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Scenarios Methodology Report

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1 INTRODUCTION

The purpose of the Scenarios Methodology Report is to provide insight into the methodologies used for developing the scenarios. This aids the reader in better understanding the figures, charts, and results of the Scenarios Main Report by offering additional information. It also aims to clarify the scenario development process itself.

1.1 How to read this document

The main body of the document (sections 1, 2, 3 and 4) is designed to provide a comprehensive overview of the scenarios building process (for National Trends, Distributed Energy and Global Ambition). These sections describe step by step the modelling approaches, the process and sequences followed from the data collection until the post-processing of the results and provide the essential information of the modelling building blocks and related parameters.

The appendices aim to provide further details about the tools used, the modelling innovations embedded in this edition (Hybrid heating supply, P2G methodology and its possible configurations, EV and prosumer nodes, Offshore Hubs, and Synthetic Fuel production) as well as detailed description and insights behind the different choices for modelling the demand, the supply and other parameters like fuel and CO_2 prices.

This division allows the reader to have a first, complete understanding of the overall Scenarios modelling process, but at the same time the freedom to further explore details about certain building blocks of this methodology without affecting the readability of the full document.

Before exploring each section, the two following paragraphs describe the major improvements for this edition and what has been the general decisional process that leads to the modelling features implemented for this 2024 edition.

1.2 Decisional process for designing the methodology

The methodology report presented in this document can be considered as the outcome of a collective decisional process from different experts from both gas and electricity TSOs in the Working Group Scenario Building (WGSB). Stakeholder feedback derived from public consultation and bilateral engagement constitutes a major input for the work of the WGSB. The WGSB is organized in sub-teams, each sub-team has worked on specific themes and modelling aspects based on the expertise of its members. Hence, the choices defining the methodology applied for the TYNDP 2024 Scenarios have been processed and debated within each sub-group depending on their field of expertise before discussion at WG Scenario Building level. Choices have been made giving priority to the accuracy of the model but also considering constraints such as the timeline, data availability and computation time.

The overall structure for the organisation of tasks and decisions related to the scenario building is pictured in Figure 1.

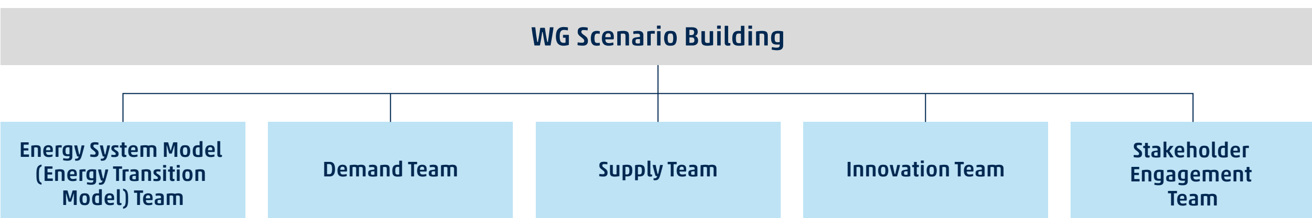


Figure 1: Decision making groups for the Scenario building methodology definition

1.3 Summarising the improvements

The evolution of TYNDP Scenarios produced by ENTSO-E and ENTSOG is two-fold. On the first hand the storylines are adapted to capture evolving stakeholders' expectations and the European policy and climate ambition. Thereby the improvements of the TYNDP 2024 scenarios are to a large extend based upon the evaluation of the TYNDP 2022 scenarios and the feedback given by stakeholders. On the other hand, some modelling innovations are developed and implemented to better capture the dynamics of a fast-changing energy system.

The present document describes the methodology used to convert storylines into fully-fledged scenarios. Compared to the previous edition, improvements cover many aspects of scenario development and offered the opportunity of closer interaction with the respective sectors. The improvements achieved to model different sectors (among which electrolysis, prosumer and EV node, hybrid heating, offshore network development and synthetic fuels) have benefited from both the expertise of those stakeholders that, being closer to certain sectors, have manifested their availability for bilateral exchanges and feedback received during the public consultations. More details on stakeholders' interactions and exchanges are provided in a dedicated section of the TYNDP 2024 Scenario Report.

As WGSB responsible for the TYNDP 2024 scenarios, we are proud of the development that we have been through, but we acknowledge that we might have some blind spots on our methodology. If you, the reader, have any input or expertise in this area, we will be happy to interact with you and learn from your expertise so that we can improve it further – do not hesitate to reach out to us!

1.3.1 Hydrogen Modelling

In the previous edition, electrolysis was modelled with 5 configurations, considering a range of different potential operational profiles and assets. These configurations are explained in the depth in the 2022 TYNDP scenario building guidelines.[1]

Considering the development of hydrogen strategies at national, European, and global level as well as the increasing number of projects (e.g., electrolysis, mobility, industrial applications, cross-border infrastructure), it has been decided to focus on the coupling of hydrogen with the rest of the energy system. The coupling of hydrogen with the rest of the energy system can happen via different pathways. This is depending on the availability/development of alternative hydrogen sources (SMR/ATR), storages or an integrated hydrogen system. To capture the possible pathways, four different configurations of power-to-gas have been modelled in this edition. Their place will depend on scenario and time horizon.

1.3.2 Synthetic Fuel Modelling

In this scenario development cycle, synthetic fuels were included as a notable innovation. These are fuels such as e-kerosene, e-diesel and synthetic methane which are produced by converting hydrogen and biogenic CO_2 through processes like the Fischer-Tropsch and methanation. This approach leverages CO_2 and promotes a shift away from fossil fuels. It also impacts the hydrogen demand, ensuring that hydrogen demand for synthetic fuels is accounted in the supply side of the model. This development supports our storyline of decarbonising energy. The demand for synthetic fuels is defined as an input. The quantity that can be produced within Europe is determined by the availability of biogenic CO_2 in Europe.

In National Trends the methodology varies from the methodology used in Distributed Energy and Global Ambition.

1.3.3 Offshore Wind Hubs

Instead of modelling all offshore as wind radially connected to their home market without any offshore interconnection, offshore infrastructure including wind turbines, electrolysers as well as cables and pipelines has been modelled explicitly in the TYNDP24 cycle. To do so, the European seas are divided into 56 offshore zones where infrastructure can be built, and which can be connected to the mainland as well as to other offshore zones. This allows the model to jointly optimise the expansion of onshore and offshore grids and to give insights into the most cost-effective path to a European-wide offshore and onshore power infrastructure.

1 See here

1.3.4 Prosumer and EV modelling

The energy system will be increasingly impacted by development at end-user level. It results both from societal expectations (e.g., prosumers aiming at optimising their connection to the grid through the investment of their own solar rooftop and/or batteries) and technology revolution such as e-mobility offering the potential of enhanced sector coupling and large-scale deployment of heat pumps offering energy efficiency gains.

The interaction of prosumer and e-mobility with the wholesale market are explicitly modelled. Such approach will enable to capture the amount of electricity production and flexibility available at end-user level when designing the electricity system of each scenario.

1.3.5 Hybrid Heat Pumps

DE and GA scenarios incorporate the modelling of Hybrid Heat Pumps (HHP) as a heating technology, which utilizes electricity, hydrogen, and methane as energy carriers. This report outlines the process involved in Utilising HHPs to meet heat demand requirements within these scenarios, with a specific focus on the methodologies employed and the role of ETM in determining heat demand.

By Utilising HHPs in conjunction with multiple energy carriers, the optimisation process seeks to maximise energy efficiency and minimise environmental impact.

1.3.6 District heating

In NT+, primary energy demand for district heating is coming directly from the data collection while in the Distributed Energy and Global Ambition scenarios the ETM tool generates a demand for heat. The values from the NT+ survey is used directly in the supply tool while the heat demand from the ETM tool is transferred into a demand for the primary energy carriers using same distribution and efficiencies as the TSOs has given in the NT+ data collection.

1.3.7 Transition to Energy Transition Model

In the TYNDP 2024, for the first time the Energy Transition Model (ETM) is used for demand quantification. The ETM is a comprehensive and open-access online model developed by Quintel Intelligence to build and explore energy system scenarios, covering all relevant sectors and energy carriers. The model can be used for any interested third parties to create the TYNDP Scenarios with the published scenario links.

1.3.8 Transition to Demand Forecasting Tool

The forecasting toolbox (abbreviated as DFT) allows to easily perform electric load prediction starting from data analysis of historical time series (electric load, temperature, climate variables and other). It is an advanced forecasting tool which leads to a stronger harmonisation of forecasting activities and comparability of their outcomes provided by ENTSO-E members.

2 HIGH LEVEL PROCESS //

TYNDP 2024 scenario cycle will include six scenarios and depending on how there are developed, these scenarios are labelled either National Trends+ ('NT+') scenarios or Deviation Scenarios (Distributed Energy 'DE' and Global Ambition 'GA'). Figure 2 illustrates how ENTSO-E and ENTSOG plan to cover the different time horizons in their scenarios for TYNDP 2024.

TYNDP 2024 SCENARIOS STRATEGY

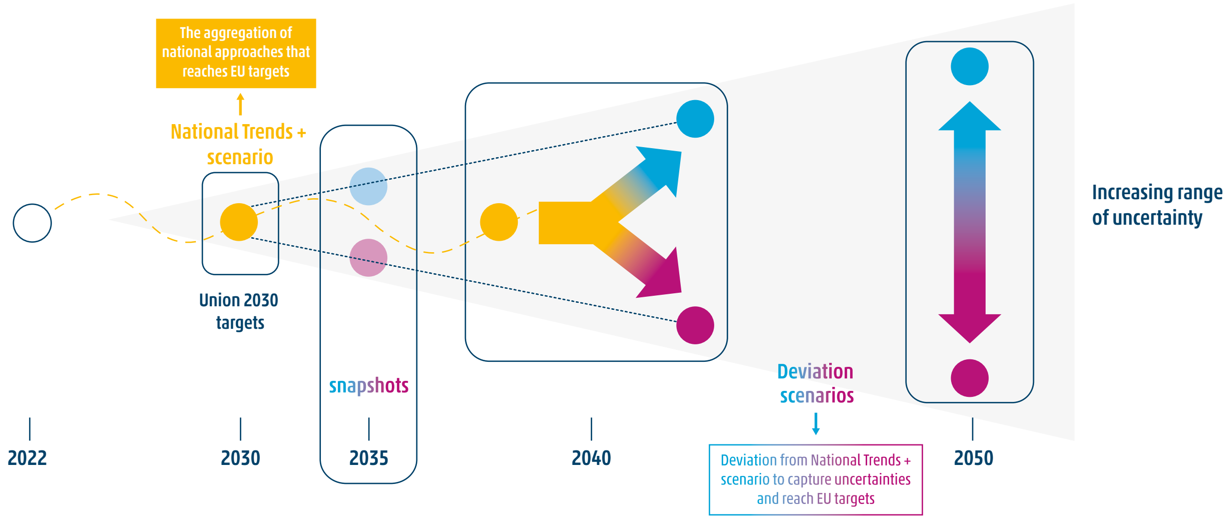


Figure 2: TYNDP Scenario horizon and framework

National Trends+ scenario is in line with national energy and climate policies (NECPs, national long-term strategies, hydrogen strategies ...) derived from the European targets. The electricity and gas datasets for this scenario are based on figures collected from the TSOs translating the latest policy- and market-driven developments as discussed at national level. These scenarios are available for the 2030 and 2040 time-horizons, as datasets for the 2050 time-horizons are not available in all Member States (MS). For TNYDP 2024, as the dataset collection is finalised in the first half of 2023 prior to the publication of the draft updated NECPs, which was due to be published in summer 2023. Therefore, the differences between recently updated NECPs and the datasets are expected. Moreover, for the first time in this edition, the National Trends+ scenario is quantified for all energy carriers (as opposed to just electricity and gas in the previous instalments). This will enable an assessment of the European Union's 2030 targets for energy and climate as required by the Regulation. The gap between the EU targets and this scenario, is transparently presented during the consultation process and closed according to the consulted 'NT+ Energy mix gap filling methodology'[2].

In addition to the NT+ scenario, which is aligned with national policies, ENTSOG and ENTSO-E developed t**wo deviation scenarios (DE and GA) for the time horizon 2040 and 2050 to cover increased uncertainties**. These scenarios are deviations from the NT+ 2030 scenario according to their respective storylines explained in Section 3.3. Scenario Storylines for Distributed Energy and Global Ambition. For these scenarios, NT+ 2030 represent the starting point and they are developed for the 2040- and 2050-time horizons. In addition, the 2035-time horizon is available as a snapshot, represents the average between 2030 & 2040. These scenarios are also built as full energy scenarios (all sectors, all energy carriers) to quantify compliance with EU targets. For 2035 and 2040, a meaningful transition from 2030 EU targets is sought, while for 2050 reaching carbon neutrality is mandatory.

2 See here

2.1 Data Collection

A core element of the ENTSOs' scenario building process is gathering the supply and demand data from both gas and electricity TSOs. This bottom-up data collection remains a key component of the scenario building exercise and provides useful insights and trends that exist at a national level.

National Trends+ (NT+) scenario uses predefined demand and capacity figures resulting from TSO data collection. Therefore, the model is more simplified, focusing only the optimisation of the generation figures with given capacities & demand.

For TNYDP 2024, the National Trends (NT+) dataset collection is finalised, prior to the publication of the draft updated NECPs, which was due to be published in summer 2023. Therefore, the differences between recently updated NECPs and the datasets are expected.

Moreover, for the first time in this edition, the National Trends+ Scenario is quantified for all energy carriers (as opposed to just electricity and gas in the previous instalments). As the demand data is fully bottom-up too; the annual demand (per sectorial per carrier) is collected from TSOs (**'National Trends+ Energy Mix Survey'**). This enabled an assessment of the European Union's 2030 targets for energy and climate as required by the Regulation. The gap between the EU targets and this scenario, is transparently presented during the consultation process and closed according to the consulted 'NT+ Energy mix gap filling methodology[3]. The original NT+ energy mix survey per country, the calculated EU27 gap with the FEC target and adjusted NT+ energy mix (EU27 level) can be reached on 2024 TYNDP Scenarios dedicated webpage[4].

The Deviation Scenarios (Distributed Energy 'DE' and Global Ambition 'GA') starts from National Trends+ 2030 scenario (with starting grid, generation capacities, and demand) and uses predefined demand figures for 2040 and 2050 resulting from TSO data collection which are finalised according to the public consultation feedback. Differently than National Trends, the capacity for DE and GA scenarios are not predefined, rather the result of the expansion model according to the cost optimisation.

For the certain technologies the capacities are not extended according to the cost optimisation, as the decisions are less bounded with the economy but also political directions and targets:

- Gas power plants don't extend but rather decommissioned according to TSO data collection (PEMMDB),

3 See here

4 See here

- No expansion on the nuclear plants, capacities are provided by the TSOs ex-ante[5] for all scenarios.

Some technologies due to certain restrictions (e.g., political decisions, technical potential etc) cannot be extended without limitations. Therefore, minimum, and maximum capacities are collected from the TSOs ('Trajectories'). These trajectories serve as boundary conditions for the model (e.g., low trajectory corresponds as starting capacity and expansion can be possible till high trajectory). The trajectories are collected for following technologies and went through public consultation:

- Solar, wind, prosumer batteries, large-scale batteries
- H_2 import potentials (low and upper import bands)

To ensure the consistency of the data set, a synchronisation of key data was carried out between the gas and electricity TSOs, as shown in Table 1. Collected energy specific data are defined in Table 2.

ELECTRICITY AND GAS TSO JOINT DATA COLLECTION/SYNCHRONISATION
GAS-FIRED POWER GENERATION CAPACITY FOR 2030 & 2040
GRID CONNECTED ELECTROLYSER CAPACITY FOR 2030 & 2040
NATIONAL TRENDS+ ENERGY MIX SURVEY FOR 2030 AND 2040
DEFAULT DE & GA DEMAND INPUTS FOR 2040 AND 2050

Table 1: Synchronised data collection among ENTSO-E and ENTSOG

ELECTRICITY TSO DATA COLLECTION	GAS TSO DATA COLLECTION
PEMMDB* - **Renewable energy sources** (NT capacities and minimum and maximum trajectories for deviation scenarios) - **Thermal unit capacity & must-runs** - **Nuclear unit capacity & must-runs** (together with minimum and maximum trajectories for deviation scenarios) - **Detailed electricity demand input** (for NT+ scenario) - **Electrolyser** (connected to electricity grid) - **Battery capacities** (prosumer and market participating) - **Demand-side response** (capacity & activation price bands) **Reference Grid for 2030** (used for NT2030 and starting point for deviation scenarios) **Reference Grid for 2035** (used for NT2040)	**Reference Grid for 2030** ('infrastructure level low', used for NT2030 and starting point for deviation scenarios) **Reference Grid for 2040** ('infrastructure level low', used for NT2040 and starting point for deviation scenarios) **Hydrogen project candidates and cost** ('infrastructure level high', expansion candidate for deviation scenarios) **SMR capacities** (details on with or without CCS) **Biomethane survey** (biomethane potentials) **Import potentials for Hydrogen, Ammonia and Methane** **Hydrogen project candidate and cost** (expansion candidate for deviation scenarios)

Table 2: Energy specific data collection per sector for building the National trends scenarios (*See here)

2.1.1 Electricity Demand and Renewable Profiling

Collected TSOs' demand and Renewable Energy Sources (RES) data are provided on annual basis. This, in turn, must be translated into an hourly profile to enable the modelling of the power system.

- **Demand profiling**: for most of the countries the Demand Forecasting Toolbox (see section 2.2.2) is used to produce hourly demand profiles for a range of climate years based on a climate database
- **Wind and solar profiling**: hourly load factors are derived from a climate database (differentiating existing and new technologies for wind).

5 While there is currently a governmental ambition to build new nuclear capacity in the Netherlands, it is not yet a concrete/formalised target and the required technical, political, and economic boundary conditions are still largely uncertain. Therefore, new nuclear capacity has not been considered in the base scenarios of this TYNDP. However, the further developments in this area are monitored closely and taken into account in national and European studies where necessary.

2.1.2 Electricity Reference Grid

The electricity reference grid provides ENTSO-E's most objective perspective on the network's state in 2030 (NT2030) and 2035 (NT2040). It encompasses net transfer capacity (NTC) values representing interconnections between market zones in the market model.

An electricity reference grid collection has been performed by ENTSO-E for three-time horizons in April 2023: first mid-term time horizon (2025), second mid-term time horizon (2030), long-term time horizon (2035). These terms are coherent with the maturity criteria stipulated in the 4th CBA Guidelines[6].

For each of the reference grid time horizons ENTSO-E used the fundamental criteria mentioned in the CBA 4 Guidelines to ensure that only those projects whose timely commissioning is reasonably certain are to be included in each of the reference networks.

For the first mid-term time horizon only projects that were either in construction phase or have successfully completed the environmental impact assessments have been included. This is in line with criteria a) and b) of the CBA guidelines and appears reasonable for the given time horizon.

For the second mid-term time horizon projects that have successfully completed the environmental impact assessments or are in the 'permitting' or 'planned, but not yet permitting' phase, and their timely realisation is most likely have been included (e.g., when the project is supported by country-specific legal requirements or the permitting and construction phase can be assumed to be short, such as for transformers, phase shifters etc.). These requirements could have been strengthened by applying further criteria, such as:

- The project is considered in the National Development Plan of the country where it is expected to be located.
- The project fulfils the legal requirements as stated in the specific national framework where the project is expected to be located.
- The project has a defined position with respect to the Final Investment Decision related to its implementation.
- There is a documented reference to the request for permits.
- A clearly defined system needs, to which a project contributes, could help to identify the reference grid.
- Year of commissioning, chosen depending on the year of the study and the scenario horizon used to perform the study.

For the long-term time horizon projects in the 'permitting' or 'planned phase, but not yet permitting', and their timely realisation is most likely have been included (e.g., when the project is supported by country-specific legal requirements or the permitting and construction phase can be assumed to be short, such as for transformers, phase shifters etc.). These requirements could have been strengthened by applying further criteria, such as:

- The project is considered in the National Development Plan of the country where it is expected to be located.
- The project fulfils the legal requirements as stated in the specific national framework where the project is expected to be located.
- The project has a defined position with respect to the Final Investment Decision related to its implementation.
- There is a documented reference to the request for permits.
- A clearly defined system needs, to which a project contributes, could help to identify the reference grid.
- Year of commissioning, chosen depending on the year of the study and the scenario horizon used to perform the study.

In cases where a cross-border project involved countries with different permitting processes and procedures compared to what is assumed in the CBA 4th Guidelines expert evidence-based judgement has been used with strong support of relevant national TSOs.

Within the Scenario Building process, the following assumptions were used:

	DISTRIBUTED ENERGY & GLOBAL AMBITION	NATIONAL TRENDS 2030	NATIONAL TRENDS 2040
REFERENCE GRID	2030	2030	2035

Table 3: Refeference grid configuration per scenario

The reference grid used in National Trends 2030 is used as a starting point for the top-down scenarios in 2030. Additional grid is then built through an expansion model, considering the transmission projects provided by the TSOs as potential candidates. For the electricity model specifically, Distributed Energy & Global Ambition do not include countries in North Africa, Ukraine, Turkey, and Moldova.

6 See here

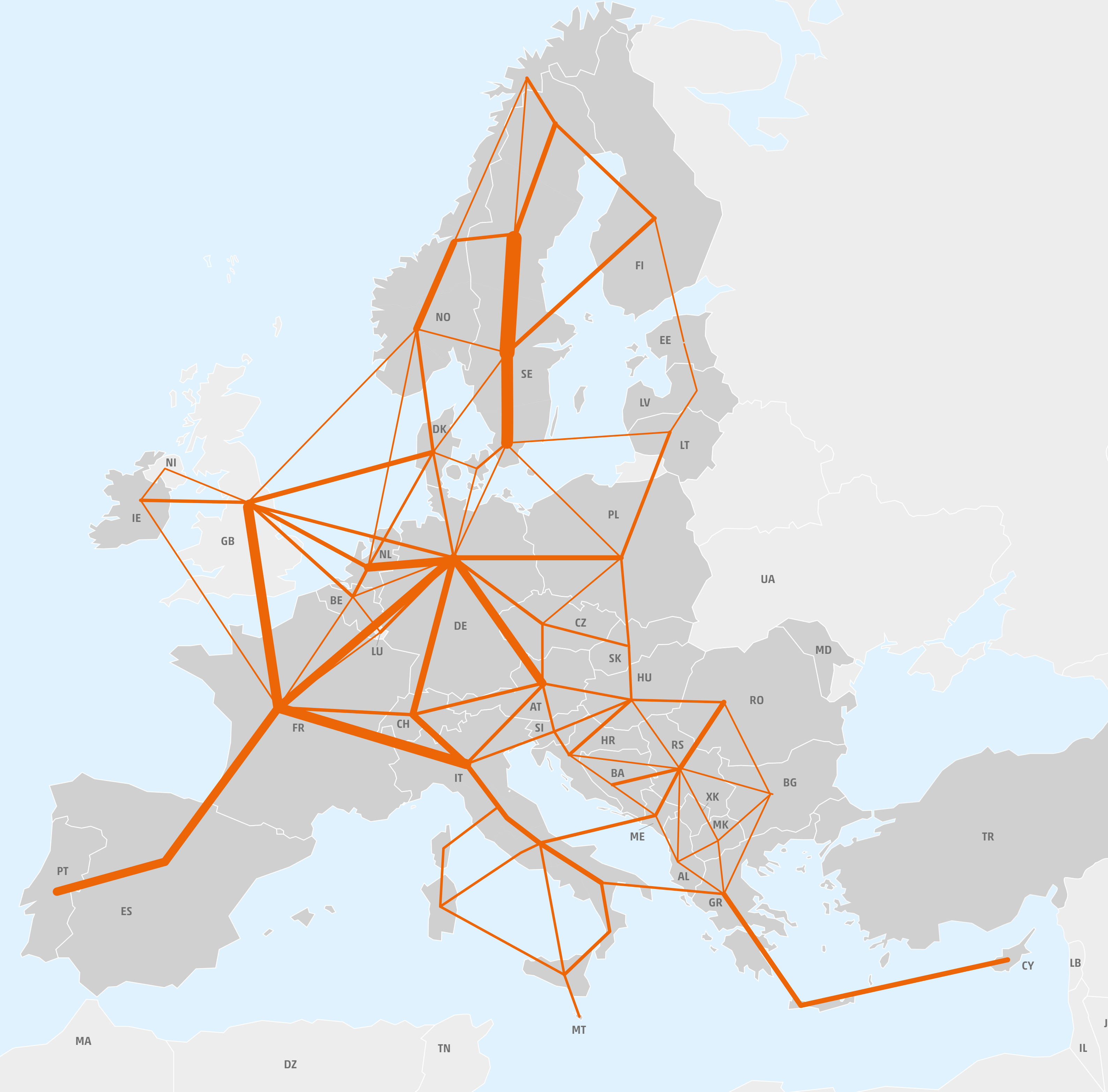


Figure 3: Electricity Reference Grid Input Net Transfer Capacities (MW)

2.1.3 Hydrogen Reference Grid

The hydrogen reference grid gathers all cross-border transmission (or, interconnector) capacities across Europe, according to the data that member TSOs have for 2030. The year is the only one for which a reference grid is provided, as 2030 is the starting point for the DE/GA scenarios. After 2030, investment can happen in transmission candidate projects, which are gathered separately.

It should be noted that the scenarios also use a SPOT market approach for the hydrogen system. It is not yet clear what the market design will be for the hydrogen market. This approach may not sufficiently consider cooperation agreements between TSOs or planned flows. In general, the scenario development process is not equipped and does not aim to give an assessment of infrastructure needs. This assessment is performed with the TYNDP process.

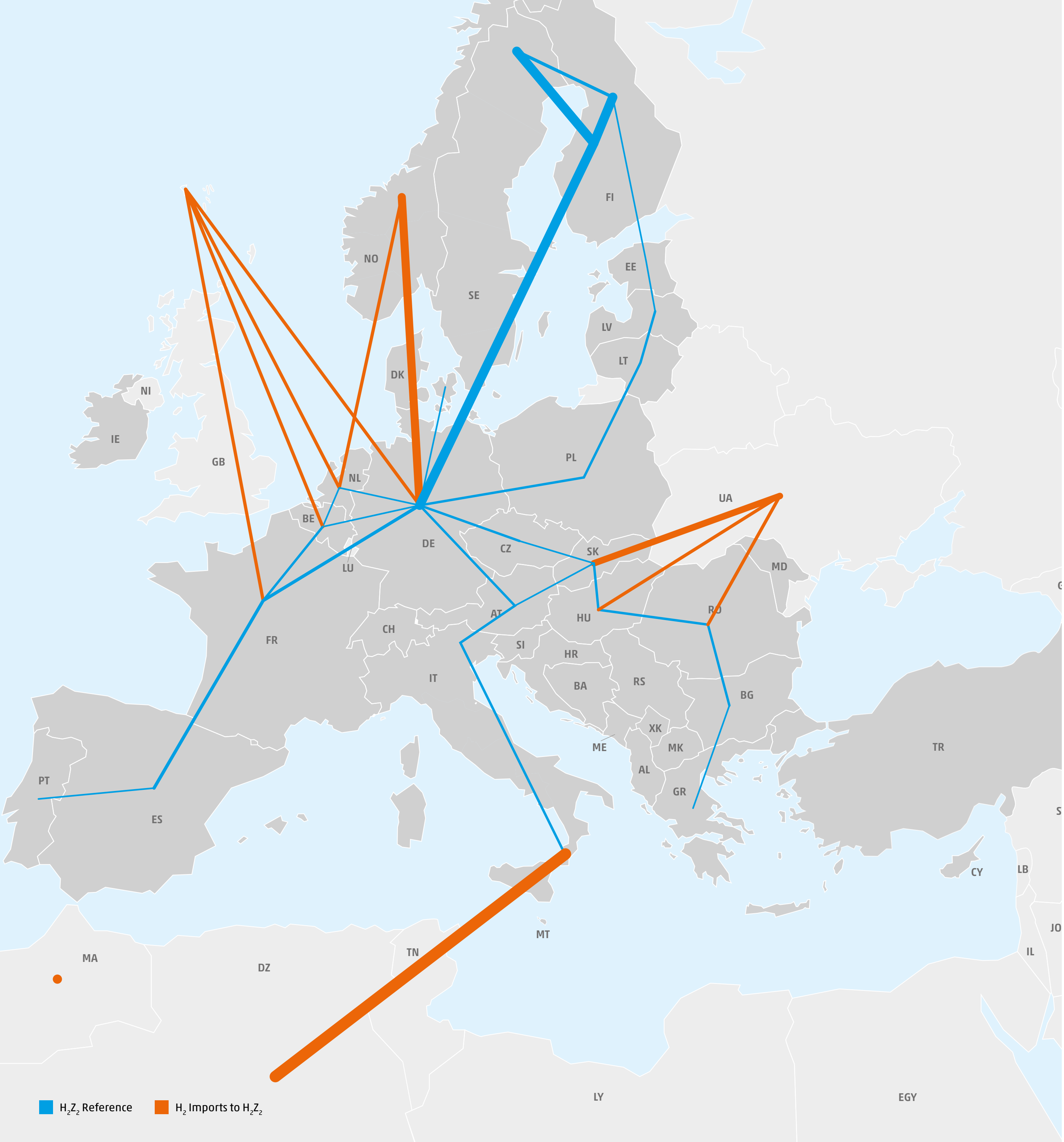


Figure 4: Hydrogen Reference Grid Pipeline Input Capacities (MW)

The hydrogen reference contains the following information:

- Border – the border on which the interconnector is found.
- Summary Direction 1 – capacity of interconnector (expressed in GW) in one direction, e.g., AT to DE
- Summary Direction 2 – capacity of interconnector (expressed in GW) in the direction opposite to the one mentioned before, e.g., DE to AT

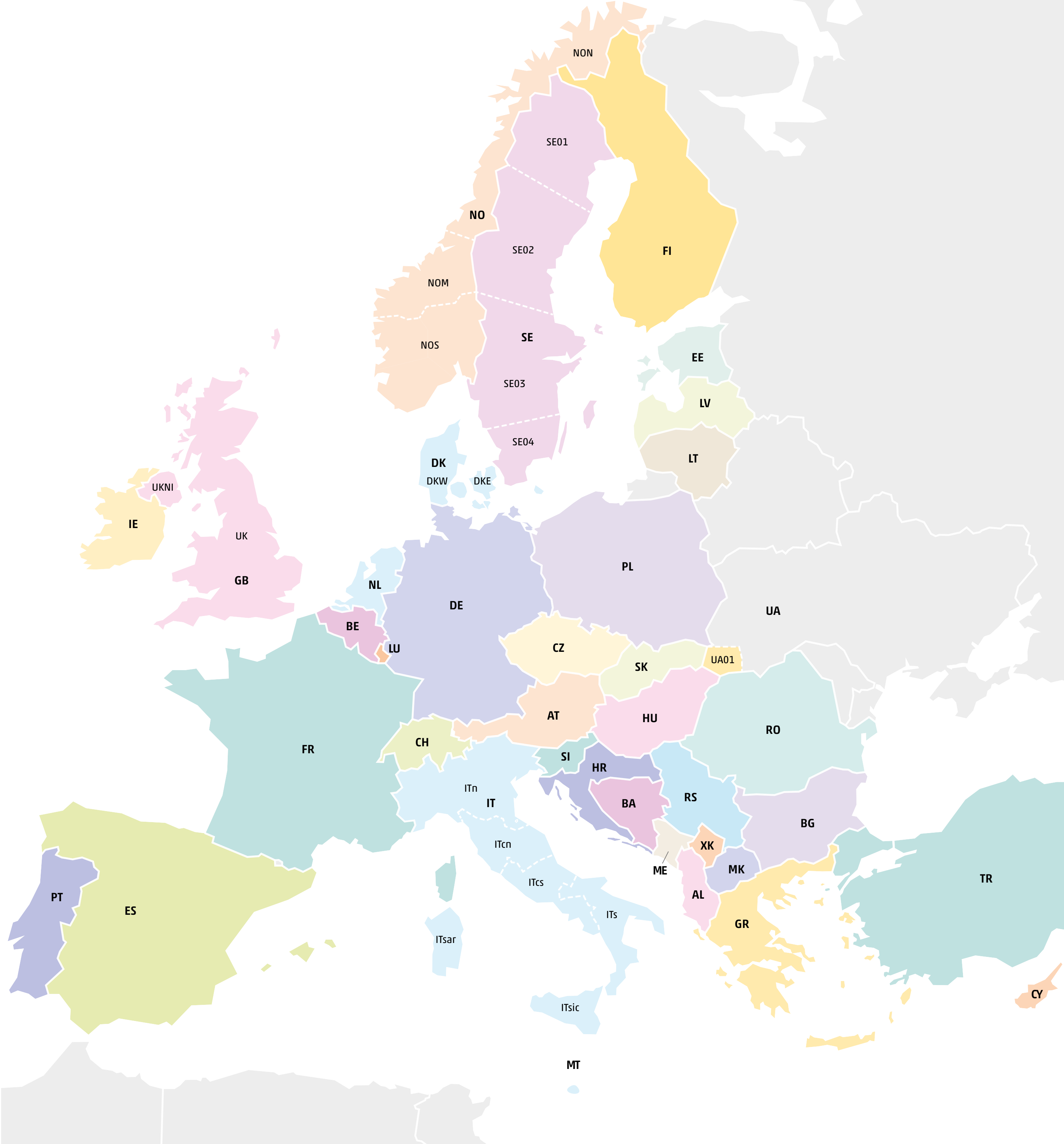


Figure 5: The bidding zones considered for each country modelled

2.1.4 Electricity System Modelling

The Electricity System is modelled using a nodal topology based on bidding zones. Figure 5 shows the bidding zones considered for each country modelled.

Each electricity market node contains its own generation mix, demand, and interconnections with neighbouring countries. North African electricity markets (those who are part of MedTSO[7] association) are also modelled only in National Trends, being the exchanges with these non-EU countries an output of the optimisation tool.

As a novelty in this TYNDP, ONDP figures have been included in the models. This alignment has led to an increase of offshore nodes.

7 See here

2.2 Hydrogen System Modelling

The Hydrogen System is modelled using a nodal topology based on a 1 node per country approach.

Each Hydrogen market node contains its own hydrogen supply source mix, demand, and interconnections with neighbouring countries.

It should be noted that the scenarios also use a SPOT market approach for the hydrogen system. It is not yet clear what the market design will be for the hydrogen market. This approach may not sufficiently consider cooperation agreements between TSOs or planned flows (e.g. EU Projects of Common Interest). In general, the scenario development process does not aim to give an assessment of infrastructure needs. This infrastructure need assessment is performed in the later stage of the TYNDP process.

In addition, as the model operates with a limited nodal topology, where each country is represented as a single node, cross-border flows supplying hydrogen from one region to another within the same country, but passing through another country, are not reflected in the model, even though these flows generate significant transport volumes in the transit country – such hydrogen flows are hidden in the respective country node.

Imports are considered from Norway, Ukraine, Morrocco, and Algeria. UK is also considered an import source, but as the electricity system is modelled using the same methodology as EU members and observer members, the same approach will be taken for the hydrogen system.

Offshore Hydrogen hubs have also been considered for the hydrogen system using the same topology as has been used for the electricity system.

Electrolysers create a link between the electricity and hydrogen markets, running when the electricity marginal price and the P2G unit efficiency is lower than the hydrogen marginal price. The electrolyser operation also considers that electrolysers should never be supplied using electricity generation linked to CO_2 emissions.

P2G installations without connection to the electricity market, referred to as dedicated RES (DRES), was reported for Spain. However, electrolysers operating with DRES were not foreseen in the proposed modelling methodology for the NT+ scenarios.

Expected DRES electrolyser capacity in Spain would be able to fully meet domestic demand, according to the Spanish gas TSO's estimates. Hence, it was decided that Spanish demand is not met endogenously by the model, but exogenously by matching it with expected domestic DRES electrolyser production. Hydrogen demand will be consistently modelled within the TYNDP process including the off-electricity grid electrolyser capacities submitted by the TSO.

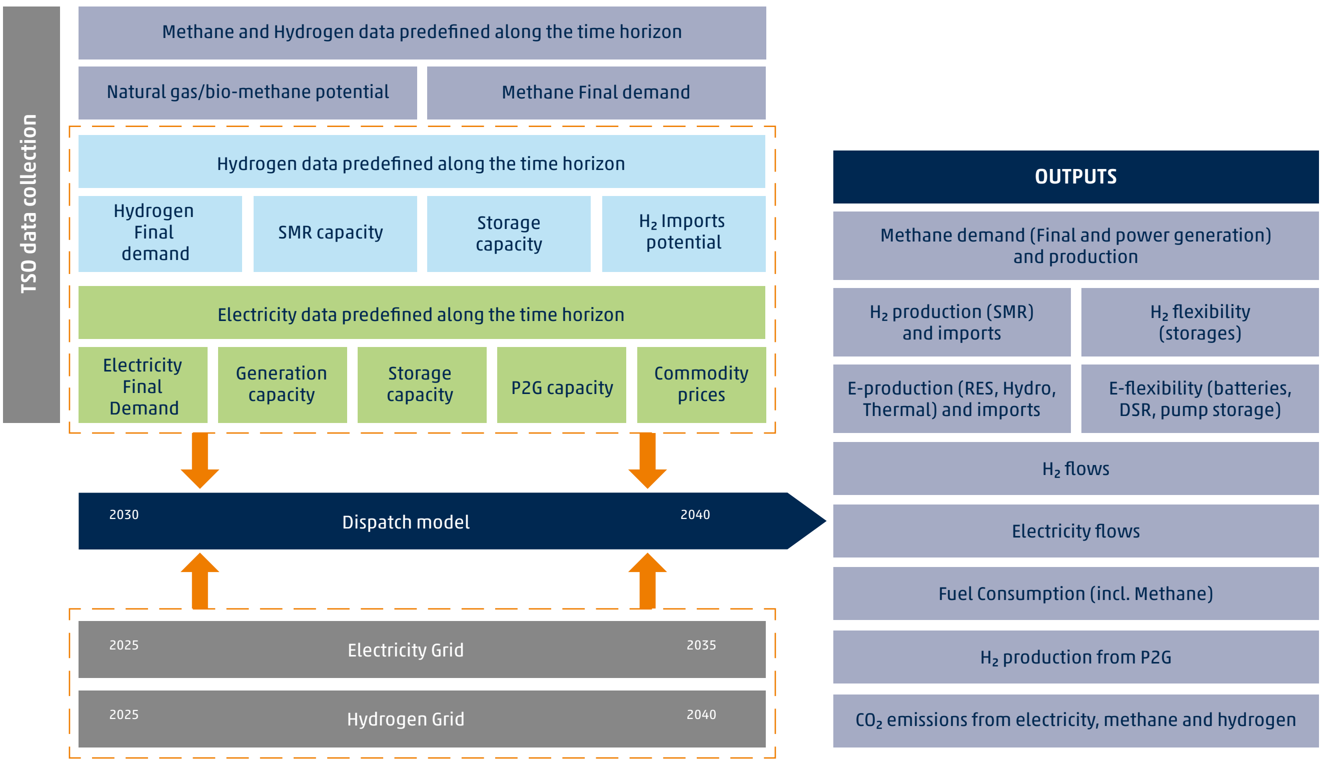


Figure 6: Building blocks for national trends scenario

2.3 DE & GA Scenario Modelling Principles

For TYNDP 2024, Distributed Energy and Global Ambition are labelled as deviation scenarios. These scenarios cover the overall European energy mix (all sectors including non-energy use and all energy carriers) to enable the assessment of carbon emissions at a given time horizon and carbon budget on the period. The overarching goal in the development of these scenarios is to achieve the future climate targets defined for the energy system. Energy system models help to validate these goals by quantifying the use of energy across different energy carriers, sectors, and applications both on the supply and demand side.

2.3.1 Scenario toolchain

To model these scenarios, a chain of different tools is applied with each a different scope. Starting with a quantification of expected energy demand per carrier in the scenarios (Energy Transition Model), the electricity demand is translated into a set of hourly demand profiles (Demand Forecasting Tool). In a next step the required supply of gaseous and biomass carriers to serve the demand of these carriers is being calculated (Supply Tool). The respective outputs of the beforementioned tools are used as input for the investment modelling tool (PLEXOS) which determines, along with a set of model boundary conditions (e.g. a valid range of installed capacities of a technology) and technology cost assumptions, a cost-optimal European mix of assets for the different target years (2030, 2035, 2040, 2045 and 2050). In a last step, all model results are being summarised in the visualisation platform for analyses purposes and to ensure transparency towards stakeholders. Between the different tools, data interfaces ensure that the right information is provided in a defined format. Figure 6 shows a high-level overview of the different processing steps and tools applied.

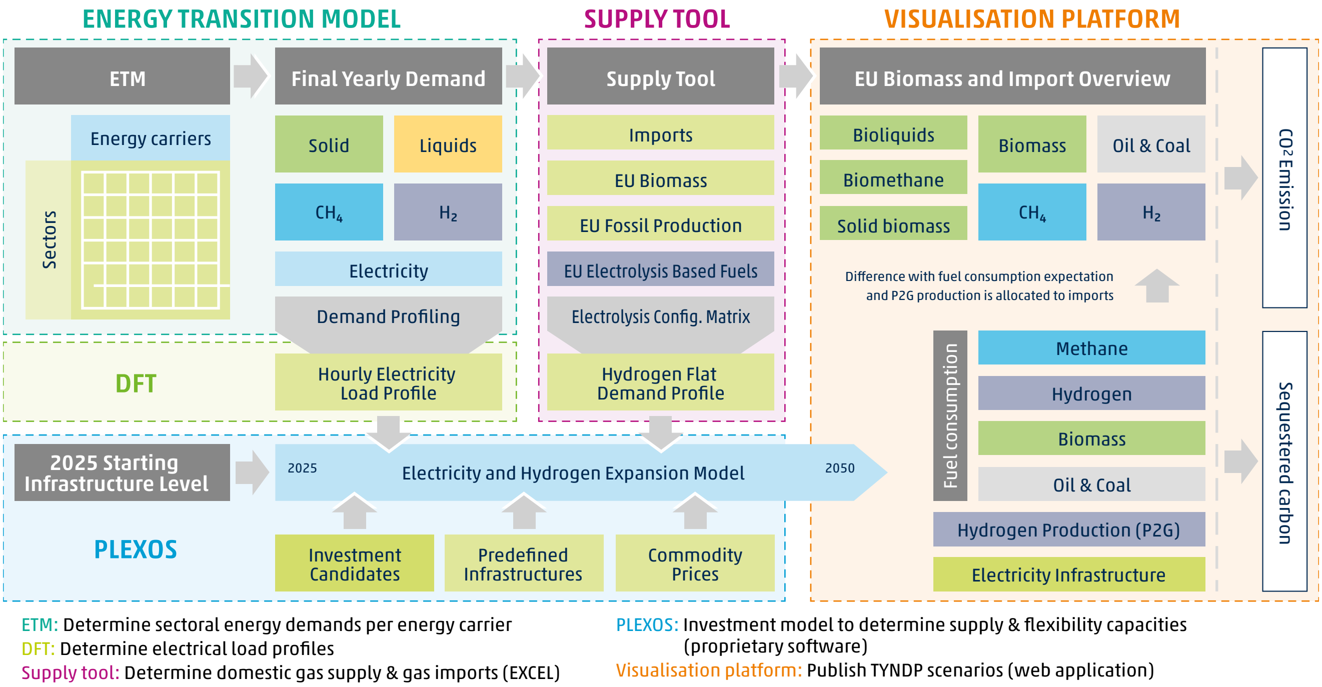


Figure 7: Building blocks for distributed energy and global ambition scenarios

In the following paragraphs a brief explanation of each tool is given.

2.3.2 Energy Transition model (ETM)

Model description

In the TYNDP 2024, for the first time the Energy Transition Model (ETM) has been applied. The ETM is a comprehensive and open-access online model developed by Quintel Intelligence to build and explore energy system scenarios, covering all relevant sectors and energy carriers. The model can currently be applied for all EU countries and the UK, is being used by different parties across Europe (e.g. grid operators, industry parties) and has seen a steady further development in the recent years.

Starting point of each ETM scenario is today's energy balance per country[8] and a database which reflects the technical and economical characteristics of the technologies applied in the energy system (e.g. a heat pump). In combination with a user-defined set of scenario assumptions for a specific target year (e.g. 2040), the ETM then projects the future use of energy. Depending on the user assumptions on future supply, demand and available flexibility options, the model ensures a yearly balance for each energy carrier. For the carrier's electricity, methane, hydrogen and heat the calculations are conducted at an hourly basis to consider the relevant market dynamics[9].

