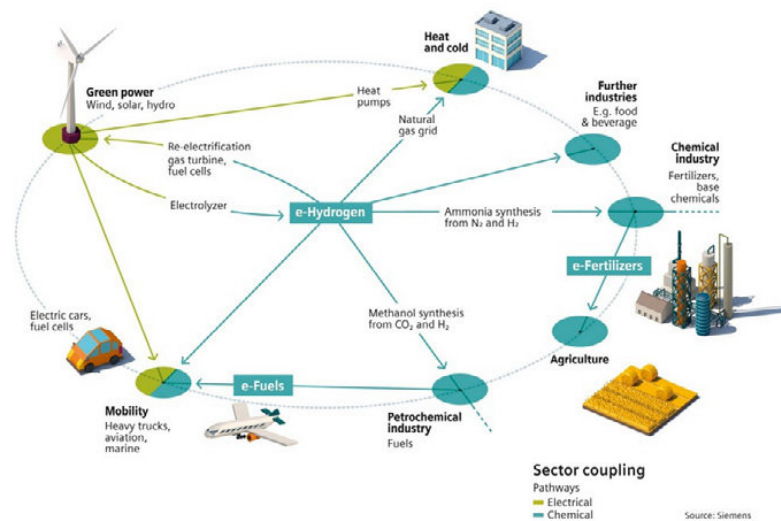


Figure 1: Visual representation of sector coupling through the use of electricity and hydrogen (Pflugmann and Blasio, 2020).

1.2 The Dutch: leaders or laggards in the changing European energy landscape?

The Dutch energy landscape is changing consequential to the European Union its renewable energy directive. What makes the Netherlands notable, is the Urgenda court ruling. The highest court in the Netherlands

ruled that the Dutch state must intensify its efforts to limit the emissions of green house gasses by 25% in 2020, compared to the level of 1990 (Verschuuren, 2019a). Amongst other measures, the Dutch government substantiates the latter by accelerating the phase out of coal fired power plants, with roughly 3.5 GW of capacity closed down in the period 2013 till 2020, and is projected to phase out by 2030 Verschuuren (2019b). These coal fired power plants are currently replaced by (existing) biomass and natural gas fired power plants and, more importantly, additional intermittent energy technologies including solar photo voltaic (PV) (9GW_{p2022}), and on-(4.1 GW₂₀₂₂) and offshore (2.5GW₂₀₂₂) wind turbines (Rijksoverheid, 2022b). The expected share of renewable electricity from wind and solar is forecasted to be 70% in 2030 (EZK, 2019). It is expected that 21 and 38 GW of capacity of offshore wind will be installed in 2030 and 2040 respectively (Rijksoverheid, 2022b). Additionally, the installed capacity of solar will increase from 9 GW_p in 2022, to at least 18 and 36 GW_p in 2030 and 2040 respectively (RVO, 2020). To put these numbers in perspective, the average base load in the Netherlands is currently 15 GW on average (TenneT, 2022b). This implies that on a day with favorable wind speeds and/or high irradiation, the average base load can, theoretically, be completely covered with renewables.

In line with the European energy integration approach, the Netherlands substantiated a framework that aims to enable sector coupling through subsidy schemes and tax benefits for renewable energy technologies, including efficiency, conversion and storage. Examples of these schemes include the 'sde++' (promotion of sustainable energy), 'subsidie hernieuwbare energie' (Subsidy for renewable energy), 'energie investerings aftrek' (energy interest deduction) and 'investeringssubsidie duurzame energie' (investment subsidy renewable energy). Several sectors are experiencing, or are expected to undergo, tremendous changes, including the built environment, transport and industries. For example, Dutch dwellings are transitioning from natural gas boilers, which currently making up 86% of the technology share, to heat pumps to fulfill their energy demand for heating (CBS, 2022). Mobility is increasingly electrified, and industries are exploring decarbonization pathways through efficiency, electrification and the utilisation of green fuels.

The ambitions of the Netherlands are well in line with EU targets. However, the Urgenda ruling was the first ruling which enforced a government to reach specific climate targets, and indicate a lagging character. Therefore, current progress is put in to perspective to its neighbouring countries, depicted in table 2. All though the ambitions of the Dutch are well in line with targets set by the EU, today's representation regarding the share of renewable in their electricity supply and final energy consumption does not represent a leading position in the EU. A steep increase in efforts is required to comply to the targets set by the EU renewable energy directive.

Table 2: Share of electricity and final energy consumption from renewables of neighboring countries of the Netherlands and the European Union (EC, 2022b, Max and Esteban, 2022).

Country	Share of electricity production from renewables	Share of final energy consumption from renewables	Unit
The Netherlands	26.7	14.0	%
Germany	43.9	19.3	%
Belgium	26.5	13.0	%
United Kingdom	42.9	21.5	%
Norway	98.7	77.4	%
Denmark	80.4	31.6	%
EU	36.8	22.1	%

1.3 Problem definition

Designing, and more importantly, balancing variable renewable energy systems poses complex challenges. The energy supply and demand must be balanced in time, space and through multiple energy carriers. Other than fossil power plants, variable renewable energy sources (VRES) usually can't ramp their supply on its own to adjust to demand, and rely on meteorological conditions that determine the power output (Shahmohammadi et al., 2018). Also, thermal power plants suffice base-load supply, and can therefore satisfy demand at all times. However, variable energy supply creates an incentive for variable energy demand, also referred as demand response. In traditional power response, the incentive to change power consumption for additional benefits is largely driven by a change in electricity price (Huang et al., 2019). However, demand response is intended change consumers electricity consumption behavior in light of time-of-use electricity price or dispatch instruction to limit peak demand. In recent years, the focus is also orientated to adapt demand response to multiple energy carriers, also called integrated demand response (Huang et al., 2019, Bahrami and Sheikhi, 2015).

Additionally, VRES are usually located far from areas of high demand including industrial clusters and densely populated areas. The latter results in a requirement of interconnection across geographical locations (Smith et al., 2019). Figure 2 shows the location of wind turbines and transmission lines in the Netherlands. The latter indicates that offshore wind turbines are located far from areas with high demand including Rotterdam, Amsterdam and Geleen (Limburg).



Figure 2: Location of wind turbines (dots, all colours) in the Netherlands, at February 22, 2022. The lines represent the high voltage transmission network. Transmission voltages included are: 380kV (red), 220 kV (green), combi line (pink), 150 kV (blue), 110 kV (black) and 50 kV (grey). Figure adapted from Atlasomgeving (2022).

The mismatch of power production far from areas of high demand poses several challenges for the Dutch

transmission operator TenneT and distribution operators including Alliander, Liander, Stedin and Enexis. Congestion issues nowadays occur in the Netherlands, depicted in figure 3. Congestion occurs when the requested power flow from point A to B is too large in magnitude (Hadush and Meeus, 2018). The latter also conflicts VRES, which are forced to opt for curtailment to prevent excessive load on the grid. A comparison of figure 2 and 3 indicates a correlation between the number of wind turbines and congestion. It can be observed that congestion is less eminent in the well enforced regions in Amsterdam and Rotterdam. Consequentially, Congestion issues lead to new suppliers and costumers with a connection larger than 3X80A not being able to connect to the grid, leading to a possible slow down of electrification, VRES deployment and thus the energy transition.

Integrating large amounts of VRES in the energy system requires a change of thinking in how energy is transported and used in time. Alternative energy carriers, such as hydrogen, are widely being considered. A simplistic consideration to maximise expansion of the electricity grid is in unrealistic to integrate renewable energy. However, grid expansion is required to limit grid congestion. Grid expansion is carried out by the Dutch TSO regarding transmission lines of 380, 220 150 and 110 kV, and by the Dutch DSOs for the remainder voltages below 110 kV.

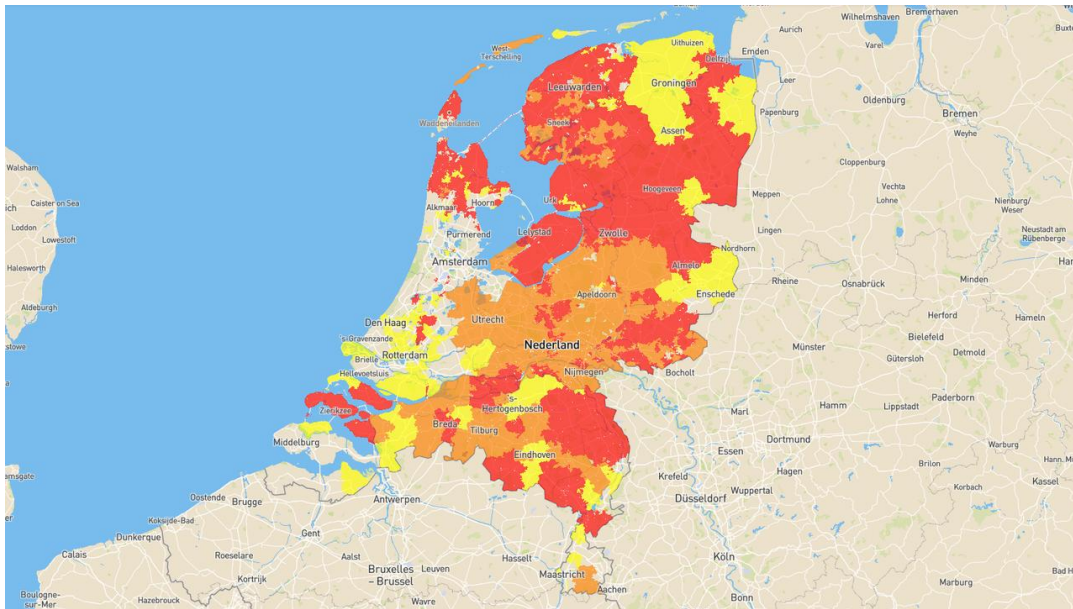


Figure 3: Overview of congestion in the Netherlands for suppliers of power, at February 2022. Level of congestion issues: no issues (transparent), congestion issue likely to occur (yellow), structural congestion issues (orange), structural congestion, new appliances for transmission not accepted (red) (NetbeheerNederland, 2022).

Transmission of energy originated from VRES will not be solely carried out in the form of electricity for the several reasons. First, the magnitude and temporal speed that VRES are installed outpace the capacities of high voltage lines to be installed. In Western Europe, it can easily take 10 years from feasibility to the completion of construction for an overhead high voltage line (ICF, 2003). Second, the volume of energy transported through an high voltage alternate current (HVAC) cable is limited to 560 MW due to physical constraints (Reddy, 2009). HV direct current (HVDC) is not limited by theoretical constraints, but is not economically effective for distance below 100 and 400km for offshore and overhead connections, respectively (Abedrabbo et al., 2017).

A secondary transmission system complimenting the power transmission system is proposed in the Nether-

lands, namely the (already existing) natural gas pipelines. In the Netherlands, transmission pipelines are operated by GasUnie, the Dutch gas TSO. The capacity of energy transported through pipelines with hydrogen in the Netherlands is roughly 10 GW (Gasunie, 2021). This capacity is, contrary to electricity, able to act as a short-term buffer. Electricity can't be stored in wires, and a surplus or deficit will merely lead to a deviation in frequency. Amongst reinforcement and re-purposing of the Dutch electricity and natural gas transmission grid respectively, the effect of international exchange of (renewable) power is not neglected in the Netherlands and the EU (Zappa and van den Broek, 2018, EC, 2022a). Ummels (2009) explored the effect of interconnection of wind power in the Netherlands and found that roughly 15% of available wind is wasted when no international exchange is allowed. International exchange of power and energy is regarded a key pillar to enable large scale deployment of VRES in the EU. The energy system integration leads to higher electrification and utilization of e-fuels through out the EU. Therefore, the installed capacity of renewable energy technologies such as wind turbines and solar PV increase multi folds. Installed capacities of offshore wind, onshore wind and solar PV are expected to increase from 25 to 300, 155 to 480 and 138 to 891 GW from 2022 to 2050, respectively (IRENA, 2020). Additionally, the EU aims to install 40 GW of electrolysis capacity in 2030, enabling seasonal storage to overcome periods of VRES deficits, and cross-European trade of hydrogen through the European hydrogen backbone, or EHB (EC, 2022a).

The ten year network development plan (TYNDP) assesses roughly 180 transmission and storage projects across the EU and estimates an increase of 50 GW of additional cross border transmission capacity in 2030 (Entso-e, 2022a). The Netherlands and its neighboring countries are likely to experience large periods of surpluses and deficits of energy production and it is therefore imperative to validate whether these outlooks will suffice for our future energy needs. In previous studies (Berenschot, 2021), Guidehouse and others explored nation wide system integration of offshore wind in the Netherlands. However, static inter connection was assumed, implying import and export that is unaffected by meteorological conditions of its neighboring countries. Energy system modeling is an appropriate way to see how variable interconnection can affect integration of VRES and induces a need for long term energy storage. Energy system modeling is further elaborated in section 1.4.

1.4 Research gap in energy system modeling

Quantitative methodologies to perform research on the integration of renewables, transmission, conversion and storage are often substantiated through energy system modeling. An energy system model is a mathematical representation the physical world varying in complexity on technical, spatial and temporal scope (Hoffman and Wood, 1976). For complex issues such as energy system modeling regarding the integration of renewables, transmission and storage, sophisticated models are required. A majority of the energy system models tend include a trade-off of temporal or spatial resolution to maintain traceability and decrease computational times. Hence, simplifications of spatial granularity might not represent realistic situations regarding inter-connectivity, where solely one spoke represents the connection between two nodes. Neglecting cross-border trade between regions can heavily influence the energy system optimization results Poncelet et al. (2016a), Brown et al. (2019), Fattahi et al. (2021). Fattahi et al. (2021) found that neglecting intersectoral flexibility can increase total system costs by 20%. It is therefore imperative to take interconnection and intersectoral coupling into account for VRES integration in (cross-border) energy systems. Previous studies treated the Netherlands as a single, homogeneous region (Hainsch et al., 2021, Brown et al., 2018, Koivisto et al., 2020, Zappa et al., 2019). This leads to the agglomeration of interconnections towards its neighbouring countries, and can therefore neglect specific connections. In addition, by modeling the Netherlands with a finer spatial resolution, the requirement of flexibility can be determined in a more accurate manner. This research therefore contributes in a better understanding of individual interconnection and requirement on a finer spatial resolution for flexibility through conversion and storage.

2 Research question

The problem definition leads to the following overarching research question.

“What system design choices, regarding inter-connectivity and storage, can contribute towards the integration of variable energy sources in the Dutch energy system, in the year 2030 and 2040?”

In this study, the role of inter-connectivity and storage regarding the integration of VRES in the Dutch energy system is assessed. Therefore, the expected demand and supply profiles of individual regions is established through sub question 1. Consequentially, the interaction between production and demand of different regions regarding electricity and hydrogen are assessed. The outcome of sub question 1 will serve as a basis to answer sub question 2. To conclude, sub question 3 depicts the inter-dependency of interconnection and storage of offshore wind in the Netherlands, depicted in sub question 3.

SQ1: *What is the expected exchange capacity and volume for electricity, natural gas and hydrogen, and what are the implications for the economic feasibility of VRES in the Netherlands, in 2030 and 2040?*

SQ2: *What are the interactions between hydrogen and electricity, in the Dutch energy system, and how does this affect the economic feasibility of VRES in the Netherlands?*

SQ3: *How does electricity and gas interconnection affect the need for storage and conversion flexibility for the integration of offshore wind?*

3 Research scope and boundaries

In this section, a brief outline of the research is presented. The research question will be answered using energy system modeling of the energy system including the Netherlands, Germany, the United Kingdom, Denmark, Norway, Belgium and the rest of the EU. The energy carriers included for this research are electricity, hydrogen and methane. First, a theoretical background reviewing the state-of-the-art of different aspects regarding energy modeling is provided. Hence, Grey and peer reviewed literature is reviewed to provide validated data of energy generation, transmission and storage technologies, compose time series of demand and load profiles, disaggregated data of regions within the Netherlands and Germany and aggregated data for the remainder countries and EU. The Netherlands is split up in 12 NUTS-2 (Nomenclature of Territorial Units for Statistics) regions, and includes 4 additional nodes for offshore wind production. A fine spatial granularity allows for a high level of detail of analysis regarding interconnection between individual nodes regarding the modeling process. Hence, all neighbouring countries of the Netherlands are modeled as a single node. A visual representation of the energy model is presented in figure 4.

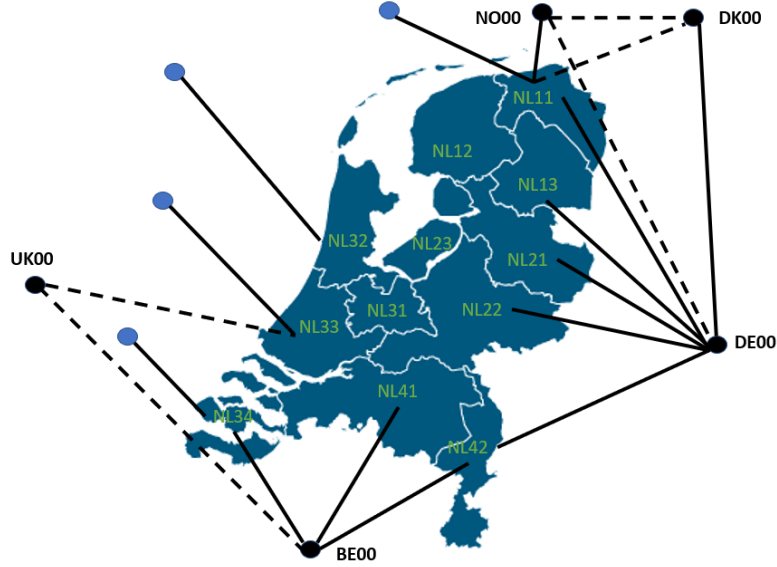


Figure 4: Visual representation of all nodes and spokes modeled in this research. Black nodes represent NUTS-0 regions of the UK (UK00), Norway (NO00), Denmark (DK00), Belgium (BE00) and Germany (DE00) and NUTS-2 regions in The Netherlands. Dotted spokes represent subsea connections. The nodes consist of demand, supply and interconnection capacities. Blue nodes represent offshore wind connected to their respective landing points.

The data is gathered in an workbook that serves as input for the energy system modeling carried out in the Low Carbon Pathway model provided by Guidehouse. This workbook serves as input to answer sub question 1, where supply, demand and transmission capacities are determined and depict the expected exchange capacity and volume of electricity, hydrogen and methane in 2020, 2030 and 2040. The scenario planning for the years 2030 and 2040 is based on the ten year network development plan (TYNDP) of Entso-E and Entso-G Entso-e (2022a). Two scenarios included are the global ambitions (GA) and Distributed Energy (DE). The GA scenario depicts a transition which is initiated at a European and international level and the DE scenario depicts a transition initiated at a local and national level. Hence, GA aims for high EU renewable energy supply (RES) development, supplemented with low carbon energy and imports and the DE aims for energy autonomy through maximization of RES and smart sector integration. The TYNDP provides an aggregated scenario outlook for the EU, and individual countries for the years 2030 and 2040 (Entso-e, 2022b). Planned capacity additions and retirements regarding supply, demand and interconnections are determined through national and regional statistics, TSOs and DSOs. Hence, the results and sensitivity runs serve as input to answer sub questions 2 and 3. An overview of the research outline is provided in figure 5.

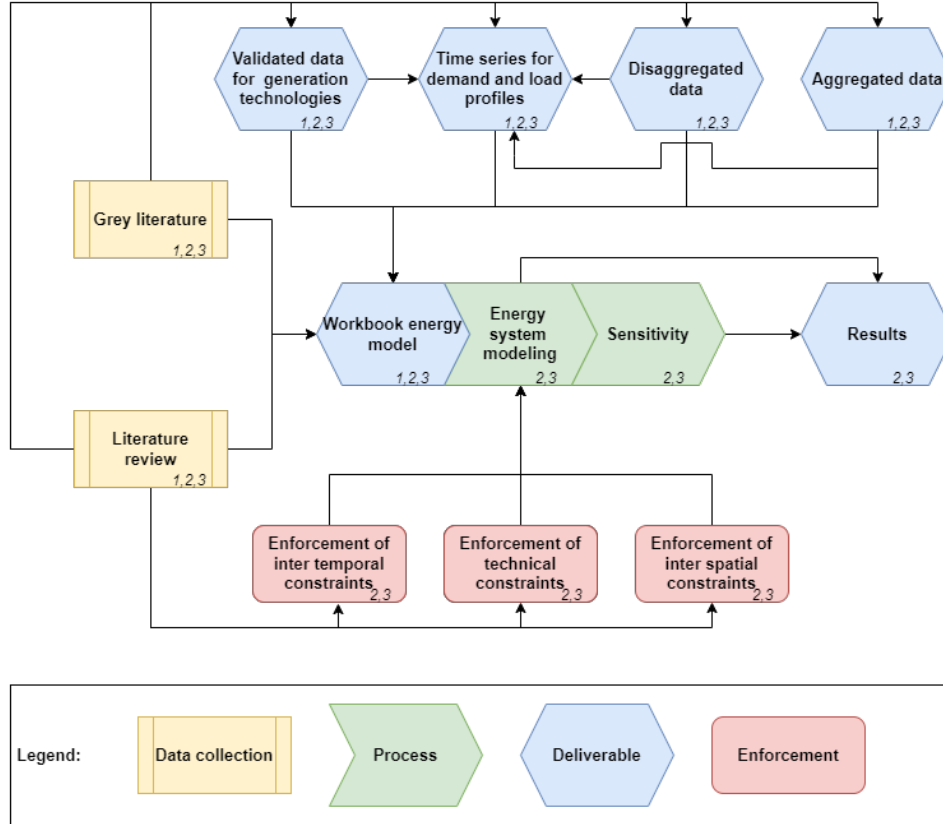


Figure 5: Research outline visualized through data collection (yellow), processes (green), deliverable (blue) and enforcements of the modeling process (red). The numbers 1,2 and 3 resemble the sub questions described in section 2. TYNDP scenarios are referred as 'grey literature'.

4 Theoretical background

In this section, a generic representation of the the theoretical background of the applied methodologies is presented. First, energy system modeling is discussed. Third, background regarding aggregated and disaggregated energy system modeling is provided. Last, a review of important modeling characteristics is discussed.

4.1 Energy system modeling

In general, energy system models rely on energy balances which often don't include energy conversion towards e.g., heat, light or mechanical work. However, conversion steps of energy carriers determine the required infrastructure required to meet demand (Morrison, 2018). Priesmann et al. (2021) incorporates a bottom-up and bottom-down modeling approach to model NUTS-2 regions in Germany. Separate calculations are performed for residential, industrial, service and mobility sectors. A variety of data sources is combined including weather time series, standard load profiles, census data, movement data and employment figures. Sections 4.1.2 - 4.4 further elaborate on the bottom-up and bottom-down modeling approach of the latter.

4.1.1 Representative days

Representative days usually depend on weather conditions including temperature, irradiation and wind speeds, and are usually determined by upper and lower boundaries (Van Der Heijde et al., 2019). Van Der Heijde et al. (2019), Poncelet et al. (2016b) considers representative periods with basic heuristics including highest, average and lowest average generation of PV and wind conditions for all 4 seasons i.e., spring, summer, autumn and winter. Especially lowest average generation of PV and wind during winter season is interesting, as this is often referred as a "dunkelflaute" event in Europe (Li et al., 2021). The latter is defined as a period, with a minimum of seven days, with a minimum generation of renewable energy. These occurrences usually take place in January, and a correlation of wind power data sets for the Netherlands and Germany is 0.73 (Ummels, 2009).

4.1.2 Energy demand built environment and service sector

A demand profile of electricity and heat for the built environment usually consists of space heating, domestic hot water (DHW) and electrical appliances including electric appliances and lighting (Ozawa et al., 2018). In general, three main methods are described in literature regarding space heating to derive a heat demand which can be used without setting up specific energy balances for individual dwellings. This approach is less preferred, since this requires specific data regarding insulation and volumes of dwellings.

The first method proposed, is the standardised load profiles method (Metz, 2014). This approach assumes an average load profile, also recalled as a synthetic load profile, from measurements. This profile is hence linked with outdoors temperature and can thus be scaled to a specific hourly energy demand. These profiles are usually made publicly available by gas and electricity distribution companies. The NEDU and ESDN provides such load profiles in the Netherlands (Veldman, 2013).

The second approach is the reference load profiles method (Fischer et al., 2016). This approach uses representative annual load profiles from measurements. Hence, representative days for different meteorological conditions can be extracted and combined with the appropriate defined representative day.

A third method described is a statistical approach and is built on measured data. This method is purely data-driven to determine load profiles through regression methods and is described by Lindberg and Doorman (2013) and Pedersen et al. (2008). This method provides a good accuracy regarding known buildings, but lacks in predicting new buildings and building dynamics such as retrofitting.

The domestic hot water (DHW) demand in the Netherlands varies with 6% throughout the year (Ahmed et al., 2016). However, DHW is sensitive to personal preferences such as shower duration. The average DHW usage can be estimated through load data of electricity and gas market players such as Eneco, which is 30 liter per person, roughly 10 GJ, for Dutch households (Ahmed et al., 2016, Eneco, 2022). Ahmed et al. (2016) applies a normalized, constant, hourly demand profile as fractions of total annual demand.

The electricity demand in the built environment is subjective to different load profiles by function of a building (Zhao and Magoulès, 2012). Residential buildings follow roughly the same typology assumptions as for DHW, and can also be calculated through normalized hourly demand profiles as a fraction of total annual demand (Ahmed et al., 2016, Veldman, 2013). Annual demand data is often publicly available in national statistics in developed countries.

Buildings in the service sector, including offices depict a different load profile compared to residential buildings. Mikulik (2018) prescribes demand profiles of electricity and heating of offices, with an area of 30,000 square meters, in Poland. These profiles can be adjusted towards annual consumption data and follow an increasing and declining trend from 07:00 and 18:00, with a peak around 12:00. Weekends present a lower

consumption. The work of Mikulik (2018) also presents variances influenced by meteorological circumstances for aggregated daily energy uses of office buildings.

4.1.3 Energy demand industrial sectors

Industrial sectors can't be treated as a single sector due to its heterogeneous character (Maruf and Islam, 2019, Koivisto et al., 2020, Koirala et al., 2021a). Sahoo et al. (2022) proposes a method to determine region specific demand of industrial sectors like chemical production, basic metal production and others. The paper uses the MIDDEN database of PBL, which covers roughly 95% of the industries registered by the Dutch emission authority (NEA). This database provides current technologies and their associated demand of energy carriers including electricity, hydrogen and natural gas. The MIDDEN database also includes the lifetime, autoproducers and future technologies to be installed at specific sites, covered under the NEA. Auto producers are operated by enterprises which are not producing the energy as their main business, but primarily for their own consumption including steam and electricity used in the paper and chemical industry. Hence, production of these autoproducers should not be double counted.

A less accurate method to allocate energy demand for specific regions is through direct energy use per physical, economic or employment unit (Blok and Nieuwlaar, 2016). This method can provide general insight in energy consumption of specific industries, but lacks to provide distinction between different energy carriers. For this method, generalized assumption regarding these energy carriers are assumed.

4.1.4 Energy demand transport sector

Sahoo et al. (2022) uses national and regional statistics to comprise the vehicle stock of different regions. For personnel transport, domestic navigation and heavy transport, statistics are provided at Rijksoverheid (2022a). However, battery electric vehicles (BEV) should be treated differently. Brown et al. (2018) assessed a fully renewable energy system and opposed the following to model BEVs. First, existing energy demand of cars with an internal combustion engine was divided by a factor of 3.5, due to efficiency gains. Secondly, BEVs are modeled using a weekly profile. Hence, the vehicles can either be modeled with or without bidirectional capabilities (V2G). An additional option is to incorporate demand response capabilities, which is merely suggested with a high temporal resolution. For lower temporal resolutions, V2G and demand response is not suggested to incorporate in the modeling.

Modeling the energy demand of international aviation and navigation poses challenges, since these stocks aren't accurately taken in to account for national statistics. Blanco et al. (2018) utilises the EU trend scenarios regarding energy use to estimate energy use per passenger km. Blok and Nieuwlaar (2016) proposes to use national and public statistics of airports to retrieve passenger and freight data for navigation and aviation. Hence, average energy use can be coupled per passenger-km and tonne-km. In this sense navigation and aviation are modeled as generic processes, as described in Korkmaz et al. (2020).

4.1.5 Interconnection capacities

The basic function of TSOs are to forecast power flows over a long time horizon, and to ensure that limits are not exceeded, often referred to security planning (Ciupuliga, 2013). Security planning should enable a safe operation of the electrical grid. Safe operations are referred to branch loads with N, N-1 and N-2 not exceeding certain criteria of capacities. Ciupuliga (2013) reviews 3 methods for transmission network planning considering a time horizon. First, the static and dynamic methods are reviewed. The time horizon determines whether a model is static or dynamic. A static model optimizes the transmission capacity for

a specific year, disregarding the years in between. A dynamic model, the entire time horizon is considered and the expansion process is considered for multiple years. Time restrictions are enforced to consider temporal continuity, but are usually limited due to their increased complexity. Therefore, a hybrid method is proposed, analyzing separate years on the time horizon without having time restrictions on the expansion process. Ciupuliga (2013) describes three time horizon regarding expansion planning, namely:

- Long term studies up to twenty year including a high degree of uncertainty
- Medium term studies with reduced uncertainties, with a usual time horizon of ten years
- Short term studies with even more certainty, with a time horizon up to five years

Medium term studies are often referred to by European TSOs, and usually published throughout the European Union. However, Mertens et al. (2020) highlights the importance of long term studies with the nature of slow planning processes of grid expansions and energy projects in developed countries. For regulated and non-regulated power systems, Additional to static and dynamic models, Ciupuliga (2013) proposes the cost-benefit approach. This approach seeks to minimize expansion costs in both regulated and non-regulated environments. In such optimization, a optimal power flow tool is used, which considers network related constraints. In this sense, the network expansion is planned that least cost are incurred. The costs and benefits covered are commonly covered in literature. Costs include investment costs, operational costs and dismantling costs. Benefits include network losses reduction, prevention of curtailment, congestion relief, reduction of generation costs and more. This method can be combined with a time horizon and also holds for gas transmission planning (Maghouli et al., 2010).

4.1.6 Energy technology capacities

Determining energy technology capacities is a relative simple task. Koirala et al. (2021b) depicts that for every individual set of technologies, specific characteristics should be considered for each region. These include electric and thermal capacity, electric and thermal efficiency, lifetime and others. This data is usually available in national and regional statistics. The Netherlands also incorporates regional data which is available through the renewable energy strategies, also depicting regional targets regarding energy technologies. (Sahoo et al., 2022). Furthermore, TYNDP provides a comprised output of energy technologies on country level (Entso-e, 2022b).

4.1.7 Seasonal storage

Kotzur et al. (2018) provides a methodology which allows time series aggregation for energy system design that incorporates seasonal storage. Usually, energy storage system are constrained by cyclic conditions, which implies the storage system can't exchange energy between periods. A well substantiated manner to overcome this issue is presented in this paper, is to provide formulations for the state of the system on a intra- and inter-periodic states. This allows for an assumed aggregation of periods to typical periods, allowing for inter seasonal exchange. Another approach to model seasonal storage is to reduce computational requirements of the energy system model through a decrease of spatial and temporal resolution (Fattahi et al., 2020). This however, decreases the modeling detail and can lead to over estimations of dispatch and tends to unrealistic results with high shares of VRES (Poncelet et al., 2016a).

4.1.8 Imports and exports of hydrogen

Import and export of energy commodities like hydrogen is usually done with fixed prices (Burandt, 2021). Burandt (2021) assumes static prices through out the year for the im- and export of hydrogen, but interpolates year-to-year prices with a linear rate towards target prices. This leads to a hydrogen import that is non-sensitive towards meteorological variability and thus dispatch commitment.

4.2 Aggregated energy system modeling

Several studies modeled energy system with aggregated demand and supply on national level (Brown et al., 2018, Maruf and Islam, 2019). Single nodes are used to represent individual countries to decrease computational time and increase the time horizon with a higher temporal granularity. Brown et al. (2018) developed a cross-sector and cross-border integration of 30 countries in Europe. The temporal granularity was 30 seconds. Hourly electricity demand profiles of individual countries were extracted from the Open Power System Data project, which repackaged and unified data from the entso-e. Modeling single nodes significantly decreases computing time and reduces workload for the composition of input data.

4.3 Disaggregated energy system modeling

Disaggregated energy system modeling is, quote, "the breakdown of observations, usually within a common branch of a hierarchy, to a more detailed level to that at which detailed observations are taken" (OECD, 2022). The latter often includes a bottom-up and top-down modeling approach due to the heterogeneous nature of publicly available data, and allows national energy statistics to be disaggregated in to regional data, and allocated to specific sectors. The disaggregation provides sector specific data, including specific energy consumption per energy carrier across different sectors (Fischer et al., 2016, Sahoo et al., 2022, Veldman, 2013, Maruf and Islam, 2019). For energy system modeling, this is especially relevant to link current demand and supply figures with scenario outlooks. Disaggregated energy system modeling allows for higher detail, but significantly increase the computation time and workload required to compose input data.

4.4 Modeling tools and scenario building

For energy system modeling, different tools are available. Fattahi et al. (2020) provides a systemic review of integrated energy system modeling tools of national models. Models can be assessed on technical, micro-economic and macroeconomic challenges. Aspects including intermittent flexibility of renewables, (new) technologies, infrastructure, end use possibilities, social perspectives and macroeconomic interactions influence low-carbon energy modeling challenges. The temporal resolution determines the time slices of a model. Millie second to minutely resolutions allow demand fast response, battery and super capacitors being modeled in great detail. Hourly to seasonal allow modeling of storage, demand response, VRES curtailment, conventional generation and cross border trade. A fine spatial resolution can provide accurate regional insights on energy system policies. The latter allows for a better understanding of regional specifics such as capacities and properties of supply, demand and interconnection towards neighboring regions. However, identical to increasing temporal resolution, an increase of spatial resolution results in higher computing requirements. The latter indicates the significant trade-off between spatial and temporal resolution of energy system modeling.

An energy system model is highly sensitive to the underlying principles and data input of a model. It is therefore imperative to use validated data and methodologies and indicate different data sources used. Addi-

tionally, the accessibility of a data model provides an opportunity for peers to review models for improvement. This validation process is important to check for validity and applicability of such models.

5 Methodology

In this section, the methodology for this thesis is discussed. First, the data collection for the scenarios is substantiated. Second, the energy system modeling and its methodology is discussed.

5.1 Data collection

The data collection aims to define demand, supply and interconnection capacities regarding electricity, natural gas and hydrogen for the years 2022, 2030 and 2040 of each designated region. The outlooks for 2030 and 2040 are linked to the TYNDP GA and DE scenarios, explained in section 3. First, the existing demand, supply and interconnection capacities are defined for each energy carrier in every defined region. Consequentially, each electricity generation, conversion and storage technology is defined. Hence, the current and expected transmission capacities between regions in the scope of this research is discussed.

5.2 Energy Demand

The energy demand of specific sectors for a whole year is modeled through representative days. The representative days are determined through the reference load profile method and are selected with basic heuristics, including an average spring, summer, autumn, winter, peak summer (high VRES supply, average demand) and peak winter (no VRES supply, high demand). 2009 is selected in Entso-e (2022a) for the average climatic year throughout the European Union. Hence, the heuristics used to determine representative days are depicted in table 3, following the heuristic methodology of Van Der Heijde et al. (2019) and Poncelet et al. (2016b). This implies that the averages of spring, summer, autumn and winter are used as representative days. For the highest peak in winter, the day with highest demand of 2009 is selected, in this case; January 12. The demand of the peak day in summer is identical of that in a peak day in winter.

Table 3: Overview of heuristics used to select representative days of this research.

$N_{representative}$	Period	Load	Wind	PV
7	Year	Highest peak	Lowest valley	Lowest valley
1	Year	Average	Highest peak	Highest peak
378	Spring, summer, autumn, winter	Average	Average	Average

5.2.1 Built environment

The built environment includes residential and tertiary sector. For the residential sector, a building stock increase per region is adapted from CB, and is presented in Annex C in table 33. Additionally, 1% of the existing building stock is renovated per year, reducing heating demand of these buildings by 14%. The heat demand of buildings is calculated through the reference load profile method of Fischer et al. (2016). The reference load profile method consists of a temperature dependent profile (TAP) and a temperature

independent profile (TOP). The temperature dependent profile is calculated as presented in equation 1. The temperature independent profile is provided in a time series as $G2A_{TOP}$.

$$TAP = \begin{cases} T_{eff} \leq T_{TST}, G2A * (T_{TST} - T_{eff}) \\ T_{eff} \geq T_{TST}, 0 \end{cases} \quad [\text{Fraction}] \quad (1)$$

Where effective temperature is calculated by dividing the temperature (T) with the average hourly wind speed (V) divided by 1.5, as depicted in equation 2.

$$\text{Effective temperature} = \frac{T}{V/1.5} \quad (2)$$

The average effective temperature profile is the average of weather data of the climatic year (CY) 2009 from all 12 NUTS-2 regions in the Netherlands, retrieved from KNMI (2022), and is depicted in figure 6.

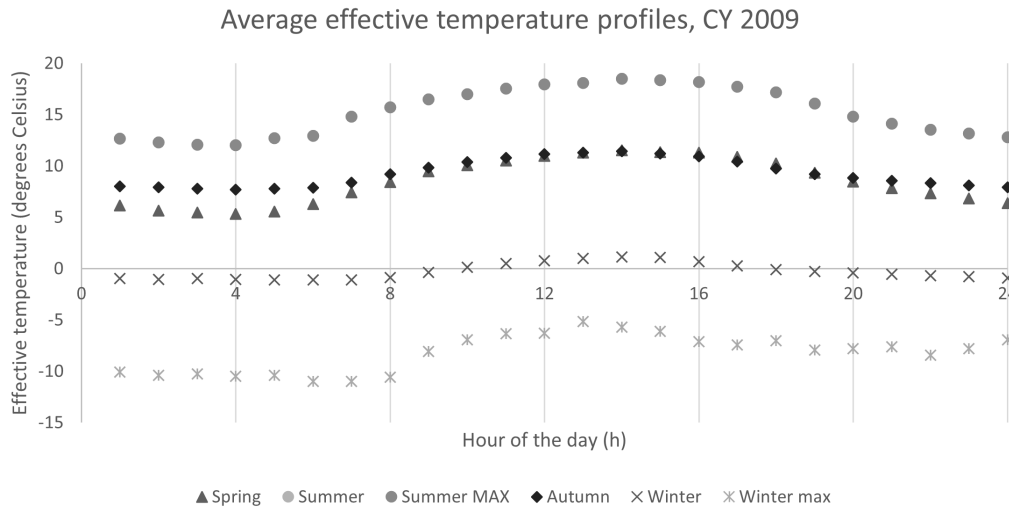


Figure 6: Effective temperature profiles in spring, summer and summer MAX (identical), autumn, winter and winter MAX in the Netherlands for the climatic year (CY) of 2009.

Representative days, determined through the heuristic method, are calculated from the NEDU and ESDN (Veldman, 2013). These are the averages of all time steps for all respective seasons.

Secondly, the DHW load profile is adapted as described by Veldman (2013) and Ozawa et al. (2018). Hence, normalized hourly demand profiles as a fraction of total annual demand are used for individual dwelling types, which is 10 GJ, or 277.8 kWh per year, resulting in figure 7. Through the DHW profile, the daily fractional heat demand is calculated. This results in a break down of the temperature independent profile which provides a further distinction between processes which require heat including showers and dishes, and cooking with natural gas.

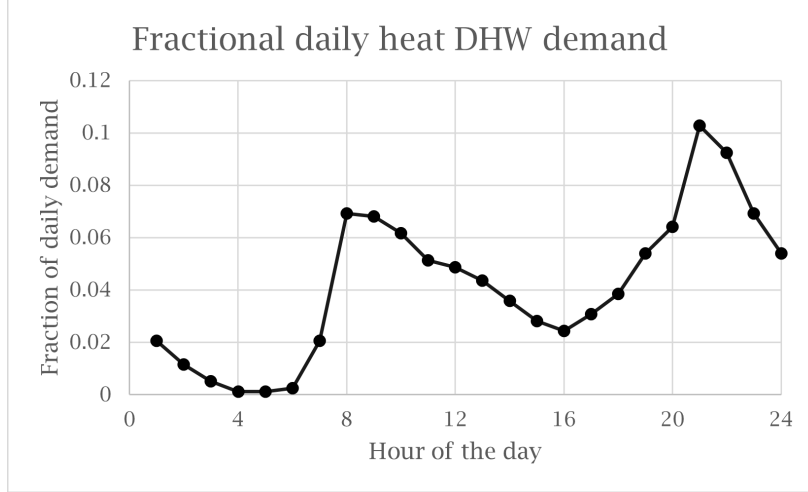


Figure 7: Fractional daily DHW demand profile for a typical Dutch dwelling, valid for all 365 days per year.

The building stock in the Netherlands is subjected to electrification by means of heat pumps (HP). Heat pumps convert electricity in to heat, but the conversion of the latter is temperature dependent. For hybrid heat pumps, the heat pump is operational till an outside effective temperature of 4 °C, below this temperature the natural gas boiler provides the heat supply (Entso-e, 2022a). The efficiency is referred as coefficient of performance, or COP. The formulation for coefficient of performance of air-to-water, ground-to-water and water-to-water source HPs is depicted in equation 3.

$$COP = \begin{cases} 6.08 - 0.09 * \Delta T + 0.0005 * \Delta T^2, & ASHP \\ 10.29 - 0.21 * \Delta T + 0.0012 * \Delta T^2, & GSHP \\ 9.97 - 0.20 * \Delta T + 0.0012 * \Delta T^2, & WSHP \end{cases} \quad [^{\circ}C] \quad (3)$$

The COP is constant at a temperature difference smaller or equal to 15. Hence, equation 3 leads to the following estimated COP curves, depicted in figure 8.

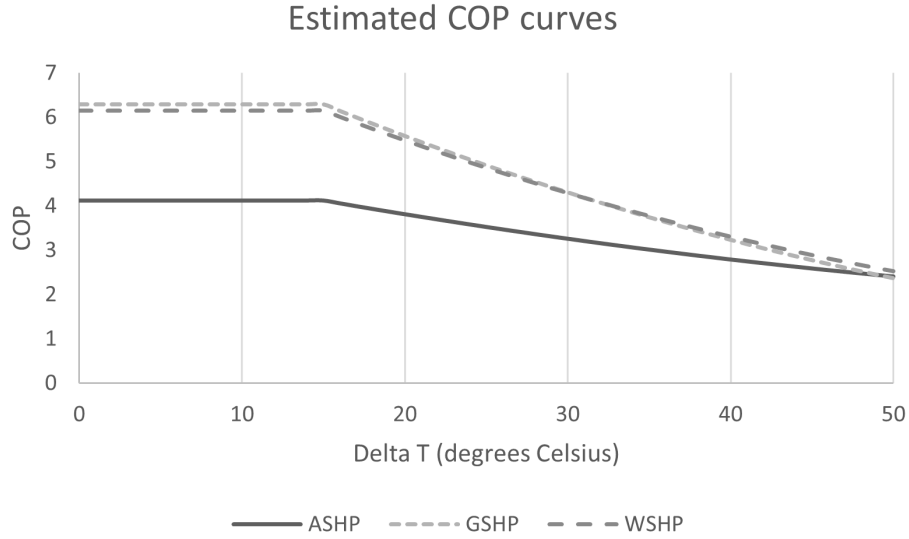


Figure 8: Estimated COP curves applicable for air-sourced (ASHP), ground-sourced(GSHP) and water-sourced (WSHP) heat pumps. The figure is an outcome from equation 3.

The temperature difference, or delta T, is substantiated through the difference of temperature of the heat source and the heat sink. The latter is depicted at equation 4.

$$\Delta T = T^{sink} - T^{source} \quad [^{\circ}\text{C}] \quad (4)$$

Hence, T^{source} is the effective average temperature in the Netherlands for the different seasons regarded in this research. The effective average temperature represent average temperature profiles for all regions in the Netherlands, depicted in figure 2.

In the Netherlands, the majority of the existing building stock includes a boiler with radiators to transfer heat throughout buildings. The sink temperature for radiators, floor heating and DHW is depicted 5.

$$T^{sink} = \begin{cases} 40^{\circ}\text{C} - 1.0 \times T^{amb}, & \text{radiator heating} \\ 30^{\circ}\text{C} - 0.5 \times T^{amb}, & \text{floor heating} \\ 55, & \text{DHW} \end{cases} \quad [^{\circ}\text{C}] \quad (5)$$

The electricity demand of electric appliances is roughly similar to that of the load profile of DHW, and therefore the same methodology is applied in regard to DHW, leading to the daily fractional electricity demand as depicted in figure 9 (Quintel, 2022b).

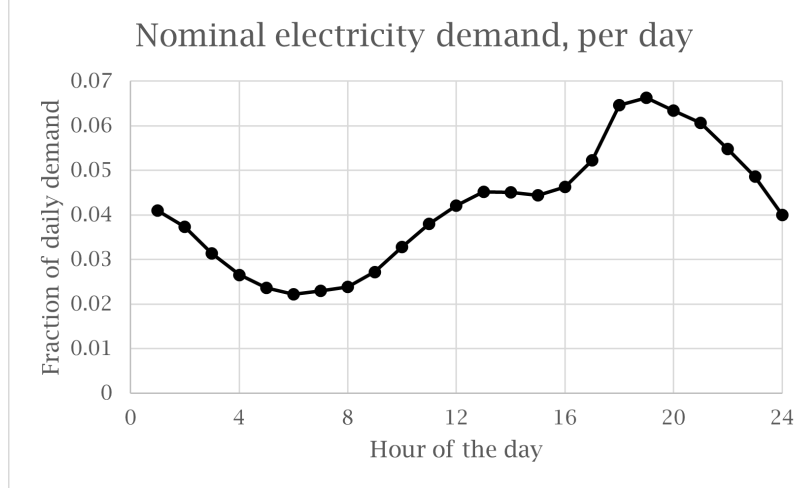


Figure 9: Fractional electricity demand of electric appliances.

For offices, the identical methodology is applied as for residential buildings. Annual demand data is publicly available at national statistics including CBS. An overview of all relevant parameters and output for the built environment is shown in table 4. Specifics regarding input parameters for the Global Ambitions and the Distributed Energy scenario can be found in tables 30-32, in annex D.

Table 4: Parameters and output relevant to built environment. (CBS, 2022)¹, (Entso-e, 2022b)², (Eurostat, 2022)³

Key factors	Unit	Type
Electricity demand in built environment ^{1,2,3}	GWh/h	Output
Natural gas demand in built environment ^{1,2,3}	GWh/h	Output
Hydrogen demand in built environment ²	GWh/h	Output
Heating demand per dwelling ¹	kWh/dwelling	Parameter
Electricity demand per dwelling ¹	kWh/dwelling	Parameter
Share type of dwelling ¹	%	Parameter
Type of heating infrastructure ^{1,2}	collective	Parameter
Office size type ¹	range m	Parameter
Electricity demand per office type ¹	kWh/h	Output
Natural gas demand per office type ¹	GJ/h	Output
Hydrogen demand per office type ²	GJ/h	Output

5.2.2 Industrial sector

The demand of all three energy carriers for the steel manufacturing, chemical production is retrieved using the method described by Sahoo et al. (2022). The MIDDEN database covers 95% of all the registered emissions under the NEA. The sectors included are branches 2nd digit by 1st digit of the SIC (standard industrial classifications) 2008 system. The latter consist of the following branches: manufacturing of food products, manufacturing of chemicals and manufacturing of basic metals (ferrous and non-ferrous metals). These branches are chosen since they consume substantial amounts of the respective energy carriers (Sahoo et al., 2022). The MIDDEN database includes detailed information of technologies used at specific sites by region in the Netherlands, including total yearly output per technology. Additionally, the required input i.e.,

fuel or raw product per FU is quantified. In this manner the yearly consumption of each individual energy carrier can be determined and scaled to an individual day through provided load factors.

An assessment is carried out whether a substitution technology is available for all industrial sites covered in the NEA database. For the DE scenario, substitution technologies considering electrification are chosen if present. For the GA scenario, substitution technologies considering hydrogen are chosen if present. For both scenarios, if no preferable technology is present; an alternative using bio methane is considered. However, if no substitution technology is present, the existing technology will remain. A graphical overview is depicted in figure 10.

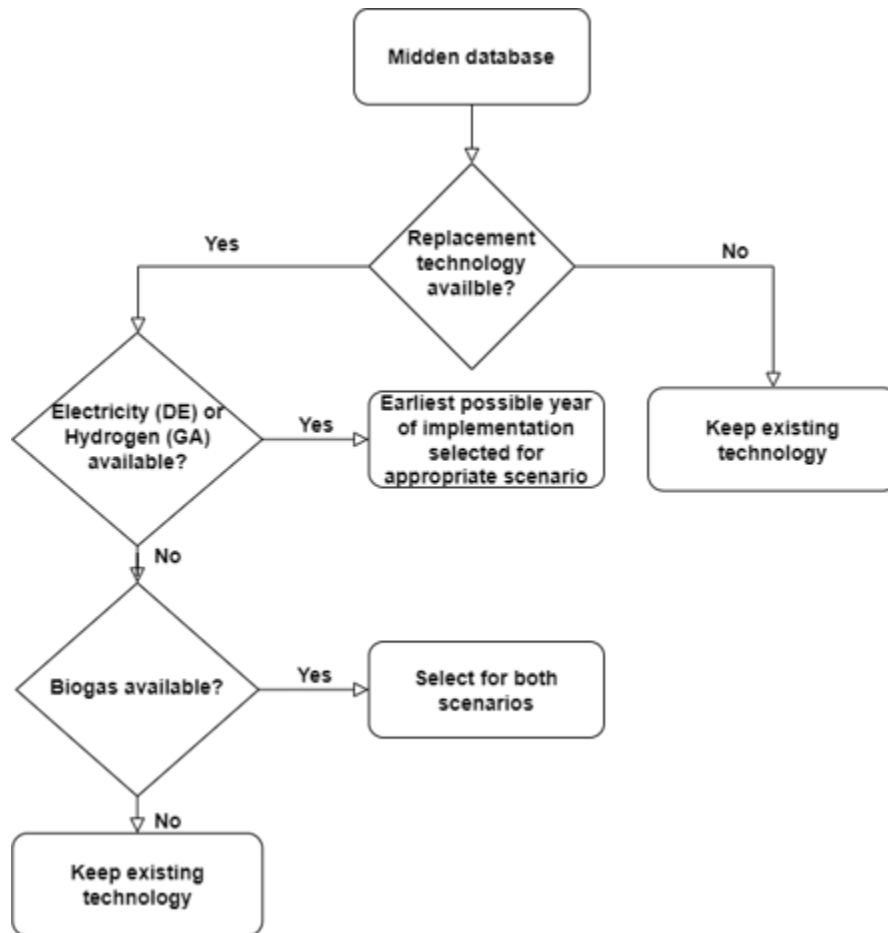


Figure 10: Decision tree for the selection of technologies in the industrial sectors covered in the MIDDEN database.

The load factors for the industrial sectors are retrieved from the Energy Transition Model, a tool which is widely used by non governmental organisations, institutions and commercial parties in the Netherlands (Quintel, 2022a). For the basic steel and chemical sectors, a flat demand curve for electricity, natural gas and hydrogen is assumed. For the food and beverages and agricultural sector, the E3D curve from NEDU is used for electricity, natural gas, and hydrogen if possible (Quintel, 2022b). These curves are already fractional demand curves, and can therefore directly be used after calculating the seasonal averages. The curves are depicted in figure 11.

Fractional natural gas demand food and beverages, and agriculture, CY 2009

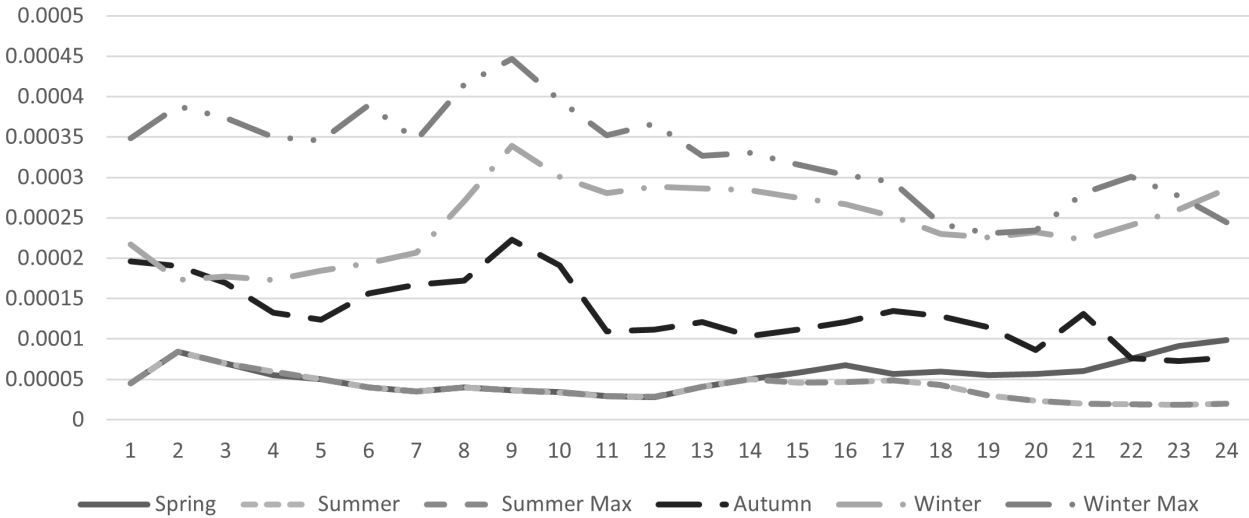


Figure 11: Fractional demand curve for the food and beverages sector, and agriculture in spring, summer, summer max, autumn, winter and winter max.

An overview of all relevant parameters and output for the industrial sectors can be found in table 5.

Table 5: Parameters and output relevant to industrial sectors. (CBS, 2022)¹, (Entso-e, 2022b)², (PBL, 2022)³

Key factors	Unit	Type
Electricity demand in industry ³	GWh/h	Output
Methane demand in industry ³	GWh/h	Output
Hydrogen demand in industry ³	GWh/h	Output
Installed year technology ³	year	Parameter
Lifetime technology ³	years	Parameter

5.2.3 Transport sector

National and regional statistics are used to comprise regional and national vehicle stocks, following the methodology of Brown et al. (2018) and Sahoo et al. (2022). Hence, BEVs that replace ICE vehicles require 3.5 less the amount of energy per km. Hence, fractional demand profiles for charging electric personnel cars, busses and trucks are retrieved from Entso-e (2022a). Liquefied natural gas (LNG), compressed natural gas (CNG) and hydrogen fractional demand profiles are equally divided over 24 hours (Entso-e, 2022a). The latter is depicted in figure 12.

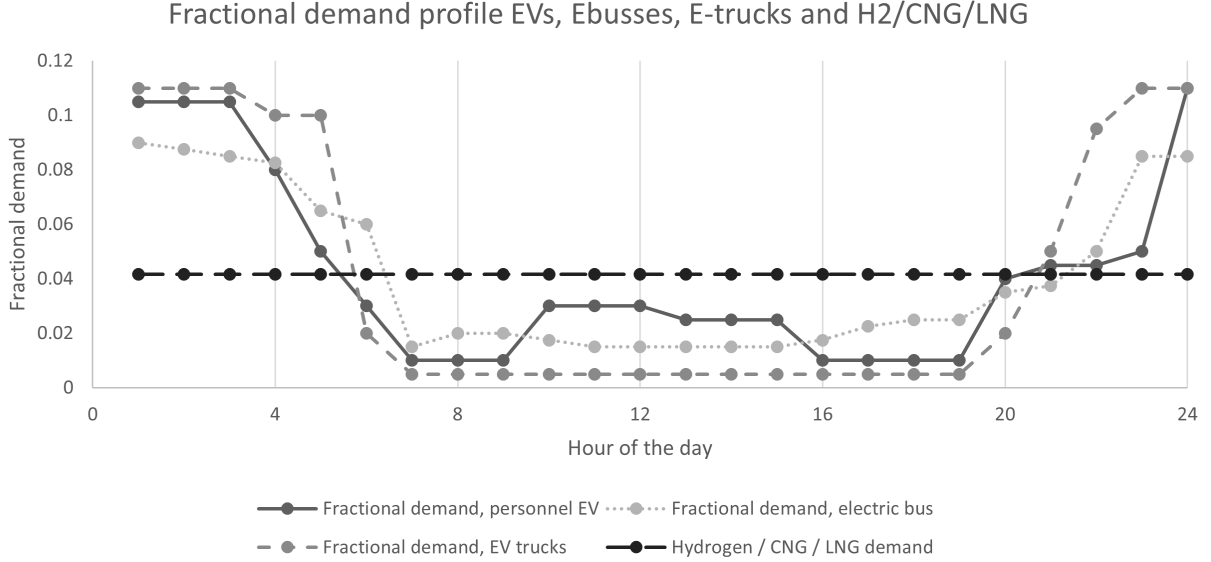


Figure 12: Fractional demand profile for charging EVs, E-busses, E-trucks and filling of CNG, LNG and hydrogen transport.

An overview of all relevant parameters for the transport sector can be found in table 6. Specifics regarding input parameters for the Global Ambitions and the Distributed Energy scenario can be found in tables 34 and 35, in annex D.