On the input side the model is structured into overall sections (supply, demand system balancing, targets, costs) which each summarize the most relevant parts and applications of the energy system. For instance, the demand section contains the relevant end user (sub)sectors, wherein the user can define various scenario parameters. As an example: For the subsector space heating in the demand sector-built environment, the user can define which share of the heat will be provided by which technology (heat pumps, gas boiler etc.) which in turn determines how much energy of which carrier is being consumed. On the output side the model provides a set of data tables and charts to visualise/explore the outcomes of a scenario and benchmark it against overall targets like the total emission reduction or energy efficiency increase. All results can be exported for further use in other applications.

The ETM can be accessed both online via a Graphical User Interface (GUI) or via an Automated Programming Interface (API), allowing more advanced users to interact with the ETM by scripts to upload data to or export data from the model[10]. Figure 8 shows the overall structure of the model.

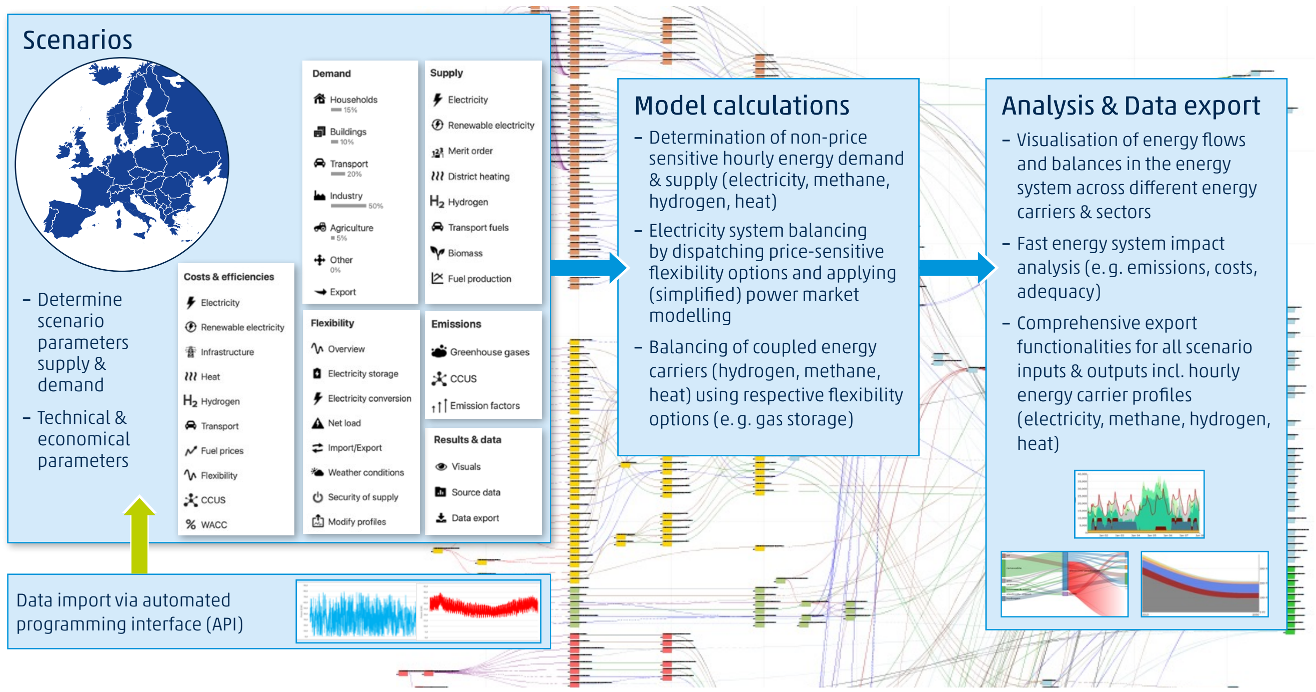


Figure 8: Overall Model structure Energy Transition Model

The model itself and a comprehensive documentation are available online via this webpage. The underlying energy balances for the reference year can be fully explored via the dataset manager.

Application for TYNDP2024 scenario building

Within the TYNDP2024 scenario building process, only the demand side modelling features of the ETM have been used and integrated into the overall scenario toolchain (see Figure 9).

The demand scenarios have been defined for all countries in scope of the TYNDP scenario building process by aligning on a set of scenario parameters per (sub)sector. These parameters range from basic assumptions on e.g. population development to more specific assumptions on technology shares or the expected characteristics of certain technologies. The resulting energy demand volumes have been exported via the ETM API and processed into a separate data analyses and visualisation tool for validation, comparison of different scenarios, analyses of target achievements and data conversions required for the interfacing with other scenario tools.

8 Largely based on historical EUROSTAT data, currently for the reference year 2019.

9 The ETM is a simulation model and does not perform optimisations, however the market dynamics are modelled in a simplified way.

10 To the TYNDP2024 a set of Python scripts has been used.

Hourly profiling of electricity load

Annual electricity final demand in each sector needs to be translated into hourly profiles for modelling purposes.

For this purpose, profiling tools are used for all sectors except district heating for space and water heating in the residential and tertiary sectors. DFT is the tool used for all countries except for Poland, Belgium, and France, where TSOs use their own tool to create the hourly profiles, in consistency with national developments, and other countries that decided to have TYNDP2022 demand profiles rescaled (such as Cyprus, Czech Republic, Spain, Croatia, Montenegro, Malta, Romania, Luxembourg).

Standard profiles for light electric vehicles and residential and tertiary are subtracted to be used in the specific EV and Prosumer nodes. The rest of the profile is used in the wholesale market node.

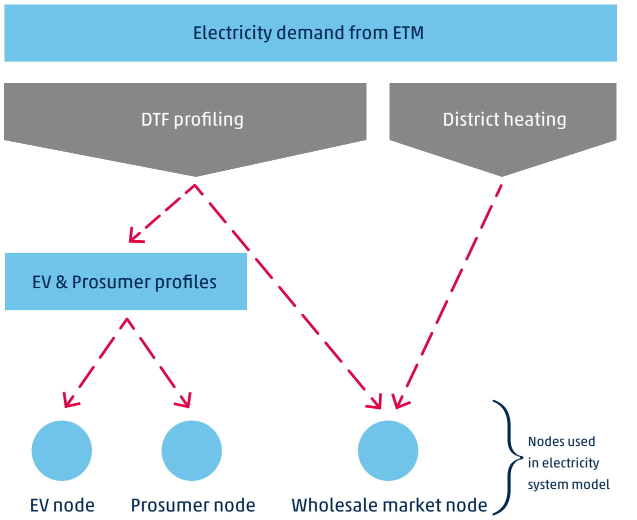


Figure 9: From the ETM to the hourly electricity load in every node of the electricity system model

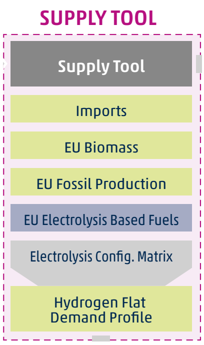
The profile of electric heat-pumps on district heating network are defined separately before being added to the electricity wholesale market node of the electricity and hydrogen model.

2.3.3 Addition of electricity transmission and distribution losses

Transmission and distribution losses are added to the electricity load-profile on hourly basis. They are assumed to represent on average 7 % of the final electricity demand in the EU-27, which is the current level in absence of further analysis.

Loss factors are listed in the Annex VI: Electricity Loss Factors. The numbers in there reflect 2030 and 2040 T&D losses determined as the relative difference between the DFT submission for the NT scenarios (incl. Losses) and the NT+ survey submission (which does not include losses). 2040 values were also assumed in 2050.

2.3.4 Building of the supply overview



In the supply tool, all energy demand and supply are merged to give an overview of the total energy flow in the system.

The demand side consists of final energy demand from ETM and additional energy demand as output from the energy system model, such as primary and secondary energy sources used for electricity production or e-fuels. Additionally, some demand is calculated ex-post based on the operation of certain technologies by the model (Methane for SMR, demand for district heating, losses in electricity, and biomass demand for biomethane production).

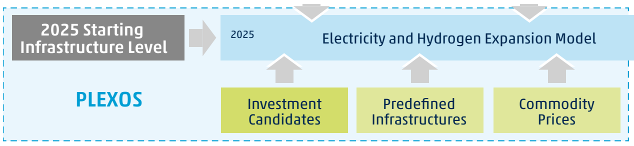
On the supply side, the model determines how demand is met by the available supply sources. Model outputs include production and imports of hydrogen, methane, biomethane, liquids, solids, and biomass. Furthermore, local production of biomethane, Lignite has been constrained to reflect difference in either cost or availability for each country.

Figures are available on country level and for each scenario on a total EU level as well. For NT+ results for 2030 and 2040 are shown and for DE and GA the results are shown for 2040 and 2050.

For each scenario the carbon budget (only emissions for NT+) is calculated.

The hydrogen to be supplied by electrolysis is split into the different Power-to-gas configurations using a matrix which parameters are scenario and time horizon dependent.

2.3.5 Electricity and hydrogen expansion model



Using the electricity and hydrogen demand profiles, an electricity and hydrogen expansion model is run. It aims to define the level and location of capacity (generation, flexibility, P2G) consistent with scenario storyline and associated cost assumptions.

To place the different investment options (RES, P2G, etc.) in accordance with the Scenario Storylines and to ensure the meaningfulness of the results, the investment model is also given the degree of freedom to expand electricity and hydrogen interconnectors. Therefore, the tool develops the infrastructure it deems economically viable to develop coherent scenarios in which energy is produced and transported throughout Europe. Such grid developments do not signify project identification for a future time horizon but gives an indication of how grid capacities in certain borders could develop in the scenarios under a European optimisation of the energy system based upon the assumptions used.

It should be noted that the TYNDP process block "Identification of System Needs[11]" is not part of the scenario building exercise but is part of the ENTSO-E TYNDP where the European infrastructure needs are investigated and presented.

After the expansion model has run, the scenario is going through quality control iterations, to identify and correct any errors in the modelling. These iterations were first done on a technical level within the Innovation Team, and then later expanded to the entire working group to ensure quality control.

11 For more information about the Identification of System Needs study please see here.

2.3.6 SoS loop

Compared to the draft scenarios, a security of supply (SoS) step has been added at the end of the modelling process to ensure an adequacy level close to the current level for all three TYNDP 2024 climate years. These years include 1995, 2008 and 2009 which have been deemed as the most representative climate years from the last 30 years through statical analysis. The script results in additional adequacy units which are then considered in the WGSB dispatch modelling, ensuring that the amount of unserved energy is limited to periods of severe scarcity.

The additional adequacy unit is defined at country level as described below:

Electricity system:

1. For each climate year the hourly unserved energy is calculated for the wholesale market, prosumer, and EV node.
2. For each climate year and each country, up to 3 hours of highest unserved energy are ignored (LOLE = 3h). The unserved energy in hour 4, is used to define the capacity of the new adequacy unit. If unserved energy in the 4th hour is less than 100 MWh, no additional unit will be added.
3. No specific technology is assigned to this unit.
4. Maximum capacity per unit is 500 MW. If unserved energy in hour 4 is higher than 500 MWh, more than one adequacy units will be added.
5. Variable Operational & Maintenance costs are higher than OCGTs, so adequacy units are the most expensive in the merit order.
6. Even if the unserved energy appears in the prosumer or EV nodes, adequacy units are installed in the wholesale market node.

Hydrogen system:

For the first time, an adequacy loop has been applied in the hydrogen system.

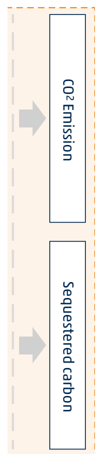
1. For each climate year the hourly curtailed hydrogen demand is calculated for hydrogen zones 1 and 2.
2. For each climate year and each country, up to 3 hours of highest curtailed hydrogen demand are ignored (LOLE = 3 h). The curtailed hydrogen demand in hour 4, is used to define the capacity of the new adequacy unit. If unserved energy in the 4th hour is less than 100 MWh, no additional unit will be added.
3. No specific technology is assigned to this unit.
4. Maximum capacity per unit is 500 MW. If unserved energy in hour 4 is higher than 500 MWh, more than one adequacy unit will be added.
5. Variable Operational & Maintenance costs are higher than ammonia imports, so adequacy units are the most expensive in the merit order.
6. Since there are countries where hydrogen zones 1 and 2 lack interconnection, the deployment strategy for adequacy units is tailored to address energy deficiencies within each zone in all the countries modelled. If energy not served (ENS) is observed in zone 1, the adequacy unit will be installed there to rectify the shortfall. Conversely, if ENS occurs in zone 2, the unit will be deployed within zone 2 to mitigate the deficit. In instances where ENS is identified in both zones, adequacy units will be installed in each zone.

2.3.7 GHG emission accounting

CO_2 emissions are calculated based on the annual consumption of each primary fuel (being produced in Europe or imported) considering their specific emission factor. Non-CO_2 emissions from e.g. agricultural land are derived from European Environment Agency for the latest data and projected to 2050 using the predictions in the EC Impact Assessment scenarios.

Estimates of CCS and LULUCF are included and based on the status from several sources and the predictions for the future set up in the Impact assessment from the EU commission.

As each scenario is defined along a pathway from 2030 to 2040 for NT+ and for 2040 to 2050 for DE and GA, it is possible to calculate the GHG emission for every year and thus evaluate carbon budget and emissions from the scenarios. The carbon budget is evaluated against the carbon budget presented in the Impact Assessment[12] from the EU commission.



12 Impact Assessment report; see here

3 DISPATCH AND EXPANSION MODELLING //

When building European energy scenarios, it is necessary to model the electricity system at European scale at an hourly granularity to capture its dynamics. It is particularly important when the energy transition results into a stronger influence of climate parameters on the operation of the electricity system due to the development of electric heating and RES. As the emergence of a hydrogen economy is largely linked to the development of electrolysis, it is increasingly necessary to use a joint modelling approach between the two energy carriers.

As part of the TYNDP scenario building process, the modelling of the electricity and hydrogen systems has two functional requirements:

- Defining the dispatch of electricity and hydrogen based on a pre-defined level of infrastructure (generation, flexibility, and grid) and considering commodity prices. This input is based on National Trends 2030
- Identifying the infrastructures to be built on top of pre-defined infrastructure considering the evolution of electricity and hydrogen demand and commodity prices -> Expansion model. The expansion model is used in Distributed Energy and Global Ambition and starts from 2035.

3.1 Basic principles of Dispatch Model

The purpose is to identify the generation unit commitment minimising the variable costs of the electricity and hydrogen system. This optimisation considers the available infrastructure and commodity prices. The aim is to minimise the objective function.

$$\sum_{System}^{X\ years} Variable\ OPEX + \sum_{System}^{X\ years} Fuel\ cost + \sum_{System}^{X\ years} CO_2\ emissions\ cost + \sum_{System}^{X\ years} VOLL$$

Equation 1: Objective function for the dispatch model optimisation (variable costs of the system)

The Value of Lost Load (VoLL) is used in energy optimisation models to assign a monetary value to the economic impact of energy not being supplied when demand exceeds supply. For the TYNDP 2024 Scenario Report National Trends is based on a wide range of dispatch modelling tools, for example Plexos, Antares, Promed, and APG. Whereas Distributed Energy and Global Ambition are only run on Plexos.

3.2 Basic Principles of Expansion Model

The energy transition has a wide range of possible pathways to carbon neutrality. For a defined electricity and hydrogen demand, different conceivable forms of electricity and hydrogen systems (generation, flexibility, and grid) can be imagined. For this reason, it is necessary to use modelling tools able to define infrastructure pathways and not only to rely on expertise which would bear the risk to be too much based on current historic experience or to project predefined solutions.

Tools having investment loop capabilities are extremely useful to implement such an approach. It is based on:

- A demand defined along the time horizon
- A starting status of infrastructure development
- Some infrastructures which level of development is predefined along the time horizon
- A list of infrastructure candidate for investment and/or decommissioning
- A set of economic parameters along the time horizon
- The tool runs an optimisation of the overall system to identify investment candidates using a Benders'-decomposition[13] method with the energy dispatch as a sub-problem. The aim is to minimise the following objective function below along the time horizon.

$$\sum_{Candidate}^{X\ years} CAPEX + \sum_{Candidate}^{X\ years} Fixed\ OPEX + \sum_{System+Candidates}^{X\ years} Variable\ OPEX$$
$$+ \sum_{System+Candidates}^{X\ years} Fuel\ cost + \sum_{System+Candidates}^{X\ years} CO_2\ emissions\ cost$$
$$+ \sum_{System+Candidates}^{X\ years} VOLL$$

Equation 2: objective function for the expansion model optimisation

The reduction of CO_2 emissions is ensured through the combination of RES development (minimum trajectory and decreasing cost) and an exogenously defined CO_2 price. As a result, the emissions are an output of the model. If the reduction is considered as not sufficient, both in terms of reduction at a given time horizon and of carbon budget, it is necessary to act on RES minimum trajectory and/or CO_2 price.

The expansion function is run on the most representative climate year (2009), which also happens to be relatively stressful climate year regarding weather patterns for power generation. The resulting investments are then implemented in dispatch models, which are run on three different climate years. Final dispatch outputs are weighted to ensure the representativeness of the combination of climate years, as detailed in Section 4.1.

Draft TYNDP 2024 Distributed Energy and Global Ambition scenarios have been modelled using the expansion functionality of the Plexos (LT Plan) tool[14].

3.3 Multi-temporal vs. Bundling of Multi-Temporal Timeframe Approaches

Renewable generation and the different types of flexibility have a major role to play in decarbonising the energy system. To capture their variability when making infrastructure investment decisions, the highest possible granularity in the expansion model is needed.

A multi-temporal approach was already used in TYNDP2022 whereby the tool had visibility over each year of the study horizon. This helped the model to decide the best time to invest. However, the optimisation problem was so large that the maximum granularity that the expansion model allowed was 3 blocks per month per load duration curve (LDC). This meant that batteries could not expand, since their behaviour over the course of a day was not visible.

In TYNDP2024, as an innovation, a bundling of multitemporal timeframe approach has been chosen. It allows the tool to increase the granularity to several blocks per day, e.g. permitting the expansion of batteries. Execution times are significantly reduced.

The following sections will elaborate on the details of the two approaches.

13 Large-scale power system planning using enhanced Benders decomposition, IEEE Conference Publication, IEEE Xplore, see here
14 PLEXOS Market Simulation Software, Energy Exemplar

3.3.1 2022 edition methodology for Distributed Energy and Global Ambition: multi-temporal

The multi-temporal approach brings visibility on the path to follow towards 2050. Nevertheless, running a continuous multi-temporal expansion run on 25 years (from 2025 to 2050), with all modelling innovation related to sector coupling, induced a computation load too large for present commercial modelling tools. For this reason, it was necessary to cluster the overall mathematical problem into sub-horizons. Considering the calculation capacity and the project timeline, the 25 years were split into 8 sub-time horizons with a 2-year overlap:

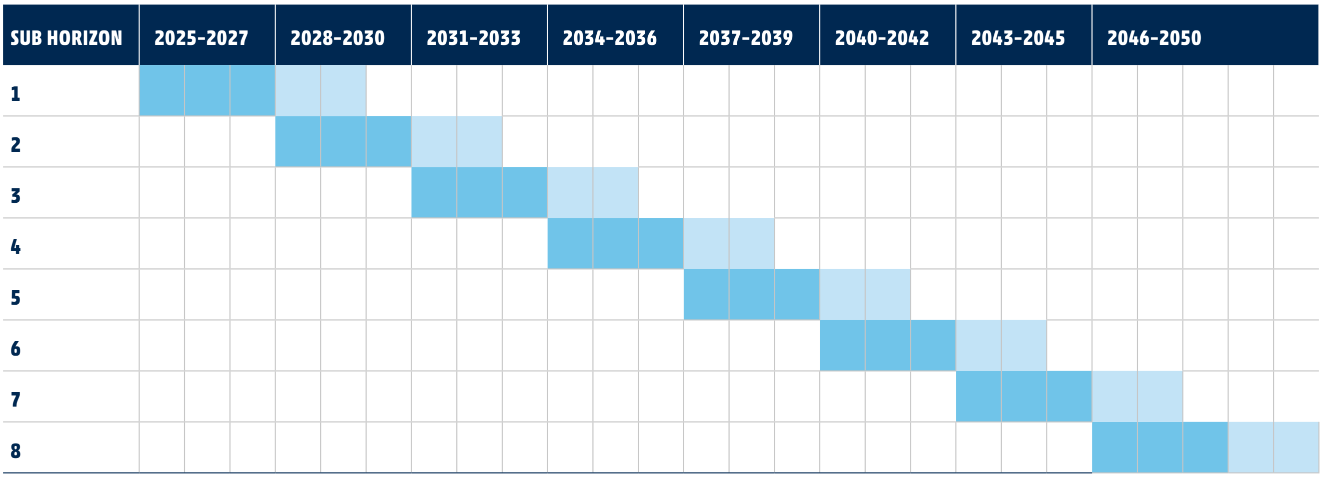


Figure 10: Sub-horizons clustering

The overlap enabled to provide visibility on the evolution of key parameters (e.g. carbon price and electricity demand) when getting close to the end of the sub-horizon:

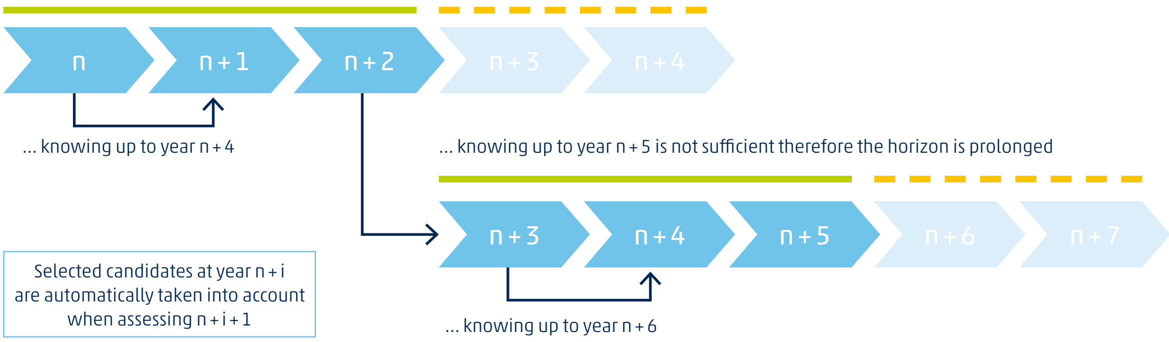


Figure 11: Multitemporal approach with sub horizons clustering

The clustering of the overall time horizon is also a way to mitigate the usual bias of perfect foresight of modelling tools resulting in over optimistic results.

Regarding LDC, due to the complexity of the model, only three blocks per month could be used. The tool decided the length and the starting point of these blocks based on the demand profiles in the model. This provoked the non-expansion of batteries.

3.3.2 2024 edition methodology for Distributed Energy and Global Ambition: bundling of multitemporal timeframe

The bundling of multitemporal timeframe aims to capture the behaviour of all the expansion candidates. Several blocks per day are required to allow the expansion of batteries. This can only be managed if the whole optimisation problem is reduced in the expansion model.

TYNDP2024 Scenarios cover a 20-year horizon (2030–2050). A new methodology has been developed to turn those 20 years into 5 Target Years which reduces the optimisation problem's complexity:

The starting point is 2030 and an expansion loop is run on Target Years 2035, 2040, 2045 and 2050. These are the only years modelled in Plexos. However, inputs must ensure that the Net Present Value (NPV) of investments in each target year is equivalent to the NPV that would be obtained in those years when running the 20-year rolling horizon, so the build-out in both models is equivalent too.

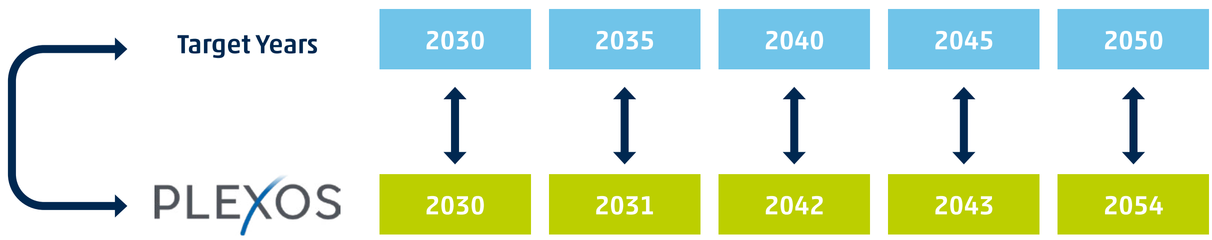


Figure 12: Plexos investment decisions

Plexos investment decisions are based on annuities. The key parameter within the Plexos model which needs to be adapted in this approach is the Discount rate:

$$DR_{5yr} = (1 + DR_{20yr})^5 - 1$$

Keeping the rest of economic parameters (economic life, WACC, build costs, etc.) as in the 20-year model, the NPV in both models is equivalent.

This adaptation gives the opportunity to increase the granularity of the expansion model has been increased to 3 blocks per day. With such granularity, the behaviour of renewable generation and batteries is properly captured. LDC blocks are also selected ex-ante, ensuring that the first daily block corresponds to 01:00–08:00 h, the second block corresponds to 09:00–16:00 h, and the third block corresponds to 17:00–00:00 h to cover the PV electricity in-feed as good as possible.

By using this methodology, it is no longer necessary to divide the horizon into sub-horizons and avoids overlaps. The problem is reduced to a single simulation in which the optimiser looks directly at 5 years (equivalent to 20).

3.4 Integer vs Linear modelling

Linear programming (LP) is a mathematical method used to find the optimal outcome, in this case cost minimisation, in a model whose requirements are represented by linear relationships. Integer programming (IP), a subset of linear programming, requires some or all the decision variables to be integers, making it suitable for solving problems where the solutions must be whole numbers.

The difference between linear and integer modelling in optimisation lies mainly in the types of decisions they are best suited to handle. LP models involve continuous decision variables that can take on any value within a specified range, useful for optimising systems where decisions can be fractionally allocated. However, they might not accurately capture situations where decisions must be whole numbers or follow specific discrete steps. IP models restrict decision variables to integer values, making it ideal for scenarios where decisions are discrete, in this case determining the number of facilities to build, where partial units may not be realistic or feasible.

The scenario models are very large and complex, and thus linear models are used to reduce simulations time. Switching to integer modelling could lead to more accurate investment decisions but at the cost of significantly increased computational complexity, hence only the Linear model was used.

4 OVERVIEW OF MODELLING PARAMETERS OF THE DEVIATION SCENARIOS //

For Distributed Energy and Global Ambition, the expansion modelling aims at building the power generation mix, electricity, and hydrogen flexibility assets, P2G and grids in terms of level and location.

This objective translates into a scenario specific definition of the building blocks of the expansion model as illustrated by Table 4.

<table>
<tr><th colspan="2">BUILDING BLOCK</th><th>DISTRIBUTED ENERGY & GLOBAL AMBITION</th></tr>
<tr><td colspan="2">TIME HORIZON</td><td>2035, 2040, 2045 and 2050</td></tr>
<tr><td colspan="2">CLIMATE YEARS</td><td>Expansion Model 2009
Dispatch – 1995, 2008, 2009</td></tr>
<tr><td colspan="2">ADEQUACY</td><td>e-VoLL: 3,000 €/MWh for the electricity
H2-VoLL: Average (cheapest power plant SRMC/electrolyser efficiency, most expensive H_2 import)
DE: 120 €/MWh in 2035, 131 €/MWh from 2040 to 2050
GA: 120 €/MWh in 2035, 112 €/MWh in 2040, 110 €/MWh in 2045 and 107 €/MWh in 2050
SoS script ensuring each country ENS ≤ 3 hr</td></tr>
<tr><td colspan="2">COMMODITY PRICES</td><td>Scenario specific.</td></tr>
<tr><td colspan="2">SECTOR COUPLING MODELLING
– Power-to-gas
– EV/Prosumer
– District heating</td><td>– Two P2G configurations
– Yes
– Embedded in electricity and hydrogen load profiles</td></tr>
<tr><td colspan="2">STARTING GRID</td><td>TYNDP 2024 electricity and hydrogen Reference Grid for 2030 Time Horizon:
Data collection has been updated by the TSOs to reach the best estimates in terms of infrastructure development for the given time horizon</td></tr>
<tr><td colspan="2">PREDEFINED CAPACITY AT TIME HORIZON</td><td>– Hydro
– Nuclear
– Solar thermal
– Marine
– H_2 storages</td></tr>
<tr><td rowspan="5">INVESTMENT CANDIDATES</td><td>NTC</td><td>Based on investment candidates of TYNDP 2024 Scenario Building data collection</td></tr>
<tr><td>Generation</td><td>Onshore wind (wholesale market and dedicated for P2G)
Offshore wind (wholesale market and dedicated for P2G)
PV (wholesale market, prosumer and dedicated for P2G)
Hydrogen storage (salt caverns, aquifers, depleted gas fields etc, based on TSO submission)
Batteries (wholesale market and prosumer)</td></tr>
<tr><td>P2G</td><td>Separately for each P2G configuration</td></tr>
<tr><td>H_2 grid</td><td>Retrofit methane pipeline
Newly built pipeline</td></tr>
<tr><td>Offshore hubs</td><td>Offshore wind generation capacity and infrastructure</td></tr>
<tr><td colspan="2">MUST-RUNS</td><td>Removed after 2030*</td></tr>
</table>

Table 4: Modelling parameters

* Minimum supply profile has been kept for other non-RES to translate CHP operation

This section provides a detailed description of the setting of each parameter of the expansion and dispatch models used to build scenarios.

4.1 Climate Years

The number of climate years considered by the model strongly influences the computation time. It is therefore necessary to select a limited combination of years while ensuring the representativeness of the climate variability of the last 30 years. The selection of the most representative climate years is performed according to the methodology established in Section 6.3 of the TYNDP 2022 IoSN Implementation Guidelines .

In the case of definition of representative climate years, the approach is as follows:

1. Definition of hourly time series of residual load (final demand minus wind and solar power generation) on a regional level, to capture the temporal and spatial variability of the system state due to climate conditions.
2. Compute delta indicators to assess how years compare to the 30-year average on a regional level.
3. Selection of most representative combination of 3 years for the study

The process begins with defining residual load distributions, calculated hourly by subtracting renewable energy sources' infeed (based on the Pan European Climate Database (PECD), from the system load. This hourly resolution captures system variability, while regional aggregation preserves distinct regional information, resulting in 8,760 values per year per region.

Delta Indicators are employed to select optimal combinations of three-year periods from a 30-year dataset. This involves comparing the distributions of all possible three-year combinations to the aggregated 30-year distribution using mean value and standard deviation. Standardization and weighting allow for combination of indicators, with regional relevance factored in.

Candidate combinations are filtered to represent the aggregate distribution, evaluating them based on Euclidean distance. The best candidates are then chosen through K-Medoids clustering score, ensuring representation and diversity within the selection.

The result of this analysis identifies the years 1995, 2008, and 2009 as the most representative climate years, with the following weights: 23 %, 37 % and 40 %, respectively.

For Distributed Energy and Global Ambition, the computation time is very high due to the time horizon, sector coupling (combined H_2 and electricity modelling) and number of investment candidates. Expansion modelling is run only on the most representative year (2009).

For dispatch models, the reduced computation load enables the use of a wider climate year panel. Therefore, simulations are run on the three most representative climate years, 1995, 2008 and 2009.

It must be noted that 2009 ranks at the second most stressful climate year in terms of 2-week Dunkelflaute situation at European aggregated level after 2012. The year 2012 will be used as a stress case in the Hydrogen TYNDP.

4.2 VoLL and spillage costs

As the objective function of dispatch and expansion model is in monetary terms, it is necessary to translate security of supply and energy efficiency in similar terms. Such conversion enables the comparison with investment candidate CAPEX and system OPEX (including commodity prices).

When jointly modelling electricity and hydrogen, it is necessary to consistently define the value of lost load (VoLL) of each energy carrier to avoid undue "non-served energy" of a given carrier. In TYNDP2022 the VoLL of hydrogen was established at a parity level with electricity considering the efficiency of electrolysers. In TYNDP2024 this VOLL parity disappears to avoid simultaneous generation of electrolysers and thermal power generation.

Electricity nodes' VoLL is set as 3000 €/MWh. This value is too high for the hydrogen system, where it would be more profitable to produce hydrogen with thermal power generation than to curtail hydrogen demand. For this reason, hydrogen nodes' VoLL has been calculated as an intermediate value between the cheapest thermal power generator's marginal cost (considering the efficiency of electrolysers) and the most expensive source in the hydrogen market: ammonia imports.

Thus, the optimiser will prefer to curtail hydrogen demand after all H_2 sources in the market are exhausted rather than producing blue hydrogen.

H_2 VOLL (€/MWh)	2035	2040	2045	2050
DE	120	131	131	131
GA	120	112	110	107

Table 5: VoLL and spillage costs

4.3 Commodity prices and emission factor

Commodity prices include both fuel and CO_2 prices. They intervene in the dispatch optimisation and therefore in the expansion model. The emission factors quantify how much CO_2 is emitted during fuel combustion therefore they are used to measure in which extent CO_2 price impacts fuel prices. The emissions factors are used to calculate the emissions in the carbon budget as well. The emission factors are derived from JRC[15] and summarised below.

FUEL	EMISSION FACTOR (tCO_2/MWh)
OIL	0.267
SOLIDS	0.354
PRIMARY SOLID BIOFUELS	0
BIO GASOLINE/BIODIESELS	0
OTHER LIQUID BIOFUELS	0
BIOMETHANE	0
NATURAL GAS	0.202
BIOMETHANE	0
DECARBONIZED HYDROGEN IMPORTS AND EUROPEAN SMR/ATR WITH CCS*	0.0262
RENEWABLE HYDROGEN IMPORTS	0

Table 6: Emission factor of fuels

* For methane reforming (SMR/ATR) an efficiency factor of 77 % is used. For CCS processes a capture rate of 90 % is considered, to account for the part of the CO_2 that cannot be captured in the process and that is therefore released in the atmosphere

Methane and hydrogen emission factors depend on the composition of different sources:

- Methane: natural gas, biomethane and synthetic methane
- Hydrogen: electrolysis, hydrogen imports and SMR/ATR production

The composition of the methane is dependent on scenarios and time horizon. The emission factors of electrolysis-based products (hydrogen, synthetic methane, and synthetic liquids) are an output of the electricity modelling.

The commodity prices are common to all scenarios and dependent either from local drivers (shale oil and lignite) or from a very specific and slow evolving value chain (nuclear). Table 7 provides an overview of the commodity prices. The lignite commodity prices are divided into four groups dependent on their location. The methane prices are calculated based on the composition of Natural gas, biomethane and synthetic methane in each scenario.

15 Koffi, B., Cerutti, A., Duerr, M., Iancu, A., Kona, A. and Janssens-Maenhout, G., Covenant of Mayors for Climate and Energy: Default emission factors for local emission inventories – Version 2017, EUR 28718 EN, Publications Office of the European Union, Luxembourg, 2017; see here

FUEL	2030	2040	2050	SOURCE
NUCLEAR	1.7	1.7	1.7	EIA
LIGNITE (G1)	1.4	1.4	1.4	Booze&co same as 2022
LIGNITE (G2)	1.8	1.8	1.8	Booze&co same as 2022
LIGNITE (G3)	2.4	2.4	2.4	Booze&co same as 2022
LIGNITE (G4)	3.1	3.1	3.1	Booze&co same as 2022
HARD COAL	1.8	1.6	1.6	IEA 2022 (APS)
NATURAL GAS	6.3	5.7	5	IEA 2022 (APS)
CRUDE OIL	9.2	8.9	8.6	IEA 2022 (APS)
BLUE HYDROGEN [1]	Scenario and year dependent			IEA 2022 (APS)
SYNTHETIC METHANE	27.6	25	23.5	IEA 2022 (APS)
LIGHT OIL	11.7	11.4	11	Based on crude oil price
HEAVY OIL	9.6	9.3	9	Based on crude oil price
OIL SHALE	1.9	2.7	3.9	Member information
IMPORTED AMMONIA	38.3	30.1	24.1	EWI tool calculation
BIOMETHANE	18.8	18	17.3	Danish Energy agency
METHANE NT+	7.5	9	-	Based on composition
METHANE DE	-	10.9	17.9	Based on composition
METHANE GA	-	9.8	15.8	Based on composition

Table 7: Fuel prices (€/gj)

The CO_2 prices will impact the final commodity price based on the fuel's emission factor. The CO_2 price is equal in all scenarios and are presented in Table 8.

	2030	2040	2050	SOURCE
CO_2	113.4	147.0	168.0	EIA

Table 8: CO_2 prices (€/ton)

4.4 Sector coupling modelling

The operation and the evolution of the electricity, hydrogen and methane systems will increasingly depend on each other and other sectors. As a result, it is necessary to model its interaction with other sectors as part of the dispatch and expansion model. The modelling of sector coupling is the priority enhancement of the 2022 edition and innovative modelling approaches have been defined to capture the dynamics of:

1. **Electrolysers:** two electrolyser configurations are modelled based on the use of hydrogen (final demand or synthetic fuel production) and the evolution of the hydrogen market. It captures a wide range of interactions between electricity and hydrogen systems.
2. **Prosumer and Electric Vehicle (EV):** development on the end-user side will impact the design and the operation of the electricity system. For this purpose, specific nodes have been introduced as part of the electricity market modelling of Distributed Energy and Global Ambition. A detailed description of Prosumer and EV modelling can be found in.
3. **Hybrid heating:** the combination of different heat supply sources on a closed network such as a residential home or tertiary business, enables an optimised design and operation of connected heat pumps. Such specific behaviour is captured in the electricity demand profile used as an input to the electricity system modelling

Explicit sector coupling modelling in National Trends is less ambitious compared to Distributed Energy and Global Ambition. It is due to its shorter time horizon (2040) making less critical and to the fact that some sector coupling components are already captured in collected data. For this scenario P2G is modelled in a single configuration which capacity is defined as part of the TSO data collection.

4.5 Starting grid

For all scenarios and time horizon, the model bases its expansion on a best estimate of the grid level of development for the year 2030 (the same grid as in NT2030 scenario). The starting grid for electricity and hydrogen are taken from the TYNDP. For the electricity system, the updated reference grid for TYNDP 2024 is available and thus has been used within the scenario building cycle. The hydrogen reference grid is taken from the TYNDP 2022 as the 2024 infrastructure levels were not available during the scenario building timeline. The hydrogen reference infrastructure levels will be updated for the TYNDP 2024 process.

4.6 Predefined capacity level

Distributed Energy and Global Ambition generation fleets will mostly differ in terms of wind, solar and nuclear capacity. The variable renewable sources Onshore Wind, Offshore Wind (aligned with ONDP), Solar PV and Rooftop PV, start from the capacities submitted by TSOs in NT2030. Additional capacity is created using an expansion model while nuclear is defined ex-ante based on range in the Final Storyline Report[16] of each scenario to ensure sufficient difference. The other generation technologies will see the same level of development in the two scenarios. Such development is based on National Trends and joint collection as stated in Table 9.

TECHNOLOGY	2030	2035	2040	2045	2050
WIND AND SOLAR	Defined by the expansion model based on 2030 level and trajectories				
NUCLEAR	Distributed Energy: 45-year lifetime for existing and under construction units (unless anticipated phase-out policy) Global Ambition: 55-year lifetime for existing, under construction and planned units				
HYDRO, SOLAR THERMAL AND MARINE	National Trends				
THERMAL	e/g. TSOs 2030 aligned figures		Interpolation 2030–2040	e/g TSOs 2040 aligned figures	Interpolation 2040–2050
BATTERY – PROSUMER	Defined by the expansion model based on 2030 level and trajectories				
BATTERY – UTILITY SCALE	Defined by the expansion model based on 2030 level and trajectories				
BATTERY – V2G	NºEVs × Unitary capacity				
	DE: 60 kWh/vehicle GA: 60 kWh/vehicle	DE: 72 kWh/vehicle GA: 66 kWh/vehicle	DE: 83 kWh/vehicle GA: 72 kWh/vehicle	DE: 92 kWh/vehicle GA: 81 kWh/vehicle	DE: 100 kWh/vehicle GA: 90 kWh/vehicle
H2 STEEL TANKS	Defined ex-ante capacities				
H2 SALT CAVERNS	Defined by the expansion model based on 2030 level and trajectories				

Table 9: Starting generation and storage capacity for Distributed Energy and Global Ambition scenarios

16 See here

4.7 Investment Candidates

In the case of the Distributed Energy and Global Ambition scenarios, the expansion model is used to define the level of development of storyline-dependent technologies. Such technologies cover renewable sources (wind and solar), conversion facilities (electrolysers), power and hydrogen storages, electricity, and hydrogen interconnections. Interconnection candidates enable a meaningful location of other candidates and do not intend to identify any investment gap. Further information on the offshore development methodology can be found in RES candidates.

RES candidates can be installed in different nodes of the system depending on its needs (electricity mix decarbonisation, minimisation of the prosumer connection to the grid, hydrogen production, etc.). The expansion model will then select the most suitable technology based on their cost and the specific need of each configuration. Table 10 describes the possible locations for wind and solar.

TECHNOLOGY	E-MARKET	PROSUMER	HYDROGEN ZONE 1	HYDROGEN ZONE 2
WIND ONSHORE	X	-	X (Shared RES)	X (Dedicated RES)
WIND OFFSHORE	X (Radial & Hub)	-	-	X (Hub)
SOLAR	X (Utility Scale PV)	X (Rooftop PV)	X (Shared RES - Utility Scale PV)	X (Dedicated RES - Utility Scale PV)

Table 10: Location of res investment candidates for distributed energy and global ambition

The expansion model selects investment candidates based on a defined set of parameters. Candidates are identified individually for each zone, including interconnections for electricity and hydrogen transport infrastructures:

- Maximum development level for each time horizon, based on country specific potentials
- Minimum expected development level for each time horizon on a country level
- CAPEX
- OPEX
- Economic lifetime
- Weighted average cost of capital (WACC)
- Discount rate

The levels of capacity expansion for RES technologies are defined by trajectories. The LOW and HIGH trajectories have been used as lower (minimum levels of capacity expansion) and upper (maximum levels of capacity expansion) bounds for the expansion of RES in 2040 and 2050 and are common to both Distributed Energy and Global Ambition Scenarios.

- **Solar PV Rooftop:** Solar PV Rooftop installations are designated to the Prosumer node within the expansion model framework. The decision on the quantity of Solar Rooftop to be constructed in each country is subject to the discretion of the optimiser, while maintaining alignment with the LOW and HIGH trajectories provided by TSOs. The expansion model commences from 2030 figures as its baseline.
- **Solar PV Utility:** Solar PV Utility installations offer flexibility in their deployment, with options to be established in the e-market, SRES node, or DRES node. The optimiser is tasked with determining both the location and quantity of installations, ensuring adherence to the LOW and HIGH trajectories outlined by TSOs. The Solar PV trajectory encompasses installations across all three locations, with expansion initiation points set as follows: 2030 figures for e-market, and zero capacity for both SRES and DRES nodes.
- **Wind Onshore:** Wind Onshore installations follow a similar trajectory to Solar PV Utility, with the optimiser responsible for determining their location and quantity within e-market, SRES, and DRES nodes. This decision-making process is guided by the LOW and HIGH trajectories provided by TSOs. Commencing from 2030 figures as the initial reference point in the e-market node, Wind Onshore trajectory planning sets zero capacity for both SRES and DRES nodes.
- **Wind Offshore:** The cost of RES development comes from the Danish Energy Agency (DEA), and it has been used as a baseline for the differentiation between scenarios. Costs for RES technologies are adjusted relative to the baseline (± 15 % in 2040 and ± 20 % in 2050) according to the storylines of DE and GA scenarios.

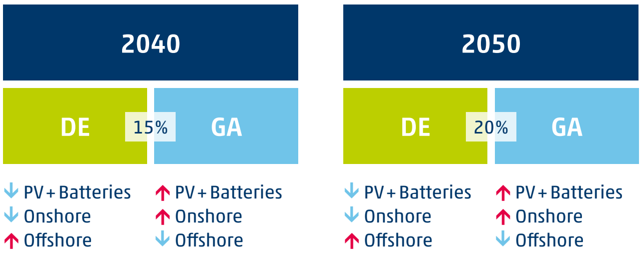


Figure 13: Cost differentiaton in DE and GA Scenarios

E-market RES generation operates on radial connections. This e-market RES build cost is calculated as the sum of the RES generator cost and the grid connection cost.

Dedicated RES (DRES) generation requires an electrolyser connection to the H_2 market, eliminating the need for electricity grid connection costs of integrating renewables into the electricity market. The DRES generator cost is derived by subtracting the grid connection cost from the e-market RES build cost, while electrolyser, as an independent expansion candidate, incurs its own build cost.