Table 6: Parameters and relevant to transport. (CBS, 2022)¹, (Entso-e, 2022b)², (Eurostat, 2022)³, (Blok and Nieuwlaar, 2016)⁴

Key factors	Unit	Type
Electricity demand ^{1,2,3}	GWh/h	Output
Natural gas demand ^{1,2,3}	GWh/h	Output
Hydrogen demand ^{1,2}	GWh/h	Output
Vehicles ^{1,2}	vehicle per region	Parameter
Average distance ^{1,2}	km per person per day	Parameter
Aviation passengers ^{1,2}	passenger	Parameters
Tonnes transported ^{1,2}	ton	Parameter
Distance share ^{1,2}	%	Parameter
Technology share ²	%	Parameter
Energy consumption ⁴	MJ/km	Parameter
Energy consumption ⁴	MJ/tkm	Parameter

5.3 Energy supply

Energy supply technologies for the base year 2022 are derived from Schram et al. (2019), entso e (2022), national and regional statistics and, regional energy scenarios and TYNDP data for the years 2030 and 2040. The investment candidates eligible in this research are identical to those in Entso-e (2022a). Primary inputs for the modeling are the types of investment candidates and their techno-economic parameters, and

the quantity allowed to be built per specific node. Hence, an overview of the investment candidates with their associated capital (CAPEX), fixed (FOM), variable (VOM) operational and retirement expenditures is shown in table 7. An average discount rate of 4% is used (Hermelink and de Jager, 2015). Additionally, coal and lignite fired coal power plants are not allowed to be built from 2030 onward. An overview regarding all technological parameters of all technologies used are shown in table 24 in Annex A.

Table 7: CAPEX, FOM, VOM costs and lifetime for all relevant investment candidates concerning electricity production, conversion and storage (Entso-e, 2022a).

Technology	Scenario	CAPEX (EUR/MW)		FOM (EUR/MW-yr)		VOM (EUR/MWh)		Retirement (EUR/MW)		Lifetime (years)
		2030	2040	2030	2040	2030	2040	2030	2040	
Onshore wind	DE	915000	817000	10500	9100	1.302	1.281	n/a	n/a	30
	GA	1220000	1166000	14700	13400	1.302	1.281	n/a	n/a	
Offshore wind	DE	2076000	1954000	38800	35900	2.835	2.625	n/a	n/a	30
	GA	1620000	1440000	30500	26600	2.835	2.625	n/a	n/a	
Solar PV	DE	380000	330000	6000	5400	0	0	n/a	n/a	40
	GA	444000	385000	8300	7900	0	0	n/a	n/a	
Gas CCGT	DE/GA	83000	800000	27800	26900	0	0	n/a	n/a	30
Gas OCGT	DE/GA	435000	424000	27800	26900	0	0	n/a	n/a	30
P2G	DE/GA	340000	270000	15000	12500	0	0	n/a	n/a	25
Hydrogen OCGT	DE/GA	435000	424000	27800	26900	0	0	n/a	n/a	30
Hydrogen CCGT	DE/GA	83000	800000	27800	26900	0	0	n/a	n/a	30
Coal	DE/GA	n/a	n/a	25.6	25.6	0	0	32500	32500	50
Lignite	DE/GA	n/a	n/a	32.5	32.5	0	0	32500	32500	50
Nuclear	DE/GA	5700000	5700000	0	0	92.5	92.5	n/a	n/a	70
Hydro - reservoir	DE/GA	6400	6400	0	0	0.001	0.001	n/a	n/a	100
Hydro - run off	DE/GA	6400	6400	25	25	0	0	n/a	n/a	100
Hydro - pumped storage	DE/GA	7000	7000	0	0	0.1	0.1	n/a	n/a	100
Battery	DE/GA	730000	650000	18000	16000	0	0	n/a	n/a	30

Per region, existing supply technologies are taken in to account for the year 2020. Hence, regional RES strategies of the Netherlands are used for the allocation of newly built solar PV and onshore wind for each individual NUTS-2 region in the Netherlands (RES, 2022). These allocations are scaled accordingly to match the Global Ambition and Distributed Energy scenario for their respective capacities. Second, the allocation of offshore wind is done according to the tender allocation of the ministry of economic affairs (EZK, 2022), to meet the target of 21 and 38 GW in 2030 and 2040 respectively. According to TYNDP scenario output, newly built gas fired turbines will be fired by hydrogen from 2040 onward. The built out of these turbines is optimized in the modeling process. Hence, no allocation is predefined for the latter. An overview of all installed capacities of the two scenarios in the Netherlands is depicted in figure 13. The installed capacities of all supply technologies for the Netherlands its neighbouring countries is retrieved from Entso-e (2022a). An overview of the latter can be found in table 28 in Annex C.

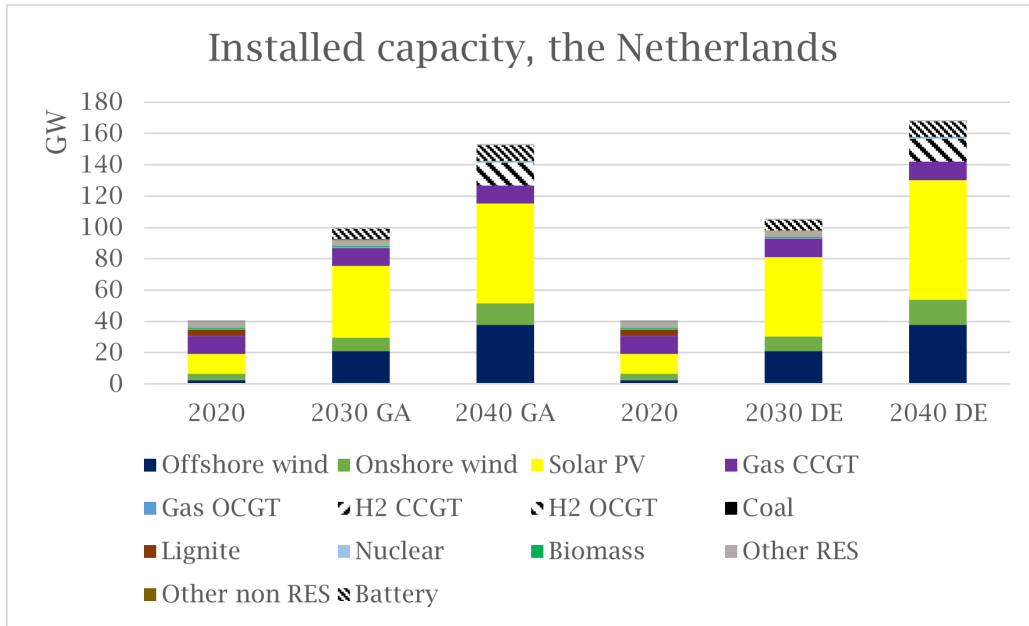


Figure 13: Installed capacity supply technologies in the Netherlands for the GA and DE scenarios in 2020, 2030 and 2040.

The allocation of power to gas (P2G) is done according to previous research of Guidehouse, with an inland configuration of electrolysis. Inland electrolysis is considered in this research, since the first configurations of electrolysis will emerge on-land (TKI, 2021). For further scenario planning with a time planning till 2050, offshore hydrogen configurations should be taken in consideration (Berenschot, 2021). In 2030, 5008 and 5186 MW of electrolysis capacity is allocated to the locations for the respective DE and GA scenario. The latter is also done for the respective capacities of 25273 and 24810 MW in 2040. An overview of the installed capacities per region is provided in table 28, in annex C.

5.3.1 Supply curves variable renewable energy sources

The production of on- and offshore wind is defined by the normalized power curve of the wind turbines in specific locations provided by Renewables Ninja, an open source data base which converts Merra-2 Global weather data in to hourly power output rates for solar PV and specific wind turbines. Output is generated from CSV. files is hence adjusted to generate average power curves by calculating the average power output for each hour step from 1 to 24, for each respective season. For the summer max season, the day with the highest average capacity factor of the summer season is used. For the winter max season, the day with the lowest average capacity factor is used.

For on- and offshore wind turbines, the Vestas V110 2000 MW and V165 9000 MW curves are used for existing turbines, respectively. A correction factor of 63% is applied to prevent overestimation of the capacity factors in the Netherlands (Staffell and Pfenninger, 2016). For newly built offshore wind turbines, the TYNDP climate database provides supply curves for 2030 offshore wind turbines. Hence, these supply curves are therefore used for each respective region. 15% wake losses are assumed for both on- and offshore wind turbines. For solar PV, renewables Ninja is used to comprise supply curves at NUTS-2 level in the Netherlands, with the average tilt used in the Netherlands of 35 °and a azimuth of 180°. For NUTS-0 regions, the TYNDP climatic database is used in the same manner as for the on- and offshore wind turbines. 10%

system losses accounted are for solar PV. An overview of the average capacity factors concerning on- and offshore wind turbines and solar PV for all NUTS 2 regions in the Netherlands are shown in table 8. The capacity factors for all VRES technologies per individual region can be found in Annex B and C.

Table 8: Average seasonal capacity factors for all NUTS-2 regions in the Netherlands.

	Offshore wind	Onshore wind	Solar PV
Spring	0.47	0.20	0.14
Summer	0.43	0.24	0.20
Summer Max	0.43	0.37	0.21
Autumn	0.58	0.26	0.09
Winter	0.58	0.36	0.03
Winter Max	0.12	0.17	0.03

5.3.2 Availability of energy carriers

Domestic availability and production of energy carriers are in many cases not sufficient to meet demand. Therefore, imports of energy carriers like natural gas, LNG, bio methane and hydrogen are allowed, but bounded to availability. This research assumes unlimited availability of biomass, uranium, coal, wind, solar, and others. However, natural gas, bio methane, hydrogen and LNG are limited in their availability from specific locations. The locations and their associated yearly maximum fuels are adapted from Entso-e (2022b) and Guidehouse (2022). For this research, the upper boundaries are used, and are shown in table 9. The resources are either available through pipe (Methane East, North Sea and South) or through ship (LNG). The capacities are defined by pipeline size and turnover capacities at specific ports. An overview of LNG capacity per area and pipeline capacity is depicted in table 29 in Annex D.

Table 9: The availability of the bounded resources towards the European Union.

Feedstock	Sub region	Season	2020 (TWh)	2030 (TWh)	2040 (TWh)
Methane East	Total	Total	1236	993	104
Methane North Sea	Total	Total	104	39	6
Methane North	Total	Total	1045	801	801
Hydrogen South	Total	Total	0	0	259
Hydrogen East	Total	Total	0	0	114
Hydrogen North	Total	Total	0	217	217
LNG Middle East	Total	Total	153	139	57
LNG North Africa	Total	Total	86	81	61
LNG Russia	Total	Total	12	20	8
LNG Others	Total	Total	149	141	60
LNG North America	Total	Total	111	176	70
Methane Bio	Total	Total	46.7	80.3	127

5.3.3 Emission factors and costs

In the modeling process, fossil fuels lead to emissions. The emission factors for coal, lignite and natural gas are 0.347, 0.364, and 0.202 ton of CO₂ per MWh, following the guidelines of Entso-e (2022a). Emissions from VRES, biomass and hydrogen are set to zero. Hence, emissions from power production are subjected

to costs per ton CO₂ emitted to the environment. An overview of the emission costs for the years 2020, 2030 and 2040 is shown in table 10.

Table 10: Emission costs in Euro per ton CO₂

Year	2020	2030	2040
Emission costs (EUR/ton CO ₂)	78	78	123

5.4 Interconnection

Interconnection capacities between regions in the scope of this research are retrieved from Guidehouse, TSOs and regional and international energy scenarios, for all respective energy carriers. Transmission and distribution capacities within the nodes are not in the scope of this research, and are therefore allowed to expand indefinitely at no costs. From personnel communication with TenneT, the net transfer capacity of transmission between the NUTS-2 regions is set at two thirds of the MVar (Wevers, 2022). Static prices for the import of hydrogen are assumed concerning the import of hydrogen throughout the seasons and the respective time steps. Figure 14 and 15 illustrate the high voltage network and the natural gas transmission network respectively.



Figure 14: High voltage transmission network operated by TenneT in the Netherlands.



Figure 15: Transmission network operated by Gasunie in the Netherlands.

No additional transmission capacity is built for methane in the Netherlands (Gasunie, 2021). Hence, no

expansion for methane infrastructure is allowed. Additionally, a maximum of 10 GW of pipeline capacity is available for the conversion to retrofitted hydrogen pipelines (Gasunie, 2021). No constraint is in place for newly built hydrogen pipelines. Expansion of the electricity, hydrogen and natural gas transmission grid is considered as an investment candidate in the modeling process. An overview of the CAPEX, FOM and VOM costs for each candidate is shown in table 11. The assumption is made that all hydrogen pipelines are 1.21 m in diameter, since only the transmission network is taken in to account (Guidehouse, 2022). Transmission losses for overhead HVAC, subsea HVAC, overhead HVDC and subsea HVDC are set at 0.7, 0.7, 0.35 and 0.35% per 100 km (entsoe, 2022, Zappa et al., 2019).

Table 11: CAPEX, FOM and VOM for different types of infrastructure technologies for transmission of electricity, hydrogen and natural gas.

Infrastructure technology	Type	CAPEX (EUR/km/MW)	FOM (EUR/km/MW - year)	VOM (EUR/MWh)
HVAC	Over land	698	13.96	0.04
HVAC	Subsea	1344	26.88	0.04
HVDC	Over land	940	18.8	0.04
HVDC	Subsea	1900	38	0.04
Natural gas pipe	Over land	141	2.82	0.03
Natural gas pipe	Subsea	250	5	0.03
Hydrogen retrofit	Over land	94	1.88	0.05
Hydrogen retrofit	Subsea	156	3.12	0.05
Hydrogen new	Over land	281	5.62	0.05
Hydrogen new	Subsea	500	10	0.05

5.5 Storage

Energy storage facilities in the scope of this review are salt caverns applicable for hydrogen storage, battery storage, pumped hydro storage facilities and hydro reservoirs. Salt caverns are currently the only proven storage facilities which can store hydrogen (Guidehouse, 2022). The size and location of these are taken from research of Guidehouse for the European Hydrogen Backbone in Europe. In this research, all eligible locations are selected and quantified by size, injection capacity and withdrawal capacity. An overview of all storage facilities in the Netherlands is shown in figure 16. The capacity of the salt cavern storage, 'De Zuidwending', is roughly 6 TWh that can be stored. The withdrawal and injection capacity has a maximum of almost 16 GW. The total storage capacity of the other gas storage facilities in this research is roughly 120 TWh, and are able to inject or withdrawal at a capacity of 114 GW (Gasunie, 2021).

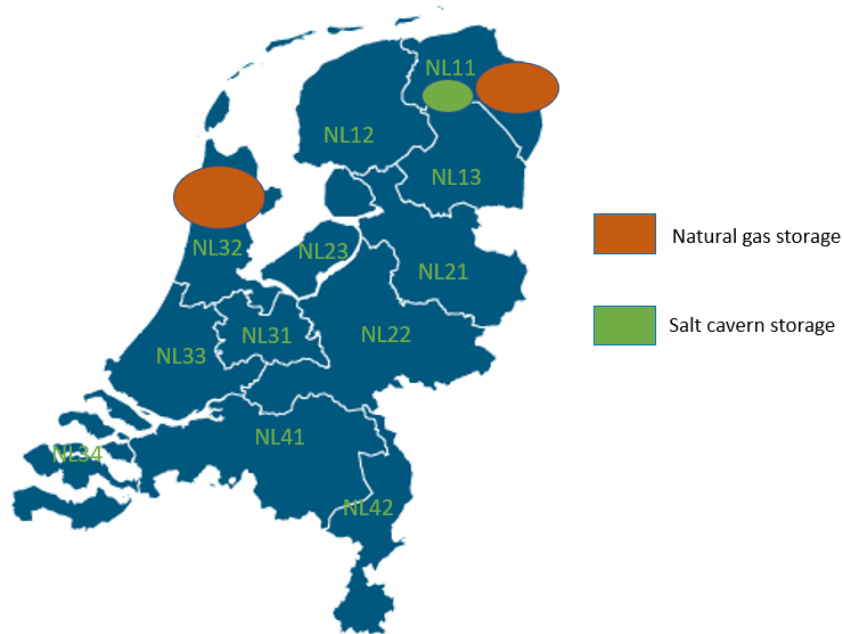


Figure 16: Natural gas storage facilities in the Netherlands, brown indicating regular natural gas storage and green indicating salt cavern storage.

Hence, since the conversion of salt caverns into hydrogen storage facilities and operation of natural gas storage are also treated as an investment candidates in the modeling process, an overview of the economic parameters is shown in table 12.

Table 12: CAPEX, FOM, FOM and retirement costs for hydrogen storage and natural gas storage.

Infrastructure technology	CAPEX (EUR/MWh)	FOM (EUR/MWh - year)	VOM (EUR/MWh)	Retirement (EUR/MWh)
Hydrogen storage	172.00	6.88	0.00	n/a
Natural gas storage	114.67	0	10.00	172.02

Battery storage and the available capacities are taken from TYNDP (Entso-e, 2022b). The storage capacities of batteries is 3 hours of the existing capacity (Entso-e, 2022a). In the Netherlands, the allocation of batteries is done according to the ratio of installed onshore renewable capacity relative to the total installed onshore renewable capacities in the Netherlands. Onshore renewable capacities include onshore wind turbines and solar PV.

The pumped hydro storage in neighbouring countries differs of size and installed capacity. The characteristics including efficiency and lifetime of pumped hydro facilities are the homogeneous over all countries. Pumped hydro facilities have a maximum energy that is depicted by the amount of energy that can be stored in a reservoir. The total energy storage capacity for each country is presented in table 13. In the model, the total energy storage capacity is reflected by multiplying the installed capacity with the amount of hours (referred in the characteristics as 'Storage Duration') to reach the maximum energy storage.

Table 13: Installed capacity and storage size of pumped hydro in Belgium (BE00), Germany (DE00), Norway (NO00) and the United Kingdom (UK00).

	Capacity (MW)	Storage (GWh)
BE00	1310	5.7
DE00	9280	39.12
NO00	1369	399.4
UK00	2833	26.7

Hydro reservoirs, in contrary to pumped hydro storage, can't store electricity and are reliant on the inflow of water. The TYNDP climatic database, included with the TYNDP building guidelines, provides hourly capacity factors of hydro reservoirs for individual countries, which also take the availability of water in to consideration. Consequentially, the average hourly capacity factors of each respective season are used to represent the hourly electricity production from these reservoirs.

5.6 Energy system modeling

In this section, an introduction of the model used is provided. Thereafter, a formulation for the economic optimisation of the energy system is provided.

5.6.1 LCP model

The model used in this research is the low carbon pathway (LCP) model, which is written in R programming language. Guidehouse's LCP model is a long-term energy system model that allows for integrated capacity expansion and dispatch optimization across multiple sectors of the energy system (power, gas, hydrogen, heat, and others) to meet future demand while meeting greenhouse emission and other defined targets.

The LCP model is formulated as linear optimization problem and minimizes from a central planning perspective the net present value of total capital expenditures and operational expenditures over the study period. Investments and decommissioning of generation, storage and transmission capacities are optimized simultaneously while considering inter-dependencies between sectors caused by sector-coupling technologies such as power-to-gas, power-to-heat or gas-fired power plants. To ensure fast computational time, representative days with chronological time-steps are used to consider seasonal and diurnal variability of demand and availability of intermittent renewable energy resources during investment decisions.

Major results of the LCP model are the optimal build out and utilization of generation, storage and transmission capacities to meet future demand, capital and operational expenditures and greenhouse gas emissions over the study period, and energy flows between sectors and regions.

5.6.2 Formulation for the economic optimisation of the energy system

In this subsection, the formulation for the economic optimisation of the LCP model is described. The LCP model is a linear cost optimization where the CAPEX of the built out of technology and infrastructure and OPEX of infrastructure and technology operations, fuel costs and emission costs are subjected to minimize costs. Hence, the set of quantities, or decision variables, to be determined to solve the problem are depicted

in section 5.6.5. Consequentially, the optimization problem is bounded by constraints; further elaborated in section 5.6.4.

An overview of all terms and subscripts used is depicted in table 14. A specification for costs, losses and emissions can be found in section 5.

Table 14: Terms and subscripts used for the economic optimisation of the energy system.

Label	description	Unit	Label	description	Unit
t	1 hour interval	hour	p_i	infrastructure costs	Eur/MW-km
T	number of intervals	n	$P_{com/decom}$	capacity expansion/ decommissioning costs	Eur/MW
i	area	n	I	new infrastructure built	MWkm
G_n	total area	n	B	new capacity built	MW
n	unit	n	P	power	MW
N	all units	n	NG	Natural gas	MW
m	export / import area	n	H	Hydrogen	MW
M	all export / import areas	n	L	losses	MW
k	period	n	X	import / export	MW
K	all periods	n	SoC	state of charge	GWh
C	total costs	Eur	SoC ₀	starting state of charge	GWh
p_f	fuel costs	eur/MWh	E	emissions	tco ₂
SC	Start up costs	Eur	F	fuel	MWh
p_e	emission costs	eur/tco ₂	R	Existing infrastructure	MW
D	Discharge	MWh			

5.6.3 Objective function

The objective of the optimization model is to minimize costs regarding the demand of electricity, hydrogen and natural gas through the pre-determined set of 365 representative days. The objective function is formulated in equation 6.

$$\text{Objective Function} = \underset{\text{minimize}}{\left\{ \sum_{n \in N} \sum_{i \in G_n} (SC_i^n(t) + \sum_{t \in T} C_i^n(P_i^n(P_i^n(t), NG_i^n(t), H_i^n(t))) \right\}} \quad (6)$$

The objective function is dependent on the formulation of the total costs induced by capital expenditures, variable (VOM) and fixed (FOM) operation and maintenance costs. The costs are defined as depicted in equation 7.

$$C(P, NG, H) = (p_f + p_e)(P^n * F^n) + (p_i + p_{com/decom})(I + B) + R^n * p_i \quad (7)$$

5.6.4 Constraints concerning optimisation problem

In this subsection, the constraints applicable for the LCP model are shown. For all respective energy carriers, the supply must be equal to supply. Supply equals regional generation plus import and minus exports. The balances are depicted in equations 8-10.

Where, electricity balance constraint:

$$\sum_{i \in G_n} P_i^n(t) - L_i^n(t) + \sum_{m \in M} X_m(t) - \sum_{m \in M} X_m(t) = 0, \quad \forall n \in N \quad (8)$$

The natural gas balance constraint:

$$\sum_{i \in G_n} NG_i^n + \sum_{m \in M} X_m(t) - \sum_{m \in M} X_m(t) = 0, \quad \forall n \in N \quad (9)$$

And the hydrogen balance constraint:

$$\sum_{i \in G_n} H_i^n(t) + \sum_{m \in M} X_m(t) - \sum_{m \in M} X_m(t) = 0, \quad \forall n \in N \quad (10)$$

Hence, the inter-area capacity can't be larger than available infrastructure, which is depicted in equation 11.

$$X_m(t) \leq \bar{X}_m, \quad \forall t \in T, \forall m \in M \quad (11)$$

Consequentially, equation 12 depicts new capacities allowed for construction which can't exceed the maximum allowed capacity to be built between two regions. This maximum is derived from the results of subsection 5.4.

$$X_{m,new} \leq \bar{X}_{m,scenario}, \quad \forall t \in T, \forall m \in M \quad (12)$$

Hence, the maximum and minimum generation can't exceed minimum power and maximum power of each energy technology, usually between 0 and P_{max} , except for nuclear which is usually not switched off. The latter is depicted at equation 13.

$$\underline{P}_i^n \leq P_{i(t)}^n \leq \bar{P}_i^n, \quad \forall i \in G_n, \forall n \in N, \forall t \in T \quad (13)$$

The ramp rate of specific energy technologies is depicted by equation 14. The ramp rate specifies the rate that power increases or decreases per unit of time, until it reached the minimum or maximum generation capacity respectively.

$$max_t \left| \frac{P_i^n(t+1) - P_i^n(t)}{\Delta t} \right| \leq R_i^n(t), \quad \forall i \in G, \forall n \in N \quad (14)$$

The inter periodic energy stored in pumped storage is modeled as shown in equation 15. The latter describes the power generated can't exceed the amount of energy in the reservoir.

$$\sum_{kn_{period}}^{(k+1)_{period}} P_i^n * \Delta t \leq E_i^n(k), \quad \forall i \in G_n, \forall n \in N, \forall k \in K \quad (15)$$

Hence, the inter periodic equation for hydrogen storage is depicted in 16.

$$\sum_{kn_{period}}^{(k+1)_{period}} P_i^n * \Delta t \leq E_i^n(k), \quad \forall i \in G_n, \forall n \in N, \forall k \in K \quad (16)$$

Seasonal energy storage modeling for hydrogen storage and the intra-state of the SoC is depicted in equation 17. This depicts the SoC for time steps in a period k .

$$\sum_{i \in G_n} SoC_{k,t+1}^n = SoC_{k,t}^n (1 - \eta^{self} \Delta t) + \Delta t \{ \eta^{charge} \dot{E}_{k,t}^{charge} - \frac{\dot{E}_{k,t}^{dis}}{\eta^{dis}} \} \quad \forall k \in K, \forall n \in N \quad (17)$$

However, the storage can't be below 0 or exceed the maximum capacity of the SoC. The latter is depicted in equation 18.

$$0 \leq SoC_{k,t}^n (1 - \eta^{self}) + SoC_{k=f(t)}^n \leq D, \quad \forall t \in T, \forall n \in N \quad (18)$$

The state of charge at the first time slice is set at 0, depicted in equation 19.

$$SoC_{k,1}^n = 0, \quad \forall n \in N, \forall k \in K \quad (19)$$

The SoC between different periods is shown in equation 20.

$$\sum_{i \in G_n} SoC_{k+1}^n = SoC_k^n (1 - \eta^{self})^K + SoC_{t,k+1}^n, \quad \forall n \in N, \forall k \in K \quad (20)$$

Also, all the SoCs of multiple periods are linked as shown in equation 21.

$$SoC_{k+1}^n = SoC_k^n, \quad \forall k \in K, \forall n \in N \quad (21)$$

Finally, an emission constraint can be set in the LCP model, to align emissions with targets set by specific or agglomerate regions. The latter is depicted in equation 22.

$$\sum_{i \in G_n} E_i^n \leq E_{max}, \quad \forall n \in N \quad (22)$$

5.6.5 Decision variables

The decision variables for the linear optimization problem are depicted by the built out of transmission infrastructure and storage. However, the built out of repurposed hydrogen and wires is constraint, the built out of newly built hydrogen infrastructure is not constrained. Additionally, from 2040 onwards, hydrogen fired gas turbines are allowed to be built. There is no freedom for the model to optimize the built out of other energy conversion technologies, these are all set to fixed capacities.

5.7 Analysis of results

The results regarding solving the optimization problem will be analyzed on several key performance indicators (KPI). The KPIs are: direct electricity use (equation 23) and indirect electricity use (equation 24) to indicate the ratio of conversion need of electricity.

$$\text{Direct electricity use} = \frac{\sum P_{n,NL}^{i,NL}}{\text{Demand}_{i,NL}} \quad [\%] \quad (23)$$

and

$$\text{Indirect electricity use} = \frac{\sum P_{n,NL}^{i,NL}}{\text{Demand}_{i,n,NL}^{P2G}} \quad [\%] \quad (24)$$

The ratio of exported energy relative to domestic production and the ratio of imported energy relative to domestic demand are calculated by dividing the sum of imported and exported energy (of all individual energy carriers separately) by the sum of domestic production and demand respectively, for the years 2030 and 2040. This KPI provides insight in the dependency on imports and exports for the Netherlands. Additionally, the ratio of imported energy relative to domestic demand also provides insight regarding the self-sufficiency of the Netherlands for the year 2030 and 2040. Another KPI used in the analysis of the results is the ratio of VRES relative to the total production. This KPI provides insight regarding the decarbonization of the Dutch energy system. Lastly, the amount of curtailment and unserved energy in the system are selected as KPIs. The latter indicate economic feasibility of the system, as a higher degree of curtailment indicates a lower economic feasibility for VRES. The yearly curtailment is calculated by dividing the yearly dispatched energy with the total yearly maximum energy to be dispatched (in MWh), depicted in equation 25. The maximum energy to be dispatched is dependant on the supply curves of individual supply technologies.

$$E_{\text{curtailed}} = \frac{\text{Yearly dispatched energy}}{\text{Yearly maximum energy to be dispatched}} \quad [\text{MWh}] \quad (25)$$

Unserved energy usually impedes higher system costs, which in this model are tackled through slack variables, with a standardized penalty of 50 times the costs of the respective energy carrier at the given time step and area. Hence, unserved energy will lead to substantially higher shadow costs for the production of either electricity or hydrogen. The amount of unserved energy is calculated as provided in equation 26.

$$\text{Unserved demand} = \text{yearly demand} - (\text{yearly production} - \text{yearly curtailed energy}) \quad [\text{MWh}] \quad (26)$$

The storage facilities for hydrogen and inter-connectors for all three respective energy carriers are assessed on the capacity factor of the storage facilities. The capacity factor is calculated through equation 27.

$$\text{Capacity factor}_i = \frac{E_{\text{generated},i}}{\text{Capacity}_i * 8760\text{hours}} \quad (27)$$

6 Reference scenario validation

The building guidelines of TYNDP 2022 determine the story line of the Distributed Energy and Global Ambitions scenarios. These story lines eventually determine the key technologies used per (sub-)sector, except for the industrial demand for the respective energy carriers. However, the story lines build upon a reference case, in this case the year of 2020. Therefore, the calculated annual demand through the representative days should be assessed for validation of reference data.

The reference scenario considers the built environment, industrial sector including the branches of the manufacturing of food products, chemicals, and basic metals, totalling the majority of the respective energy carriers assessed in this research (Sahoo et al., 2022). The transport sector considers the light and heavy duty road transport, busses, aviation, shipping and rail transport in the Netherlands. A comparison between historic data and calculated data for the sectors in scope for the year 2020 in the Netherlands is shown table 15.