Shared RES (SRES) generation necessitates grid connection to the e-market and electrolyser connection to the H_2 system. Unlike e-market RES, where grid capacity requirement is assumed to be equal to the generation capacity, and where grid costs (~50 k€/MW) are included in the total build cost, SRES grid connection can be determined by the model as a separate expansion candidate.

An analysis of Solar PV and Onshore Wind capacity factors, considering the 8 hour-blocks used by the expansion tool, weather patterns, maintenance, and outages, reveals that these technologies typically feed in a maximum of 40–90 % of their capacity on an aggregated level. Consequently, the model would tend to favour investment in SRES over e-market RES due to reduced grid capacity requirements. To address this bias, SRES grid costs have been increased by a factor of two.

SRES electrolyser is also an independent expansion candidate, incurring its own associated cost.

The parameters of the investment candidates can be found under Section 6.1.2.

4.7.1 Cross-border candidates

The electricity reference grid for 2030 is the starting point for the DE/GA scenarios. Post-2030, investments can be made in transmission candidate projects, which are gathered from the Promoters (TSOs and third parties).

The process of collecting electricity infrastructure investment candidates is a two-step approach:

1. The first step involves using existing projects from the previous TYNDP list, complete with their economic parameters (CAPEX, OPEX, transfer capacity impact). These candidates form a reliable basis for the system needs studies and scenario building process, as these projects have been analysed during the TYNDP CBA phase and consulted with ACER and European NRAs.
2. The second phase allows project promoters from the previous TYNDP cycle to submit new candidates. Most of these candidates were submitted by ENTSO-E TSOs with clearly defined economic parameters. The CAPEX for these projects also had to account for the costs of the internal reinforcements that accompany the project implementation. Importantly, TSOs had the chance to add extra costs associated with internal reinforcements for the projects by third-party organisations.

Consequently, there are two categories of investment candidates in the electricity grid:

– "Real" projects:
  - Already investigated in the previous TYNDP cycle
  - Usually expected to be commissioned in a near future
  - Technical and economic parameters are more certain
– "Concept" projects
  - Expected commissioning date is after 2040
  - Technical and economic parameters are less certain
  - Incremental capacity adds to borders with already existing transmission capacity

The hydrogen reference grid for 2030 is the starting point for the DE/GA scenarios. Post-2030, investments can be made in transmission candidate projects, which are gathered from TSOs.

In the TYNDP 2022, each target year (2030, 2040, 2050) has 2 infrastructure levels available a "low infrastructure level" and a "high infrastructure level". The "Low infrastructure level" is a collection of projects submitted to the first hydrogen TYNDP in 2022. An approach based on project status (as was used for the methane TYNDP) is not a meaningful KPI when developing infrastructure from inauguration. The "high infrastructure level" includes additional cross border capacities submitted by TSOs to ENTSOG's H_2 Taskforce.

The hydrogen candidate projects used are based on the difference in pipeline capacity between "low infrastructure level" and "high infrastructure level", for each target year.

Infrastructure costs must then be considered for the expansion of hydrogen pipeline. As there is almost no real-world data for this, the costs are based on external studies. The main study used is the European Hydrogen Backbone studies. The methodology followed based on this study is, CAPEX cost is split between repurposed and new hydrogen pipeline with a split of 75 % to 25 % respectively. A distance must also be considered, in this case 15 % of the distance from capital to capital is used, referencing a distance related dataset from EWI[17] study on the cost of H_2 imports to the EU.

It is important to note that while the expansion methodology views candidates as discrete investment decisions, the solution method assumes a linear relaxation. This means that any proportion of the installed capacity within the [0,1] interval can be part of the solution to the expansion planning problem.

4.7.2 Electrolyser candidates

If required, the expansion model can be utilised to establish additional electrolyser capacity. The maximum capacity that can be built out increases across the target years. Specifically, the growth of electrolysers per market area (regardless of the market areas size) is capped at a certain limit that adjusts according to the Target Years (12/24/48/96 GW in 2035/2040/2045/2050 respectively).

The model can construct electrolysers in the following distinct configurations:

- Utilising E-market to generate hydrogen for Hydrogen Zone 1
- Utilising E-market to generate hydrogen for Hydrogen Zone 2
- Associated with Shared RES to produce hydrogen for Hydrogen Zone 1
- Associated with Dedicated RES to produce hydrogen for Hydrogen Zone 2
- Installed in Offshore Hubs: electricity from Wind Offshore is used to produce on-site hydrogen which is then transported to Hydrogen Zone 2 via a hydrogen pipeline

By 2030, the initial capacity may have been established according to the National Trends data provided by TSOs, with allocation to electrolysers in Hydrogen Zones 1 and 2. This allocation is determined by the hydrogen demand within these zones. In countries where there is no hydrogen demand within either of the two zones, in one or all target years, the National Trends electrolyser capacity is assigned to Zone 2.

All remaining electrolysers commence with a capacity of 0 MW, allowing the optimiser to determine the investment quantity and location, while adhering to the above limits, based on their respective costs.

In line with the National Trends scenario, a significant capacity of P2G within the Spanish DRES nodes was reported by the Spanish Gas TSO. The electrolyser DRES capacity in Spain starts at 19 GW in 2030. The renewable capacity in the DRES Spanish zone starts at 0 MW. These electrolysers are modelled in DE and GA as starting DRES electrolyser capacities. The model can only make use of the electrolysers if renewable capacity is built in the DRES zone.

17 EWI dataset available here

4.7.3 Hydrogen storage candidates

The gas TYNDP is typically assessed based on 2 level of infrastructure, simply called infrastructure level 1 and infrastructure level 2 both submitted by gas TSOs in the TYNDP 2022. The starting hydrogen storage capacities come from the data submitted by gas TSOs in the "Infrastructure Level 1". This is the lower of the 2 infrastructure levels. The model can then invest in additional capacities, up to infrastructure level two based on costs outlined in the hydrogen backbone report.

4.7.4 Batteries candidates

Batteries link up with both the electricity market on a utility scale and to the prosumer node tied to Solar Rooftop. The minimum capacities of these batteries (GWh) are derived from data provided by electricity TSOs. Beginning with 2030NT as a baseline, the model has the capability to augment capacity investment up to a maximum trajectory as outlined in Section 16 Electricity Generation Trajectories. The power of batteries (MW) is determined by the optimiser, factoring in the capacity investment and the operational duration of the battery, which stands at 2.5 hours for prosumer batteries and 4 hours for utility scale batteries.

4.7.5 Thermal capacities

There is no thermal investment of decommissioning candidates present for Thermal plants in the investment models. The thermal generation capacities are based on the PEMMDB figures collected from the TSOs.

Distributed Energy and Global Ambition show an increased focus on renewable energy sources, including an integrated offshore network. The model is effective in highlighting potential investment pathways towards variable renewable centred energy landscape, but solely considers the day-ahead market. This day ahead market focus cannot fully capture the dynamic needs and economic factors generation dispatch, particularly in relation to gas and hydrogen turbines which could be pivotal in providing flexibility and backup power.

4.8 Must-run of thermal units

With the development of wind and solar, it will be necessary for the electricity system to become more flexible. Must runs of thermal units are used generally to picture system stability constraints (either voltage or frequency) or constraints beyond the European electricity system. In scenarios aiming at carbon neutrality, the GHG emissions induced by these must-runs will become obstacles to decarbonisation in the medium term. As a result, it is assumed that must-run will be removed after 2030 for Distributed Energy and Global Ambition, replaced by other technologies beyond the definition of the scenarios. For Other Non-RES, minimum supply at zero cost has been kept capturing CHP operation not directly linked to the wholesale market price.

5 DISTRICT HEATING SUPPLY //

5.1 Heat supply from ETM to supply tool

From ETM comes demand for heat for district heating. This heat demand covers heat for district heating in the residential, tertiary, industry, and agricultural sectors. In the supply tool, this demand is converted into demand for primary energy carriers to supply this heat demand.

Data from the NT+ data collection on energy consumption in district heating (final demand for different energy carriers and their respective efficiencies) is used, to determine the primary energy demand for each energy carrier. Basically, the same share of primary energy carriers is used to supply the heat in the top-down scenarios as in the NT+ data collection. By then adding the efficiencies (also available in the NT+ data set) the demand for the primary energy carrier can be derived.

Basically, the same number was used, but we substituted oil and coal with biomethane and hydrogen in 2040 and 2050 in both the top-down scenarios to emphasise a decarbonisation in district heating.

6 HYBRID HEAT PUMPS //

The 2024 Scenario Building process explicitly considers Hybrid Heat Pumps (HHP) as heating technology (boiler and electric heat pump) that use energy from three carriers: electricity, hydrogen, and methane.

The demand is categorised into Prosumer Heating and District Heating. Prosumer Heating, newly modelled in Plexos, entails the optimisation of electricity and gas requirements for HHP. District Heating follows the approach from TYNDP 2022 Scenarios, where electricity and gas demands are pre-determined by ETM and integrated into the final electricity and gas demand profiles.

As a simplification to the model, the capacity of heat pumps and boilers (as a part of the hybrid system) are sufficient to meet peak heating demand inside the node. It is likely that in some buildings, heat pumps would not be sized to meet the peak demand if a boiler is also available, but this may be a case-by-case assessment as the demand for buildings containing hybrid heat pumps consider both the residential and tertiary sectors. This can lead to the hybrid heat pumps using either 100 % hydrogen/methane or 100 % electricity, based on the simplification.

6.1 Methodology for Obtaining Hourly Heat Demand Profiles

The methodology for obtaining hourly heat demand profiles entails several steps. As the ETM tool provides Heat demand figures solely for Climate Year 2019, a procedure has been devised to extrapolate hourly heat demand profiles per country and for CY 1982–2019.

Initially, Utilising Open Power System Data – When to Heat demand profiles, available for all EU27 countries and the UK from 2008 to 2020, regression analysis is conducted to discern the relationship between temperature and heat demand. Subsequently, a model trained on data from 2008 to 2013 is employed to estimate heat demand for all years within the specified timeframe.

Climate data analysis involves linear regression, with straight-line equation (y=mx+c) utilised to calculate heat demand:

$$Heat\ Demand = HDDx + c$$

Where:

- HHD (Heating Degree Days) is computed as the maximum of the difference between the heating threshold temperature at which heating starts and the average daily temperature, and zero.

$$HDD = max\ (T_{threshold\ heating} - T_{mov},\ 0):$$

- $x = coefficient$
- $c = y\ intercept$
- $T_{mov} = average\ daily\ temperature$
- $T_{threshold\ heating} = temperature\ at\ which\ heating\ starts$

Additionally, climate variability data is analysed, with the mean value per hour calculated across all climates, and the variance from the mean calculated for each climate year as a percentage.

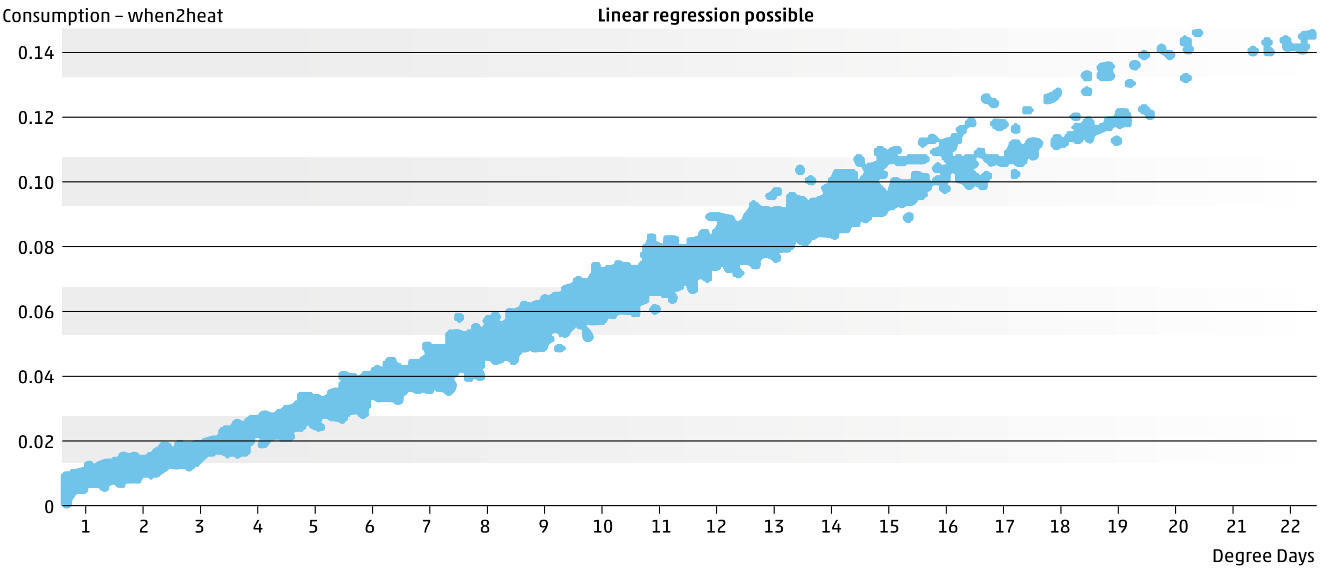


Figure 14: Linear regression possible

Creation of demand timeseries involves dividing the demand into two parts: space heating and water heating. While water heating demand remains climate-independent and is multiplied by countries' water heating profiles, space heating profiles are developed in two steps. Initially, the most representative climate year per country, which serves as the base heating profile, is multiplied by the annual heating demand. Subsequently, these heating profiles are further multiplied by climate variability data to derive climate-specific profiles.

6.1.1 Coefficient Of Performance

The Coefficient of Performance (COP) is calculated based on climate and country-specific curves following ETM's formula:

COPT = base COP + COP per degree * T

Where:

T is ambient temperature

Base COP = 2.32333

COP per degree = 0.05783

6.1.2 Hybrid Heat Pumps Modelling

Hybrid Heat Pumps (HHP) combine an electric heat pump with a gas (H_2 or CH_4) boiler, each operating depending on the outside temperature as per COP curves.

The number of HHPs per country are provided by ETM, though in Plexos, HHP capacities are aligned with peak heat demand at respective nodes.

Specifically, H_2 HHPs are connected to the Prosumer Node for the electric heat pump and H_2 Zone 2 Node for the H_2 boiler. Similarly, CH_4 HHPs are connected to the Prosumer Node for the electric heat pump, with the CH_4 boiler fuelled by CH_4 from a non-modelled market, with a heat rate of 0.93 GJ/GJ.

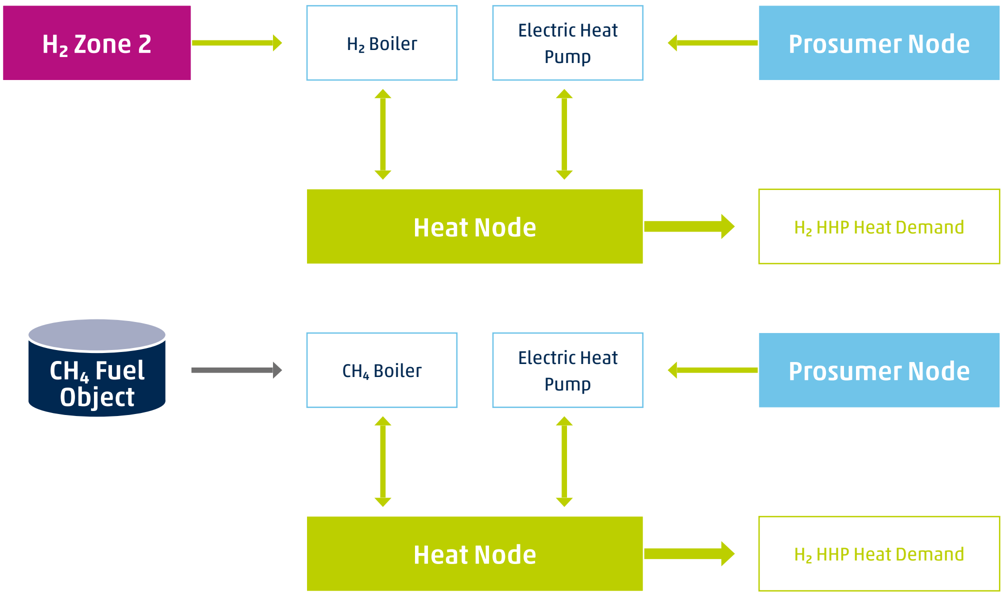


Figure 15: Hybrid Heat Pumps Modelling

7 PROSUMER AND EV MODELLING //

As illustrated in Figure 16, the overall approach is to split each EU27 bidding zone of the model into four nodes (except for very small zones such as Corsica and Crete) based on the main drivers influencing the investment and/or dispatch decision:

- **Transmission and Distribution Node** (T&D Node): production and demand following the wholesale market price signal.
- **Prosumer Node**: part of the consumers aims at some degree of energy autonomy to minimise their energy bill (including distribution costs)
- **Electric Vehicle Street Node** (EV Street Node): charging strategy will be impacted by mobility need and consumer's will to participate in the energy market.
- **Electric Vehicle Prosumer Node** (EV Prosumer Node): charging strategy will also be impacted by mobility need and prosumer's will to participate in the energy market.

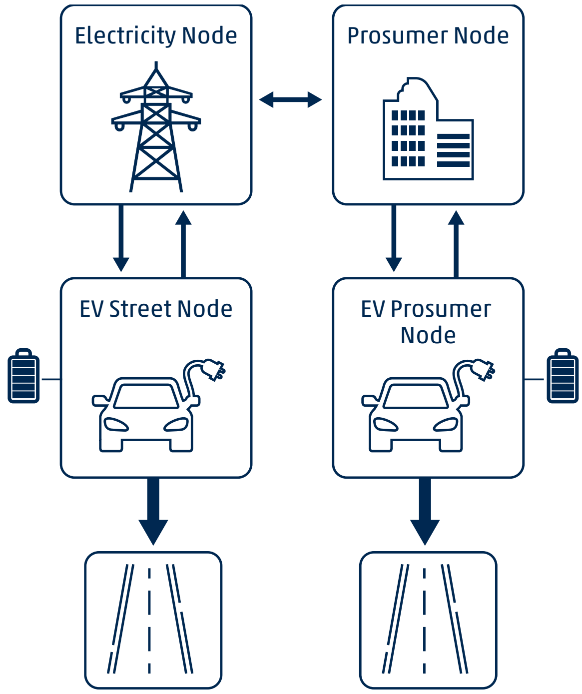


Figure 16: Nodes split: transmission and distribution, EV and prosumer nodes

7.1 Prosumer Node

As can be seen in the illustration, there is a connection between the Electricity Node and the Prosumer Node. A capacity/energy delivery cost will be attached to this connection. This cost is used to reflect the additional tariffs involved in supplying energy from the electricity market to the residential and tertiary buildings. This cost will be used in the expansion process to determine how much rooftop solar and batteries (2.5 h capacity) will be installed in the Prosumer Node, considering that residential consumers invest in and operate their local assets in order to minimise their own energy bill, this arbitrage is seen through the cost to deliver electricity from the electricity market to the final consumers. Subsidies will be included in the technology cost assumptions. No capacity constraint will be considered between the two nodes ensuring the modelling interactions are fully based on costs.

In TYNDP 2024 scenarios, the cost attached to the Electricity node to Prosumer node connection is country specific and it is based on 2022[18] electricity prices for household consumers derived from EC materials[19]. The energy cost dimension is discarded, since it will be an output of the optimisation, using only distribution costs and taxes.

18 No 2022 data available for UK. The latest available figures have been used: 2019.

19 See here

	DISTRIBUTION PRICE (€/MWh)	TAXES (€/MWh)	TOTAL (€/MWh)
AUSTRIA	58.5	87.7	146.2
BELGIUM	140.9	92.8	233.7
BULGARIA	24.0	18.6	42.6
CROATIA	43.3	33.9	77.2
CYPRUS	41.7	49.5	91.2
CZECHIA	116.2	85.7	201.9
DENMARK	91.2	287.2	378.4
ESTONIA	74.0	53.5	127.5
FINLAND	56.1	65.8	121.8
FRANCE	66.9	69.0	136.0
GERMANY	82.0	173.8	255.8
GREECE	33.6	44.1	77.7
HUNGARY	41.7	19.9	61.6
IRELAND	67.4	46.5	113.9
ITALY	59.2	102.8	162.0
LATVIA	56.3	52.8	109.1
LITHUANIA	58.4	37.4	95.8
LUXEMBOURG	86.7	50.4	137.2
MALTA	24.7	6.5	31.2
NETHERLANDS	18.0	7.7	25.7
NORTHERN IRELAND	67.4	46.5	113.9
POLAND	41.0	29.3	70.3
PORTUGAL	92.4	48.4	140.7
ROMANIA	73.2	73.2	146.4
SLOVAKIA	48.5	59.3	107.8
SLOVENIA	45.9	43.1	89.0
SPAIN	61.4	147.4	208.8
SWEDEN	79.7	88.8	168.6
UNITED KINGDOM	46.7	50.9	97.6

Table 11: Distribution prices

7.2 EV Nodes

TYNDP 2024 Scenarios have included passenger Electric Vehicle (EV) modelling in Distributed Energy and Global Ambitions PLEXOS models. The following paragraphs delineate the methodology and parameters employed.

Two distinct nodes have been established: 'EV Street' Node linked to the e-market Node, and 'EV Prosumer' Node, associated with the Prosumer Node. They will facilitate the relation between vehicular electrification and grid dynamics.

Passenger vehicles are represented as batteries, capable of drawing power from the grid and engaging in Vehicle-to-Grid (V2G) interactions.

EV demand profiles represent the driving profile of passenger vehicles, i.e., the electricity consumption of the EV motor during propulsion. Notably, fast charging, devoid of price sensitivity, is excluded from the modelling. Consequently, its electricity profiles are amalgamated into the final electricity demand.

Distribution of charging infrastructure is factored in, with 30 % of vehicles accessing street charging points and 70 % availing prosumer charging facilities.

Availability profiles have been defined to limit the flexibility that such large batteries would give to the system. The concept of the availability profile is, an EV cannot simultaneously be connected to a residential property and a street charger.

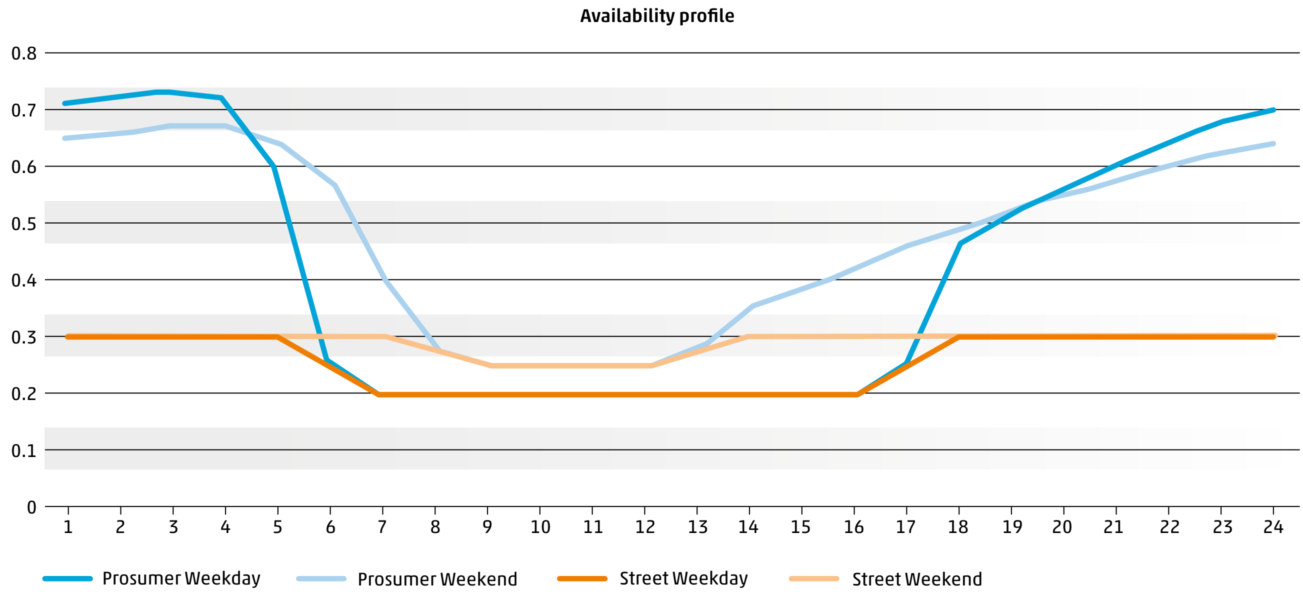


Figure 17: Availability Profile weekday and weekend

It is important that the values used for modelling EVs in the TYNDP 2024 Scenarios represent the average European EV owner in the best way.

In 2022 approximately 1.5 million EVs were sold in Europe across multiple models[20]. Most EV models are available in standard and long range (driving range), with different sized battery capacities. Using publicly available data on useable battery capacities of EV models, a weighted average is calculated for 2030, based on the EVs sold in Europe in 2022[21].

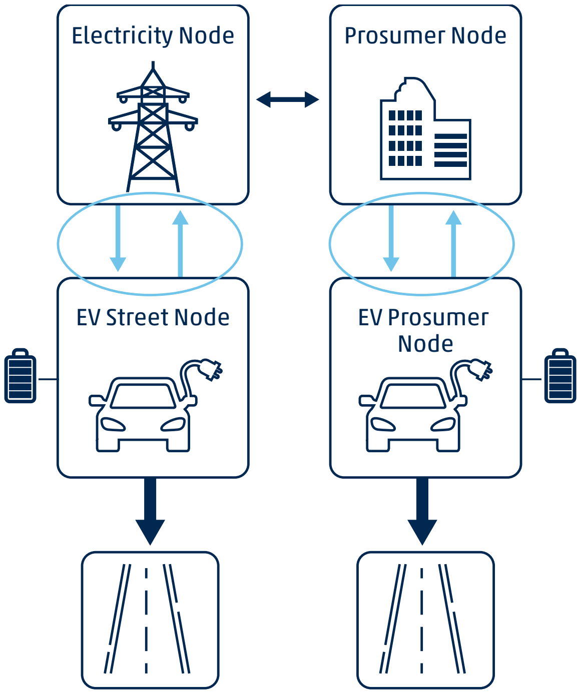
To be in line with the storylines of TYNDP 2024, it is determined that Distributed Energy will apply the higher ranges of battery capacities of EVs sold in 2022, while Global Ambition will apply the lower ranges.

It is assumed that technological developments in battery capacities and EV design will drive an increase in EV battery capacities towards 2050.

20 See here

21 Compare electric vehicles – EV Database (ev-database.org)

Lines



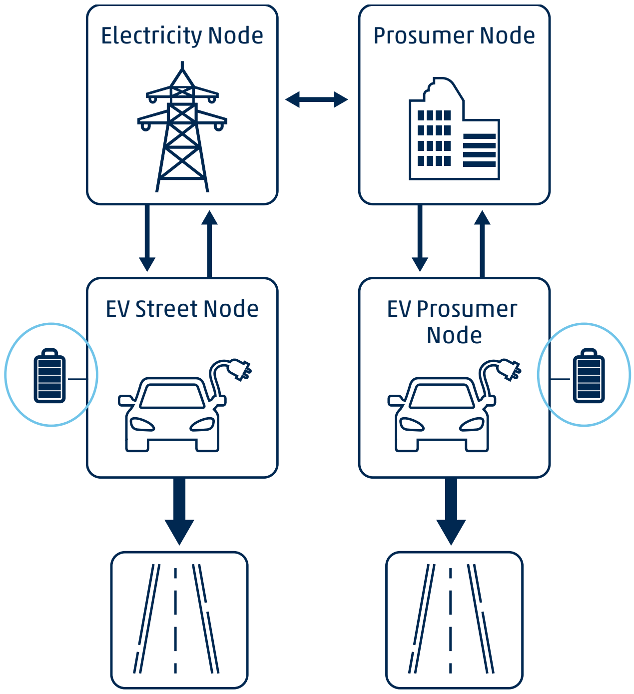
These lines represent the connection between EV and electricity nodes. Their capacity is set as follows:

- **Charging from the grid: Charging Station Charge Rate*NºEVs*Availability Profile* %EVs**
- **V2G: Charging Station Charge Rate*NºEVs* Availability Profile* %EVs* %V2G**

Energy supply from electricity to EV nodes, as well as V2G have the following costs:

- **Prosumer: 30€/MWh**
- **Street: 35 €/MWh**

Batteries



EV batteries are modelled using the following properties:

- **Capacity (MWh) = NºEVs*Unitary Capacity* %EVs**
- **Max Power (MW) = NºEVs*Unitary Charge Rate* Availability Profile* %EVs**
- **Efficiency = 94 %**
- **Initial State of Charge = 50 %**
- **Min State of Charge = profile**

7.3 Transmission and Distribution Node

Beyond flexible power generation, this node includes additional flexibility options:

- Demand shedding: tertiary and industrial consumers may offer a downward load adjustment at a given price. The consumer load decreases when wholesale market price reaches the offered price.
- Utility-scale batteries (4h capacity) are optimised over a 24-hour period with a 1 day look ahead, which represents the current day ahead and intra-day markets, as the bulk of renewables are contained in the electricity market the transmission level batteries play a much larger role as compared to residential batteries.
- Hydro pump storage with both Open Loop (a plant which uses a reservoir to which water can be pumped) and Closed Loop (a plant with no natural water inflow, but where water can be circulated between two reservoirs of different heights).

8 OFFSHORE INFRASTRUCTURE //

The refinement of the offshore modelling methodology is a major innovation in this scenario cycle. Instead of modelling offshore wind as radial capacity connected to the respective home market, the offshore territory has been divided into offshore zones where the wind power infrastructure for each zone as well as the interconnectors between zones are modelled explicitly.

This allows the scenarios to include the development of a future offshore electricity grid and hydrogen infrastructure and give insights into the most cost-effective path for planning a European-wide offshore wind power and hydrogen infrastructure. By allowing the model to invest in hydrogen as well as electricity offshore infrastructure the new methodology enables the model to answer questions like:

- Should wind power be oversized compared to transmission capacity?
- Should wind farms be radially connected to the home market or integrated into an offshore grid?
- Should the energy be transported as electricity or hydrogen, or a combination of the two?

The offshore modelling in TYNDP 2024 is a compromise between accuracy and complexity. Since a capacity expansion of the whole European electricity and hydrogen infrastructures is done in the scenarios it was important to devise a methodology that would not add too much complexity to the scenarios while at the same time giving useful results for the offshore infrastructure planning. For more detailed information and modelling regarding European offshore planning, please refer to the Offshore Network Development Plan.

8.1 Offshore zones topology

The offshore modelling methodology divides the European offshore territory into 56 zones, where each zone is an aggregation of one or more zones modelled in the Pan-European Climate Database (PECD), as shown in Figure 18. This aggregation of PECD zones was chosen to strike a balance between providing sufficient geographical resolution for modelling the offshore infrastructure while at the same time not imposing a too high computational burden due to the extra complexity added to the model. An offshore zone can be either a hub or a radial zone. For hubs, the offshore zone is explicitly included as a node in the model, which allows the connection of neighbouring hubs to form an offshore grid. On the other hand, for radial zones all capacity is radially connected to the onshore home market zone, similarly to how offshore wind was modelled in previous cycles of the TYNDP scenarios. Figure 18 shows offshore hubs marked with a circle, while all offshore zones, whether hubs or radial, are shown as shaded areas in different colours.

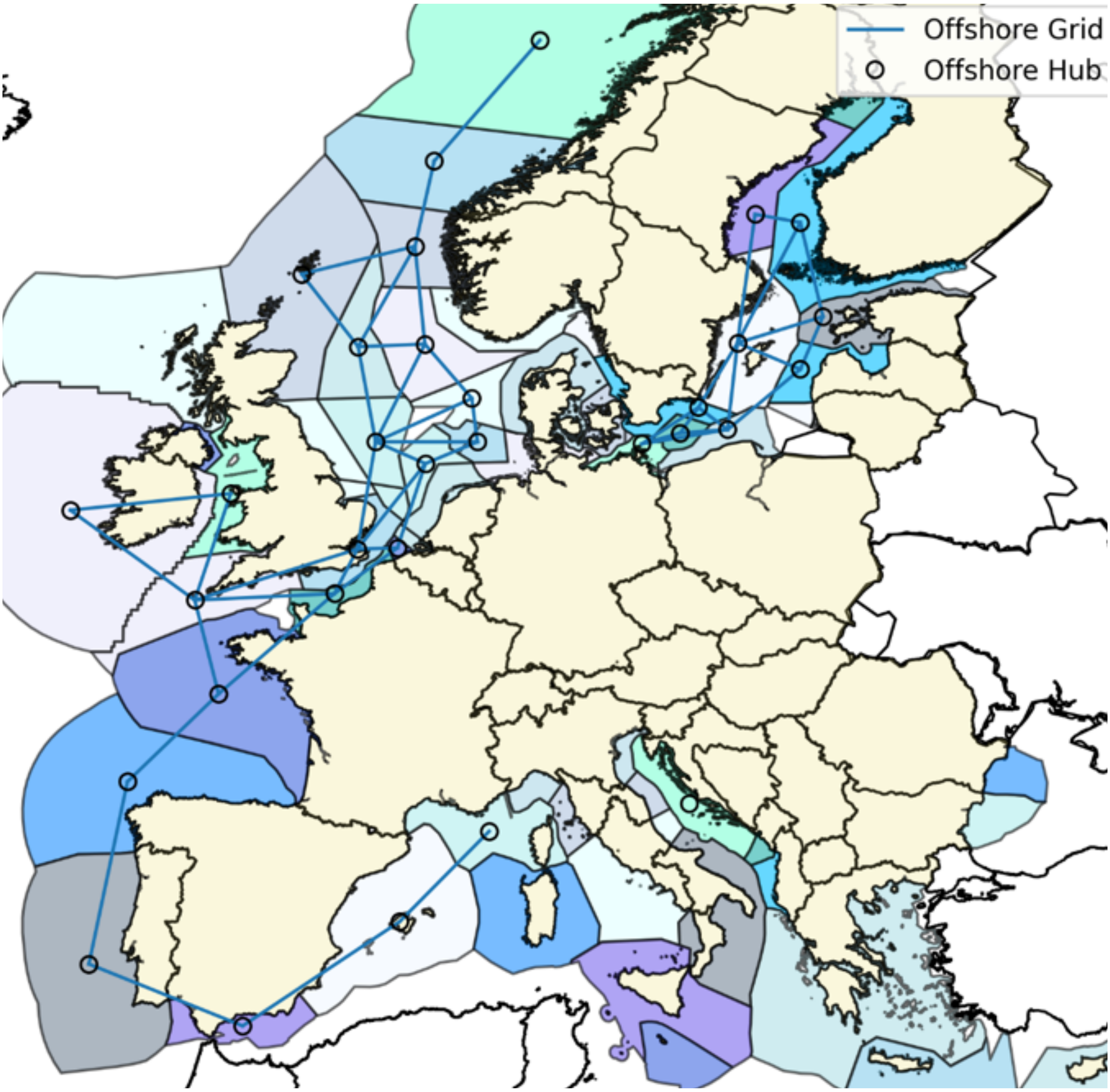


Figure 18: Zone and network topology for offshore modelling

Figure 18 also shows the possible investment candidates for the offshore grid connecting different offshore zones. These lines represent both electricity and hydrogen connections that may be built by the expansion model. Thus, in contrast to the onshore grid expansion, which is limited to proposed as well as conceptual projects, offshore infrastructure build out is generally possible between neighbouring offshore zones independent from eventual onshore investment candidates. This difference between the onshore and offshore grid expansion could potentially result in a situation where building an offshore grid becomes a substitute for building an onshore grid if there are limited onshore investment candidates available. To limit the possibility for the model to over-invest in offshore grid infrastructure, the maximum capacity between offshore hubs was set to 10 GW for electricity connections and 30 GW for hydrogen connections. Furthermore, a connection can only be built by the model between direct neighbouring hubs, so for instance a direct connection between the Dutch and Danish hub is model wise not possible.

8.2 Sectioning of offshore zones based on distance to shore and bathymetry

Each offshore zone has a maximum potential for offshore wind capacity that is based on the total surface area of that zone and the maximum offshore capacities submitted by the TSOs during the data collection process. To capture the varying costs for offshore wind power due to site-specific geographical factors, each offshore zone is divided into sections based on the distance to shore and the water depth. This was done considering European-wide bathymetry data, as illustrated in Figure 19. The waters within 22 km of shore are excluded when computing the maximum wind capacity potential since offshore wind development in these areas is usually considered to be too intrusive for human activities and marine habitats. Between 22 km and 50 km from shore all wind power is assumed to be radially connected by AC cables to the home market. Wind power built more than 50 km from shore is assumed to be DC-connected to the home market or "hub-connected", i.e., electrically connected to the respective hub for that offshore zone. Furthermore, each zone is sectioned by the water depth, depending on if it is greater or less than 200 m. Thus, there is a fixed fraction for the technical offshore potential of each offshore zone which is AC-connected and with a water depth less than 200 m, and similarly for all combinations of distance to shore and water depth.

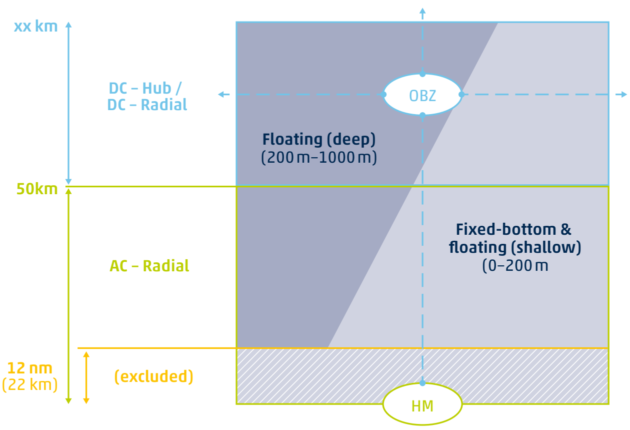


Figure 19: Schematic of subdivision of an offshore zone into different sections

Note that while wind power capacity in the AC-band is always radially connected to the home market, in the DC-band this is only the case for wind power capacity planned to become operational before 2030. Offshore wind farms planned to be built after 2030 are generally modelled as hub-connected, which means that they are electrically connected to the respective offshore hub. The offshore hub is then connected to both an offshore electricity grid and an offshore hydrogen grid, through which the energy may be transported. In other words, the offshore network may transport the power to the home market through DC cables, or first to another offshore zone and then to shore, and the same holds for the hydrogen network, provided that the wind farm has onsite electrolysers to generate hydrogen. However, some offshore zones have been designated as radial zones, which means that they are not connected to the offshore electricity/hydrogen grids, and that all wind power in the zone must be radially connected to the home market. This was done to account for regional variations in the offshore grid development plans, where the plants for some regions such as the North Sea have come further.

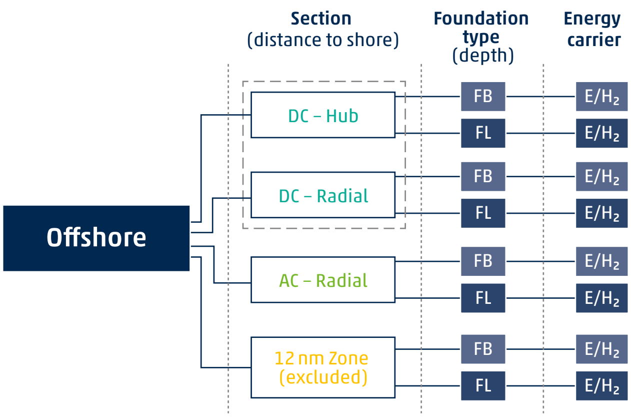


Figure 20: Offshore wind configurations based on distance to shore, water depth, and carrier type

Figure 20 shows the total combinations of possible offshore wind configurations based on the geographical subdivision and technology choices for each zone. Notice that offshore wind power may be built as generating either electricity or hydrogen. The investment costs for wind farms vary depending on the configuration as explained further in Section V.D. The capacity potentials and costs for the configurations in Figure 20 apply to the expansion of additional offshore wind power capacity on top of the existing capacity, which was specified by TSOs in the PEMMDB in the data collection process. To align the existing capacity with the properties specified for offshore wind farms in the PEMMDB, some reallocation of existing capacity between the different configurations was required. Specifically, capacity was shifted to ensure that the share of the existing capacity that is radially connected to the home zone agrees with the data submitted in the PEMMDB. This was also done to align the existing capacity dedicated to hydrogen production.

8.3 Offshore hubs

In the TYNDP modelling methodology offshore hubs offer full flexibility to serve the electricity as well as the hydrogen sector (see Figure 21). Each hub provides the option to connect electricity generating as well as hydrogen generating offshore windfarms. Electricity generating windfarms are connected to the hub via AC cables whereas the hydrogen generating windfarms are assumed to have on site electrolysers which allows a connection to the hub via pipeline. Moreover, offshore hubs serve as an option to link the electricity and hydrogen sector as they can host offshore electrolysers.

To transport the energy to the onshore markets, each offshore hubs can be connected to its respective home market via DC cable as well as via hydrogen pipeline. In addition, the model can also invest into hydrogen pipelines and electricity lines connecting hubs in neighbouring offshore zones to form an offshore network linking different countries and sea basins.

Due to this flexible hub topology the model can choose from a wide range of options to integrate offshore wind into the European energy system. One option might be to build a 2 GW electricity generating offshore wind farm which is directly connected to its home market via the offshore hub. But the model could also choose to dedicate 1 GW offshore wind to hydrogen production and the other 1 GW to electricity production. The energy in the form of electricity and hydrogen would also not have to be transported to the home market but could be exported to non-neighbouring market areas through the offshore network. Of course, there are many more options as the model could also build less than 2 GW of offshore wind capacity or could combine an electricity generating offshore wind farm with an offshore electrolyser located on the same or even a neighbouring offshore hub.

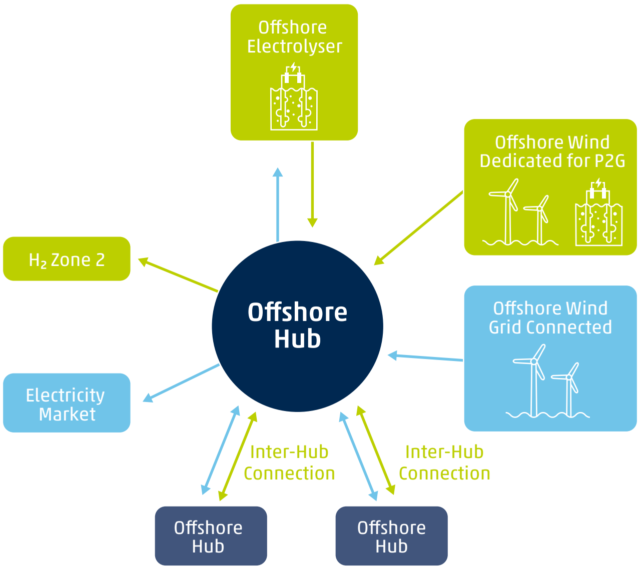


Figure 21: Schematic of the offshore hub topology

8.4 Costs for offshore investments

The investments costs vary for each possible configuration of wind power capacity shown in Figure 20. For radially connected offshore wind, the connection costs are included in the investment cost of the wind farms. This includes the cable cost as well as the costs for the onshore converter station in the case of radial DC-connected wind. The cable cost is based on the distance between the offshore zone (taken as the geographical mid-point of the zone) and the closest point onshore from the home market zone, with an additional 30 km distance added to account for the distance from the shore to the actual grid connection point, which is assumed to be further inland. For the hubs, the connections to its onshore home zone and neighbouring hubs along with their costs are modelled explicitly. The connection between the hub and its home zone includes the extra 30 km onshore grid connection distance as well as the onshore converter station. For connections between two hubs, an additional routing factor increasing the distance between the mid points of the hubs by 20 % is applied to account for deviations in the cable route from the shortest distance. In short, the impact of the distance to shore on the connection costs are either included in the wind farm investment costs or modelled explicitly through the expansion costs for the offshore grid.

For offshore wind dedicated to hydrogen generation, i.e., the configurations with H_2 as energy carrier in Figure 21, the electrolyser cost is included directly in the offshore wind investment costs. However, the model can also build stand-alone electrolysers in the hub which may produce hydrogen using electricity coming from any of the DC-connected wind farms. In this way several wind farms can be served by the same electrolyser capacity, which may be more efficient than having on-site electrolysers for all wind farms. The costs for hydrogen pipelines are calculated in a similar manner as for electricity connections, with a 30 km extra distance added to pipelines between an offshore zone and its onshore home market zone, and a 20 % routing factor applied to pipelines between two offshore zones.