Table 15: Comparison of historical annual demand of the Netherlands with calculated annual demand for electricity, natural gas and hydrogen for the year 2020 in TWh. **Hydrogen demand is currently produced through steam methane reforming/auto thermal reforming, and therefore included in natural gas figures.*

	Historic data, all sectors in 2020 (TWh)	Historic data, sectors in scope in 2020 (TWh)	Calculated, sectors in scope in 2020 (TWh)	Difference, sectors in scope (%)
Electricity	111.2	99.6	92.2	-9.2
Methane	239.2	222.5	232.8	+4.6
Hydrogen*	0.0	0.0	0.0	0.0

7 Results

In this section, the results of the three sub-questions are presented in order to answer the main research question, which is presented as "What system design choices, regarding inter-connectivity and storage, can contribute towards the integration of variable energy sources in the Dutch energy system, in the year 2030 and 2040?". First however, general results regarding the final annual energy demand of the Global Ambitions and General Ambitions scenarios are provided in section 7.1. Second, the first sub-question will be answered in section 7.2 using the key performance indicators described in section 5.7. The latter is also performed in sections 7.3 and 7.4.

7.1 General results Global Ambitions and Distributed Energy scenario

In this section, the general results of the Global Ambitions and Distributed Energy scenarios are provided. First, the annual final energy demand for electricity, hydrogen and natural gas in the Netherlands are depicted in figure 17. Additionally, the availability of the bounded resources is assessed for the total demand of all regions incorporated in this research.

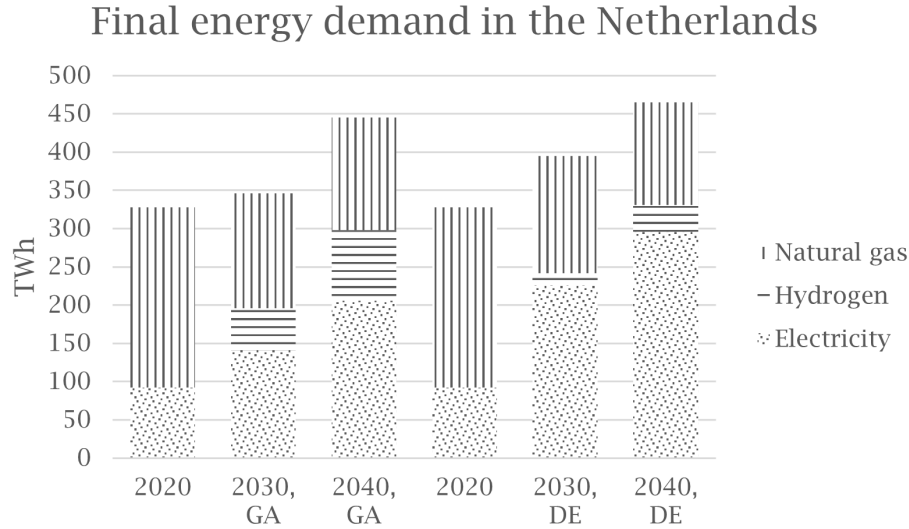


Figure 17: Final energy demand of DE and GA scenario for electricity, hydrogen and natural gas in the Netherlands in the years 2020, 2030 and 2040.

The annual demand for electricity steeply increases towards 2030 and 2040 in both scenarios. However, the Distributed Energy scenario depicts an increase towards 225.7 and 295.8 TWh in 2030 and 2040 respectively. This is a relative difference of 59.9 and 43.6 % compared to the Global Ambitions scenario. On the other hand, the annual demand of hydrogen rapidly evolves in the Global Ambitions scenario towards the respective values of 54.5 and 92.6 TWh in 2030 and 2040. This is a relative difference of 342.8 and 262.9 % compared to the Distributed Energy scenario in 2030 and 2040 respectively.

In 2030, the availability of imports of hydrogen can't satisfy maximum demand (GA) for all the regions modeled in this regions, which is 361.3 TWh annually. Hence, there is a requirement to at least produce 144.3 TWh of hydrogen per year in 2030. In 2040, 590 TWh of hydrogen imports is available, compared to 773 TWh of maximum demand (GA), which results in a required production of 183 TWh per year. The total import availability of natural gas is 2470.3 TWh in 2030, and total demand is well below with 1286 TWh (GA). In 2040, 1297 TWh of natural gas is available for transport. With a maximum demand (GA) of 843.8 TWh, import is able to suffice demand.

7.2 Expected exchange capacity and volume for electricity, natural gas and hydrogen, and implications for the economic feasibility of VRES in 2030 and 2040

In this section, the exchange capacity and volume for electricity, methane and hydrogen and its implications for the economic feasibility for VRES in 2030 and 2040 are discussed. The exchange between the energy carriers depends on the demand and availability, with the latter comprising of domestic/regional production and interconnection capacities with surrounding regions. If domestic or regional supply can't satisfy demand, demand should be satisfied through interconnection with neighbouring regions. Hence, this implies that peak demand should be able to be fulfilled by the sum of production and import for all areas in consideration. The modeled interchange capacities are shown in figures 18 - 21 and depicted in tables 17 and 16.

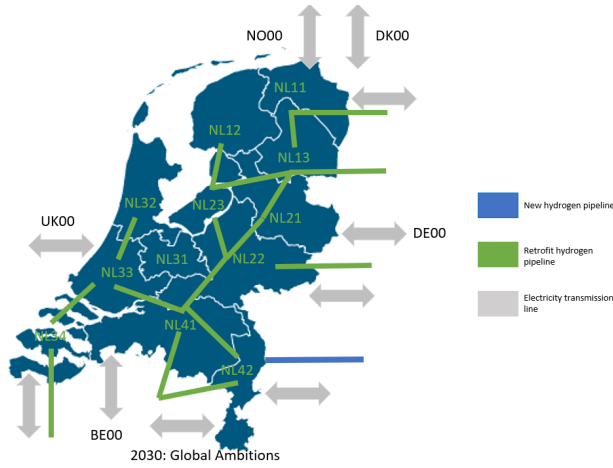


Figure 18: Overview exchange capacities GA 2030 for retrofitted hydrogen pipelines (green), newly built hydrogen pipelines (blue) and electricity transmission lines (grey).

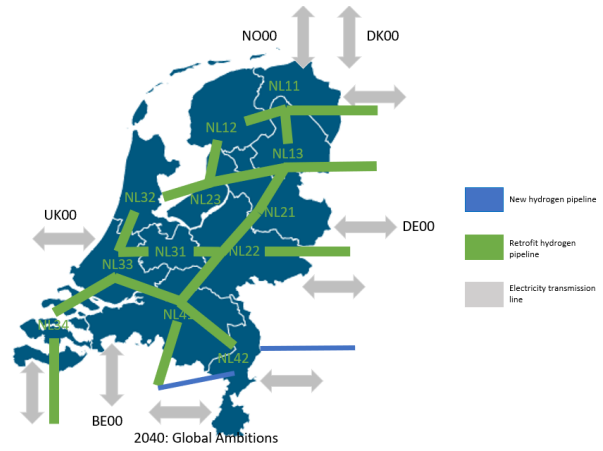


Figure 19: Overview exchange capacities GA 2040 for retrofitted hydrogen pipelines (green), newly built hydrogen pipelines (blue) and electricity transmission lines (grey).

Table 16: Interconnection capacities with neighboring countries of the Netherlands regarding electricity, hydrogen and natural gas for Global Ambitions scenario in the years 2030 and 2040,.

	Electricity 2030 (MW)	Electricity 2040 (MW)	Hydrogen New 2030 (MW)	Hydrogen new 2040 (MW)	Hydrogen retrofit 2030 (MW)	Hydrogen retrofit 2040 (MW)	Natural gas 2030 (MW)	Natural gas 2040 (MW)
NL11-DE00	900	900	0	0	10000	20000	59305	49605
NL11-DK00	700	700	0	0	0	0	0	0
NL11-NO00	700	700	0	0	0	0	35958	35958
NL13-DE00	0	0	0	0	10000	13200	3200	0
NL21-DE00	1250	1600	0	0	10000	20000	19964	9964
NL22-DE00	1250	1600	0	0	10000	20000	12092	2092
NL33-UK00	1000	1000	0	0	0	0	20583	20583
NL34-BE00	90	1350	0	0	10000	20000	45444	35444
NL41-BE00	500	1000	0	0	10000	20000	14817	4817
NL42-DE00	800	800	10562	10562	0	0	41583	41583
NL42-BE00	450	450	0	1242	0	0	13861	13861

All the electrical transmission lines are fully expanded in the DE scenario till the constraint depicted by TYNDP. For the repurposed pipelines, the same is observed within the Netherlands and from the Netherlands towards neighbouring countries. However, there are also newly built hydrogen pipelines built from Germany (DE00) to Limburg (NL42), and from Belgium (BE00) to Limburg in the years 2030 and 2040. No new undersea pipelines are built from the Netherlands towards the United Kingdom (UK00), Denmark (DK00) and Norway(NO00).

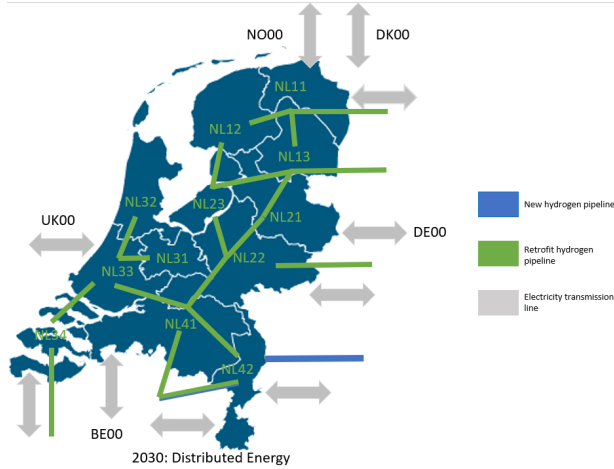


Figure 20: Overview exchange capacities DE 2030 for retrofitted hydrogen pipelines (green), newly built hydrogen pipelines (blue) and electricity transmission lines (grey).

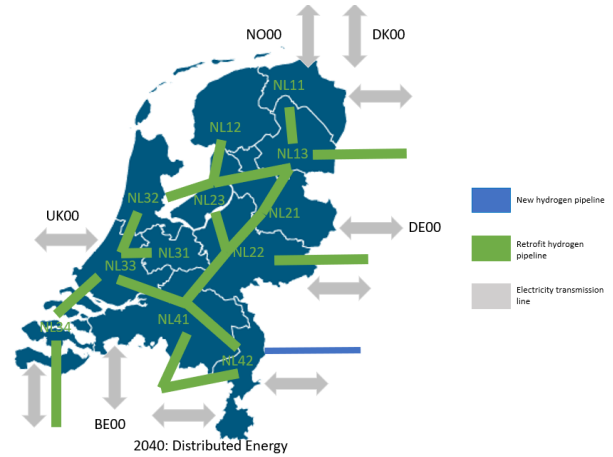


Figure 21: Overview exchange capacities DE 2040 for retrofitted hydrogen pipelines (green), newly built hydrogen pipelines (blue) and electricity transmission lines (grey).

Table 17: Interconnection capacities with neighboring countries of the Netherlands regarding electricity, hydrogen and natural gas for Distributed Energy scenario for the years 2030 and 2040,.

	Electricity 2030 (MW)	Electricity 2040 (MW)	Hydrogen New 2030 (MW)	Hydrogen new 2040 (MW)	Hydrogen retrofit 2030 (MW)	Hydrogen retrofit 2040 (MW)	Natural gas 2030 (MW)	Natural gas 2040 (MW)
NL11-DE00	900	900	0	0	10000	20000	59305	49605
NL11-DK00	700	700	0	0	0	0	0	0
NL11-NO00	700	700	0	0	0	0	35958	35958
NL13-DE00	0	0	0	0	10000	13200	3200	0
NL21-DE00	1250	1600	0	0	10000	20000	19964	9964
NL22-DE00	1250	1600	0	0	10000	20000	12092	2092
NL33-UK00	1000	1000	0	0	0	0	20583	20583
NL34-BE00	90	1350	0	0	10000	20000	45444	35444
NL41-BE00	500	1000	0	0	10000	20000	14817	4817
NL42-DE00	800	800	13769	13679	0	0	41583	41583
NL42-BE00	450	450	293	1137	0	0	13861	13861

Similar to the DE scenario, all of the electrical transmission lines are fully expanded in the GA scenario till the constraint depicted by TYNDP. For the repurposed pipelines, the same is observed. However, there are also newly built hydrogen pipelines built from Germany (DE00) to Limburg (NL42), and from Belgium (BE00) to Limburg in the years 2030 and 2040. However, there is a -23.3% difference between the newly built out hydrogen pipelines in the GA scenario relative to the DE scenario.

The energy system and its infrastructure is optimized to fulfill demand at peak demand. Hence, figures 22 and 23 illustrate peak demand of the Netherlands in 2030 and 2040, regarding electricity, methane and electricity for 2030 and 2040 for the Global Ambitions and Distributed Energy scenarios respectively.

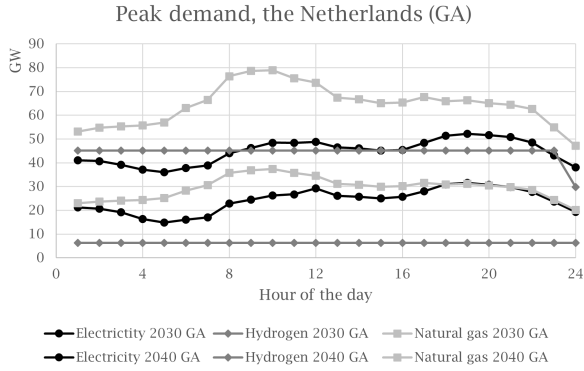


Figure 22: Peak demand in the Netherlands for GA scenario during winter, in the years 2030 and 2040.

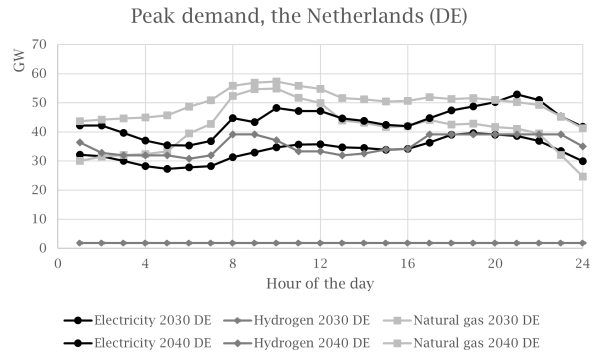


Figure 23: Peak demand in the Netherlands for DE scenario during winter, in the years 2030 and 2040.

The hourly demand for electricity and natural gas is variable over time and temperature dependent. Also, hydrogen is solely used in the chemical and steel manufacturing sectors, resulting in a flat demand curve of the energy carrier. However, these demand figures do incorporate the endogenous demand for hydrogen and methane for power production. Therefore, this results in a higher demand of both energy carriers.

The demand in the regions of the scope of this research ultimately determine the exchange volume of electricity, hydrogen and natural gas. Figure 24 depict the annual exchange volume for the latter in the years 2030 and 2040 for the GA and DE scenarios.

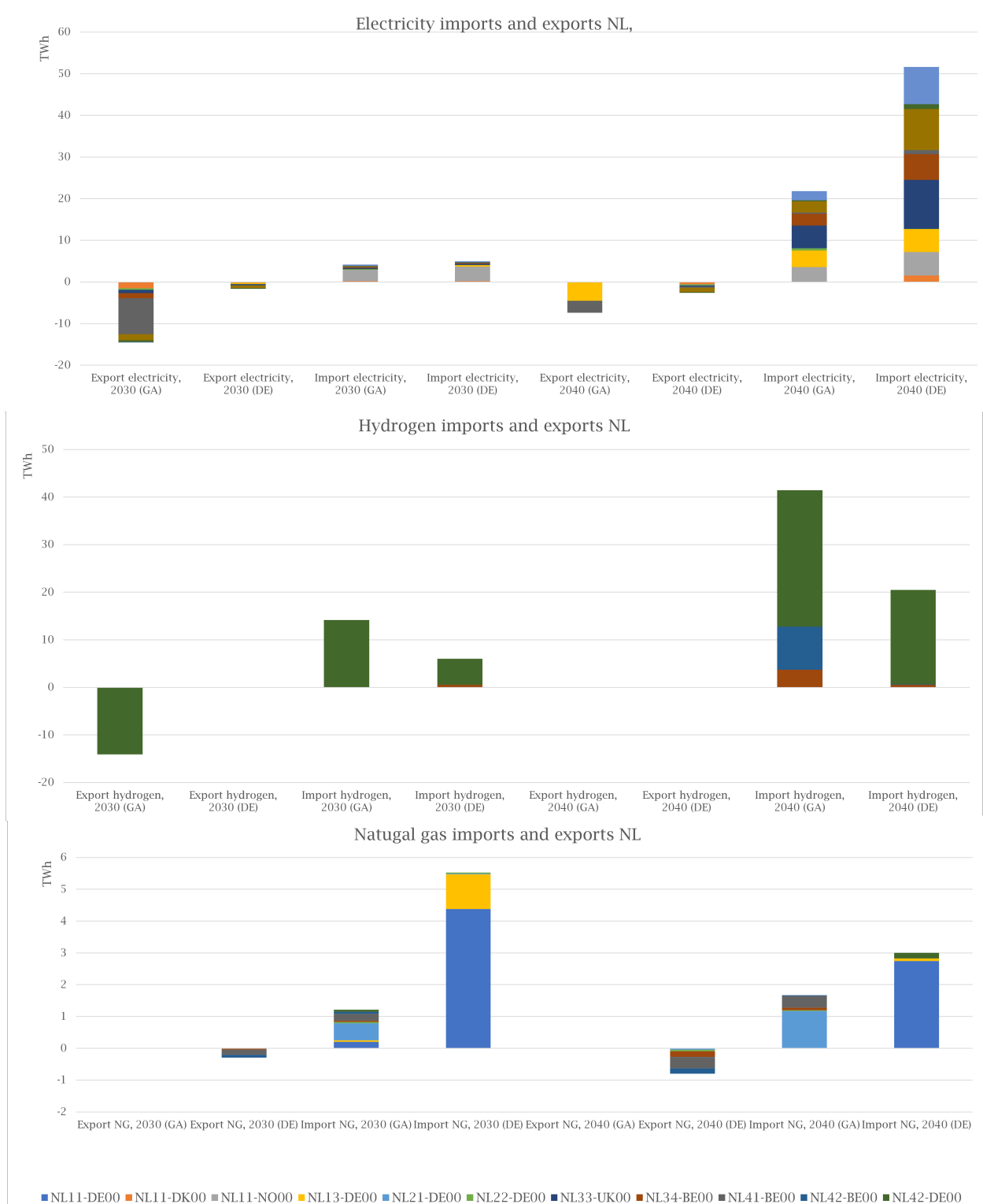


Figure 24: Import (positive) and export (negative) of electricity, hydrogen and natural gas for the GA and DE scenarios in the years 2030 and 2040.

The import and export of electricity differs for both scenarios. Due to the relatively lower electricity demand in the GA compared to the DE scenario, a larger amount of electricity is exported towards neighbouring countries (14.6 TWh/year). The largest export is from Brabant (NL41) towards Belgium (BE00) being 8.6 TWh per year. Import is in the same magnitude of size for both scenarios, with 4.2 and 5.0 TWh of imports per year for the GA and DE scenario respectively. In 2040 however, the Netherlands become largely dependent of its neighbouring countries to meet demand, especially Germany and Norway. Germany still retains 76.8 GW (roughly 70% of peak hour demand) being flexible, whilst Norway acts as a large energy buffer with 31 GW of installed hydro capacity. In the DE scenario, 51.6 TWh of electricity imports per year are required. The latter can be explained by the relatively large dependence on VRES in 2040, with only 16% (27.5 GW) of the total installed capacity being flexible. Of this 27.5 GW, 14.7 GW substantiates of H2OCGT, which also implies that relatively expensive hydrogen is used for electricity production. This relatively expensive power production can depict the merit order, and it can therefore be cost effective to import cheaper electricity from abroad. Figure 25 depicts the average shadow costs of electricity generation in 2040 for the DE scenario. And for vast amounts of the time, the price of electricity generation is higher in the Netherlands (on average) compared to its neighbouring countries.

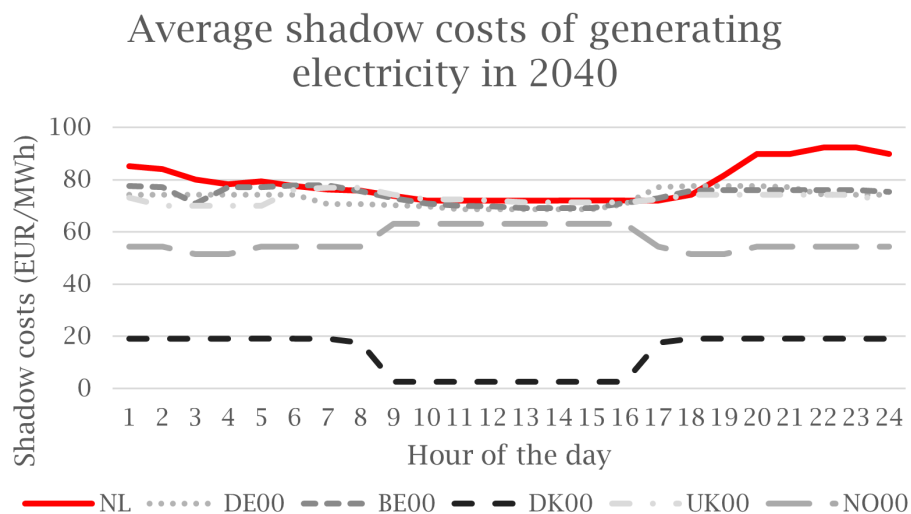


Figure 25: Average shadow costs of generation in 2040, Distributed Energy scenario.

The imports and exports of hydrogen are primarily driven by domestic and surrounding demand of the Netherlands and its neighbouring countries. In 2030, domestic production in the Netherlands is usually not able to match demand in the Distributed Energy scenario during winter and peak demand season, when solar PV production is low. At these moment, imports are usually occurring, On the other hand, during peak moments of solar (usually at noon), hydrogen is exported to primarily Germany (maximum peak of 21 GW), which is the largest consumer of hydrogen in Europe. In 2030, unserved demand during the winter occurs for hydrogen end use in Germany. The maximum availability of hydrogen imports from the North is used, production is not able to fulfill demand in 2030. This induces high shadow costs for the end user, reaching a maximum of 9870 Euro per MWh, implying current shadow costs at almost 200 Euro per MWh.

The import and export of natural gas is, compared to 2022 numbers, especially low. However, current LNG capacity is expanded from 12 billion cubic meters, or bcm, to roughly 25 bcm per year. 25 bcm is equal 244 TWh, which is already sufficient to cover the yearly demand of roughly 150 TWh of natural gas in 2030 for both respective scenarios. The injection and withdrawal capacity sums up to roughly 32 GW, and storage

capacity totalling to 114 GW. Peak demand of natural gas lies somewhere around 90 GW in 2030, and dispatch is therefore sufficient to meet demand. Dispatch occurs primarily during peak winter, to satisfy additional demand of the sectors in consideration and flexible power generation of natural gas fired turbines. The retirement of natural gas pipelines seems not to pose any transmission issues within and from and towards the Netherlands in 2030 and 2040. Solely salt caverns are retrofitted for hydrogen storage, allowing for seasonal storage. The other two major gas storage facilities remain in their function to store natural gas, with a total capacity to store roughly 120 TWh of natural gas.

To conclude this section, table 18 depicts the ratio of imported energy relative to domestic demand and ratio of exported energy relative to domestic production for the Netherlands regarding electricity, hydrogen and natural gas for the GA and DE scenarios. The imported hydrogen in 2030 and 2040 for the DE scenario is 0.28 and 0.58, which indicates a development of heavier reliance of imports of hydrogen in the Netherlands.

Table 18: Ratio of imported energy versus domestic demand and ratio of exported energy versus domestic production

	GA 2030	GA 2040	DE 2030	DE 2040
Ratio imported versus electricity demand	0.03	0.11	0.02	0.17
Ratio imported versus hydrogen demand	0.26	0.45	0.28	0.58
Ratio imported versus natural gas demand	0.01	0.01	0.04	0.02
Ratio exported versus electricity production	0.08	0.02	0.01	0.01
Ratio exported versus hydrogen production	0.34	0.00	0.00	0.00
Ratio exported versus natural gas production	0.00	0.00	0.00	0.01

7.3 Interactions between hydrogen and electricity, in the Dutch energy system and implications for the economic feasibility of VRES in 2030 and 2040

In this section, the interactions between hydrogen and electricity in the Dutch energy system and its implications for the economic feasibility of VRES are explored. First a selection of representative days is shown, hereafter annual figures are discussed.

7.3.1 Selection of representative days

In this section, a selection of representative days is shown to illustrate the hourly dispatch of electricity in the Netherlands in the years 2030 and 2040. Technologies included are energy generation technologies mentioned in section 5.3 and import and export of electricity with neighbouring countries. Representative days selected are the summer max, when the production of VRES is high but demand is average, and winter max, when the production of VRES is low but demand is high. The built out of infrastructure is optimized to be able to match demand and supply during these peak days. Hence, these situations can provide insight how the Dutch energy system interacts with its neighbouring countries during these situations. Figure 26 depicts the two situations for both scenarios.

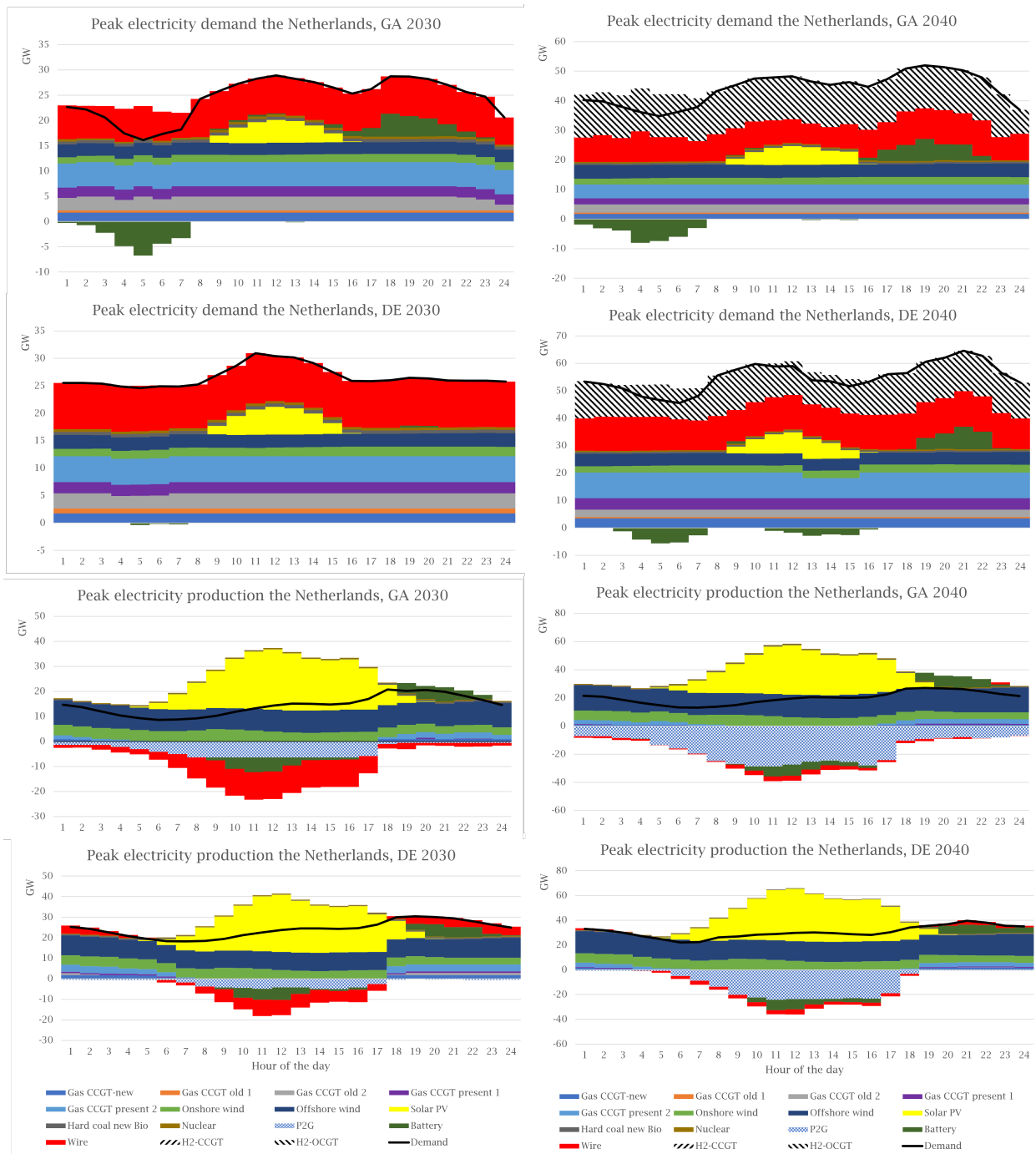


Figure 26: Representative days including peak demand during winter (winter max) and peak load during summer (summer max).