The impact of the foundation on the costs is considered by differentiating the costs by the depthof the section of the offshore zone. For shallow waters, up to 200m[22] deep, the total cost for offshore wind based on fixed foundations or shallow floating foundations are assumed to be very similar. For deeper waters, only floating offshore wind can be installed. As floating wind is less mature than bottom fixed wind, the starting costs are higher in the short term, but decreasing as the technology develops.

Tables 18 and 19 in Section 9.3.3 provide the cost assumptions for all equipment considered when determining the costs for the different offshore wind configuration, including electrical cables and hydrogen pipelines, HVDC converter stations and stand-alone electrolysers.

22 Source: Bilateral exchange with Wind Europe.

9 HYDROGEN AND SYNTHETIC FUELS MODELLING METHODOLOGY //

9.1 Introduction

The purpose of this chapter is to introduce the modelling methodology of P2G used in the TYNDP 2024 scenarios. The concept of P2G will be defined and the basic modelling methodologies specified. Then the hydrogen demand and the core P2G technologies will be presented. Lastly the P2G configurations used in the TYNDP 2024 scenarios will be described. This chapter explains the operation of the P2G plants and the modelling methodologies. For information on how the system is built, see section 3.2 on Basic Principles of Expansion Model. The final capacities in each of the scenarios can be found on the visualisation platform.

P2X, Power-to-X is a relatively loose term that spans a lot of different technologies converting power into something/X. The process starts with power used in an Electrolyser to split water into Hydrogen and Oxygen, and then afterwards the hydrogen can be used either directly, or as an input in the production process of other gases or liquid fuels. The first step of the process, where hydrogen is produced is typically the most energy intensive, and here the operation on the Electrolyser has a large impact in the energy system. This impact is seen both in the electricity system, where flexible operation will be defined by, and impact the price formation in the electricity market, as well as in the gas system, where regional differences in hydrogen supply and demand, lead to future energy-transmission needs.

In the TYNDP 2024 scenarios, the term P2G is chosen to describe the first step of the process, where hydrogen is produced through electrolysis, regardless of if the end use of the energy is in the form of hydrogen, synthetic methane, or synthetic fuels.

One of the key benefits of P2G is the possibility to store renewable energy, to transport it over long distances by using the gas infrastructure or directly use it as a feedstock in industry. This source of renewable gas can be used to decarbonize sectors. It also has the potential to provide a demand side balancing mechanism to the power system. In addition, it could enable the installed capacity of renewable power generation to increase, along with the overall usage of renewable sources in the energy mix. P2G is a technology that enables the convergence of the electricity and gas systems, Utilising the respective strengths of each.

The P2G methodology in the TYNDP 2024 scenarios has evolved compared to TYNDP 2022 Scenario Report where P2G was modelled based on several configurations which foresaw multiple designs of P2G operation. The methodology has been further developed to include additional hydrogen demand sources such as, hydrogen for production of synthetic fuels and hydrogen for use in gas turbines. Additional supply sources have also been added such as ammonia and the exploration of different colours of hydrogen production through steam methane reformers. In turn the 5 hydrogen configurations have been reduced to 2 configurations, one based on a hydrogen market and another which considered the supply of hydrogen demands operating outside of the hydrogen market.

The purpose of this approach is to reflect the correct dynamics between electricity and gas markets as well as investigating the benefits of a European hydrogen infrastructure from the standpoint of optimising the European energy system with a holistic approach.

9.2 Introduction to technologies

The purpose of this section is to introduce the different technologies that constitute the P2G configurations building blocks in the final energy system that is modelled. The one-by one introduction serves to provide both a technical foundation as well as an understanding of the operational dynamics of the technology.

9.2.1 Electrolysers

Electrolysis is one of the most important technologies for providing decarbonized hydrogen, and the hydrogen produced by electrolysis using RES is often referred to as renewable hydrogen. In electrolysis the production of hydrogen is done via electrolysis of water using electricity. Today, there are several technological options to produce hydrogen via electrolysis, like alkaline water electrolysis, polymer electrolyte membrane electrolysis, anion Electrolyser membrane, and solid oxide Electrolyser cell. Each technology has its own characteristics and differentiating factors and are at different technology readiness levels.

In the TYNDP 2022 process for simplicity reasons only Alkaline and PEM are modelled, as currently these techniques are frontrunners. It is assumed that alkaline electrolysers are dominant in the start, and in time PEM will see an increasing market share. Assumptions are shown in Table 12.

MARKET SHARES ALKALINE	90 %	90 %	77 %	51 %
MARKET SHARE PEM	10 %	10 %	23 %	49 %

Table 12: Market share of european flee of electrolysers

to use credible values for costs and efficiencies, it is chosen to take an average of values from Hydrogen Europe, IRENA and E3M. With the market shares above, this leads to the fleet efficiencies and costs for providing an additional average kW of electrolysis, as shown in Table 13.

PROPERTY		2020	2025	2030	2040	2050
DE & GA	Efficiency (%NCV)	66 %	68 %	69 %	71 %	74 %
	CAPEX (€/kW)		565	366	290	198
	OPEX (€/kW/yr)		12	11	11	10

Table 13: European electrolyser fleet efficiency and investment costs

The electrolysis is in the market model assumed to be fully flexible. This seems to be a fair assumption, as the market model uses an hourly resolution, and most electrolysis will be able to perform a warm start within minutes. A cold start takes longer and can be done in a few hours depending on technology, but since weather forecasts, and thereby RES production is relatively reliable for predicting days forward, it is assumed that operators will be able to plan for when electrolysis should be warm for stand-by.

9.2.2 Steam Methane Reforming and Autothermal Reforming

There are several technologies available to convert methane to hydrogen. The two most common ones are Steam Methane Reforming (SMR) and Autothermal Reforming (ATR). Both are used for splitting methane into hydrogen and carbon dioxide. If equipped with CCS to capture the CO_2, the hydrogen produced by SMR and ATR is referred to as decarbonized hydrogen.

The SMR and ATR capacity currently installed in Europe can producee about 265 TWh/y. Current SMR and options option to provide low carbon hydrogen and can beneficially contribute to the uptake of a hydrogen economy in Europe. SMR and ATR plants are today typically located in proximity to the consumer and are often located in industrial clusters with access to methane infrastructure. As far as this capacity is not 'captured', this opens the door to the long-term perspective for connecting these locations to hydrogen infrastructure, which makes it possible to import renewable hydrogen as a replacement, or export decarbonized hydrogen. The European Hydrogen Strategy envisages that both technologies be retrofitted with CCS. If a country has a published CCS strategy, it can be assumed that the current facilities without CCS will be retrofitted with CCS by 2030. Greenfield ATR with CCS shows a CO_2 capture rate potential up to 97 %; SMR retrofitted with CCS achieves a capture rate between 60 % and 90 %. An overall average CO_2 capture potential rate of 90 % is used. In countries where no CCS strategy can be found these production facilities will remain a grey hydrogen source. Countries considered having a CCS strategy are the countries with published projects according to the homepage of IOGP . The countries considered having a CCS strategy are Bulgaria, Croatia, Czech Republic, Denmark, France, Greece, Hungary, Italy, The Netherlands, Norway, and UK. Besides these countries Germany and Belgium are considered as well because they will connect to projects in the North Sea.

Depending on the scenario, the current SMR and ATR capacity will slowly decrease (Distributed Energy scenario) or kept at current capacity level (Global Ambition).

The cost for producing hydrogen via SMR and ATR is hugely dependent on the natural gas price as well as the CCS costs and the CO_2 price for the residual CO_2 emissions. Due to SMR and ATR plants' nature of being large scale operations and having long warm-up times, a minimum warm-up time of 24 hours and a cooldown time of 24 hours as well as maximum ramps of 1.7 % of their installed capacities (= 60 h to fully ramp up/down) are implemented in the model.

COUNTRY	CCS STRATEGY	COUNTRY	CCS STRATEGY
AT	Yes	**HU**	No
BE	No	**IT**	No
BG	No	**LT**	Yes
CZ	Yes	**NL**	No
DE	No	**PL**	Yes
EE	Yes	**PT**	Yes
ES	Yes	**RO**	Yes
FI	Yes	**SE**	Yes
FR	No	**SK**	Yes
GR	No	**UK**	No
HR	No		

Table 14: CCS strategy

9.2.3 Hydrogen pipelines

Both repurposed grid, and new build grid, are investment candidates to the investment model. The associated costs are based on the study European Hydrogen Backbone, which is conducted by Gas for Climate[23]. The costs used in the investment modelling are based on several parameters related to the expansion of the hydrogen pipelines. The parameters are displayed in Table 15.

TIME HORIZON	CATEGORY	DESCRIPTION	VALUE	UNIT
2030	Repurposed	%-Share Repurposed Pipelines	60 %	
2030	New	%-Share New Pipelines	40 %	
2040	Repurposed	%-Share Repurposed Pipelines	60 %	
2040	New	%-Share New Pipelines	40 %	
2030 & 2040		Pipeline length in km either based on % share capital to capital distance or TSO submission	30 %	Data submitted by TSOs
2030 & 2040	New	CAPEX – pipelines S	1.5	mEUR/km
2030 & 2040	New	Electricity requirements for compression	0.206	MW/km
2030 & 2040	New	CAPEX – Compressor Station	3.4	mEUR/MW
2030 & 2040	Repurposed	CAPEX – pipelines S	0.3	mEUR/km
2030 & 2040	Repurposed	Electricity requirements for compression	0.206	MW/km
2030 & 2040	Repurposed	CAPEX – Compressor Station	3.4	mEUR/MW
2030 & 2040		Denominator in GW	1,200	MW
2030 & 2040	New	CAPEX – pipelines M	2.20	mEUR/km
2030 & 2040	New	Electricity requirements for compression	0.21	MW/km
2030 & 2040	New	CAPEX – Compressor Station	3.40	mEUR/MW
2030 & 2040	Repurposed	CAPEX – pipelines M	0.40	mEUR/km
2030 & 2040	Repurposed	Electricity requirements for compression	0.21	MW/km
2030 & 2040	Repurposed	CAPEX – Compressor Station	3.40	mEUR/MW
2030 & 2040		Denominator in GW	4,040	MW

23 See here

TIME HORIZON	CATEGORY	DESCRIPTION	VALUE	UNIT
2030 & 2040	New	CAPEX – pipelines L	2.80	mEUR/km
2030 & 2040	New	Electricity requirements for compression	0.21	MW/km
2030 & 2040	New	CAPEX – Compressor Station	3.40	mEUR/MW
2030 & 2040	Repurposed	CAPEX – pipelines L	0.50	mEUR/km
2030 & 2040	Repurposed	Electricity requirements for compression	0.21	MW/km
2030 & 2040	Repurposed	CAPEX – Compressor Station	3.40	mEUR/MW
2030 & 2040		Denominator in GW	13,000	MW

Table 15: Parameters used for hydrogen modelling

All data in Table 15 is derived from the EHB study.

When the investment model is run, and the optimal hydrogen infrastructure is determined, the hydrogen system will be modelled under the same constraints as the electricity system. In other words, the model will clear the market for an optimal system price in both the electricity and the hydrogen market, and there will be a price for hydrogen in every hour of the year. This is a needed assumption, as required per the methodology of the tools available to the WGSB. Even though it does not reflect the gas market, it is estimated that this modelling methodology shows sufficient operational dynamics to both the electricity and gas market.

As for electricity, hydrogen interconnections are also potential investment candidates for the expansion model to optimise the location of electricity production and electrolysis. Such grid developments result from a European optimisation of the energy infrastructure and do not signify a particular transmission need or the identification of a project for a future time horizon.

9.2.4 Hydrogen Storages

- One of the main sources of flexibility in the hydrogen system is hydrogen storage. In the TYNDP 2024 scenarios, two different storage technologies are defined with different tasks assigned:
- Underground storage: large scale storage option that is connected to the hydrogen grid to offer security of supply and flexibility to the system for different time periods (daily to seasonal).
- Decentral pressurised hydrogen tanks: Small scale storage option that is not connected to the hydrogen grid. It is used to achieve a decoupling from the electricity market for a limited period (up to 24 h), e.g., to avoid producing hydrogen during some hours with high electricity prices. No offer of security of supply.

9.2.5 Salt cavern

Salt caverns appear to be one of the most promising storage technologies for large scale hydrogen storage and are one of the few tested technologies for large scale operation. Due to the sheer size of potential salt cavern storages, they are expected to play a key role in balancing the hydrogen grid.

The potential for European salt cavern storages have been identified through a screening of existing salt cavern storages used for methane today. Due to the expected decline in methane demand until 2050, an increasing proportion of the salt cavern storages, can over time be converted to hydrogen. Table 16 shows the salt cavern storage that can be converted to hydrogen storage as well as the resulting storage capacities that are available for modelling.

	2030	2040	2050
Hydrogen storage working gas volume (TWh/NCV)	23.35	75.20	126.58

Table 16: Salt cavern storage conversion potentials for hydrogen in the investment loop

The investment costs for salt cavern storages can be found in Table 17. The costs are found in the Technology Data for Energy Storage, published by the Danish Energy Agency.

YEAR	CAPEX (€/MW)	OPEX (€/MW/YEAR)
2030	0.002	0.00004
2035	0.00175	0.000035
2040	0.0015	0.00003
2045	0.00135	0.000027
2050	0.0012	0.000024

Table 17: Salt cavent storage investment costs

9.2.6 Decentralised pressurised hydrogen tanks

Decentralised hydrogen storage tanks for pressurised hydrogen serve a critical purpose for providing flexibility for Decentralised hydrogen demand that is not located so that it can be connected to the hydrogen grid. Pressurised storage tanks can be steel tanks, aluminum tanks or composite tanks.

Due to difficulties in having the investment loop in the scenario development determine the size of the Decentralised tanks, their size was chosen ex ante and defined to be enough for serving 24 hours of hydrogen demand and be filled in 4 hours. This number was chosen based on experience from modelling and optimising similar stand-alone systems from various TSOs, and is not an optimised value, but a qualified estimate of where the extra size of Decentralised storage begins to see diminishing returns. The exact value can be discussed and might be developed in future TYNDP scenarios.

From a modelling standpoint, the flexibility from Decentralised hydrogen storage is to be modelled as short-medium (hours-days) term storage units for the gas system, like the way that grid scale batteries short-medium term flexibility for the electricity system.

9.3 The Hydrogen network configurations modelled in TYNDP 2024 scenarios.

The future operation and configuration of the hydrogen network is still uncertain, which are the main drivers for developing and modelling P2G using a plurality of configurations in the TYNDP2024 scenarios. The main purpose of using different 'zones' is to reflect their distinct operational dynamics towards the electricity market.

Figure 22 shows an overview of the modelling zones for P2G and the H_2 grid, used in the TYNDP 2024 scenarios. In general, it is seen that the H_2 demand is split into two zones, each with specific supply sources and flexibilities.

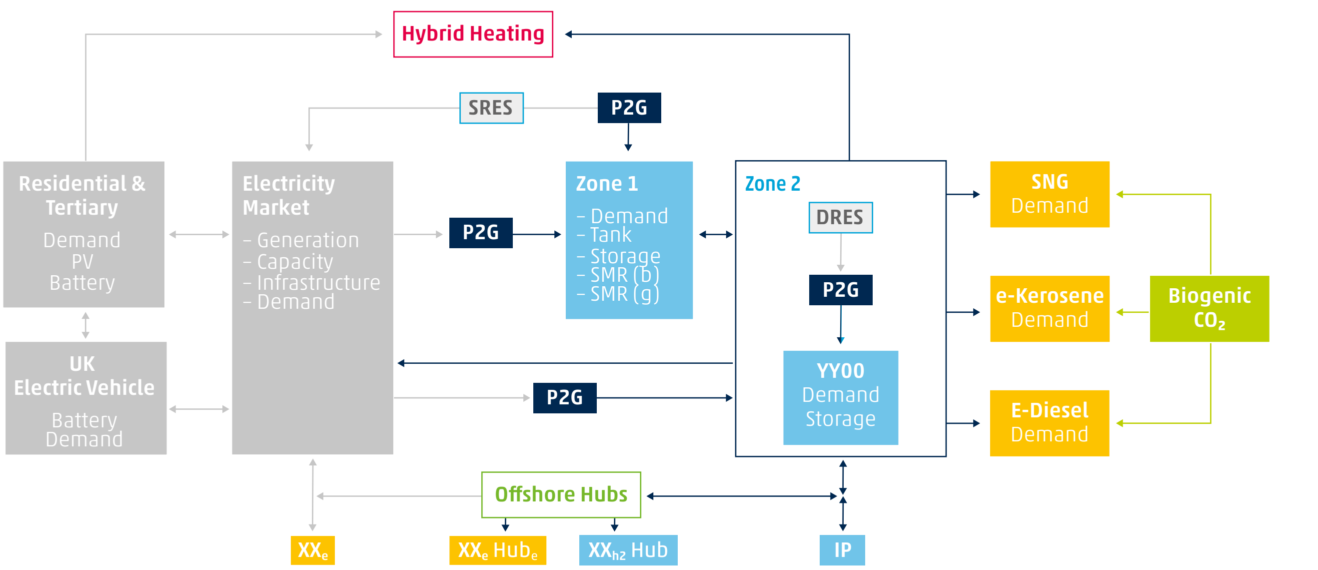
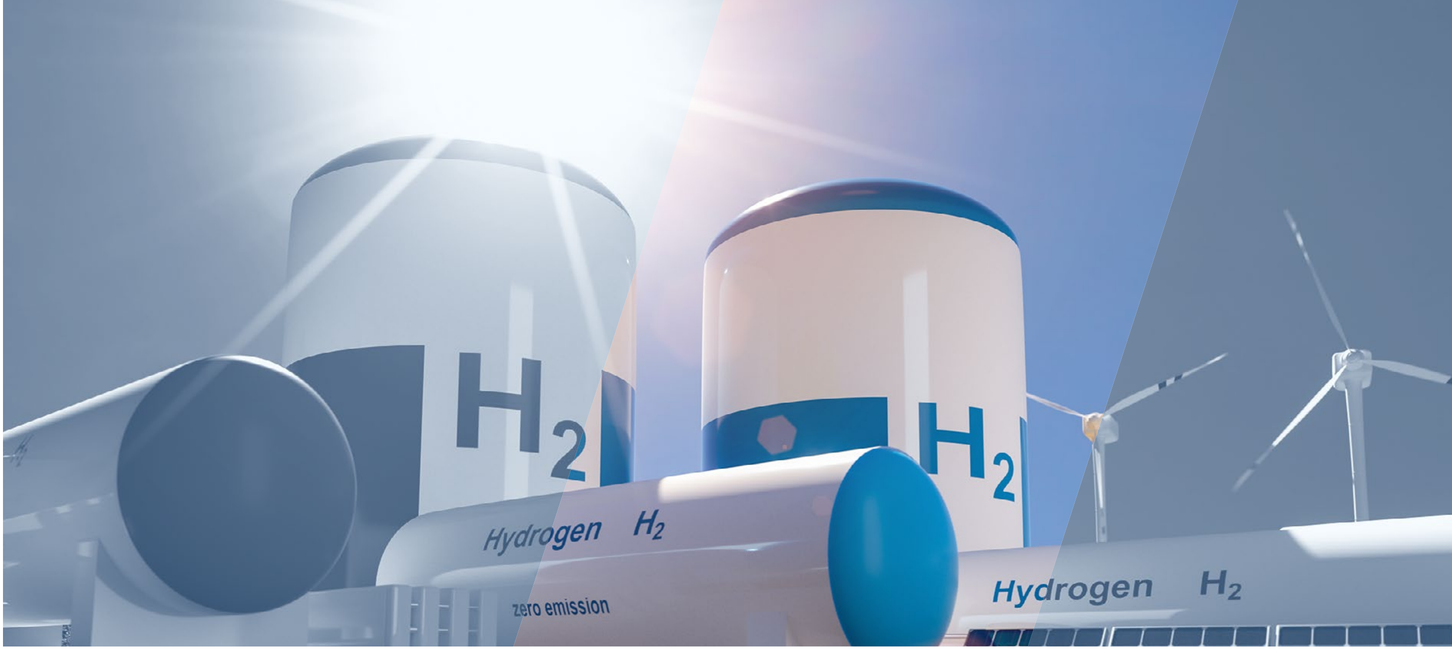


Figure 22: Modelling configurations for P2G and H_2-Grid in the TYNDP2024 scenarios



9.3.1 Zone 1: Indirect H_2 demand for decentralised upgrading facilities

The purpose of this zone is to reflect plants that are Decentralised throughout Europe and that have a hydrogen demand. These plants will be in relative proximity to the locations where the production facilities are located.

Hydrogen can be produced, either from electricity produced by shared renewable sources (noted 'SRES' in Figure 22), Steam methane reformers or the electricity from the electricity market. Therefore, from an electricity market perspective there will be a pull for electricity that is inverse to renewable production as the hydrogen demand must be met with either DRES or from the electricity market.

This zone also contains decentralised pressurised hydrogen tanks to deliver flexibility for the demand. This may represent hydrogen refueling stations for transport, or to cover consumers, that due to time or geographical constraints, cannot be covered by a national hydrogen infrastructure. For example, consumers might like to phase out their currently used fossil fuel by completing it with hydrogen produced by an on-site electrolyser before a hydrogen transmission pipeline can be built to decrease their carbon emission. Therefore, they install pressurised hydrogen tanks to act as a buffer, so that they have room for optimising the operation of the electrolyser to the hours where electricity is cheaper and more renewable.

The dynamics of this configuration, as seen from the electricity market, is so that the electrolyser will optimise operation depending on both the electricity price, the expected electricity price, and the current storage level. This means that low price hours with a large penetration of RES will be preferred. In long periods with low-res penetration and high electricity prices, the plant might be forced to run the electrolyser to ensure that the demand is met, which entails a carbon-emission for these hours. In general, the dynamic of this configuration is like what would be expected from a fleet of EVs with smart charging, but without V2G capabilities.

The capacity of the decentralised pressurised hydrogen storage is defined ex ante to cover 24 hours of hydrogen demand.

Zone 1 also reflects plants that currently have a hydrogen demand, which is served by sources such as Steam Methane Reformers (SMR) or Autothermal Reforming (ATR). It is assumed that these plants over time would like to replace their hydrogen from SMR/ATR with renewable hydrogen, which is why they install an Electrolyser to produce renewable hydrogen in the hours where electricity from the market has low costs, and low carbon emissions. Since the hydrogen consumers in this category are already connected to the methane grid, and parts of the methane grid over time can be converted to hydrogen. This configuration will, over time, be connected to the hydrogen market, which is described in the next paragraph.

The dynamics of this configuration are simple cut-in/cut-out dynamics based on the price of hydrogen from the SMR/ATR plant. Renewable hydrogen and low hydrogen are the cheapest sources, followed by blue hydrogen from the SMR/ATR. Over time, as the hydrogen grid develops, this dynamic will have to consider the price formation on the hydrogen market, where both the electrolyser and the SMR/ATR will be able to deliver hydrogen.

In this configuration, the expansion model can invest in electrolyser capacity. The SMR/ATR capacity is kept at the current level in Global Ambition and is decommissioned over time in Distributed Energy.

9.3.2 Zone 2: National and European Hydrogen Markets

The purpose of this configuration is to reflect the rollout of a national and European hydrogen market with various sources and interconnected between countries, with a hydrogen transmission grid. As resources for RES vary in different locations, and hydrogen transmission infrastructure after conversion is cost competitive to electricity infrastructure , it is to be expected that much of Europe's hydrogen end use demand will be connected to the grid. This is in line with the perspectives seen in the European Hydrogen Backbone study and builds on the same principles.

In this configuration hydrogen can be produced from multiple sources.

- interlinkage to configuration 1. This link is activated only in countries with SMRs containing CCS.
- Extra EU imports via pipeline.
- Renewable hydrogen from various sources. Grid connected electrolysis.
- A dedicated feed-in-zone, where the newly built Dedicated RES is co-located with an electrolyser and partly connected to both the electricity and the hydrogen grid. The hydrogen market has various flexibility sources. One of the largest sources for flexibility is underground storage which is available for the hydrogen market. Underground storages such as salt cavern storages act like a buffer to the renewable hydrogen, and arbitrages from charging in hours where plenty hydrogen is available and prices are low, to discharging in higher price hours. The main driver for providing flexibility is the price of hydrogen in this market node, like what it is in the electricity market. This will drive production from the various sources and drive the flows in the hydrogen grid between countries that have an excess or need for hydrogen.

In this configuration, the expansion model can invest Electrolyser capacity connected to the electricity market, RES capacities in the feed-in-zone, electrolyser capacity in the feed-in-zone, electricity grid connection to/from the feed-in zone, dedicated RES and the corresponding electrolysis, new hydrogen storage facilities as well as hydrogen grid between countries.

9.3.3 Synthetic Fuels: Production of Synthetic methane, eKerosene and eDiesel

In addition to the standard expansion model as described above, a plausible use of renewable energy and hydrogen is to produce synthetic fuels. In the case of the deviation scenarios, the fuels which will be created are eKerosene, eDiesel and synthetic methane.

The demand for synthetic fuels is established on a EU27 level and is distributed around Europe endogenously by the model. All nodes are connected to each synthetic fuel node and can provide hydrogen to create hydrocarbons. The share of the EU synthetic fuel demand that each country can produce is based on the National Trends (NT)scenario. This share is increased by 30 % to give a further distributed of produced which can be further optimised by the model. E.g. if country XY supplies 10 % of the European synthetic fuel demand in NT it could produce 10 % * 1.3 = 13 %. This forces the production of synthetic fuels to follow the demand (based on NT scenarios), which would otherwise be concentrated in countries with both cheap renewables and imports.

The total amount of synthetic fuels which can be produced across the three fuel categories is limited by a single CO_2 source. The source of this biogenic CO_2 is fuel of bio-origin such as biogas, biomethane and biomass. The production capacity in each year is determined from the scenario inputs given by the TSOs. A progressive CO_2 capture rate is then applied per scenario and timeframe.

ESTIMATED CAPTURE RATES		2030	2040	2050
Capture rates (%) post cumbustive	Biomethane	10 %	20 %	30 %
	Biofuels	10 %	15 %	20 %
	Biomass for electricity generation	30 %	60 %	90 %
	Biomass for final energy demand	15 %	23 %	30 %
Capture rate from biogasproduction	DE	50 %	70 %	90 %
	GA	25 %	48%	70%
CAPTURED BIOGENIC CO_2 (MIO. t)		**2030**	**2040**	**2050**
DE		115.9	136.3	187.3
GA		104.7	144.1	222.3

Table 18: Estimated capture rates

Once the CO_2 potentials have been set the chemical balance for the fuel synthesis must be approximated in the model. The process to produce eDiesel and eKerosene is called Fischer-Tropsch, which is a process of chemical reactions that converts a mixture of carbon monoxide and hydrogen gas into liquid hydrocarbons. This is done by subjecting the gases to high temperatures (typically 150–300°C) and pressures (typically 20–30 bar). The amount of hydrogen (GWh) and CO_2 (tonnes) required to create a fuel can be calculated from the stoichiometry of the underlying chemical reactions:

- Synthetic methane: $1\ CO_2 + 4\ H_2 \rightarrow 1\ CH_4 + 2\ H_20$
- E-kerosene: $12\ CO_2 + 37\ H_2 \rightarrow 1\ C_{12}H_{26} + 24\ H_20$
- E-diesel: $24\ CO_2 + 71\ H_2 \rightarrow 2\ C_{12}H_{23} + 48\ H_20$

Using the molar masses and the lower heating values of the reactants then allows to calculate amounts of H_2 and CO_2 needed.

In National Trends the methodology varies from the methodology used in Distributed Energy and Global Ambition. The demand for synthetic fuels is submitted by some TSOs and this demand is added to the hydrogen demand profiles. For those TSOs with no data on efuels available, we used an average demand as projected by the EC. There may be some countries that have some insight into efuel import quantities, but as only a select few countries have provided data on these import quantities, the majority off efuel demand is converted to a hydrogen demand considering the chemical balance mentioned above. However, other supply sources may emerge in the future.

9.4 Distribution of hydrogen demand in configurations

As many of the production facilities in the different configuration are options for the expansion model, the demand in each node must be determined ex ante. This distribution of demand has been done by WGSB and is based on each of the scenario storylines matched with the configurations. In general, it is assumed that most of the demand over time will be moved to configuration 2 where it can be served from a market to exploit the benefits of an integrated and flexible hydrogen market. The total hydrogen demand is distributed in the form of both direct and indirect hydrogen demand for the Distributed Energy and Global Ambition scenarios.

H_2 NODE	SECTOR	2030	2040	2050
ZONE 1	Feedstock	60 %	30 %	10 %
	Industry – Energetic	50 %	30 %	15 %
	Transport	50 %	25 %	15 %
ZONE 2	Feedstock	40 %	70 %	90 %
	Industry – Energetic	50 %	70 %	85 %
	Space & Water Heat	100 %	100 %	100 %
	Transport	50 %	75 %	85 %
	Gas Turbines	100 %	100 %	100 %

Table 19: Distribution of hydrogen demand across electrolysis configurations for Global Ambition

10 INVESTMENT COST ASSUMPTIONS //

10.1 Hydrogen interconnection and salt cavern

In the TYNDP 2022, each target year (2030, 2040, 2050) has 2 infrastructure levels available a "low infrastructure level" and a "high infrastructure level". The "Low infrastructure level" is a collection of projects submitted to the first hydrogen TYNDP in 2022. An approach based on project status (as was used for the methane TYNDP) is not a meaningful KPI when developing infrastructure from inauguration. the "high infrastructure level" includes additional cross border capacities submitted by TSOs to ENTSOG's H_2 Taskforce.

The hydrogen candidate projects used are based on the difference in pipeline capacity between "low infrastructure level" and "high infrastructure level", for each target year.

Infrastructure costs must then be considered for the expansion of hydrogen pipeline. As there is almost no real world data for this, the cost are based on external studies. The main study used is the European Hydrogen Backbone studies. The methodology followed based on this study is, CAPEX cost are split between repurposed and new hydrogen pipeline with a split of 60 % to 40 % respectively. A distance must also be considered, in this case either the default distance of 30 % of the distance from capital to capital is used, referencing a distance related dataset from ewi study on the cost of H_2 imports to the EU, or a different distance provided by the TSO to include a country specific viw that is not captured by the general methodology.

Annex II provides the detail of each project's capacity and costs.

10.2 Electricity interconnection

The electricity infrastructure investment candidates were prepared in 2-step approach.

In the first step the existing projects from the already published TYNDP list were used with their economic parameters (CAPEX, OPEX, transfer capacity Impact). Those candidates constitute very reliable base for the system needs studies together with scenario building process, as these projects were analysed within the TYNDP CBA phase and were consulted with ACER and European NRAs.

In the second phase, project promoters from the last already published TYNDP cycle were given an opportunity to submit new candidates. Most of such candidates were submitted by ENTSO-E TSOs with clear distinguished economic parameters. CAPEX for such projects also had to include the costs of the internal reinforcements that are accompanying the project implementation. As the important step, TSOs had opportunity to add additional costs associated with internal reinforcements for the projects that were submitted by 3rd party organisations. This step is very logical, considering the deep knowledge of the national network by given TSOs.

It is important to note that all the conceptual projects (not yet submitted in ENTSO-E TYNDP cycle) are those candidates for which TSOs were already investigating the possibility of potential new interconnection, therefore, economic parameters of such project candidates could be to some degree uncertain but very probable and technically justifiable. In some cases, even preliminary technical studies were performed to analyse potential new connections.

Annex II provides the detail of each project's capacity and costs.

10.3 Power generation and electrolysers

The assumptions on power generation CAPEX and OPEX are primarily based on Danish Energy Agency's Technology Catalogue for Generation of Electricity and District Heating[24], excluding offshore and battery technologies. Other sources such as "Annual Technology Baseline", reports "European Hydrogen Backbone April 2022", "Screening of possible hub concepts to integrate offshore wind capacity in the North Sea", "Cost and performance data for offshore hydrogen production" were used for the offshore and battery technologies costs assumptions. ANNEX II: Investment Costs of this document presents the CAPEX and OPEX assumptions. All costs are in real terms.

Global Ambition and Distributed Energy scenarios differentiate regarding RES costs to reflect their different technology focus. Global Ambition considers the lower costs for offshore wind in coherence with the focus on large generation units. Distributed Energy considers the lower costs for onshore wind, solar PV, and batteries in coherence with Decentralised technologies. CCGT, OCGT and electrolysers have the same CAPEX and OPEX for both scenarios. Costs differentiation between the DE and GA based on the trend of the cost reference. The band was determined by difference between the reference trend and linear trend with maximum costs differentiation of +/– 1 % for 2030, +/– 15 % for 2040 and +/– 20 % for 2050.

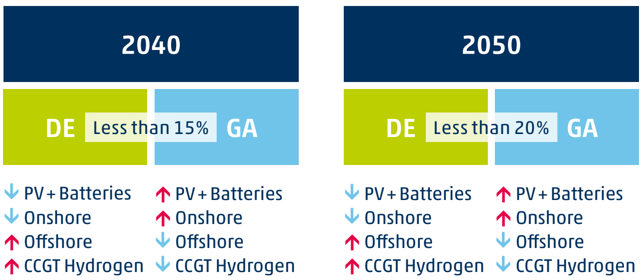


Figure 23: Cost differentiation between DE and GA scenarios

24 See here

11 DUNKELFLAUTE //

Dunkelflaute is an adequacy study case which represents a two-week cold spell with low wind load factors and solar radiation. There are also countries with climate depending on CHP and Other RES generation, generation from these units are considered from these few countries.

From a modelling perspective, the Dunkelflaute case is defined as the 2-week period of highest residual electricity demand (final electricity demand reduced by PV and wind generation) for the months of December to February according to 30 climate years (from 1987 to 2016). This calculation is done at European aggregated level to reflect the European dimension of the electricity system balancing.

The Dunkelflaute case is not run during the scenario development process, however it is used in the Hydrogen TYNDP as an adequacy case.

Among the 3 most representative climate years (1995, 2008 and 2009) as defined under chapter 4.1, 1995 and 2009 represent the most stressful situation (2009 second after 2012 the most stressful of the last 30 years).

The actual level of stress depends on the electricity demand and RES capacity of each scenario (e.g. a scenario with high solar capacity will be more stressful during periods of low solar radiation). Considering such a factor, 1995 appears as the most stressful climate year for the COP21 scenarios.

As a second step, the gas-fired power generation production is derived from the modelling of electricity system for the Dunkelflaute period of 1995 and converted into gas demand in each country based on the efficiency of each power plant category. Some countries may have their 2-week of highest gas demand for power generation during other periods, but the approach focuses on the power generation activation at European level.

As a third step, the gas demand for power generation during this Dunkelflaute is added to the final gas demand. The final gas demand considered is the one of a 2-week period under 1-in-20[25] conditions of each country. This situation can occur in January or February and not specifically during the reference period (e.g., 15 to 29 January of 1985) identified in the first step. The gas modelling of the Dunkelflaute study case is then based on the aggregation of these national demand levels.

The rationales of the differences between electricity and gas calculations are:

- Final gas demand during a cold spell is mostly temperature related while the electricity system is also wind and sun dependent.
- Every national gas system should be able to ensure the supply of gas-fired power generation as required by the European Dunkelflaute situation even if facing its own 1-in-20 final gas demand maximum on 2 weeks.

25 In certain countries a specific design case condition may be applied to ensure consistency with national regulatory frameworks (for example 1-in-50).

12 DEMAND //

12.1 Building of the energy demand overview (EV, Electricity, Hydrogen and Hybrid Heat Pump demand profiles)

The first step of the process is the definition of the yearly final demand for each energy carrier based on a sectorial analysis carried out for each Member State. The ETM is at the core of this quantification ensuring the translation of storylines into quantified demand scenarios considering country specifics jointly by electricity and gas TSOs (See chapter 2.2.1 for more information).

Hourly profiling of electricity load

Annual electricity final demand in each sector needs to be translated into hourly profiles for modelling purposes. For this purpose, profiling tools are used for all sectors except district heating for space and water heating in the residential and tertiary sectors. DFT is the tool used for all countries except for Poland, Belgium, and France, where TSOs use their own tool to create the hourly profiles, in consistency with national developments, and other countries that decided to have TYNDP2022 demand profiles rescaled (such as Cyprus, Czech Republic, Spain, Croatia, Montenegro, Malta, Romania, Luxembourg).

Standard profiles for light electric vehicles and residential and tertiary are subtracted to be used in the specific EV and Prosumer nodes. The rest of the profile is used in the wholesale market node.

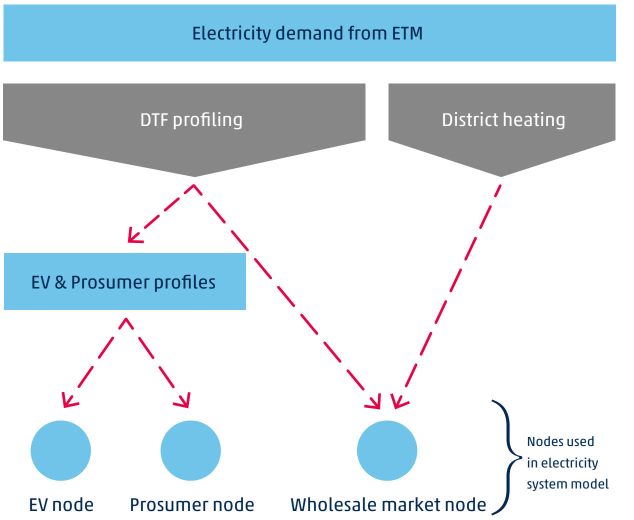


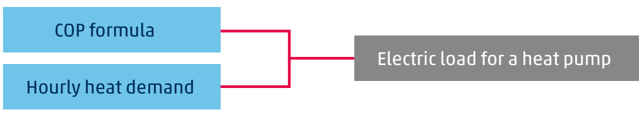
Figure 24: From the ETM to the hourly electricity load in every node of the electricity system model

The profile of electric heat-pumps on district heating network are defined separately before being added to the electricity wholesale market node of the electricity and hydrogen model.

12.1.1 Heat pumps, air-conditioners, hybrid heat pumps, sanitary water

Basic logic

From a high-level perspective the same basic methodology applies to all these technologies, and sometimes we will refer to them as heat pump methodology in this section.



As it can be seen from the above picture the heat pump methodology has two underlying bricks that calculate the heat demand for heating and sanitary water on one side, and the COP (efficiency of the heat pump) on the other side.

The final electric load for one specific type of heat pump is computed as dividing heat demand by COP:

$$electric_{load} = \frac{heat_{demand}}{COP}$$

This electric load is then multiplied by all the additional number of heat pumps for each category (brand new units of HP for heating for example) from the reference year to the forecasted year. In the end, all the categories of heat pumps are summed to have the total load of all heat pumps.

Exception: for heat pumps that replace electric heaters (or water heaters/cooling system), DFT subtracts heat demand for this specific heat pump from the electric load that was previously calculated. This way the switch to more efficient technology is reflected in the results.

$$electric_{load,hp\ replacing} = \frac{heat_{demand}}{COP} - heat_{demand}$$

12.1.2 Assumptions for Heat Pumps (HPs) modelling

The consumptions associated to HPs are constructed starting from the definition of a comfort temperature above (conditioning) or below (heating) of which electricity consumptions are expected from consumers. These comfort temperatures could be computed by the model itself starting from historical data or directly inputted.

For each type of HPs (air/air, air/water and geothermal) a Coefficient of Performance (COP) is considered. For air/air and air/water HPs a COP curve is defined according to temperature and humidity (default value 75 %). For geothermal HPs a single value is used (default value 3.2). It is possible to use custom values for the COP. No assumption on electricity back-up resistance for heating service is considered.

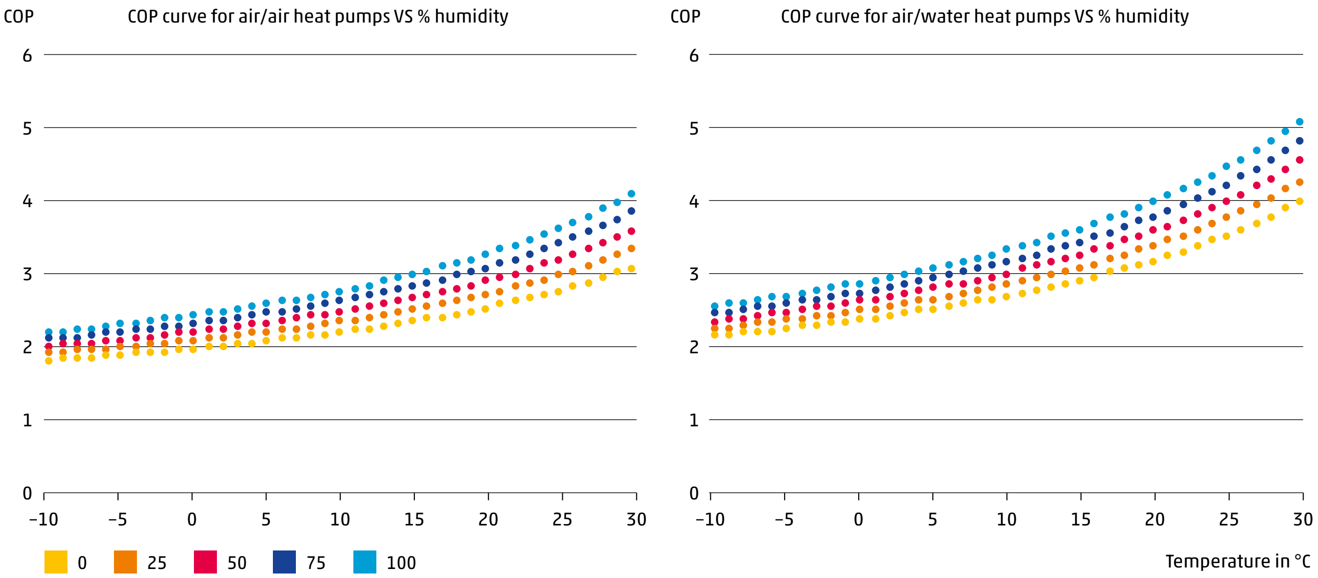


Figure 25: Example of COP curve for air/air and air/water heat pumps

12.1.3 Assumptions for Hybrid Heat Pump modelling

Hybrid heat pumps combine an electric air/water heat pump with a gas boiler. The hybrid heat pumps consist of a heat pump COP which is determined by a weighted average of ground source and air source heat pumps per country. These heat pumps are then given an hourly and country-based COP profiles based on the COP curve. Hydrogen and Methane boilers are given an efficiency of 93 %. The solver will then look at the cost in each system + the efficiency to determine the cost of delivering energy by each of the heating technologies. The capacity of the heat pump and boilers are sufficient to meet 100 % of the peak heating demand. This approach is a simplification, it is likely consumers who install hybrid heat pumps will not install enough heat pump capacity to meet peak demand. This means that it is possible that one source, either boilers or heat-pumps, could be 100 % of demand in a country.

Figure 26 illustrates the difference of electricity load profile between individual all electric and hybrid heat pumps. It shows how the latter have a lower capacity design, because peak demand is provided for back-up boilers.

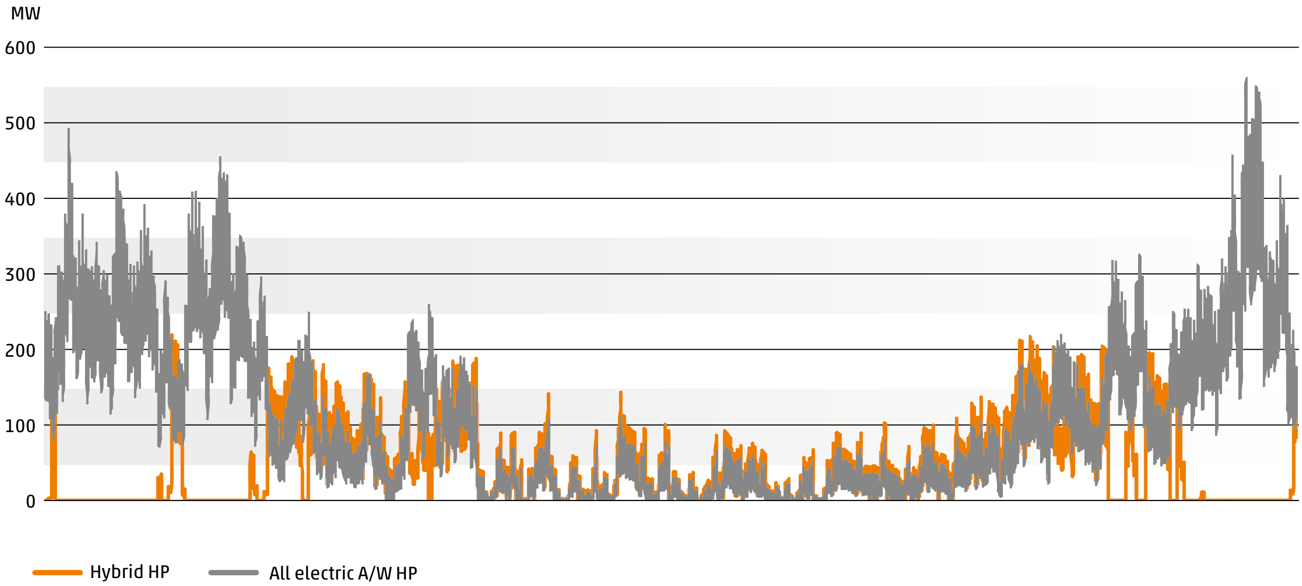


Figure 26: Example of all electric and hybrid heat pumps load across the year

12.1.4 EV patterns

Electric vehicle consumption is modeled using a deterministic physics-based model. The total electric vehicle load for a specific forecast year is calculated using the following formula:

$$
\begin{aligned}
Total\ Load = \sum_{e}^{EV\ types} \sum_{d}^{Day\ types} \sum_{c}^{Charging\ types} & Additional\ number\ of\ vehicles_{(e)} \\
& * average\ effective\ usage_{(e,d)} * efficiency_{(e)} * load\ distribution_{(e,d,c)} \\
& * charging\ fraction_{(e,c)}
\end{aligned}
$$

The load values are calculated for each type of load, type of day and type of vehicle and then summed.

12.1.5 Electricity Demand Process Flow

Both heat demand and COP are calculated based on best practices from the related literature and publicly available databases (When2Heat, ENTSO-E Transparency Platform).

A more comprehensive overview of the methodology can be seen in Figure 27.

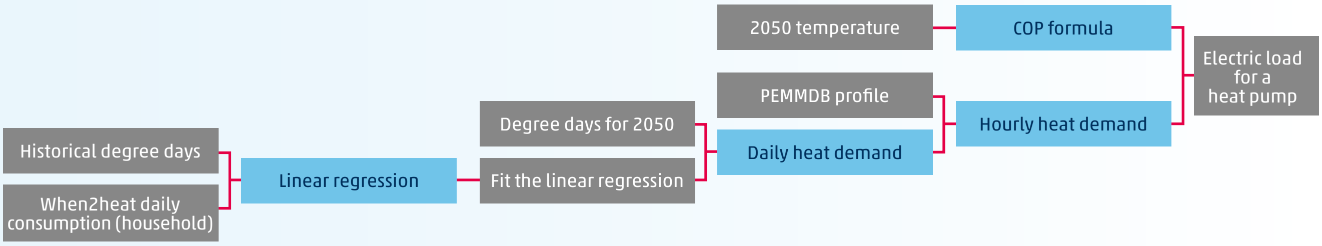


Figure 27: Electricity Demand Process Flow

To get daily heat demand for every market node and HP type a historical analysis was carried out. This analysis is based on the Heating Degree Days (HDD) and Cooling Degree Days (CDD) concept. HDD and CDD are linked to the daily heating and cooling demand of a household through a linear regression. This relationship is then transferred to future climate scenarios to get a predicted daily heat demand for every heat pump type.

As a final step to reach hourly heat demand the user-defined daily profile is used for hourly modulation of the heat pump demand.

To get the estimated hourly COP time-series the tool assumes a functional (quadratic) relationship between the sink and source temperate difference and the actual COP of the specific heat pump. This COP function cuts below 15 C temperature difference. In addition, a constant correction factor (0.85) is applied to the calculation at the end to account for real-world loss effects.

Further information about the underlying methodology can be found in the online documentation of the tool.

12.1.6 Batteries

In the tool, batteries and PV are computed jointly, and they are added after the baseload forecasting. Since this tool is only used to compute the energy demand, it aims to model only residential PVs and batteries. The energy computed in this technological brick represents how the energy is produced, stored, and used by the household. Eventually, it is going to be a negative load (as this energy will not be consumed from the grid).

PV computation

The first step is to compute how much energy is produced by the PVs for the market node. Steps:

- get the irradiance for the market node (from PECD data for the climate year selected)
- then normalise it by dividing it by the maximum value of the year (to get values between 0 and 1)
- get the total PV power from PEMMDB (user-defined parameter)
- The total PV production is estimated as total PV power multiplied by the normalised irradiance.

Once PV production is computed, we can compute battery usage. In the tool 3 different ways of computing batteries charging and discharging is implemented:

- Fixed profiles for the discharging of the batteries
- Maximising auto consumption
- Maximising profit by inputting the prices of electricity of the different hours of the days

Further information about these discharging methods can be found in the online documentation of the tool.

12.1.7 Target demand rescaling

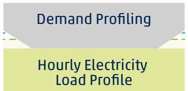
A rescaling methodology was developed to comply with the target demand requirements provided by the user for a given target year and market node.

The rescaling is performed by applying a constant rescaling ratio to the raw load curves. The rescaling ratio is computed using the difference between the expected target demand input by the user and the annual sum of the raw forecasts calculated by DFT.

Technically, the rescaling is done in three steps:

- First, a rescaling ratio for Heat Pumps is computed and rescaled load curves for heat pumps are obtained.
- Second, a different rescaling ratio for Batteries and Baseline demand is computed based on the remaining target demand (not covered by the rescaled heat pump demand).
- Then rescaled load curves for batteries and baseline are obtained.
- Finally, the total rescaled load curve is obtained by summing the load curves that are supposed to be rescaled with the load curves that are not supposed to be rescaled.

12.2 Electricity profile building process: Demand Forecasting Tool



For the creation of hourly load profiles for most of the European countries, ENTSO-E uses a load forecasting toolbox that incorporates uncertainty analysis under various climate conditions. The toolbox comes in a software application developed by an external provider.

The demand forecasting toolbox (abbreviated as DFT) allows to easily perform electric load prediction starting from data analysis of historical time series (electric load, temperature, climate variables and other). It is an advanced forecasting tool which leads to a stronger harmonisation of forecasting activities and comparability of their outcomes provided by ENTSO-E members.

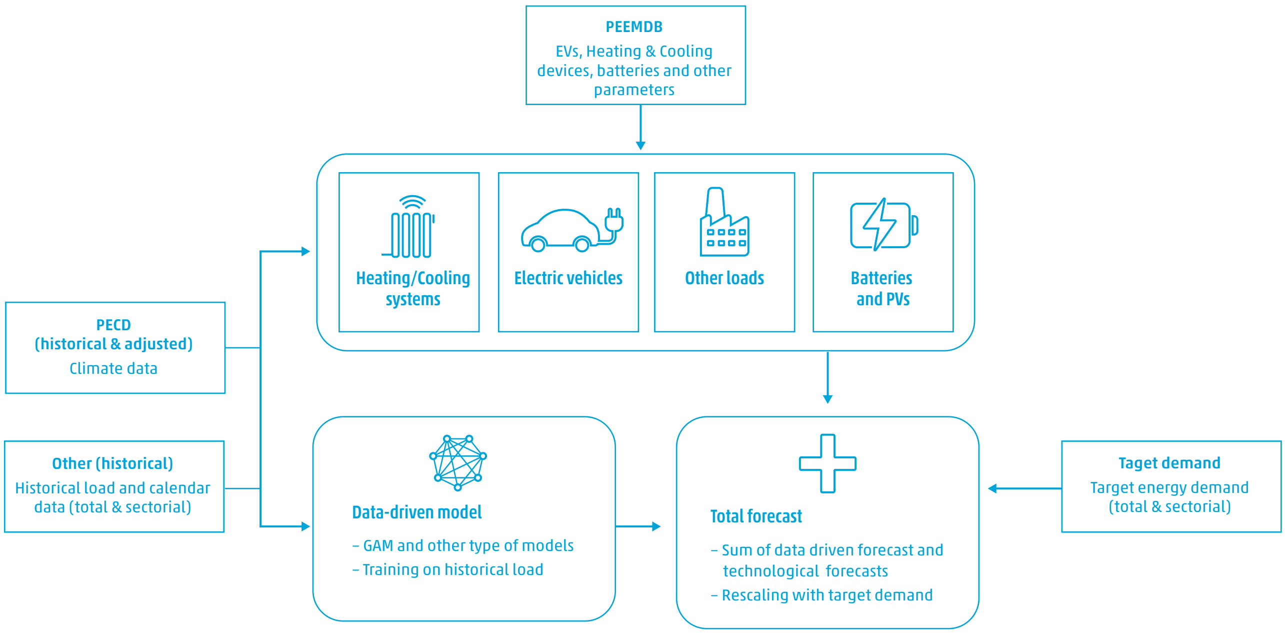


Figure 28: The embedding of demand forecasting in ENTSO-E LoNG-term studies

Figure 28 shows the position of demand forecasting within the ENTSO-E long term studies. As can be seen, it provides together with generation capacity forecasts and transmission capacity information fundamental input to market modelling. A more detailed description of input data, methodology and consistency checks are described in the further.

The DFT tool has been conceived to address the problem of electric load prediction based on temperature and other climate variables. More precisely, the tool is meant to provide an estimate of the daily load profile based on historical data of the load and of the climate variables affecting the load. In addition, the tool has been prepared to perform load adjustment to consider the electrical market evolution such as the penetration of the heat pump technology, the increase of electric cars, batteries, the evolution of the base load, etc.

The DFT methodology is proposed to overcome the limitations of traditional approaches by allowing the possibility of reconstructing entire daily load profiles. The idea is to isolate significant load components via a mathematical analysis of the available integral load profiles. To achieve this goal:

- Prediction of the whole daily load profile
- Analysis of the changes in the whole daily load profile during the year
- Identification of dependencies associated with different groups of days.
- Identification and representation of bank holidays in specific market nodes
- Identification of seasonal trends, such as daylight-saving time and summer vacation period.
- Decomposition of the load components and reconstruction of a generic daily load profile

As mentioned, the methodology is based on the extraction of a few independent (orthogonal) load components via an SVD decomposition of the available daily loads. These load components represent optimal basis functions for the reconstruction of a generic daily load profile.

SVD factorisation allows isolating load components that:

- can be used to optimally reconstruct a generic load profile. The SVD has the property of producing basis functions that are ordered by importance, so that the first few ones allow retaining most of the information available.
- tend to be related to different physical components of the load, which implies different types of dependencies over the climate variables or the types of days.

The DFT toolbox contains three different algorithms for modeling the hourly electric load time series. These are popular machine learning algorithms that can provide precise estimates of future load curves. At the same time these methods can give interpretable results so the main drivers of load evolution can also be inferred. Currently available algorithms in DFT:

- **GAM (Generalised Additive Models)**
- **Random Forest**
- **Linear regression**

GAM

In statistics, a generalised additive model (GAM) is a generalised linear model in which the linear response variable depends linearly on unknown smooth functions of some predictor variables, and interest focuses on inference about these smooth functions. The model relates a univariate response variable, Y, to some predictor variables, xi. An exponential family distribution is specified for Y (for example normal, binomial or Poisson distributions) along with a link function g (for example the identity or log functions) relating the expected value of Y to the predictor variables via a structure such as:

$$g(E(Y)) = \beta 0 + f1(x1) + f2(x2) + \ldots + fm(xm)$$

Since all regressors are independent in GAMs, the model can compute the different regressors simultaneously which allows a very quick fitting time. Because of the independence between regressors, we can easily infer the impact of each predictor variable on the prediction. Depending on the type of regressors, we can have continuous dependence plot, or non-continuous ones for categorical features.

Random Forest

Random Forest (similarly to GAMs) consists of non-parametric models that explore different non-linear possibilities for the relationships between Y (explained variables) and X (explanatory variables). Apart from that it is a very different modeling approach which originates from simple decision tree models. To put it simply: every tree (estimator) takes a random subset of training samples along with a random subset of variables (features). Then the algorithm applies and searches for the optimal decision rules based on some goodness-of-fit measures. As a regularization step, a complex aggregation of the trees (estimators) is used to avoid overfitting.

Linear regression

Regression analysis is a statistical methodology that allows us to determine the strength and relationship between a set of variables. The results from the regression help in predicting an unknown variable depending on its relationship with the predicting variables.

A linear regression can be written as:

$$y = \beta.X + \varepsilon, \text{ with } \beta = \beta 0 + \beta 1 + \beta 2 + \ldots + \beta n \text{ and } X = 1 + X1 + X2 + \ldots + Xn$$

Here, y is the observed values, β is the linear coefficient, X is the set of variables and ε the error. β is calculated using the ordinary least squares method which minimises the quadratic error between the prediction and the observations.

Set of predictor variables

The algorithms in the DFT toolbox accept the following predictor variables, allowing the freedom for the user to choose from them:

- Climate variables from the PECD database (temperature, windspeed, irradiance)
- Seasonality and trend components (day-of-year, day-of-week, month, etc.)
- Special calendar effects (different user-defined group of days)

Model selection

Another feature of the DFT toolbox is the model selection process. The process is designed to make it easy for the user to select the best fitting data-driven model based on several objective metrics. These performance indicators make it possible to assess the forecasting performance of the estimated models. The metrics include RMSE, MAPE, cross-validated RMSE, cross-validated MAPE for both the training and the test set.

DFT approach: electric load correction

In addition to a load prediction based on climate variables (and groups of days), DFT gives the user the possibility to correct these predictions based on information and estimates about other load components. In particular, the possibility is provided to include predictions about:

- electric vehicles,
- sanitary water demand,
- air conditioning demand (cooling),
- cooling heat pumps demand,
- heating heat pumps demand,
- hybrid heating heat pumps demand,
- batteries impact,
- additional base loads,
- energy demand increase.

12.3 Methane and hydrogen demand

This section provides the methodology and processes used to collect and calculate the total gas demand (methane and hydrogen) for the scenarios to be used for TYNDP 2024. Total gas demand is made up of final gas demand (defined as residential, tertiary, industrial (including non-energy use) and transport sectors) and gas demand for power generation.

Gas demand for power generation is the result of the ENTSO-E modelling process, with a conversion from electricity generation into gas demand.

12.2.1 High case demand situations

Gas demand in Europe shows a strong seasonal pattern, with higher demand in winter than in summer. These variations are largely driven by temperature-related heat demand in the residential and tertiary sectors. In the long-term, considering some level of electrification in the heating sector, also an increasing seasonality in the gas demand for power generation is assumable. This is due the role of gas-fired power plants being the back-up for variable renewables in a "kalte Dunkelflaute" (German for "cold dark doldrums" describing a 2-week cold spell with very low variable renewable electricity generation).

In addition, the day of highest consumption in the year is a key input that represents one of the most stressful situations to be covered by the gas infrastructure (including transmission, distribution, and storage).

As a result of these situations, high case demand data is contemplated. Table 20 presents an overview the different cases.

DESIGN CASE (DC)	Final Peak Demand
	Power Peak Demand
2 WEEK COLD SPELL (2 W)	Final 2W Demand
	Power 2W Demand
DUNKELFLAUTE (DF)	Final 2W Demand
	Power Dunkelflaute Demand

Table 20: High case variations

12.2.2 Monthly variation

Average demand and monthly variation

Monthly demand factors are used to distribute the annual demand to the twelve months of the year and thus create monthly demand profiles. They are used to consider the variability of the methane and hydrogen demand over the year.

High case demand: Design case (DC)

The Design Case (DC) is the maximum level of gas demand used for the design of the network to capture maximum transported energy and ensure consistency with national regulatory frameworks. The peak day takes place based on the modelled situation from the over-the-whole-year simulation and is modelled on 31 January (after day 91 of storage withdrawal period).

Depending on the type of scenario the methodology varies:

- National Trends: final demand values are collected from TSOs. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.
- Distributed Energy and Global Ambition scenarios: final demand values are calculated following the Gas Peak Demand Methodology. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.

High case demand: Two-week cold spell (2W)

Maximum aggregation of gas demand reached over 14 consecutive days once every 20 years in each country to capture the influence of a cold spell on supply and especially on storage. The 14-day high demand period takes place based on the modelled situation from the over-the-whole-year simulation and is modelled starting on 15 February (after day 106 of storage withdrawal period).

Depending on the type of scenario, the methodology varies:

- National Trends: final demand values are collected from TSOs. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.
- Distributed Energy and Global Ambition scenarios: final demand values are calculated based on the Gas Peak Demand Methodology. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.

High case demand: Kalte Dunkeflaute (DF)

The so-called "Kalte Dunkelflaute" (German for "cold dark doldrum") describes an extended period with very low outside temperature as well as low production of wind and solar energy. This weather phenomenon is frequently seen, e.g. in Germany from 16 to 26 January 2017, with up to 90 % of the generation coming from conventional power plants at peak demand.

With higher electrification of final demand sectors, especially the residential and tertiary sector, and high penetration of renewables in the power market, the "Kalte Dunkelflaute" becomes a new security of supply case for a hybrid energy system.

Final demand values are the same as for the 2 Week demand as explained in above section, and further explained in following sections. Gas demand for power generation is calculated from the results of ENTSO-E modelling process, as it is explained in chapter 3.

12.2.3 Data estimation methods for final gas demand

Three scenarios are considered: National Trends +, Distributed Energy and Global Ambition. The demand for the National Trends + is derived from data collected from TSOs whereas the demand for the Global Ambition and Distributed Energy scenarios are derived from the Energy Transition Model - ETM.

YEARS	SCENARIO NAME	DEMAND DERIVED FROM
2030-2040	National Trends + (NT+)	TSO Data Collection
2040-2050	Global Ambition (GA)	Energy Transition Tool
2040-2050	Distributed Energy (DE)	Energy Transition Tool

Table 21: ENTSOs scenarios

National Trends +

Demand data is submitted from TSOs in accordance with the National Trends + storyline, parameters, and prices, using national expertise to provide country-level specifics. A data collection is sent to TSOs for this purpose.

Values are provided for the years 2030 and 2040 for the yearly volume, monthly demand factors, as well as high demand cases for the peak day (Design Case), the 2-week high demand case and the "Dunkelflaute" case.

Global Ambition and Distributed Energy

Annual demand data is calculated using the Energy Transition Tool. The Energy Transition Tool calculates country-level demand based on different end-user technology shares for each country. A sectorial approach based on storylines for Global Ambition and Distributed Energy, considering fuel and technology switch, energy efficiencies and decarbonisation is used. The specific countries inputs are then reviewed by TSOs and publicly consulted.

12.2.4 Gas peak final demand methodology for Global Ambition and Distributed Energy scenarios

To calculate the gas high case demand for Global Ambition and Distributed Energy scenarios the same methodology as for TYNDP 2022 is used.

The methodology has two approaches depending on the data used: Full Load Hours (FLH) per sector and High Case Temperatures. FLH is the number of hours per year that a sector works at its maximum performance. The High Case Temperatures are reference temperatures for different cases (Average Year, Design Case and 2 Week Case) for each country. TSOs are asked to choose which option is better for their country.

The two approaches to calculate the gas high case demand are described below.

Standard Approach: Linear temperature interpolation

This approach consists of calculating the demand for 2 Week Case by linear interpolation from the Design Case and the Average Year demand values and the different case temperatures per country. Design Case demand is based on average demand and FLH per sector. The following figure illustrates the temperature-demand relationship in the gas sector and how it is applied to calculate the different daily case figures for the gas demand.

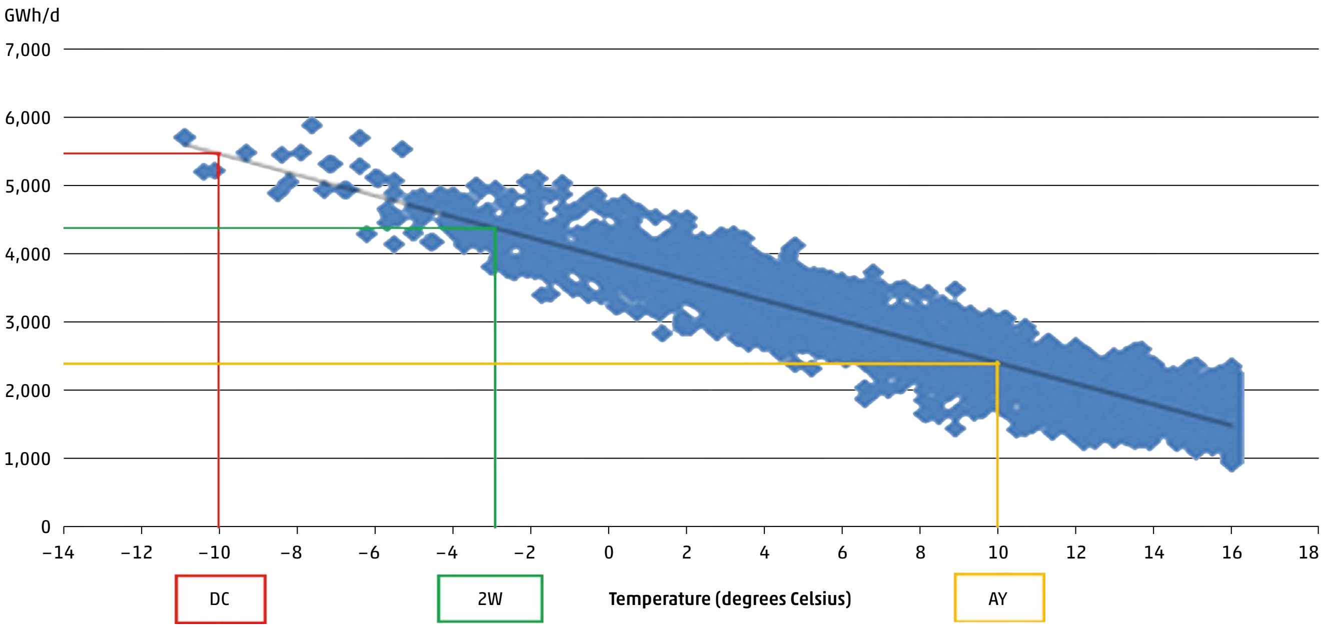


Figure 29: Temperature versus demand interpolation

Alternative Approach: Using collected data as reference.

For the calculation of the final high case demand in the residential and tertiary sectors for Global Ambition and Distributed Energy scenarios the same relation between final high case demand and final average demand from National Trends + scenario is used.

For non-temperature-related sectors (industrial and transport) the high case demand was calculated based on the average demand and the FLH per sector.

For tertiary and residential peak demand, the behaviour of hybrid heat pumps needs to be considered. Hybrid heat pumps are used for space heating and sanitary water. The ENTSOs' assumed that hybrid heat pumps start running when the outside temperature is below 16 °C, consuming electricity to heat up a building. When the outside temperature reaches around 5 °C, the consumption switches to gas (methane). A major part of sanitary water heating is gas consumption.

Therefore, gas peak demand from hybrid heat pumps was calculated according to the average temperature profiles of each country, considering the number of hours of a year with outside temperatures below 16 °C and below 5 °C.

12.2.5 Gas demand for power generation

Gas demand for power is an additional demand sources for hydrogen and methane. It is determined by the electricity system in the dispatch models and used in the gas TYNDP to ensure there is enough supply to meet all gas demand. In the hydrogen system the CCGTs are connected directly to the hydrogen nodes, and therefore the demand is added to the hydrogen system as it is created by the electricity system. For the methane system, it is assumed that there is sufficient supply to meet the demand of methane turbines. This demand is then extracted an inserted into the models used in the gas TYNDP.

12.4 Hydrogen Hourly Demand Profiles

Hydrogen demand that needs to be fulfilled in the modelling is the sum of energy sectors which use hydrogen as a supply source.

Hydrogen can be used as an energy carrier or as a feedstock. For instance, it is used in industry, such as steel production, where current fuels like coal and methane are replaced by hydrogen. Other applications could be in the transportation sector, e.g., in heavy transportation by trucks, or, to a lesser extent, in the residential and tertiary sector using hydrogen in district heating or hybrid heat pumps.

Hydrogen is also needed for other energy vectors, such as synthetic methane or synthetic liquid that has hydrogen as one of the main energy inputs. The refinement of hydrogen into synthetic methane or synthetic liquids, such as ammonia or carbon-based fuels like synthetic diesel for road transport or jet-fuel can be located both centrally in large scale facilities and decentral, if there is an existing methane infrastructure like in biogas-upgrading facilities. The demands are created endogenously as opposed to being an input to the model, as the solver optimises based on country specific parameters such as energy prices, supply sources and infrastructure.

An additional hydrogen demand source comes from hydrogen fueled gas turbines. These turbines are linked directly to the hydrogen node and a demand in the hydrogen system is created once the hydrogen CCGT is an economic dispatch option based on the day ahead market. The Ancillary and in particular Intraday markets could trigger a higher demand for hydrogen turbines as the system relied more and more on variable renewable energy sources.

The total hydrogen demand modelled in the TYNDP 2024 scenarios is the sum of these different components.

Hydrogen demand starts from the annual figures taken from the ETM and includes a breakdown of the 4 sectors (residential, tertiary, transport, and industry). For each sector historical profiles are used to build hourly profiles from the annual numbers taken from the ETM.

Hydrogen Demand in Buildings

Hydrogen in the residential sector will mainly be used for heating purposes. The annual demand is decomposed into hourly profiles by using climate dependent historical heating profiles. A linear regression model was created to understand the relation between temperature and residential and tertiary heat demand. The regression is performed using heating degree days (HDD) and a threshold temperature for each node. The equation y = HDDx + c is then used to measure this relationship. The process has been run for the last 30 climate years. The relationship between Heat Demand

and ambient temperature can be seen in Figure 30. The base year 2009 is used as the starting point and an hourly climate variability profile is developed using this reference. From final demand profiles for the residential and tertiary sectors it can be determined for all climate years in the database. It should be noted that this process is used for space heating and water heating separately as the relationship between temperature and these uses cases can vary significantly. The demands for space and water heating are combined to determine the final hydrogen demand for heating.

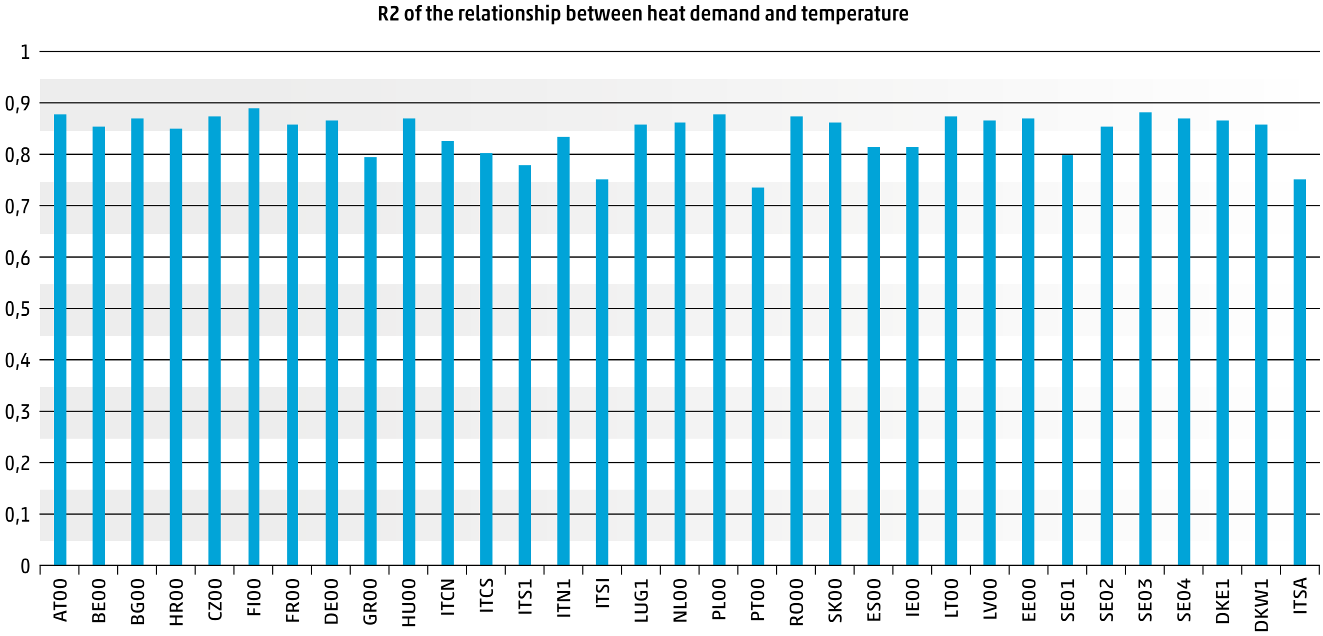


Figure 30: Relationship between heat demand and temerature

In the transport sector hydrogen will be used mainly for aviation and heavy vehicles. The heavy vehicles are given a flat profile. This is a simplification as some countries implement restrictions such as no heavy vehicles on Sundays. For aviation historical kerosene profiles are mapped for each country to understand what aviation activity looks like and therefore the seasonal supply need for hydrogen. The historical data is taken from Eurostat which shows no additional variations considered in terms of consumer behavior in the future.

Hydrogen is used for various industrial purposes. Hydrogen in industry is used for both energic purposes such as process heating and for non-energetic processes such as direct reduction in steel production or feedstock for the chemical sector. For these sectors the hydrogen profiles are modelled as flat. There will be some intraday and potential intraweek variation, but less seasonal variability. The reason therefore that flat profiles are used is that gas systems are typically modelled at a daily granularity rather than hourly due to the use of line pack as a short-term storage medium.

13 CLIMATE DATABASE //

The modeling of wind power is based on Pan-European Climate Database (PECD). PECD is a result of complementary work carried out between ENTSO-E and the Danish Technical University (DTU) reflecting the evolution of the wind load factors due to the commissioning of more efficient technologies (new farms or replacement of existing farms).

Two types of profiles were made available by DTU: profiles for existing wind power (representing technology installed before 2020) and future wind power (representing technology to be installed after 2020, and after 2030). Generation profiles for existing wind farms reflect the technology mix as historically installed in the countries. Generation profiles for future wind farms reflect the technologies estimated to be installed in the future. The technologies are differentiated between hub height and specific power (metric derived from generator size and rotor radius).

For onshore wind, the expected future wind power technology mix varies country-by-country, based on expectations collected from TSOs or estimated based on historical development. This is because environmental restrictions (such as limitations in the turbine tip height) vary country by country, which may include or exclude a certain turbine type. Furthermore, differences in wind conditions could facilitate the use of different turbine technologies in terms of specific power, higher specific power being sometimes preferred in more windy locations. Difference in turbine technology mix is also reflected country-by-country in the CAPEX estimates of the onshore wind power plants, with the assumption that cost of a turbine is related to the size of its tower, rotor, and generator. This means that while a turbine with lower specific power is likely to have higher average utilization factor due to a relatively smaller generator size, it also carries a higher CAPEX cost in terms of EUR/MW, again due to smaller generator size. Similarly, a turbine with higher hub height also costs more than a turbine with lower hub height.

The average load factor of existing Onshore Wind turbines is 23 %. This is increase to an average of 35 % for new wind farms.

For offshore wind, a single future technology was chosen for all the countries since tip height limits and other similar restrictions are less likely to impact turbine dimensions offshore. Therefore, for offshore wind, a single CAPEX could be used for investment options in future offshore wind all around the modeled region.

In addition to wind power, solar power also follows the load factors provided in the PECD. For solar power, current and future technologies are not differentiated since the evolution of technology is assumed to result in a decline of investment cost rather than improvement of load factors. PECD does not currently cover tracking PV technologies, which means all PV is considered as stationary installations.

14 FUEL COMMODITIES AND CARBON PRICES //

Fuel prices are key assumptions as they determine the merit order of the electricity generation units, hence the electricity dispatch and resulting electricity prices. Future fuel and CO_2 prices will depend on global energy demand/supply but also on European and world policies. Moreover, one should also distinguish short term variations/volatility from long-term trends.

The fuel and CO_2 prices that are needed to be quantified can be listed in three categories and its related commodities with prices in real terms (in € 2022).

- Stable or 'low volatility' prices/country dependent: Nuclear, Lignite
- Driven by world/regional demand & supply and policies: Oil, Coal, and Natural Gas
- Driven by European policies (CO_2) and by investment costs expectations (Hydrogen, Biomethane, Synthetic Methane).

14.1 Stable or 'low volatility' prices/country dependent: Nuclear and Lignite

Nuclear, given its market specifics, and lignite prices, given its local aspects, have very little variation over time. Given those particularities, the nuclear and lignite prices are assumed to stay stable over the time horizons and across the scenarios. The nuclear price is based on a study by EIA[26] and the lignite prices on an external, dedicated study for lignite[27]. Lignite prices are also country dependent although it has been decided to provide average prices per group of countries within the same range. These prices are equal to:

- Nuclear: 1.7 €/GJ
- Lignite Group 1(Bulgaria, Republic of North Macedonia, and Czech Republic): 1.40 €/GJ
- Lignite Group 2 (Slovak Republic, Germany, Republic of Serbia, Poland, Montenegro, United Kingdom/Northern Ireland market node, Ireland and Bosnia and Herzegovina): 1.80 €/GJ
- Lignite Group 3 (Slovenia, Romania, and Hungary): 2.37 €/GJ
- Lignite Group 4 (Greece and Turkey): 3.10 €/GJ

14.2 Prices driven by policies and world/regional markets.

Coal, oil, natural gas, and CO_2 prices are mainly driven by world/regional and future supply/demand dynamics, so their evolution will depend on many variables. The evolution over time will also be different. It is assumed that the price of coal, oil, natural gas, and CO_2 are the same across Europe and in all scenarios.

Having as few sources for commodity prices as possible has been given high priority. This is because the prices used will provide a total price picture of all energy carriers and the CO_2 price in the future. Because the price assumptions of the energy carriers are related, the same trends and assumptions should apply to all commodity prices. By having as few sources as possible (preferably one) it can be certain that trends, assumptions, and price relations are similar for all commodity and CO_2 prices, thereby painting a reasonable overall price picture. The source picked for the prices is IEA World Energy Outlook[28], where the prices given for the APS (Announced Pledges Scenario) have been selected.

Among the reasons for picking this source is that IEA is seen as a credible source with full public access. IEA has com-

26 EIA "Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities"

27 Booz & Co "Understanding Lignite Generation Costs in Europe"

28 IEA "World Energy Outlook 2022"

modity prices for all the energy carriers' oil, electricity, coal, hydrogen (blue imports), methane and synthetic methane. It also has a price trajectory for CO_2.

Light and heavy oil prices have been derived by applying respectively a 28 % and 8 % price increase in the crude oil prices using the historic average ratio under the assumption that even if values change, the ratio remains the same as there is no significant change in the conversion process.

For those years and horizon when an explicit forecast is not available, the prices have been linearly interpolated assuming the same growth/decreasing trend observed in the previous decade.

The hard coal, natural gas and oil prices for the different scenarios and horizon are shown in Table 7 (chapter 4.3). Oil shale is in the scenarios restricted to the Estonia power system only. Therefore, the price for shale oil has been directly provided by the related TSO. It evolves over time, but it is not scenario dependent.

14.2.1 Gas blends

The gas in the scenarios is a gas blend between different gas types (methane, biomethane and synthetic methane). Hence, the gas price in each scenario will depend on the composition of the gas in the system. The composition was set before the modelling.

Therefore, the composition is only indicative and will be a bit different after the modelling. The gas shares considered in each scenario are presented below.

	NT+		DE		GA	
	2030	2040	2040	2050	2040	2050
Methane	90 %	76 %	68 %	21 %	61 %	5 %
Biomethane	9 %	20 %	29 %	63 %	34 %	76 %
E-methane	0 %	4 %	3 %	17 %	5 %	20 %

Table 22: Gas composition in the scenarios

14.2.2 Import prices for H_2 and Ammonia

The import prices for H_2 and ammonia are set for each import route and are further differentiated between the scenarios.

Hydrogen price

The hydrogen import prices are taken from the European hydrogen backbone study[29] and are presented in Table 23.

YEAR	EXPORTER	IMPORTER	PRICE €/MWh
2030	NO	DE, BE	48
	UA	RO, HU, SK	78
2040	MA	ES	42
	DZ	IT	42
	NO	DE, BE	48
	UA	RO, HU, SK	51
2050	MA	ES	42
	DZ	IT	42
	NO	DE, BE	48
	UA	RO, HU, SK	51

Table 23: Base price for imported hydrogen

29 Guidehouse "Five hydrogen supply corridors for Europe in 2030"

Ammonia

The price for imported ammonia has been sourced from the EWI tool[30]. The tool is used to compute the import price for ammonia. The price includes transport and reconversion to Hydrogen in the EU. The ammonia imports considered in the scenarios therefore only serve to supply the energy system with H_2. Ammonia for other processes (agriculture and industry) is not considered as part of the imports used in scenarios.

The parameters and assumptions using the tool was as follows:

1. Overall import assumptions to the EU: 2030 (4 mio. t), 2040 (5 mio. t), 2050 (6 mio.t).
2. The import potential (?) assumption is divided by 6, assuming the import is coming from the 6 cheapest countries.
3. The six cheapest countries to supply this amount of hydrogen were selected. However, countries with pipeline access to the EU have been deselected. (they export pure H_2 to the EU instead)
4. The highest price of the cheapest six was selected as the price setter and therefore used as the ammonia import price.

The computed ammonia prices are shown in Table 24.

YEAR	PRICE €/MWh
2030	137.9
2040	108.4
2050	86.8

Table 24: Computed ammonia import prices using EWI tool

Hydrogen and ammonia price differentiation

The import prices for hydrogen and ammonia were differentiated between the scenarios to support the storylines. The import prices in GA should be lower than in DE to support higher imports in the GA scenario.

In addition, the prices were also split into high and low bands. This was done to secure a diversified import picture from all routes to the EU and ensure that several RES technologies for green hydrogen production are used (wind, solar and hydro). Finally, this will also support SoS in the EU, by having several import routes. The Ammonia price has a fixed minimum import quantity to ensure certain imports of ammonia. The differentiated prices are displayed in the table below.

Based on national views and to increase the Security of Supply and diversify the Hydrogen supply, ammonia flows are assumed in all time horizons.

SCENARIO	DE		GA	
	2040			
IMPORT SOURCE	LOW BAND	HIGH BAND	LOW BAND	HIGH BAND
Marocco	36	60	27	45
Algeria	36	60	27	45
Ukraine	44	73	33	54
Norway	41	69	31	51
AMMONIA	Fixed Quantity	125	Fixed Quantity	92
	2050			
IMPORT SOURCE	LOW BAND	HIGH BAND	LOW BAND	HIGH BAND
Marocco	36	60	27	42
Algeria	36	60	27	42
Ukraine	59	59	43	41
Norway	41	69	31	48
AMMONIA	Fixed Quantity	125	Fixed Quantity	69

Table 25: H_2 import prices in DE and GA

30 EWI "Tool for costs of hydrogen"

15 METHANE AND HYDROGEN SUPPLY //

This chapter describes the main storylines assumptions and methodologies regarding the gas supply mix, gas source composition and gas supply potentials. ENTSOs scenarios differentiate between gas type, gas source and imports or indigenous production.

Gas sources: The demand for the two different gas types can be supplied by multiple gas sources, which can be non-decarbonised, decarbonised, and renewable.

For methane, potential sources are:

1. Natural gas
2. Natural gas with post-combustive CCS
3. Biomethane produced from organic material
4. Synthetic methane produced via electrolysis.

For hydrogen, potential sources are:

1. Natural gas with SMR (steam methane reforming) or ATR (Autothermal Reforming)
2. Natural gas with SMR+CCS/ATR+CCS
3. Electrolysis
4. By-products from industrial processes

Imports and indigenous/national production: Both gas types from each source can be either produced indigenously or imported from outside Europe.

15.1 Hydrogen Import Potentials

The Extra EU supply potential for TYNDP24 was consulted with stakeholders on 7 July 2023.

The import potentials of hydrogen are assessed in a different way compared to the assessment of the import potential of methane to reflect the main difference: the maturity of the import infrastructure. Methane imports can rely on an existing import infrastructure, allowing the methane to reach the EU via different import routes with sufficient capacity. The infrastructure for hydrogen imports still needs to be developed. We assume that suppliers, TSOs, and the buyer/market for hydrogen are working together to establish hydrogen imports on a project basis. The projects are assumed to use retrofitted methane pipelines to import hydrogen and thus offer less import of energy due to the different energy content of methane and hydrogen. Therefore, retrofitted hydrogen pipelines might limit the import potentials of hydrogen and set the boundaries for the import potentials of hydrogen in a short- to mid-term time horizon. The total import potential for hydrogen is lower in Distributed Energy compared to Global Ambition.

In general, hydrogen can be imported to the EU via import pipelines or maritime shipping. From a cost perspective, hydrogen imports via ships are not expected to be competitive in the short-term due to the high costs of liquefaction, regasification, cooling, etc. compared to pipeline imports. However, based on TSOs' projects and to increase the Security of Supply and diversify the Hydrogen supply, ammonia flows are assumed in all time horizons.

The import pipelines enter certain European countries, and the imported hydrogen is then distributed throughout Europe via the hydrogen infrastructure.

The potential H_2 supply sources used in the TYNDP draft scenario report are Norway, Russia, North Africa, Ukraine, and UK. This choice was based on several factors, namely the potential for RES, existing access to the trans-European gas infrastructure, methane production, and being able to store CO_2.

As described above, for each supply source, a base price is estimated included transmission cost.

SOURCE H_2 SUPPLY	2030	2040
NORTH AFRICA	63	42
UKRAINE	78	51
NORWAY	48	48

Table 26: BASE Prices for hydrogen imports (€/MWh)

The figures below show the hydrogen import potentials used in the TYNDP24 scenarios in TWh per year (based on net calorific value).

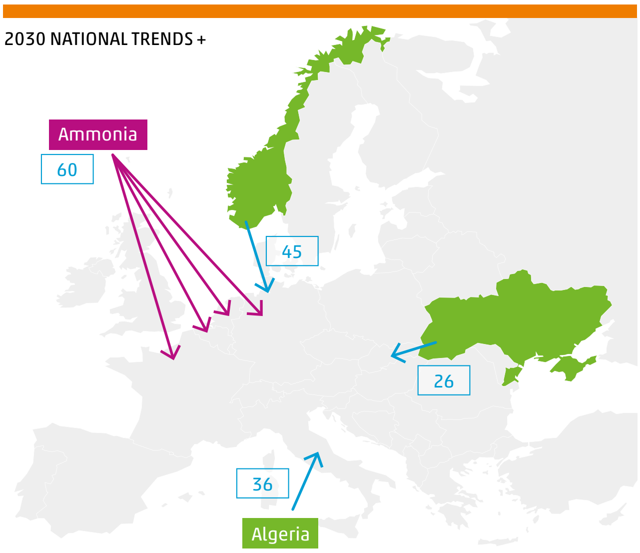


Figure 31: Extra-EU supply potential for Hydrogen in National Trends+ in 2030 (TWh)

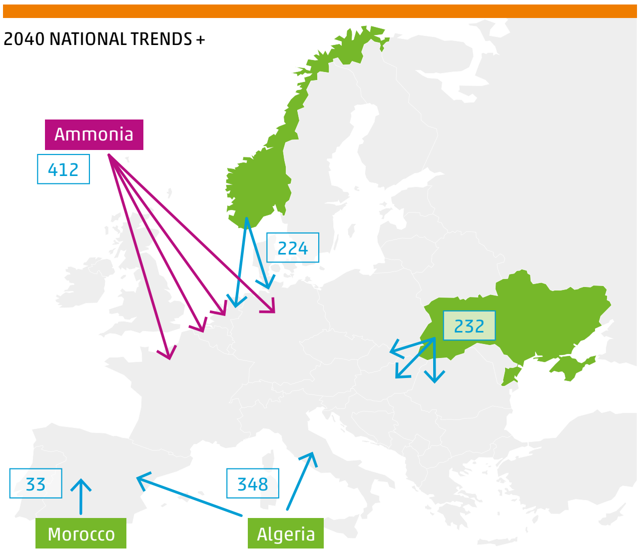


Figure 32: Extra-EU supply potential for hydrogen in National Trends+ in 2040 (TWh)

For the NT+ scenario, fixed imports have been established for the import corridors in 2030 and 2035 to ensure that the hydrogen import pattern aligns with the National Energy and Climate Plans (NECPs). These imports have no associated prices and are restricted to 30 % of the import potential. The Algeria-Italy import route utilises a higher limit of fixed import (51 %), to consider, the updated potential, in line with the PCI SouthH2 Corridor (450 GWh/day), approved for this route at the end of 2022.

Similarly, adjustments have been made for the liquefied import segment. However, this adjustment directly aligns with the specified figures in the NECPs of the involved countries. In the National trends model, imports cannot exceed these predetermined shares in 2030 and 2035.

Looking ahead to 2040, the minimum import is fixed to the 30 % of the total import (as the 2030 case), however, the residual H_2 potential (which account for the supply potential minus the fixed import portion) is available with a price related to the hydrogen supply source with a 25 % increase to the base prices, as shown in Table 27.