During peak demand, the Netherlands is heavily dependent on imports from its neighbouring countries. A significant proportion is accountable to the lack of thermal power units in the Netherlands. In 2030, only 16.2% of the total installed capacity consists of thermal power units in the Netherlands, see figure 13. The sum of imports is 169.4 and 200.4 GWh per day for the GA and DE scenario respectively. In 2040

however, additional flexible capacity is added in the form of HOCGT. The HOCGT lead to a peak demand of hydrogen during winter days. At peak hours, during winter max, the latter leads to 23.6 GWh of imports from Germany to Limburg (NL42). From here the hydrogen is redistributed to Brabant (1.4 GW_{e,P2G}), Utrecht (1.3 GW_{e,P2G}), North-Holland (2.0 GW_{e,P2G}) and South-Holland (9.6 GW_{e,P2G}). Representative days (summer max and winter max) for the sum of the neighbouring countries can be found in annex E from figures 39 and 46.

Moreover, the situation for peak electricity production illustrates a situation where demand, storage and conversion depict the use of electricity per scenario. With lower electrification rates, but higher hydrogen demand in the GA scenario; more electricity is converted to hydrogen. 87.4 GWh of electricity is converted in to hydrogen, compared to 50.9 GWh in the DE scenario. The latter is explicitly prominent in the year of 2040, where electricity and hydrogen demand are on average -5 and +26% compared to the DE scenario.

7.3.2 Annual figures

In this section, the interaction between hydrogen and electricity in the Dutch energy system, and its implication for the economic feasibility of VRES are discussed. The results are analyzed on direct use electricity and electricity use for hydrogen production. The economic feasibility is analyzed on the rate of curtailment of VRES and the correlation of electricity production of VRES with hydrogen production in 2030 and 2040. Average

Figure 27 depicts the annual electricity generation and consumption for all NUTS-2 regions in the Netherlands. Curtailment of VRES occurs in the Netherlands, all though very little. The curtailment of offshore wind solely takes place in 2030, with 7 and 2% curtailment for the GA and DE scenario respectively. No curtailment of solar PV occurs, which is likely related to the hydrogen production for both scenarios. Curtailment of onshore wind does occur in 2030 and 2040 for the GA scenario, with respective values of 2.4 and 3.5%. Curtailment primarily occurs during spring season, when on- and offshore wind conditions are favorable and solar PV production is peaking at noon.

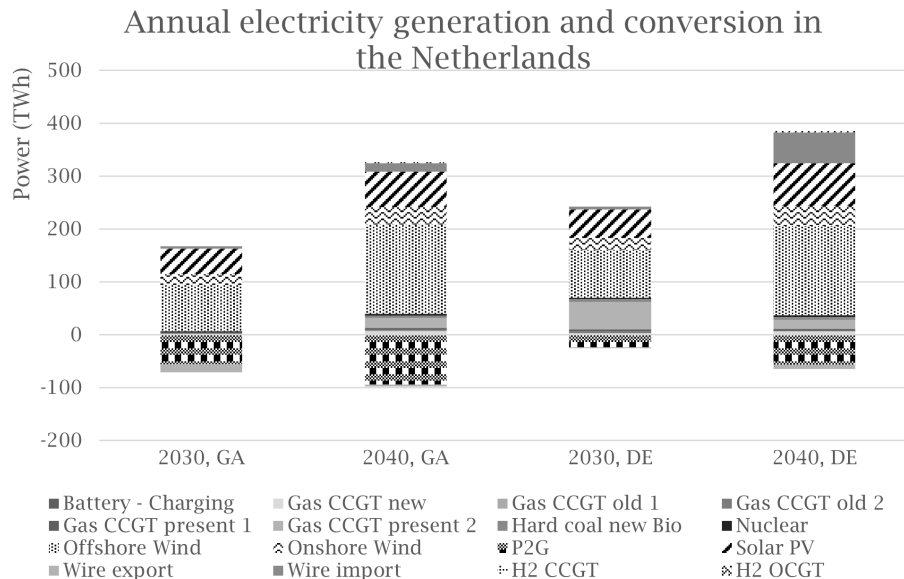


Figure 27: Annual electricity generation and consumption in the Netherlands for the GA and DE scenarios.

The annual output in 2030 of offshore wind is around 90.3 TWh in the Distributed Energy scenario, compared to 87.7 TWh in the Global Ambitions scenario. The respective values for onshore wind and solar PV production are 22.6 and 20.6, and 53.9 and 48.4 TWh. In 2040, offshore wind totals up to 169.1 and 169.2 TWh for the DE and GA scenario respectively. For onshore wind and solar PV the respective values are 37.3 and 32.6, and 81.4 and 67.3 TWh. Hence, the share of VRES in 2030 is 84.4 and 68.5% for the GA and DE scenario respectively. The respective shares for 2040 are 83 and 88.5%.

Ultimately, the capacity factors of the electricity and generation technologies for electricity and hydrogen are depicted in table 19.

Table 19: Capacity factors for Gas CCGT, nuclear, biomass, offshore and onshore wind, solar PV, P2G and hydrogen gas turbines (H2GT),

	2030, GA	2040, GA	2030, DE	2040, DE
Gas CCGT	2.0%	30.9%	61.1%	27.9%
Nuclear	70.4%	70.6%	70.6%	86.0%
Biomass	36.4%	96.6%	93.5%	95.9%
Offshore wind	47.7%	50.9%	49.1%	50.8%
Onshore wind	24.8%	23.7%	27.2%	27.2%
Solar PV	12.1%	12.1%	12.1%	12.1%
P2G	97.8%	43.9%	97.8%	11.1%
H2GT	0	1.7%	0	1.9%

Interestingly, the capacity factor of Natural gas combined cycle is low at 2.0%. However, offshore and onshore wind usually cover the load, and CCGT kicks in during the winter peak days. Eventually, the electricity which is produced in the Netherlands is used for either direct use or indirect use. For both scenarios, the latter is depicted for the years 2030 and 2040 in table 20.

Table 20: Direct and indirect electricity use in the years 2030 and 2040 for the GA and DE scenarios.

	2030, GA	2040, GA	2030, DE	2040, DE
Direct electricity use	65%	55%	95%	92%
Indirect electricity use	35%	45%	5%	8%

For the economic business case of VRES and hydrogen production, it is useful to check for a correlation between the production of electricity by VRES and the production of hydrogen by electrolysis (P2G). The correlation between VRES and hydrogen production can be found by dividing the covariance by the product of two variables' standard deviations. The correlation of VRES with P2G and the standard deviations of VRES and P2G can be retrieved in table 21

Table 21: Correlation and standard variation of VRES with production of P2G.

Correlation	2030 GA	2040 GA	2030 DE	2040 DE
Solar PV	5.4%	20.0%	4.5%	53.6%
Wind onshore	0.1%	0.2%	0.0%	0.5%
Wind offshore	7.4%	10.2%	0.1%	0.4%
Standard deviation				
Solar PV	445.31	616.88	494.05	743.26
Wind onshore	212.65	336.25	233.42	384.95
Wind offshore	1182.86	1982.33	1189.32	1982.33
P2G	341.15	1207.21	331.40	557.48

It is shown that in the current configuration of onshore electrolysis, the highest correlation of hydrogen production is found with solar PV, especially for the DE scenario. The large spikes of electricity production in during day-time induce the largest surplus of generation. Considering figure 26, it can be seen that solar PV drives hydrogen production at peak load days. Hydrogen production in the GA scenario is, just as offshore wind production, relatively stable and therefore explaining the, all though lower, correlation of offshore wind. The correlation of onshore wind is for both scenarios negligible. It is likely that onshore wind contributed towards direct electricity consumption on land. Hence, with the existing configuration of hydrogen production, solar PV is the most favorable combination to maximize hydrogen production through electrolysis on land.

7.4 Requirement for storage and conversion flexibility for the integration of offshore wind

In this section, the requirement for storage and conversion for the integration of offshore wind in the Netherlands is presented. The results are analyzed on curtailment of offshore wind, and the utilization, and effect of, hydrogen storage in the Netherlands.

Indicated in table 21, the correlation between hydrogen production and offshore wind electricity production is relatively low at 10.2%. However, the Netherlands comprises of 4 offshore landing points, where amongst the other 8 NUTS-2 regions, hydrogen production takes place. Figure 28 depicts the dispatch of P2G in all NUTS-2 regions in the Netherlands, with the regions with offshore landing points indicated in red. Additionally, the demand (black stacked line) and remainder VRES production of onshore wind and solar PV (yellow stacked area) of the four areas is provided at offshore landing points.

P2G dispatch, summer max 2040 GA scenario

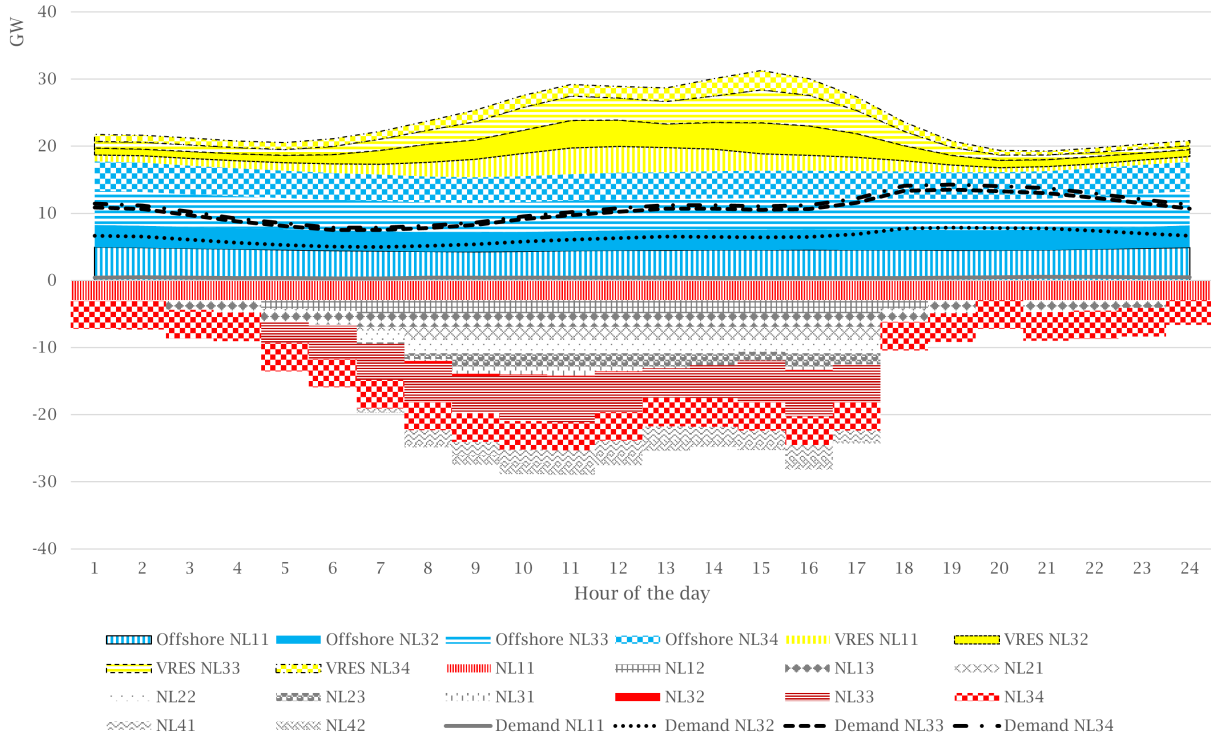


Figure 28: Dispatch of the four P2G sites at the offshore landing points in red, and the dispatch of the remainder P2G sites in grey. Light blue stacked area indicate offshore dispatch at the four landing sites. Yellow stacked area displays onshore and solar PV production at landing sites. Black lines indicate electricity demand excluding P2G at offshore landing regions.

In the provinces of Groningen (NL11) and Zeeland (NL34), electricity is constantly fed in to P2G at a constant dispatch of 2.9 and 4.2 GW respectively. These two areas have a relative low demand at roughly 0.5 GW. P2G serves here as a flexibility and storage measure for offshore wind. For Noord-Holland (NL32), electricity demand is fluctuating between 5 and 7 GW. However, in North-Holland, electricity demand is particularly high as hydrogen production at the TATA steel plant happens onsite, resulting in a electricity demand on NUTS-2 scale. This results in a flat demand of roughly 2.5 GW. In Zuid-Holland (NL33), hydrogen production is in line with solar PV production, and offshore wind is primarily directly used to provide base load for a demand ranging between 4 and 6 GW. Figure 29 depicts the situation for the DE scenario in 2040.

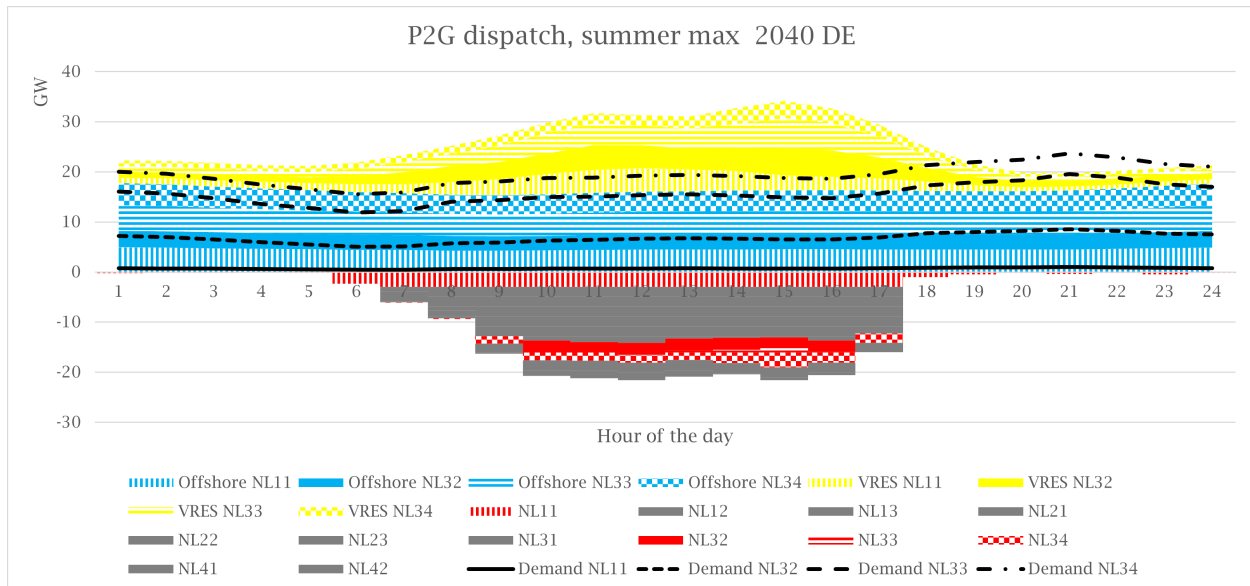


Figure 29: Dispatch of the four P2G sites at the offshore landing points in red, and the dispatch of the remainder P2G sites in grey. Light blue stacked area indicate offshore dispatch at the four landing sites. Yellow stacked area displays onshore and solar PV production at landing sites. Black lines indicate electricity demand excluding P2G at offshore landing regions.

In the DE scenario, for all four provinces with landing points, the production of hydrogen is following the curve of solar PV production. Higher electrification in all sectors lead to a substantial higher electricity demand in all regions. Also in Groningen, the majority of industrial processes are electrified, leading to peaking demand values of 1.6 GW. The dispatch of P2G is following the least costs, hence no thermal units are used to produce hydrogen.

The high correlation of hydrogen production with solar PV is reflected in the filling of the hydrogen storage during spring, summer and autumn (filling seasons). The average hourly filling during filling and withdrawal (winter and winter max) seasons is depicted in figure 30.

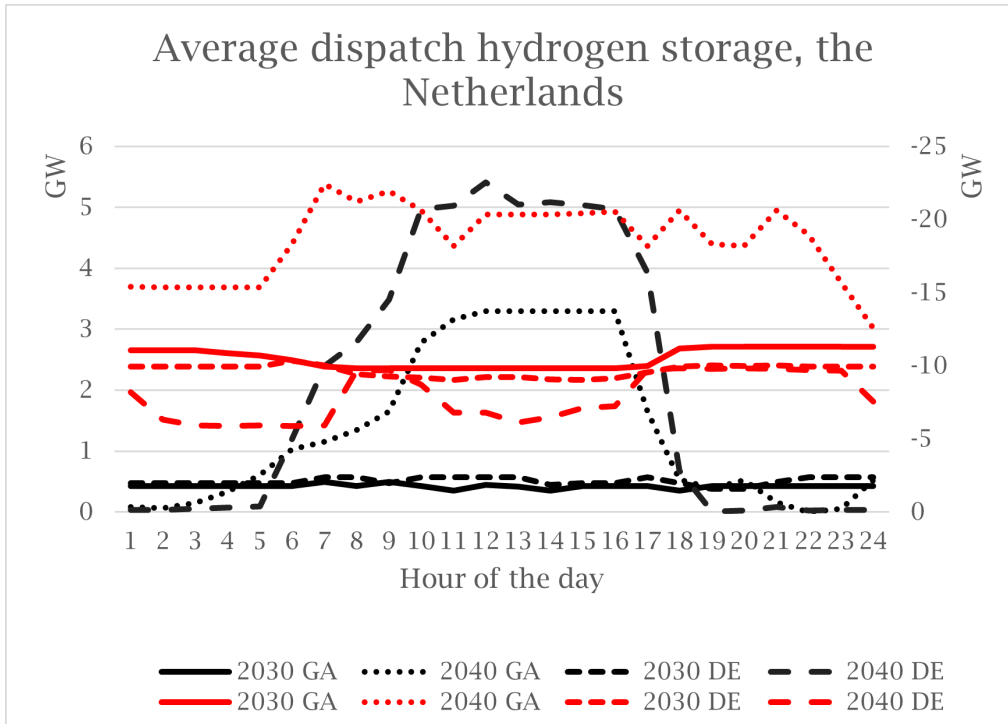


Figure 30: Average hourly filling and withdrawal rate of hydrogen storage in the Netherlands. The red lines indicate withdrawal and are plotted on the right y-axis.

The withdrawal and injection capacity in the Netherlands for hydrogen storage is rated at 15.9 GW in 2030 and 31.2 GW in 2040, and totals a total capacity of almost 6 TWh. This is currently sufficient, since the filling rate does not get higher than 6.4 GW. In 2040 however, the filling rate does not reach its maximum, but the withdrawal reaches the maximum of 31.2 GW during peak demand for the GA scenario, to fulfill the demand of the hydrogen turbines in the Netherlands. Hydrogen production takes place throughout all regions in the Netherlands, but geographical locations depict the correlation between dispatch of offshore wind and hydrogen production. The vast amount of hydrogen production is correlated to solar PV production throughout the Netherlands, except for Groningen and Zeeland. In the GA scenario, annual charging of hydrogen amounts to 3.7 and 6.0 TWh in 2030 and 2040 respectively. The respective values in the DE scenario are 3.3 and 6.0 respectively. This indicates that the storage facility is fully utilized from 2040 onward.

7.5 Sensitivity of results

In this section, sensitivity runs are carried out on several variables. First, the built out of interconnection capacities of all respective energy carriers in 2030 and 2040 is modified with a range between -50% and +50%. Second, sensitivity runs are performed by allowing the hydrogen storage, and thereby injection and withdrawal capacity, to expand with 20%. The effect of limiting the latter with -20% is carried out as well. Third, a sensitivity on import costs of -50 and +50% is carried out.

7.5.1 Interconnection capacities

In this section, a sensitivity is performed on the allowance of built out of additional interconnection capacities from the Netherlands towards its neighbouring countries. The sensitivity test assesses the capacity factor of power to gas and the ratio of imported energy relative to domestic demand and exported energy relative to domestic energy production. The capacity factor of power to gas is analyzed to assess if domestic hydrogen production is dependent on the import electricity.

With a 50% reduction in interconnection capacity with the Netherlands and its neighbouring countries, is unfeasible. Therefore, intermediary steps of 25% are depicted for the ratio of imported energy relative to domestic demand is depicted in figure 31

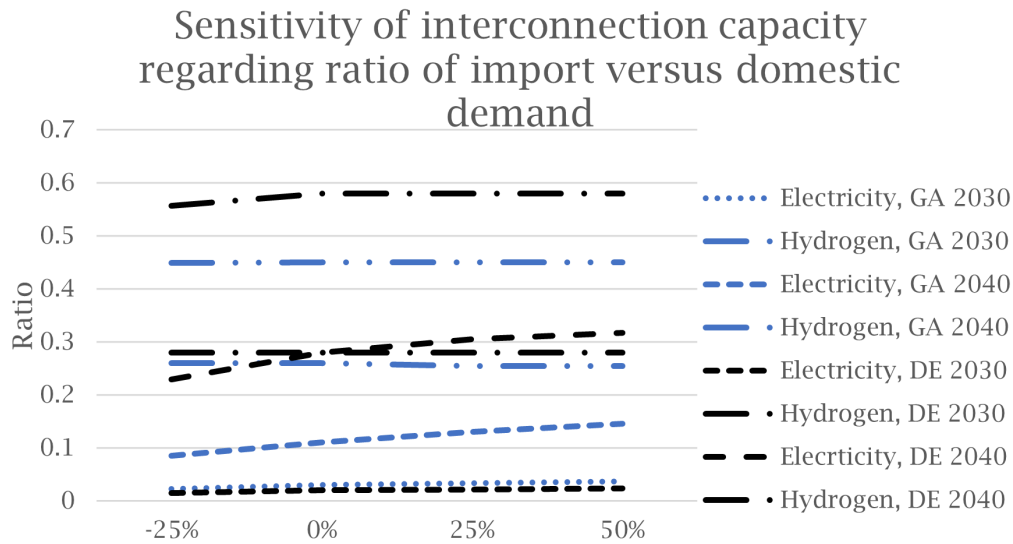


Figure 31: Ratio of imported energy versus domestic demand through a sensitivity for a decrease and increase of interconnection capacity.

A decrease in import for both scenarios for electricity is observed. The largest decrease is observed for electricity imports in the GA 2040 scenario, with a decrease of 23% in imports of electricity. For the DE scenario, a decrease of 21 and 18% is observed for the respective years of 2030 and 2040. The latter is explained by the decrease of interconnection between Belgium and Germany during peak demand in the hours from 20:00 to 22:00 PM. An increase in battery charging and is observed to increase dispatch during these hours for both scenarios, since no additional thermal power units are present in 2030. In 2040, additional capacity of 1.57 and 1.89 GW HOCGT is built out for the GA and DE scenario respectively. The ratio of hydrogen import is only slightly affected in 2040 for the DE scenario, where a decrease is observed of 4%.

The results of the sensitivity of the export relative to the domestic supply of energy in the Netherlands is shown in table 22.

Table 22: Sensitivity of interconnection capacity regarding ratio of export versus domestic supply for electricity and hydrogen.

	-25%	0%	25%	50%
Electricity, GA 2030	0.08	0.08	0.08	0.08
Hydrogen, GA 2030	0.34	0.34	0.34	0.34
Electricity, GA 2040	0.02	0.02	0.02	0.02
Hydrogen, GA 2040	0	0	0	0
Electricity, DE 2030	0.01	0.01	0.01	0.01
Hydrogen, DE 2030	0	0	0	0
Electricity, DE 2040	0.01	0.01	0.01	0.01
Hydrogen, DE 2040	0	0	0	0

The ratio of exported energy is less affected by variance in interconnection capacities. With an increase of capacity, no difference in export is observed. Since the capacity factor of hydrogen production doesn't increase, it is likely that there is simply no additional power available to be exported towards neighbouring countries.

An additional result from the increase of interconnection capacities. Is that on average, electricity and hydrogen shadow prices for end-users become increasingly homogeneous across different regions. This implies that the merit is valid for multiple regions, and that the same merit depicts in a larger area across Europe.

7.5.2 Hydrogen storage

In this section, a sensitivity is performed by decreasing and increasing the hydrogen storage capacity, and associated injection and withdrawal capacity, by 20% for all regions. The results will be analyzed on the ratio of imported energy relative to domestic demand and the capacity factor of hydrogen storage.

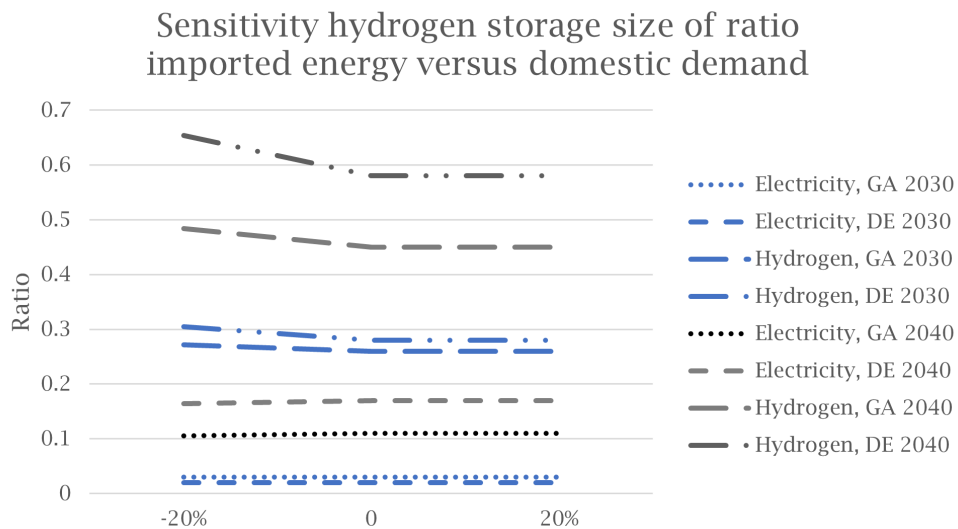


Figure 32: Sensitivity on a change of storage capacities ranging from -20% to +20%.

With lower capacity for hydrogen storage, supply of hydrogen is tightened during peak demand and winter days. The reduction in capacity in injection and withdrawal leads to an increase of imports of hydrogen from the Netherlands and its neighbouring countries. The steepest increase on imports is observed in 2040 for the DE scenario, amounting 6.4%. The observed increases in hydrogen imports are identical to the observed decrease of hydrogen storage dispatch in the years 2030 and 2040. With an increase in storage capacity, a minor decrease in hydrogen imports in 2040 of 0.24% and 0.12% is observed for the respective GA and DE scenarios. The capacity factors of the hydrogen storage facilities obtain the values of roughly 63 and 100% in the respective years of 2030 and 2040. Hence, an increase in capacity factor is observed. The maximum injection capacity is 6.4 GW. Therefore, the injection of hydrogen is not affected. The withdrawal in the DE, scenario is unaffected in 2030 and 2040. In the Gobaal Ambition scenario however, the maximum withdrawal decreases, and therefore more hydrogen must be imported via Germany through pipeline. For both scenarios less seasonal storage is possible, leading to somewhat lower exports of electricity (-0.06%) in the DE 2040 scenario.

8 Discussion

In this section, the results of section 7 are discussed. First, general aspects of the modeling process are discussed, which are valid for all optimization runs. Consequentially, the results of the DE and GA scenario is discussed. Thereafter, the results of both scenarios are compared and discussed.

8.1 General discussion regarding modeling process

The LCP model is used to minimize the total system costs. Hence, the optimization problem is highly sensitive towards techno-economic parameters. In this sense, the dispatch and built out of technologies and infrastructure is sensitive to infrastructure costs including CAPEX, FOM, VOM and retirement costs, fuel costs, emissions costs, capacity factors. Some of these factors are discussed.

First the costs for technology and infrastructure are homogeneous for all regions. However, factors such as labor costs and local availability and prices of materials can lead to a significant difference per region (entsoe, 2022). The costs of fuel are the same over all seasons and regions for imports, which is not the case for in instance natural gas and LNG. In the current context of a global energy crisis, price fluctuations increase and decrease in a matter of days or weeks. Therefore, used assumptions on pricing of methane by pipeline and LNG can be outdated in a short notice. Additional to the current context of the energy crisis, the expansion of global, and specifically European, Asian and American LNG capacity leads to a globalization of the LNG market. Globalization of the LNG market induces price variability of LNG, especially during winter months, when demand is usually high across the EU, US and Asia. It is therefore advised to incorporate seasonal pricing of LNG, and to incorporate regional discrepancies for the built out of supply technology and infrastructure.

Second, the capacity factors are based on seasonal averages, which can lead to deviations in supply profiles, and an underestimation for stress tests incorporated in this research. A more sophisticated method compared to the heuristic method of selection of representative days can lead to more accurate supply curves. Consequentially on the method for representative days, this research only selects representative days per season, and is therefore neglecting variability between workdays and weekends, and holidays during summer Fattahi et al. (2020). The combination of the average hourly load factors and average representative days per season can lead to a deviation to reality up to 20% (Van Der Heijde et al., 2019, Poncet et al., 2016b). It is therefore recommended to perform an alternative method to represent multiple seasons in a year.