SOURCE H_2 SUPPLY	POTENTIAL (TWh)		PRICES (€/MWh)	
	2030	2040	2030	2040
NORTH AFRICA	36	171	Fixed quantity	
UKRAINE	26	93	Fixed quantity	
NORWAY	45	90	Fixed quantity	
HIGH PRICES FIGURES				
NORTH AFRICA	-	210	-	52.5
UKRAINE	-	139	-	63.8
NORWAY	-	134	-	60

Table 27: Specific potentials and Prices for hydogen imports IN NT+

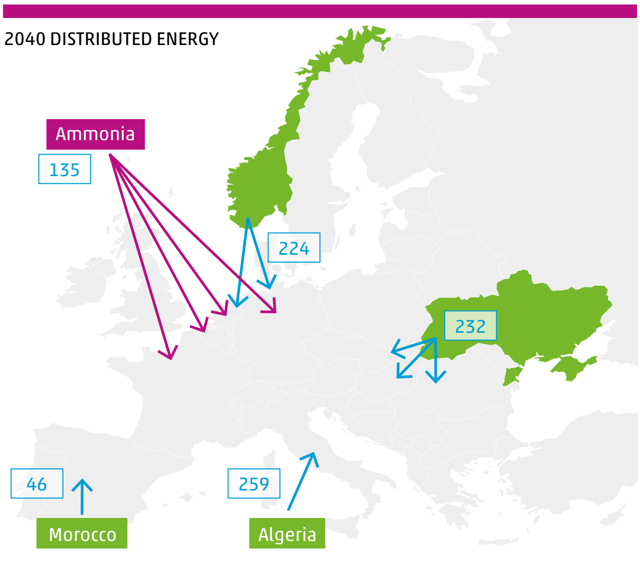


Figure 33: Extra-Eu supply potential for hydrogen in Distributed Energy in 2040 (TWh)

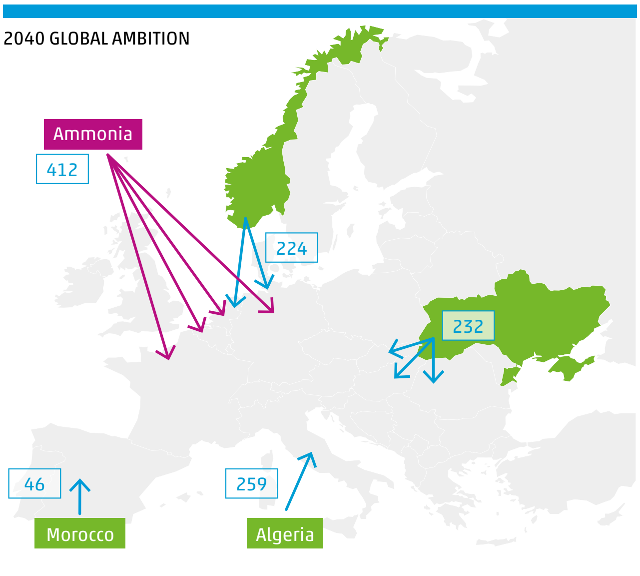


Figure 34: extra-eu supply potential for hydrogen in Global Ambition in 2040 (TWh)

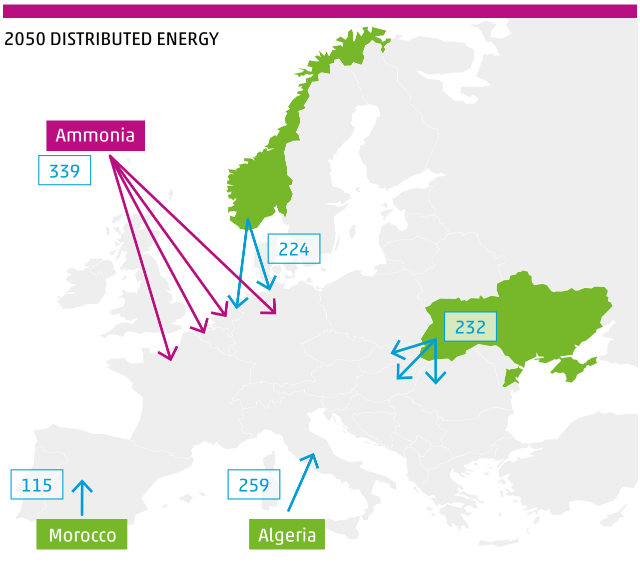


Figure 35: Extra-EU supply potential for hydrogen in Distributed Energy in 2050 (TWh)

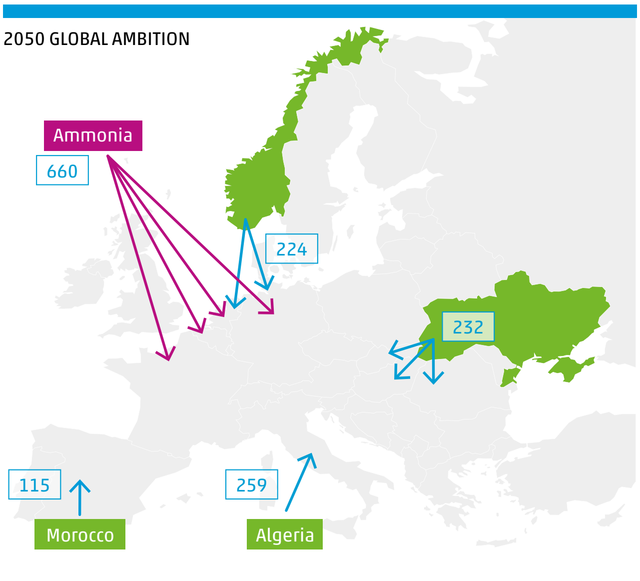


Figure 36: Extra-EU supply potential for hydrogen in Global Ambition in 2050 (TWh)

For Distributed Energy scenario, the overall price for H_2 imports have been increased 15 % in 2040 compared to the base prices. The same prices have also been applied for 2045 and 2050. These adjusted base prices are again differentiated for each import corridor in a low-price part (30 % of the import potential) and a high price part (70 % of the import potential). The prices in the low-price part are reduced by 25 %, while the prices in the high price part are increased by 25 %. For the shipped hydrogen carriers, a zero price is used for the low-price band. For the high price band, a 25 % factor is added to the adjusted base prices.

For Global Ambition scenario, the overall price for H_2 imports have been decreased by 15 % in 2040 and by 20 % in 2050 compared to the base prices to be compliant with the scenario storylines. These adjusted H_2 prices are split for each import corridor in a low-price part (50 % of the import potential) and a high price part (50 % of the import potential). The prices in the low-price part are reduced 25 %, whereas the prices in the high price part are increased by 25 %. For the shipped hydrogen carriers, a zero price is used for low price band. For the high price band 25 % is added to the adjusted base prices.

	DE				GA			
SOURCE H_2 SUPPLY	**POTENTIAL (TWh)**		**PRICES (€/MWh)**		**POTENTIAL (TWh)**		**PRICES (€/MWh)**	
Low prices figures	**2040**	**2050**	**2040**	**2050**	**2040**	**2050**	**2040**	**2050**
North Africa	86.7	102.0	36.2	36.2	146.0	170.0	27.0	26.0
Ukraine	69.6	69.6	44.0	44.0	116.0	116.0	32.5	30.6
Norway	67.2	67.2	41.4	41.4	112.0	112.0	30.6	28.8
AMMONIA	135.4	135.4	0	0	135.4	135.4	0	0
High prices figures								
North Africa	217.1	272.0	60.4	60.4	159.0	204.0	45.0	43.3
Ukraine	162.4	162.4	73.3	73.3	116.0	116.0	54.2	51.0
Norway	156.8	156.8	69.0	69.0	112.0	112.0	51.0	48.0
AMMONIA	0	203.1	0	104.0	276.6	524.6	92.0	69.0

Table 28: Specific potentials and prices for hydrogen imports for DE an GA scenarios

15.2 Biomethane potentials

ENTSOG has used same tool and numbers to calculate the biomethane potentials as in last cycle. However, the countries were asked to verify the potentials used. Entsog sent an email to the gas TSOs to verify their potentials. The TSOs was presented with the values calculated by the ENTSOG's biomethane tool (same value used in DE in the last cycle) together with the numbers used in Repower EU by the EU Commission and numbers from the study "Biomethane production in the EU" by Guidehouse.

The numbers from the EU Commission are slightly more conservative than the numbers from ENTSOGs biomethane tool, while the numbers from the Guidehouse report are slightly more optimistic.

The TSOs were presented with all three potentials for their countries and asked for an update. Where no answer was given, the numbers used in last cycle were used.

11 countries updated their numbers. For 2030, the total EU potential was slightly decreased by the updates while the potentials for 2040 and 2050 were slightly increased. The changes are shown in Table 29.

	2030	2040	2050
TYNDP 2022	399	727	985
TYNDP 2024	379	767	1,070

Table 29: Biomethane potentials compared to last cycle

The assumption and methodology used in the ENTSOG biomethane tool is described in the following sections.

15.2.1 Biomethane tool – Input assumptions and methodology

This section describes the input assumptions and methodology used to develop the estimations for biomethane potentials in 2050 in ENTSOG's biomethane tool. A S-curve approach has been applied to compute values for 2030 and 2040. For 2030, it is assumed that 40 % of the 2050 potentials will be produced. For 2045 it is assumed that 90 % of the potentials for 2050 will be produced. The values for Distributed Energy are calculated based on the assumptions explained below. According to the storylines, Global Ambition will rely less on domestic production, therefore we assume that the biomethane production in Global Ambition is within a range of 90 % compared to Distributed Energy.

15.2.2 Global Inputs and Scenario Inputs

Global Inputs contains all general inputs used throughout the tool impacting the calculations of all feedstock types. Different inputs are specified:

- the country lists
- the feedstock categories and feedstock types
- natural gas net calorific value
- biomethane net calorific value
- biogas and biomethane yields per feedstock type
- average shares of biomethane and carbon dioxide in biogas from anaerobic digestion
- average share of carbon dioxide in biomethane from thermal gasification

Scenario Inputs gathers all inputs specific to each feedstock type included in the tool. In Scenario Inputs, an overview of the input assumptions specific to each feedstock type is given. The common parameters for almost all feedstock types are:

- moisture content (%)
- allocation share of [feedstock type] to biomethane use (%)
- yield increase to 2050 (%)

15.2.3 Original Feedstock Raw Data

Original Feedstock Raw Data contains the raw data per feedstock type that are used as a basis to calculate the feedstock potentials in 2050. Feedstock potentials are calculated in ktonnes of Dry Material (DM) and 1,000 hectares, per feedstock type in the respective data year. Data years vary per feedstock type as follows:

- 2010 – Manure
- 2015 – Branches & tops
- 2016 – Waste wood, Thinnings
- 2017 – Sequential cropping, MSW
- 2030 – Agricultural residues, Food waste, Sewage sludge, Landscape care wood and roadside verge grass

In the following subsections, a more detailed step by step explanation is given on the methodology used per feedstock type to calculate the feedstock potentials that will lead to the estimated biomethane potentials per Member State by 2050.

15.2.4 Sequential cropping

The sequential cropping concept is based on cultivating a second crop (or winter crop) to produce biomethane in addition to the production of the main crop. No agricultural crops that are produced as the main crop would be used for biomethane production. Sequential cropping is estimated to represent a significant share of the feedstock potential in the EU by 2050. To estimate this potential raw data from Eurostat has been used to extract the Utilised Agricultural Area (UAA) per Member State in 2017.

A share of this utilised agricultural land is assumed to have the potential to be used for sequential cropping. By default, the same share has been assumed for each Member State. However, this can vary significantly per country, and it is at the user's discretion to define the most appropriate share for a given country.

$$\text{Land for sequential cropping in 2017 (1,000 ha)} = \text{UAA per MS (1,000 ha)} \times \text{Share of UAA for sequential cropping (\%)}$$

Crop yield estimations for sequential crops (winter crops) are calculated as a share of the average summer silage crop yields. The share of summer silage crop yield that would reflect the average sequential crop yield differs per region in Europe. Climatological conditions in southern European countries are more favourable compared to Northern countries where the average yield for sequential crops is assumed to be zero. Table 28 shows the three regions defined, i.e. North, Centre and South, that capture the different climatological conditions in Europe impacting the introduction of sequential cropping.

$$\text{Sequential crop yield in 2050} \left(\frac{\text{tonne DM}}{\text{ha}}\right) = \text{Average summer silage crop yield in 2050} \left(\frac{\text{tonne DM}}{\text{ha}}\right) \times \text{Sequential crop yield (\% of average summer silage crop yield)}$$

MEMBER STATE REGION	MEMBER STATES
NORTH	Denmark, Estonia, Finland, Latvia, Lithuania, Sweden
CENTRE	Austria, Belgium, Bulgaria, Croatia, Czech Republic, Germany, Hungary, Ireland, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, UK
SOUTH	Cyprus, France, Greece, Italy, Spain

Table 30: Regions in Europe with varying climatological conditions impacting the introduction of sequential cropping

Next to that, the average summer silage crop yield in 2050 is calculated by applying a yield increase to the average summer silage crop yield assumed in 2017. Subject to the Member State in question and the region it falls under, different average summer silage crop yields have been estimated, being higher in Southern countries than in Northern ones due to more favourable climatological conditions.

$$\text{Average summer silage crop yield in 2050}\ (\frac{\text{tonne DM}}{\text{ha}}) = \\ \text{Average summer silage crop yield in 2017}\ (\frac{\text{tonne DM}}{\text{ha}}) \times (1 + \text{Yield increase to 2050 (\%)})$$

Finally, the actual sequential crop harvested in 2050 is calculated considering the sequential crop yield calculated for 2050 and the available land for sequential cropping in 2017, which is assumed to remain approximately the same in 2050.

$$\text{Harvested sequential crop in 2050 (ktonnes DM)} = \\ \text{Land for sequential cropping in 2017 (1,000 ha)} \times \text{Sequential crop yield in 2050}\ (\frac{\text{tonne DM}}{\text{ha}})$$

Table 31 gives an overview of the input assumptions considered for all intermediate calculation steps to derive the feedstock potential from sequential crops in 2050

PARAMETER	UNITS	VALUE
Share of UAA for sequential cropping	%	10 %*
Average summer silage crop yield in 2017 – North	tonne/ha DM	10**
Average summer silage crop yield in 2017 – Centre	tonne/ha DM	14**
Average summer silage crop yield in 2017 – South	tonne/ha DM	20**
Yield increase to 2050	%	20 %
Average summer silage crop yield in 2050 – North	tonne/ha DM	12
Average summer silage crop yield in 2050 – Centre	tonne/ha DM	17
Average summer silage crop yield in 2050 – South	tonne/ha DM	24
Sequential crop yield as % share of summer crop yield – North	%	0 %***
Sequential crop yield as % share of summer crop yield – Centre	%	25 %****
Sequential crop yield as % share of summer crop yield – South	%	55 %***, ****

Table 31: Input assumptions used for feedstock potential in 2050 from sequential cropping

* Navigant expert opinion ** CIB input

*** Navigant expert opinion foresees a default value for sequential crop yield as % share of summer crop yield – Centre of 30% and for sequential crop yield as % share of summer crop yield – South of 60%. We slightly lowered these numbers based on the feedback received for the TYNDP 2020 methodology report.

**** Spottle et al., 2013, "Low ILUC potential of wastes and residues for biofuels: "Straw, forestry residues, UCO, corn cobs"

15.2.5 Agricultural residues

Elbersen et al. (2016), in his study "Outlook of spatial biomass value chains in EU-28" assessed the feedstock potential from a set of different agricultural residues that include: cereal straw, grain maize stover, rapeseed and sunflower stubbles, rice straw and sugarbeet leaves, and prunings.

Raw data on the estimated sustainable potential per type of agricultural residue and Member State in 2030 is extracted from this study. However, only a share of this sustainable potential will be allocated to the production of biomethane.

$$\text{Sustainable potential allocated to biomethane use in 2030 (ktonne DM)} = \\ \text{Sustainable potential per agricultural residue type in 2030 (ktonne DM)} \times \text{Allocation share to biomethane use (\%)}$$

The percentage share of cereal straw available for energy production is expected to be low. Cereal straw is of high quality, so it finds numerous non-energies uses such as animal bedding and feed. On the other hand, the percentage share of rapeseed & sunflower stubbles available for energy production is expected to be relatively high. Oil crop residues are of low quality so more potential can be allocated for energy production. With regards to prunings, alternative uses of the pruning material other than for nutrient and soil conservation are scarce. The source used assumes that high mobilisation rates are possible to arrive at the estimated potential.

Finally, a yield increase is applied to the sustainable potential allocated to biomethane use in 2030 to estimate that of 2050. In the default scenario, for straw and stubble no major changes are foreseen in the total potential towards 2050. For prunings, figures for 2030 from the high biomass sustainability scenario in the Elbersen et al. study are taken. However, after 2030 no major changes in potentials are expected as there is a limit to the mobilisation of biomass that is currently burned on the field. Olive pits potential is expected to stay the same towards 2050.

$$\text{Sustainable potential allocated to biomethane use in 2050 (ktonne DM)} = \\ \text{Sustainable potential allocated to biomethane use in 2030 (ktonne DM)} \times (1 + \text{Yield increase to 2025 (\%)})$$

Table 32 shows the input assumptions related to the calculation steps followed to estimate the feedstock potential from agricultural residues in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Allocation shares of agricultural residues to biomethane use – Cereal straw	%	30 %*
Allocation shares of agricultural residues to biomethane use – Grain maize stover	%	50 %**
Allocation shares of agricultural residues to biomethane use – Rapeseed & sunflower stubbles, rice, straw, and sugar beet leaves	%	50 %**
Allocation shares of agricultural residues to biomethane use – Prunings (including apples, peers, cherries, vineyards, olive pits and citrus)	%	100 %***
Yield increase to 2050	%	0 %****

Table 32: Input assumptions used for feedstock potential in 2050 from agricultural residues

* Spottle et al., 2013, "Low ILUC potential of wastes and residues for biofuels– Straw, forestry residues, UCO, corn cobs"

** CIB input

*** Elbersen et al., 2016, "Outlook of spatial biomass value chains in EU-28"

**** Navigant expert opinion considering the EU Agricultural Outlook for 2030

15.2.6 Food waste

In the case of food waste feedstock, raw data on the total technical potential of animal and mixed food waste plus vegetable waste in 2030 is extracted from Elbersen et al. (2016). An additional share needs to be considered on top of the estimated technical potential to derive the sustainable potential. This share is referred to in the calculations as *additional share from technical to sustainable potential*.

$$\text{Sustainable potential of food waste in 2030 (ktonne DM)} = \text{Total technical potential of animal \& mixed food waste plus vegetable waste in 2030 (ktonne as received)} \times (1 + \text{Additional share from technical to sustainable potential (\%)})$$

Since the raw data on the total technical potential of animal and mixed food waste plus vegetable waste is given in ktonnes of fresh matter, a moisture content factor needs to be applied to calculate the remaining dry matter available for production of biomethane.

$$\text{Sustainable potential of food waste in 2030 (ktonne DM)} = \text{Sustainable potential of food waste in 2030 (ktonne as received)} \times (1 - \text{Moisture content (\%)})$$

Finally, a yield increase is applied to derive the sustainable potential of food waste in 2050, in case it becomes relevant. By default, this factor has been set to zero since no major changes are expected in the feedstock amounts for food waste. Table 33 gives an overview of the input assumptions related to the calculation steps followed to estimate the feedstock potential from food waste in 2050.

$$\text{Sustainable potential of food waste in 2050 (ktonne DM)} = \text{Sustainable potential of food waste in 2030 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

PARAMETER	UNITS	DEFAULT VALUE
Additional share from technical to sustainable potential	%	10 %*
Moisture content	%	40 %**
Yield increase to 2050	%	0 %*

* CIB input

** Elbersen et al., 2016 Outlook of spatial biomass value chains in EU-28

Table 33: Input assumptions used for feedstock potential in 2050

15.2.7 Manure

The Elbersen et al. study was also used to extract the raw data on the technical potential of manure produced in stables in dry matter basis for the year 2010 throughout Europe. Different solid (cattle, pig, poultry, sheep/goat) and liquid (cattle, pig) manure types are considered and different sustainable shares per manure type and per Member State are applied to estimate the sustainable potential of this feedstock.

$$\text{Sustainable potential of manure produced in stables in 2010 (ktonne DM)} = \text{Technical potential manure produced in stables in 2010 (ktonne DM)} \times \text{Sustainable potential share per manure type in 2010 (\%)})$$

As with other feedstock types, a yield increase factor is applied to estimate the potential in 2050 compared to 2010. However, no major changes are expected in the total manure potential towards 2050 as EU livestock heads would remain approximately the same as suggested by the EU Agricultural Outlook for 2030.

$$\text{Sustainable potential of manure produced in stables in 2050 (ktonne DM)} = \text{Sustainable potential of manure produced in stables in sustainable scenario in 2010 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

15.2.7 Sewage sludge

Raw data was extracted from the Elbersen et al. study, where they assessed the potential of common sludges produced in households and in other sectors in 2030 in dry matter basis. In addition, a yield increase was applied to estimate the 2050 potential. However, as Table 34 shows, the potential is estimated to remain the same as in 2030.

PARAMETER	UNITS	DEFAULT VALUE
Yield increase to 2050	%	0 %*

Table 34: Input assumptions used for feedstock potential in 2050 from sewage sludge

* Navigant expert opinion considering the EU Agricultural Outlook for 2030

$$\text{Total potential of common sludges produced in households and in other sectors in 2050 (ktonne DM)} = \text{Total potential of common sludges produced in households and in other sectors in 2030 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

15.2.8 Municipal Solid Waste (MSW)

Eurostat provided raw data on the municipal waste generated in 2017 in fresh matter basis. However, only the dry organic fraction of it is suitable for biomethane production. Therefore, a share representing the organic fraction and a share for the moisture content are applied.

Table 35 shows the input assumptions related to the calculation steps followed to estimate the feedstock potential from municipal solid waste in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Additional share from technical to sustainable potential	%	10 %*
Moisture content	%	40 %**
Yield increase to 2050	%	0 %*

Table 35: Input assumptions used for feedstock potential in 2050 from municipal solid waste

* CIB input

** Navigant expert opinion considering the EU Agricultural Outlook for 2030

$$\text{Organic municipal waste generated in 2017 (ktonne as received)} = \text{Municipal waste generated in 2017 (ktonne as received)} \times \text{Share of organic fraction in MSW (\%)}$$

Additionally, it is assumed that only a share of the dry organic municipal waste generated will be allocated to biomethane use.

$$\text{Organic municipal waste generated allocated to biomethane use in 2017 (ktonne DM)} = \text{Organic municipal waste generated in 2017 (ktonne DM)} \times \text{Allocation share of organic volume to biomethane use (\%)}$$

Finally, a yield increase of –30 % is assumed in this case to estimate the potential in 2050. A reduction in municipal waste is expected towards 2050 due to increased separation and recycling.

$$\text{Organic municipal waste generated allocated to biomethane use in 2050 (ktonne DM)} = \text{Organic municipal waste generated allocated to biomethane use in 2017 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

15.2.9 Waste wood

Raw data from Eurostat was collected on wood waste generated in fresh matter basis for 2016. A moisture content factor was applied as well as a share to account for the part that will be allocated to biomethane use. Finally, a yield increase was applied to derive the 2050 potential of waste wood. Overall, waste wood will stabilise, so same figures as in 2016 apply for 2050.

Table 36 shows the input assumptions related to the calculation steps followed to estimate the feedstock potential from waste wood in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Moisture content	%	20 %
Allocation shares of waste wood to biomethane use	%	50 %*
Yield increase to 2050	%	0 %*

Table 36: Input assumptions used for feedstock potential in 2050 from waste wood

* Ecofys, 2018, "Mobilising woody residues to produce biomethane"

** Engineering toolbox

$$\text{Wood waste generated in 2016 (ktonne DM)} = \text{Wood waste generated in 2016 (ktonne as received)} \times (1 - \text{Moisture content (\%)})$$

$$\text{Wood waste generated allocated to biomethane use in 2016 (ktonne DM)} = \text{Wood waste generated in 2016 (ktonne DM)} \times \text{Allocation share of waste wood to biomethane use (\%)}$$

$$\text{Wood waste generated allocated to biomethane use in 2050 (ktonne DM)} = \text{Wood waste generated allocated to biomethane use in 2016 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

15.2.10 Landscape care wood and roadside verge grass

Landscape care wood and roadside verge grass potentials for 2030 are estimated in Elbersen et al. study in fresh matter basis. Again, this source is used for the raw data of this feedstock type. Next to that, by applying a moisture content factor, an allocation shares to biomethane use and a yield increase share, the potential allocated to biomethane use in dry matter basis and for 2050 is estimated. The Elbersen et al. study does not expect major changes in the total potential in 2050. It is assumed that it will remain stable.

Table 37 gives an overview of the input assumptions in relation to the calculation steps followed to estimate the feedstock potential from waste wood in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Moisture content	%	25 %*
Allocation shares of landscape care wood and roadside verge grass to biomethane use	%	90 %**
Yield increase to 2050	%	0 %**, ***

Table 37: Input assumptions used for feedstock potential in 2050 from landscape care wood and roadside verge grass

* CIB input

** Engineering toolbox

*** Navigant expert opinion considering the EU Agricultural Outlook for 2030

$$\text{Landscape care wood in 2030 (ktonne DM)} = \text{Landscape care wood in 2030 (ktonne as received)} \times (1 - \text{Moisture content (\%)})$$

$$\text{Roadside verge grass in 2030 (ktonne DM)} = \text{Roadside verge grass in 2030 (ktonne as received)} \times (1 - \text{Moisture content (\%)})$$

$$\text{Landscape care wood allocated to biomethane use in 2030 (ktonne DM)} = \text{Landscape care wood in 2030 (ktonne DM)} \times \text{Allocation share of landscape care wood and roadside verge grass to biomethane use (\%)}$$

$$\text{Roadside verge grass allocated to biomethane use in 2030 (ktonne DM)} = \text{Roadside verge grass in 2030 (ktonne DM)} \times \text{Allocation share of landscape care wood and roadside verge grass to biomethane use (\%)}$$

$$\text{Landscape care wood allocated to biomethane use in 2050 (ktonne DM)} = \text{Landscape care wood allocated to biomethane use in 2030 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

$$\text{Roadside verge grass allocated to biomethane use in 2050 (ktonne DM)} = \text{Roadside verge grass allocated to biomethane use in 2030 (ktonne DM)} \times (1 + \text{Yield increase to 2050 (\%)})$$

15.2.11 Thinnings

Eurostat is used as the source for raw data on the harvest of roundwood removal, for both coniferous and non-coniferous species, per Member State in fresh matter basis and in 1,000 m^3. To calculate the total potential of primary thinnings in seasoned wood allocated to biomethane use, the following parameters need to be applied:

- Mass density of thinnings (tonnes/m^3) – this allows to calculate the raw potential in ktonnes
- Moisture content (%) – this allows to calculate the share of the potential that is dry wood and hence suitable for energy use
- Harvest increase to 2050 – this accounts for the expected increase in the harvest of wood growth
- Yield increase to 2050 – to estimate the increase in the yield of wood growth
- Share of primary thinnings as % of roundwood removal – this accounts for the part of roundwood removal that is primary thinnings
- Allocation shares of primary thinnings to biomethane use – finally, this accounts for the share of primary thinnings that will be allocated to biomethane production

Table 38 shows the input assumptions used in each calculation step to derive the feedstock potential from thinnings in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Mass density of thinnings	tonnes/m^3	0.50
Moisture content	%	20 %
Harvest increase to 2050	%	20 %
Yield increase to 2050	%	10 %
Share of primary thinnings as % of roundwood removal	%	5 %
Allocation shares of primary thinnings to biomethane use	%	100 %

Table 38: Input assumptions used for feedstock potential in 2050 from thinnings

The formulas below reflect each of the calculation steps when applying each of the parameters above.

$$\text{Roundwood removal – seasoned wood in 2016 (ktonne as received)} =$$
$$\text{Roundwood removal – all species (over bark) in 2016 (1,000 m}^3\text{)} \times \text{Mass density of thinnings (tonnes/m}^3\text{)}$$

$$\text{Roundwood removal – seasoned wood in 2016 (ktonne DM)} =$$
$$\text{Roundwood removal – seasoned wood in 2016 (ktonne as received)} \times (1 - \text{Moisture content (\%)})$$

$$\text{Roundwood removal – seasoned wood in 2050 (ktonne DM)} =$$
$$\text{Roundwood removal – seasoned wood in 2016 (ktonne DM)} \times (1 + \text{Harvest increase to 2050 (\%)} + \text{Yield increase to 2050 (\%)})$$

$$\text{Primary thinnings in seasoned wood in 2050 (ktonne DM)} =$$
$$\text{Roundwood removal – seasoned wood in 2050 (ktonne DM)} \times \text{Share of primary thinnings from roundwood removal (\%)}$$

$$\text{Primary thinnings in seasoned wood allocated to biomethane use in 2050 (ktonne DM)} =$$
$$\text{Primary thinnings in seasoned wood in 2050 (ktonne DM)} \times \text{Allocation share of primary thinnings to biomethane use (\%)}$$

15.2.12 Branches and tops

Similarly, as with thinning, raw data from Eurostat was collected on the roundwood (wood in the rough) for over bark for coniferous and non-coniferous species (1000 m3) for the year 2015 per Member State.

To calculate the total potential of branches and tops from roundwood, the following parameters are applied:

- Average Biomass Expansion Factors (BEFs) for coniferous and non-coniferous species in EU – these factors allow to estimate the amount of crown mass for different species groups according to the climate zone. Member States are categorised by climate zone. Within the EU-27, Member States are predominantly located in the temperate climate zone
- Sustainable removal rate of branches & tops (%) – this accounts for the rate at which branches & tops are sustainably removed from trees. This estimate already includes sustainable potential
- Mass density of branches & tops (tonnes/m3) - this allows to calculate the potential in ktonnes
- Moisture content (%) – this allows to calculate the share of the potential that is dry wood and hence suitable for energy use
- Yield increase to 2050 – to account for the increase in the yield of forestry residues assumed towards 2050

Table 39 shows the input assumptions used in each calculation step to derive the feedstock potential from branches and tops in 2050.

PARAMETER	UNITS	DEFAULT VALUE
Average Biomass Expansion Factors (BEFs) – Coniferous species in EU temperate climate zone	-	0.30
Average Biomass Expansion Factors (BEFs) – non-coniferous species in EU temperate climate zone	-	0.40
Sustainable removal rate of branches & tops	%	20 %
Moisture content	%	20 %
Mass density of branches & tops	tonnes/m^3	0.50
Yield increase to 2050	%	10 %

Table 39: Input assumptions used for feedstock potential in 2050 from branches and tops

The formulas below guide the calculation steps applied with each parameter above.

$$\text{Sustainably removed roundwood in 2015 – coniferous species} \ = \\ \text{Roundwood for over bark for coniferous species in 2015 } (1{,}000\text{ m}^3) \times \text{Average BEFs} - \text{Coniferous species in EU} \\ \times \text{Sustainable removal rate of branches \& tops } (\%)$$

$$\text{Sustainably removed roundwood in 2015 – non} - \text{coniferous species } (1{,}000\text{ m}^3) = \\ \text{Roundwood for over bark for non} - \text{coniferous species in 2015 } (1{,}000\text{ m}^3) \times \text{Average BEFs – Non} - \text{coniferous species in EU} \\ \times \text{Sustainable removal rate of branches \& tops } (\%)$$

$$\text{Sustainably removed roundwood in 2015 – coniferous \& non} - \text{coniferous species (ktonne DM)} = \\ \text{Sustainably removed roundwood in 2015 – coniferous \& non} - \text{coniferous species } (1{,}000\text{ m}^3) \times \\ \text{Mass density of branches \& tops } (\text{tonnes/m}^3) \times (1 - \text{Moisture content } (\%))$$

$$\text{Sustainably removed roundwood in 2050 – coniferous \& non} - \text{coniferous species (ktonne DM)} = \\ \text{Sustainably removed roundwood in 2015 – coniferous \& non} - \text{coniferous species (ktonne DM)} \times (1 + \text{Yield increase to 2050 } (\%))$$

15.3 Hydrogen Flexibility

15.3.1 Introduction to molecule storage flexibility

Currently, short-term flexibility in the methane gas grid is utilised to balance grid supply and demand discrepancies that typically last a few hours to a few days. This is achieved through line pack and two types of storage: multicycle and seasonal. Multicycle storage involves frequent injections and withdrawals throughout the year, typically using caverns with relatively low working gas volumes and balanced injection and send-out capacities. However, these facilities are limited to a few countries in Europe.

Seasonal storage, often located in depleted gas reservoirs or aquifers, offers both short-term and seasonal flexibility. It provides crucial support especially in European countries without multicycle storage, allowing for both hourly and daily adjustments. Seasonal storage is crucial for addressing larger seasonal demand fluctuations, such as increased heating requirements in winter. These facilities typically have high working gas volumes and are designed to send out gas over thousands of hours. They often have higher send-out than injection capacities and operate on a single cycle yearly, making them cost-effective for seasonal but not frequent cycling.

15.3.2 Modelling demand for hydrogen flexibility

In the current model for some countries underground storages are modelled as caverns (identical injection and send out capacity and a relatively low working gas volume), whereas for other countries underground storages are modelled as depleted gas fields (relative low injection and a large working gas volume). In general caverns are more suitable for short term storage and depleted gas fields serve seasonable flexibility.

15.3.3 Hydrogen Flexibility

Several sources have been identified as potentially enhancing flexibility due to the simplifications employed. These include Steam Methane Reformers (SMR), efuels, Ammonia Imports, and Pipeline-imported H_2. For SMRs, many model inputs are derived from external sources, with additional assumptions made to account for technologies retrofitted to include Carbon Capture and Storage (CCS). However, no economic viability assessments have been conducted for these modifications, which may not have led to the adoption of CCS technology or decommissioning.

e-fuel production is characterised by spikes in production profile. Additional constraints are seen as necessary as these spikes may not reflect real world operation. The spikes are influenced by assumptions about the hydrogen market operating on a spot market basis, which is not a certainty.

As a conclusion, recognizing the above-mentioned limitations in modelling assumptions and their operational dynamics suggests that enhancing the role of hydrogen storage could provide a more realistic and robust solution for managing flexibility within the energy system. This shift will ensure that the asset base is equipped to handle the dynamics of the hydrogen system.

16 ELECTRICITY GENERATION TRAJECTORIES //

Electric generation can be supplied from a wide amount of energy sources. To meet European climate goals renewable energy sources are needed to reduce greenhouse gas emissions but the potential to produce varies from region to region.

Then TSOs were consulted to provide the minimum and maximum potential for each technology in their country based on national forecasts and NECPs. These values were commented on by stakeholders in a public consultation during summer 2023 and updated afterwards considering their feedback.

Trajectory values are considered during the building of scenarios including its technology cost to optimise the installed capacity in each scenario.

16.1 Solar Photovoltaic

Solar PV trajectories include data provided by TSOs and the information provided by stakeholders like Solar Power Europe Trajectories. The following figures show the range of installation for each country in 2040 and 2050.

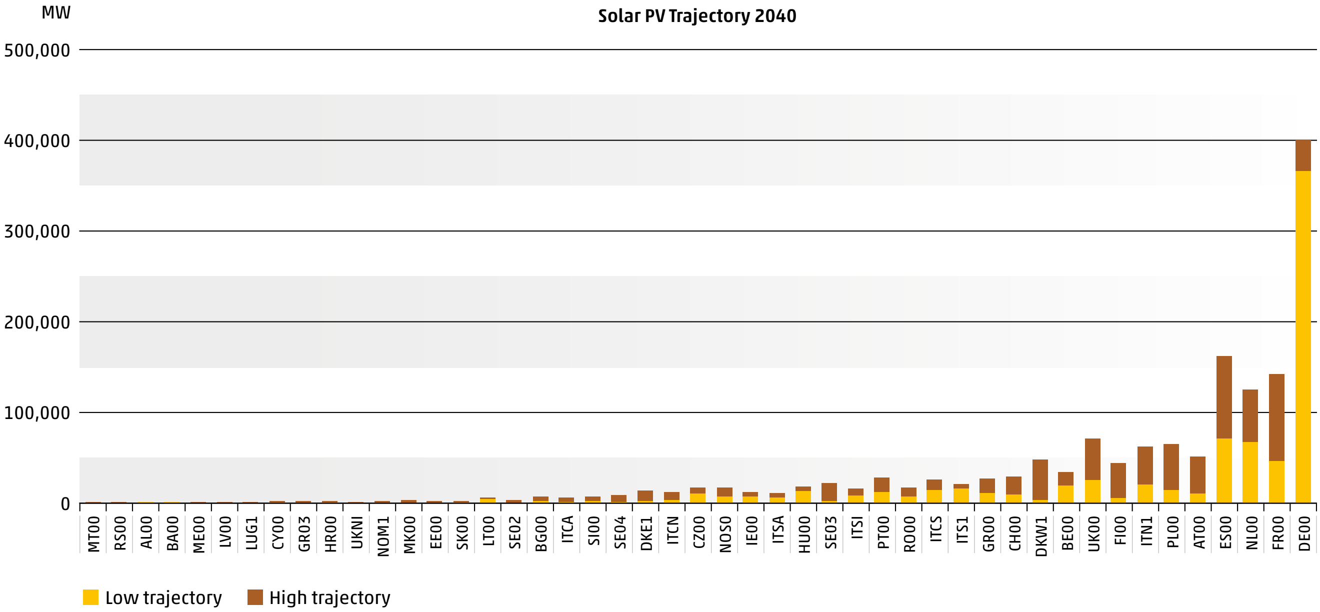


Figure 37: Solar PV Trajectory 2040

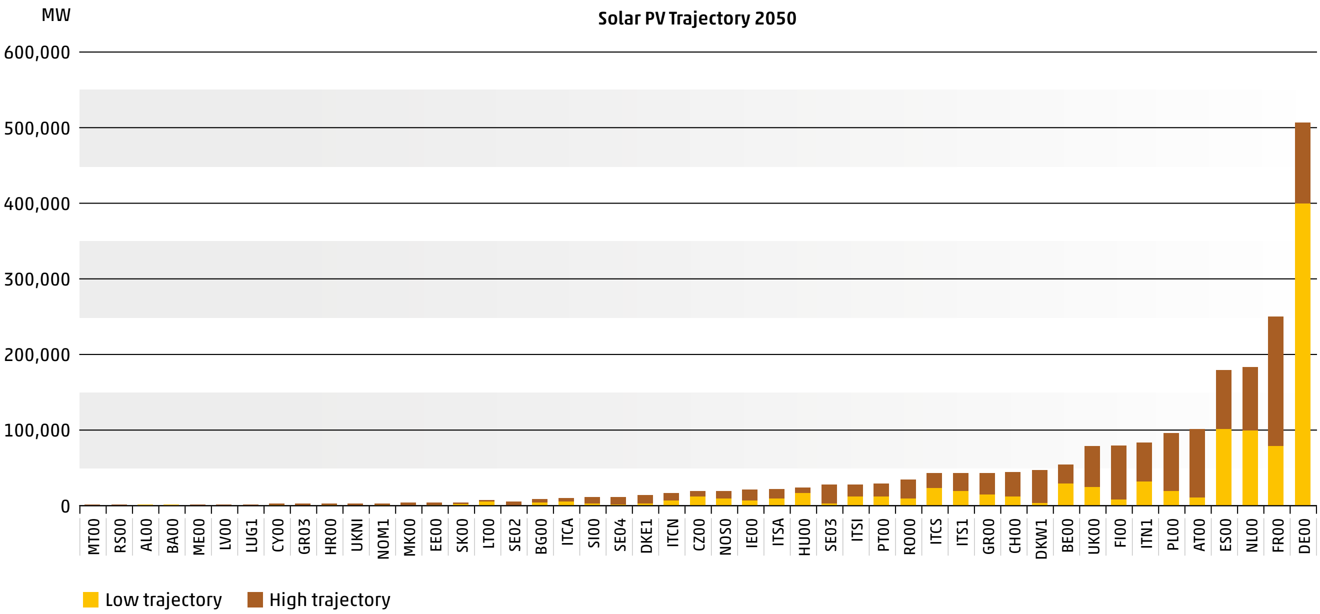


Figure 38: Solar PV Trajectory 2050

Total high potential in 2050 raises to almost 2,200 GW of installed power. Germany is the country with an ambitious trajectory of installation but also southern countries like Spain, Italy and France have big potentials and ranges of installation.

Solar PV trajectories are split in Utility Scale PV farms and Rooftop PV. The first one is directly connected to e-market while the second one is connected to the prosumer node. The amount assigned to each node is taken from the ratio provided by TSOs in the PEMMDB for 2030.

16.2 Wind Onshore

Like Solar PV, Wind Onshore potentials were provided by TSOs and then publicly consulted. The figures show the ranges for each country.

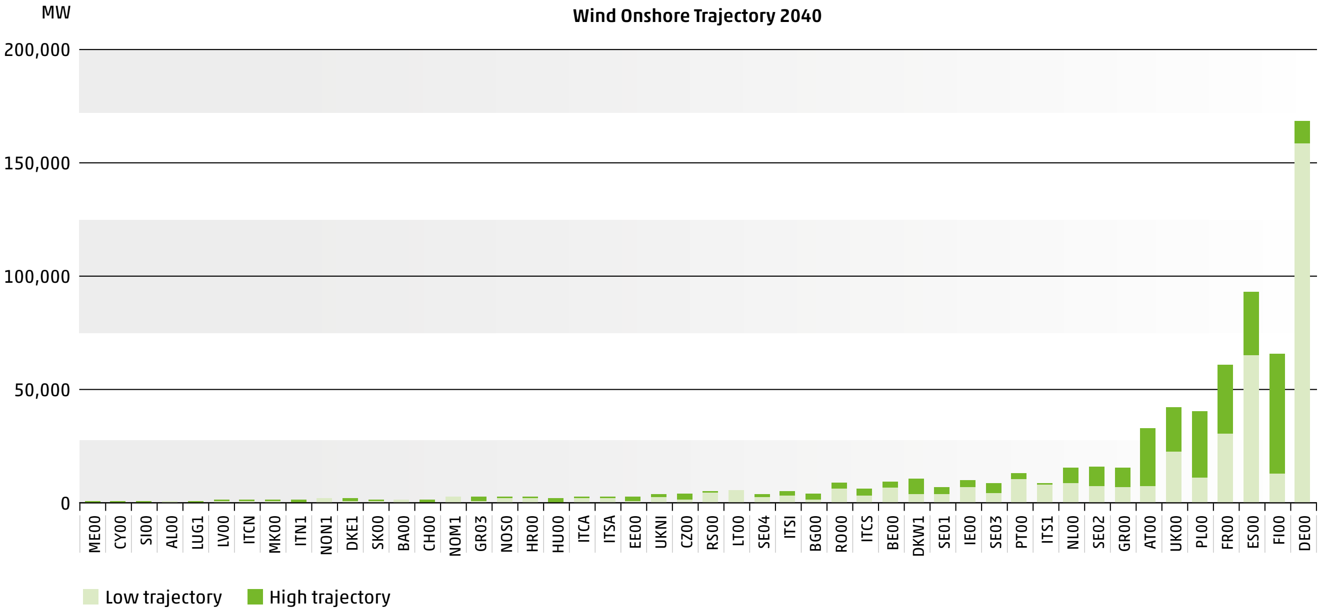


Figure 39: Wind Onshore Trajectory 2040

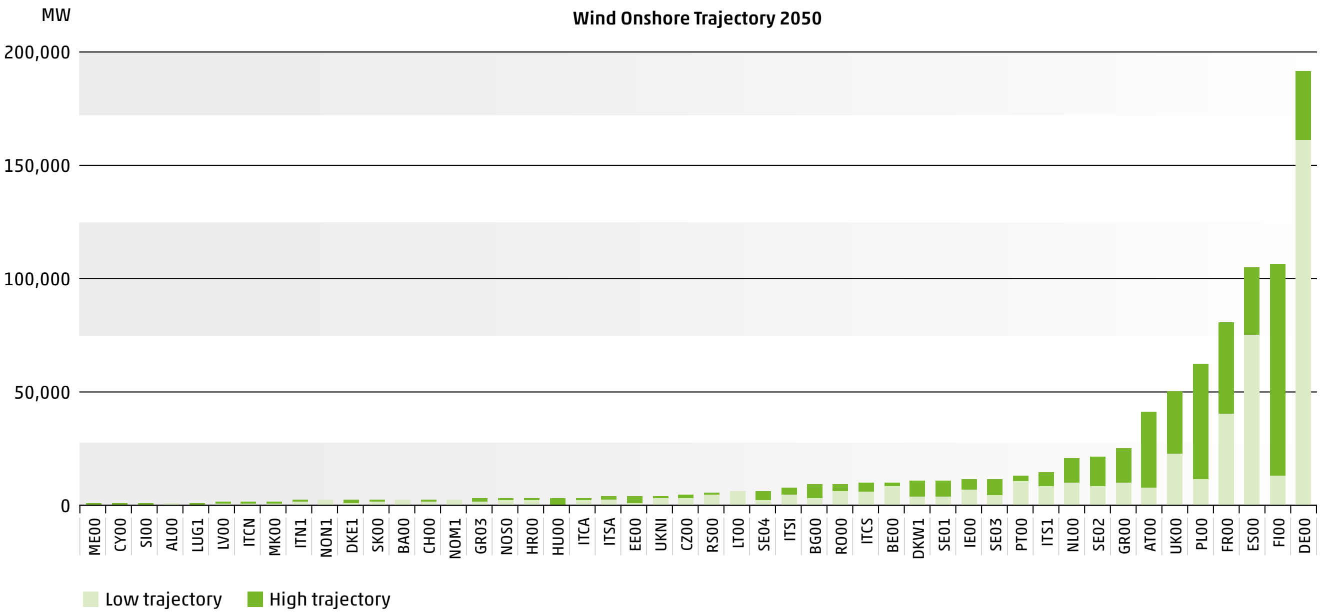


Figure 40: Wind Onshore Trajectory 2050

Provided potentials for Wind Onshore are lower that for PV. The maximum amount for 2050 is almost 900 GW. As for PV, Germany is the country with higher estimations and the higher ranges correspond to Finland, Poland, and France.

16.3 Wind Offshore

Wind Offshore data was divided by PECD regions, so each country has more than one region to consider the installation of wind offshore generation. To build the trajectories, TSO data was also used but it was complemented with ONDP process outcome that consider non-binding Member States agreements. ONDP data was used as the minimum potential and data from TSOs was used as the maximum of the range.

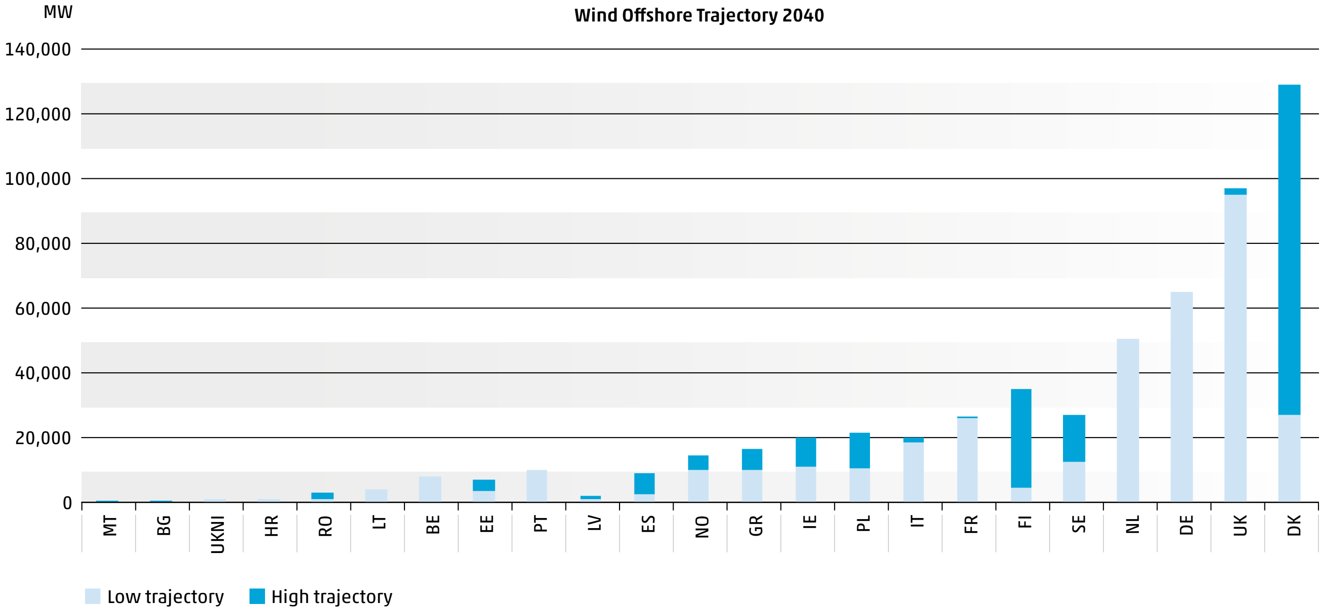


Figure 41: Wind Offshore Trajectory 2040

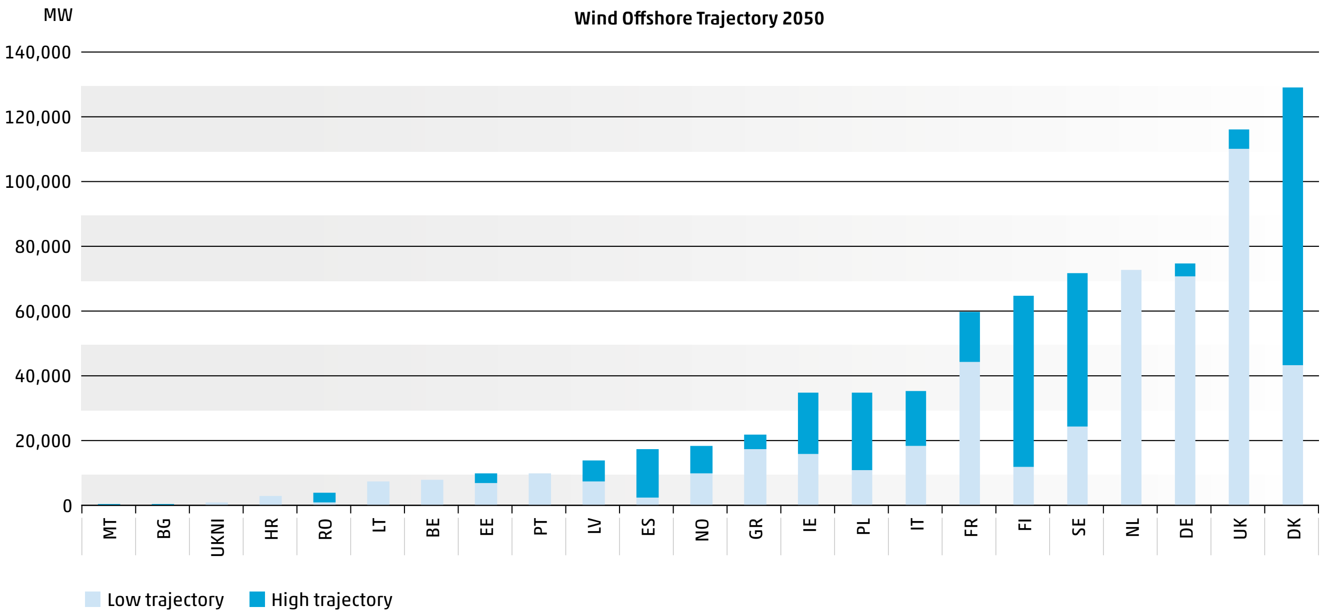


Figure 42: Wind Offshore Trajectory 2050

The total maximum potential is just slightly smaller than Wind Onshore maximum potential, namely around 800 GW. With Denmark having the greatest potential and the widest range of installation. Germany and the Netherlands also have a high potential with a narrow potential corridor. Other northern countries like Finland and Sweden also present high values in the trajectories.

16.4 Batteries

Battery trajectories were prepared based on TSOs data and feedback by EASE. As far as possible TSO data was used to build the trajectories. In those cases where TSO data was not detailed enough, a proportion with solar PV trajectories was used. This relationship was used because it was considered the best available indication of the trend to install batteries:

- If the trajectories for batteries were not available but the differentiation among utility scale and prosumer batteries was provided, the high value of the trajectory was escalated in the same proportion as the solar PV trajectory.
- If the differentiation between utility scale and prosumer was not provided, the value was split with the same proportion as the solar PV data.
- If no data was provided for batteries, mean value with geographical differentiation was used.

Considered duration is 2.5 hours for prosumer and 4 for utility scale batteries.

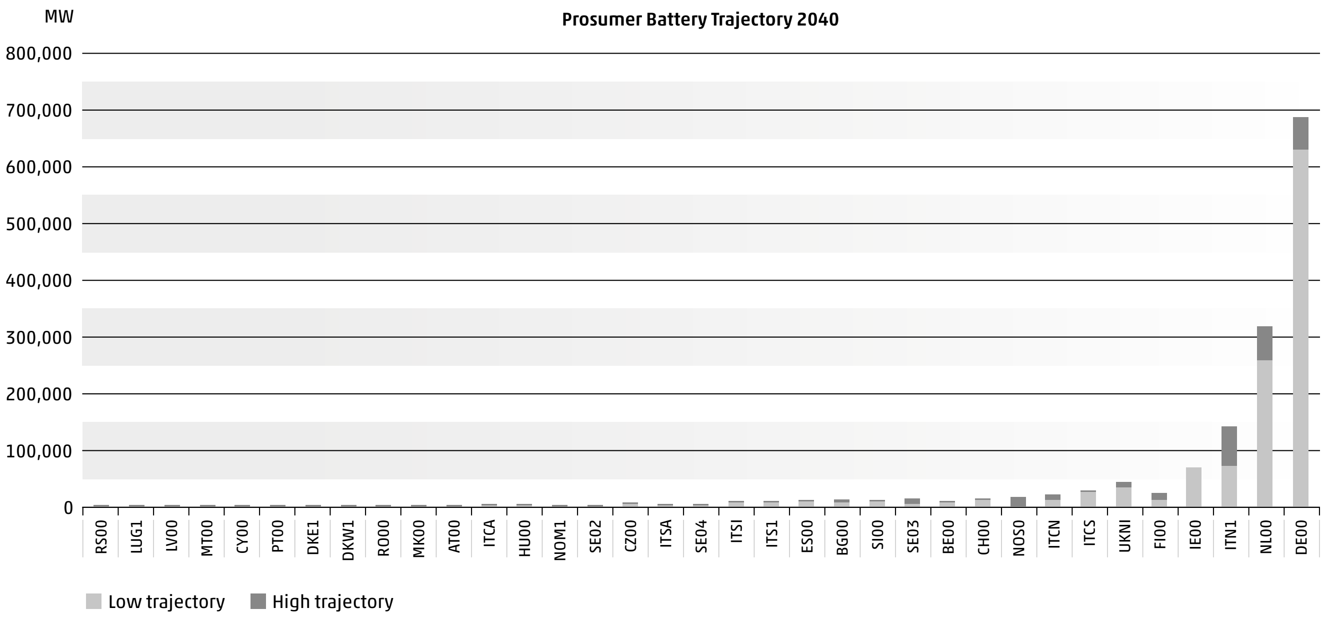


Figure 43: Prosumer Batteries Trajectory 2040

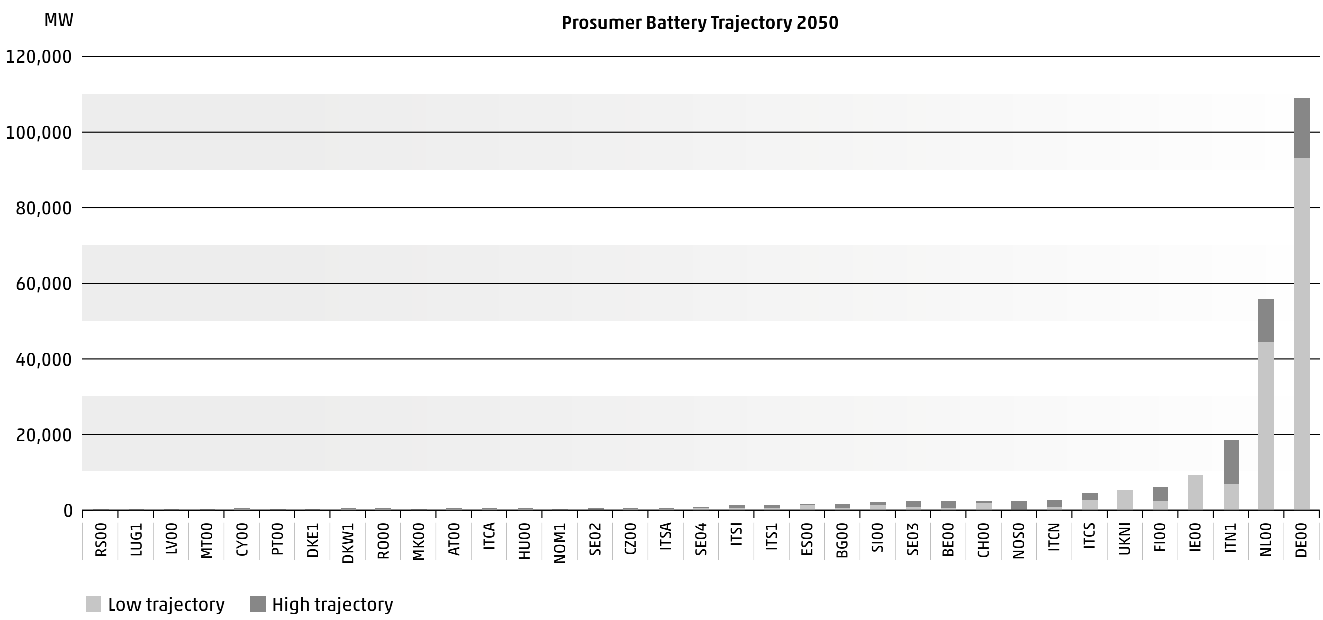


Figure 44: Prosumer Batteries Trajectory 2050

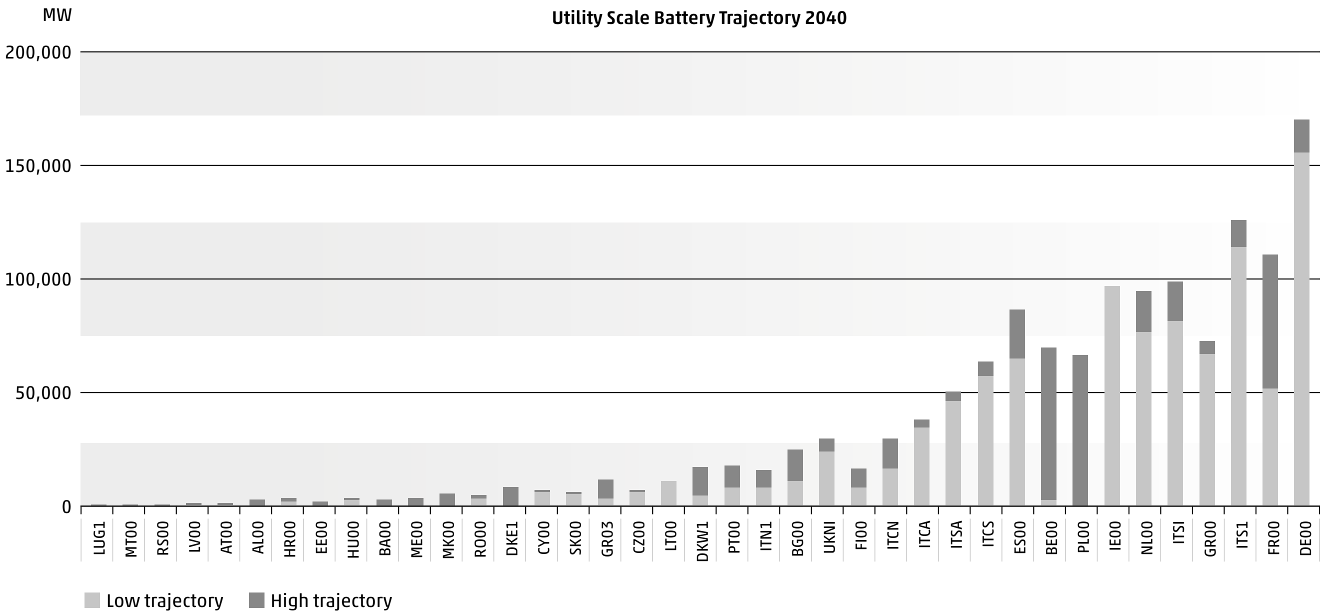


Figure 45: Utility Scale Batteries Trajectory 2040

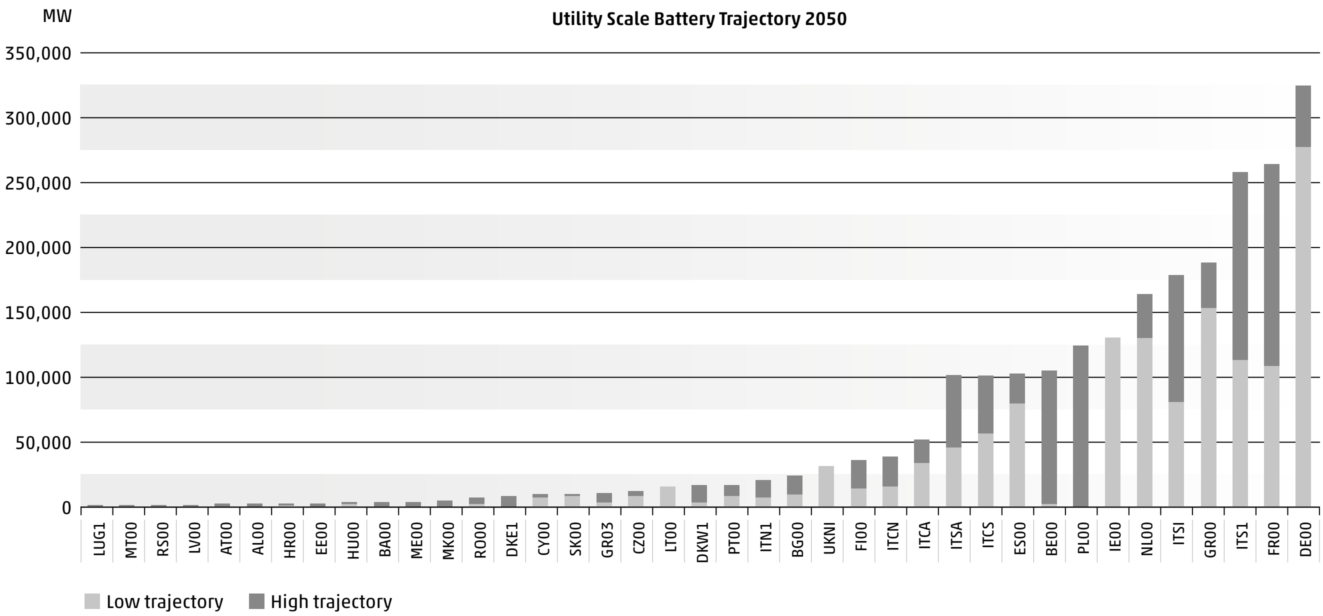


Figure 46: Utility Scale Batteries Trajectory 2050

As Germany was the country with higher forecasts of PV installation, so it has the higher trajectories for battery installation, both for prosumer batteries and utility scale batteries. For Utility Scale batteries, several other countries like France or Italy in many of its regions allow for a relevant installation of batteries. Total maximum amount across Europe is almost 500 GW of power.

ANNEXES //

ANNEX I: EV PROPERTIES //

Input parameters to the model are summarised in Table A01:

PARAMETER	VALUE					
NUMBER OF EVS	ETM values per country and Target Year					
CAPACITY (KWH/VEHICLE)		2030	2035	2040	2045	2050
	DE	60	72	83	92	100
	GA	60	66	72	81	90
EFFICIENCY (WH/KM)	DE	170				
	GA	200				
DEMAND (KM/VEHICLE)	ETM values per country and Target Year converted into hourly profiles based on REM2030					
EV MAX CHARGE/DISCHARGE RATE (KW/VEHICLE)	DE	7.4				
	GA	7.2				
CHARGE/DISCHARGE EFFICIENCY (%)	94					
USE OF SYSTEM CHARGE – PROSUMER (€/MWH)	30					
USE OF SYSTEM CHARGE – STREET (€/MWH)	35					
INITIAL STATE OF CHARGE (%)	50					
MINIMUM STATE OF CHARGE (%)	Profile					
PROSUMER CHARGER SHARE (%)	Availability profiles* based on ETM					
STREET CHARGER SHARE (%)						
%EVS THAT HAVE ACCESS TO PROSUMER CHARGING POINT (%)	70					
%EVS THAT HAVE ACCESS TO STREET CHARGING POINT (%)	30					
%V2G PROSUMER – VEHICLES THAT CAN PROVIDE V2G (%)		2030	2035	2040	2045	2050
	DE	30	35	40	45	50
	GA	15	17.5	20	22.5	25
%V2G STREET – VEHICLES THAT CAN PROVIDE V2G (%)		2030	2035	2040	2045	2050
	DE	0	5	10	15	20
	GA	0	2.5	5	7.5	10
CHARGE/DISCHARGE EFFICIENCY (%)	94					

Table A01: Input parameters to the model.

* The availability profile outline the share of vehicles which can be charged by a particular type of charging station. The share will be split between weekdays/weekends and by station type.

Minimum State of Charge profiles, developed within the Innovation Team, account for EV charging/discharging and driving behaviors on weekdays and weekends for every Target Year, offering insights into the system's dynamics.

Defined assumptions underpin the modelling process, providing clarity and coherence to the methodologies employed.

Assumptions on Utilisation and charging possibilities:

PROSUMER CHARGING VEHICLES	WEEKDAY	WEEKEND
1. Office workers (during the day)	**85 %**	**85 %**
1a. Office workers with charging + discharging available	10 %	0 %
1b. Office workers with (only) charging available	40 %	10 %
1c. Office workers without charging available	40 %	10 %
1d. Office workers on holidays (average, including part time)	10 %	80 %
2. Night workers	**15 %**	**15 %**
2a. Night workers with charging + discharging available	10 %	0 %
2b. Night workers with (only) charging available	10 %	0 %
2c. Night workers without charging available	65 %	20 %
2d. Night workers on holidays (average, including part time)	15 %	80 %
STREET CHARGING VEHICLES	**WEEKDAY**	**WEEKEND**
3. Office workers (during the day)	**80 %**	**80 %**
3a. Office workers with charging + discharging available	10 %	0 %
3b. Office workers with (only) charging available	40 %	10 %
3c. Office workers without charging available	40 %	10 %
3d. Office workers on holidays (average, including part time)	10 %	90 %
4. Night workers	**20 %**	**20 %**
4a. Night workers with charging + discharging available	10 %	0 %
4b. Night workers with (only) charging available	10 %	0 %
4c. Night workers without charging available	65 %	20 %
4d. Night workers on holidays (average, including part time)	15 %	80 %

Table A02: Assumptions on Utilisation and charging possibilities.

As a result, the following Minimum State of Charge profiles have been generated:

2030	MIN 25 % CHARGED					
HOME CHARGING VEHICLES				STREET CHARGING VEHICLES		
HOUR	WEEKDAY	WEEKEND		HOUR	WEEKDAY	WEEKEND
0	26 %	25 %		0	37 %	30 %
1	26 %	25 %		1	37 %	30 %
2	26 %	25 %		2	37 %	30 %
3	26 %	25 %		3	37 %	30 %
4	26 %	25 %		4	37 %	30 %
5	26 %	25 %		5	37 %	30 %
6	38 %	28 %		6	37 %	30 %
7	38 %	28 %		7	37 %	30 %
8	38 %	28 %		8	37 %	30 %
9	30 %	26 %		9	37 %	30 %
10	30 %	26 %		10	30 %	28 %
11	28 %	26 %		11	31 %	29 %
12	28 %	26 %		12	31 %	29 %
13	28 %	26 %		13	31 %	29 %
14	28 %	26 %		14	31 %	29 %
15	28 %	26 %		15	31 %	29 %
16	33 %	27 %		16	35 %	29 %
17	33 %	27 %		17	35 %	29 %
18	33 %	27 %		18	35 %	29 %
19	33 %	27 %		19	35 %	29 %
20	25 %	25 %		20	35 %	29 %
21	27 %	26 %		21	39 %	30 %
22	27 %	26 %		22	39 %	30 %
23	27 %	26 %		23	39 %	30 %

Table A03: Minimum State of Charge profiles (2030).

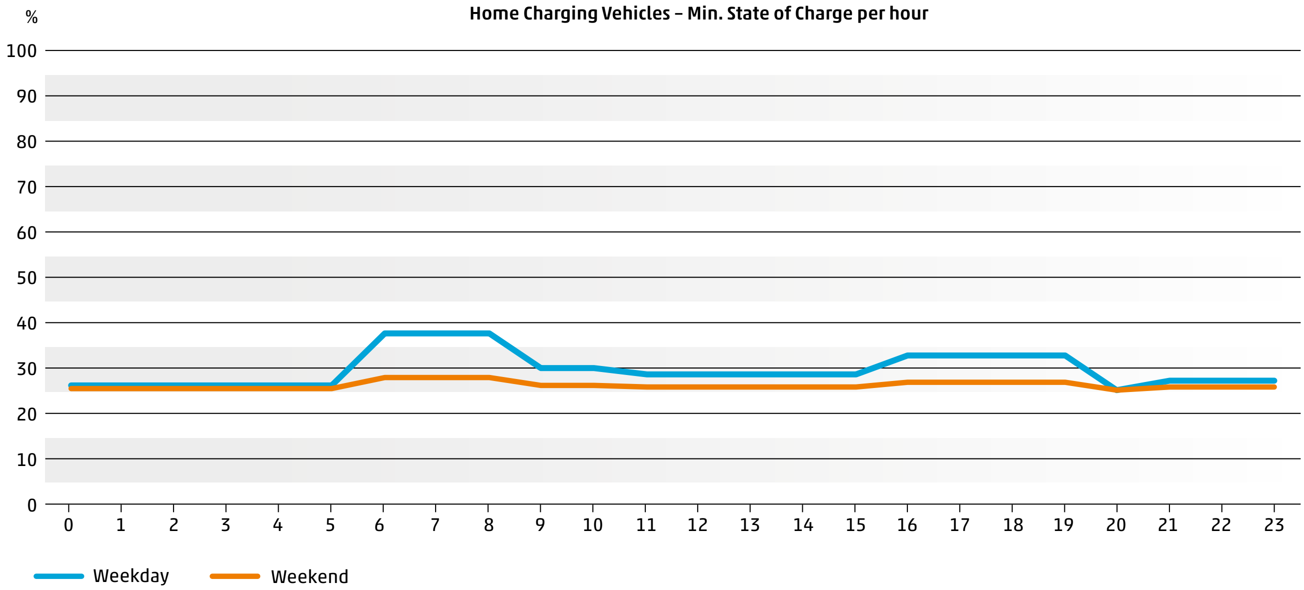


Figure A01: Home Charging Vehicles (2030)

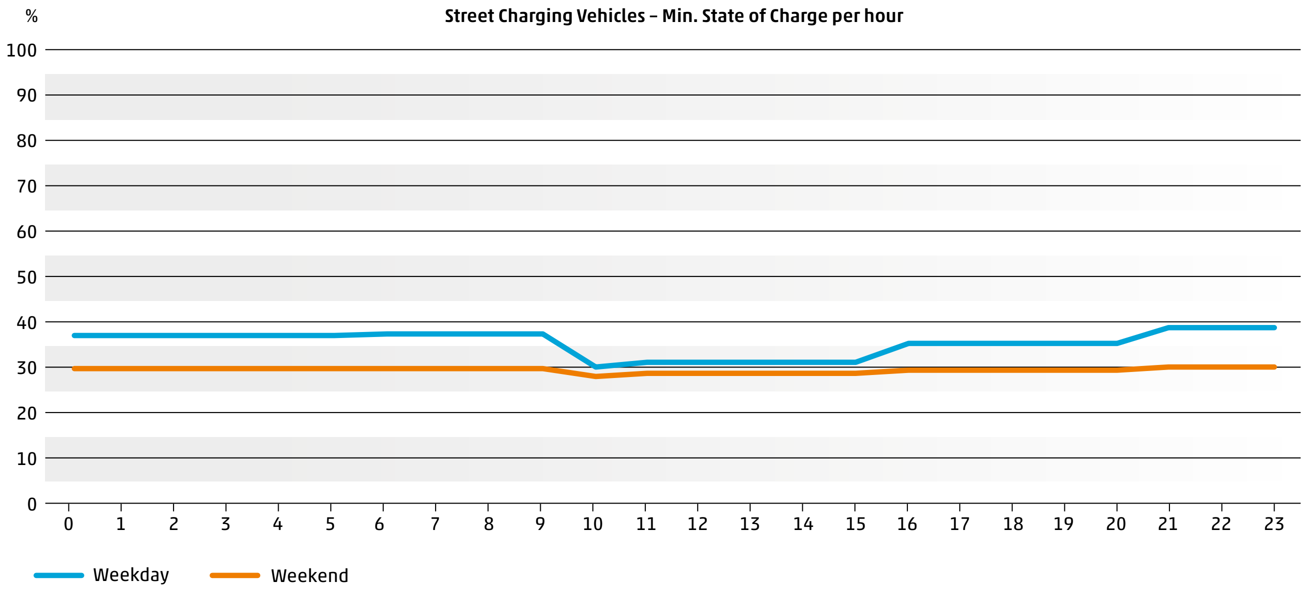


Figure A02: Street Charging Vehicles (2030)

2040	MIN 20 % CHARGED					
HOME CHARGING VEHICLES				**STREET CHARGING VEHICLES**		
HOUR	**WEEKDAY**	**WEEKEND**		**HOUR**	**WEEKDAY**	**WEEKEND**
0	21 %	20 %		0	32 %	24 %
1	21 %	20 %		1	32 %	24 %
2	21 %	20 %		2	32 %	24 %
3	21 %	20 %		3	32 %	24 %
4	21 %	20 %		4	32 %	24 %
5	21 %	20 %		5	32 %	24 %
6	33 %	23 %		6	32 %	24 %
7	33 %	23 %		7	32 %	24 %
8	33 %	23 %		8	32 %	24 %
9	25 %	21 %		9	32 %	24 %
10	25 %	21 %		10	25 %	23 %
11	23 %	21 %		11	26 %	23 %
12	23 %	21 %		12	26 %	23 %
13	23 %	21 %		13	26 %	23 %
14	23 %	21 %		14	26 %	23 %
15	23 %	21 %		15	26 %	23 %
16	28 %	22 %		16	30 %	24 %
17	28 %	22 %		17	30 %	24 %
18	28 %	22 %		18	30 %	24 %
19	28 %	22 %		19	30 %	24 %
20	20 %	20 %		20	30 %	24 %
21	22 %	21 %		21	34 %	25 %
22	22 %	21 %		22	34 %	25 %
23	22 %	21 %		23	34 %	25 %

Table A04: Minimum State of Charge profiles (2040).

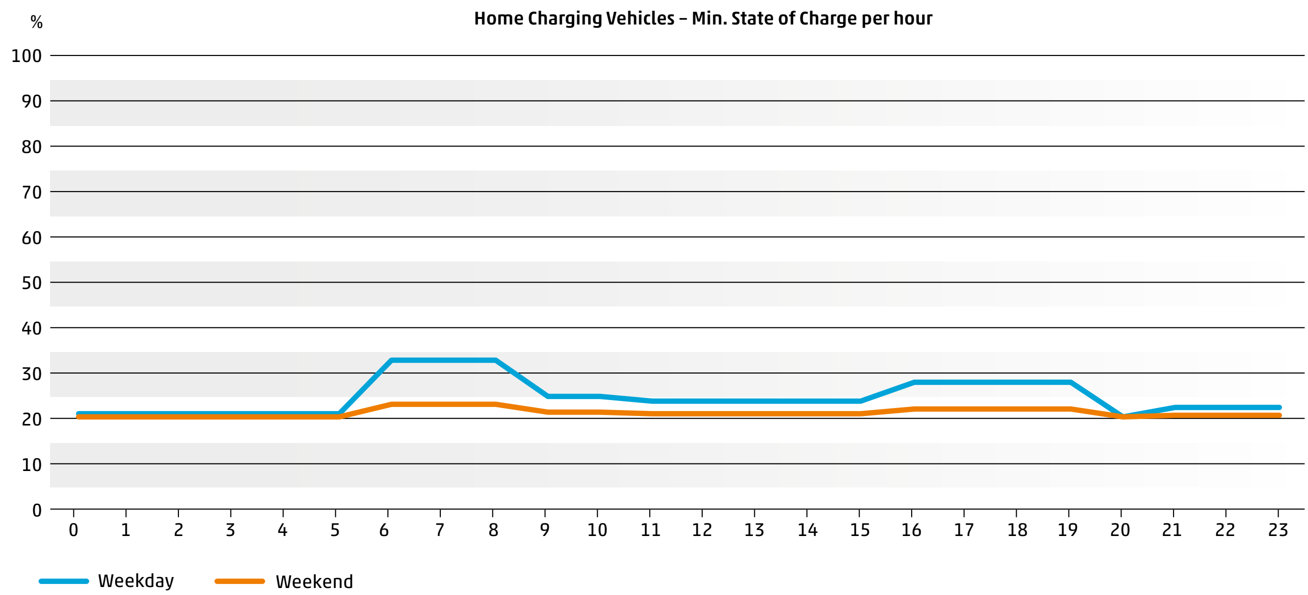


Figure A03: Home Charging Vehicles (2040)

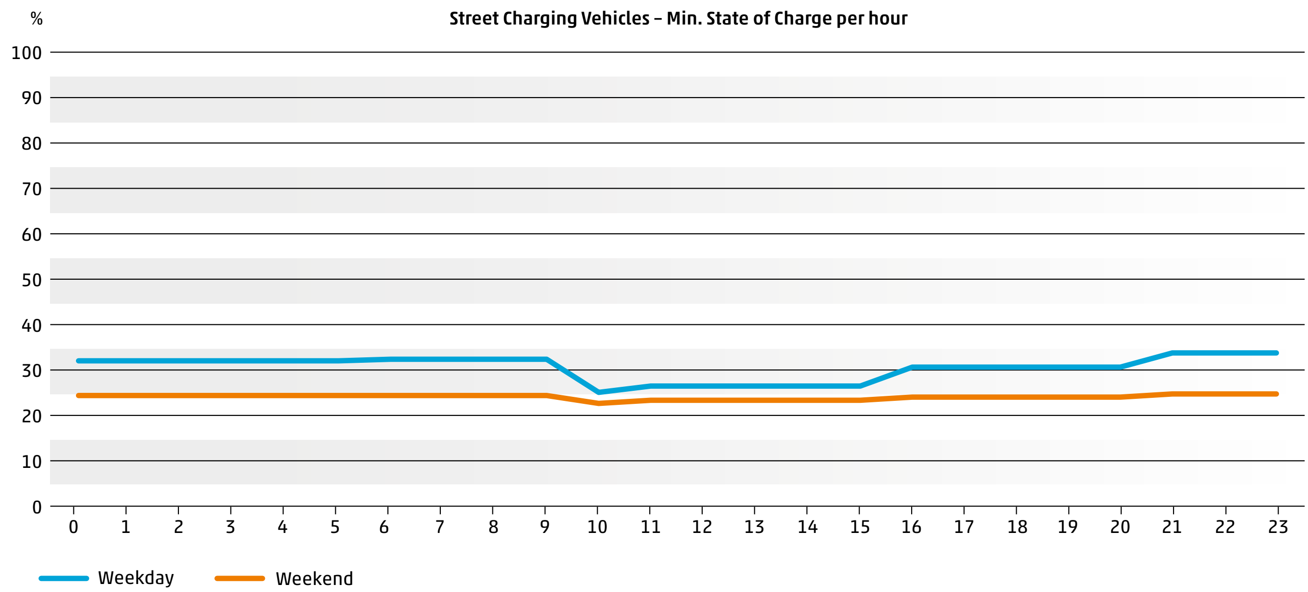


Figure A04: Street Charging Vehicles (2040)

2050	RATIONAL BEHAVIOUR					
HOME CHARGING VEHICLES				STREET CHARGING VEHICLES		
HOUR	WEEKDAY	WEEKEND		HOUR	WEEKDAY	WEEKEND
0	7 %	7 %		0	23 %	22 %
1	7 %	7 %		1	23 %	22 %
2	7 %	7 %		2	23 %	22 %
3	7 %	7 %		3	23 %	22 %
4	7 %	7 %		4	23 %	22 %
5	7 %	7 %		5	23 %	22 %
6	24 %	21 %		6	24 %	22 %
7	24 %	21 %		7	24 %	22 %
8	24 %	21 %		8	24 %	22 %
9	14 %	19 %		9	24 %	22 %
10	14 %	19 %		10	14 %	20 %
11	11 %	16 %		11	15 %	21 %
12	11 %	16 %		12	15 %	21 %
13	11 %	16 %		13	15 %	21 %
14	11 %	16 %		14	15 %	21 %
15	11 %	16 %		15	15 %	21 %
16	18 %	18 %		16	22 %	22 %
17	18 %	18 %		17	22 %	22 %
18	18 %	18 %		18	22 %	22 %
19	18 %	18 %		19	22 %	22 %
20	5 %	5 %		20	22 %	22 %
21	8 %	8 %		21	25 %	23 %
22	8 %	8 %		22	25 %	23 %
23	8 %	8 %		23	25 %	23 %

Table A05: Minimum State of Charge profiles (2050).

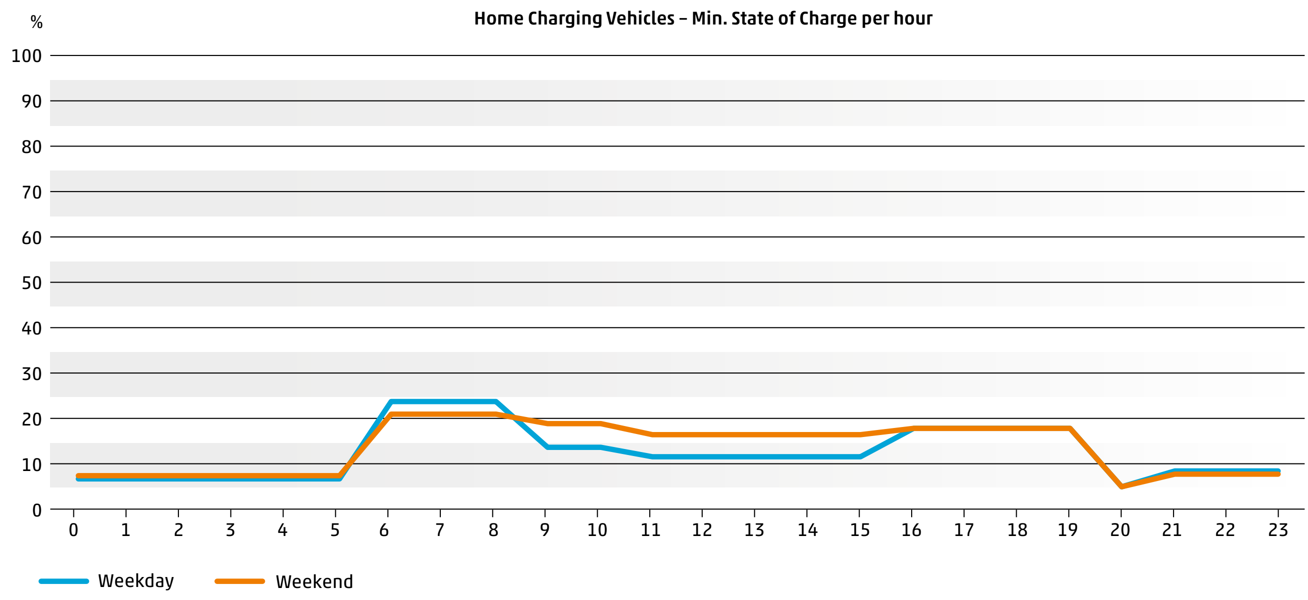


Figure A05: Home Charging Vehicles (2050)

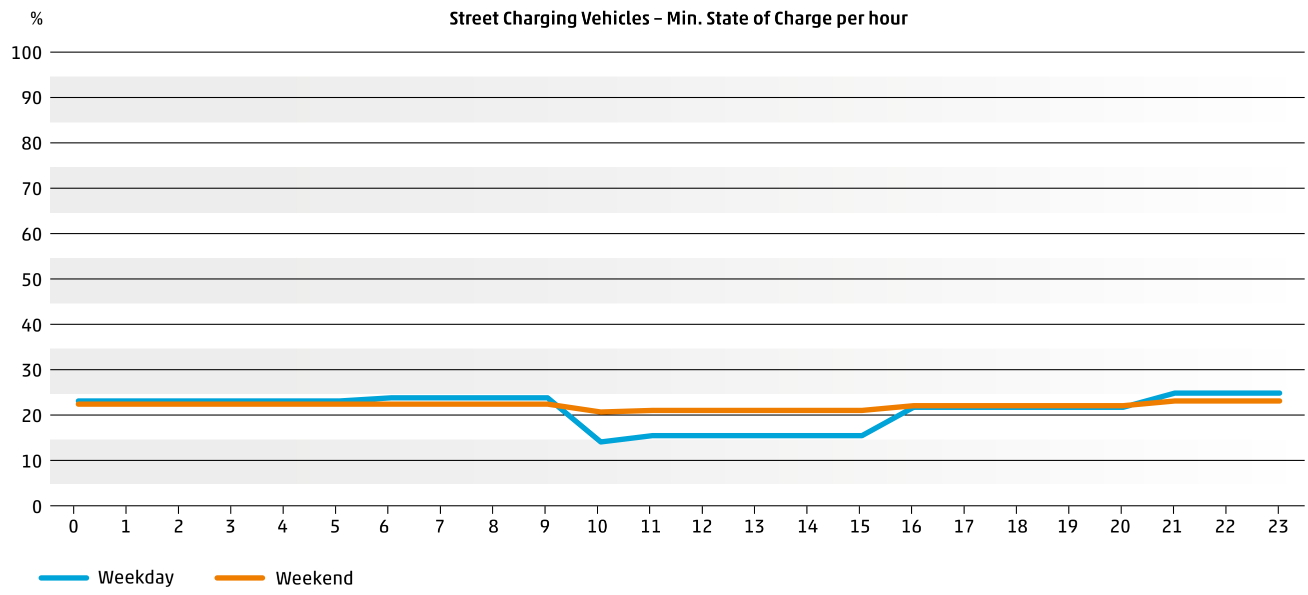


Figure A06: Street Charging Vehicles (2050)

ANNEX II: INVESTMENT COSTS //

NO		YEAR		2030	2040	2050
1	**ROOFTOP PV (ONLY RESIDENTIAL)**	CAPEX	€/MW	720,000	580,000	520,000
		OPEX	€/MW/a	10,700	9,600	8,900
2	**UTILITY-SCALE PV**	CAPEX	€/MW	380,000	330,000	290,000
		OPEX	€/MW/a	9,500	8,100	7,400
3	**UTILITY-SCALE PV GROUND MOUNTED SINGLE AXIS TRACKING**	CAPEX	€/MW	450,000	390,000	350,000
		OPEX	€/MW/a	10,400	9,400	9,000
4	**UTILITY-SCALE BATTERY STORAGE – 4 HR**	CAPEX	€/MW	716,480	627,122	537,562
		OPEX	€/MW/a	17,912	15,678	13,439
5	**RESIDENTIAL BATTERY STORAGE – 5 KW – 12.5 KWh**	CAPEX	€/MW	1,731,283	1,515,143	1,298,463
		OPEX	€/MW/a	43,282	37,879	32,462
6	**ONSHORE WIND**	CAPEX	€/MW	1,040,000	990,000	970,000
		OPEX	€/MW/a	12,600	11,592	11,340
7	**AC RADIAL WIND OFFSHORE FIXED**	CAPEX	€/MW	1,800,000	1,650,000	1,640,000
		OPEX	€/MW/a	58,000	51,000	49,000
8	**DC RADIAL WIND OFFSHORE FIXED**	CAPEX	€/MW	2,470,000	2,310 000	2,290,000
		OPEX	€/MW/a	73,000	66,000	64,000
9	**HUB CONNECTED WIND OFFSHORE FIXED**	CAPEX	€/MW	2,060,000	1,900,000	1,880,000
		OPEX	€/MW/a	65,000	58,000	56,000
10	**HUB CONNECTED WIND OFFSHORE H_2 FIXED**	CAPEX	€/MW	2,310,000	2,000,000	1,900 000
		OPEX	€/MW/a	93,000	78,000	73,000
11	**AC RADIAL WIND OFFSHORE FLOATING**	CAPEX	€/MW	2,898 000	1,996,500	1,902,400
		OPEX	€/MW/a	87,000	61,200	53,900
12	**DC RADIAL WIND OFFSHORE FLOATING**	CAPEX	€/MW	3,976,700	2,795,100	2,656,400
		OPEX	€/MW/a	109,500	79,200	70,400
13	**HUB CONNECTED WIND OFFSHORE FLOATING**	CAPEX	€/MW	3,316 600	2,299,000	2,180,800
		OPEX	€/MW/a	97,500	69,600	61,600
14	**HUB CONNECTED WIND OFFSHORE H_2 FLOATING**	CAPEX	€/MW	3,719,100	2,420,000	2,204,000
		OPEX	€/MW/a	139,500	93,600	80,300
15	**HVDC CABLES**	CAPEX	€/MW/km	1,617,50	1,617,50	1,617,50
		OPEX	€/MW/km/a	40,44	40,44	40,44
16	**ONSHORE HVDC STATION**	CAPEX	€/MW	250,000	250,000	250,000
		OPEX	€/MW/a	0	0	0
17	**ELECTROLYSIS OFFSHORE**	CAPEX	€/MW	850,000	680,000	630,000
		OPEX	€/MW/a	18,000	15,000	14,000
18	**H_2-PIPELINE**	CAPEX	€/MW/km	528,57	528,57	528,57
		OPEX	€/MW/km/a	1,66	1,66	1,66

NO		YEAR		2030	2040	2050
19	**ELECTROLYSIS ONSHORE**	CAPEX	€/MW	550,000	375,000	325,000
		OPEX	€/MW/a	17,500	12,000	10,500
20	**GAS TURBINE, OPEN CYCLE – BACK PRESSURE – NATURAL GAS – MEDIUM**	CAPEX	€/MW	440,000	425,000	410,000
		OPEX	€/MW/a	7,745	7,584	7,423
21	**GAS TURBINE COMBINED CYCLE – EXTRACTION – NATURAL GAS – LARGE**	CAPEX	€/MW	830,000	815,000	800,000
		OPEX	€/MW/a	27,800	26,900	26,000

			DISTRIBUTE DISTRIBUTED ENERGY			GLOBAL AMBITION		
	YEAR		2030	2040	2050	2030	2040	2050
ROOFTOP PV (ONLY RESIDENTIAL)	CAPEX	€/MW	712,800	493,000	416,000	727,200	667,000	624,000
	OPEX	€/MW/a	10,593	8,160	7,120	10,807	11,040	10,680
UTILITY-SCALE PV	CAPEX	€/MW	376,200	280,500	232,000	383,800	379,500	348,000
	OPEX	€/MW/a	9,405	6,885	5,920	9,595	9,315	8,880
UTILITY-SCALE PV GROUND MOUNTED SINGLE AXIS TRACKING	CAPEX	€/MW	445,500	331,500	280,000	454,500	448,500	420,000
	OPEX	€/MW/a	10,296	7,990	7,200	10,504	10,810	10,800
UTILITY-SCALE BATTERY STORAGE – 4 HR	CAPEX	€/MW	709,315	533,054	430,050	723,645	721,190	645,074
	OPEX	€/MW/a	17,733	13,326	10,751	18,091	18,030	16,127
RESIDENTIAL BATTERY STORAGE – 5 KW – 12.5 KWh	CAPEX	€/MW	1,713,970	1,287,872	1,038,770	1,748,596	1,742,414	1,558,156
	OPEX	€/MW/a	42,849	32,197	25,970	43,715	43,561	38,954
ONSHORE WIND	CAPEX	€/MW	1,029,600	955,350	920,100	1,050,400	1,024,650	1,019,900
	OPEX	€/MW/a	12,474	11,186	10,757	12,726	11,998	11,923
AC RADIAL WIND OFFSHORE FIXED	CAPEX	€/MW	1,818,000	1,809,750	1,801,600	1,782,000	1,490,250	1,478,400
	OPEX	€/MW/a	58,580	55,938	53,828	57,420	46,062	44,172
DC RADIAL WIND OFFSHORE FIXED	CAPEX	€/MW	2,494,700	2,483,150	2,471,800	2,445,300	2,136,850	2,108,200
	OPEX	€/MW/a	73,730	70,947	69,081	72,270	61,053	58,919
HUB CONNECTED WIND OFFSHORE FIXED	CAPEX	€/MW	2,080,600	2,071,100	2,061,800	2,039,400	1,728,900	1,698,200
	OPEX	€/MW/a	65,650	63,223	61,415	64,350	52,777	50,585
HUB CONNECTED WIND OFFSHORE H_2 FIXED	CAPEX	€/MW	2,333,100	2,300,000	2,280,000	2,286,900	1,700,000	1,520,000
	OPEX	€/MW/a	93,930	89,700	87,600	92,070	66,300	58,400
AC RADIAL WIND OFFSHORE FLOATING	CAPEX	€/MW	2,926,980	2,295,975	2,282,880	2,869,020	1,697,025	1,521,920
	OPEX	€/MW/a	87,870	70,380	64,680	86,130	52,020	43,120
DC RADIAL WIND OFFSHORE FLOATING	CAPEX	€/MW	4,016,467	3,214,365	3,187,680	3,936,933	2,375,835	2,125,120
	OPEX	€/MW/a	110,595	91,080	84,480	108,405	67,320	56,320
HUB CONNECTED WIND OFFSHORE FLOATING	CAPEX	€/MW	3,349,766	2,643,850	2,616,960	3,283,434	1,954,150	1,744,640
	OPEX	€/MW/a	98,475	80,040	73,920	96,525	59,160	49,280
HUB CONNECTED WIND OFFSHORE H_2 FLOATING	CAPEX	€/MW	3,756291	2,783,000	2,644,800	3,681,909	2,057,000	1,763,200
	OPEX	€/MW/a	140,895	107,640	96,360	138,105	79,560	64,240

Table A05: OPEX and CAPEX costs for market capacties (for level 1 capacity potential. Capacity potential available at the reference cost as defined under the Investment candidate chapter)

For Distributed Energy and Global Ambition scenarios, CAPEX of wind and solar directly connected to Electrolyser have been discounted to picture the saving on electricity grid connection[1]. The reduction on CAPEX is as follow:

- Onshore wind: 50 €/kW
- Offshore wind: 245 €/kW
- Solar PV: 10 €/kW

The following table provides the resulting costs.