Third, the future energy landscape is heavily dependent on policies in the Netherlands and the European Union. Directives like RePowerEU and the delay of retirement of existing coal and natural gas plants can heavily influence future investments regarding renewables and infrastructure. The existence of flexible power supply can significantly reduce the requirement of investments in the electricity grid. Such policies will not only steer the direction of deployment of supply and infrastructure technologies, but are also likely to steer electrification and the adoption of hydrogen in the end use. However, this research depicts two cases with a stronger emphasis towards electrification in the Distributed Energy scenario and a stronger emphasis on the adoption of hydrogen (and hydrogen imports) in the Global Ambitions scenario.

Fourth, beside batteries, power to gas and pumped hydro, no additional flexibility technologies are incorporated in this research. Vehicle to grid and demand side response are not taken in account. However, this can be justified with the temporal granularity of one hour (Brown et al., 2018). However, these flexibility measures can significantly influence this research, especially in the Netherlands. The Netherlands has one of the highest shares of electric vehicles, and vehicle to grid can significantly alleviate the grid in the foreseeable future (Brinkel et al., 2020).

At last, a net transfer capacity of 2/3 of MVar is assumed from personnel communications with TenneT for the regions in the Netherlands. This might lead to under- and over-estimations of the transmission capacities within the Netherlands. However, for the scope of this research, the retrieved values were, according to Wevers (2022), acceptable. However, for congestion studies of power grids; such estimations are not sufficient.

8.2 Global Ambition

In the results of the TYNDP modeling, the dispatch of solar PV, onshore wind and offshore wind for the years of 2030 and 2040 is 45.8 and 60.7, 20.9 and 29.6, and 80.0 and 208.9 TWh respectively. A difference of plus 2.6 and plus 6.6 TWh is observed between solar PV for the respective years. For onshore wind, differences of minus 0.4 TWh and plus 3.0 TWh are observed. Lastly, for offshore wind, respective differences of plus 7.1 TWh and minus 31 TWh are observed. The 2040 value in TYNDP however, assumes a system including 50 GW of installed offshore wind in the Netherlands. This figure is not incorporated, and the assumption of 38 GW is used. However, if the 50 GW is scaled to 38 GW, the difference would be plus 10.7 TWh. The latter can be explained by the use of average capacity factors and modeling of individual nodes (i.e., NUTS-2 regions and offshore nodes) in the Netherlands. Each node has an individual supply curve, which might lead to different output than an average supply curve for the Netherlands as a whole.

A discrepancy is observed between the Distributed Energy and Global Ambitions scenario regarding the utilization the types of infrastructure. The Netherlands is merely importing roughly 3% of its total electricity demand in 2030. In 2040 however, the Netherlands become increasingly dependent on the import of electricity, with roughly 11% of its domestic demand imported. This is in line with a recent market update from TenneT, that from 2025 onward, the Netherlands are increasingly reliant on electricity imports from neighbouring countries to assure security of supply (TenneT, 2022a). However, TenneT indicates less imports required in 2030, this is roughly 3 to 4 GW less compared to the outcome in this research. The latter can be explained by not incorporating demand side response and vehicle to grid. According to TenneT (2022c), the current demand side response capacity is roughly 0.7 GW, with a maximum theoretical potential of 3.5 GW. Exact figures of the potential for vehicle to grid is hard to quantify (Entso-e, 2022a), but with increasing electrification and development of bi-directional charging technologies; the potential for vehicle to grid can be significant. Thus, including the latter might lead to additional storage that can balance the the grid. Moreover, imports of hydrogen are necessary to fulfill demand in 2030 and 2040. With a respective 26% and 45% ratio of imported hydrogen relative to domestic demand. However, 34% and none of the hydrogen produced in 2030 and 2040 is exported towards neighbouring countries. The exchange volumes of electricity, hydrogen and natural gas are substantiated by demand, supply and inter-

connection capacity with neighbouring regions. In the GA scenario, a lower demand for electricity and a higher demand of hydrogen lead to a larger indirect share of indirect electricity use in the years 2030 and 2040.

The interaction between hydrogen and electricity is largely depicted by solar PV throughout the Netherlands. Considering installed capacity of 45.6 and 63.5 GW induce large loads during spring, summer and summer peak hours at noon. In 2030, the production of hydrogen is even more correlated with hydrogen production compared to solar PV. However, solar PV production is only taking place during the day, which explains a part of non-correlation. In 2030, the demand profile of electricity is favorable for the production of hydrogen, but this is also dependent on geographical location. At densely populated and industrialized regions, electricity demand is usually higher. This leads to a higher direct use of electricity. In areas like Groningen and Zeeland, where offshore wind lands, hydrogen production, especially in 2040, is taking place through out the day during spring, summer and autumn.

The role of hydrogen storage becomes increasingly significant from 2040 onward. The hydrogen storage salt cavern is then fully utilized. However, the role of hydrogen storage in the Netherlands has an inter dependency with the capacity of hydrogen pipelines from and towards neighbouring countries. Peak export is at 13 GW towards Germany. However, peak import is at 33 GW from Germany in the GA scenario. If demand would further increase, either an expansion of transmission capacity is required, or additional hydrogen storage is required to satisfy demand.

8.3 Distributed Energy

In the results of the TYNDP modeling, the dispatch of solar PV, onshore wind and offshore wind for the respective years is 49.5 and 73.7, 22.1 and 35.9, and 59.4 and 166.2 TWh. A difference of plus 4.3 and plus 7.6 TWh is observed between solar PV for the respective years. For onshore wind, differences of plus 0.4 TWh and plus 1.4 TWh are observed. Lastly, for offshore wind, respective differences of plus 24.5 TWh and plus 2,9 TWh are observed. The large discrepancy between 2030 values is due to the difference of installed capacity, which is 7 GW in respect to capacity used by TYNDP.

The high degree of electrification in industries and the built environment leads to a significant increase in electricity demand. This in turn leads to a high share of direct electricity use, and on- and offshore wind often serves as a base load from 2030 onward. With the retirement of flexible power supply, there is a large need for flexibility which is not yet met in 2030, resulting in a large dependency of imports during peak days, as depicted in figure 26. Additionally, the average shadow prices of electricity generation are often higher in the Netherlands compared to its neighbouring countries. The optimization minimizes costs, and therefore imports will usually be used. Outside peak days, the majority of load during peak hours in 2030 is covered with thermal power plants (gas CCGT). However, the latter decreases towards 2040, where additional VRES is more often able to meet demand. Considering hydrogen, 28% of domestic hydrogen demand is covered by import in 2030, which is in line with the electrification rate of 95%. However, absolute numbers are relative low, with an annual demand of roughly 16 TWh in 2030. But demand picks up to 35.2 TWh in 2040, resulting in a significant amount of hydrogen imports of 19 TWh, or 58% in 2040.

With favorable solar conditions, the majority of hydrogen is produced; underlined by the high correlation 53.6% (table 21). This is also underlined at figure 29, where it can be seen that for the most of the Netherlands, except for Groningen, the production follows the curve of electricity production of solar PV. Thus, flexibility measures for offshore wind are less dependent on hydrogen production. However, the landing point of offshore wind is an extremely important factor for the flexibility requirement of dispatch of offshore wind. However, this research neglects imposed costs and practicalities of the expansion of the transmission and distribution system within nodes (Mayer et al., 2020). This might therefore lead to an underestimation of system costs and actual feasibility to deploy or land additional renewable capacity.

Following the interactions of VRES and hydrogen, the role of storage is also eminent for especially 2040, since hydrogen is dispatched for to cover peak demand with hydrogen fired gas turbines. In 2030, demand is relatively low with a flat curve of 1.8 GW, resulting in slightly less demand for hydrogen storage.

8.4 Comparison between Global Ambition and Distributed Energy

The Distributed Energy scenario, in contrary to the Global Ambitions scenario, is designed to promote self sufficiency throughout the European Union and its member countries. Besides, a strong emphasis lies on the electrification amongst sectors, which leads to a significantly lower hydrogen, but higher electricity demand compared to the Global Ambitions scenario. The demand for hydrogen in the Global Ambition scenario is 54.5 and 92.6 TWh compared to 15.9 and 35.2 TWh of hydrogen in 2030 and 2040 respectively in respect to the Distributed Energy scenario in the Netherlands. Therefore, the Netherlands are significantly more reliant on hydrogen imports for the years 2030 and 2040. However for both scenarios, a complete hydrogen infrastructure is built out in the Netherlands, comprising of 10 and 20 GW transmission capacity in 2030 and 2040 respectively. The latter is also valid for the built out of retrofitted hydrogen infrastructure towards Belgium and Germany. The complete built of the infrastructure in 2030 is likely due to the agglomeration of hydrogen that must be transported through the Netherlands. No undersea retrofitted and newly built pipelines are observed towards the United Kingdom, Denmark and Norway from the Netherlands. This is likely because it is cost optimal to built out a hydrogen infrastructure from Norway towards Denmark which leads to Germany, since these lines are primarily built over land.

The production of electricity by solar PV imposes unevenly distributed temporal load on the Dutch electricity grid. For both scenarios, solar PV imposes a larger requirement for flexibility compared than on- and offshore wind. Wind energy is, compared to solar PV, more reliable and possesses on average a higher capacity factor. Closer to shore, or preferable at sea, capacity factors increase, which reduces the variability of electricity supply and imposes less stress on the electricity grid. A hybrid combination with wind and solar is likely favorable, but further research could be done in the sizing of both technologies. However, the latter is dependent on geographic circumstances, and does not necessarily provide a 'one sizing fits all approach' (Sinha and Chandel, 2015).

The storage of hydrogen allows for seasonal storage and additional dispatch of hydrogen fired gas turbines. Hydrogen fired gas turbines provide flexible supply at peak load hours in 2040, and are solely used for 1.7 and 1.9% in the Global Ambitions and Distributed Energy scenario respectively. However, a capacity factory of 1.9% is not sufficient, and a minimum capacity factor of 20% is likely required for an investor to have an acceptable pay back time of the investment (Bexten et al., 2021).

For both scenarios, relatively little methane is imported by pipeline. Current import capacity is 12 bcm of natural gas per year, equivalent to roughly 117 TWh. With an additional 13 bcm to be built before 2030, the total supply capacity increases to 244 TWh per year. With the associated capacities of LNG production and storage withdrawal capacities, the latter is sufficient to cover the methane demand in 2030 and 2040, with the demand profiles substantiated in this research in the Netherlands. Second, for both scenarios, the Netherlands imports 11 and 17% of electricity. In order to assure security of supply, more flexibility is required. However, since the model ran on a cost optimization, increasing the security of supply for The Netherlands will come at higher costs. Third, the Netherlands will significantly rely on imports of hydrogen. Hydrogen is imported when production costs for hydrogen exceeds those of imports. With a stringent electricity supply in The Netherlands, the economics of importing hydrogen are sensible.

9 Conclusion

The expected exchange capacities in the Netherlands are required in the Netherlands to fulfill exchange volumes in 2030 and 2040. The amount, and type of, energy carriers that are exchanged between The Netherlands and its neighbouring countries are dependent on several aspects. First the type of deployment of renewables, and its quantity significantly influence the requirement of flexibility. Second, the demand of energy carriers and its end use flexibility contribute towards the requirement of conversion, storage and interconnection. Third, the circumstances of the previous two points are of large importance to determine the geographical location and size of flexibility measures. Interconnection with neighbouring countries of the Netherlands contributes significantly towards the integration of renewables when less electrification of demand occurs. In 2030, 8% of the domestic production of electricity is exported, but this slightly decreases when demand for electrification, direct and indirect, increases in 2040. From 2040 onward, interconnection is primarily required to ensure security of supply, especially with higher rates of electrification.

For the Netherlands as a whole, a correlation of 20% between the production of hydrogen through electrolysis using electricity from solar PV is found for the scenario where the European Union aims for high penetration of renewables, but compliments the latter with low carbon energy imports, the Global Ambitions scenario. A correlation of 54 % is found for a scenario which emphasizes self-sufficiency through high penetration of renewables and electrification of demand, the Distributed Energy scenario. With high electrification, on- and offshore wind primarily provide the base-load for the electricity grid. In the Global Ambitions scenario, a higher correlation for hydrogen production is found, with a maximum of 10%.

The conversion of electricity to hydrogen and storage lead to additional flexibility for the energy system. Energy can be stored over the long term, and hydrogen can be used during periods of low availability hydrogen production. Through energy storage, it is possible to store cheap and abundant hydrogen in favorable seasons for renewable power production including spring and summer, and use it at less favorable seasons including autumn and winter. With higher penetration of renewables, a 100% utilization of hydrogen storage is achieved in 2040, and additional hydrogen storage leads to a minor decrease of imports. At higher electrification rates in 2030 and 2040, the ratio of hydrogen imports relative to domestic demand is 28 and 58%, compared to 26 and 45%.

To conclude, interconnection, and flexibility through conversion and storage, contributes to the integration of renewable energy in the Netherlands. Interconnection eminent with lower and higher rates of electrification. However, with lower rates of electrification, additional interconnection capacity allows for export of renewable electricity, which is therefore in favor of the business case of VRES. On the other hand, with higher rates of electrification, more flexibility on the electricity grid is required, and a relative larger dependency on the import of hydrogen is observed, since less electricity is available for conversion.

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Annex A: Techno-economic parameters

Table 23 depicts the fuel types and their associated costs in Euro per MWh. Hence, the price of electricity is endogenously calculated through the latter in the model, determined through the associated efficiencies, CAPEX and OPEX.

Table 23: Fuel types and associated costs in Euro per MWh (Entso-e, 2022a).

Fuel type	Region	Season	Timestep	2020	2030	2040
Wind	All	All	All	0.0	0.0	0.0
Solar	All	All	All	0.0	0.0	0.0
Water	All	All	All	0.0	0.0	0.0
Uranium	All	All	All	2.0	2.0	2.0
Coal	All	All	All	8.0	7.0	7.0
Biomass	All	All	All	20.0	17.0	17.0
Methane East	All	All	All	20.0	14.0	15.0
Methane North Sea	All	All	All	20.0	14.0	15.0
Methane North	All	All	All	20.0	14.0	15.0
Methane Bio	All	All	All	86.0	75.0	61.0
Hydrogen South	All	All	All	200.0	74.3	57.9
Hydrogen East	All	All	All	200.0	74.3	57.9
Hydrogen North	All	All	All	200.0	74.3	57.9
LNG Middle East	All	All	All	23.5	17.5	18.5
LNG North Africa	All	All	All	21.0	15.0	16.0
LNG Russia	All	All	All	20.8	14.8	15.8
LNG Others	All	All	All	23.7	17.7	18.7
LNG North America	All	All	All	22.3	16.3	17.3
Other	All	All	All	0.0	0.0	0.0

Supply Technology	Supply Tech Type	Input Fuel	Output Fuel	Lifetime	Degradation Factor	Storage Duration	Duration Unit	SOC0	Seasonal Storage	Tech Efficiency	Emissions per Output	Firm Capacity Credit	Minimum Utilization	Ramp Up Rate	Ramp Down Rate
Offshore Wind	Generation	Wind	Electricity	30	0	0				1	0	0.2	0	1	1
Onshore Wind	Generation	Wind	Electricity	30	0	0				1	0	0.2	0	1	1
Solar PV	Generation	Solar	Electricity	30	0	0				1	0	0	0	1	1
Gas CCGT new	Crossload	Methane	Electricity	30	0	0				0.6	0	0.8	0	1	1
Gas CCGT old 1	Crossload	Methane	Electricity	30	0	0				0.36	0	0.8	0	1	1
Gas CCGT old 2	Crossload	Methane	Electricity	30	0	0				0.41	0	0.8	0	1	1
Gas CCGT present 1	Crossload	Methane	Electricity	30	0	0				0.56	0	0.8	0	1	1
Gas CCGT present 2	Crossload	Methane	Electricity	30	0	0				0.58	0	0.8	0	1	1
Reservoir	Storage	Water	Electricity	100	0	Variable	Hour		Yes	0.95	0	0.8	0	1	1
Pumped hydro	Storage	Electricity	Electricity	100	0	Variable	Hour		Yes	0.95	0	0.8	0	1	1
Run-of-River	Generation	Water	Electricity	100	0	0				0.95	0	0.8	0	1	1
Gas conventional old 1	Crossload	Methane	Electricity	30	0	0				0.36	0	0.8	0	1	1
Gas conventional old 2	Crossload	Methane	Electricity	30	0	0				0.41	0	0.8	0	1	1
Lignite new	Generation	Coal	Electricity	70	0	0				0.41	0.3636	0.8	0	1	1
Gas CCGT old 2 Bio	Crossload	Methane	Electricity	30	0	0				0.48	0	0.8	0	1	1
Gas conventional old 2 Bio	Crossload	Methane	Electricity	30	0	0				0.41	0	0.8	0	1	1
Hard coal new Bio	Generation	Biomass	Electricity	70	0	0				0.38	0	0.8	0	1	1
Hard coal old 1 Bio	Generation	Biomass	Electricity	70	0	0				0.32	0	0.8	0	1	1
Hard coal old 2 Bio	Generation	Biomass	Electricity	70	0	0				0.32	0	0.8	0	1	1
Heavy oil old 1 Bio	Generation	Biomass	Electricity	70	0	0				0.3	0	0.8	0	1	1
Lignite old 1 Bio	Generation	Biomass	Electricity	70	0	0				0.25	0	0.8	0	1	1
Gas OCGT new	Crossload	Methane	Electricity	30	0	0				0.42	0	0.8	0	1	1
Gas OCGT old	Crossload	Methane	Electricity	30	0	0				0.35	0	0.8	0	1	1
Nuclear	Generation	Uranium	Electricity	31	0	0				0.33	0	1	0.7	0.33	0.33
Other RES	Generation	Other	Electricity	25	0	0				1	0	0.4	0	1	1
Battery	Storage	Electricity	Electricity	20	0.005	3	Hour		No	0.9025	0	0.4	0	1	1
P2G	Crossload	Electricity	Hydrogen	30	0	0				0.75	0	0.2	0	1	1
H2 Storage	Storage	Hydrogen	Hydrogen	30	0.005	Variable	Hour		Yes	0.8721	0	0.8	0	1	1
Natural Gas Storage	Storage	Methane	Methane	100	0.005	Variable	Hour		Yes	0.99	0	0.8	0	1	1
Methane East	Generation	Methane East	Methane	100	0	0				1	0	0	0	1	1
Methane North Sea	Generation	Methane North Sea	Methane	100	0	0				1	0	0	0	1	1
Methane North	Generation	Methane North	Methane	100	0	0				1	0	0	0	1	1
LNG Middle East	Import	LNG Middle East	Methane	100	0	0				1	0	0	0	1	1
LNG North Africa	Import	LNG North Africa	Methane	100	0	0				1	0	0	0	1	1
LNG Russia	Import	LNG Russia	Methane	100	0	0				1	0	0	0	1	1
LNG Others	Import	LNG Others	Methane	100	0	0				1	0	0	0	1	1
Biomethane	Generation	Methane Bio	Methane	100	0	0				1	0	0	0	1	1
LNG North America	Import	LNG North America	Methane	100	0	0				1	0	0	0	1	1
Hydrogen South	Generation	Hydrogen South	Hydrogen	100	0	0				1	0	0	0	1	1
Hydrogen East	Generation	Hydrogen East	Hydrogen	100	0	0				1	0	0	0	1	1
Hydrogen North	Generation	Hydrogen North	Hydrogen	100	0	0				1	0	0	0	1	1
H2-CCGT _{new}	Crossload	Hydrogen	Electricity	30	0	0				0.6	0	0.88	0	1	1
H2-CCGT _{new}	Crossload	Hydrogen	Electricity	30	0	0				0.42	0	0.91	0	1	1
Hard coal	Generation	Coal	Electricity	70	0	0				0.38	0.347	0.8	0	1	1

Table 24: Technological parameters for the supply, conversion and storage technologies.

Region in	Region out	From	To	Voltage (kV)	Maximum current Summer (A)	Maximum Current Winter (A)	Average Maximum Current spring/autumn (A)	Length (km)	Nr of lines	Spring (MW)	Summer (MW)	Autumn (MW)	Winter (MW)	Average (MW)
NL32	NL23	Diemen	Lelystad	380	2500	3100	2800	50.43	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL23	NL32	Lelystad	Diemen	380	2500	3100	2800	50.43	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL22	NL41	Dodewaard	Boxmeer	380	2500	2500	2500	41.7	2	1266.67	1266.67	1266.67	1266.67	1266.67
NL22	NL21	Doetinchem	Hengelo	380	2500	3100	2800	58.6	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL21	NL22	Hengelo	Doetinchem	380	2500	3100	2800	58.6	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL23	NL21	Ens	Zwolle	380	2500	3100	2800	60.1	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL21	NL23	Zwolle	Ens	380	2500	3100	2800	60.1	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL42	NL41	Maasbracht	Boxmeer	380	2500	2875	2687.5	56.6	1	680.83	633.33	680.83	728.33	680.83
NL41	NL42	Boxmeer	Maasbracht	380	2500	2875	2687.5	56.6	1	680.83	633.33	680.83	728.33	680.83
NL42	NL22	Maasbracht	Dodewaard	380	2500	2875	2687.5	87.5	1	680.83	633.33	680.83	728.33	680.83
NL22	NL42	Dodewaard	Maasbracht	380	2500	2875	2687.5	87.5	1	680.83	633.33	680.83	728.33	680.83
NL21	NL11	Zwolle	Meeden	380	4000	4000	4000	89.4	2	2026.67	2026.67	2026.67	2026.67	2026.67
NL11	NL21	Meeden	Zwolle	380	4000	4000	4000	89.4	2	2026.67	2026.67	2026.67	2026.67	2026.67
NL31	NL33	Breukelen Kortijk	Krimpen ad IJssel	380	2500	2500	2500	39.5	1	633.33	633.33	633.33	633.33	633.33
NL33	NL31	Krimpen ad IJssel	Breukelen Kortijk	380	2500	2500	2500	39.5	1	633.33	633.33	633.33	633.33	633.33
NL31	NL32	Breukelen Kortijk	Diemen	380	2500	3100	2800	18.6	1	709.33	633.33	709.33	785.33	709.33
NL32	NL31	Diemen	Breukelen Kortijk	380	2500	3100	2800	18.6	1	709.33	633.33	709.33	785.33	709.33
NL34	NL41	Riland	Geertruidenberg	380	2500	3100	2800	56.4	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL41	NL34	Geertruidenberg	Riland	380	2500	3100	2800	56.4	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL21	NL23	Hessenweg	Ens	220	2500	2500	2500	50.8	2	733.33	733.33	733.33	733.33	733.33
NL23	NL21	Ens	Hessenweg	220	2500	2500	2500	50.8	2	733.33	733.33	733.33	733.33	733.33
NL13	NL21	Zeyerveen	Hessenweg	220	2500	2750	2625	56.3	2	770.00	733.33	770.00	806.67	770.00
NL21	NL13	Hessenweg	Zeyerveen	220	2500	2750	2625	56.3	2	770.00	733.33	770.00	806.67	770.00
NL12	NL11	Bergum	Vierverlaten	220	2500	2500	2500	32.1	2	733.33	733.33	733.33	733.33	733.33
NL11	NL12	Vierverlaten	Bergum	220	2500	2500	2500	32.1	2	733.33	733.33	733.33	733.33	733.33
NL41	BE00	Riland	Zandvliet	380	2500	3100	2800	9.5	2	1418.67	1266.67	1418.67	1570.67	1418.67
BE00	NL41	Zandvliet	Riland	380	2500	3100	2800	9.5	2	1418.67	1266.67	1418.67	1570.67	1418.67
NL41	BE00	Maasbracht	Van Eyck	380	2500	2875	2687.5	103.1	2	1361.67	1266.67	1361.67	1456.67	1361.67
BE00	NL41	Van Eyck	Maasbracht	380	2500	2875	2687.5	103.1	2	1361.67	1266.67	1361.67	1456.67	1361.67
NL11	DE00	Meeden	DE00	380	4000	4000	4000	28.4	2	2026.67	2026.67	2026.67	2026.67	2026.67
NL22	NL31	Nijmegen	Nieuwegein	150	2500	2500	2500	56.9	2	500.00	500.00	500.00	500.00	500.00
INVESTMENT PLANS TENNET														
NL32	NL23	Diemen	Lelystad				0	50.43		0.00	0.00	0.00	0.00	2091.70
NL23	NL32	Lelystad	Diemen				0	50.43		0.00	0.00	0.00	0.00	2091.70
NL23	NL21	Ens	Zwolle				0	60.1		0.00	0.00	0.00	0.00	1358.70
NL21	NL23	Zwolle	Ens				0	60.1		0.00	0.00	0.00	0.00	1358.70
NL41	NL42	Eindhoven	Maasbracht				0	43.9		0.00	0.00	0.00	0.00	2829.30

Table 25: Net transfer capacities TenneT transmission network in the Netherlands.

Annex B: Supply technologies the Netherlands

Table 26 shows the thermal power plants in the Netherlands in 2022, retrieved from Schram et al. (2019) and is validated through the Entso-e transparency platform (Entsoe, 2022).

Table 26: Characteristics thermal power plants in the Netherlands, 2022 (Schram et al., 2019).

Name	Main fuel	Installed Capacity (MW)	Efficiency	Marginal costs (Euro/MWh)	Decommissioned
Centrale maasvlakte	Coal	1070	46.0%	27.0	no
Eemshavencentrale	Coal	1560	46.0%	27.5	no
Engie Centrale Rotterdam 11	Coal	730	46.0%	27.5	no
Amer Bio WKC	Coal	600	40.0%	31.2	2020
Centrale Hemweg	Coal	630	40.0%	31.2	2017
Maasvlakte-2	Coal	520	38.0%	31.9	2017
Maasvlakte-1	Coal	520	38.0%	32.7	2015
Gelderland-13	Coal	602	38.0%	32.7	2016
Amer-8	Coal	645	37.0%	33.5	no
Diemen-34	Gas	435	59.0%	43.9	no
Centrale Hemweg (gas)	Gas	435	59.0%	43.9	no
Sloecentrale-10	Gas	432	58.7%	44.1	no
Sloecentrale-20	Gas	432	58.7%	44.1	no
Maximacentrale FL5	Gas	439	58.5%	44.3	no
Magnum Eemshaven-10	Gas	440	58.0%	44.3	no
Magnum Eemshaven-20	Gas	440	58.0%	44.6	no
Magnum Eemshaven-30	Gas	440	58.0%	44.6	no
Moerdijk-2	Gas	426	58.0%	44.6	no
Enecogen	Gas	870	58.0%	44.6	no
Maasstroom energie	Gas	427	58.0%	44.6	no
Maasbracht-C (Claus)	Gas	1275	56.0%	46.2	no
Rijnmond Energie	Gas	820	56.0%	46.2	no
Pergen-1	Gas	260	56.0%	46.2	no
Eemscentrale EC4	Gas	341	55.0%	47	no
Eemscentrale EC5	Gas	341	55.0%	47	no
Eemscentrale EC6	Gas	341	55.0%	47	no
Eemscentrale EC7	Gas	341	55.0%	47	no
Eemscentrale EC3	Gas	341	53.0%	48.7	no
Energiecentrale Den Haag	Gas	95	52.0%	49.6	no
Diemen-33	Gas	266	51.0%	50.6	no
Lage Weide	Gas	248	45.0%	57.2	no
Eemscentrale EC20	Gas	695	45.0%	57.2	no
Merwede-12	Gas	225	45.0%	57.2	no
Centrale Bergum CB10	Gas	332	43.0%	59.8	no
Centrale Bergum CB20	Gas	332	43.0%	59.8	no
Centrale RoCa	Gas	220	42.0%	61.2	no
Centrale Swentibold	Gas	230	42.0%	61.2	no
Merwede-11	Gas	103	41.0%	62.6	no
Velsen-24	BF-Gas	459	35.0%	74.2	no

Table 27 presents the installed capacity of power to gas (P2G) in the different regions in the Netherlands for the years 2030 and 2040 (Berenschot, 2021).

Table 27: Installed power to gas (P2G) capacity in the Netherlands per region for the Global Ambitions and Distributed Energy scenarios in 2030 and 2040.

Region	DE 2030	GA 2030	GA 2030	GA 2040	Total
NL11	440	440	2200	2200	2200
NL12	297	297	1486	1486	1486
NL13	297	297	1486	1486	1486
NL21	297	297	1486	1486	1486
NL22	297	297	1486	1486	1486
NL23	297	297	1486	1486	1486
NL31	297	297	1486	1486	1486
NL32	360	360	1800	1800	1800
NL33	1020	1020	5100	5100	5100
NL34	640	640	3200	3200	3200
NL41	297	297	1486	1486	1486
NL42	297	297	1486	1486	1486

Figure 33 presents the hourly capacity factors of onshore wind turbines for the NUTS-2 regions in The Netherlands.

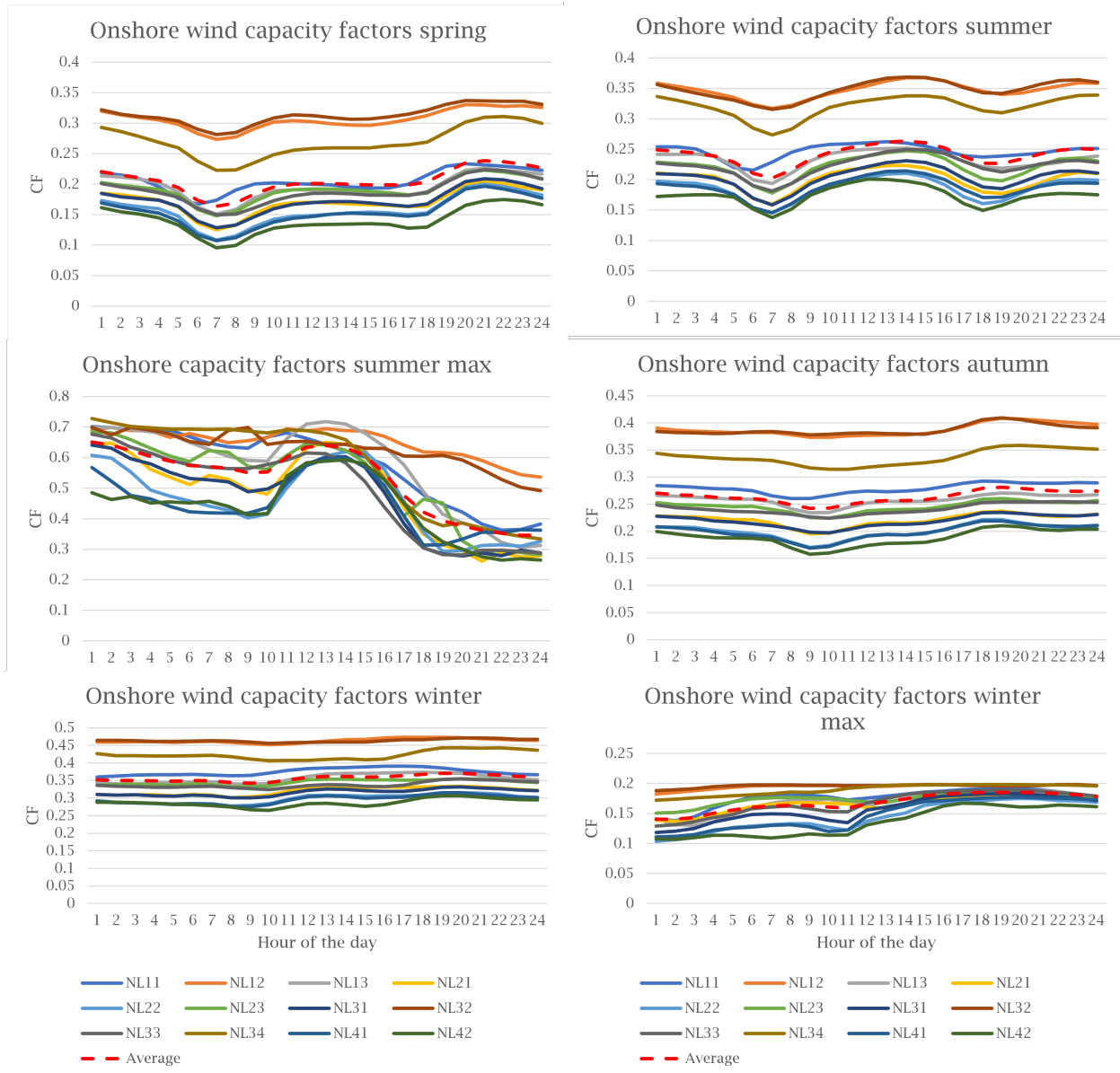


Figure 33: Hourly capacity factors (CF) of onshore wind for NUTS-2 regions in the Netherlands, and weighted average of all regions (red).

Figure 34 presents the hourly capacity factors of offshore wind turbines for Groningen (NL11), Noord Holland (NL32), Zuid Holland (NL33) and Zeeland (NL34).

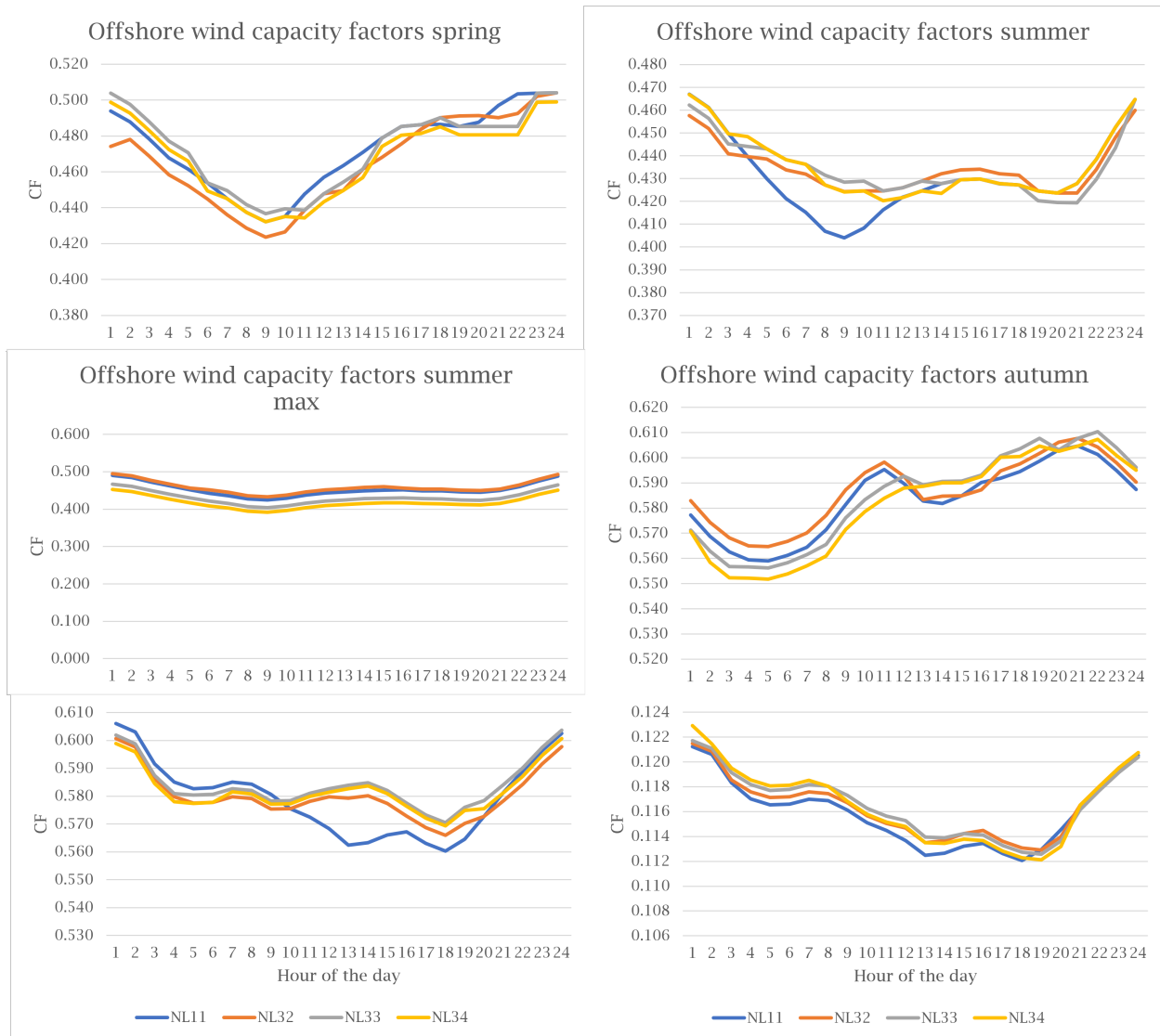


Figure 34: Hourly capacity factors (CF) of offshore wind for offshore nodes in the Netherlands.

Figure 35 presents the hourly capacity factors of solar PV for the NUTS-2 regions in The Netherlands.

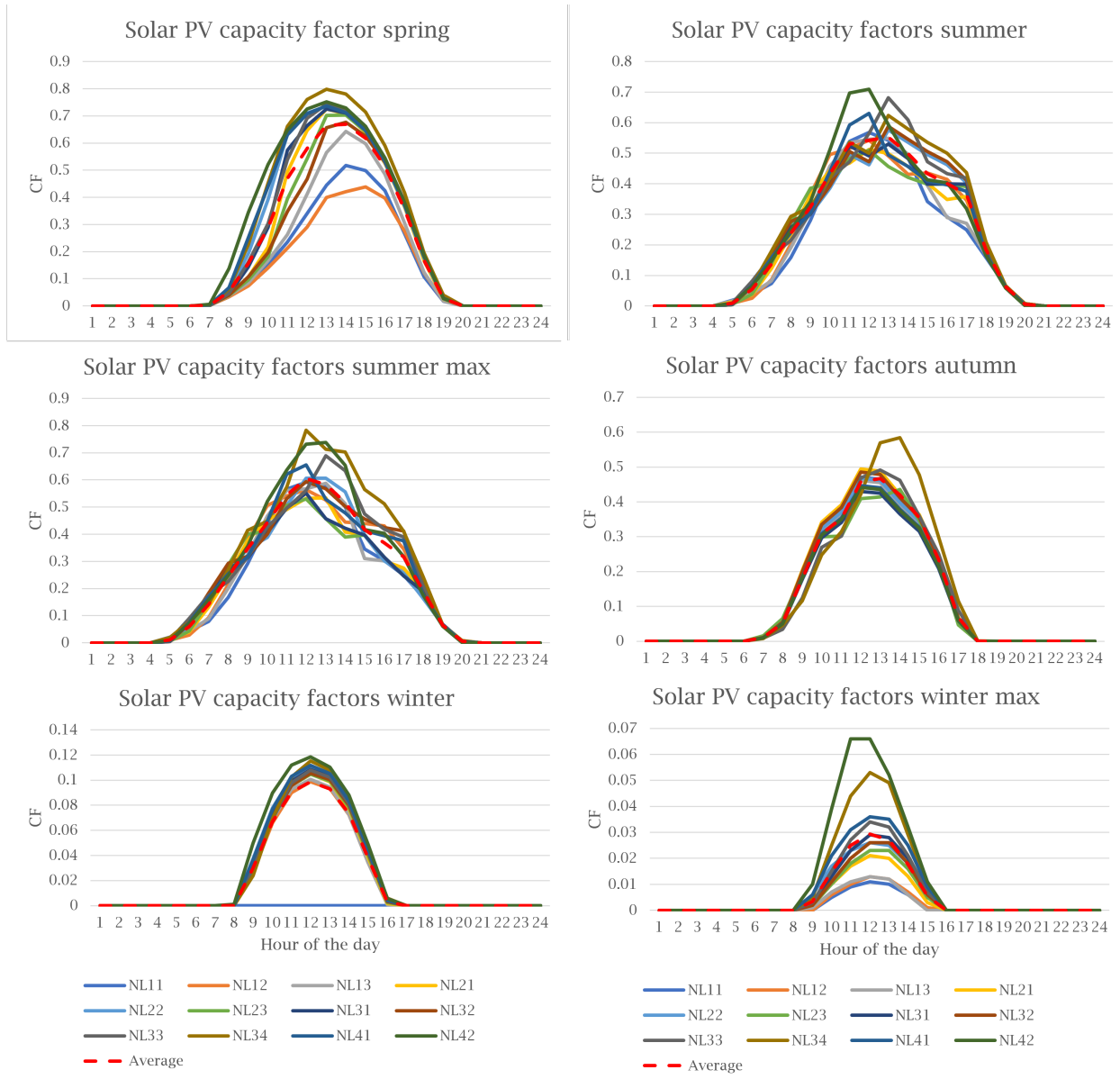


Figure 35: Hourly capacity factors (CF) of solar PV for NUTS-2 regions in the Netherlands, and weighted average of all regions (red).

Annex C: Neighbouring countries of the Netherlands

Table 28 shows the installed capacities of the energy supply technologies incorporated in this research.

Table 28: Installed capacities per neighboring country. The table continues for 3 pages (Entso-e, 2022b).

SupplyTechnology		DE 2030	GA 2030	DE 2040	GA 2040
Battery	BE00	4254	4254	8714	8714
	DE00	18249	18249	37385	37385
	DK00	223	223	269	269
	NO00	408	408	388	388
	UK00	20289	20289	26158	26158
Gas CCGT new	BE00	2499	2499	2499	2499
	DE00	49540	49540	49540	49540
	DK00	1067	1067	1067	1067
	NO00	0	0	0	0
Gas CCGT old 1	UK00	0	0	0	0
	BE00	1199	1199	1199	1199
	DE00	3671	3671	3671	3671
	DK00	0	0	0	0
Gas CCGT old 2	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	965	965	965	965
	DE00	5511	5511	5511	5511
Gas CCGT old 2 Bio	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
Gas CCGT present 1	DE00	8198	8198	8198	8198
	DK00	0	0	0	0
	NO00	642	642	642	642
	UK00	39822	39822	39822	39822
Gas CCGT present 2	BE00	3287	3287	3287	3287
	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
Gas OCGT new	UK00	0	0	0	0
	BE00	0	0	0	0
	DE00	3102	3102	3102	3102
	DK00	0	0	0	0
Gas OCGT old	NO00	0	0	0	0
	UK00	0	0	0	0
Gas OCGT old	BE00	0	0	0	0
	DE00	281	281	281	281
Gas OCGT old	DK00	0	0	0	0

Table 28: Installed capacities per neighboring country. The table continues for 3 pages (Entso-e, 2022b).

SupplyTechnology		DE 2030	GA 2030	DE 2040	GA 2040
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
Gas conventional old 1	DE00	1993	1993	1993	1993
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	781	781	781	781
Gas conventional old 2	DE00	1120	1120	1120	1120
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
Gas conventional old 2 Bio	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
H2-CCGT_new	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
H2-OCGT_new	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	11587	0
	BE00	0	0	0	0
Hard coal	DE00	9030	9030	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	5241	5241	5241	5241
	BE00	0	0	0	0
Hard coal new Bio	DE00	8543	8543	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	4528	4528	0	0
	BE00	0	0	0	0
Hard coal old 1 Bio	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	682	0	682	0
Hard coal old 2 Bio	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0

Heavy oil old 1 Bio

Table 28: Installed capacities per neighboring country. The table continues for 3 pages (Entso-e, 2022b).

SupplyTechnology		DE 2030	GA 2030	DE 2040	GA 2040
	DE00	3966	3966	0	0
	DK00	588	588	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
Lignite new	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	0	0	0	0
Lignite old 1 Bio	DE00	0	0	0	0
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	0	0	0	0
	BE00	5943	5943	5943	5943
Nuclear	DE00	4056	4056	4056	4056
	DK00	0	0	0	0
	NO00	0	0	0	0
	UK00	8256	8256	8256	14333
	BE00	4243	4243	5987	5987
Offshore Wind	DE00	30391	36531	51000	59942
	DK00	13143	13143	26992	26992
	NO00	1188	1188	1450	1188
	UK00	31020	42553	57520	68051
	BE00	3084	3735	8859	4825
Onshore Wind	DE00	84671	79279	127157	115520
	DK00	5437	5437	7346	7346
	NO00	11191	7435	14547	10341
	UK00	24179	22967	36629	31946
	BE00	0	0	0	0
Other RES	DE00	7935	7935	7935	7935
	DK00	2506	2506	1723	1723
	NO00	195	195	195	195
	UK00	6344	0	9713	0
	BE00	0	0	0	0
Reservoir	DE00	1397	1397	1397	1397
	DK00	0	0	0	0
	NO00	29727	29727	29727	29729
	UK00	0	0	0	0
	BE00	1310	1310	1310	1310
Pumped hydro	DE00	9280	9280	9280	9280
	DK00	0	0	0	0
	NO00	1369	1369	1369	1369
	UK00	2833	2833	2833	2833
	BE00	177	177	177	177
Run-of-River	DE00	3718	3718	3718	3718
	DK00	0	0	0	0
	NO00	1149	1149	1149	1149

Table 28: Installed capacities per neighboring country. The table continues for 3 pages (Entso-e, 2022b).

SupplyTechnology		DE 2030	GA 2030	DE 2040	GA 2040
Solar PV	UK00	1919	1919	1919	1919
	BE00	17845	15556	32404	23909
	DE00	123439	67298	253032	133049
	DK00	17187	6481	31288	27771
	NO00	333	333	333	333
	UK00	41678	27761	85917	46738

Table 29 presents the capacities for the import of natural gas through LNG, pipelines, the production of natural gas and bio methane, and the import capacity of hydrogen. Capacities differing per year are specified per year (2030 or 2040).

Table 29: Import capacities for LNG, pipelines, natural gas production, bio methane production and hydrogen imports (Entsog, 2022).

Region	LNG import capacity (GW)	Pipeline import capacity (GW)	Natural gas production capacity (GW)	Biomethane production (GW)	Biomethane production 2030 (GW)	Biomethane production 2040 (GW)	Hydrogen import capacity 2030 (GW)	Hydrogen import capacity 2040 (GW)
BE00	22.5	47	0	0	233	711	0	29.6
DE00	5.6	206.7	0	3.2	4.3	11	0	13
DK00	0	5.6	31.2	0.8	1.3	2.4	0	0
NO00	0	0	39	0	0	0	24.8	24.8
UK00	30.1	62.5	50.1	0	0	0	0	13

Figure 36 presents the hourly onshore wind capacity factors of the neighbouring countries during the seasons incorporated in this research.

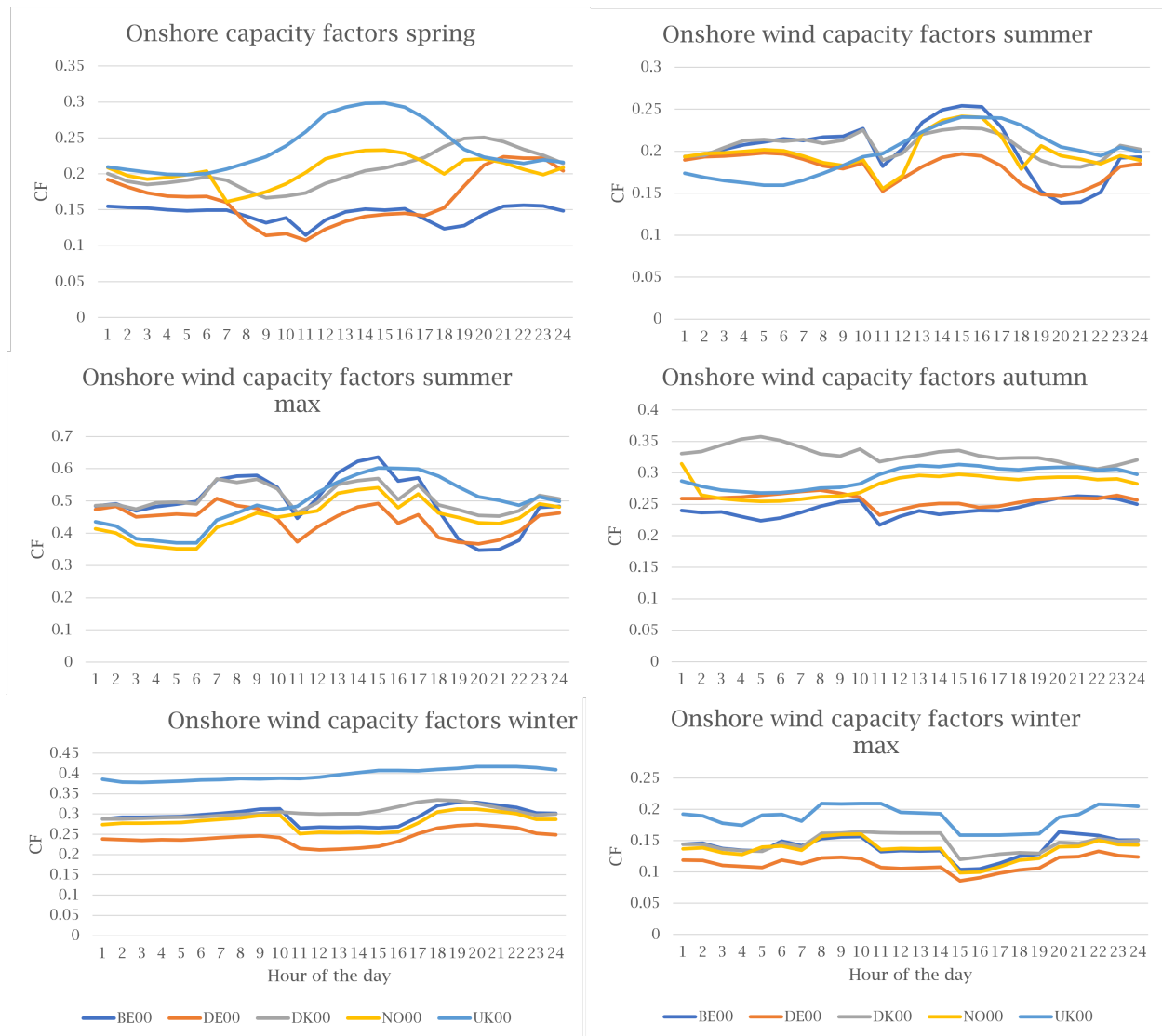


Figure 36: Hourly capacity factors (CF) for onshore wind turbines in Belgium (BE00), Germany (DE00), Denmark (DK00), Norway (NO00) and United Kingdom (UK00).

Figure 37 presents the hourly offshore wind capacity factors of the neighbouring countries during the seasons incorporated in this research.

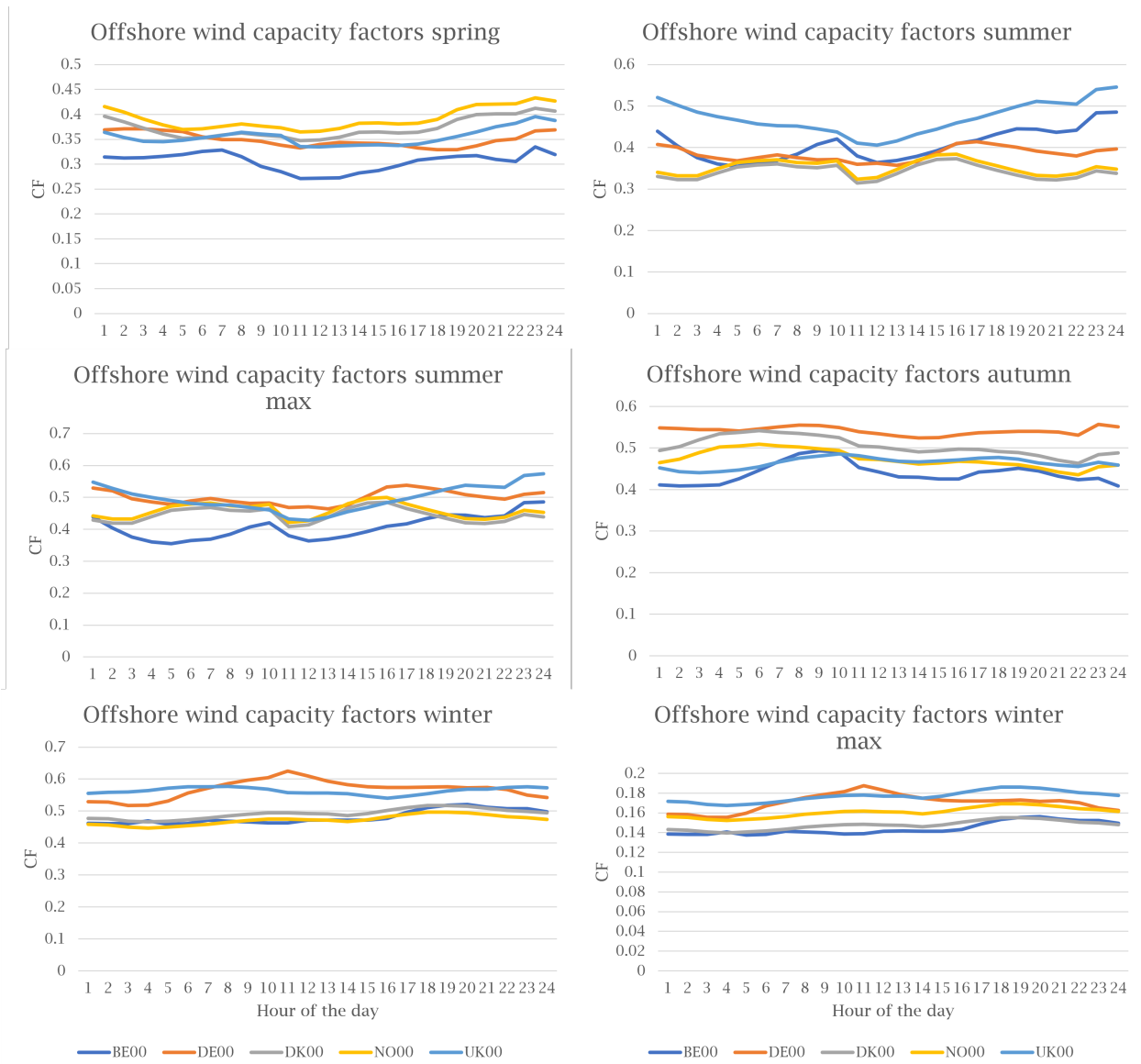


Figure 37: Hourly capacity factors (CF) for onshore wind turbines in Belgium (BE00), Germany (DE00), Denmark (DK00), Norway (NO00) and United Kingdom (UK00).

Figure 38 presents the hourly solar PV capacity factors of the neighbouring countries during the seasons incorporated in this research.

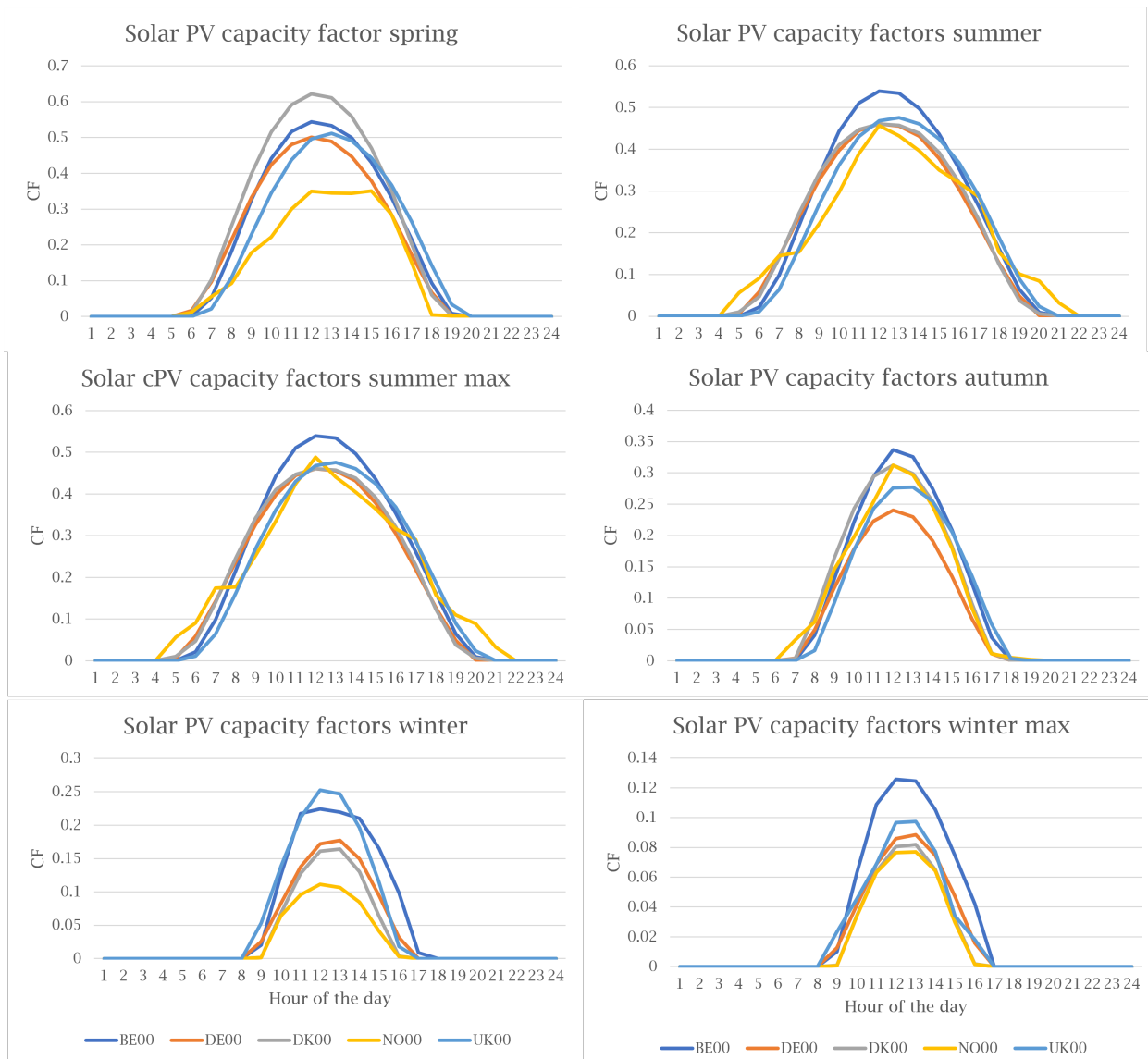


Figure 38: Hourly capacity factors (CF) for solar PV in Belgium (BE00), Germany (DE00), Denmark(DK00), Norway (NO00) and United Kingdom (UK00).

Annex D: Parameters used for demand profiles

The annual natural gas demand figures, presented in table 30 are used to comprise the hourly gas demand as described in section 4.

Table 30: Annual natural gas demand figures (m³), the Netherlands 2020 (CBS, 2022).