			2030	2040	2050	2030	2040	2050
			DISTRIBUTED ENERGY			GLOBAL AMBITION		
UTILITY-SCALE PV	CAPEX	€/MW	366,200	270.500	222.000	373,800	369,500	338,000
	OPEX	€/MW/a	9,405	6.885	5,920	9,595	9,315	8,880
ONSHORE WIND	CAPEX	€/MW	979,600	905,350	870,100	1,000 400	974,650	969,900
	OPEX	€/MW/a	12,474	11,186	10,757	12,726	11,998	11,923
AC RADIAL WIND OFFSHORE FIXED	CAPEX	€/MW	1,573,000	1,564,750	1,556,600	1,537,000	1,245,250	1,233,400
	OPEX	€/MW/a	58,580	55,938	53,828	57,420	46,062	44,172
DC RADIAL WIND OFFSHORE FIXED	CAPEX	€/MW	2,249,700	2,238,150	2,226,800	2,200,300	1,891,850	1,863,200
	OPEX	€/MW/a	73,730	70,947	69,081	72,270	61,053	58,919
HUB CONNECTED WIND OFFSHORE FIXED	CAPEX	€/MW	1,835,600	1,826,100	1,816,800	1,794,400	1,483,900	1,453,200
	OPEX	€/MW/a	65,650	63,223	61,415	64,350	52,777	50,585
HUB CONNECTED WIND OFFSHORE H_2 FIXED	CAPEX	€/MW	2,088,100	2,055,000	2,035,000	2,041,900	1,455,000	1,275,000
	OPEX	€/MW/a	93,930	89,700	87,600	92,070	66,300	58,400
AC RADIAL WIND OFFSHORE FLOATING	CAPEX	€/MW	2,681 980	2,050,975	2,037,880	2,624,020	1,452,025	1,276,920
	OPEX	€/MW/a	87,870	70,380	64,680	86,130	52,020	43,120
DC RADIAL WIND OFFSHORE FLOATING	CAPEX	€/MW	3,771,467	2,969,365	2,942,680	3,691,933	2,130,835	1,880,120
	OPEX	€/MW/a	110,595	91,080	84,480	108,405	67,320	56,320
HUB CONNECTED WIND OFFSHORE FLOATING	CAPEX	€/MW	3,104,766	2,398,850	2,371,960	3,038,434	1,709,150	1,499,640
	OPEX	€/MW/a	98,475	80,040	73,920	96,525	59,160	49,280
HUB CONNECTED WIND OFFSHORE H_2 FLOATING*	CAPEX	€/MW	3,511 291	2,538,000	2,399,800	3,436,909	1,812,000	1,518,200
	OPEX	€/MW/a	140,895	107,640	96,360	138,105	79,560	64,240

Table A06: OPEX and CAPEX costs for dedicated res (for level 1 capacity potential. Capacity potential available at the reference cost as defined under the Investment candidate chapter)

1 See here

Hydrogen Grid Costs

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
AT-IT	AT	IT	2030	All	3,875	0	215.29
AT-SI	AT	SI	2030	All	1,375	667	92.94
AT-SK	AT	SK	2030	All	500	500	21.59
BE-FR	BE	FR	2030	All	3,833	3,833	170.99
BE-LU	BE	LU	2030	All	583	583	50.35
BE-NL	BE	NL	2030	All	6,000	6,000	50.79
BE-UK	BE	UK	2030	All	8,333	8,333	130.48
BG-RO	BG	RO	2030	All	3,875	3,875	126.24
HR-HU	HR	HU	2030	All	5,350	5,350	90.58
HR-SI	HR	SI	2030	All	667	1,375	36.04
CZ-PL	CZ	PL	2030	All	1,250	1,250	87.30
CZ-SK	CZ	SK	2030	All	6,500	500	91.18
DK-DE	DK	DE	2030	All	7,900	7,900	155.21
EE-FI	EE	FI	2030	All	4,167	0	16.72
FI-SE	FI	SE	2030	All	10,167	10,167	196.51
FR-CH	FR	CH	2030	All	4,167	4,167	119.08
FR-DE	FR	DE	2030	All	1,625	2,125	244.93
DE-CH	DE	CH	2030	All	7,000	7,000	256.89
DE-NL	DE	NL	2030	All	15,333	208	219.08
DE-PL	DE	PL	2030	All	833	0	109.96
HU-RO	HU	RO	2030	All	3,200	3,200	278.58
HU-SI	HU	SI	2030	All	817	817	114.90
HU-SK	HU	SK	2030	All	4,167	4,167	40.98
IE-UK	IE	UK	2030	All	331	331	56.60
IT-SI	IT	SI	2030	All	817	817	148.16
LT-LV	LT	LV	2030	All	3,733	0	132.21
ES-FR	ES	FR	2030	All	3,000	3,000	545.00
PL-LT	PL	LT	2030	All	2,980	0	158.31
ES-FR	ES	FR	2040	All	3,000	3,000	545.00
BE-DE	BE	DE	2040	All	1,208	1,208	53.72
BE-LU	BE	LU	2040	All	250	250	21.59
BE-NL	BE	NL	2040	All	2,000	2,000	46.77
BG-GR	BG	GR	2040	All	335	521	99.19
BG-RO	BG	RO	2040	All	1,196	1,196	106.68
CZ-DE	CZ	DE	2040	All	7,300	7,300	100.02
DE-CH	DE	CH	2040	All	3,000	3,000	304.15
DE-NL	DE	NL	2040	All	7,467	7,458	106.69
DE-PL	DE	PL	2040	All	4,464	1,131	77.91
IE-UK	IE	UK	2040	All	858	858	146.71
LV-EE	LV	EE	2040	All	1,115	0	484.19

Table A07: Hydrogen pipeline investment candidates

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
AT00-ITN1 REAL 1	AT00	ITN1	2035	All	500	500	175
AT00-ITN1 REAL 2	AT00	ITN1	2040	All	150	150	148.18
AT00-SI00 REAL 1	AT00	SI00	2035	All	500	500	316.7
BE00-DE00 REAL 1	BE00	DE00	2040	All	1,000	1,000	964
BE00-FR00 REAL 1	BE00	FR00	2030	All	1,000	1,000	150
BE00-LUG1 REAL 1	BE00	LUG1	2040	All	500	500	210
BE00-NL00 REAL 1	BE00	NL00	2035	All	1,000	1,000	1,090
BE00-NL00 REAL 2	BE00	NL00	2035	All	1,000	1,000	94
BE00-UK00 REAL 1	BE00	UK00	2035	All	1,400	1,400	1,649
BG00-TR00 REAL 1	BG00	TR00	2040	All	1,100	700	60
CH00-DE00 REAL 1	CH00	DE00	2035	All	200	0	290.22
CH00-DE00 REAL 2	CH00	DE00	2035	All	100	600	86
DE00-CH00 REAL 1	DE00	CH00	2040	All	1,000	1,000	1,096
CH00-ITN1 REAL 1	CH00	ITN1	2035	All	1,000	1,000	1,289
DE00-NL00 REAL 1	DE00	NL00	2035	All	1,000	1,000	200
DKW1-UK00 REAL 1	DKW1	UK00	2035	All	1,400	1,400	1,471
ES00-FR00 REAL 1	ES00	FR00	2030	All	1,500	1,500	1,221
ES00-FR00 REAL 2	ES00	FR00	2030	All	1,500	1,500	1,554
FR00-UK00 REAL 1	FR00	UK00	2035	All	1,250	1,250	1,200
IE00-UKNI REAL 1	IE00	UKNI	2030	All	950	950	363
UK00-UKNI REAL 1	UK00	UKNI	2030	All	700	700	446
BA00-HR00 REAL 1	BA00	HR00	2035	All	998	302	267.03
BG00-RS00 REAL 1	BG00	RS00	2035	All	490	270	272.5
CZ00-SK00 REAL 1	CZ00	SK00	2035	All	500	500	133.35
DE00-SE04 REAL 1	DE00	SE04	2035	All	700	700	661
DE00-UK00 REAL 1	DE00	UK00	2030	All	1,400	1,400	1,675
DKW1-SE03 REAL 1	DKW1	SE03	2035	All	700	700	317
EE00-FI00 REAL 1	EE00	FI00	2035	All	700	700	630
EE00-LV00 REAL 1	EE00	LV00	2035	All	1,000	1,000	900
FI00-SE01 REAL 1	FI00	SE01	2035	All	800	800	270
FI00-SE01 REAL 2	FI00	SE01	2030	All	900	800	270
FI00-SE03 REAL 1	FI00	SE03	2040	All	800	800	500
GR00-ITS1 REAL 1	GR00	ITS1	2035	All	1,000	1,000	1,323.2
GR00-MK00 REAL 1	GR00	MK00	2035	All	500	500	5,63
GR00-TR00 REAL 1	GR00	TR00	2035	All	600	600	87,55
HR00-RS00 REAL 1	HR00	RS00	2040	All	600	600	44
HU00-RO00 REAL 1	HU00	RO00	2035	All	1,410	740	145.88
HU00-RS00 REAL 1	HU00	RS00	2030	All	500	500	120.1
ITCS-ME00 REAL 1	ITCS	ME00	2035	All	600	600	345
LT00-SE04 REAL 1	LT00	SE04	2030	All	600	600	284

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
LV00-SE03 REAL 1	LV00	SE03	2035	All	500	500	799
SE02-SE03 REAL 1	SE02	SE03	2035	All	2,000	2,000	0
SE02-SE03 REAL 2	SE02	SE03	2040	All	1,000	1,000	0
AT00-CH00 CONCEPT 1	AT00	CH00	2030	All	500	500	433.53
AT00-CH00 CONCEPT 2	AT00	CH00	2030	All	500	500	416.53
AT00-DE00 CONCEPT 1	AT00	DE00	2030	All	1,000	1,000	1,385.06
AT00-DE00 CONCEPT 2	AT00	DE00	2030	All	1,000	1,000	1,489.92
AT00-DE00 CONCEPT 3	AT00	DE00	2040	All	1,000	1,000	2,285.92
AT00-DE00 CONCEPT 4	AT00	DE00	2040	All	1,000	1,000	5,674.1
AT00-ITN1 CONCEPT 1	AT00	ITN1	2030	All	500	500	741.2
AT00-ITN1 CONCEPT 2	AT00	ITN1	2030	All	500	500	781.2
AT00-SI00 CONCEPT 1	AT00	SI00	2030	All	500	500	547.24
AT00-SI00 CONCEPT 2	AT00	SI00	2040	All	500	500	656.3
AT00-SI00 CONCEPT 3	AT00	SI00	2040	All	500	500	744.55
BE00-DE00 CONCEPT 1	BE00	DE00	2030	All	1,000	1,000	965
BE00-DE00 CONCEPT 2	BE00	DE00	2040	All	1,000	1,000	1,550
BE00-FR00 CONCEPT 1	BE00	FR00	2040	All	1,000	1,000	762
BE00-FR00 CONCEPT 2	BE00	FR00	2040	All	1,000	1,000	722
BE00-NL00 CONCEPT 1	BE00	NL00	2030	All	1,000	1,000	968.2
BE00-NL00 CONCEPT 2	BE00	NL00	2030	All	1,000	1,000	1,184
BE00-UK00 CONCEPT 1	BE00	UK00	2040	All	2,000	2,000	2,617
BG00-TR00 CONCEPT 1	BG00	TR00	2040	All	500	500	110.5
BG00-TR00 CONCEPT 2	BG00	TR00	2040	All	500	500	222.7
CH00-FR00 CONCEPT 1	CH00	FR00	2040	All	1,000	1,000	755
CH00-FR00 CONCEPT 2	CH00	FR00	2040	All	1,000	1,000	1,290
CH00-ITN1 CONCEPT 1	CH00	ITN1	2030	All	1,000	1,000	1,406
CH00-ITN1 CONCEPT 2	CH00	ITN1	2030	All	1,000	1,000	1,600
DE00-CH00 CONCEPT 1	DE00	CH00	2030	All	1,000	1,000	1,100
DE00-CH00 CONCEPT 2	DE00	CH00	2040	All	1,000	1,000	1,900
DE00-FR00 CONCEPT 1	DE00	FR00	2040	All	1,000	1,000	1,312
DE00-FR00 CONCEPT 2	DE00	FR00	2040	All	1,000	1,000	1,405
ES00-FR00 CONCEPT 1	ES00	FR00	2040	All	1,500	1,500	2,977
ES00-FR00 CONCEPT 2	ES00	FR00	2040	All	1,500	1,500	4,065
ES00-PT00 CONCEPT 1	ES00	PT00	2040	All	500	500	81
ES00-PT00 CONCEPT 2	ES00	PT00	2040	All	500	500	110
ES00-PT00 CONCEPT 3	ES00	PT00	2040	All	500	500	131
ES00-PT00 CONCEPT 4	ES00	PT00	2040	All	500	500	151.6
FR00-IE00 CONCEPT 1	FR00	IE00	2030	All	700	700	1,800
FR00-IE00 CONCEPT 2	FR00	IE00	2030	All	700	700	2,450
FR00-ITN1 CONCEPT 1	FR00	ITN1	2030	All	1,000	1,000	1,560

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
FR00-ITN1 CONCEPT 2	FR00	ITN1	2030	All	1,000	1,000	2,540
FR00-UK00 CONCEPT 1	FR00	UK00	2040	All	1,300	1,300	1,350
FR00-UK00 CONCEPT 2	FR00	UK00	2040	All	1,300	1,300	1,635
GR00-TR00 CONCEPT 1	GR00	TR00	2040	All	500	500	347.8
GR00-TR00 CONCEPT 2	GR00	TR00	2040	All	500	500	477.8
ITN1-SI00 CONCEPT 1	ITN1	SI00	2040	All	500	500	540
ITN1-SI00 CONCEPT 2	ITN1	SI00	2040	All	500	500	640
ITSI-TN00 CONCEPT 1	ITSI	TN00	2030	All	500	500	950
ITSI-TN00 CONCEPT 2	ITSI	TN00	2030	All	500	500	1,150
NL00-UK00 CONCEPT 1	NL00	UK00	2030	All	1,000	1,000	1,510
NL00-UK00 CONCEPT 2	NL00	UK00	2030	All	1,000	1,000	1,520
NOS0-UK00 CONCEPT 1	NOS0	UK00	2040	All	1,000	1,000	2,390
UK00-IE00 CONCEPT 1	UK00	IE00	2030	All	700	700	850
UK00-UKNI CONCEPT 1	UK00	UKNI	2030	All	700	700	950
DE00-NL00 CONCEPT 1	DE00	NL00	2030	All	1,000	1,000	2,075
DE00-NL00 CONCEPT 2	DE00	NL00	2040	All	1,000	1,000	2,125
BE00-LUG1 CONCEPT 1	BE00	LUG1	2040	All	500	500	210
NOS0-UK00 CONCEPT 2	NOS0	UK00	2040	All	1,000	1,000	2,800
AL00-ME00 CONCEPT 1	AL00	ME00	2040	All	500	500	9.4
AL00-ME00 CONCEPT 2	AL00	ME00	2040	All	500	500	10.5
AL00-RS00 CONCEPT 1	AL00	RS00	2040	All	500	500	24.5
AL00-RS00 CONCEPT 2	AL00	RS00	2040	All	500	500	92.8
AL00-MK00 CONCEPT 1	AL00	MK00	2040	All	500	500	47.7
AL00-MK00 CONCEPT 2	AL00	MK00	2040	All	500	500	77.7
AL00-GR00 CONCEPT 1	AL00	GR00	2040	All	500	500	232
AL00-GR00 CONCEPT 2	AL00	GR00	2040	All	500	500	240
AL00-ME00 CONCEPT 3	AL00	ME00	2040	All	500	500	12.5
AL00-ME00 CONCEPT 4	AL00	ME00	2040	All	500	500	36
AT00-CZ00 CONCEPT 1	AT00	CZ00	2030	All	500	500	365.38
AT00-CZ00 CONCEPT 2	AT00	CZ00	2030	All	500	500	499.18
AT00-CZ00 CONCEPT 3	AT00	CZ00	2040	All	500	500	1,314.5
AT00-HU00 CONCEPT 1	AT00	HU00	2030	All	1,000	1,000	866.4
AT00-HU00 CONCEPT 2	AT00	HU00	2040	All	1,000	1,000	1,703.05
BA00-ME00 CONCEPT 1	BA00	ME00	2040	All	500	500	18.86
BA00-ME00 CONCEPT 2	BA00	ME00	2040	All	500	500	24
BA00-HR00 CONCEPT 1	BA00	HR00	2040	All	500	500	162
BA00-HR00 CONCEPT 2	BA00	HR00	2040	All	500	500	117
BA00-HR00 CONCEPT 3	BA00	HR00	2040	All	500	500	132.1
BA00-ME00 CONCEPT 3	BA00	ME00	2040	All	500	500	36.88
BA00-ME00 CONCEPT 4	BA00	ME00	2040	All	500	500	29.46

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
BA00-RS00 CONCEPT 1	BA00	RS00	2040	All	500	500	54.58
BA00-RS00 CONCEPT 2	BA00	RS00	2040	All	500	500	62.48
BG00-GR00 CONCEPT 1	BG00	GR00	2040	All	500	500	221
BG00-GR00 CONCEPT 2	BG00	GR00	2040	All	500	500	225
BG00-RO00 CONCEPT 1	BG00	RO00	2040	All	500	500	221
BG00-RO00 CONCEPT 2	BG00	RO00	2040	All	500	500	219
BG00-RS00 CONCEPT 1	BG00	RS00	2040	All	500	500	283.44
BG00-RS00 CONCEPT 2	BG00	RS00	2040	All	500	500	283.44
BG00-MK00 CONCEPT 1	BG00	MK00	2040	All	500	500	110.8
BG00-MK00 CONCEPT 2	BG00	MK00	2040	All	500	500	181
CZ00-DE00 CONCEPT 1	CZ00	DE00	2040	All	500	500	1,550
CZ00-DE00 CONCEPT 2	CZ00	DE00	2040	All	500	500	3,243
CZ00-DE00 CONCEPT 3	CZ00	DE00	2040	All	500	500	3,244
CZ00-DE00 CONCEPT 4	CZ00	DE00	2040	All	500	500	3,245
CZ00-PL00 CONCEPT 1	CZ00	PL00	2040	All	1,000	1,000	779
CZ00-PL00 CONCEPT 2	CZ00	PL00	2040	All	1,000	1,000	10,000
CZ00-SK00 CONCEPT 1	CZ00	SK00	2040	All	500	500	345.3
CZ00-SK00 CONCEPT 2	CZ00	SK00	2040	All	500	500	396.24
DE00-DKE1 CONCEPT 1	DE00	DKE1	2030	All	500	500	383.3
DE00-DKE1 CONCEPT 2	DE00	DKE1	2030	All	500	500	384.3
DE00-DKE1 CONCEPT 3	DE00	DKE1	2040	All	500	500	385.3
DE00-DKE1 CONCEPT 4	DE00	DKE1	2040	All	500	500	386.3
DE00-DKE1 CONCEPT 5	DE00	DKE1	2040	All	500	500	387.3
DE00-DKE1 CONCEPT 6	DE00	DKE1	2040	All	500	500	388.3
DE00-DKW1 CONCEPT 1	DE00	DKW1	2040	All	2,000	2,000	4,800
DE00-NOS0 CONCEPT 1	DE00	NOS0	2040	All	1,000	1,000	4,000
DE00-NOS0 CONCEPT 2	DE00	NOS0	2040	All	1,000	1,000	4,000
DE00-PL00 CONCEPT 1	DE00	PL00	2040	All	2,000	2,000	1,080
DE00-PL00 CONCEPT 2	DE00	PL00	2040	All	2,000	2,000	10,000
DE00-SE04 CONCEPT 1	DE00	SE04	2040	All	500	500	478.6
DE00-SE04 CONCEPT 2	DE00	SE04	2040	All	500	500	479.6
DE00-SE04 CONCEPT 3	DE00	SE04	2040	All	500	500	480.6
DE00-SE04 CONCEPT 4	DE00	SE04	2040	All	500	500	481.6
DE00-SE04 CONCEPT 5	DE00	SE04	2040	All	500	500	482.6
DE00-SE04 CONCEPT 6	DE00	SE04	2040	All	500	500	483.6
CZ00-DE00 CONCEPT 5	CZ00	DE00	2040	All	500	500	3,246
CZ00-DE00 CONCEPT 6	CZ00	DE00	2040	All	500	500	3,247
DKE1-SE04 CONCEPT 1	DKE1	SE04	2040	All	500	500	150
DKE1-SE04 CONCEPT 2	DKE1	SE04	2040	All	500	500	150
DKE1-DKW1 CONCEPT 1	DKE1	DKW1	2030	All	600	600	600

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
DKE1-SE04 CONCEPT 3	DKE1	SE04	2030	All	500	500	150
DKE1-SE04 CONCEPT 4	DKE1	SE04	2040	All	500	500	150
DKW1-NOS0 CONCEPT 1	DKW1	NOS0	2040	All	1,000	1,000	1,150
DKW1-NOS0 CONCEPT 2	DKW1	NOS0	2040	All	1,000	1,000	850
DKW1-SE03 CONCEPT 1	DKW1	SE03	2030	All	500	500	471
DKW1-SE03 CONCEPT 2	DKW1	SE03	2030	All	500	500	472
DKW1-NL00 CONCEPT 1	DKW1	NL00	2040	All	1,000	1,000	3,250
DKW1-NL00 CONCEPT 2	DKW1	NL00	2040	All	1,000	1,000	3,850
DKW1-SE03 CONCEPT 3	DKW1	SE03	2030	All	500	500	471.4
DKW1-SE03 CONCEPT 4	DKW1	SE03	2030	All	500	500	471.4
DKW1-SE03 CONCEPT 5	DKW1	SE03	2035	All	500	500	471.4
DKW1-SE03 CONCEPT 6	DKW1	SE03	2035	All	500	500	471.4
EE00-FI00 CONCEPT 1	EE00	FI00	2030	All	700	700	850
EE00-FI00 CONCEPT 2	EE00	FI00	2040	All	700	700	900
EE00-LV00 CONCEPT 1	EE00	LV00	2030	All	1,000	1,000	1,150
EE00-LV00 CONCEPT 2	EE00	LV00	2040	All	1,000	1,000	1,200
FI00-NON1 CONCEPT 1	FI00	NON1	2040	All	500	500	1,000
FI00-SE01 CONCEPT 1	FI00	SE01	2030	All	800	800	300
FI00-SE01 CONCEPT 2	FI00	SE01	2040	All	800	800	300
FI00-SE02 CONCEPT 1	FI00	SE02	2030	All	500	500	450
FI00-SE02 CONCEPT 2	FI00	SE02	2040	All	500	500	450
FI00-SE03 CONCEPT 1	FI00	SE03	2030	All	500	500	450
FI00-SE03 CONCEPT 2	FI00	SE03	2040	All	500	500	450
FI00-NON1 CONCEPT 2	FI00	NON1	2040	All	500	500	1,000
FI00-SE01 CONCEPT 3	FI00	SE01	2040	All	800	800	300
FI00-SE02 CONCEPT 3	FI00	SE02	2040	All	500	500	450
FI00-SE02 CONCEPT 4	FI00	SE02	2040	All	500	500	450
FI00-SE03 CONCEPT 3	FI00	SE03	2040	All	500	500	450
FI00-SE03 CONCEPT 4	FI00	SE03	2040	All	500	500	450
GR00-ITS1 CONCEPT 1	GR00	ITS1	2040	All	500	500	1,700
GR00-ITS1 CONCEPT 2	GR00	ITS1	2040	All	500	500	2,000
GR00-MK00 CONCEPT 1	GR00	MK00	2040	All	500	500	48
GR00-MK00 CONCEPT 2	GR00	MK00	2040	All	500	500	118.75
HR00-HU00 CONCEPT 1	HR00	HU00	2040	All	500	500	410.4
HR00-HU00 CONCEPT 2	HR00	HU00	2040	All	500	500	624.6
HR00-RS00 CONCEPT 1	HR00	RS00	2040	All	500	500	89.45
HR00-RS00 CONCEPT 2	HR00	RS00	2040	All	500	500	124.23
HR00-SI00 CONCEPT 1	HR00	SI00	2040	All	1,000	1,000	91.1
HR00-SI00 CONCEPT 2	HR00	SI00	2030	All	1,000	1,000	126
HU00-SI00 CONCEPT 1	HU00	SI00	2030	All	500	500	183.6

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
HU00-SI00 CONCEPT 2	HU00	SI00	2030	All	500	500	327.6
HU00-SK00 CONCEPT 1	HU00	SK00	2030	All	500	500	441.5
HU00-SK00 CONCEPT 2	HU00	SK00	2030	All	500	500	303
HU00-RO00 CONCEPT 1	HU00	RO00	2040	All	2,000	2,000	1,939
HU00-RO00 CONCEPT 2	HU00	RO00	2040	All	2,000	2,000	2,500
HU00-RS00 CONCEPT 1	HU00	RS00	2040	All	500	500	478.18
HU00-RS00 CONCEPT 2	HU00	RS00	2040	All	500	500	2,500
HU00-SK00 CONCEPT 3	HU00	SK00	2040	All	500	500	441.5
HU00-SK00 CONCEPT 4	HU00	SK00	2040	All	500	500	303
ITCS-ME00 CONCEPT 1	ITCS	ME00	2030	All	500	500	750
ITCS-ME00 CONCEPT 2	ITCS	ME00	2030	All	500	500	900
LT00-LV00 CONCEPT 1	LT00	LV00	2030	All	500	500	300.7
LT00-LV00 CONCEPT 2	LT00	LV00	2030	All	500	500	369
LT00-LV00 CONCEPT 3	LT00	LV00	2030	All	500	500	430.28
LT00-SE04 CONCEPT 1	LT00	SE04	2040	All	500	500	1,025
LT00-SE04 CONCEPT 2	LT00	SE04	2040	All	500	500	1,850
ME00-RS00 CONCEPT 1	ME00	RS00	2040	All	500	500	54.82
ME00-RS00 CONCEPT 2	ME00	RS00	2040	All	500	500	83.5
MK00-RS00 CONCEPT 1	MK00	RS00	2040	All	500	500	95.34
MK00-RS00 CONCEPT 2	MK00	RS00	2040	All	500	500	144.78
NL00-NOS0 CONCEPT 1	NL00	NOS0	2040	All	1,000	1,000	2,600
NL00-NOS0 CONCEPT 2	NL00	NOS0	2040	All	1,000	1,000	2,610
NOM1-SE02 CONCEPT 1	NOM1	SE02	2040	All	500	500	250
NOM1-SE02 CONCEPT 2	NOM1	SE02	2040	All	500	500	250
NON1-SE01 CONCEPT 1	NON1	SE01	2040	All	500	500	250
NON1-SE01 CONCEPT 2	NON1	SE01	2040	All	500	500	250
NON1-SE02 CONCEPT 1	NON1	SE02	2040	All	500	500	250
NON1-SE02 CONCEPT 2	NON1	SE02	2040	All	500	500	250
NOS0-SE03 CONCEPT 1	NOS0	SE03	2040	All	500	500	250
NOS0-SE03 CONCEPT 2	NOS0	SE03	2040	All	500	500	250
NOS0-SE03 CONCEPT 3	NOS0	SE03	2040	All	500	500	250
NOS0-SE03 CONCEPT 4	NOS0	SE03	2040	All	500	500	250
PL00-SE04 CONCEPT 1	PL00	SE04	2040	All	500	500	1,640
PL00-SE04 CONCEPT 2	PL00	SE04	2040	All	500	500	1,690
PL00-SK00 CONCEPT 1	PL00	SK00	2040	All	1,000	1,000	1,338
PL00-SK00 CONCEPT 2	PL00	SK00	2040	All	1,000	1,000	10,000
RO00-RS00 CONCEPT 1	RO00	RS00	2040	All	500	500	149.01
RO00-RS00 CONCEPT 2	RO00	RS00	2040	All	500	500	248.9
SE01-SE02 CONCEPT 1	SE01	SE02	2040	All	1,000	1,000	630
SE01-SE02 CONCEPT 2	SE01	SE02	2040	All	1,000	1,000	630

BORDER	FROM NODE	TO NODE	YEAR	SCENARIO	DIRECT CAPACITY INCREASE (MW)	INDIRECT CAPACITY INCREASE (MW)	CAPEX (M€)
SE02-SE03 CONCEPT 1	SE02	SE03	2040	All	1,000	1,000	780
SE02-SE03 CONCEPT 2	SE02	SE03	2040	All	1,000	1,000	780
SE03-SE04 CONCEPT 1	SE03	SE04	2040	All	1,000	1,000	550
SE03-SE04 CONCEPT 2	SE03	SE04	2040	All	1,000	1,000	550
ITCS-ITS1 CONCEPT 1	ITCS	ITS1	2030	All	300	300	274
ITCS-ITS1 CONCEPT 2	ITCS	ITS1	2030	All	200	200	60
ITCS-ITN1 CONCEPT 1	ITCS	ITN1	2030	All	2,000	2,000	2,675
ITCS-ITCN CONCEPT 1	ITCS	ITCN	2030	All	800	0	0
ITCS-ITCN CONCEPT 2	ITCS	ITCN	2030	All	500	500	2,355
ITCS-ITS1 CONCEPT 3	ITCS	ITS1	2030	All	600	600	0
ITCS-ITCN CONCEPT 3	ITCS	ITCN	2030	All	500	500	0
ITCN-ITN1 CONCEPT 1	ITCN	ITN1	2030	All	2,000	2,000	0
ITCS-ITCN CONCEPT 4	ITCS	ITCN	2030	All	600	600	280
ITSI-ITCA CONCEPT 1	ITSI	ITCA	2030	All	2,000	2,000	1,410
ITS1-ITCA CONCEPT 1	ITS1	ITCA	2030	All	2,000	2,000	2,724
ITCS-ITS1 CONCEPT 4	ITCS	ITS1	2030	All	2,000	2,000	0
ITSA-ITCS CONCEPT 1	ITSA	ITCS	2030	All	1,000	1,000	1,422

Table A08: Electricity grid investment candidates

ANNEX III: DUNKELFLAUTE //

Table A09 provides the level of combined climate stress for each time horizon (1 is the highest stress) based on the climate years 1987 to 2016. It captures temperature, wind, and solar radiation level on the most stressful 2-week period of the year.

CLIMATE YEAR	TIME HORIZON		
	2030	2040	2050
1987	3	3	3
1988	20	20	19
1989	26	26	25
1990	23	24	24
1991	6	6	5
1992	28	28	27
1993	14	13	11
1994	22	22	22
1995	5	4	4
1996	25	25	26
1997	27	27	28
1998	16	16	18
1999	19	18	16
2000	13	12	10
2001	10	10	13
2002	7	7	7
2003	9	9	9
2004	18	19	20
2005	12	11	12
2006	17	17	17

Table A09: Ranking of climate years on the most stressful dunkel-flaute case for each time horizon

ANNEX IV: BIOFUEL POTENTIAL FOR MANURE //

PARAMETER	UNITS	DEFAULT VALUE
SUSTAINABLE POTENTIAL SHARES PER MANURE TYPES	%	See Table 30
YIELD INCREASE TO 2050	%	0 %

Table A10: Input assumptions used for feedstock potential in 2050 from manure

COUNTRY	SOLID				LIQUID	
	CATTLE	PIG	POULTRY	SHEEP/GOAT	CATTLE	PIG
AUSTRIA	3 %	30 %	30 %	1 %	5 %	61 %
BELGIUM	9 %	33 %	26 %	2 %	18 %	66 %
BULGARIA	34 %	49 %	46 %	13 %	67 %	98 %
CROATIA	0 %	0 %	0 %	0 %	0 %	0 %
CYPRUS	47 %	49 %	44 %	12 %	93 %	99 %
CZECH REPUBLIC	44 %	0 %	42 %	9 %	85 %	96 %
DENMARK	39 %	50 %	49 %	18 %	91 %	99 %
ESTONIA	38 %	48 %	1 %	7 %	73 %	97 %
FINLAND	13 %	41 %	42 %	2 %	22 %	82 %
FRANCE	30 %	49 %	45 %	13 %	61 %	97 %
GERMANY	30 %	44 %	45 %	18 %	60 %	88 %
GREECE	16 %	33 %	28 %	2 %	33 %	67 %
HUNGARY	37 %	36 %	34 %	11 %	70 %	72 %
IRELAND	19 %	0 %	47 %	11 %	45 %	99 %
ITALY	29 %	0 %	47 %	6 %	57 %	94 %
LATVIA	38 %	47 %	33 %	17 %	75 %	95 %
LITHUANIA	13 %	38 %	41 %	7 %	26 %	75 %
LUXEMBOURG	0 %	0 %	0 %	0 %	0 %	0 %
MALTA	16 %	38 %	29 %	1 %	32 %	76 %
NETHERLANDS	28 %	0 %	33 %	1 %	0 %	53 %
POLAND	37 %	0 %	49 %	19 %	73 %	98 %
PORTUGAL	5 %	18 %	40 %	2 %	11 %	36 %
ROMANIA	27 %	44 %	39 %	9 %	44 %	88 %
SLOVAKIA	45 %	44 %	40 %	30 %	90 %	88 %
SLOVENIA	28 %	46 %	46 %	7 %	65 %	92 %
SPAIN	21 %	46 %	47 %	19 %	40 %	93 %
SWEDEN	4 %	0 %	17 %	6 %	9 %	32 %

Table A11: Sustainable potential shares to calculate the sustainable potential for different manure types and per member state

ANNEX V: MARKET MODELLING INPUTS //

PARAMETER	SECTOR	SOURCE
DEMAND PROFILES		
PROSUMER	Electricity	ETM
MARKET	Electricity	ETM
EV	Electricity	ETM
PROSUMER HEAT	Heat	ETM
H_2 ZONE 1	Hydrogen	ETM
H_2 ZONE 2	Hydrogen	ETM
SYNTHETIC FUELS	e-fuels	ETM
INFRASTRUCTURE		
HYDROGEN PIPELINES	Hydrogen	ENTSOG
OFFSHORE HVDC CABLES	Electricity	European Hydrogen Backbone
OFFSHORE HVDC STATION	Electricity	?
ELECTRICITY REFERENCE GRID	Electricity	ENTSO-E
ELECTRICITY PRODUCTION		
HYDRO	Electricity	ENTSO-E
NUCLEAR	Electricity	ENTSO-E
GAS TURBINES (CH_4)	Electricity	ENTSO-E
GAS TURBINES (H_2)	Electricity	ENTSO-E
COAL	Electricity	ENTSO-E
LIGNITE	Electricity	ENTSO-E
OIL	Electricity	ENTSO-E
OTHER NON-RES	Electricity	ENTSO-E
OTHER RES	Electricity	ENTSO-E
CONCENTRATED SOLAR POWER	Electricity	ENTSO-E
ONSHORE WIND	Electricity	Trajectories
OFFSHORE WIND	Electricity	Trajectories
SOLAR PV	Electricity	Trajectories
PECD	Weather	ENTSO-E
RADIALLY AC-CONNECTED WTG	Renewables	ONDP
RADIALLY DC-CONNECTED WTG	Renewables	ONDP
HUB CONNECTED WTG	Renewables	ONDP
HUB CONNECTED HYDROGEN-WTG	Renewables	ONDP

PARAMETER	SECTOR	SOURCE
HYDROGEN SUPPLY SOURCES		
ELECTROLYSIS OFFSHORE	Hydrogen	Expansion Model
ELECTROLYSIS ONSHORE	Hydrogen	Data Collection + Expansion Model
HYDROGEN IMPORTS	Hydrogen	European Hydrogen Backbone
STEAM METHANE REFORMING CAPACITY	Hydrogen	ENTSOG
FLEXIBILITIES		
DSR	Electricity	ENTSO-E
BATTERY STORAGE	Electricity	ENTSO-E
HYDROGEN STORAGE	Hydrogen	ENTSOG
ELECTRIC VEHICLE BATTERIES	Electricity	WGSB Innovation Team
ELECTRIC VEHICLES		
START SOC	EV	WGSB Innovation Team
MIN SOC	EV	WGSB Innovation Team
CAPACITY	EV	WGSB Innovation Team
EFFICIENCY	EV	WGSB Innovation Team
PARTICIPATION IN DSR	EV	WGSB Innovation Team
AVAILABILITY PROFILES	EV	WGSB Innovation Team
CHARGING STATION CHARGE RATE	EV	WGSB Innovation Team
CHARGING STATION EFFICIENCY	EV	WGSB Innovation Team
SPACE AND WATER HEATING		
HEAT DEMAND FOR HHP	Space Heat	ETM
NUMBER OF HEAT PUMPS IN HHP	Space Heat	ETM
INSTALLED CAPACITY PER HEAT PUMP IN HHP	Space Heat	ETM
HEAT PUMP COP	Space Heat	ENTSO-E
BOILER EFFICIENCY IN HHP (HEAT RATE)	Space Heat	ENTSOG
SYNTHETIC FUELS		
CO_2/SYNTHETIC FUEL RATIOS	Hydrogen	WGSB Innovation Team
BIOGENIC CO_2 SUPPLY	Hydrogen	WGSB Supply Team
OTHER		
COMMODITY PRICES		WGSB Supply Team
GAS PRICE & CO_2 EMISSIONS FACTOR		WGSB Supply Team

Table A12: Market Modelling Inputs

ANNEX VI: ELECTRICITY LOSS FACTORS //

NODE	YEAR	LOSSES
AT00	2030	0.03
BE00	2030	0.04
BG00	2030	0.05
CY00	2030	0.04
CZ00	2030	0.04
DE00	2030	0.05
EE00	2030	0.00
ES00	2030	0.03
FI00	2030	0.04
FR00	2030	0.06
HU00	2030	0.03
IE00	2030	0.03
LT00	2030	0.07
LUG1	2030	0.05
LV00	2030	0.02
MT00	2030	0.08
NL00	2030	0.03
PL00	2030	0.04
PT00	2030	0.04
SI00	2030	0.06
SK00	2030	0.08
IT00	2030	0.06
DK00	2030	0.02
SE00	2030	0.03
GR00	2030	0.07
RO00	2030	0.04
HR00	2030	0.04

NODE	YEAR	LOSSES
AT00	2040	0.0809
BE00	2040	0.05216
BG00	2040	0.04
CY00	2040	0.02
CZ00	2040	0.04
DE00	2040	0.05
EE00	2040	0.05
ES00	2040	0.03
FI00	2040	0.06
FR00	2040	0.04
HU00	2040	0.03
IE00	2040	0.04
LT00	2040	0.07
LUG1	2040	0.04
LV00	2040	0.04
MT00	2040	0.09
NL00	2040	0.03
PL00	2040	0.04
PT00	2040	0.03
SI00	2040	0.05
SK00	2040	0.07
IT00	2040	0.03
DK00	2040	0.02
SE00	2040	0.03
GR00	2040	0.05
RO00	2040	0.03
HR00	2040	0.03

Table A13: Electricity Loss Factors

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