	Average NG consumption detached (2020)	Average NG consumption semi detached (2020)	Average NG consumption town house (2020)	Average NG consumption corner house (2020)	Average NG consumption multi-family house* (2020)	Average NG consumption apartment (2020)
Groningen	2020	1540	1300	1490	940	940
Friesland	1800	1360	1210	1350	840	840
Drenthe	2040	1510	1230	1400	860	860
Overijssel	1990	1510	1130	1310	740	740
Gelderland	1490	1130	700	890	400	400
Flevoland	2130	1550	1100	1290	800	800
Utrecht	2370	1730	1050	1290	630	630
North Holland	2120	1680	1130	1380	780	780
South Holland	2120	1570	1070	1300	800	800
Zeeland	1680	1310	1090	1240	770	770
North Brabant	2120	1560	1120	1310	690	690
Limburg	2110	1590	1260	1430	830	830

The annual electricity demand figures, presented in table 30 are used to comprise the hourly electricity demand as described in section 4.

Table 31: Annual electricity demand figures, the Netherlands 2020 (CBS, 2022).

	Average electricity use detached (2020)	Average electricity use semi detached (2020)	Average electricity use town house (2020)	Average electricity use corner house (2020)	Average electricity use multi-family house* (2020)	Average electricity use apartment (2020)
Groningen	3380	2820	2500	2620	1810	1810
Friesland	3260	2670	2320	2420	1670	1670
Drenthe	3610	2990	2490	2600	1830	1830
Overijssel	3940	3240	2710	2840	1920	1920
Gelderland	4210	3550	2970	3100	1980	1980
Flevoland	4060	3290	2710	2850	1930	1930
Utrecht	4470	3620	2880	3070	1990	1990
North Holland	4040	3480	2860	3000	1920	1920
South Holland	4370	3650	2980	3130	2050	2050
Zeeland	3210	2760	2350	2440	1820	1820
North Brabant	4370	3500	2920	3080	2010	2010
Limburg	4080	3210	2890	3010	1980	1980

The types of heating equipment used in the years 2020, 2030 and 2040 determine the energy requirement of natural gas and electricity in the built environment. The input parameters are presented in table 32.

Table 32: Heating equipment in 2020, 2030 and 2040 (Entso-e, 2022a, CBS, 2022)

Heating equipment NL	Distributed Energy			Global Ambition		Efficiency of technology
	2022	2030	2040	2030	2040	
Year	2022	2030	2040	2030	2040	
Share of NG boiler	76.1%	43.2%	22.8%	48.6%	25.7%	95%
Share biomass boiler	3.3%	2.9%	1.4%	2.8%	2.0%	95%
Solar	0.3%	0.2%	0.1%	0.2%	0.1%	100%
Share district heating gas	2.9%	7.5%	5.3%	3.9%	4.2%	93%
Share district heating coal	0.3%	0.6%	0.2%	0.3%	0.0%	89%
Share district heating biomass	0.2%	9.0%	7.9%	3.1%	3.3%	30%
Share district heating electricity + ambient heat	3.1%	3.7%	5.5%	2.6%	3.5%	171%
Share hybrid electric part	5.8%	8.2%	11.8%	20.2%	31.0%	Temperature dependent
Share hybrid gas part	2.1%	3.3%	4.9%	8.4%	13.1%	Temperature dependent
Share electric direct	3.0%	1.7%	0.8%	1.9%	1.4%	99%
Share electric heat pump air source	2.5%	12.1%	24.5%	4.5%	8.8%	Temperature dependent
Share electric heat pump ground source	0.0%	7.4%	14.9%	3.3%	6.8%	Temperature dependent

The additional residential buildings per province in the Netherlands for 2030 and 2040 is identical for both scenarios. However, the latter impedes additional demand of energy. Table 33 presents the additional houses in 2030 and 2040.

Table 33: Additional residential buildings per province in The Netherlands in the years 2030 and 2040.

Province	2030	2040
Groningen (NL11)	1383	3112
Friesland (NL12)	3877	8724
Drenthe (NL13)	2682	6035
Overijssel (NL21)	8729	19640
Gelderland (NL22)	13344	30023
Flevoland (NL23)	21185	47666
Utrecht (NL31)	22984	51715
Noord-Holland (NL32)	54818	123339
Zuid-Holland (NL33)	60959	137158
Zeeland (NL34)	2248	5057
Noord-Brabant (NL41)	33126	74534
Limburg (NL42)	3986	8969

The type of vehicles, and the rate of electrification, differs amongst the Distributed Energy and Global Ambitions scenario. Therefore, the input parameters are presented in table 34.

Table 34: Input parameters personnel transport (Entso-e, 2022a, Blok and Nieuwlaar, 2016)

Share energy carriers personnel transport	Value	Unit	Distributed Energy		Global Ambition	
			2030	2040	2030	2040
Year	2020		2030	2040	2030	2040
Share gasoline (2021)	80.3%		64.9%	32.5%	71.7%	40.1%
Share diesel (2021)	12.3%		10.0%	5.0%	11.0%	6.2%
Share LPG (2021)	1.3%		1.0%	0.5%	1.1%	0.6%
Share electricity (2021)	6.0%		24.0%	61.0%	12.0%	31.0%
Share CNG (2021)	0.1%		0.1%	0.0%	0.1%	0.1%
Share FCEV	0.0%		0.0%	1.0%	4.0%	22.0%
Average charging efficiency	90%		90%	90%	90%	90%
Average energy use electric vehicle	0.204	kWh/km				
Average energy use ICE	1.92	MJ/p-km				

The type of fuels used for heavy transport, and the rate of electrification, differs amongst the Distributed Energy and Global Ambitions scenario. Therefore, the input parameters are presented in table 35.

Table 35: Input parameters heavy transport (Entso-e, 2022a, CBS, 2022)

	2020	Unit	Value		Distributed Energy		Global Ambitions	
			2030	2040	2030	2040	2030	2040
International shipping								
Share fossil	99%		75%	37%			75%	37%
Share methane (LNG, CNG)	1%		25%	48%			25%	48%
Share hydrogen	0%		0%	15%			0%	15%
Transshipped cargo in kton (2019)	607525	kton						
International navigation bunkers NL (2019)	489.484	PJ						
Energy intensity per kton	0.000805702	PJ/kton						
Aviation	2020		2030	2040			2030	2040
Share intra EU flights	42%							
Share international flights	58%							
International aviation								
Share kerosene	100%		100%	90%			100%	90%
Share hydrogen	0%		0%	10%			0%	10%
Number of flights, NL (2019)	603633							
International aviation bunkers (2019)	164.379	PJ						
Energy intensity per flight	0.000272316	PJ/flight						
Intra EU aviation			2030	2040			2030	2040
Share kerosene	100%		95%	70%			95%	75%
Share hydrogen	0%		0%	10%			5%	20%
Share electric	0%		5%	20%			0%	5%
Heavy trucks	2020		2030	2040			2030	2040
Transported tonkm	3395300000	tkm						
Energy use per ton km	1.1	MJ/tkm						
Total number of heavy trucks	143670							
Transported tonkm per truck	236326	tkm/year						
Share fossil	99.0%		81.0%	53.0%			88.0%	69.0%
Share methane (LNG, CNG)	1.0%		3.0%	1.0%			3.0%	1.0%
Share hydrogen	0.0%		1.0%	25.0%			5.0%	15.0%
Share electric	0.0%		16.0%	21.0%			4.0%	15.0%
Light trucks	2020		2030	2040			2030	2040
Transported tonkm	1420900000	tkm						
Energy use per ton km	9.4	MJ/tkm						
Total number of light trucks	960130							
Transported tonkm per truck	14799	tkm/year						
Share fossil	94.0%		79.0%	41.0%			87.0%	47.0%
Share plug-in hybrid	4.0%		4.0%	5.0%			3.0%	4.0%
Share electric plug-in hybrid	12.0%							
Share electric	0.0%		14.0%	48.0%			5.0%	16.0%
Share methane (LNG, CNG)	2.0%		1.0%	3.0%			3.0%	19.0%
Share hydrogen	0.0%		2.0%	3.0%			2.0%	13.0%
Busses	2020		2030	2040			2030	2040
Share fossil	79.5%		45.0%	22.0%			42.0%	26.0%
Share methane (LNG, CNG)	6.9%		0.0%	0.0%			0.0%	0.0%
Share electric	13.2%		50.0%	62.0%			41.0%	46.0%
Share hydrogen	0.0%		5.0%	16.0%			17.0%	29.0%
Total km	639400000	km						
Energy use per km, gasoline/diesel/lpg	13	MJ-km						
Energy use per km, electric	1.395	kWh/km						
Total number of busses	6693							
km per bus	95532.64605							

Annex E: Daily profiles neighbouring countries

Neighbouring countries winter max DE 2030

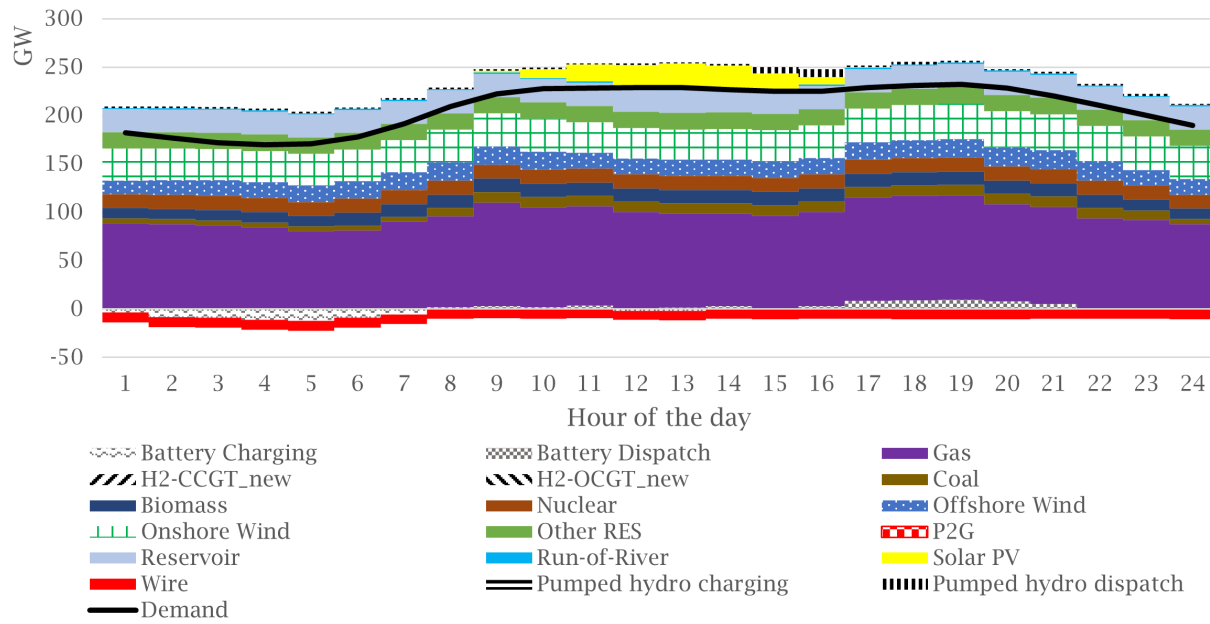


Figure 39: Representative day during peak demand during winter for the DE scenario in 2030 (winter max).

Neighbouring countries winter max DE 2040

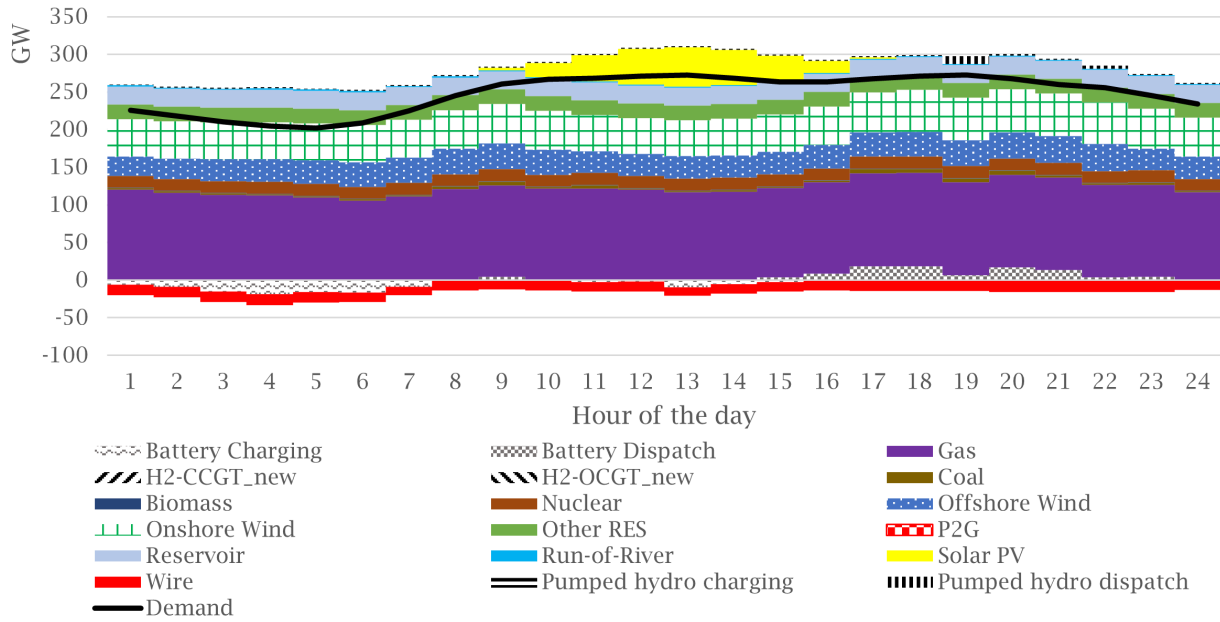


Figure 40: Representative day during peak demand during winter for the DE scenario in 2040 (winter max).

Neighbouring countries summer max DE 2030

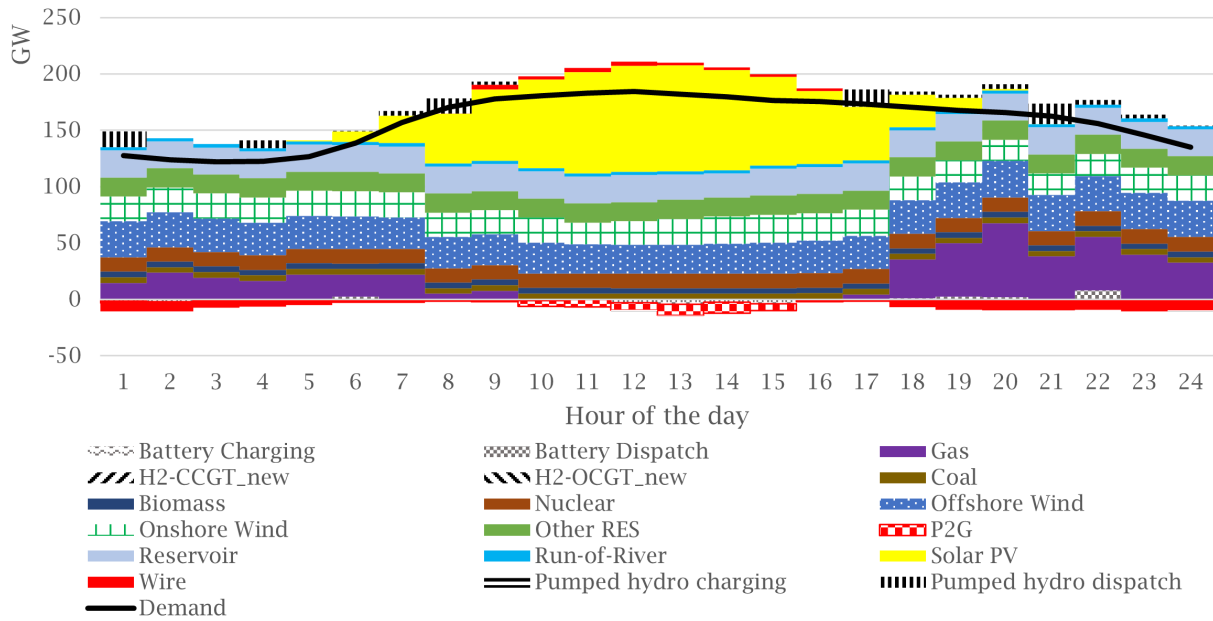


Figure 41: Representative day peak demand peak load during summer for the DE scenario in 2030 (summer max).

Neighbouring countries summer max DE 2040

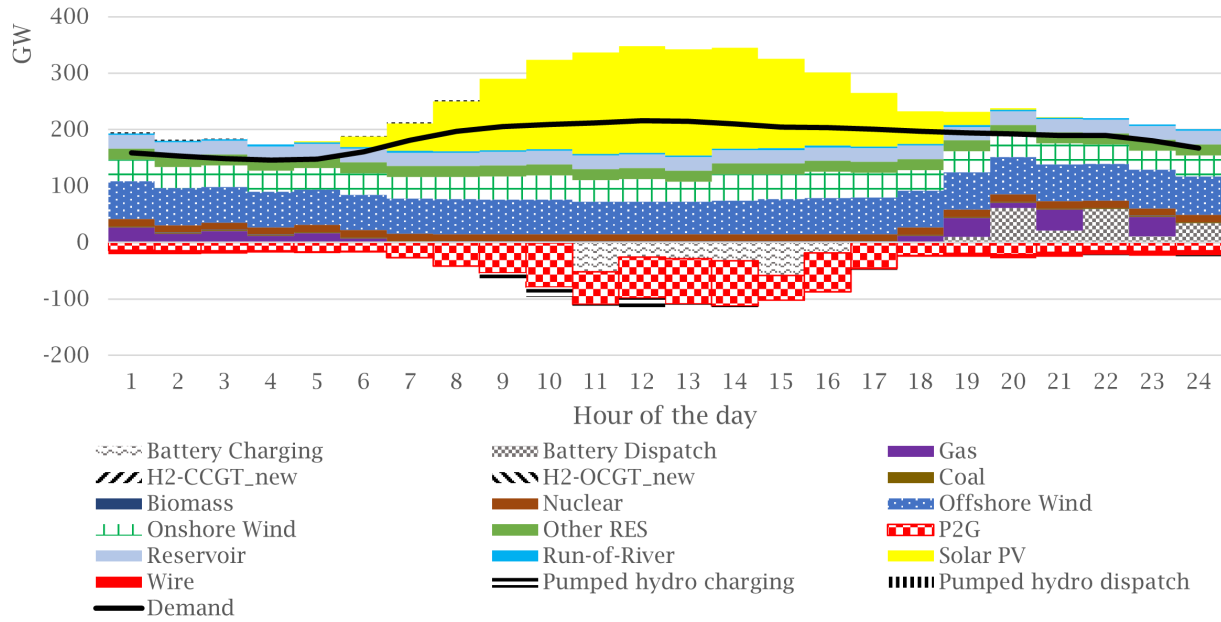


Figure 42: Representative day during peak demand peak load during summer for the DE scenario in 2040 (summer max).

Neighbouring countries winter max GA 2030

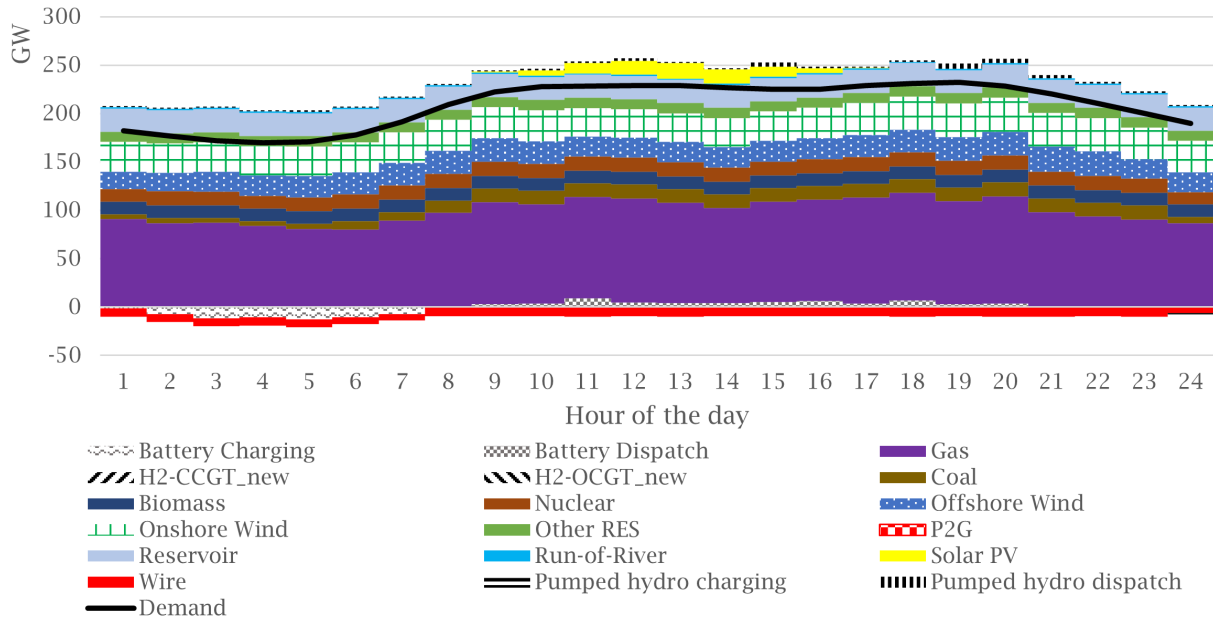


Figure 43: Representative day during peak demand during winter (winter max) for the GA scenario in 2030.

Neighbouring countries winter max GA 2040

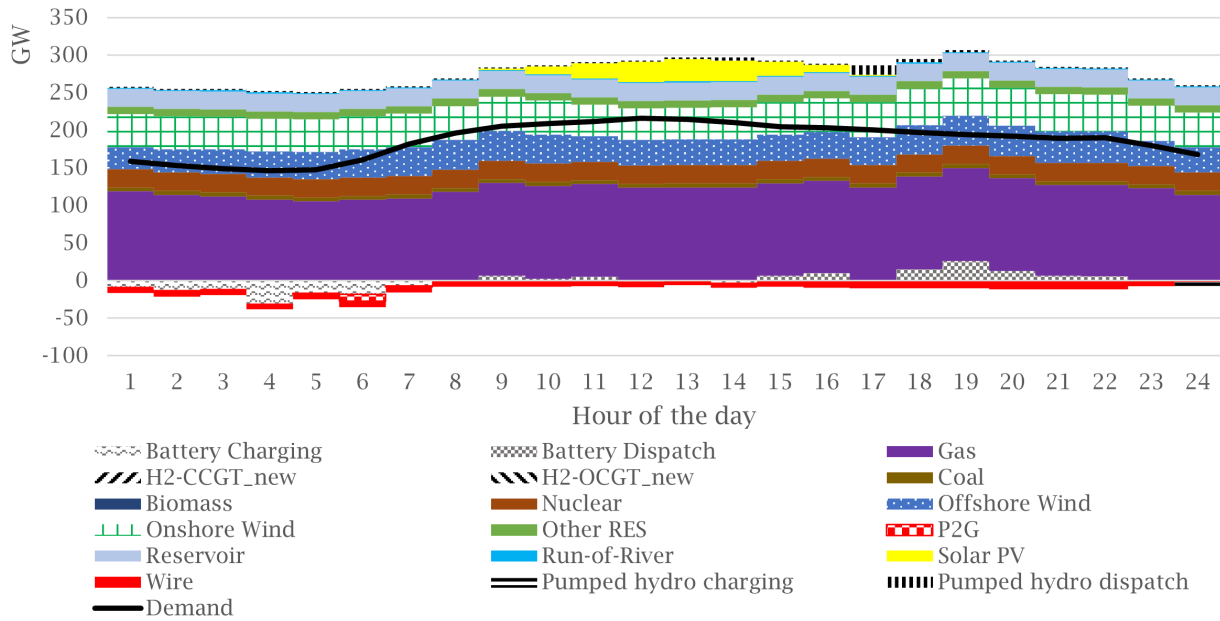


Figure 44: Representative day during peak demand during winter (winter max) for the GA scenario in 2040.

Neighbouring countries summer max GA 2030

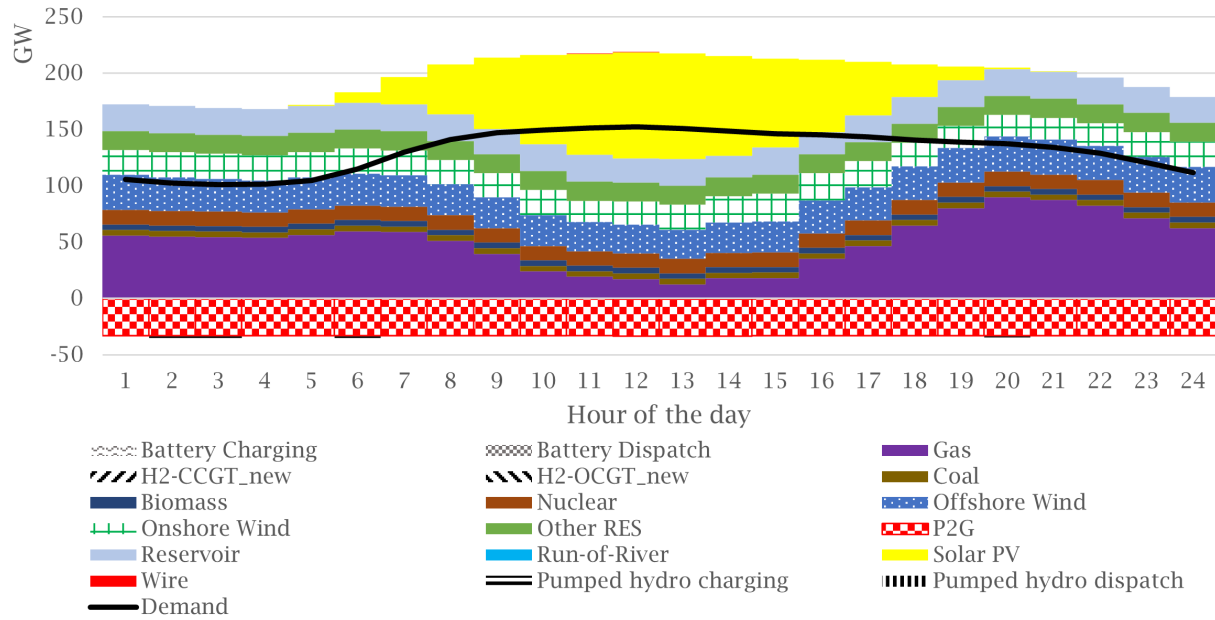


Figure 45: Representative day during peak load during summer for the DE scenario in 2030 (summer max).

Neighbouring countries summer max GA 2040

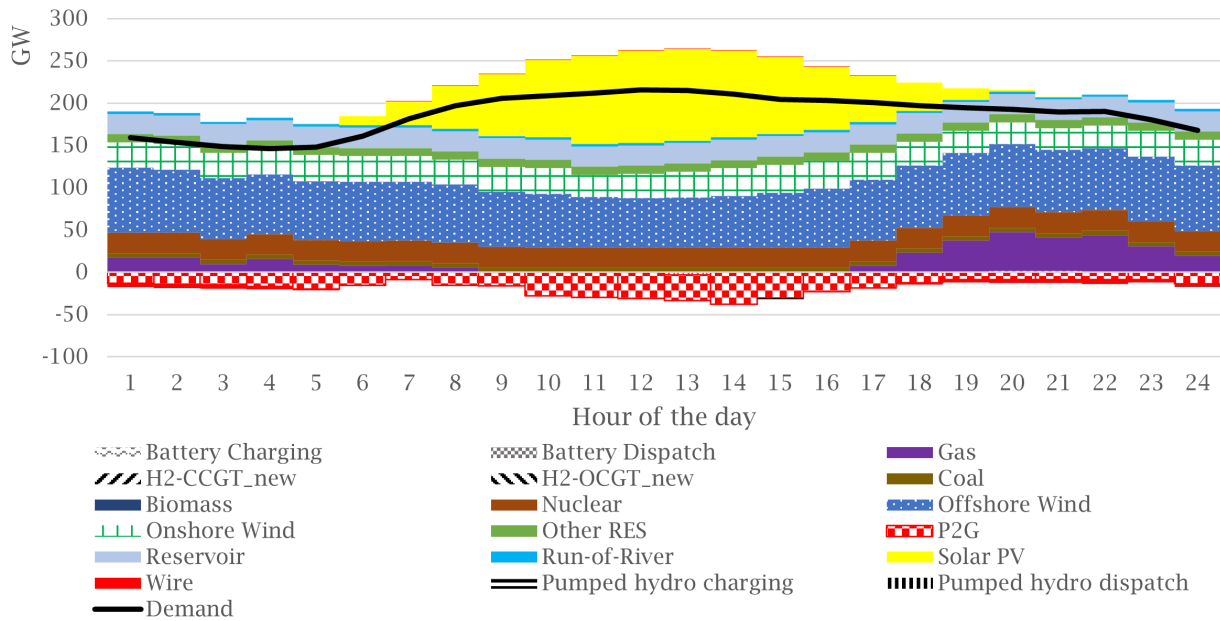


Figure 46: Representative day during peak load during summer for the DE scenario in 2040 (summer max).